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10 January 2023

Ms Anna Collyer
Chair
Australian Energy Market Commission

By online submission

Dear Ms Collyer

Rule change request – Scheduled Lite Mechanism in the National Electricity Market (NEM)

The Australian Energy Market Operator (AEMO) requests that the Australian Energy Market Commission (AEMC) consider making a rule change under Section 91 of the National Electricity Law.

This rule change request details AEMO's proposal to establish the Scheduled Lite mechanism, put forward by the Energy Security Board in its Post 2025 Market Design Final Advice to Energy Ministers.

The Scheduled Lite mechanism would enable the integration of price-responsive distributed resources into market scheduling processes by establishing a voluntary and flexible participation framework. For consumers, this will translate into innovation and enhanced competition in consumer service offerings, delivering supplementary revenue streams beyond existing feed-in-tariffs and off-market retail demand response offerings. For the broader system, the proposal will 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; ultimately lowering costs to all consumers.

More broadly, the proposal seeks to harness the potential capabilities of price-responsive distributed resources, thereby facilitating the optimal allocation of resources to meet the demand for energy services over time, whilst ensuring that Australia's energy system remains secure and reliable.

AEMO looks forward to working collaboratively with the AEMC to support the implementation of this key ESB reform.

Any queries concerning this rule change proposal should be directed to Kevin Ly, Group Manager – Reform Development & Insights on Kevin.Ly@aemo.com.au.

Yours sincerely,

Violette Mouchaileh
Executive General Manager Reform Delivery

Electricity Rule Change Proposal

Scheduled Lite

January 2023

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New South Wales | Queensland | South Australia | Victoria | Australian Capital Territory | Tasmania | Western Australia
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1. Summary

In July 2021, the Energy Security Board (ESB) recommended the development of a 'Scheduled Lite' mechanism as part of its Post 2025 Market Design Final Advice to Energy Ministers, which was endorsed by National Cabinet in October 2021. The Australian Energy Market Operator (AEMO) was tasked with preparation of a high-level design and submission of a rule change request for the implementation of the reform, which forms part of the ESB's Consumer Energy Resources (CER) Implementation Plan[1].

Scheduled Lite is a voluntary mechanism that aims to lower barriers and offer incentives for price-responsive, distributed resources to provide visibility and participate in the market scheduling process of the National Electricity Market (NEM). Participation in Scheduled Lite presents new opportunities for distributed resources to make valuable contributions to the secure and reliable operation of the power system, whilst providing new ways to enable and reward consumers for their flexibility. Although a key focus of the mechanism is to improve visibility and better integrate CER into the market, it will also accommodate a range of resources that currently do not participate in scheduling processes, such as large users and small generating or bidirectional units currently exempt from registration in the NEM.

The forecast rapid growth in distributed resources, particularly those owned by household and business consumers, is drastically changing the energy landscape of the NEM. These resources are increasingly being aggregated into large portfolios and operated in response to price signals in a manner that is not visible to the market operator. This creates a range of operational challenges for AEMO for which its existing toolkit was not designed, particularly in managing complex operational conditions. Scheduled Lite responds to these challenges by integrating distributed resources into the market through a flexible framework that facilitates their value to the system, and in the longer term, enables distributed resources to contribute to the future firming capacity needs of the NEM.

Driven by the need to keep pace with the evolving mix of resources comprising the NEM's generation fleet, Scheduled Lite is essential to facilitate and support the participation of all resources in both a visible and dispatchable manner, to maintain the secure and reliable operation of the power system.

Collaborative and consumer-focused design

Scheduled Lite is designed to contribute to core customer outcomes described in the CER Implementation Plan, being that:

> '*Consumers have access to secure, reliable, affordable, and sustainable energy no matter how they choose to participate*'; and
>
> *'Consumers are able to realise the value of their flexible demand and DER'*[2].

The high-level design for Scheduled Lite, which has informed this rule change request, was built on the ESB's recommendations and developed in close collaboration with stakeholders. As part of the ESB's Customer Insights Collaboration, the ESB's Consumer Risk Assessment Tool helped inform and adjust the design. Scheduled Lite is part of a suite of reforms that aim

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[1] The ESB's Consumer Energy Resources (CER) Implementation plan was previously known as the Distributed Energy Resources (DER Implementation Plan).

[2] ESB, 2021. Available at: https://www.energy.gov.au/sites/default/files/2021-12/Attachment%20A%20-%20DER%20Implementation%20Plan%20-%20Three%20Year%20Horizon%20-%20December%202021.pdf

to support innovation in CER products and services that create value for all energy consumers, improving energy affordability, empowering consumers around how they manage their energy use, and delivering on Australia's emissions reduction goals. By integrating into, and leveraging existing, functionality within the current market framework and recent rule changes, it supports greater consumer choice and engagement in the market, where consumers choose to participate. Any market complexities, risks and day-to-day participation obligations are managed by traders on behalf of consumers.

Two complementary models have been developed as part of the high-level design:

- Visibility model: to provide visibility of price--responsive, distributed resources and their market intentions. Participating traders will be required to provide a forecast of generation and consumption at various price points over the short-term operational horizon. This visibility will improve load and price forecasting accuracy, leading to market operational efficiency and reducing the frequency of emergency interventions that may include curtailing either consumer-owned resources or grid-scale assets.
- Dispatch model: to integrate price-responsive distributed resources into the NEM dispatch and scheduling processes. This will contribute to the dispatchability of the power system, enhancing controllability, firmness and flexibility and supporting the balancing of supply and demand. This drives alignment between price-responsive resources and power system needs, delivering the critical services that will be required as penetration of distributed resources rises and thermal generation exits the system.

The Visibility and Dispatch models work in tandem to harness the potential capabilities of distributed resources. Together, they facilitate more effective allocation of resources to meet the demand for energy services over time, while ensuring that Australia's energy system remains secure and reliable.

Proposed changes to the National Electricity Rules (NER)

This rule change request proposes modifications to the NER to give effect to the proposals outlined in the Scheduled Lite high-level design. The proposed amendments aim to establish a flexible framework to efficiently integrate price-responsive, distributed resources into the NEM by lowering barriers to participation and better valuing the services they provide.

The key proposed amendments include:

- In NER chapter 2, the establishment of a new light scheduling unit (LSU) classification to enable distributed resources (including portfolios of aggregated resources) to be represented in market scheduling processes and systems. AEMO proposes that the new LSU classification references two alternative modes of participation, Visibility and Dispatch, corresponding to the models proposed in the high-level design.
- In NER chapter 3, the integration of LSUs and their operational modes into market scheduling processes. This includes the establishment of:
  - Operational requirements, including provision and integration of Visibility information.
  - Requirements for resource aggregation.
  - Requirements for participation in central dispatch processes, including appropriate dispatch conformance criteria.
  - The ability to value Visibility services and other incentives to encourage participation.

Contribution to the National Electricity Objective (NEO)

Scheduled Lite contributes to a more reliable, efficient and secure system for all consumers in three ways:

1. *By maximising the value of distributed resources for consumers and the broader system through increased competition and access to markets*. Scheduled Lite increases access to markets and revenue opportunities for distributed resources, including CER, by rewarding service provision and lowering barriers to participation in market scheduling processes. The framework is designed around incentives and market signals to facilitate participation, rather than mandatory requirements, to recognise the breadth and maturity of business models and to align incentives with power system needs.
2. *By promoting efficient system operation and delivery of electricity services.* Scheduled Lite is designed to address risks associated with growing operational uncertainty and drive more efficient use of security and reliability measures. It will assist in minimising uncertainty within operational timeframes, reducing the need to procure frequency services and emergency reserves. It will also reduce the need for unnecessary use of curtailment and backstop mechanisms and support timely commitment decisions in the market. More efficient system operation lowers system service costs for all consumers.
3. *By enhancing the efficiency of long-term investment in electricity services.* Scheduled Lite would enhance system-wide forecasting and planning assessments over the long-term, delivering a more efficient mix of resources to meet consumer needs and lowering overall system costs. It achieves this outcome by facilitating the visibility and active participation of distributed resources in the market, helping to align their behaviour with the needs of the system. Over the long-term, effective market integration of these resources could avoid the need to duplicate capacity via large-scale resource investments, including network build, to fulfil power system needs.

Package of documents

This rule change request is accompanied by several appendices, including the high-level design, justification and use cases, as described below.

Document	Description
Rule change request	NER Rule Change Request
Appendix A – Justification for Scheduled Lite	Appendix establishing the case for change and a narrative for how Scheduled Lite meets consumer and system needs.
Appendix B – High-level design	Technical document describing operationalisation, new guidelines and changes to systems and processes
Appendix B.1 – Related projects	Relationship of Scheduled Lite with related projects (i.e. Project EDGE; SCADA for DER; Power System Data Communications Standard)
Appendix B.2 – Stakeholder feedback	Summary and responses to stakeholder feedback to date
Appendix B.3 – Use cases	Use cases stepping through how different distributed resources (incl. aggregations) may participate in Visibility and Dispatch models
Appendix C – Mapping of proposed rule amendments	Mapping of proposed rule amendments to high-level design elements.

AEMO looks forward to working collaboratively with the AEMC to support the implementation of this key ESB reform.

2. Relevant background

2.1. ESB CER Implementation Plan

The ESB was tasked by the former Council of Australian Governments (COAG) Energy Council to deliver a market design for the NEM to meet the needs of the energy transition beyond 2025. In its Post 2025 Final Advice to Ministers, the ESB recommended a CER Implementation Plan setting out reform activities necessary to support the effective integration of CER and flexible demand. In October 2021, Ministers endorsed the ESB's recommendations, tasking the ESB and market bodies with delivery of the CER Implementation Plan over the next three years, with tasks assigned to respective market bodies as appropriate[3].

The reforms outlined in the CER Implementation Plan address a range of technical, regulatory and market issues over a three-year period. The reforms are intended to leverage new technology and data, improve access and efficiency, enhance market participation, and strengthen customer protections and engagement. The Plan sequences key dependencies to ensure reforms are introduced in a timely manner to address urgent needs associated with the rapid take-up of CER and flexible demand.

Scheduled Lite is a Horizon One reform within the CER Implementation Plan and is one of several initiatives that aim to create value for customers through the integration of CER and flexible demand within the wholesale market. As part of the CER Implementation Plan, AEMO was tasked with the preparation of a high-level design and the submission of a rule change request to the AEMC for the implementation of Scheduled Lite.

The purpose of Scheduled Lite is to enable small to medium sized resources (including demand and generation) to actively participate in market processes or dispatch. For the purpose of this rule change proposal, these resources will be referred to generally as 'distributed resources' as they refer to a broad range of customers and assets including CER, flexible demand and other unscheduled resources.

As a market mechanism, the role of Scheduled Lite is foundational to enabling greater customer side participation in the NEM in the long term, beyond 2025. To achieve this, the ESB proposed two models forming the basis for this proposal:

- Visibility model: provide additional information on the future behaviour and intentions of price-responsive resources, without requiring participation in dispatch or full responsiveness.
- Dispatchability model: encourage additional resources to participate directly in scheduling and potentially setting the market price, through reducing some of the barriers to participation and providing greater incentives.

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[3] Department of Climate Change, Energy, the Environment and Water, 2021. Available at https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/post-2025-market-design/der-implementation-plan-design-and-implementation-process

2.2. Stakeholder engagement

AEMO has engaged extensively with stakeholders in the development of this rule change request, building on the engagement undertaken by the ESB during the development of Scheduled Lite as a reform initiative captured within the CER Implementation Plan and part of Final Advice to Ministers. Engagement has included:

- A Consumer Insights Collaboration workshop in September 2022, held jointly with the ESB, to explore the customer journey, barriers and opportunities, and consumer interface with the Scheduled Lite mechanism. A summary of workshop outcomes is included in Appendix A.
- A series of workshops with the Distributed Energy Resources (DER) Market Integration Consultative Forum (MICF), which have informed a broad range of Scheduled Lite design elements. A detailed overview of feedback received is included in Appendix B.2.
- Public consultation on a draft high-level design paper in June 2022, which received six submissions from industry commenting on a range of design matters. A detailed overview of feedback received from these submissions is included in Appendix B.2, and submissions are on AEMO's website[4].
- A number of engagements with ESB forums, including the CER Stakeholder Working Group. These sessions were focused on engaging on the proposed design of the mechanism, understanding its impacts on stakeholders and its linkages to related reform initiatives.
- A number of meetings and workshops with individual stakeholders including retailers, energy service and technology providers, network service providers, consumer advocates and others; these typically focused on particular aspects of the design and approach.

AEMO thanks all stakeholders who have engaged in the design process to date for valuable feedback and perspectives which have helped inform and refine this proposal.

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[4] At https://aemo.com.au/initiatives/trials-and-initiatives/scheduled-lite

3. Statement of issue

Australia's electricity supply chain and energy system are shifting at a rapid pace, requiring the market to evolve to support the continued supply of secure and reliable electricity. Scheduled Lite is a key reform designed to integrate distributed resources into the market and realise their full value for consumers and the system.

Below are three core issues and challenges that this Scheduled Lite rule change proposal seeks to address.

3.1. Changing role and opportunity for consumers

Consumer-driven growth in rooftop solar photovoltaics (PV), battery storage, electrification of transport and continued advances in digital technology are revolutionising the way consumers receive, use and generate energy.

Today the penetration of these resources represents a sizeable and growing proportion of total price-responsive generation and demand in the NEM. The aggregate capacity of controlled distributed resources is already approaching that of the largest 'units' on the system. Further, by 2050, the Integrated System Plan (ISP) modelling forecasts that virtual power plants (VPPs), vehicle-to-grid (V2G) services and other emerging technologies will provide approximately 31 gigawatts (GW) of dispatchable storage capacity[5].

The NEM's existing market framework does not support or reward the visibility or scheduling of CER in the market. As a result, the procurement of system security services and energy to ensure reliability of supply mostly occurs from scheduled and semi-scheduled grid-scale resources. As a result, the investments consumers have made in CER and behind-the-meter demand flexibility are not rewarded in the market. Specifically, small customers are locked out from participating and engaging in the market; and off-market arrangements such as retailer-led demand response programs and the behaviour of VPPs are neither visible nor easily forecastable in the energy market, and are less transparent than on-market arrangements. Consequently, costs to deliver essential system services and ensure system reliability will be higher and capital may be misdirected.

By making visible the price-responsive intentions of CER, as well as removing barriers to market participation, a unique opportunity is presented to both unlock value for consumers that invest in distributed resources and lower costs for all energy system users. If this inability to unlock value from consumer-owned resources persists:

- Consumers are denied an opportunity to realise additional market revenue streams;
- More frequent intervention will be required to maintain the secure and reliable operation of the system (see Section 3.2); and
- Unnecessary investments in additional generation and network resources may occur (see Section 3.3).

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[5] AEMO 2022 Integrated System Plan (ISP), at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

3.2. Visibility of distributed resources

The current market framework does not provide a mechanism for visibility information to be shared with the market, nor does it value the visibility of distributed resources and flexible demand.

Grid-scale generators are required to participate as scheduled resources in the NEM with their bids providing visibility of their availability and market intentions. In comparison, unscheduled price-responsive resources, such as distributed storage aggregated into VPPs, respond to energy price signals beyond the visibility of the market and forecasting processes. A lack of visibility of these resources increases short-term operational uncertainty resulting in greater intervention by AEMO and Network Service Providers (NSPs) to maintain a secure and reliable power system. Interventions by AEMO and NSPs include actions such as the curtailment of rooftop solar PV, the application of network constraints across parts of the network, and maintaining higher operating reserves and security margins across the grid.

In addition, market participants trading energy and services from scheduled and semi-scheduled resources are unaware of the behaviour and intentions of this growing resource base across all NEM regions. This can interact with participants' unit commitment decisions and portfolio management considerations across operational timeframes.

A lack of visibility by AEMO and market participants of the behaviour and intentions of price-responsive resources, introduces additional uncertainty into operational timeframes; while also impacting longer-term planning and investment studies and models. The effect of this uncertainty contributes to the challenges in maintaining the efficient, safe and secure operation of the electricity system.

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. The adoption of these types of resources is changing consumers' grid demand, particularly during daylight hours, leading to record low levels of minimum operational demand[6] and creating power system security and operability issues[7].

The magnitude of these challenges is set to escalate, as the rapid uptake of these resources continues while their operation remains unpredictable[8]. This affects the accuracy of the outcomes of market processes (such as forecasting processes) which are used to inform security and reliability functions as well as inform the market for coordination and commitment decisions.

AEMO already performs and administers a variety of functions to take into consideration the behaviour and intentions of these resources. While these tools and arrangements improve AEMO's ability to operate and plan for the secure and reliable operation of the system, and can support decision making by market participants, they have a number of limitations:

- The Demand Side Participant (DSP) Information Portal: the portal is one channel through which information on off-market price-responsive and reliability-responsive activity, contracts and agreements are provided to the market operator and made available to market participants. This portal enables the provision of inputs from financially responsible

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[6] Minimum operational demand means the lowest level of demand supplied by the grid in any given day, week or year.

[7] AEMO's ISP Appendix 7. Power system security, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a7-power-system-security.pdf?la=en

[8] Without AEMO visibility of price-responsive distributed resources, AEMO forecasts can contain significant, untenable errors (greater than 1 GW), which may result in compromised system security, or the inefficient procurement of reserves.

market participants to AEMO used to inform load forecasts within a high DER power system. However, a considerable gap going forward is real-time visibility of the intentions (forecasts) actual behaviour of these price-responsive resources.

- DER Register: the DER Register is a database of static information about distributed resource devices, such as the number of devices installed, manufacturer and rated capacity. Data is collected from residential or business locations across the NEM at the point in time of CER installation or upgrade. It does not consider any actor-led or market-based intentions or behaviour. This resource data informs forecasting, planning and power system models and is used to support the efficient operation of the electricity system, however its functional value depends upon initial and maintained data quality. AEMO's Engineering Framework identified the need to establish confidence in DER Register data, including robust data entry, validation and compliance arrangements to unlock its value. Work is currently underway to enhance data quality for the DER Register. The Scheduled Lite mechanism aims to leverage the DER Register enhancement as part of the Stage 2 development.
- Australian Solar Energy Forecasting System for rooftop systems (ASEFS2): ASEFS2 is a tool for modelling rooftop PV as an input in load forecasts. Using a combination of statistical and physical methods, along with numerical weather prediction-based models, ASEFS2 produces solar generation forecasts up to seven days ahead and in 30-minute resolution. This approach allows load forecasting models to use rooftop PV as an explanatory variable for forecasting operational demand (which is key given the penetration of distributed PV). The effect of localised weather on intraday volatility in solar output can lead to large forecasting uncertainty in ASEFS2 forecasts. Into the future, more behind-the-meter actor-led control of price-responsive rooftop solar PV will compound this volatility, and contribute to larger forecasting uncertainty.

The suitability of existing market arrangements and operational tools is inadequate to accommodate these growing visibility challenges. So long as a gap remains in both the provision of operational visibility and submission of price-responsive intentions within the market, the system operator will need to increasingly forecast behaviour prospectively while relying on interventions such as curtailing resources or activation of emergency reserves to maintain system security.

3.3. Contribution of distributed resources to firming capacity requirements

As coal-fired generation exits and the generation fleet transitions to one dominated by variable renewable generation, the NEM must efficiently match when and where electricity is generated, with when and where it is needed. To do so, large investments in firming capacity are required to replace the retirement of coal-fired generation, with the last units expected to exit the power system as early as 2040.

Currently, the NEM relies on 23 GW of dispatchable firm capacity from coal-fired generation, 11 GW from gas-fired and liquid-fuelled generation, 7 GW from hydro generation (excluding those that rely solely on pumped hydro to operate), and 1.5 GW from dispatchable energy storage (including pumped hydro and battery storage)[9].

Without coal-fired generation, ISP modelling suggests that the NEM will require firming capacity by 2050 comprised of 46 GW / 640 gigawatt hours (GWh) of dispatchable storage, in all its forms. The ISP modelling expects that VPPs, V2G services and other emerging technologies will provide approximately 31 GW of dispatchable storage capacity. However, this is subject to these resources being integrated into market scheduling processes, and a precursor that these types of resources are visible, dispatchable, and predictable. Scheduled Lite provides an opportunity for distributed resources / CER to make valuable contributions to the firming capacity required by the future power system.

In the event that firming capacity from distributed resources cannot be leveraged because it is not integrated into market scheduling processes, it is expected additional investment in grid-scale storage will be required to cover any resulting gaps.

Appendix A explores the potential cost of duplicating a proportion of projected, coordinated distributed storage capacity, with grid-scale storage in the absence of a mechanism to facilitate the efficient utilisation of distributed resources achieved by bringing them in-market.

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[9] AEMO's 2022 Integrated System Plan, June 2022. Available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

4. Scheduled Lite design

4.1. Overview of design

AEMO has developed a high-level design for the Scheduled Lite mechanism which aims to address the issues identified in Section 0.

Scheduled Lite provides a voluntary mechanism to incentivise price-responsive, distributed resources to provide visibility and participate in the market scheduling process of the NEM. The high-level design is provided in Appendix B.

This section provides a brief overview of key design elements to support the rule change proposal outlined in Section 6.

Two complementary models have been developed as part of the high-level design:

- **Visibility model**: the Visibility model is designed to provide visibility of price--responsive, distributed resources and their market intentions, leading to more accurate short-term load and price forecasting. Participating traders will be required to provide a forecast of generation and consumption at various price points over the short-term operational horizon called 'indicative bids'.
- **Dispatch model**: the Dispatch model will integrate unscheduled price-responsive resources (for example, price-responsive CER and flexible demand) into the NEM central dispatch and scheduling processes. Traders will be able to provide bids for their generation and load, receive and follow dispatch targets. Through participation in dispatch, traders could also access existing or potential future markets that require services from scheduled resources.

The registration and participation framework for both models are similar, with the mechanism designed to facilitate participation by a range of customers and traders as well as both consumption and generation resources that are not currently scheduled in the market. This may include:

- Aggregated portfolios of small resources through VPPs;
- Non-scheduled generating and bidirectional units;
- Large users; and
- Aggregated demand response portfolios.

Importantly, small customers will generally not participate in Scheduled Lite directly and instead a registered trader will participate on their behalf.

Key participation elements include:

- Voluntary participation supported by an incentive framework and a flexible operating model.
- Participant registration in accordance with the NER registration framework, with participants able to be registered as Integrated Resource Providers (IRPs), Market Customers or Generators.

- A new classification, 'light scheduling unit' (LSU), into which resources may be classified for participation in both models.
- Two modes of participation, Visibility mode and Dispatch mode, with different eligibility requirements and obligations for participation. These operationalise each of the two proposed Scheduled Lite models.
- A minimum aggregated capacity threshold enabling traders to 'graduate' from Visibility to Dispatch when their portfolio reaches an appropriate size, and they have developed the necessary operational capabilities.
- Self-management of aggregated resource portfolios, including automated aggregation and re-aggregation of resources in accordance with zones.
- Flexibility in participation models, with optionality around whether (and how) flexible distributed resources are separated for participation in accordance with flexible trading arrangement models (noting the participation framework does not involve baselining).

Visibility model

The Visibility model will enhance the accuracy of load and price forecasting by enabling traders to communicate the forecast behaviour of price-responsive resources to AEMO for use in market scheduling processes. Traders will provide standing data as well as real-time, forecast and indicative bids for consumption and generation via an application programming interface (API) over the short-term operational horizon. Traders will not be required to participate in central dispatch.

Scheduled Lite is a voluntary mechanism and as a consequence its value to the power system is dependent on the volume and rate at which customers choose to participate in the mechanism. The benefits of participation in the Visibility model largely accrue to the market rather than the individual customer or trader, and as such a visibility service payment is proposed as an incentive for participation.

Traders that meet performance thresholds for forecast accuracy and consistency of data submissions would be eligible for incentives. A trader may be suspended from participation if their performance is outside or significantly deviates from the thresholds. The framework would also allow for flexible participation over operational timeframes rather than requiring 24/7 active operation, with benefits only accruing to a trader during periods of active participation.

Dispatch model

The Dispatch model is designed to encourage resources that are currently below NEM scheduling thresholds to actively participate in the central dispatch process by recognising the main challenges and reducing barriers to enable wider participation.

Dispatchability services - comprising controllability, firmness and flexibility - are essential requirements for the operation of the power system. As thermal generation exits the power system it will become increasingly valuable for dispatchability services to be provided by distributed resources. The Dispatch model aims to establish fit-for-purpose arrangements for distributed resources to participate in market scheduling processes.

A minimum threshold of 5 MW is proposed for participation in Dispatch mode, and new Supervisory Control and Data Acquisition (SCADA) arrangements that better suit distributed resources will be an essential pre-requisite. Technical standards for communication and coordination of distributed resources that will be developed through the ESB's interoperability policy will provide an important foundation for the implementation of Scheduled Lite.

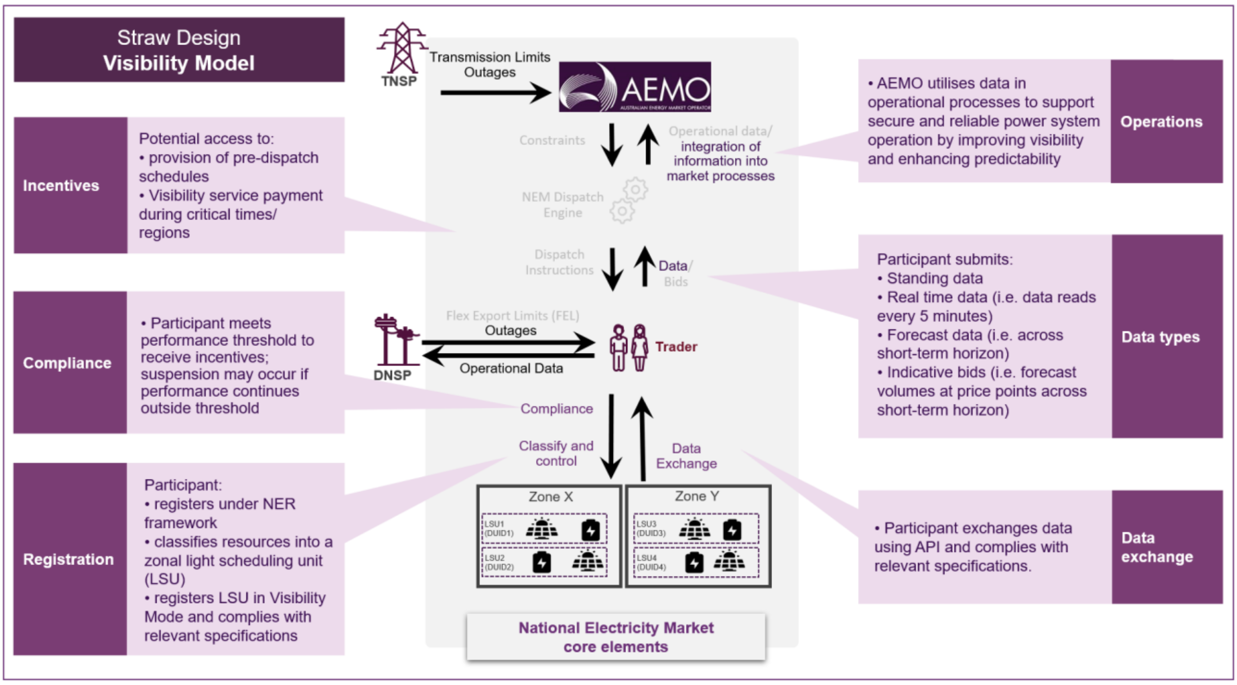
AEMO will update constraint equations to incorporate an LSU that operates in Dispatch mode at the time of registration. The trader will be responsible for managing their energy, frequency control ancillary services (FCAS) and local service bids and dispatch to ensure they operate within the flexible export limits (FELs)[10] for their portfolio.

A trader will bid into the NEM wholesale spot market when an LSU is operating in Dispatch mode for energy and FCAS the same as any other scheduled resource, with bids indicating the expected quantity of consumption or production at different price bands. The NEM Dispatch Engine (NEMDE) will treat LSUs as any other scheduled unit, including producing co-optimised energy and FCAS dispatch instructions. Traders will need to manage their portfolio to conform to the dispatch instructions issued for their LSU, such as providing the appropriate limits to allow for co-optimisation (for example, providing an FCAS trapezium per LSU).

Based on stakeholder feedback, the ability to co-optimise energy and FCAS and the eligibility to provide Regulation FCAS are likely to encourage some participation in Dispatch. However, the potential to provide future new services like operating reserves or capacity certificates are likely to provide stronger participation incentives. If these new mechanisms do not progress, then an incentive scheme (like capacity certificates) specific to distributed resources may need to be considered provide a sufficient incentive to encourage participation.

Figure 1 and Figure 2 below summarise the key design elements for the Visibility and Dispatch models respectively.

Figure 1 Straw design for the Visibility model



Incentives

Potential access to:
- provision of pre-dispatch schedules
- Visibility service payment during critical times/ regions

Compliance

- Participant meets performance threshold to receive incentives; suspension may occur if performance continues outside threshold

Registration

Participant:
- registers under NER framework
- classifies resources into a zonal light scheduling unit (LSU)
- registers LSU in Visibility Mode and complies with relevant specifications

Operations

- AEMO utilises data in operational processes to support secure and reliable power system operation by improving visibility and enhancing predictability

Data types

Participant submits:
- Standing data
- Real time data (i.e. data reads every 5 minutes)
- Forecast data (i.e. across short-term horizon)
- Indicative bids (i.e. forecast volumes at price points across short-term horizon)

Data exchange

- Participant exchanges data using API and complies with relevant specifications.

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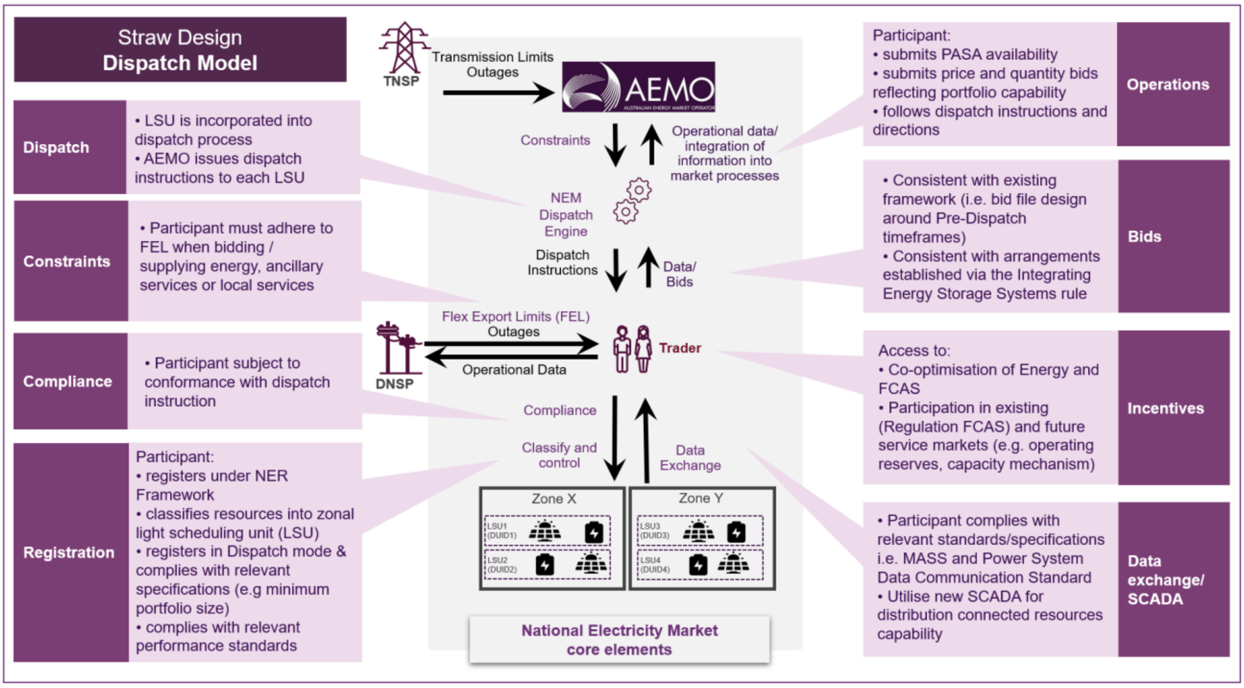
[10] 'Flexible export limits' are also commonly referred to as 'dynamic operating envelopes'.

Figure 2 Straw design for the Dispatch model



4.2. Design approach

Foundations for the design

The approach to the Scheduled Lite design has been underpinned by the following principles[11]:

- The Scheduled Lite framework is designed around **incentives and market signals** to facilitate participation rather than regulation and mandatory participation. Scheduled Lite needs to offer sufficient incentives and lower barriers for resources to provide greater visibility to the market or participate central dispatch. Participation is accompanied by appropriate performance thresholds and compliance obligations that balance the need for reliable outcomes with cost and ease of participation. AEMO considers that a voluntary approach aligning incentives with benefits to the power system is more likely to drive accurate forecasting and compliance, and as a consequence maximise the utilisation and integration of CER and flexible demand in the market.

- The approach **enhances options for consumers** through more opportunities for market engagement, with complexity, risk and day-to-day participation largely managed by traders on behalf of consumers.

- The proposed framework is **technology-neutral and facilitates a range of business models** without eroding consumer protections. Once the framework is established, traders will have opportunities to adapt their business models and consumer offerings to take advantage of the opportunities offered by participation in Scheduled Lite, including visibility payments and access to new markets and services, in accordance with consumer preferences. Importantly, the mechanism is intended to work within the established NER

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[11] See AEMC, 2019. *Applying the energy market objectives*. Available at https://www.aemc.gov.au/sites/default/files/2019-07/Applying%20the%20energy%20market%20objectives_4.pdf

participant registration framework. For small customers, participation is expected to occur via an authorised retailer.

- **Risks are allocated to the party best able to manage them**. The Scheduled Lite framework is designed for traders to manage the risks of participation. Consumers themselves (particularly small consumers) are not expected to participate directly in the mechanism, but rather through market offers that align with their preferences. The trader will be the consumer's financially responsible market participant.

Thoughtful and pragmatic design

The Scheduled Lite mechanism has been conceived in collaboration with stakeholders and is designed to address specific barriers facing consumers. It contributes to core customer outcomes described in the CER Implementation Plan, being that:

- '*Consumers have access to secure, reliable, affordable, and sustainable energy no matter how they choose to participate*'; and
- *'Consumers are able to realise the value of their flexible demand and DER'*[12].

This proposal for a new mechanism is considered in its design approach. It integrates into, and leverages, existing functionality within the current market framework. It also builds on capabilities introduced by recent or proposed rule changes that specifically seek to enable greater consumer choice and engagement in the market as outlined in Table 1.

Table 1 Scheduled Lite design builds on recent rule changes

Market feature or framework	Scheduled Lite relationship
Trader Services model:[13] The Trader Services construct envisions a simplification of the participation framework, minimising the number of market participant registration categories (i.e. 'traders') such that traders could offer different services to and from customers, subject to meeting relevant service specifications. Furthermore, in line with the characteristics of a two-sided market, this construct envisions an energy market in which both demand and generation would participate in the market and respond to price based on cost preferences.	Both Scheduled Lite models would unlock the ability of more resources to provide services into market scheduling processes. Furthermore, different types of traders participating in Dispatch mode could choose to participate in energy and ancillary service markets on behalf of customers. Traders aggregating CER and distributed resources into portfolios and participating in dispatch may even set the market price for energy or ancillary services.
Integrating Energy Storage Systems (IESS) rule change:[14] The IESS Final Determination established the role of the IRP; and defined arrangements for how bi-directional resources would participate and be integrated into market processes and systems.	Scheduled Lite would leverage the registration and participation arrangements and operational capabilities being established through IESS that allow IRP (formerly Small Generation Aggregators) to aggregate small generation and bi-directional resources for participation in energy and FCAS markets.
Flexible Trading Arrangements rule change proposal (pending):[15] Would facilitate the separation of price-responsive resources from passive resources within a customer's electrical installation for market purposes, supporting consumers' choice to engage a separate trader and provides services from these resources.	Pending the next steps for the flexible trading arrangements rule change consultation, this functionality would support the delineation of price-responsive resources participating in either Visibility or Dispatch mode without the requirement for baselines. It would enable traders to participate in Scheduled Lite with a customer's controllable resources only, rather than needing to account for passive/uncontrollable use, enhancing the ability to comply with performance and compliance requirements.

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[12] ESB, 2021. Available at: https://www.energy.gov.au/sites/default/files/2021-12/Attachment%20A%20-%20DER%20Implementation%20Plan%20-%20Three%20Year%20Horizon%20-%20December%202021.pdf

[13] ESB, 2021, p 84. Available at https://esb-post2025-market-design.aemc.gov.au/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf

[14] AEMC, 2021. Available at https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

[15] AEMO, 2022. Available at https://www.aemc.gov.au/rule-changes/flexible-trading-arrangements-consumer-energy-resources

Market feature or framework	Scheduled Lite relationship
Wholesale Demand Response Mechanism (WDRM):[16] Instigated the establishment of a range of portfolio management capabilities enabling traders (in this case Demand Response Service Providers) to manage a portfolio of National Metering Identifiers (NMIs).	Scheduled Lite would build on existing portfolio management capabilities enabling the aggregation of NMIs for market forecasting, bidding, settlement and retail processes (i.e. LSU NMI management; customer switching).

Leveraging such initiatives will support the Scheduled Lite mechanism to efficiently provide the vehicle for participation of distributed resources in the market scheduling process. Further, once the Scheduled Lite mechanism is implemented, other policy and reform initiatives could be linked to participation in Scheduled Lite. For instance, a state-based incentive scheme could link eligibility for incentive payments to participation in Scheduled Lite (and in turn utilise market information to validate eligibility and performance).

Further considerations influencing participation

The rate at which eligible resources participate in the Scheduled Lite mechanism, and therefore its effectiveness, could be influenced by the following key factors:

- Pace of progress of related initiatives: Scheduled Lite is an initiative in the ESB’s CER Implementation Plan and is one of several initiatives that aim to create value for customers, through the integration of CER and flexible demand within the wholesale market. Successful coordination of the development and implementation of those initiatives would facilitate broader participation in the Scheduled Lite mechanism. For instance, if progressed, flexible trading arrangements would support participation in the Scheduled Lite mechanism by enabling price-responsive, distributed resources to be separately traded and aggregated into an LSU, and simplify compliance arrangements for market participants (see Table 1).

- Pace of technology change and consumer uptake: a slowing in the pace of consumer device technological change, a slower uptake in new devices by consumers or higher technology costs for consumers would result in smaller volumes of price-responsive, distributed resources and in turn a smaller participation rate in Scheduled Lite.

- Evolution of network tariffs: Scheduled Lite aims to enable innovation in consumer service offerings. Evolution of network tariffs to align with changing system dynamics and needs have the potential to complement and enhance participation in Scheduled Lite with traders developing attractive consumer service offerings that optimise and respond to signals across networks and energy markets.

- Appropriate incentives: the voluntary nature of the Scheduled Lite mechanism is underpinned by an incentive framework which recognises the contribution of distributed resources to the efficient operation of the power system. A voluntary approach that aligns incentives with benefits to the power system is likely to encourage participation and drive accurate forecasting and compliance by traders. Further, related initiatives such as the emerging market reforms contained in the ESB's Post 2025 Electricity Market Design[17] could represent a strong incentive for participation in Scheduled Lite (Dispatch model). If these new mechanisms do not progress, an incentive scheme (like capacity certificates) specific to distributed resources should be developed.

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[16] AEMO, 2021. Available at https://aemo.com.au/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism/wdr-updates-to-system-and-procedure-documentation/work-package-1-wdr-guidelines

[17] ESB, Post 2025 Electricity Market Design. Available at https://esb-post2025-market-design.aemc.gov.au/

Evolution of design

As explored in the high-level design, and in response to feedback from stakeholders, AEMO considers that the implementation of Scheduled Lite should evolve over time as the size and capabilities of aggregated portfolios of distributed resources increase.

The rule change proposal (see Section 6) establishes the framework for the Scheduled Lite mechanism, with an expectation that its implementation, and market integration, will evolve over time.

Table 2 below outlines the potential phasing for the delivery of the Scheduled Lite reforms, with indicative timing drawn from the strategic pathway within the NEM Reform Implementation Roadmap published by AEMO.[18]

Table 2 Phasing of Reform Delivery

Phase of development	Incremental development of Scheduled Lite design			Indicative timing
Visibility mode	Registration	Provide forecast and actual consumption and generation information	Incentives	November 2024
Dispatch mode **Stage 1**	System limits	Short-term capacity and bids	Dispatch and compliance	October 2025
Dispatch mode **Stage 2**	Integration with DER Register	Integration of FELs into market operations. integration of technical limits for scheduling of Frequency Control Ancillary Services (FCAS)	Enhancements to dispatch and further integration with security and reliability processes	Post 2025

Alternative options considered

Alternative market-based arrangements to support visibility and participation of distributed resources within market scheduling processes and dispatch have been considered in past rule change proposals, including:

- Non-scheduled Generation and Load in Central Dispatch[19]: In 2015 Snowy Hydro Limited submitted a rule change request related to obligations in respect of loads and Engie submitted a rule change request related to the obligations of non-scheduled generators. The two requests were consolidated and considered together by the AEMC. Both sought to address issues caused by the behaviour of non-scheduled generation and price-responsive load on pre-dispatch forecasting inaccuracies, leading to inefficiencies in the market. The AEMC determined not to make a final rule, mainly due to the potential high-cost implementation of full scheduling of these resources (e.g. SCADA cost). Challenges associated with aggregated CER were not explicitly considered in this rule change.
- Generator Registration and Connection[20]: In 2018, the Australian Energy Council submitted a rule change request that sought to increase the participation of smaller generators in central dispatch (reduce the threshold for classifying generators as non-scheduled from 30 MW nameplate capacity to 5MW), to enable improved management of

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[18] AEMO (2022) NEM reform implementation roadmap. Available at https://aemo.com.au/initiatives/major-programs/nem-reform-implementation-roadmap

[19] AEMC, 2017. Available at https://www.aemc.gov.au/rule-changes/non-scheduled-generation-in-central-dispatch

[20] AEMC, 2021. Available at https://www.aemc.gov.au/sites/default/files/documents/generator_registrations_and_connections_-_erc0256_-_final_determination.pdf

the power system and the efficient operation of the market. The AEMC did not make a rule regarding the scheduling threshold; the reasons included that the cost of scheduling for smaller generators would be significant, and that these costs would likely be passed onto consumers. The AEMC also noted that the ESB's Scheduled Lite work program was expected to deal with the challenge of increasing participation from participants that are currently non-scheduled in a more holistic way.

- Wholesale Demand Response Mechanism (WDRM):[21] In 2018, the Total Environment Centre, Australia Institute and Public Interest Advocacy Centre submitted a rule change request to introduce a WDRM. In 2020, the AEMC made a final determination to establish the WDRM, designed to allow meaningful volumes of demand-side participation in dispatch. The final design requires consumer loads to be controllable for the purposes of scheduling and predictable for the purposes of baselines and is restricted to participation by large customers.It was documented that extending the WDRM to cater for small customers would: significantly increase complexity of the systems changes and in turn, significantly increase implementation costs and time; provide limited additional benefits as small customer demand response is not suited to participating in central dispatch in the short to medium term; and require the development of baselines for individual small customers which is difficult to do accurately.

Alternative options to enable participation in the market scheduling processes by distributed resources were also considered in the process of developing a Scheduled Lite design. These include:

- Extending the DSP Information Portal: AEMO considered extending the DSP Information Portal obligations to provide additional operational timeframe information, potentially reflecting the Scheduled Lite ‘Simple Model’. The current DSP arrangements are a rules-based reporting obligation for relatively static inputs, used to inform planning time horizons. It is important to establish incentives that encourage accurate, timely and consistent submission of information and intentions. Considerable changes would be necessary to deliver the granularity of information required and its delivery would still require building an effective interface and portfolio management system to enable traders to manage portfolios of small resources.
- Mandatory obligations: In addition to broad stakeholder support for a voluntary mechanism, the ESB noted concerns about low uptake (and therefore limited benefits) and the possibility of Scheduled Lite moving towards a mandatory mechanism in the future. A similar view was expressed at the ESB’s Consumer Insights Workshop in September 2022 that, given its importance to system operations, elements of mandatory participation may support greater planning and forecasting for all energy system users. Consistent with the ESB’s proposed approach, AEMO considers that the initial design should focus on appropriate incentive structures, facilitating ease of participation and lowering barriers and transaction costs to support greater participation, prior to the consideration of mandatory elements. Voluntary participation, underpinned by appropriate incentives, is likely to be the most effective approach to encourage accurate forecasting. However, it is acknowledged that due to the pace of change and the growing operating challenges that elements of the visibility model may need to be considered as mandatory requirements for certain resources.

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[21] AEMC, 2022. Available at https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf

5. How the proposal will address the issues

The proposed rule change addresses the issues outlined in section 3 by enabling participation of price-responsive distributed resources in market scheduling processes to support secure and reliable operation of the power system.

Enabling participation by distributed resources

Scheduled Lite would establish a market framework that specifically encourages, values, enables and rewards energy users, including small consumers, for the investments they have made in distributed resources and demand flexibility. Its design carefully navigates the existing market framework to establish a voluntary mechanism that supports consumer choice (visibility or dispatchability) while opening access to markets and revenue sharing via traders. By placing obligations with traders (retailers and aggregators), consumers can choose to actively utilise their resources in the market, within their own tolerance, while avoiding the complexity of market operations.

Scheduled Lite is proposed to accommodate a broad range of customers and resources (Table 3). In addition to CER, the proposed Rule is also applicable to generation connected within the distribution network classified as a non-scheduled generating or bidirectional units and small resources that are exempt from registration (but may currently be aggregated for market participation).

Table 3 Potential registration categories for market participants participating in Scheduled Lite

Participant registration	Label	Resource/ classification	Examples of customer / resource types
IRP or Market Customer	**Market Customer**	End user connection point (non-scheduled load), classified by a Market Customer as a market connection point	Large users, VPPs (incl. Electric Vehicle [EV] V2G), aggregated demand response portfolio (incl. EV demand response)
IRP or Generator	**Non-Scheduled Generator**	Non-scheduled generating unit: Non-exempt generating unit with nameplate rating <30 MW	20 MW diesel generator, not exempt
IRP	**Non-Scheduled IRP**	Non-scheduled bidirectional unit (BDU): Non-exempt BDU with nameplate rating <5 MW	3 MW battery in a registered hybrid system
	Small Resource Aggregator	Small resource connection point: small generating unit and/or small BDU (on its own connection point) classified by an IRP (Small Resource Aggregator) as a market connection point	Exempt 1 MW battery on its own connection point, exempt 2 MW cogeneration plant on its own connection point

The successful implementation of Scheduled Lite would increase the revenue accruing to distributed resources, enable them to obtain the full value of their capability and enhance the operation of, and investment in these resources. Increased participation and orchestration of distributed resources will support the visibility, predictability and dispatchability of the power system, strengthening AEMO's ability to operate the system efficiently as distributed resource uptake grows. It provides an enhanced toolkit for addressing complex and emerging power system challenges, avoiding the need for increasing reliance on mitigation measures to manage system security and reliability. For consumers, it provides additional opportunities to maximise the value of their CER while lowering overall costs.

Lowering barriers

Scheduled Lite addresses barriers to participation by distributed resources by recognising and designing around their operational capabilities and the need to accommodate the preferences of participating consumers. Scheduled Lite does this through:

- Providing a flexible participation framework: in addition to consumer-driven opt-in arrangements, the proposed participation framework recognises that not all traders will be capable of 24/7 operation, and provides options to opt-out of participation across both operational and non-operational timeframes[22].
- Proposing appropriate incentives: the incentives proposed reflect the trade-off between the capabilities required for participation and the value provided through participation[23].
- Fit-for-purpose compliance arrangements: the proposed arrangements reflect the capabilities of these resource types, while balancing the need for accurate participation across both models[24].
- Leveraging the capabilities introduced by recent rule changes that specifically seek to enable greater consumer choice and engagement in the market, as outlined in Table 1. For instance, Scheduled Lite would build on existing portfolio management capabilities enabling self-management of aggregated resource portfolios, including automated aggregation and re-aggregation of resources.
- Integrating into, and leveraging existing/evolving functionality within the current market framework. For example, a recently-completed review of the Power System Data Communication Standard[25] has allowed for additional communication pathways that could better facilitate data exchange between AEMO and market participants with distributed resources.

Releasing value

As the Scheduled Lite participation rate increases, so does the level of integration of distributed resources into forecasting and market scheduling processes, paving the way towards:

- An optimised two-way market that enables aggregations of price-responsive resources to reduce energy and system service costs for all consumers and even set the market price.
- Secure system operation with high distributed resource penetration in both system normal and in adverse conditions with orchestration of distributed resources supporting stable system operation.
- Efficient network and generation investment decision making in the longer term, avoiding the need for significant duplication of investment in large-scale dispatchable generation and storage, as well as supporting local network needs.

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[22] Further detail can be found in the high-level design section 4.2.7 (Visibility Model/Opt-out arrangement) and section 5.2.9 (Dispatch Model/Opt-out arrangement)

[23] Further detail can be found in the high-level design section 4.2.5 (Visibility Model/Incentives) and section 5.2.9 (Dispatch Model/Incentives)

[24] Further detail can be found in the high-level design section 4.2.6 (Visibility Model/Compliance) and section 5.2.8 (Dispatch Model/Compliance)

[25] AEMO, 2022. Review of Power System Data Communication Standard webpage. Available at https://aemo.com.au/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard

The ISP Optimal Development Path (ODP) anticipates these outcomes by assuming an increased level of coordinated distributed storage[26] within system and market requirements. The ISP ODP recognises coordinated distributed storage as a key source of required firming capacity, projecting that by 2050 coordinated distributed storage will represent half of dispatchable capacity (in MW terms), reducing the need for shallow storage at utility scale. The behaviour of coordinated distributed storage is not visible to the market and is currently embedded within demand forecasts with a level of uncertainty – by providing a mechanism for their market integration, Scheduled Lite will be important to realising its value, and facilitating investment to a scale predicted in the ISP.

The Visibility and Dispatch models work in tandem to deliver these outcomes:

- Visibility model: By enabling AEMO to better understand the behaviour of price-responsive resources through real time information, forecasts and market intentions, the Visibility model will assist in more efficient management of power system operational needs. The information provided through the model will be incorporated into load forecasting and market scheduling processes, improving the accuracy and effectiveness of short-term operations, reducing operational uncertainty, and thereby reducing the requirement for measures such as constraints, reserves and security margins.
- Dispatch model: By integrating distributed resources into the central dispatch process, the Dispatch model contributes to the dispatchability of the power system, enhancing controllability, firmness and flexibility and supporting the balancing of supply and demand. This drives alignment between price-responsive resources and power system needs, providing the critical services that will be required as penetration of distributed resources rises and thermal generation exists the system.

Appendix A provides a more detailed consideration of the operational challenges that Scheduled Lite is designed to address and benefits of the mechanism, including exploring the important role of consumers.

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[26] Coordinated distributed storage – includes behind-the-meter battery installations that are enabled and coordinated via VPP arrangements. This category also includes EVs with V2G capabilities.

6. Proposed Rule

This section describes how the NER could be amended to give effect to the proposals outlined in the Scheduled Lite high-level design. The proposed amendments outline the new concepts and structure of the changes required to relevant NER chapters. Noting the possibility of different drafting approaches, as well as the number and extent of rule change projects either in progress or completed but not yet in effect, AEMO has not proposed detailed rule drafting. The description of proposed amendments is based on the IESS final consolidated rule[27].

6.1. Description of the proposed Rule

An overview of the proposed rule change to establish Scheduled Lite is shown in Figure 3 below. The overview provides a high-level description of the proposed amendments to the NER and provides a mapping to the core elements of the high-level design.

A more detailed mapping of the proposed rule amendments against the relevant elements of the high-level design can be found in Appendix C.

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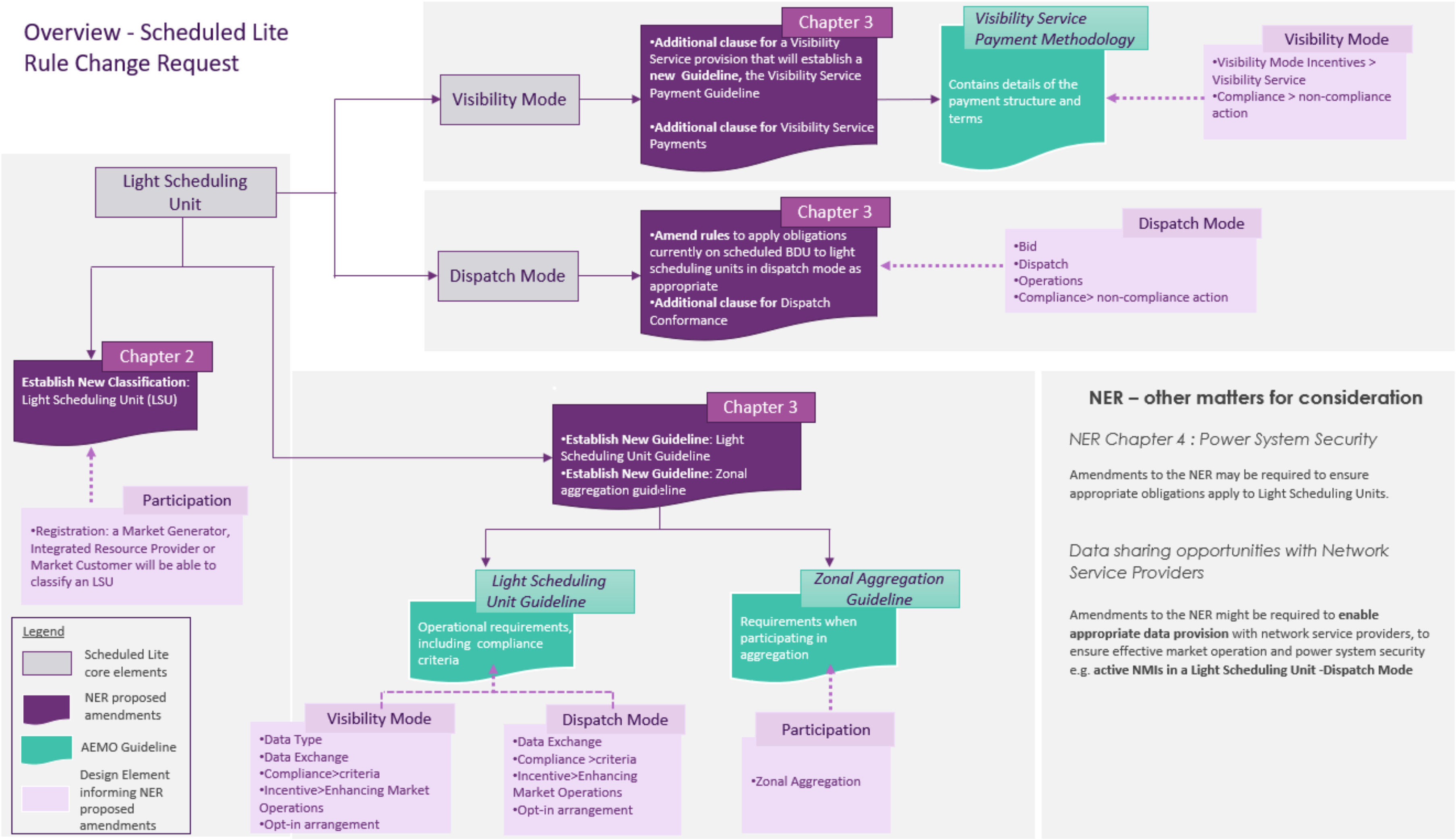
[27] AEMC, Integrating Energy Storage Systems final consolidated rule, December 2021. Available at https://www.aemc.gov.au/sites/default/files/2021-12/2._final_consolidated_rule_markup_-_integrating_energy_storage_energy_systems_into_the_nem.pdf

Figure 3 Overview of the Scheduled Lite rule change request



- **Additional clause for** a Visibility Service provision that will establish a **new Guideline,** the Visibility Service Payment Guideline
- **Additional clause for** Visibility Service Payments

Contains details of the payment structure and terms

- Visibility Mode Incentives > Visibility Service
- Compliance > non-compliance action

- **Amend rules** to apply obligations currently on scheduled BDU to light scheduling units in dispatch mode as appropriate
- **Additional clause for** Dispatch Conformance

- Bid
- Dispatch
- Operations
- Compliance> non-compliance action

Establish New Classification: Light Scheduling Unit (LSU)

- Registration: a Market Generator, Integrated Resource Provider or Market Customer will be able to classify an LSU

- **Establish New Guideline**: Light Scheduling Unit Guideline
- **Establish New Guideline**: Zonal aggregation guideline

Operational requirements, including compliance criteria

Requirements when participating in aggregation

- Data Type
- Data Exchange
- Compliance>criteria
- Incentive>Enhancing Market Operations
- Opt-in arrangement

- Data Exchange
- Compliance >criteria
- Incentive>Enhancing Market Operations
- Opt-in arrangement

- Zonal Aggregation

NER – other matters for consideration

NER Chapter 4 : Power System Security

Amendments to the NER may be required to ensure appropriate obligations apply to Light Scheduling Units.

Data sharing opportunities with Network Service Providers

Amendments to the NER might be required to **enable appropriate data provision** with network service providers, to ensure effective market operation and power system security e.g. **active NMIs in a Light Scheduling Unit -Dispatch Mode**

6.1.1. National Electricity Rules

NER Chapter 2: Registered Participants and Classification

The proposed framework establishes a new 'light scheduling unit' (LSU) classification, enabling Market Participant portfolios (including portfolios of aggregated resources) to be represented in market scheduling processes and systems.

Once an LSU is established, a Market Participant (which is not otherwise required to classify its resources as scheduled) would classify its resources into the LSU for participation in accordance with the relevant guideline. Depending on the resources it intends to classify for Scheduled Lite participation, Market Participants may be registered as an IRP, Market Customer or Generator in accordance with the existing participant registration framework.

As there would be no new unique registration category for Market Participants with LSUs, NER obligations that relate to LSUs can be applied simply to 'Market Participants' or 'Registered Participants', as appropriate, in respect of those units. Alternatively, if for drafting convenience it is considered necessary to designate a new term to refer to Market Participants in that capacity, a new term such as 'LSU Provider' could be defined and referenced in rule 2.12, in much the same way as 'Ancillary Service Provider' currently refers to Generators, Market Customers or Demand Response Service Providers (DRSPs) who have classified facilities as ancillary service units.

AEMO proposes that the new LSU classification references two alternative modes of participation by an LSU, which will determine the NER obligations to be met by a Market Participant for its LSUs. This should include:

- Visibility Mode
  - Purpose: to facilitate the visibility of price-responsive distributed resources in market processes and systems (for example, the integration of the market intentions of distributed resources within AEMO demand forecasts).
  - Definition: a mode of operation by an LSU in which it provides visibility information to AEMO.
  - Description: Visibility LSU. Possible participant description (if required for drafting obligations): LSU Visibility Provider.
- Dispatch Mode
  - Purpose: to facilitate the participation of price-responsive distributed resources in the NEM central dispatch and scheduling processes.
  - Definition: a mode of operation by an LSU in which it participates in central NEM dispatch which includes the submission of a bid, receipt of dispatch instructions and conformance with those instructions. An LSU in dispatch mode would be included in the NER definition of a scheduled resource.
  - Description: Dispatch LSU. Possible participant description (if required for drafting obligations): LSU Dispatch Provider.

- Classification criteria:
  - AEMO to approve classification based on the relevant Market Participant satisfying eligibility requirements as specified in the rules, including:
    1) Requirement to have adequate communications and/or telemetry in place to support the exchange of the required data relevant to their mode of operation.
    2) In the case of Dispatch mode operation, the Market Participant has submitted data in accordance with schedule 3.1.
    3) Demonstrated capability to meet all other requirements in the Light Scheduling Unit Guideline (as established under Chapter 3) relevant to their mode of operation.
- AEMO may establish terms and conditions of ongoing classification relevant to ensuring that the LSU continues to maintain the capability to meet the NER obligations (in at least one mode). This could include, for example, compliance with relevant technical standards[28].
- AEMO proposes that this new classification be a non-exclusive classification; that is, each connection point can be classified for other purposes. The effect of the proposal is that an LSU classification would layer on top of existing classifications and relevant units with the rights and obligations applicable to LSUs applying in priority.

Further consideration of consequential amendments is outlined in section 0.

NER Chapter 3 Market Rules

To allow the integration of LSU information and operation into market scheduling processes, the NER must provide for:

- LSU operating criteria.
- The provision of LSU information by Market Participants.
- Use of information.
- Publication or disclosure of information (where suitable).
- Establishment of compliance and incentives.

AEMO proposes that Chapter 3 of the NER would be amended as described below.

Establishing LSU operation

A new Light Scheduling Unit Guideline will be established by AEMO under the NER, to outline the operational requirements of an LSU. AEMO proposes the Guideline would include the following:

- Visibility Mode operational requirements, including:
  - Visibility Information: describing the type of data along with the associated requirements to be provided by a Market Participant. The proposed type of data is described in the high-level design and makes reference to:

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[28] The AEMC is currently reviewing the technical standards relevant to CER. https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards

        - Standing data: this includes the capacity and price-responsive capacity of the resources at each connection point (consumption and generation)
        - Real time: aggregate actual consumption and generation information
        - Forecast: aggregate consumption and generation capacities across the operational horizon, updated as necessary to reflect changes in resource availability.
        - Indicative Bids: forecast aggregate consumption and generation at different price points across the operational horizon, updated as necessary to reflect changes in portfolio capacities, market conditions and behaviour.
    - The requirements for telemetry and communications equipment for a Visibility LSU.
    - Compliance criteria and process: describing the performance thresholds for accuracy and consistency of data submission that a participant must meet, and processes for establishing compliance or identifying and remedying non-compliance.
    - Provision of data by AEMO to a Market Participant. This includes the publication of private pre-dispatch schedules[29] for an LSU.
    - Data sharing with Distribution Network Service Providers (DNSPs)[30].
    - Requirements and process to be followed by a Market Participant who wishes to opt-out of Visibility Mode for a limited time.
    - Requirements and process to be followed by a Market Participant to opt back into Visibility Mode.
- Dispatch Mode operational requirements, including:
    - Minimum threshold for nameplate rating or combined nameplate rating of a Dispatch LSU. Initially it is proposed that the threshold is set at a capacity of 5 MW or greater.
    - Any specific requirements for how a Dispatch LSU is required to participate in dispatch, noting that Dispatch LSUs are generally expected to operate as scheduled BDUs (as described in the *Integration into scheduling and dispatch process* below).
    - Requirements for telemetry and communications equipment for a Dispatch LSU.
    - Compliance criteria and processes for establishing compliance or identifying and remedying non-compliance.
    - Requirements and process to be followed by a Market Participant which is unavailable for participation in Dispatch Mode.
    - Requirements and process to be followed by a Market Participant which returns to being available for participation in Dispatch Mode.
- General conditions to operate as an LSU, including:

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[29] The provision of pre-dispatch schedules is being proposed as an incentive to Market Participants operating in the Visibility Mode. Further information can be found in the high-level design.

[30] Similar to WDRM guidelines-Data Sharing with DNSPs.

  - Requirements for continuous operation of the LSU in either Visibility or Dispatch mode in accordance with the relevant conditions.
  - In respect of connection points classified in a Market Participant's LSU, the Market Participant must be the financially responsible Market Participant of that connection point.
  - Process for entering inactive status, including:
    - 'Self-hibernation' status outside of operational timeframes: ability to hibernate for an amount of time specified by participant
    - Enforced inactive status: applies when there is non-compliance with ongoing active conditions in accordance with the Guideline (the rules will allow for AEMO to take this step).
    - Requirements for reactivation.

Zonal Aggregation

The proposed framework acknowledges that economies of scale associated with participation will drive the need to aggregate in order to deliver value. The proposed minimum participation threshold (of 5MW) to operate in Dispatch Mode, would require most distributed resources to participate in aggregate.

AEMO proposes the Rule would provide for AEMO to establish a Zonal Aggregation Guideline covering the following:

- Zone specifications (zonal load forecasting process currently under development by AEMO).
- Requirements and conditions for zonal aggregation of NMIs into LSUs, such as technical and operational requirements (for example, system security requirements)
- Guidance on automated zonal aggregation processes for LSUs, including to support:
  - Initial establishment and configuration of LSUs.
  - Maintenance of LSUs (e.g. addition or removal of NMIs from portfolios).
  - Changes to zone configurations (i.e. automated disaggregation and re-aggregation of NMIs).
  - AEMO validation processes.

Visibility Mode incentive

AEMO proposes a new rule to establish a payment mechanism for visibility services that would be made in respect of an LSU that operates in Visibility mode. Rules for 'Visibility Services' would:

- Establish principles and requirements for the payment, including:
  - Service objective.
  - Service procurement trigger.

- Establish the principles and minimum requirements for a Visibility Service Payment methodology set by AEMO or some other body. The methodology would detail the payment structure and terms within the NER principles and requirements. This is intended to provide flexibility for AEMO to value and compensate a range of participation models (for example, a 'simple' visibility model as explored in the high-level design).
- Establish conditions for Market Participants to be eligible (or not eligible) to receive a service payment. Eligibility is established if the Market Participant is providing the service in accordance with the Light Scheduling Unit Guideline.

A new rule is required to establish the recovery of visibility service payments. AEMO proposes for simplicity that the recovery rules would be consistent with the non-energy cost recovery framework established as part of the IESS rule.

Integration of Dispatch LSUs into dispatch and scheduling

AEMO considers that the integration of Dispatch LSUs into the central dispatch and scheduling process is best achieved through an extension of the rules that apply to scheduled BDUs.[31]

The scheduled BDU provides a logical foundation to enable flexibility for how Market Participants may choose to operate an LSU. For example, when a Dispatch LSU is an 'only generation' type of unit, the Market Participant will only use the generation bid bands for that unit, and set any load bid bands to zero.

AEMO proposes that the obligations for a Dispatch LSU should follow those already established in the NER for a scheduled BDU. This means that a Dispatch LSU will be added into the rules wherever reference is made to scheduled BDUs, with exemption or exception where appropriate. Exemption or exception may be appropriate in circumstances such as clause 3.7.2 (Medium term Projected Assessment of System Adequacy [PASA]). The high-level design recommends that LSUs are reflected in Medium term PASA through AEMO's demand forecast and as such, it is not expected LSUs should be required to provide any specific information. AEMO's recommendations on specific rules where exemptions or exceptions should apply to Dispatch LSUs are outlined in Appendix C.

Dispatch conformance

AEMO considers that rules for dispatch conformance should recognise the different capabilities of LSUs. Therefore, AEMO proposes a new rule to establish dispatch conformance specific to an LSU.

It is proposed that this new rule establishes that a non-conforming LSU will be identified in accordance with the Light Scheduling Unit Guideline, and AEMO will determine how a non-conforming LSU is to be treated in dispatch depending on the nature and impact of the issue. AEMO proposes that when an LSU is ultimately identified as being non-conforming, the LSU would be unavailable for dispatch but obligations in relation to visibility would continue to be applicable to the LSU.

The conformance arrangements outlined in the Light Scheduling Unit Guideline will reflect the ability for an LSU to opt out of the Dispatch mode for a limited time.

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[31] Classification established through the Integrating Energy Storage Systems rule change.

Frequency performance payments

The National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022 No. 8 requires AEMO to replace the current settlement solution for the allocation of the costs of enabling Regulation FCAS. Rather than the current solution, which simply distributes the costs on the basis of contribution factors (shares), the new solution will also introduce frequency performance payments, distribute the costs of these payments, whilst also allocating the cost of regulation FCAS. To participate units need to have appropriate metering to assess whether, during a dispatch interval, actual generation (or load) was aligned with the unit's dispatch trajectory. If performance is good the unit can earn performance payments and avoid paying a share of Regulation FCAS. If performance is poor, it may pay these costs. If a unit does not have appropriate metering it will be treated like the elements of the power system that AEMO must forecast, and will pay a share of costs of frequency performance payments and regulation FCAS, charged on a per MWh basis.

Ideally, LSUs will be able to access frequency performance payments, providing an incentive to participate in the mechanism. An amendment to clause 3.15.6AA (Frequency performance payments and cost recovery for regulation services) will be required to include LSUs as an eligible unit. To participate, LSUs will be subject to complying with relevant requirements, such as having appropriate metering.

Clause 4.4.2(c1) requires Scheduled Generators to comply with the Primary Frequency Response Requirements. For clarification, due to maturity of distributed resources, AEMO proposes that LSU will not need to comply with the Primary Frequency Response Requirements under 4.4.2(c1).

NER – other matters for the AEMC's consideration

AEMO recommends proposed amendments for the following sections/areas of the NER.

NER Chapter 4: Power System Security

NER chapter 4 provides for the achievement and maintenance of a secure power system, including conditions under which AEMO may intervene to maintain or re-establish a secure and reliable power system. Chapter 4 will require changes to incorporate Dispatch LSUs and ensure that any system security obligations which apply to these units are appropriate. It is proposed that Dispatch LSUs will be considered 'scheduled resources' unless an exception is appropriate. AEMO has considered the following clauses of chapter 4:

- Clause 4.8.9 (Power to issue directions and clause 4.8.9 instructions): As scheduled resources, Market Participants participating in the Dispatch model will be subject to AEMO-issued '*directions*' in respect of Dispatch LSUs. AEMO considers that this is appropriate as it has the ability to consider the capabilities of Dispatch LSUs to comply with directions and respond to maturation of these capabilities over time. For example, AEMO may consider the inclusion of Dispatch LSUs in the directions process as a Stage 2 development as resources develop the capability to respond appropriately.
- Clause 4.9.2 (Instructions to Scheduled Generators, Semi-Scheduled Generators and Scheduled Integrated Resource Providers): Dispatch LSUs should be included in this clause, which should be amended to refer to 'Registered Participants' in respect of the specific scheduled resources covered by the clause, rather than listing all registration categories.

- Clause 4.9.4 (Dispatch related limitations on Scheduled Generators, Semi-Scheduled Generators and Scheduled Integrated Resource Providers): This clause should be amended to cover Dispatch LSUs, so that they are only permitted to send out energy in accordance with a dispatch instruction when actively participating in Dispatch Mode. See also the note on rule 4.9.2 above regarding references to Registered Participants.
- Clause 4.11.1 (Remote control and monitoring devices): This clause will need to be amended to cover Dispatch LSUs. See also the note on rule 4.9.2 above regarding references to Registered Participants.

Data sharing opportunities with Network Service Providers

The nature of LSUs and their integration into market systems might deliver datasets that are not currently contemplated in the NER instruments which enable appropriate data provision with network service providers. For example, it may be appropriate for network service providers to receive data on active NMIs in a Dispatch LSU. Amendments to the NER might be required to confirm that data may be appropriately shared with network service providers. This will promote effective market operation and power system security.

Minor/consequential Rule changes

The proposed rule changes described in section 6.1.1 will require a number of consequential changes, for example:

- Definitions: the definition of *scheduled resource* will need to be updated to include Dispatch LSUs, but each instance of its use will need to be reviewed to confirm the relevant provision should apply to Dispatch LSUs without modification.
- Review and amendment as necessary to ensure that all Dispatch LSUs are covered as scheduled resources under all relevant provisions. Noting that AEMO proposes that LSUs may be classified by several market participant categories, there may be opportunities to streamline some provisions so that they are applied to 'Market Participants' or 'Registered Participants' in relation to specified unit types, including LSUs.

There are also likely to be consequential changes required to other chapters of the NER which are not considered in detail in this proposal. This may include minor changes to accommodate requirements and obligations associated with the introduction of LSUs. For example:

- NER chapter 4A (Retailer Reliabillity Obligation), which covers obligations associated with the Retailer Reliability Obligation, which is a mechanism designed to assist in maintaining reliability in the NEM.
- NER chapter 7 (Metering), which sets out the roles and responsibilities of financially responsible Market Participants, metering coordinators and AEMO, and other obligations for the administration of metering installations and use of meter data.
- NER chapter 8 (Administrative Functions), which describes key processes and obligations associated with the administration of the Rules, such as dispute resolution and monitoring and reporting.

6.2. Transitional matters

AEMO considers that transitional arrangements will not be required due to the voluntary nature of the Scheduled Lite mechanism.

6.3. AEMO Procedure changes

Extensive AEMO procedure changes will be required to accommodate outcomes from this rule change proposal. An initial high-level assessment of the required changes is provided in Table 4 and Table 5.

Table 4 Proposed new procedures

Procedure	Proposed content
Light Scheduling Unit Guideline	A new Light Scheduling Unit Guideline will be established by AEMO under the Rules to outline the operational requirements of an LSU. AEMO proposes the Guideline would include the following: • Visibility mode operational requirements • Dispatch mode operational requirements • General conditions to operate as an LSU Further details can be found in section **6.1.1**.
Zonal Aggregation Guideline	AEMO proposes the Rule would provide for AEMO to establish a Zonal Aggregation Guideline covering the following: • Zone specifications (zonal load forecasting process currently under development by AEMO) • Requirements and conditions for zonal aggregation of NMIs into LSUs • Guidance on automated zonal aggregation processes for LSUs Further details can be found in section 6.1.1.
Visibility Service Payment Methodology	The proposed Visibility Service Payment methodology would contain details of the payment structure and terms within principles to be established in the rules. Further details can be found in section 6.1.1.

Table 5 Current relevant procedures

Type of Procedure	Change
Registration information resource & guidelines, including: • Application forms & application guides for registration • Application forms & guides for Customer and Generator registration and classification • Guide to Generator Exemption and Classification of Generating Units • Under development: IRP guides, forms, fact sheets (IESS)	Most registration/classification documents will need to change to accommodate classification of LSU, as Market Customers, Generators, IRPs (incl. SRAs) will be able to classify them. The Guide to Generator Exemption and Classification of Generating Units will also need updates to reflect the new classification.
System Operation Procedures, including: • Dispatch Procedure • Pre-dispatch procedure • Spot Market Operations • Timetable procedure • Load Forecasting procedure • Short Term PASA Process Description	Amendments will be required due to the inclusion of: • New LSU classification • Data integration into market processes from new LSU classification e.g. price adjusted demand curve definition; functionality and integration

Other procedures, including the Retail procedures, may require updates to include LSUs and associated processes. A further detailed review will be required when the final rule is made to identify the full set of procedure changes, as much will depend on the final registration structure for Scheduled Lite participation.

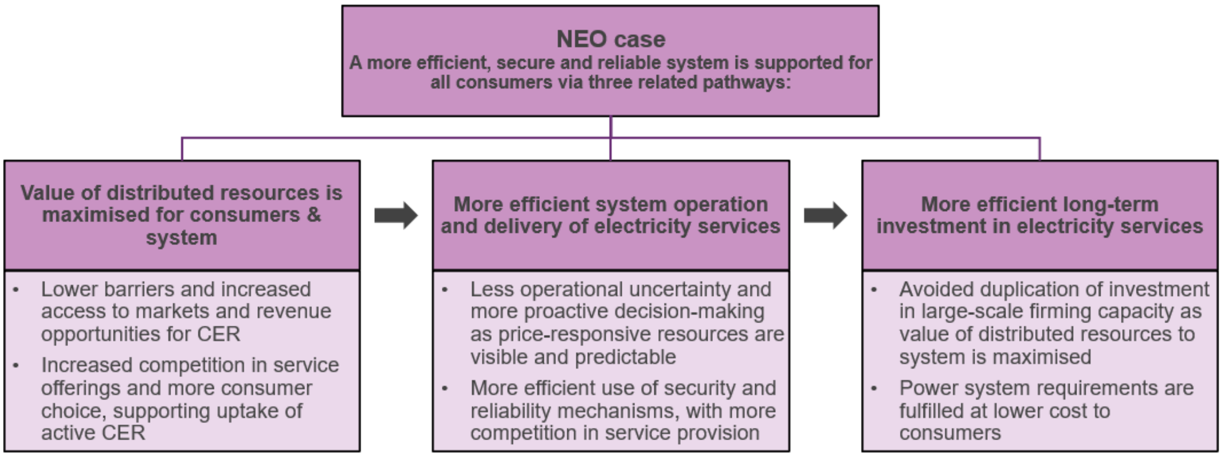
7. How the Proposed Rule Contributes to the National Electricity Objective

Before the AEMC can make a change to the NER it must apply the rule making test set out in the NEL, which requires it to assess whether the proposed rule will or is likely to contribute to the National Electricity Objective (NEO).[32] Section 7 of the NEL states the NEO is:

> *… 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, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

Figure 4 and the sections below provide an overview of how Scheduled Lite would contribute to the achievement of the NEO.

Figure 4 Overview of NEO case for Scheduled Lite



NEO case
A more efficient, secure and reliable system is supported for all consumers via three related pathways:

Value of distributed resources is maximised for consumers & system
- Lower barriers and increased access to markets and revenue opportunities for CER
- Increased competition in service offerings and more consumer choice, supporting uptake of active CER

More efficient system operation and delivery of electricity services
- Less operational uncertainty and more proactive decision-making as price-responsive resources are visible and predictable
- More efficient use of security and reliability mechanisms, with more competition in service provision

More efficient long-term investment in electricity services
- Avoided duplication of investment in large-scale firming capacity as value of distributed resources to system is maximised
- Power system requirements are fulfilled at lower cost to consumers

1. Maximising the value of distributed resources for consumers and the broader system through increased competition and access to markets

Scheduled Lite increases access to markets and revenue opportunities for distributed resources, including CER, by rewarding service provision and lowering barriers to participation in market scheduling processes. The framework is designed around incentives and market signals to facilitate participation, rather than mandatory requirements, to recognise the breadth and maturity of business models and to align incentives with power system needs.

This approach will ensure the value of distributed resources can be maximised for both consumers and the broader system, including:

- supporting greater competition and innovation in service offerings for consumers and expanding consumer choice – new revenue opportunities will enable consumers to engage with offers that are aligned with their preferences and choose the highest value uses for their investments;

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[32] AEMO recognises that Energy Ministers have recently agreed to include an emissions reduction objective into the NEO.

- supporting the growth of distributed resources that are 'active' and 'controllable' rather than passive, unlocking capacity and value from consumer investments and increasing the pool of resources eligible for participation in Scheduled Lite;
- increasing participation of distributed resources in provision of energy and system services through flexible operating models, improving the efficiency of dispatch; and
- supporting efficient power system operation and investment over operational and long-term timeframes (described further below).

If, as a result of the Scheduled Lite changes to the NER, it is necessary or desirable to make consequential changes to the National Energy Retail Rules, AEMO considers that such changes would contribute to the national energy retail objective[33] for the reasons set out above.

2. Promoting efficient system operation and delivery of electricity services

Scheduled Lite is designed to drive more efficient power system operation and address risks associated with growing operational uncertainty driven by the rise in price-responsive resources that are currently neither visible nor predictable to the system. By providing a framework to facilitate visibility, dispatchability and integration of these resources into market scheduling processes, Scheduled Lite will support efficient system operation and better utilisation of security and reliability mechanisms in the following ways:

- Active participation and greater visibility of the market intentions of price-responsive resources will enhance operational forecasting processes, support proactive operational decision-making, and sustain the secure and reliable operation of the power system in the context of the growing penetration of distributed resources.
- By minimising uncertainty within operational timeframes, the mechanism will reduce the need to procure frequency services and emergency reserves, lowering system service costs for all consumers. It will also reduce the need for unnecessary use of curtailment and backstop mechanisms, support timely commitment decisions in the market and drive more efficient use of security and reliability measures.
- The portfolio and unit-level data and capabilities required to participate in Visibility and Dispatch mode will also support future market data utilisation needs. This could inform, for example, the development of new tools and processes required to enable efficient integration and wholesale market interaction of flexible export limits.

In short, Scheduled Lite will provide AEMO with an enhanced operational toolkit for delivering safe, secure and reliable supply under increasingly challenging conditions – with fewer inefficient interventions and at lower overall cost to consumers. It provides a means to leverage, and reward consumers for, the growing volumes of latent flexibility in the system and manage risks in a more efficient, proactive manner.

3. Enhancing the efficiency of long-term investment in electricity services

Finally, Scheduled Lite would enhance system-wide forecasting and planning assessments over the long-term, delivering a more efficient mix of resources to meet consumer needs and lowering overall system costs.

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[33] National Energy Retail Law section 13.

It achieves this outcome by facilitating the visibility and active participation of distributed resources in the market, helping to align their behaviour with the needs of the system. When properly orchestrated, distributed resources have the potential to be a competitive, lower cost alternative to large-scale generation and storage. In the long term, effective market integration of these resources could avoid the need to duplicate capacity via large-scale resource investments, including network build, to fulfil power system needs.

These avoided costs of duplicated investments could be substantial, as explored in Appendix A. Corresponding infrastructure build could also be reduced, resulting in more efficient network planning and optimised capital and operational costs.

8. Expected Benefits and Costs of the Proposed Rule

Benefits

The Scheduled Lite rule change proposal seeks to enable the integration of distributed resources, including CER, into market scheduling processes, unlocking the value of these resources for consumers and the broader system. The proposal supports competition and innovation in consumer service offerings. It enhances consumer choice around active utilisation of resources in the market, in alignment with consumers' preferences, whilst avoiding the real-time complexity of market operations. Consumer benefits are explored in Appendix A, including but not limited to:

- Delivering supplementary revenue streams beyond existing feed-in-tariffs and retail energy plans.
- Reducing and minimising the activation of emergency interventions, including curtailment of consumer-owned resources.
- Increasing the provision of energy and ancillary services, enhancing competition and lowering overall costs to all consumers.

Further, the proposal is designed to promote efficient long-term investment, as orchestration of these resources facilitates system optimisation, leading to market signals that accurately reflect system needs. This will minimise costs over time to all consumers by, for example, avoiding duplicative investment otherwise required where the behaviour of distributed resources is not aligned with market and system requirements. This includes the need to invest in additional grid-scale resources, rather than harnessing, and rewarding consumers for, the generation and storage capacity of their investments.

The potential consumer cost impacts, and the broader benefits of distributed resource integration, are explored in Appendix A. Looking simply at the potential for avoided costs of duplication in large-scale investment, if 20% of the projected coordinated DER storage[34] in the 2022 ISP *Step Change* scenario were to be replicated through investment in grid-scale shallow storage each year to 2040, the cumulative capital cost would come to approximately $1.8 billion, rising to approximately $4.4 billion if 50% of the capacity needed to be replicated over that same period.[35] Studies exploring the broader opportunity and benefits of distributed resource integration have found a similar magnitude of economic benefits, demonstrating significant potential to offset the need for additional investment in large-scale assets.

Consequently, the proposal seeks to facilitate the optimal allocation of resources[36] to meet the community's demand for energy services, and to minimise costs over time to all consumers by promoting more efficient long-term investment; whilst ensuring that Australia's energy systems remain secure and reliable.

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[34] 'coordinated DER storage' includes both consumer-owned batteries and vehicle-to-grid capacity

[35] Based on ISP capital cost projections for 2-hour battery storage, AEMO 2021 Inputs, assumptions and scenarios workbook. Available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en

[36] this means that the community's demand for energy services is met by the lowest cost combination of demand and supply side options

Participant costs

The Scheduled Lite design and rule change proposal have been prepared based on the expectation that customers intending to participate in the mechanism are already responding to price signals and, where applicable, their resources are already actively managed by a trader. That is, they have, or will have the ability to, establish the necessary technology (for instance telemetry and data communication) and have appropriate retail or commercial arrangements to manage the wholesale market interface. Costs associated with the active management of a portfolio of distributed resources (including forecasting and dispatch of resources) are largely expected to be incurred by a trader irrespective of their participation in Scheduled Lite. As such, only incremental costs for traders that are specifically associated with Scheduled Lite participation (and in turn reflected in customer offers) are relevant to the consideration of the rule change proposal.

Additional costs associated with participation in Scheduled Lite that are likely to be incurred by a trader include:

- Establishing and maintaining data interfaces with AEMO.
- Operational costs associated with the managing a portfolio of resources within the market systems.
- Market settlement and prudential management.

AEMO considers that other than its own costs to implement Scheduled Lite, the proposals do not impose material costs on participants who do not intend to classify LSUs.

AEMO Implementation Costs

The ESB was tasked by the former Council of Australian Governments (COAG) Energy Council to deliver a market design for the NEM to meet the needs of the energy transition beyond 2025. In October 2021, Ministers endorsed the ESB's reform recommendations including a request for AEMO to work closely with industry to develop an integrated regulatory and IT roadmap (Roadmap) to deliver the IT system and business processes together.

AEMO has commenced work to scope the program that needs to be delivered to meet the obligations under the reforms. As part of the initial planning phase, AEMO worked with industry and stakeholder representatives comprising the Reform Delivery Committee (RDC) to identify the suite of initiatives aligned with the ESB's four reform pathways to be included in AEMO's NEM2025 Program.

The timing and costs associated with Scheduled Lite have been estimated as part of the development of the NEM2025 Implementation Roadmap and corresponding NEM2025 Gate 1 business case assessment. The NEM2025 Implementation Roadmap, now integrated into the NEM Reform Implementation Roadmap[37], establishes a basis upon which to navigate the breadth of ESB reforms over the coming few years, de-risking delivery and informing implementation timing. The NEM2025 Gate 1 business case sets out two delivery options for the NEM2025 Program and recommends a preferred option based on cost estimates and a qualitative benefits assessment.

The implementation cost for each NEM2025 initiative was estimated based on its complexity (being one of very small, small, medium, large or very large). Using a combination of the types

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[37] The NEM Reform Implementation Roadmap integrates the Regulatory Implementation Roadmap – Version 7 and NEM2025 Implementation Roadmap – Version 2 to provide a holistic view of the reform and IT uplift initiatives over the coming years.

of resources, the estimated number of resources and the estimated number of days effort, a total effort estimate was calculated for each complexity rating. The allocation and pricing of this total effort was prepared based on industry benchmarks and tested against Five-Minute Settlement (5MS) and the Wholesale Demand Response implementation projects.

Scheduled Lite was assessed as a 'large' project with upfront costs estimated to be approximately $18.2m +/-40% and ongoing costs are estimated to be $10.5m (over a 10-year period to 30 June 2032). Final costs will be dependent on the design encompassed in the final rule determination and key cost drivers will include the level of complexity associated with registration, portfolio management and dispatch functionality.

9. Appendices

The appendices to this rule change are provided as separate documents as outlined below.

Appendix A	Scheduled Lite Justification
Appendix B	High-Level Design
Appendix B.1	Related Projects
Appendix B.2	Stakeholder Engagement
Appendix B.3	Use Cases
Appendix C	Mapping of proposed rule amendments

10. Glossary

Term	Definition
5MS	Five-Minute Settlement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
API	Application Programming Interface
ASEFS	Australian Solar Energy Forecasting System
BDU	Bidirectional Unit
CER	Consumer Energy Resources
COAG	Council of Australian Governments
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DRSP	Demand Response Service Provider
DSP	Demand Side Participation
ESB	Energy Security Board
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Service
FEL	Flexible Export Limit
GW	Gigawatt
IESS	Integrating Energy Storage Systems
IRP	Integrated Resource Provider
ISP	Integrated System Plan
LSU	Light Scheduling Unit
MICF	Market Integration Consultative Forum
MW/MWh	Megawatt/ Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Metering Identifier
NSP	Network Service Provider
ODP	Optimal Development Path
PASA	Projected Assessment of System Adequacy
Project EDGE	Project Energy Demand and Generation Exchange
PV	Photovoltaic
RDC	Reform Delivery Committee
SCADA	Supervisory Control and Data Acquisition
V2G	Vehicle-to-grid
VPP	Virtual Power Plants
WDRM	Wholesale Demand Response Mechanism

Appendix A. Scheduled Lite Justification

January 2023

Appendix to the Scheduled Lite
Rule Change Request

Important notice

Purpose

This is Appendix A to the Scheduled Lite Rule Change Request.

Disclaimer

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A1 Overview

This Appendix A to AEMO's *Scheduled Lite Rule Change Request* provides additional information on the need and rationale for the Scheduled Lite mechanism.

The forecast rapid growth in distributed resources, in particular those owned by household and business consumers, will drastically change the energy landscape of the NEM. Driven by the need to keep pace with the evolving mix of resources comprising the NEM's generation fleet, Scheduled Lite is essential to facilitate and support the participation of all resources in both a visible and dispatchable manner to maintain the secure and reliable operation of the power system.

Scheduled Lite is part of a suite of reforms that aim to support innovation in CER[1] products and services needed that create value for all energy consumers, improving energy affordability, empowering consumers around how they manage their energy use and delivering on Australia's emissions reduction goals.

When evolving the market framework to address broader system needs, it is integral that consumers and consumer-owned distributed resources play a predominant role and are respected within the design. The framework must recognise, welcome and support the continued growth of consumer-owned price-responsive resources, and ensure any adjustments to the framework accommodate the distinctive capabilities of these resources and diverse preferences of their owners.

In combination with other ESB reforms, Scheduled Lite addresses two key barriers within the current framework:

1. Enabling participation; and
2. Incentivising participation.

Its design, shaped by the objective of minimising complexity for consumers while maximising functionality of existing market systems and processes, will effectively remove existing barriers and empower consumers.

Heightened consumer participation benefits not only the owners of CER but also delivers broader benefits to all consumers by improving the efficiency and capability of the shared power system.. As this Appendix will demonstrate, increasing the volume of resources participating in the market will provide system-wide benefits and lower overall energy and energy service costs for all consumers (Figure 1).

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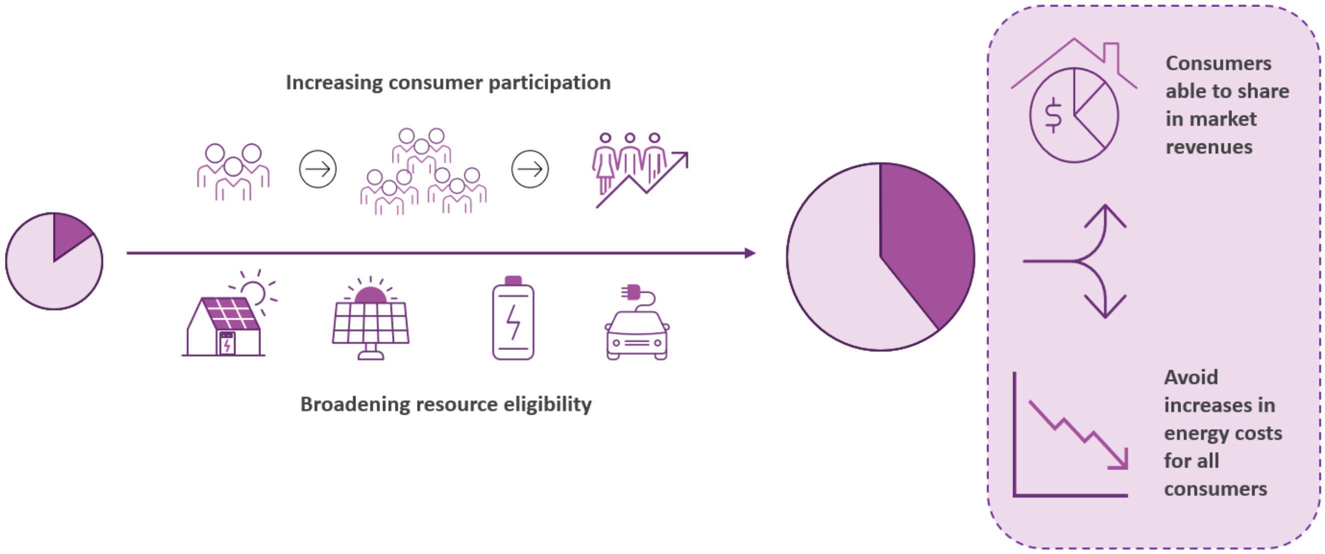
[11] ‘Customer Energy Resources’ (CER) are also commonly referred to as ‘Distributed Energy Resources’ (DER)

Figure 1 Scheduled Lite drives benefits to all consumers



This Appendix is structured as follows:

- Section A2 appreciates and establishes the important role consumers are playing in the energy transition, and reflects on how the design considers, balances and delivers benefits to all consumers.
- Section A3 explores some core challenges associated with the increased uptake of price-responsive, distributed resources and plays these challenges out through two scenarios: 'Status quo' and 'Scheduled Lite enabled'.
- Section A4 considers the rate of participation in Scheduled Lite necessary to support the optimal development path (ODP) identified in AEMO's *Integrated System Plan* (ISP), reinforcing the need for the mechanism as the rapid deployment of other price-responsive distributed resources continues at pace.

A2 Empowering consumers

A2.1 Encouraging access and reducing complexity

Scheduled Lite presents an opportunity to establish a market framework that specifically values, enables and rewards energy users for the investments they have made in distributed resources and demand flexibility. As recognised in the ESB's Release One Knowledge Share Report, [2] "*…access, understanding and trust are material barriers for consumers who are yet to engage with new products and services. We (the ESB) need to be clear about the benefits and aim high for excellent experience at every step in the customer journey, from making a choice, to installing and learning about the equipment, to using and living with it, and getting help, and being protected when things go wrong.*"

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[2] ESB, 2022, *DER Implementation Plan Customer Insights Collaboration Release One, Knowledge Share Report*. At: https://www.datocms-assets.com/32572/1658964111-esb-cic-knowledge-share-report-final_250722.pdf

Scheduled Lite recognises and builds upon this strong knowledge base and insights gained from the ESB's Customer Insights Collaboration. Its design carefully navigates the existing market framework to establish a voluntary mechanism that supports consumer choice (visibility or dispatchability) while opening access to markets and revenue sharing via traders. By placing obligations with traders (retailers and aggregators), consumers can choose to actively utilise their resources in the market, within their own tolerance, while avoiding the complexity of market operations.

The NEM's existing market arrangements have not been explicitly designed to recognise nor enable value-sharing from the investments consumers have made in distributed resources and behind-the-meter demand flexibility.

By design, the Wholesale Demand Response Mechanism[3] specifically excluded participation of small consumers, citing barriers such as the unsuitability of baselines for small customer loads, challenges of small customer demand response participating in central dispatch, and a significant increase in the complexity and cost of system changes if the mechanism were to be extended[4].

Furthermore, in the context of broader opportunities for demand response, although some forms of Retailer- and Network-led behavioural and automated small customer demand response exist (activated in response to spot price, network, system security or reliability triggers), much of this occurs off-market, remaining invisible to market participants and the system operator[5]. These off-market arrangements are less transparent with regard to overall value and benefit sharing available to consumers; as well as offering less consumer choice.

Scheduled Lite is designed to minimise the complexity of the market for consumers, overcoming some of the existing barriers locking out consumers and their resources from engaging and participating in market scheduling processes.

Scheduled Lite seeks to realise and deliver consumer benefit in the following ways:

- Direct consumer benefits.
  - Access to supplementary revenue streams beyond existing feed-in-tariffs and retail energy plans.
  - Supporting uptake of distributed resources.
  - Maximising market interaction alongside any network flexible export limits.
  - Matching consumers appetite for trader-led control of their CER.
- Indirect benefits for all consumers.
  - Increasing the provision of energy and ancillary services, enhancing competition and lowering overall costs to all consumers.
  - Minimising the activation of emergency interventions curtailing consumer-owned resources.
  - Avoiding the otherwise higher levels of procurement of additional emergency reserves and FCAS.
  - Consumer-driven investments in rooftop solar PV reducing the emissions intensity of the supply of electricity from the grid.

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[3] AEMC, 2020, *Wholesale Demand Response Mechanism Final Determination*, at https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf..

[4] Ibid.

[5] AEMO, 2022, *ESOO Appendix A6. Demand Side Participation Forecast*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en#:~:text=The%20Electricity%20Statement%20of%20Opportunities,new%20investors%2C%20and%20jurisdictional%20bodies.

A2.2 Stakeholder engagement and consumer insights

Gaining insights and perspectives from consumer representatives has been a core element of the ESB's Post 2025 Electricity Market Design. Ensuring that the voice and views of consumers actively inform reform initiatives has helped articulate and address the barriers facing consumers and opportunities that could be unlocked through the energy transition.

Appendix B.2 details the breadth of consumer and stakeholder engagement activities undertaken specifically on this Scheduled Lite initiative, including how AEMO has incorporated stakeholder feedback and questions to date within this rule change package.

A2.2.1 Consumer insights and perspectives

The ESB hosted its second consumer insights workshop in September 2022, informing Release Two of the ESB's Customer Insights Collaboration and the ongoing development of this Scheduled Lite mechanism.[6] This workshop explored ways the Scheduled Lite mechanism would inform the customer journey for CER products and services. A diverse group of stakeholders participated, including the Customer Insights Collaboration Stakeholder Steering Group for Release Two, which includes customer representatives, as well as people with network, retailer and technical experts, to:

- Explore the value proposition for customers and understand how Scheduled Lite would support CER implementation customer objectives.
- Develop a better understanding of the customer journey and value proposition associated with participation in the mechanism for customers.
- Provide insights to inform this rule change request.
- Enhance customer insights generated from ESB Customer Insights Collaboration Release One.

Key insights from the workshop have informed this rule change request and high-level design. Important and relevant considerations were explored through a customer journey exercise to further appreciate the consumer perspective and appreciate consumers' interactions with the mechanism. The discussions clustered around two themes – how Scheduled Lite could support efficient, secure and reliable system management; and how it would shape the customer experience of CER products and services.

Of pertinence were the following insights:

- As highlighted in Release One of the Customer Insights Collaboration, consumers face a range of barriers to benefiting from flexible CER and energy use and Scheduled Lite needs to be considered in this broader context.
- Scheduled Lite would need to deliver net benefits for consumers, with alternatives ways of supporting the desired consumer and system outcomes, such as mandatory participation, warranting consideration. Some participants also saw a need to reframe the role of CER customers in the energy network to reflect responsibilities as well as entitlements.

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[6] ESB, *Scheduled Lite Customer Insights Workshop Report*, Release Two Workshop Materials, at: https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand#delivering-the-customer-insights-collaboration

- Communication, and minimizing complexity, is key to gaining consumer interest and buy-in for Scheduled Lite and CER products and services more generally. A key question is how does Scheduled Lite support and shape CER products and services that open up access, create value, and deliver a positive experience for customers.
- Transparency builds trust, both through the information that is provided to consumers and through commercial arrangements that might be agreed between consumers and traders.
- Recognition of a need to unlock innovation in consumer service offerings, with Scheduled Lite a potential avenue to help achieve this.
- Consumer protections needs to be carefully considered to manage potential risks and provide traders with clear boundaries without limiting innovation.
- How Scheduled Lite can support equity outcomes by unlocking system-wide benefits for customers without CER should be considered.

A3 System challenges to overcome

The NEM is facing a breadth of challenges during the acceleration of the energy transition, to maintain operational certainty in the near-term, prepare for and manage high levels of variability and uncertainty, and support efficient long-term investment. Alongside a range of activities, mechanisms and reforms required to plan for and operate the modern power system, Scheduled Lite is proposed as a foundational tool[7].

A brief overview of some key operational and planning challenges facing the electricity supply chain are presented below. Two separate scenarios are then proffered in Section A3.2, through which to observe how these challenges might evolve over the long-term (ISP) forecast horizon, and contemplate potential outcomes for consumers and the energy system:

- **Status quo:** Explores the counternarrative where no changes are made to the regulatory framework to activate in-market participation of price-responsive, distributed resources, resulting in these resources remaining invisible to the market and not able to contribute to the firming capacity requirements of the power system.
- **Scheduled Lite enabled:** Scheduled Lite is implemented and facilitates the gradual integration of price-responsive distributed resources into the market. These capabilities strengthen AEMO and NSPs' ability to operate the system efficiently as distributed resource uptake grows and ensures their value to consumers and the power system at large can be realised.

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[7] Other key related activities or changes will include initiatives such as the ST PASA replacement project, SCADA lite and flexible trading arrangements.

A3.1 Challenges facing the electricity system

Minimum operational demand

The increased uptake of distributed resources is already reaching material thresholds impacting the bounds of uncertainty of operational forecasts used to inform short-term market and system operations. Owing to the growing adoption of these resources, consumers' grid demand is changing, particularly during daylight hours, contributing to record low levels of minimum operational demand[8].

These low operational minimum demand levels are creating power system operability issues, particularly relating to system security[9], including but not limited to:

- Reducing load available to keep synchronous generating units operating at their minimum stable outputs as they provide essential system services including system strength, inertia and voltage control[10].
- Reducing the effectiveness, and changing the nature, of critical emergency mechanisms necessary for system recovery or restoration during major power system events, due to reduced availability of stable load blocks[7].

Not only is the uptake of price-responsive distributed resources growing, but these resources are commonly aggregated into large portfolios, responding to price signals in an invisible manner off-market. As these aggregations increasingly orchestrate their responses (ramping up or down in response to price) during already low periods of minimum operational demand, producing operational forecasts with manageable bounds of uncertainty is becoming increasingly unmanageable.

The Scheduled Lite mechanism would provide visibility and predictability of these resources, reducing uncertainty and supporting the proactive decision making needed to manage challenging operational conditions, such as addressing minimum operational demand.

Figure 2 below shows that minimum operational demand is expected to rapidly decline in all regions, with South Australia forecast to reach negative minimums in the short term, driven by strong growth in DPV[11].

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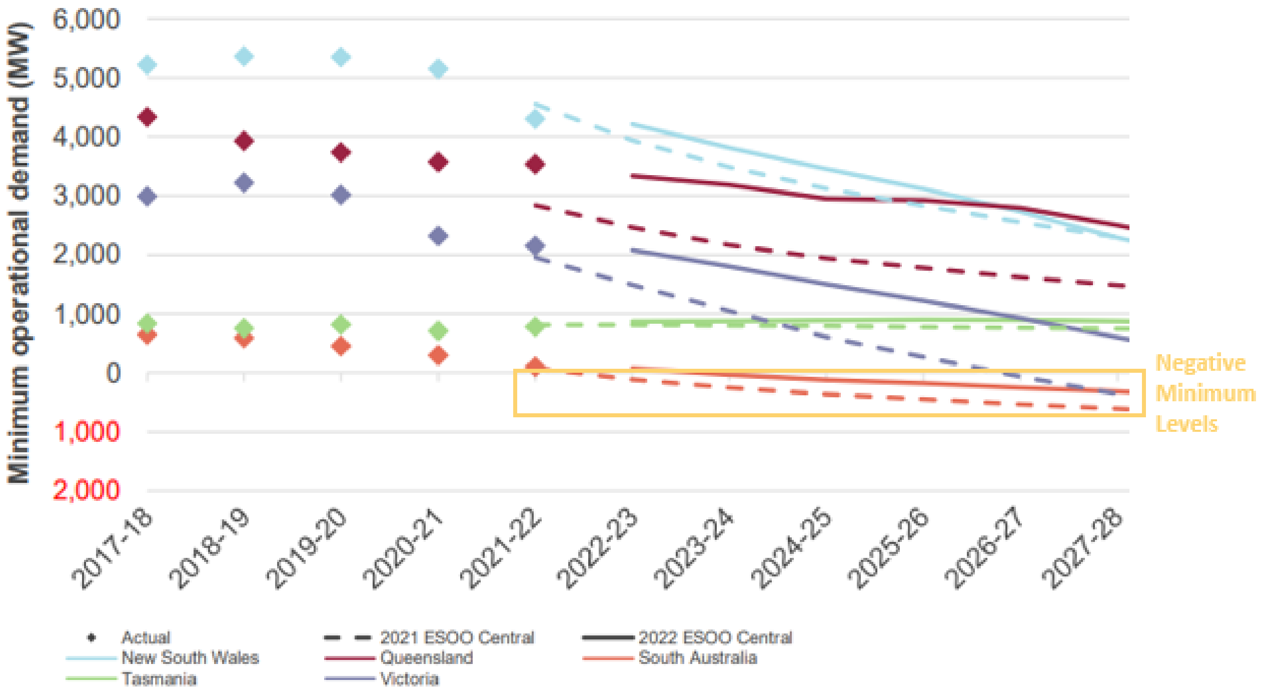
[8] Minimum operational demand means the lowest level of demand supplied by the grid in any given day, week or year.

[9] AEMO *Integrated System Plan* Appendix 4: System operability, June 2022, page 8, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a4-system-operability.pdf?la=en.

[10] AEMO *Renewable Integration Study Stage 1* Appendix A: High Penetrations of Distributed Solar PV, April 2020, page 34, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en.

[11] AEMO, *Electricity Statement of Opportunities*, August 2022, page 34, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en&hash=AED781BE4F1C692F59B1B9CB4EB30C4Chttps://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en.

Figure 2 **Regional annual actual and forecast 50% probability of exceedance (POE) minimum operational demand (sent-out)**



Note: POE is the likelihood a demand forecast will be met or exceeded; a 50% POE forecast is expected statistically to be met or exceeded one year in two and represents a forecast based on average weather conditions. The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Source: AEMO 2022 ESOO.

High levels of variability and uncertainty

The changing characteristics of distributed resources, along with their cumulative size, will lead to high levels of variability and uncertainty in the behaviour of the traditional demand side of the power system. The net effect of this type of resource on load profiles will depend on the number, location, type, performance, and operation of the resources.

To reduce operational risk arising from the additional uncertainty in the system, sufficient flexibility[12] is required within the system to deal with unexpected events. In the absence of enhanced operational tools and regulatory frameworks, curtailment and intervention may be required to maintain adequate system security across all timeframes[13].

The Scheduled Lite mechanism would enable visibility, predictability and dispatchability of distributed resources, minimising uncertainty within operational timeframes. Successful integration within market scheduling processes will avoid otherwise necessary curtailment of resources and activation of emergency reliability and security mechanisms, supporting timely commitment decisions in the market and driving more efficient use of security and reliability measures.

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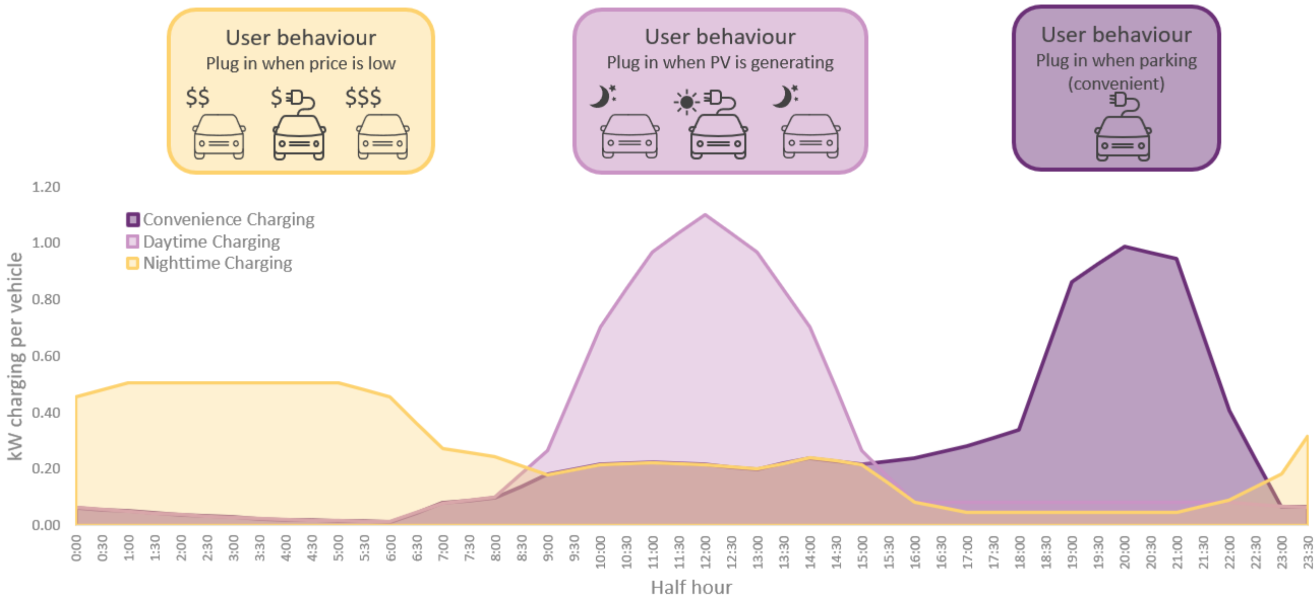
[12] System flexibility is the capability of the system to respond to expected and unexpected changes in net demand over all necessary timeframes.

[13] AEMO, *Renewable Integration Study Stage 1* Appendix C: Managing variability and uncertainty, page 45, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

Figure 3 provides one example of unpredictable aggregate distributed resource behaviour, in this case electric vehicle (EV) charging profiles. When the system operator and the market have limited visibility of this behaviour, the load profile reflects in a higher level of uncertainty and variability, impacting system stability.

Figure 3 Example home/work electric vehicle charging profiles – medium residential average half-hour charge profile (2022 ISP *Step Change* scenario)



Source: AEMO 2022 ISP Inputs, assumptions and scenarios workbook. NOTE: Recently updated ISP forecasts suggest that the convenience charging profile and daytime peak have declined significantly relative to the 2022 ISP *Step Change* scenario. These updated forecasts will be reflected in the 2023 inputs, assumptions and scenarios report and workbook once released.

Efficient investment and coordination

Over the longer term, the NEM is projected to transform rapidly, being highly influenced by electrification of business and residential sectors, and continued investment by consumers in energy resources, including electrified transport[14] (primarily EVs). A large amount of firming capacity will be required to replace the services provided by retiring coal-fired generation, with the last units expected to exit the power system as early as 2040 (see Figure 4). Collectively, these factors influence the reliability investment signals sent to the market. The requirement for investment in large-scale firming capacity will depend on the extent to which distributed resources can be utilised to fulfil power system needs. Without a mechanism to facilitate the market integration of coordinated resources, or where uptake is lower than expected, additional investments in large-scale resources will be required at higher cost to consumers (see section A4).

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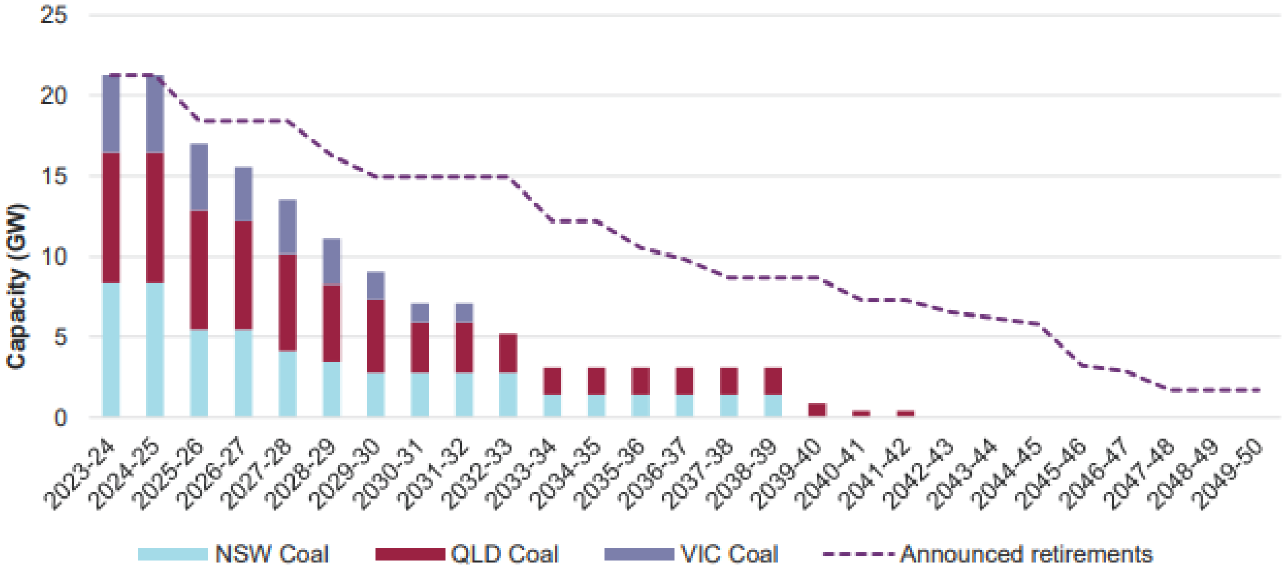
[14] AEMO, 2022, *Electricity Statement of Opportunities*, page 25, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en#:~:text=This%202022%20ESOO%20signals%20a,support%20the%20energy%20transition%20underway.

Figure 4 Forecast coal retirements, 2022 ISP *Step Change* technology and regional outlook



A3.2 Scenarios

Summary of the expected outcomes of each scenario

The two scenarios below analyse how the overarching challenges are expected to be addressed by the available resources in:

- A status quo scenario with limited visibility of unscheduled price-responsive resources; and
- A scenario that enables Scheduled Lite, facilitating the gradual integration of this type of resource into market systems.

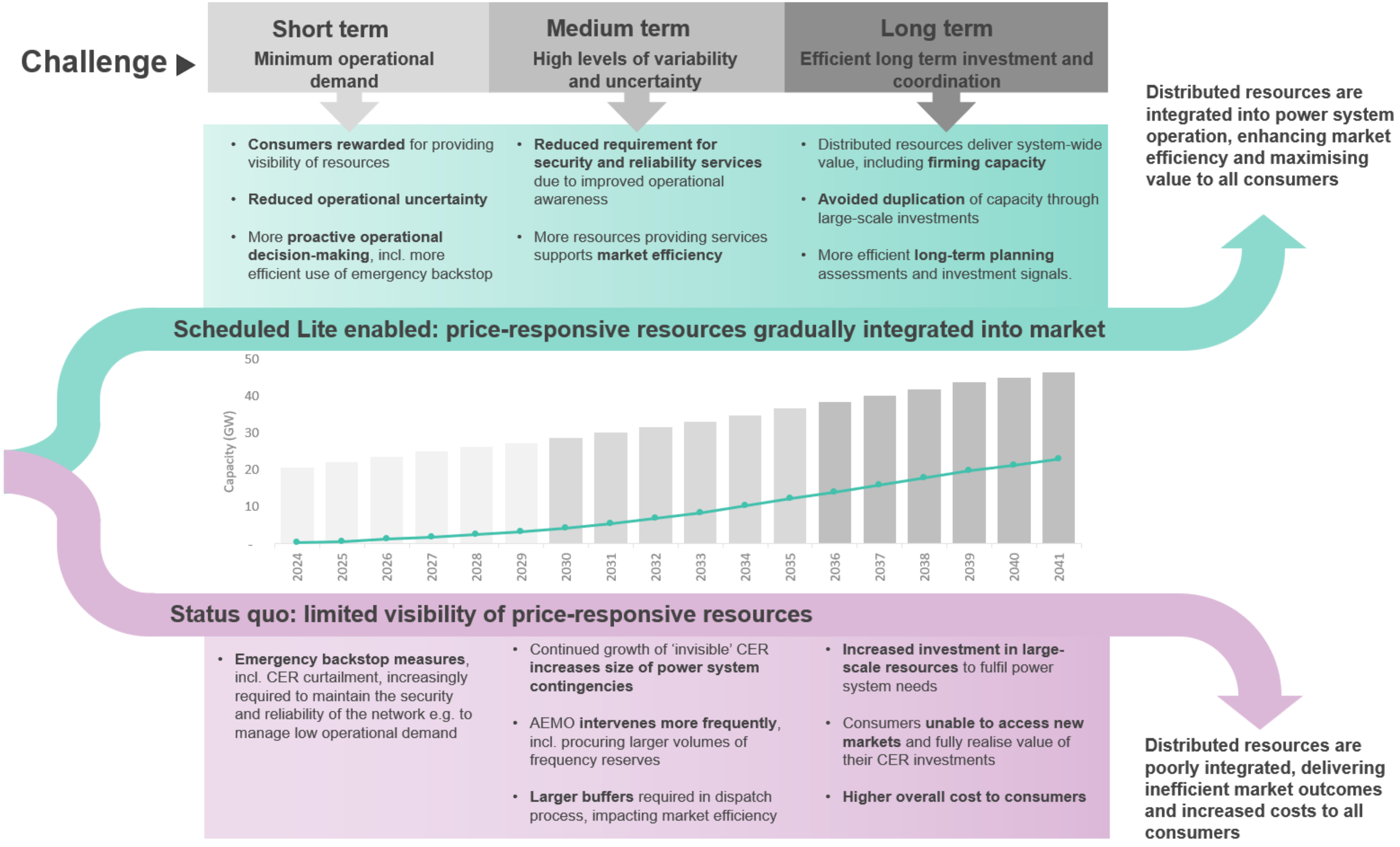
The status quo scenario would result in inefficient market operation and increased costs to all consumers, as:

- High levels of uncertainty would result in the application of limits and interventions to maintain system security and manage risks, increasing costs for all consumers.
- Distributed resources are not able to contribute to the firming capacity requirements of the NEM, requiring duplicative investment in infrastructure.

In contrast, the outcomes enabled by the introduction of the Scheduled Lite mechanism would enhance the participation of price-responsive distributed resources and allow for its optimised orchestration within the broader power system. It would improve the efficiency and robustness of the market by facilitating:

- An optimised two-way market that allows price-responsive resources to reduce costs for all consumers.
- Secure system operation with high price-responsive, distributed resources penetration in both system normal and in adverse conditions.
- Efficient network and generation investment that delivers economic benefits for all consumers, avoiding the need for significant duplication of investment in utility-scale generation and storage.

Figure 5 Overview of scenarios – Scheduled Lite Enabled versus Status Quo



Challenge ▶

Short term
Minimum operational demand

Medium term
High levels of variability and uncertainty

Long term
Efficient long term investment and coordination

- **Consumers rewarded** for providing visibility of resources
- **Reduced operational uncertainty**
- More **proactive operational decision-making**, incl. more efficient use of emergency backstop

- **Reduced requirement for security and reliability services** due to improved operational awareness
- More resources providing services supports **market efficiency**

- Distributed resources deliver system-wide value, including **firming capacity**
- **Avoided duplication** of capacity through large-scale investments
- More efficient **long-term planning** assessments and investment signals.

Distributed resources are integrated into power system operation, enhancing market efficiency and maximising value to all consumers

Scheduled Lite enabled: price-responsive resources gradually integrated into market

Status quo: limited visibility of price-responsive resources

- **Emergency backstop measures**, incl. CER curtailment, increasingly required to maintain the security and reliability of the network e.g. to manage low operational demand

- Continued growth of 'invisible' CER **increases size of power system contingencies**
- AEMO **intervenes more frequently**, incl. procuring larger volumes of frequency reserves
- **Larger buffers** required in dispatch process, impacting market efficiency

- **Increased investment in large-scale resources** to fulfil power system needs
- Consumers **unable to access new markets** and fully realise value of their CER investments
- **Higher overall cost to consumers**

Distributed resources are poorly integrated, delivering inefficient market outcomes and increased costs to all consumers

Status Quo scenario: limited visibility of price-responsive, distributed resources

The scenario

- This scenario reflects a market framework for the NEM which lacks a mechanism to facilitate the visibility and dispatchability of small, price-responsive resources within operation of the market.
- Growing portfolios of these resources, rivalling the capacity of grid-scale generators, continue to be engaged off-market by networks, retailers and aggregators.
- Static and non-differentiated demand response information is shared with the market operator and market participants, but it continues to be provided through highly manual processes such as the Demand Side Participant Information Portal and CER Register.
- Increases in the registered capacity of price-responsive load occur via the Wholesale Demand Response Mechanism, although features of the mechanism's design (baselines and resource eligibility) diminish the wholesale market benefit realised by all energy system users and continue to prove inaccessible for a large proportion of customers and resource types.
- Peak demand reaches new records as unmanaged EV charging grows, and security and reliability mechanisms are used frequently to account for uncertainty in supply requirements and ensure supply demand balance.

Expected challenges to 2040

Over the short term:

- Rapid growth in consumer-owned resources continues and conservative connection limits are preventatively placed to tighten exports limits on the distribution system.
- Material volumes of off-market, price-responsive activity increases the uncertainty of short-term operation of the power system.
- Record low levels of minimum operational demand give rise to power system operability and system security issues including the need to direct grid-scale synchronous resources to come online to maintain system strength, inertia and voltage control.
- Use of emergency backstop mechanisms occurs after all other operational measures to manage the power system have been exhausted, but they are activated at an increasingly frequent rate to account for growing uncertainty in the behaviour of price-responsive resources.
- Increasing procurement of emergency reserves and frequency response services occurs to account for growing uncertainty in the behaviour of price-responsive, distributed resources. System and network limits are deployed and are expected to first be triggered in highly congested zones.

Over the medium to long term:

- Markets are introduced to incentivise and reward the provision of operating reserves and capacity, but consumers' CER remain off-market, leaving them ineligible to participate.
- Consumers' CER investments are underutilised across the system, instead directing eligible market revenues to grid-scale resources and large loads.

- The use of system-level levers to manage minimum operational demand constrain and curtail CER (such as emergency back-stop mechanisms) are activated at a higher frequency across large areas of distribution networks.
- The increased curtailment and use of emergency security measures necessitates the retention of thermal generation, slowing the pace of thermal exit and the transition more broadly.
- The ISP forecasts for in-market participation of orchestrated storage do not materialise, contributing to a larger than forecast build-out of grid-scale resources.
- Beyond the procurement of emergency and frequency reserves, operating reserves are enabled to buffer against uncertainty contributed to by unscheduled resources across real-time dispatch intervals.

Over the long term:

- Underutilisation of distributed resources in meeting the firming capacity requirements of the NEM leads to duplicative investment in large network and grid-scale resources to meet the reliability standard and maintain system security.

Consequences

For consumers:

- The result of remaining off-market and the application of distribution level constraints on distributed resources reduce opportunities for arbitrage and access to revenue streams (feed in tariffs [FiT], FCAS, Operating Reserves and capacity credits).
- Procurement of emergency reserves and frequency services to mitigate against unknown shifts in consumption/generation and to manage the system securely and reliably increases, escalating financial recovery of these services from consumers[15].
- The activation of emergency back-stop mechanisms increases in frequency, limiting consumers' resources regardless of each resource's contribution to the uncertainty affecting the grid.

For the system:

- Grid-scale synchronous resources are retained beyond their indicated planned retirement, available for direction in response to the need to manage uncertainty in minimum load conditions and to continue to manage system security[16].
- Portfolios of aggregated consumer resources do not participate in scheduling, and more grid-scale storage resources are built beyond what is forecast in the ISP's ODP.
- Limits on consumer resources are triggered to account for greater forecasting uncertainty, resulting in 'worst-case' scenario interventions being utilised more often.

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[15] The total cost of exercising Reliability and Emergency Reserve Trader (RERT) on 14 June 2022 in New South Wales was $21,600,000. AEMO *RERT End of Financial Year 2021-22 Report*, August 2022, page 5, at: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2022/rert-end-of-financial-year-report-202122.pdf?la=en

[16] AEMO, *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*, April 2020, page 34, at: https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en

Scheduled Lite Enabled scenario: price-responsive resources gradually integrated into market

The scenario

- In this scenario, the NEM's energy supply chain is rapidly decarbonising. Conditions of 100% instantaneous penetration of renewables occur frequently, and supply-side resources are highly digitised and decentralised.
- By removing barriers and incentivising participation, distributed resources are progressively integrated into the energy and ancillary service markets, as well as potential new markets for operating reserves and capacity.
- Orchestrated portfolios of consumer resources participate in proportion to their rates of deployment, following the forecast trajectory in the 2022 ISP *Step Change* scenario.
- Over time, the supply-demand dynamics of the NEM more regularly reflect characteristics of a two-sided market, with aggregated portfolios of resources increasingly setting the market price for both supply and demand for both energy and ancillary services.

Expected challenges and opportunities to 2040

Over the short term:

- More consumers are now able to access the market and be rewarded for their demand flexibility, something which has been difficult to attain for small consumers in particular.
- Traders aggregating price-responsive consumer resources into orchestrated portfolios begin providing forecasts on behalf of consumers; sharing the value that this visibility provides to the market (visibility service payment) in the form of a revenue stream with consumers, without requiring any change in behaviour.
- This enhanced visibility further supports AEMO and NSPs in maintaining secure and reliable operation of the system. Visibility of distributed resources over the operational horizon decreases the bounds of operational uncertainty and enhances situational awareness, lowering the frequency of VRE curtailment and application of limits on distributed resources.
- The enablement requirements and cost of frequency services and operating reserves is reduced due to the larger pool of eligible resources, coupled with lower reserve requirements attributed to improved intra-day visibility of these distributed resources.
- There remains a need to engage emergency reserves (Reliability and Emergency Reserve Trader [RERT]) during continued periods of forecast tight supply as large thermal plant retire from the system. However, in many cases the pre-activation of RERT can be avoided as actual lack of reserve (LOR) conditions eventuate less frequently than otherwise, due to an increase in on-market responses from eligible resources.

Over the medium to long term:

- Trader business models evolve in the provision of future energy services and participation in Scheduled Lite grows.

- The structure and design of consumer service offerings support further rollout of CER and optimise participation, rewarding consumers for the investments they have made in behind the meter resources.
- High levels of participation advantage all energy users, through supply of electricity from lower cost, decentralised generation from the distribution network.
- By 2040, total coordinated DER storages reach 17 GW, orchestrated by traders into portfolios ranging in size from hundreds to thousands of megawatts and beyond. Their participation drives competition in the provision of energy and ancillary services, reducing overall consumer costs.
- Electrification of the transport sector, advances in V2G capability and the rapid uptake of distributed storage (see section A4) contribute to greater volumes of coordinated distributed resources. These in turn deliver a larger proportion of grid services and smooth variances in supply, driven by on-market access.
- Similarly, there is higher confidence in the system's ability to be maintained within its limits, supported by heightened visibility and predictability[17] of distributed resources.
- Aggregated portfolios of distributed resources regularly participate in Dispatch mode, supplying energy and ancillary services into the market, contributing to firming capacity that is required to replace exiting coal power stations. The effect of increased CER coordination lowers the investment requirements of utility-scale generation and storage and operates to minimise unserved energy (USE) risks. This resource base responds to market signals and actively reduces peak demand conditions. For example, the 2022 NEM *Electricity Statement of Opportunities* (ESOO) Central outlook projects VPPs will reduce maximum demand by between 6% and 16% by 2031-32; with this outcome depending on coordination of a significant number of consumer batteries.

In the long term:

- The need to duplicate investment in grid-scale storage resources to fulfill power system requirements is reduced as consumer investments in coordinated storage are utilised as firming capacity and participation is optimised (see section A4.1).
- This can lower overall energy costs for all consumers. Depending on the extent of replication required in absence of a Scheduled Lite mechanism, the avoided cost could be in the order of $1.8-$4.4 billion.

Consequences

- Participation in Scheduled Lite delivers consumers supplementary revenue streams beyond existing feed-in-tariffs and off-market retail demand response offerings.
- Innovative service offerings support greater access to, and uptake of, distributed resources available for market interaction, while maximising opportunities for trade where network flexible export limits are in place.

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[17] Visibility and predictability: data and processes to understand and account for the locational and system-wide impact of CER behaviour.

- Consumers can match their appetite for trader-led control of their CER in-line with their values.
- Indirectly, the increase in the provision of energy and ancillary services from a larger resource pool enhances competition and lowers overall costs to all consumers. Unnecessary costs associated with the risks of over-investments in grid infrastructure are mitigated.

For the system:

- There is a reduction in the frequency of emergency interventions curtailing either consumer-owned resources or grid scale assets, owning to greater visibility of the intentions of price-responsive and dispatchable resources.
- Procurement or pre-activation of additional emergency reserves is reduced.
- The grid evolves in line with the ODP of the ISP, and risks of poorly located resources or over-investment in network infrastructure are avoided due to greater in-market participation of eligible resources.

A4 Participation drives benefits for all consumers

In exploring the potential system benefits of Scheduled Lite, it is important to appreciate the growing volume of eligible resources and consider the rate at which they may participate in the mechanism.

This section explores the extent of Scheduled Lite participation required to deliver the ODP identified in AEMO's 2022 ISP, which provides an efficient pathway for the achievement of power system needs in the long-term interests of electricity consumers in the NEM:

- Section A4.1 first explores the projected uptake of coordinated DER storage in the ISP to demonstrate the benefits that active participation of these resources could provide at scale. It also considers, at a high level, the costs to duplicate a proportion of the projected grid-scale storage capacity in absence of the Scheduled Lite mechanism.
- Section A4.2 considers potential volumes of participation in Scheduled Lite based on projected uptake of coordinated DER storage as well as other eligible resources, highlighting some key factors likely to influence participation in the mechanism.
- Section A4.3 discusses assumptions and opportunities for participation by a range of resources beyond distributed storage, including EVs, distributed solar PV[18], other non-scheduled generation and demand-side participation.

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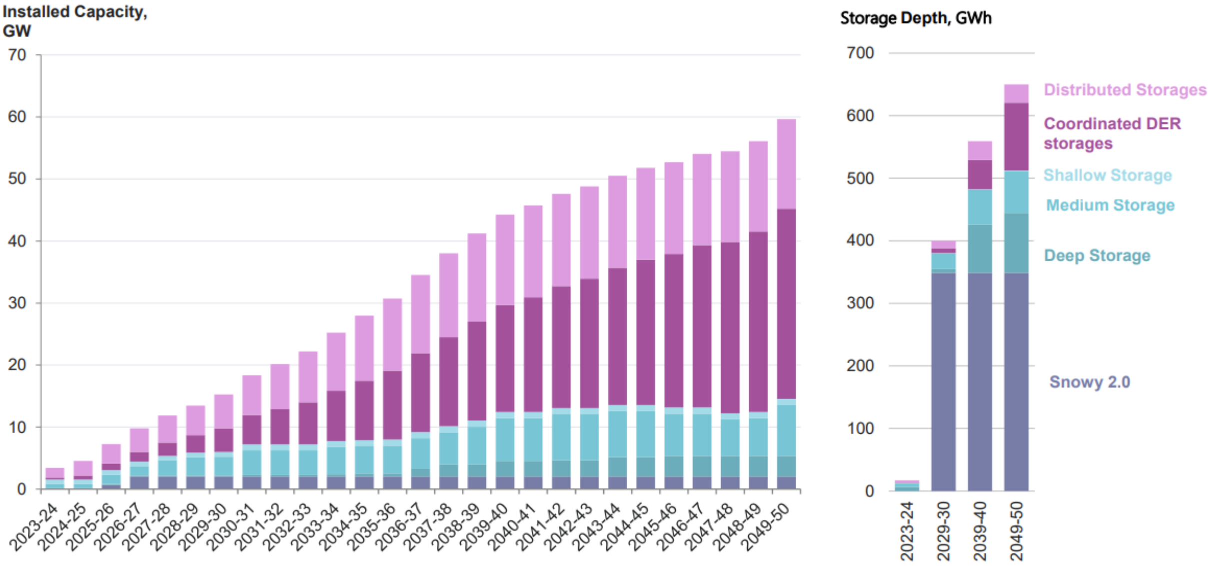
[18] Distributed solar PV refers to both rooftop PV, which includes both residential (up to 10 kW) and business (10-100 kW) systems, and PV non-scheduled generation (PVNSG), which includes systems 100 kW to 30 MW.

The Scheduled Lite participation rates explored in this section are based on the 2022 ISP *Step Change* scenario, which stakeholders identified as representing the most likely pace of change for the energy transformation.

A4.1 Enabling the benefits of distributed storage resources

The 2022 ISP *Step Change* scenario assumes strong growth in coordination and orchestration of consumer-owned storage to meet power system needs. Orchestrated consumer-owned storage, which includes both orchestrated behind-the-meter storage and EV V2G capability, represents an increasing proportion of the total firming capacity of the NEM, rising from 10% by 2030 to almost 40% in 2040. By 2050, this resource is projected to provide half of all firming capacity (31 GW), twice as much as utility-scale storage (Figure 6).

Figure 6 Forecast of MW storage capacity (left) and energy storage capacity (right) – 2022 ISP *Step Change* scenario



Note: 'Distributed storages' refers to non-aggregated behind-the-meter battery installations designed to support the customer's own load. 'Coordinated ER storages' includes behind-the-meter battery installations that are enabled and coordinated via VPP arrangements, as well as EVs with V2G capabilities. Source: AEMO 2022 ISP.

As articulated in earlier sections, the behaviour of aggregated portfolios of distributed resources is currently largely invisible to the market. Appropriate market integration of these resources, including in scheduling processes, will be critical to ensuring they are operated in accordance with system requirements and market signals – facilitating their value to the system and supporting the least-cost ODP as forecast in the ISP. Scheduled Lite provides a mechanism to enable these outcomes by enhancing visibility, predictability and dispatchability of these resources; without it, additional investment in grid-scale resources will be required to fulfill the power system's needs[19], as well as greater expenditure on network capacity, at higher cost to consumers.

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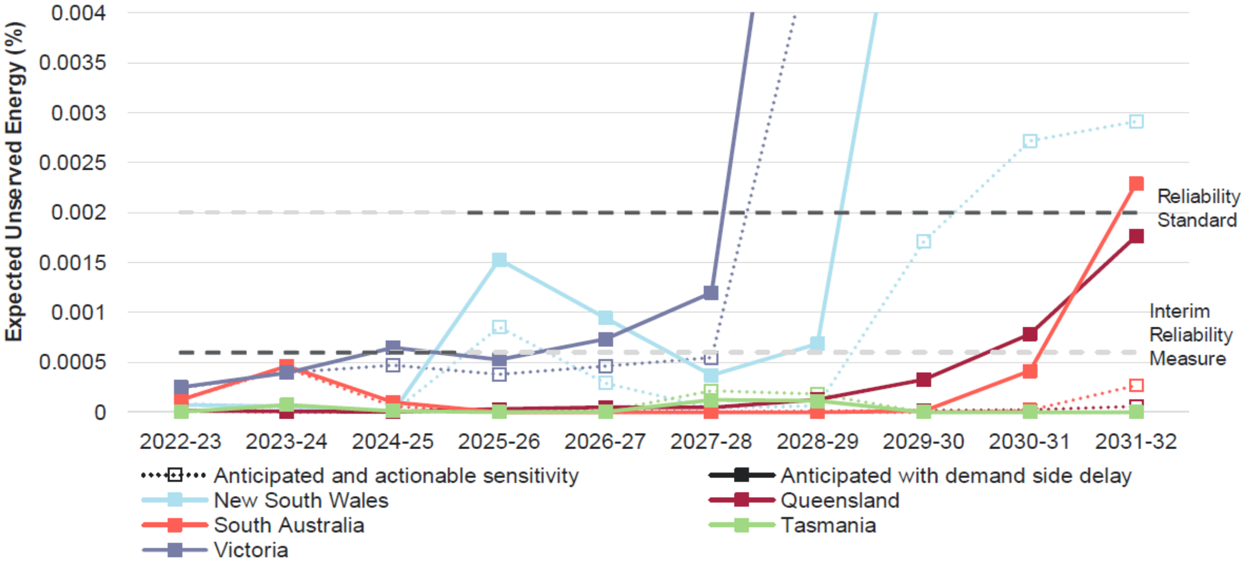
[19] AEMO, 2022, *Integrated System Plan*, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

Avoided duplication in investment costs

AEMO's 2022 ESOO concluded that "*the effect of increased DER orchestration will lower the investment requirements of utility-scale generation and storage, as the DER uptake that is orchestrated operates to minimise USE risks*"[20]. The ESOO outlined a 'consumer action' sensitivity exploring the impact of lower-than-assumed uptake of demand-side coordination services, including failure to develop coordination of consumer-owned storage (that is, uptake remains as forecast but coordination does not materialise) and non-occurrence of the New South Wales Peak Demand Reduction Scheme. The results found higher forecast expected USE in all regions, leading to increased requirements for utility-scale investment to manage these impacts (Figure 7). These results make clear the importance of effective resource coordination in leveraging the benefits of distributed resources for all consumers.

Figure 7 Results of 2022 ESOO development sensitivity – reliability impact of demand side solution delays, 2022-23 to 2031-32 (%)



The box below expands on this topic by exploring the potential cost of duplicating a proportion of projected coordinated distributed storage capacity with grid-scale storage in absence of a mechanism to facilitate the efficient utilisation of distributed resources by bringing them in-market.

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[20] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en&hash=AED781BE4F1C692F59B1B9CB4EB30C4Chttps://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en.

Duplication costs for shallow grid-scale storage

Scheduled Lite provides a mechanism for coordinated and price-responsive distributed resources to be efficiently integrated into the operation of the power system and deliver system-wide value that may otherwise need to be provided through additional investment in grid-scale resources. In other words, a system where distributed resources have low visibility and do not contribute firming capacity will require more duplication of grid-scale capacity to fulfill power system requirements, leading to greater capital expenditure[21,22].

A simple way to explore the potential benefit of Scheduled Lite is to consider the avoided capital costs of duplicating a portion of projected distributed storage capacity with shallow[23] grid-scale storage in absence of the mechanism. All else equal, duplicating 20% of the projected coordinated DER storage capacity through investment in additional shallow grid-scale storage each year to 2040 would come at a cumulative capital cost of around $1.8 billion, rising to approximately $4.4 billion if 50% of the capacity were to be replicated over that same period[24]. Recognising that future requirements for additional investments in grid-scale resources will depend on a range of variables (including factors associated with the uptake, control, behaviour and predictability of CER storage), these results indicate that it could represent a material consumer cost impact which may be avoided through implementation of a mechanism to integrate coordinated DER storage and other distributed resources into market processes.

Although avoided storage duplication costs only provide a basic, high-level metric from which to consider opportunity costs for Scheduled Lite, previous studies have modelled the issue of distributed resource integration more broadly, demonstrating substantial net benefits associated with greater coordination and 'intelligent orchestration' of these resources. These include avoided costs along the electricity supply chain such as generation investment, system balancing, and network investment, with associated reductions in consumer costs.

A review undertaken by CSIRO exploring cost-benefit analysis frameworks for CER integration estimated the net benefit of distributed resource integration for Australia to be approximately $1 billion by 2030, rising to $10 billion by 2050[25]. An assessment of CER integration frameworks undertaken as part of the Open Energy Networks project noted that "*as DER starts to displace larger transmission-connected thermal generation, AEMO will need visibility of that DER and mechanisms to ensure DER can access wholesale markets, in order to keep the system secure*" [26]. Focusing on benefits such as avoided network investment, avoided distributed resource curtailment, and reduced wholesale energy and ancillary service costs, the study found that better CER integration could lead to benefits of up to $6.5 billion by 2039 under the 2019 ESOO *Step Change* scenario.

In addition, studies exploring the opportunity and benefits of load flexibility have found that controllable and flexible demand offers significant economic value (up to the order of $8-18 billion in savings), providing enormous potential to offset the need for new-build large-scale generation assets if appropriately integrated[27].

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[21] Graham, P.W., Brinsmead, T., Spak, B. and Havas, L. 2019, *Review of cost-benefit analysis frameworks and results for DER integration*. CSIRO, Australia

A4.2 Exploring participation volumes

Figure 8 provides an indication of the resource volumes required to participate in the mechanism to 2050 to underpin the ISP's ODP (that is, coordinated distributed storage volumes), as well as other eligible resources, based on 2022 ISP *Step Change* scenario projections[28].

The estimates suggest approximately 12 GW of participating capacity by 2035, increasing to 21 GW by 2040. As described above, these volumes are largely driven by the projected growth in distributed storage orchestrated through VPPs and EVs with vehicle-to-grid capabilities (9 GW by 2035 and 17 GW by 2040), with Scheduled Lite providing the mechanism for participation of these dispatchable resources in scheduling processes. Some additional capacity is assumed to come from other eligible resources including distributed solar PV, price-responsive demand-side participation and other non-scheduled generation, as described in later sections.

It is important to recognise that participation rates will depend on a range of factors including:

- Ability to unbundle and participate with flexible resources separate from passive resources at a connection point (that is, via flexible trading arrangements).
- Customer motivation, trust and awareness of the benefits of participating in VPPs and Scheduled Lite.
- The incentive arrangements for the mechanism and any mandatory elements.
- Opportunities for participation in existing and emerging markets; for example, regulation FCAS or operating reserves in future.
- Development of aggregator business models and technologies, including energy management systems and integration with market systems.
- Compliance settings.
- Uptake of distributed storage, EVs (including participation in V2G and other dynamic charging arrangements) and 'active' distributed solar PV which can be operated to respond to market prices.

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[22] AEMO, 2022, *Integrated System Plan*, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[23] Shallow storage includes grid-connected energy storage with durations less than four hours. The value of this category of storage is more for capacity, fast ramping and FCAS (not included in AEMO's modelling) than for its energy value.

[24] Based on ISP capital cost projections for 2-hour battery storage, AEMO 2021 Inputs, assumptions and scenarios workbook, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en.

[25] See Graham, P.W., Brinsmead, T., Spak, B. and Havas, L. 2019, *Review of cost-benefit analysis frameworks and results for DER integration*. CSIRO, Australia. Estimates were based on Australian studies including modelling for the Electricity Network Transformation Roadmap and SA Power Networks low voltage management business case.

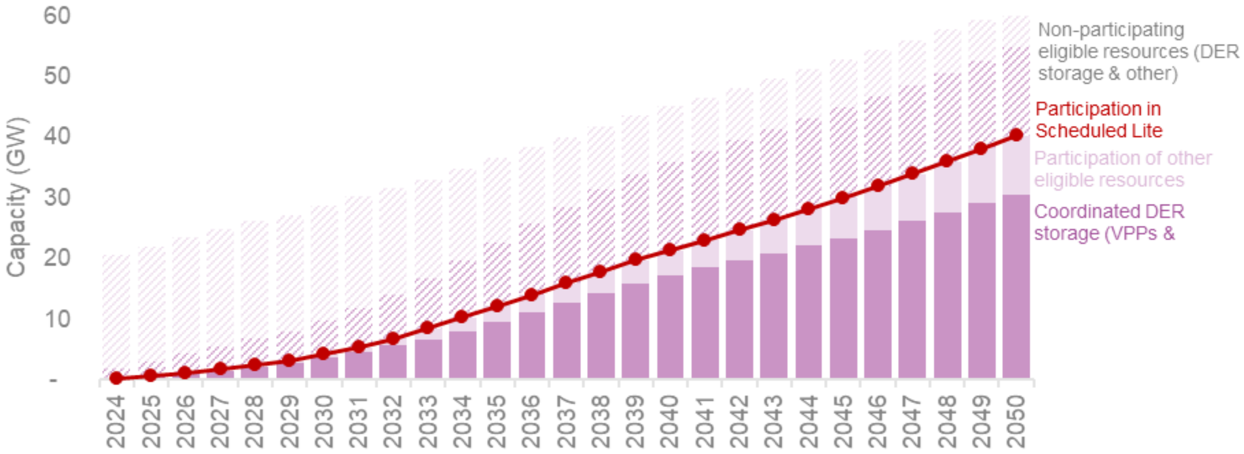
[26] Baringa Partners, 2020. *Assessment of Open Energy Networks Frameworks*. Report prepared for AEMO and ENA, at https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/assessment-of-open-energy-networks-frameworks/

[27] NERA Economic Consulting, 2022, *Valuing load flexibility in the NEM*. Report prepared for ARENA, at https://arena.gov.au/assets/2022/02/valuing-load-flexibility-in-the-nem.pdf.

[28] Note these estimates do not attempt to capture every potential source of participation in Scheduled Lite and represent a gauge of potential volumes of participation in the mechanism.

- Structure and application of flexible export limits (FELs)[29] and network tariff arrangements.
- Development of cost-effective telemetry capabilities.

Figure 8 **Potential participation in Scheduled Lite based on projected uptake of coordinated DER storage and other eligible resources (2022 ISP *Step Change* scenario)**



Note: ‘Coordinated DER storage’ includes VPPs and forecast volume of EVs with vehicle-to-grid capability. ‘Other eligible resources’ includes demand-side participation, distributed solar PV (rooftop and PV non-scheduled generation) and other non-scheduled generation. Estimated participation rates for resources other than coordinated DER storage are based on qualitative assessment of likely participation and technical capability. Further information on assumptions underpinning the *Step Change* forecasts may be found in AEMO’s 2021 *Inputs, Assumptions and Scenarios Report*.

A4.3 Broader participation by distributed resources

Electric vehicle participation

The potential rate of participation by EVs in Scheduled Lite is unclear given their low uptake to date; however, the number of EVs in the NEM is forecast (in the 2022 ISP *Step Change* scenario) to grow rapidly from the late 2020s (Figure 9) comprising around 58% of the total vehicle fleet by 2040, and 99% by 2050. In addition to creating new demand on the system, EVs have the potential to become an important source of price-responsive flexibility and could provide a range of services akin to coordinated DER storage (for example, via participation in VPPs), if appropriately managed and integrated into the market.

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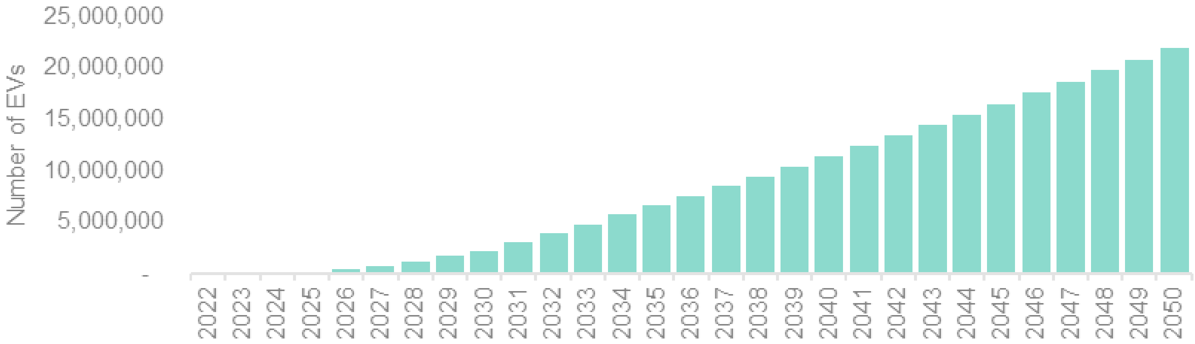
[29] FELs are also commonly referred to as ‘dynamic operating envelopes’.

Figure 9 Forecast electric vehicle uptake in the NEM (2022 ISP *Step Change* scenario)



ARENA's load flexibility study[30] found EV flexible charging to be the most utilised source of flexibility, due to its lower marginal cost relative to other forms of demand-side flexibility such as smart residential and commercial heating and cooling. In this study's 'high EV uptake' scenario, modelling suggested that more flexible EV charging – including deferred charging and vehicle-to-grid services – could deliver $3 to $5 billion in savings to consumers and contribute almost 120 TWh of load flexibility over the study period (2021 to 2040).

Scheduled Lite will assist in facilitating the market integration of EVs through enhanced visibility of price-responsive intentions and new opportunities for market participation by these devices.

The participation volumes in Figure 8 assume that participation of EVs in Scheduled Lite is driven by projected uptake of EVs with V2G capability, which involves retailers or aggregators utilising EV battery capacity to charge from and discharge to the grid at times that best values and rewards EV customers for the services provided to the grid. The uptake of other dynamic charging arrangements including 'coordinated charging' (whereby EV charging is optimised by a trader to occur when demand is otherwise low) and 'vehicle-to-home' (whereby EVs are self-incentivised to utilise excess electricity within the vehicle's battery with associated CER to export directly to the home at times that best services the needs of the household) may also drive some participation of EVs in Scheduled Lite—particularly in the Visibility model which does not require participation in Scheduling processes.

Over time, it is expected that EV charging profiles will shift increasingly towards dynamic arrangements which are optimised around the availability of low-cost generation from variable renewable energy (VRE) sources. For the 2022 ISP *Step Change* scenario, the proportion of EVs with dynamic charging profiles is expected to rise from around 3% of EVs in 2030 to over 60% of EVs by 2050, representing a potential growing source of participation in Scheduled Lite.

Participation by other eligible resources

Although the forecast volume of Scheduled Lite participation in Figure 8 is largely underpinned by orchestrated, consumer-owned storage projections, the mechanism is designed to accommodate a broader range of price-responsive resources into visibility and scheduling processes. These are also included in Figure 8 and are expected to comprise a smaller volume of overall participation, with

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[30] NERA Economic Consulting, 2022, *Valuing load flexibility in the NEM*. Report prepared for ARENA, at https://arena.gov.au/assets/2022/02/valuing-load-flexibility-in-the-nem.pdf.

qualitative assumptions for participation rates based on resource capability and projected uptake over time in ISP forecasts.

The first of these is distributed solar PV. Although most solar PV (particularly at residential scale) is not actively controllable today, this will change in future as new interoperability capabilities and requirements are introduced, making these resources more suitable for participation in Scheduled Lite. Distributed solar PV includes both:

- Rooftop PV, which includes both residential (up to 10 kW) and business (10-100 kW) systems; and
- PV non-scheduled generation (PVNSG), which includes systems 100 kW to 30 MW.

Solar PV installations will increasingly be accompanied by battery storage in the *Step Change* scenario, and as such, the proportion of distributed solar PV installations deemed to be accompanied by battery storage has been excluded from estimations in Figure 8 to avoid duplication. Scheduled Lite participation is assumed to commence slowly for distributed solar PV, particularly rooftop PV, as only new installations are likely to have the capability to be actively managed (for instance, reducing generation in response to negative prices).

Participation by distributed PV is assumed to be facilitated by a future *Aggregated DPV Visibility model* as described in section 4.2.2 of the high-level design, which is proposed specifically to accommodate portfolios comprised of price-responsive PV. For rooftop PV, Scheduled Lite participation is assumed to commence in 2032, rising to 60% of PV-only systems by 2050 (this comprises a small amount of capacity, as most residential and PV systems are projected to be accompanied by storage over time in 2022 ISP *Step Change*). For PVNSG, participation is assumed to commence in 2030, rising to 65% participation by 2050; most of this is driven by uptake of systems in the 100 kW (large commercial) to 5 MW size range.

Other non-scheduled generation (ONSG) resources may also be eligible to participate. ONSG includes non-scheduled generators smaller than 30 MW that are not solar PV, such as gas or biomass-based cogeneration, generation from landfill gas or wastewater treatment plants, and smaller peaking plants or emergency backup generators.

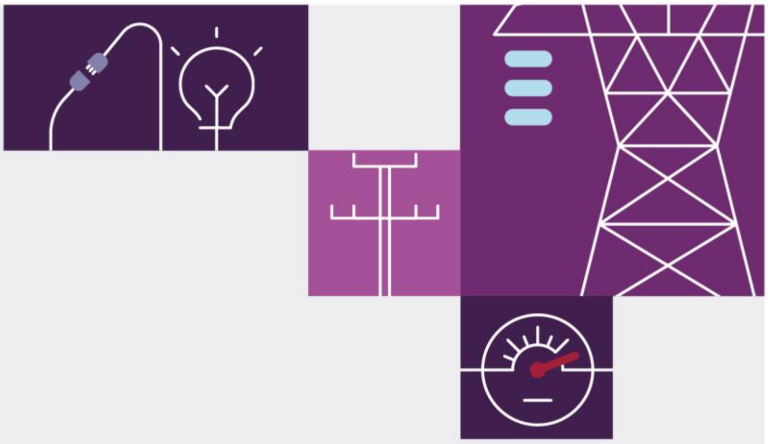
ONSG is projected to grow minimally over the forecasting horizon and comprises a small proportion of participating capacity in Figure 8. Given ONSG will often have more sophisticated control capabilities relative to other unscheduled resources, participation is assumed to commence in 2026 with 10% of systems opting in to Scheduled Lite, increasing to three-quarters of projected ONSG capacity by 2050. Note that Figure 8 likely excludes some small (non-solar PV) resources that meet AEMO's standing exemption from registration, suggesting it may underestimate the volume of capacity eligible to participate in the mechanism.

Finally, a portion of participating capacity from demand-side participation (DSP) is included to represent aggregated demand response portfolios of varying sizes. DSP reflects the capability of demand side resources to reduce operational demand at times of high wholesale prices or emerging reliability issues, and captures direct response by industrial users, as well as consumer response through programs run by retailers, DSP aggregators, or network service providers. In its DSP forecasting methodology, AEMO restricts its definition of demand-side participation to avoid double counting given that many types of DSP responses are included in AEMO's demand forecasts and supply models. The projections used in Figure 8 also exclude wholesale demand response. The 2022 ISP *Step Change* scenario assumes that DSP reaches a target level of 8.5% of peak demand by 2050. Conservative assumptions about participation have been used to recognise that not all DSP will be suitable for participation in Scheduled Lite and to further reduce the risk of double counting, with participation assumed grow from 5% to 50% of projected capacity between 2026 and 2050.

Appendix B: High Level Design

January 2023

Appendix to the Scheduled Lite
Rule Change Request



Important notice

Purpose

This is Appendix B to the Scheduled Lite Rule Change Request.

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Executive summary

Scheduled Lite is a voluntary mechanism that aims to lower barriers and provide incentives for price-responsive, distributed resources to provide visibility and participate in the market scheduling process of the National Electricity Market (NEM). This paper consolidates the high-level design that informed Australian Energy Market Operator's (AEMO's) rule change proposal for Scheduled Lite. The design incorporates stakeholder feedback received during consultation on the draft high-level design and other consultation activities, including a consumer insights workshop in collaboration with the customer insights steering group led by the Energy Security Board (ESB).

Participation in market scheduling processes will become increasingly important to the accuracy and effectiveness of short-term operations for AEMO, Network Service Providers (NSPs) and market participants as consumer energy resources (CER)[1] and flexible demand grow in both size and as a share of dispatchable capacity in the power system.

Scheduled Lite provides an opportunity for CER and flexible demand to play a role in the provision of security and reliability services in the NEM. The participation of consumers in Scheduled Lite will lead to better utilisation of resources and increase competition for the provision of services, lowering the cost of energy for all customers. It is important to recognise that while household, business and other consumers will not directly participate in Scheduled Lite, it is the use of their resources that is ultimately sought to be rewarded for being a part of the mechanism.

Engaging in the wholesale market has been a challenge for many consumers and demand-side resources. For instance, although Virtual Power Plants (VPPs) currently can provide contingency Frequency Control Ancillary Services (FCAS), their operation for wholesale energy is off-market, meaning that VPPs are not visible, dispatchable or predictable to the market. These are essential requirements for the operation of the power system needed to operate the system securely and reliably. Scheduled Lite seeks to reduce barriers to enable resources such as VPPs to provide visibility and to participate in the market scheduling process, becoming dispatchable and predictable; and to reward them for doing so.

The ESB prepared a CER Implementation Plan[2] to support the effective integration of CER and flexible demand, which was endorsed by National Cabinet in October 2021. As part of the delivery of the plan, AEMO was tasked by the ESB with the preparation of a high-level design and rule change request to implement a Scheduled Lite mechanism in the NEM.

There are important interactions between Scheduled Lite and other CER Implementation Plan initiatives which includes flexible trading arrangements, interoperability, flexible export limits (FELs), ESB's Customer Insights program and the Australian Energy Regulator's (AER's) review of Consumer Protections for Future Energy Services'. Scheduled Lite will also provide an important building block for CER and flexible demand to participate in the provision of essential system services as well as a basis for participation in a potential capacity mechanism.

Two Scheduled Lite models are being developed for participants to opt into:

- *Visibility:* to enable the provision of information relating to forecast behaviour and actual consumption and generation, and
- *Dispatch:* to integrate price-responsive load and generation into the NEM dispatch and scheduling processes.

The proposed design leverages existing market systems and processes.

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[1] Also commonly referred to as 'Distributed Energy Resources (DER)'.

[2] This was initially titled "Distributed Energy Resources (DER) Implementation Plan".

Participation

Scheduled Lite is intended to facilitate the participation of a range of customers and traders as well as both consumption and generation resources that are not currently scheduled in the market. This may include aggregated CER portfolios of small resources through VPPs; non-scheduled generating units and non-scheduled bidirectional units (BDUs); large users; and aggregated demand response portfolios. For the purpose of this high-level design, this broad range of customers and assets are referred to as distributed resources. Importantly, customers will generally not participate in Scheduled Lite directly and instead a trader will participate on their behalf.

Scheduled Lite is proposed to involve the following participation elements:

- Voluntary participation supported by an incentive framework and a flexible operating model.
- Participant registration in accordance with the National Electricity Rules (NER) registration framework.
- A new classification, 'light scheduling unit', into which resources may be classified for participation in both models.
- Two modes of participation, Visibility mode and Dispatch mode, with different eligibility requirements and obligations for participation. These operationalise each of the two proposed Scheduled Lite models.
- A minimum aggregated capacity threshold enabling traders to 'graduate' from Visibility to Dispatch when their portfolio reaches an appropriate size, and they have developed the necessary operational capabilities.
- Self-management of aggregated resource portfolios, including automated aggregation and re-aggregation of resources in accordance with zones.
- Flexibility in participation models, with optionality around whether (and how) flexible distributed resources are separated for participation in accordance with flexible trading arrangement models[3].

Participation in Dispatch mode will require more sophisticated operational capabilities compared to Visibility mode. While a trader may commence participation in Visibility mode, a transition to Dispatch mode should be encouraged and supported by the framework as its portfolio size and capabilities expand.

Visibility

The Visibility model will enhance the accuracy of load and price forecasting by enabling traders to communicate the forecast behaviour of their price-responsive resources to AEMO for use in market scheduling processes (Figure 1). AEMO does not currently receive any information about the market intentions of price-responsive distributed resources. This information will be a critical input into load forecasting performed by AEMO and DNSPs. Orchestrated portfolios of distributed resources are currently less than 200MW, but their capacity is expected to grow to around 1GW by 2025 and over 4GW by 2030. As the capacity of orchestrated resources grows, an inability to incorporate their price-responsive behaviour into load forecasting processes would result in a deterioration of the forecast accuracy.

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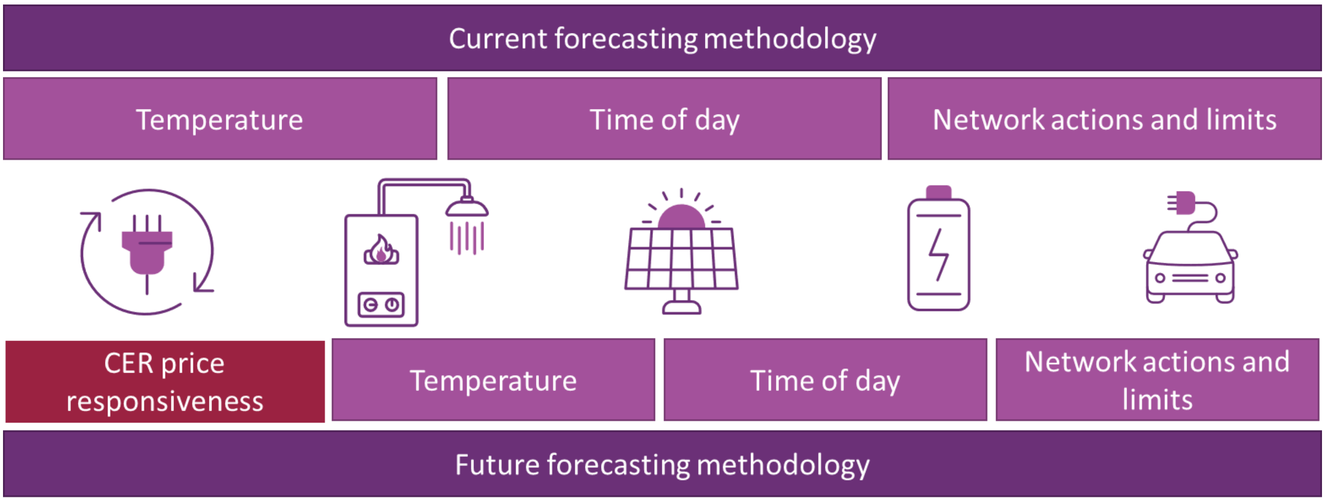
[3] The participation framework does not involve baselining.

Figure 1 **Scheduled Lite incorporates information on price-responsive behaviour into AEMO's load forecasting methodology**

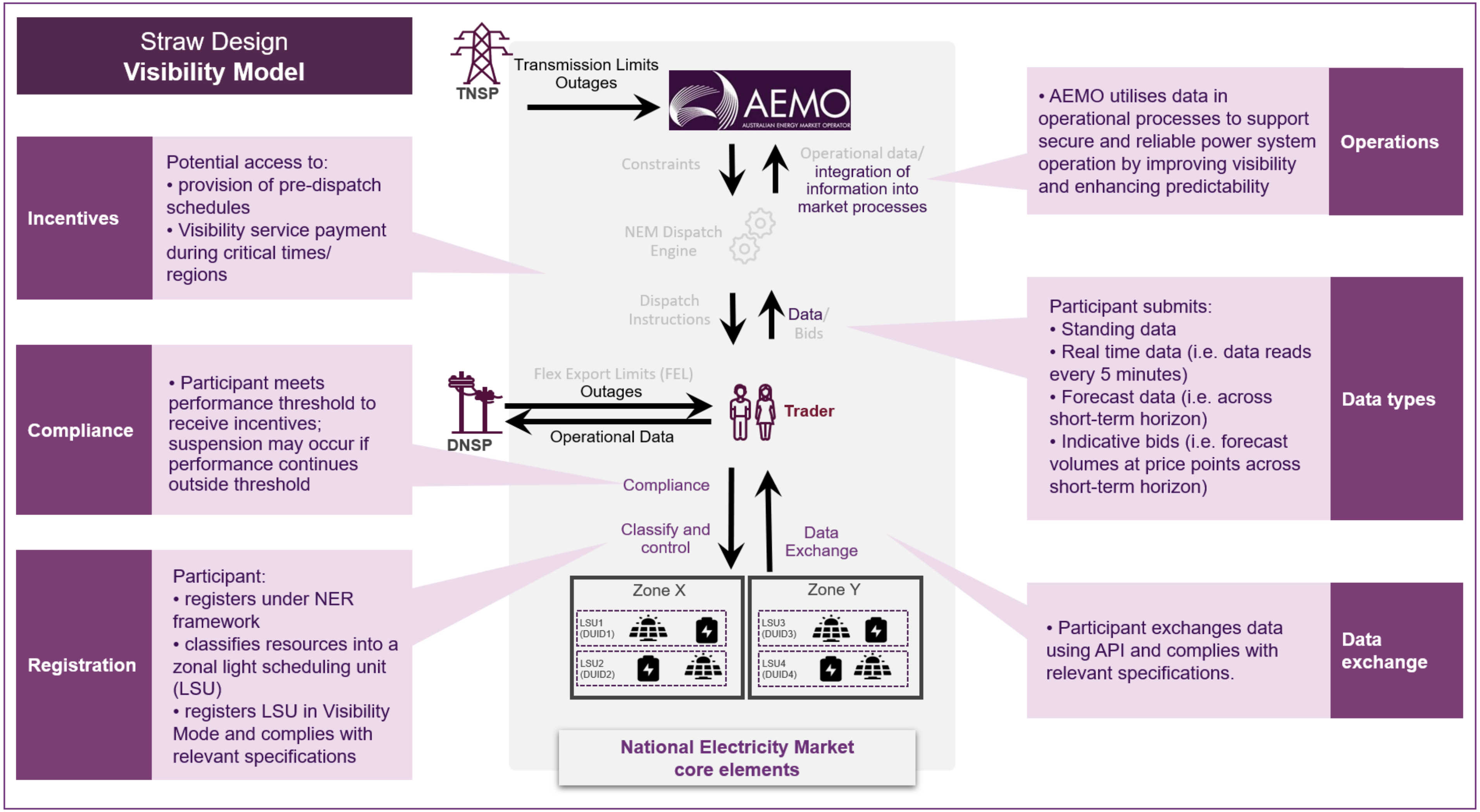


Data exchange will be facilitated through an application programming interface (API) and web interface. Traders will provide standing data as well as real-time, forecast and indicative bids for consumption and generation over the short-term operational horizon. Traders will not be required to participate in dispatch or respond to dispatch instructions or directions.

The benefits of participation in the Visibility model largely accrue to the market rather than the individual customer or trader, and as such a visibility service payment is proposed as an incentive for participation.

Traders that meet performance thresholds for forecast accuracy and consistency of data submissions would be eligible for incentives. A trader may be suspended from participation if their performance continues outside threshold or significantly deviates from threshold. The framework would allow for the trader to opt out during the operational time horizon by submitting a forecast of their expected passive consumption and generation at times when their portfolio is not responding to price signals. However, benefits would not accrue to a trader during periods they have opted out of participation.

Figure 2 Straw design for Visibility model



Straw Design
Visibility Model

Incentives

Potential access to:
- provision of pre-dispatch schedules
- Visibility service payment during critical times/ regions

Compliance

- Participant meets performance threshold to receive incentives; suspension may occur if performance continues outside threshold

Registration

Participant:
- registers under NER framework
- classifies resources into a zonal light scheduling unit (LSU)
- registers LSU in Visibility Mode and complies with relevant specifications

Operations

- AEMO utilises data in operational processes to support secure and reliable power system operation by improving visibility and enhancing predictability

Data types

Participant submits:
- Standing data
- Real time data (i.e. data reads every 5 minutes)
- Forecast data (i.e. across short-term horizon)
- Indicative bids (i.e. forecast volumes at price points across short-term horizon)

Data exchange

- Participant exchanges data using API and complies with relevant specifications.

Dispatch

Dispatchability services comprising controllability, firmness and flexibility are essential requirements for the operation of the power system. As thermal generation exits the power system it will become increasingly valuable for dispatchability services to be provided by distributed resources. The Dispatch model aims to establish fit-for-purpose arrangements for distributed resources to participate in market scheduling processes.

A minimum threshold of 5 MW is proposed for participation in Dispatch mode, and new Supervisory Control and Data Acquisition (SCADA) arrangements that better suit distributed and distribution connected resources will be an essential pre-requisite for establishment of Scheduled Lite. Technical standards for communication and coordination of distributed resources that will be developed through the ESB's interoperability policy will provide an important foundation for the implementation of Scheduled Lite.

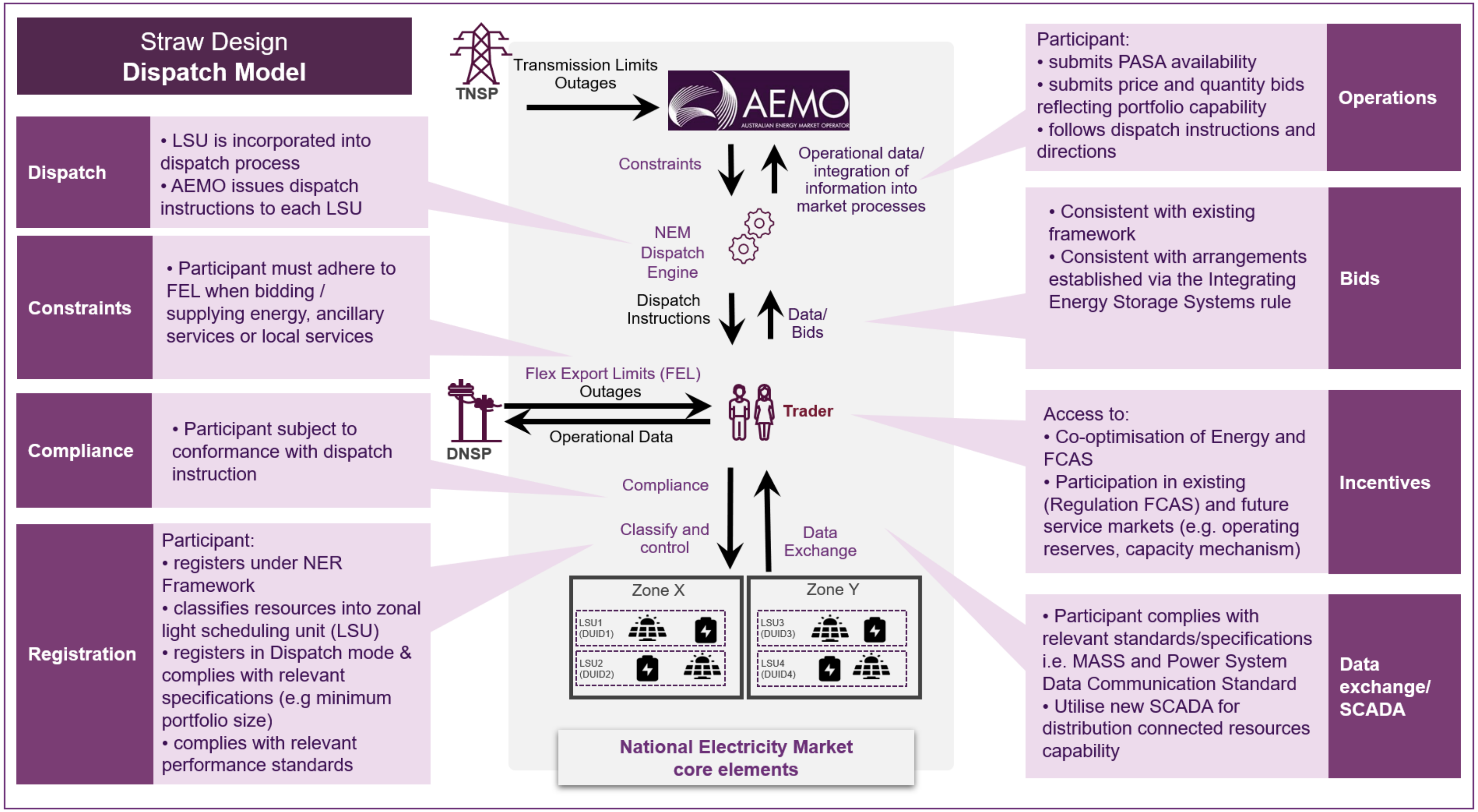
AEMO will update constraint equations to incorporate a light scheduling unit that operates in Dispatch mode at the time of registration. The trader will be responsible for managing their energy, FCAS and local service bids and dispatch to ensure they operate within the FELs for their portfolio.

A trader will bid into the NEM wholesale spot market when a light scheduling unit is operating in Dispatch mode for energy and FCAS the same as any other scheduled resource, with bids indicating the expected quantity of consumption or production at different price bands. The NEM Dispatch Engine (NEMDE) will treat light scheduling units as any other scheduled unit, including producing co-optimised energy and FCAS dispatch instructions. Traders will need to manage their portfolio to conform to the dispatch instructions issued for their light scheduling unit.

AEMO considered a suite of potential incentives to encourage participation in Dispatch ranging from the ability to co-optimise resources across energy and FCAS, financial incentives, and eligibility to participate in current or future service markets through to mandatory obligations for certain participant or resource types. AEMO considers that the ability to provide services that require the scheduling of resources would act as a strong incentive for participation in dispatch. Based on stakeholder feedback, the ability to co-optimise energy and FCAS and the eligibility to provide Regulation FCAS are likely to encourage some participation in Dispatch. However, the ability to provide new services like operating reserves or capacity certificates are likely to provide strong participation incentives. If these new mechanisms do not progress, then an incentive scheme (like capacity certificates) specific to distributed resources should be developed.

It is anticipated that a second stage of the Dispatch model will be required in the future to integrate the model with enhancements to the DER Register and FELs, and to further integrate the model into AEMO's reliability and security processes.

Figure 3 Straw design for Dispatch model



Straw Design
Dispatch Model

Dispatch
- LSU is incorporated into dispatch process
- AEMO issues dispatch instructions to each LSU

Constraints
- Participant must adhere to FEL when bidding / supplying energy, ancillary services or local services

Compliance
- Participant subject to conformance with dispatch instruction

Registration

Participant:
- registers under NER Framework
- classifies resources into zonal light scheduling unit (LSU)
- registers in Dispatch mode & complies with relevant specifications (e.g minimum portfolio size)
- complies with relevant performance standards

Operations

Participant:
- submits PASA availability
- submits price and quantity bids reflecting portfolio capability
- follows dispatch instructions and directions

Bids
- Consistent with existing framework
- Consistent with arrangements established via the Integrating Energy Storage Systems rule

Incentives

Access to:
- Co-optimisation of Energy and FCAS
- Participation in existing (Regulation FCAS) and future service markets (e.g. operating reserves, capacity mechanism)

Data exchange/ SCADA
- Participant complies with relevant standards/specifications i.e. MASS and Power System Data Communication Standard
- Utilise new SCADA for distribution connected resources capability

1 Introduction

1.1 Background

The Australian Energy Market Operator (AEMO) was tasked by the Energy Security Board (ESB) in September 2021 with the preparation of a high-level design and rule change request for a Scheduled Lite mechanism for the National Electricity Market (NEM). AEMO has prepared this high-level design in consultation with stakeholders.

Scheduled Lite is a voluntary mechanism that aims to lower barriers and provide incentives for price-responsive, distributed resources to provide visibility and participate in the NEM's market scheduling process. Through participation in Scheduled Lite, there is an opportunity for distributed resources to make valuable contributions to the secure and reliable operation of the power system. While a key focus of the mechanism is to better integrate consumer energy resources (CER) in the NEM scheduling processes, the mechanism will also be applicable to large users and small generators[4].

1.2 The need for greater visibility and dispatchability of price-responsive resources

This section provides a high-level overview of the need for greater visibility and dispatchability of price-responsive, distributed resources. Further detail on the need for the Scheduled Lite mechanism can be found in the accompanying appendix to the Rule Change Proposal (Appendix A – Scheduled Lite Justification).

Distributed resources have continued their strong growth in both size and as a proportion of dispatchable resources in the power system, resulting in operational challenges associated with balancing demand and supply, and managing system security[5]. Consequently, visibility and coordination of these new types of resources within the scheduling of the market systems is becoming increasingly important in maintaining secure and reliable operation of the power system.

Figure 4 shows the generation capacity projections from AEMO's 2022 Integrated System Plan (ISP) (*Step Change* scenario) over the next 30 years, highlighting that by 2050 virtual power plants (VPPs), vehicle-to-grid (V2G) services and other emerging technologies will provide approximately 31 GW of dispatchable storage capacity, twice as much as utility-scale storage (15 GW).

Integration of these price-responsive resources in the scheduling of the market will be critical to realising their value to the system and achieving the ISP least-cost optimal development path (ODP). For instance, the ISP least-cost ODP recognises coordination of distributed storage[6] as an alternative source to treble the firming capacity required. It projects that by 2050 distributed storage including coordinated VPPs are forecast to represent almost three-quarters of dispatchable capacity (in MW terms), reducing the need for shallow storage at utility scale.

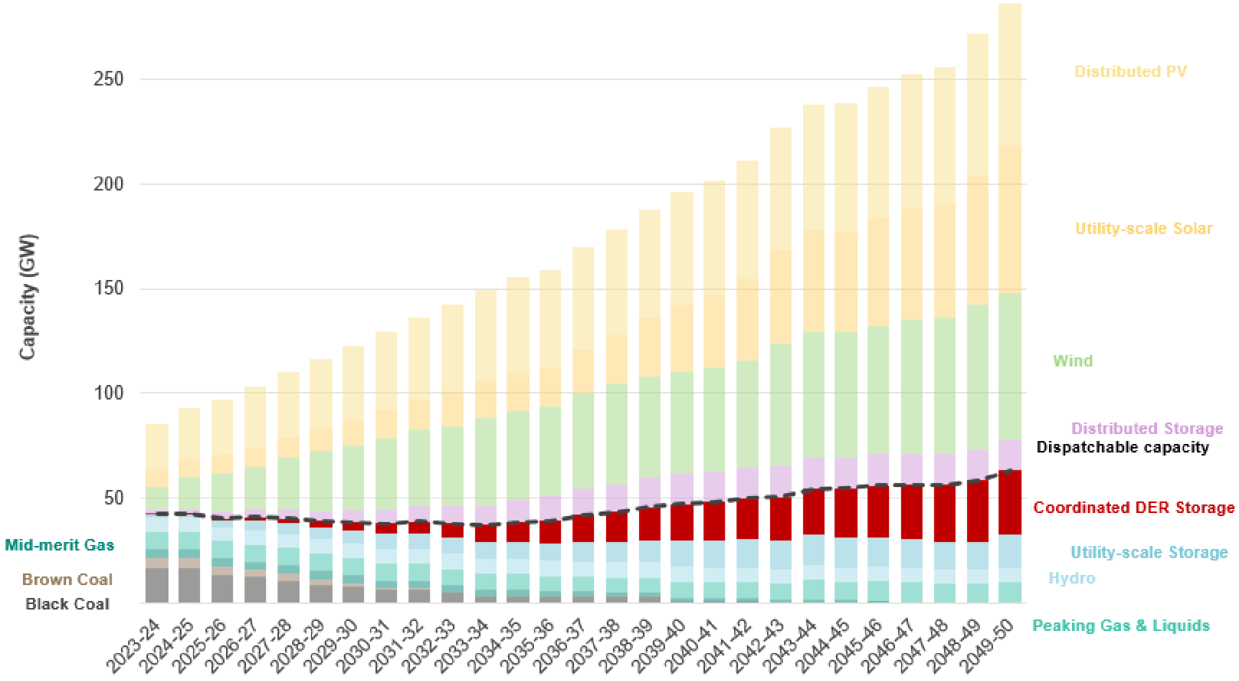
---

[4] In this context, a small generator is one that falls below the threshold to be a scheduled generator – 5MW for battery storage and 30MW all other technologies.

[5] AEMO, 2020. *Renewable Integration Study Stage 1* Appendix A: High Penetrations of Distributed Solar PV, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf.

[6] Coordinated distributed storage includes both orchestrated behind-the-meter storage and EV vehicle-to-grid capability.

Figure 4 **Forecast NEM capacity by resource type to 2050, 2022 ISP *Step Change* scenario**



Visibility

A lack of visibility of price-responsive distributed resources[7] increases short-term NEM operational uncertainty and may result in a need to apply greater constraints to the network, maintain higher operating reserves and security margins across the grid, and as a consequence, increase the cost to consumers of operating the power system. If AEMO is unable to accurately predict how the system is going to perform across operational and investment timeframes, then it will be unable to provide information needed to support the efficient operation of the market. This is further explored in the status quo scenario contained in Appendix A.

Dispatchability

The NEM is entering a transitional period where both the consumption and generation of energy are becoming more variable, decentralised, and digitised – Australia is at the cutting edge of this revolution with world leading penetrations of distributed resources across the power system. In this context, power system requirements vary as new operational conditions[8] and scenarios emerge[9].

---

[7] Price-responsive refers to CER that is controlled to optimise financial outcome for the customer around wholesale market or tariff price signals.

[8] "Operational conditions" means a particular network configuration, generation mix and loading at a point in time or over a period of time. AEMO NEM Engineering Framework March 2021, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-march-2021-report.pdf?la=en.

[9] AEMO NEM Engineering Framework Initial Roadmap, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-initial-roadmap.pdf?la=en.

AEMO's Engineering Framework has identified potential gaps (300) and operational conditions (six), where increased industry focus is needed. The Engineering Framework has also highlighted that incentives would be required for responsive demand to be aligned with system needs, enabling these resources to provide system-level flexibility and dispatchability services. These are critical services as thermal generation exits the power system.

The Dispatch model would be a vehicle to enable this alignment, by lowering barriers for distributed resources to participate in dispatch processes.

AEMO recognises that the innovation occurring in the ability for aggregation of individual price-responsive units to offer capacity, energy, and ancillary services in a controlled manner to the market would greatly contribute to improved efficiency of dispatch outcomes, while allowing future operational conditions to be navigated.

1.3 ESB's NEM Post 2025 Reform

The ESB was tasked by the former Council of Australian Governments (COAG) Energy Council to deliver a market design for the NEM to meet the needs of the energy transition beyond 2025. In its Post 2025 Final Advice to Ministers, the ESB recommended a CER Implementation Plan setting out reform activities necessary to support the effective integration of CER and flexible demand. In October 2021, Ministers endorsed the ESB's recommendations and tasked ESB with delivery of the CER Implementation Plan over the next three years.

The reforms outlined in the CER Implementation Plan address a range of technical, regulatory and market issues over a three-year period. The reforms are intended to leverage technology and data, improve access and efficiency, enhance market participation, and strengthen customer protections and engagement. The Plan sequences key dependencies to ensure reforms are introduced in a timely manner to address urgent needs associated with the rapid take-up of CER.

Scheduled Lite is a Horizon One reform in the CER Implementation Plan and is one of several initiatives that aim to create value for customers through the integration of CER and flexible demand within the wholesale market.

Interaction with CER reforms

Engagement with stakeholders to date has highlighted the importance of coordinating the development of reforms across the CER Implementation Plan. In general, the Scheduled Lite design does not seek to solve matters associated with other reform initiatives, but instead builds on their developments and highlights any specific issues or requirements to be defined through the related reform processes. The Scheduled Lite design will build upon important reforms underway by the ESB including:

- Integrating Energy Storage Systems (IESS): Creates a foundation for the aggregation of small bidirectional resources within the National Electricity Rules (NER). As outlined in section 2.1, it is proposed that the Scheduled Lite mechanism utilises, and builds on, the changes in the registration framework established in IESS. No new participant category is proposed as part of the Scheduled Lite, a trader could be registered as a Generator, Market Customer or the new Integrated Resource Provider (IRP) category.
- Flexible trading arrangements: Model 1 will be introduced as part of the IESS rule change, building on the existing Small Generation Aggregator (SGA) framework, while the Australian Energy Market Commission (AEMC) has commenced consultation on a rule change proposal for the implementation of model 2. As outlined in section 2.1, flexible trading arrangements would provide a mechanism, if required, for a trader to

separately trade its price-responsive resources in the market. This reform is important to the success of Scheduled Lite as the separate trading of price response resources will better enable customers and their traders to comply with performance standards for the mechanism.

- ESB Interoperability Policy: Technical standards for the communication and coordination of distributed resources that will be developed through the ESB's interoperability policy will provide an important foundation for Scheduled Lite.
- AEMC Technical Standards Review: considering the implementation of technical standards for CER. Technical standards provide an important foundation for resources to reliability and securely participate in market scheduling processes.
- Flexible Export Limits (FEL)[10]: Traders will need to adhere to operating limits in accordance with policy developed by the AER and Australian Renewable Energy Agency's (ARENA's) Distributed Energy Integration Program (DEIP) working group.
- Project EDGE (Energy Demand and Generation Exchange): Trialling of scheduling frameworks and processes through Project EDGE will inform Scheduled Lite regulations and detailed implementation arrangements.
- ESB Customer Insights and AER review of Consumer Protections for Future Energy Services: The participation of CER in the market scheduling processes creates potential opportunities and risks for customers. The ESB's Customer Insights program and the AER's Consumer Protections Review will provide an opportunity to give further consideration of the risks and the appropriate protections for customers participating in Scheduled Lite.

1.4 Objectives

The purpose of Scheduled Lite is to provide a mechanism that enables greater participation of CER and flexible demand in market scheduling processes, unlocking value for the owners of CER. Through participation in the market scheduling processes, CER and flexible demand will be able to make valuable contributions to the visibility and dispatchability of the power system.

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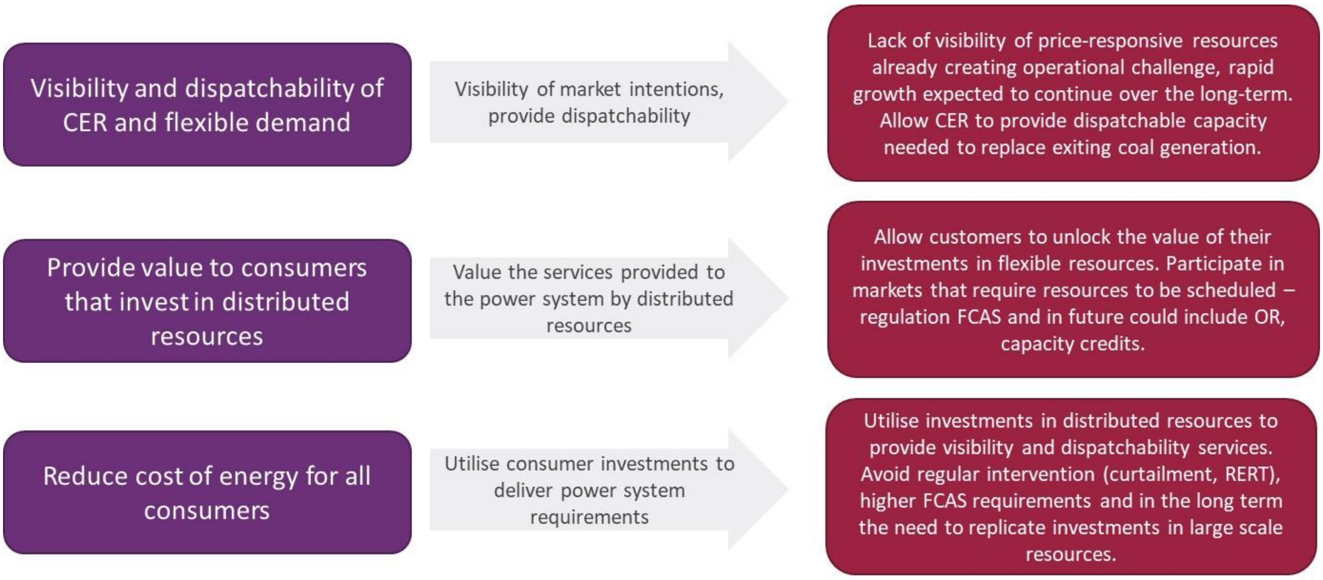
[10] Note FELs are also referred to as Dynamic Operating Envelopes (DOEs).

Figure 5 Scheduled Lite objectives



Visibility and dispatchability of CER and flexible demand

Visibility of market intentions, provide dispatchability

Lack of visibility of price-responsive resources already creating operational challenge, rapid growth expected to continue over the long-term. Allow CER to provide dispatchable capacity needed to replace exiting coal generation.

Provide value to consumers that invest in distributed resources

Value the services provided to the power system by distributed resources

Allow customers to unlock the value of their investments in flexible resources. Participate in markets that require resources to be scheduled – regulation FCAS and in future could include OR, capacity credits.

Reduce cost of energy for all consumers

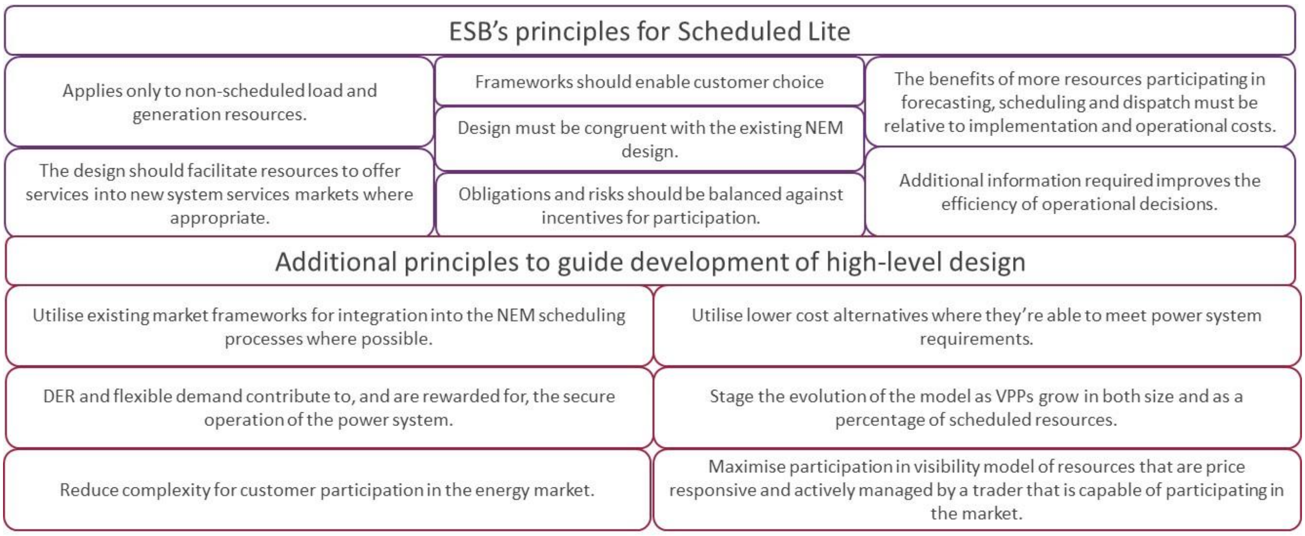
Utilise consumer investments to deliver power system requirements

Utilise investments in distributed resources to provide visibility and dispatchability services. Avoid regular intervention (curtailment, RERT), higher FCAS requirements and in the long term the need to replicate investments in large scale resources.

1.5 Principles

The ESB developed a set of principles to guide the development of the Scheduled Lite initiative as outlined in Figure 6 below. Through engagement with stakeholders, AEMO has identified additional principles to guide the design of the mechanism covering the utilisation of existing frameworks, lower cost alternatives and the staging of arrangements to align with the evolution of CER and flexible demand; these are also outlined below.

Figure 6 Principles guiding the development of Scheduled Lite



ESB's principles for Scheduled Lite

Applies only to non-scheduled load and generation resources.

Frameworks should enable customer choice

Design must be congruent with the existing NEM design.

The benefits of more resources participating in forecasting, scheduling and dispatch must be relative to implementation and operational costs.

The design should facilitate resources to offer services into new system services markets where appropriate.

Obligations and risks should be balanced against incentives for participation.

Additional information required improves the efficiency of operational decisions.

Additional principles to guide development of high-level design

Utilise existing market frameworks for integration into the NEM scheduling processes where possible.

Utilise lower cost alternatives where they're able to meet power system requirements.

DER and flexible demand contribute to, and are rewarded for, the secure operation of the power system.

Stage the evolution of the model as VPPs grow in both size and as a percentage of scheduled resources.

Reduce complexity for customer participation in the energy market.

Maximise participation in visibility model of resources that are price responsive and actively managed by a trader that is capable of participating in the market.

1.6 Scheduled Lite models

Two models have been developed as part of the Scheduled Lite high-level design:

- **Visibility**. The Visibility model enhances visibility of unscheduled price-responsive resources and their market intentions, leading to more accurate short-term load and price forecasting. Traders will be required to provide a forecast of generation and consumption at various price points over the short-term operational horizon called ‘indicative bids’[11]. Traders will not be required to participate in dispatch or respond to dispatch instructions or directions. High level design considerations for the Visibility mode are outlined in section 3.
- **Dispatch**. The Dispatch model will integrate price-responsive distributed resources (such as CER and flexible demand) into the NEM dispatch and scheduling processes. Traders will be able to provide bids for their generation and load, receive and follow dispatch targets. Through participation in Dispatch mode, traders would gain access to existing or potential future markets that require the scheduling of resources. High level design considerations for the Dispatch mode are outlined in section 4.

AEMO has developed two models for Scheduled Lite as proposed by the ESB and believes these two models are complementary and proposes that they are both implemented. As outlined in section 2.1, the proposed rule establishes a new light scheduling unit (LSU) classification. The implementation of the Scheduled Lite models will be through different modes in which an LSU may operate.

Outcomes from consultation on the draft high-level design gave rise to the consideration of two additional potential visibility models:

- Simple Visibility model: would provide a simpler mechanism for distributed resources, in particular large customers, to provide information about their price-responsive behaviour.
- Aggregated Distributed Photovoltaics (DPV) Visibility model: to provide visibility of price-responsive distributed PV behaviour to support critical operational events.

The rule change proposal will seek to establish flexibility in the framework to allow these additional visibility models to be incorporated in the implementation of Scheduled Lite, further high-level details are described in this document to allow for further consideration, see section 4.2.2.

1.7 Reform development

Stakeholders have consistently provided feedback that the implementation of Scheduled Lite should evolve over time as the size and capabilities of aggregated portfolios of distributed resources increase. Table 1 below outlines the potential phasing for the delivery of the Scheduled Lite reforms, the indicative timing is drawn from the Strategic pathway within the draft NEM 2025 Implementation Roadmap[12] published by AEMO:

- The Visibility mode would deliver changes to the registration framework, data exchange and incentives to enable Scheduled Lite.
- Stage 1 of the Dispatch mode would build on the Visibility mode, adding functionality related to bidding and dispatch of distributed resources. This stage of development would also rely on the delivery of appropriate Supervisory Control and Data Acquisition (SCADA) arrangements for CER.
- Stage 2 of the Dispatch mode is not discussed in detail in this consultation paper. This potential phase of development is included to highlight that further development of the Dispatch mode is likely to be required

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[11] Further information on Indicative Bids can be found in section 0.

[12] AEMO. Reform Delivery Committee webpage, at https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/reform-delivery-committee.

once further CER reform initiatives have been delivered. For example, FELs are expected to be widely adopted following the implementation of Scheduled Lite, as such stage 2 would allow the integration of FELs into market operations.

Table 1 Phasing of reform delivery

Phase of development	Incremental development of Scheduled Lite design			Indicative timing
Visibility mode	Registration	Provide forecast and actual consumption and generation information	Incentives	November 2024
Dispatch mode Stage 1	System limits	Short-term capacity and bids	Dispatch and compliance	October 2025
Dispatch mode Stage 2	Integration with Distributed Energy Resources (DER) Register	Integration of FELs into market operations. integration of technical limits for scheduling of Frequency Control Ancillary Services (FCAS)	Enhancements to dispatch and further integration with security and reliability processes	Post 2025

1.8 Stakeholder engagement

ESB outlined high-level aspects of Scheduled Lite as well as objectives and principles for its development in its March 2021 consultation paper and final recommendations to Ministers in August 2021. AEMO has engaged with industry through the DER Market Integration Consultative Forum (MICF) to consider the key design elements in more detail and to bring together potential designs (see Appendix B.2**Error! Reference source not found.**).

AEMO consulted with stakeholders on a draft high-level design. The feedback received[13] was incorporated into the design and is reflected in this final version of the high-level design.

To support the ongoing development of the Scheduled Lite initiative, a customer insights workshop was held to explore the opportunities and possible challenges from a customer perspective. The workshop leveraged the customer insights collaboration work being undertaken by ESB and brought together a diverse group of stakeholders from networks, retailers, technology providers, customer advocates and technical experts.

The stakeholder feedback received informed the AEMO Scheduled Lite Rule Change Request.

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[13] Appendix B.2 Stakeholder Feedback contains further details on the feedback received.

2 Participation in Scheduled Lite

2.1 Participation building blocks

This section outlines the key building blocks for participation in Scheduled Lite. The proposed design is focused on leveraging existing market systems and processes and enabling traders to participate efficiently in the mechanism depending on their resources, portfolio capacity and technical capabilities for participation.

Scheduled Lite is intended to accommodate a range of participants and resources that are not currently scheduled in the market. This may include, for example, aggregated CER portfolios (e.g. VPPs – see Box 1 below); non-scheduled generating units and non-scheduled bidirectional units (BDUs); aggregated demand response portfolios which are not eligible for, or do not wish to, participate in Wholesale Demand Response (WDR)[14]; and large unscheduled loads.

In this paper, the term 'trader' is used generally to describe entities participating directly in Scheduled Lite. This may be the resource owner/operator itself, or an entity participating with the resource on behalf of the owner to access value streams (energy or services) in accordance with system and network constraints (typically a retailer/aggregator). This terminology recognises the ESB's shift towards a 'Trader Services' participation framework whereby a single, universal registration category may be used for all entities seeking to engage across the wholesale and energy service markets. The Trader Services concept is underpinned by service-based regulation whereby obligations are attached to services provided rather than assets.

Importantly, small customers with CER will generally not participate in Scheduled Lite directly and will instead be represented in the market by a trader. The trader will actively manage resources in accordance with their agreement with the consumer; AEMO is not seeking to control the customer's assets. Reforms to establish flexible trading arrangements may also provide customers with greater flexibility to engage different service providers to manage their flexible resources; for example, a customer may engage a specialist trader to manage their solar and battery whilst remaining with their existing retailer for the rest of their electricity consumption. In the case of small customers, the trader will typically be an authorised electricity retailer, noting that the AER's *Review of consumer protections for future energy services*[15] is considering whether the existing framework remains fit for purpose for future energy services. Some large users may choose to directly participate in Scheduled Lite, particularly in the Visibility model, but could also participate via a trader.[16]

Broadly, participation in Scheduled Lite is proposed to involve the following elements:

1. **Voluntary participation** supported by an incentive framework and a flexible operating model.
2. **Participant registration** in accordance with the existing NER registration framework.
3. A **new classification**, 'light scheduling unit', or LSU, into which resources may be classified for participation and zonal aggregation of resources.

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[14] For example, they do not qualify for baselining and therefore need to participate at the connection point; e.g., not able to demonstrate that a baseline can be determined for the load that complies with the baseline methodology.

[15] At https://www.aer.gov.au/retail-markets/guidelines-reviews/review-of-consumer-protections-for-future-energy-services#:~:text=The%20AER%20is%20undertaking%20a,in%20a%20transitioning%20energy%20market.

[16] Unlike WDR, participation in Scheduled Lite does not involve baselines – resources participate via the financially responsible market participant (FRMP) at the relevant connection point and settlement is based on metered flows.

4. Two **modes of participation**, Visibility mode and Dispatch mode, with different eligibility requirements and obligations for participation. These operationalise each of the two proposed Scheduled Lite models (Visibility and Dispatchability).
5. A **minimum aggregated capacity threshold** enabling traders to ‘graduate’ from Visibility mode into Dispatch mode when their portfolio reaches an appropriate size.
6. **Self-management of resource portfolios**, including automated aggregation and re-aggregation of resources in accordance with zones.
7. **Flexibility in participation models**, with optionality around whether (and how) resources are separated for participation in accordance with flexible trading arrangement models.

These building blocks are explored in the sections below, with design elements specific to Visibility and Dispatch modes outlined in sections 3.2.1and 4.2.1 respectively.

Box 1: The relationship between Virtual Power Plants (VPPs) and Scheduled Lite

What are VPPs? Although VPPs are not defined in the NER, they typically refer to an aggregation of distributed resources coordinated to deliver services for power system operation and electricity markets. VPPs may include resources such as decentralised generation, storage and controllable loads, at a range of scales.

How do VPPs operate in the market today? VPPs can provide contingency FCAS (if compliant with the Market Ancillary Services Specification [MASS]) and operate off-market for wholesale energy, and may also provide local network support services and demand response. Although they do not participate directly in the wholesale energy market and are not scheduled for energy, VPPs can respond to energy market prices by, for example, injecting and drawing energy where they can derive value from doing so (for example, engaging in price arbitrage).

Who operates VPPs today? VPPs can be operated by a range of parties, including: Market Customers (for small customers, this will be a retailer); Demand Response Service Providers (DRSPs), which can offer an aggregation of customer loads into contingency FCAS markets; and non-retailer VPP operators if a commercial agreement is reached with the customer/retailer for the relevant connection points. Under the Small Generation Aggregator (SGA) framework (soon to be subsumed into the Integrated Resource Provider [IRP] role under the new Small Resource Aggregator label), exempt small generating and bidirectional units established on their own connection point can also be aggregated for wholesale market settlement (and FCAS from March 2023).

Why do we need Scheduled Lite if we have VPPs? Scheduled Lite provides a framework for integrating VPPs into the market to ensure they are visible, dispatchable and contribute to the firming capacity requirements of the power system. Scheduled Lite is not intended to ‘replace’ VPPs; it is expected to enhance the opportunities for VPPs to gain value from provision of services in the market. For example, the Dispatch model will enable VPPs to participate on-market for wholesale energy through scheduling processes and, through their participation as a scheduled resource, gain access to existing and future markets such as regulation FCAS or a capacity mechanism.

Today, the price-responsive behaviour of VPPs is not visible to the market, degrading the accuracy of demand forecasts and creating challenges for system operation. These challenges will grow substantially into the future, and AEMO will require new tools to manage them effectively without resorting to inefficient use of mitigation measures. In order for VPPs to support system operation and provide greater value to all consumers rather than exacerbating operational challenges in the system, a mechanism is required to ensure they can operate in alignment with system requirements. Importantly, Scheduled Lite is not just for VPPs; it is designed to accommodate a broad range of price-responsive distributed resources that are not currently scheduled in the market.

What is the relationship between Scheduled Lite and the VPP demonstration initiative? The VPP demonstration initiative, which concluded in late 2021, was designed to provide early insights on how to integrate VPPs into market frameworks at scale and develop empirical evidence to inform related changes to regulatory frameworks and operational processes. It included eight VPPs across all mainland NEM regions, with a total registered capacity of 31 MW. It trialled the capability of VPPs to: participate in markets and value stack, including through provision of contingency FCAS, responses to energy price signals, and interaction with distribution networks; provide operational visibility; improve the consumer experience; and cater for cyber security threats.

Findings from the VPP demonstration initiative have informed many aspects of the Scheduled Lite design. For example, insights on forecasting generation and consumption at different price points was adopted in the Scheduled Lite Visibility model. In addition, the Scheduled Lite rule change is progressing a number of recommendations made by the VPP demonstration initiative, including a recommendation “*to accelerate the design and implementation of the scheduled lite visibility model*” in order to support operational visibility requirements.

Other VPP integration trials currently underway, including Project EDGE and Project Edith, have also influenced the Scheduled Lite design and will continue to guide the detailed design and implementation of the mechanism.

Voluntary participation

Scheduled Lite is designed as a voluntary participation mechanism, offering incentives and lowering barriers for resources to provide greater visibility to the market or participate in scheduling and dispatch mechanisms. Participation will be accompanied by appropriate performance thresholds and compliance obligations that balance the need for ensuring reliable outcomes with cost and ease of participation. A voluntary approach that aligns incentives with benefits to the power system is more likely to drive accurate forecasting and compliance, and as a consequence maximise the utilisation and integration of CER and flexible demand in the market.

Voluntary participation is supported by flexible operating arrangements which enables traders to opt out of operating modes (unavailable) within operational timeframes[17] (see section 3.2.7 and section 4.2.9), and to 'hibernate' for longer periods, rather than requiring constant participation in market scheduling processes. AEMO considers that this will better recognise and accommodate the capabilities of traders likely to be operating in Scheduled Lite.

In addition to broad stakeholder support for a voluntary mechanism, the ESB noted concerns about low uptake (and therefore limited benefits) and the possibility of Scheduled Lite moving towards a mandatory mechanism in future. Consistent with the ESB's proposed approach, AEMO considers that the initial design should focus on appropriate incentive structures, facilitating ease of participation and lowering barriers and transaction costs to support greater participation prior to consideration of mandatory elements (such as operational metering for resources above a certain size). Voluntary participation underpinned by appropriate incentives is likely to be the most effective approach to encourage accurate forecasting.

Participant registration

To participate in Scheduled Lite, AEMO proposes that traders will first need to be registered with AEMO under the NER participant registration framework[18]. This approach is preferred over registration based on bilateral agreements between AEMO and traders as it leverages existing building blocks throughout AEMO systems and processes for information and settlement flows.

Depending on the resources being classified for participation in Scheduled Lite, the trader could be registered as a Generator, Market Customer or Integrated Resource Provider (IRP – see Box 2 below), as summarised in Table 2. AEMO expects that most traders intending to participate in Scheduled Lite will already be registered in one or more relevant registration categories.

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[17] 'Operational timeframes' refers to a seven-day period, aligned with ST PASA timeframes.

[18] See Chapter 2 of the National Electricity Rules.

Table 2 Potential registration categories for traders participating in Scheduled Lite

Participant registration	Label	Resource	Examples of customer/ resource types
IRP or Market Customer	**Market Customer**	End user connection point (non-scheduled load), classified by a Market Customer as a market connection point	Large users, VPPs (incl. Electric Vehicle [EV] V2G), aggregated demand response portfolios
IRP or Generator	**Non-Scheduled Generator**	Non-scheduled generating unit: Non-exempt generating unit with nameplate rating <30 MW[a]	20 MW diesel generator
IRP	**Non-Scheduled IRP**	Non-scheduled BDU: Non-exempt bidirectional unit with nameplate rating <5 MW[b]	3 MW battery in a hybrid system
	Small Resource Aggregator	Small resource connection point: small generating unit[c] or small BDU[d] on its own connection point classified by an IRP (Small Resource Aggregator) as a market connection point	Exempt 1 MW battery on its own connection point, exempt 2 MW cogeneration plant on its own connection point

[a] Clause 2.2.3(a) of the NER requires a generating unit with a nameplate rating of less than 30 MW (not being part of a group of generating units connected at a common connection point with a combined nameplate rating of 30 MW or greater) to be classified as a non-scheduled generating unit unless AEMO approves a different classification.

[b] Whilst such a unit would meet AEMO's standing exemption threshold (<5 MW) on its own, there may be instances where, for example, the unit could be part of a hybrid system or subject to an application to register.

[c] A small generating unit is a generating unit with a nameplate rating <30 MW incorporated in a generating system or integrated resource system that AEMO has exempted from the requirement to register as a Generator or IRP.

[d] A small bidirectional unit is a bidirectional unit with a nameplate rating <5 MW incorporated in an integrated resource system which AEMO has exempted from the requirement to register as an IRP.

Box 2: Participation by Integrated Resource Providers

The IRP participant registration category was introduced through the IESS rule change final determination in December 2021 and will commence in full in June 2024. The IRP is a technology-neutral participant category which accommodates a range of participants with bidirectional energy flows that may offer and consume energy and ancillary services.

IRPs approach a near-universal participation category and may classify:

- Scheduled and non-scheduled bidirectional units (Scheduled IRP and Non-scheduled IRP labels respectively).
- End user connection points and scheduled loads (Market Customer label).
- Scheduled, non-scheduled and semi-scheduled generating units (Scheduled Generator, Non-Scheduled Generator and Semi-Scheduled Generator labels respectively).
- Small resource connection points (Small Resource Aggregator label).
- Ancillary service units (Ancillary Service Provider label).

The IRP category subsumes the existing SGA role, which will participate under the new Small Resource Aggregator label. Upon commencement of the rule change, the IRP Small Resource Aggregator will be able to classify small bidirectional units in addition to small generating units, and is able to provide ancillary services from March 2023.

Refer to the AEMC's IESS final determination and AEMO's high-level design for further information.

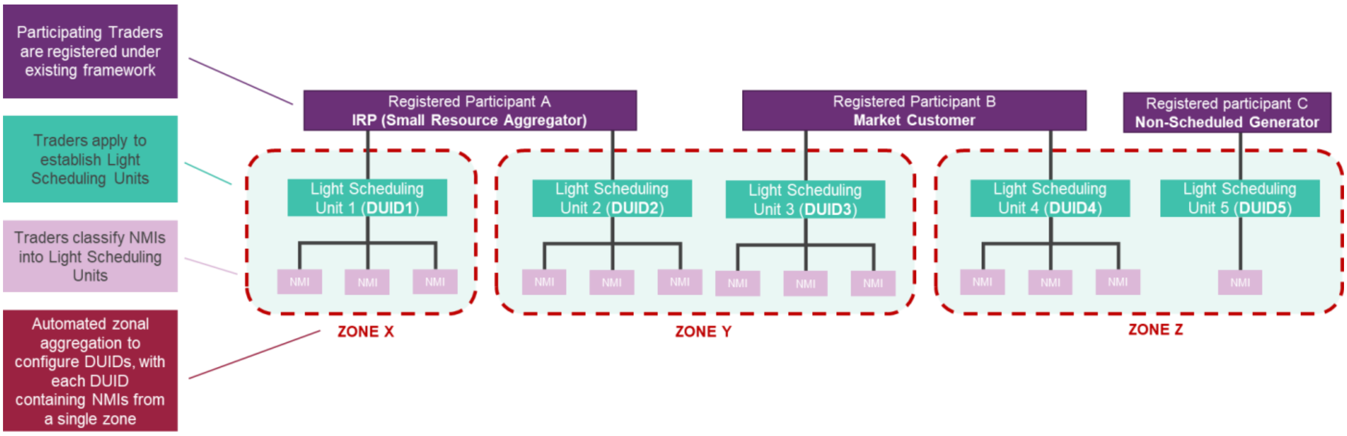
Classification and zonal aggregation

This section provides an overview of the basic classification and resource aggregation framework proposed for Scheduled Lite.

New classification: light scheduling unit

Figure 7 below illustrates the intended structure of the classification and aggregation framework. AEMO proposes the creation of a new classification, a ‘light scheduling unit’ or LSU, to enable portfolios of distributed resources to be represented in AEMO systems for the purpose of participation in Scheduled Lite. The trader would first apply for approval to establish an LSU, and then classify its resources (National Metering Identifiers [NMIs]) within its portfolio into that LSU. Each LSU would be assigned a Dispatchable Unit Identifier (DUID) for identification purposes in AEMO market systems (Visibility mode) and for bidding, scheduling and dispatch processes (Dispatch mode).[19] NMIs would be aggregated on a zonal basis, with NMIs assigned to any given LSU required to be in a single zone (see Zonal Aggregation section below).

Figure 7 Proposed structure for the Scheduled Lite classification and aggregation framework



Note: “NMI” = National Metering Identifier; “DUID” = Dispatchable Unit Identifier.

It is proposed that classification into an LSU would not be an exclusive classification. That is, a resource would retain its existing ‘underlying’ classification, with rights and obligations applicable to LSUs to apply in priority. Resources classified as LSUs could be classified as an ancillary service unit in addition to being classified into an LSU.

In the case of aggregated distributed resources, AEMO considers that manual assessment and approval of applications to classify and aggregate each connection point into an aggregator’s portfolio may not be fit-for-purpose at a scale where a single aggregation may include thousands of individual connection points. This process will need to be streamlined to support participation in Scheduled Lite. Following participant registration and establishment of an LSU for aggregation, it is proposed that the trader would self-manage the classification of connection points into its portfolio, in accordance with conditions set by AEMO. This process would be similar to that currently used for FCAS registration and classification. The Portfolio Management section provides further detail.

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[19] Note that registered non-scheduled generating units are already assigned a DUID for settlement purposes.

AEMO considers that the aggregation framework may not be relevant to some traders. For example, non-scheduled generating units, non-scheduled bidirectional units and some large non-scheduled loads may instead participate as stand-alone LSUs rather than being aggregated with other resources.

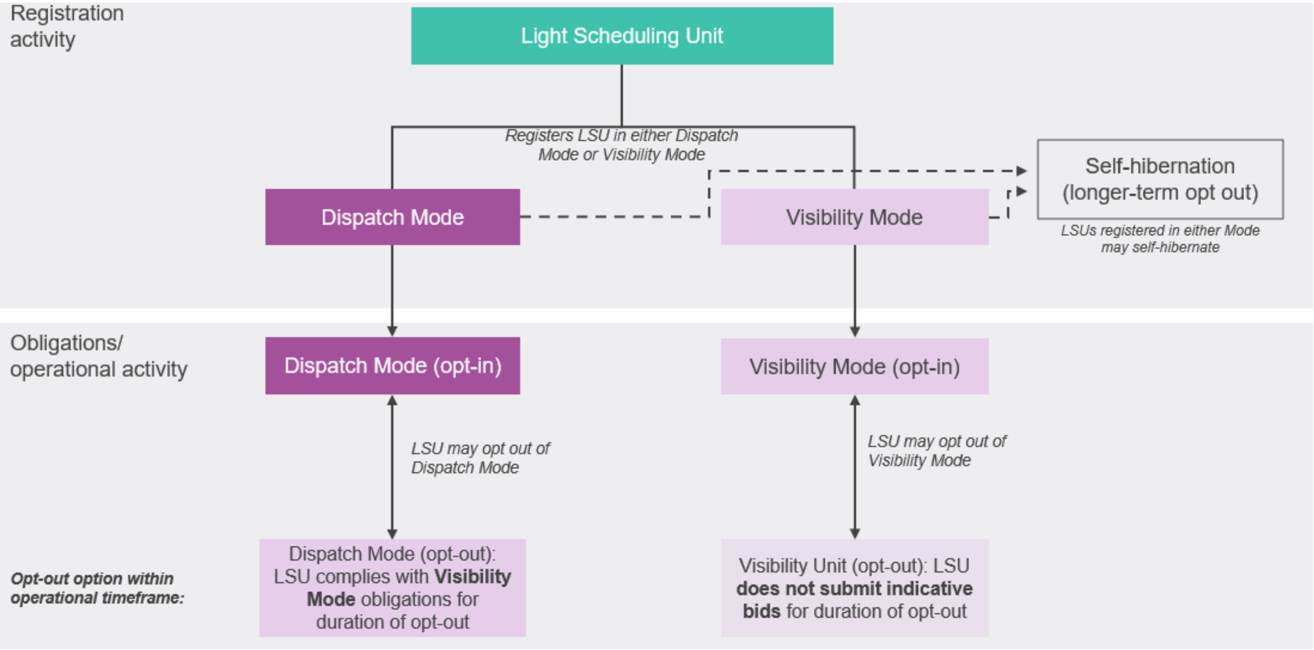
Participation modes

Once a trader has established an LSU, it may then register to participate in either Visibility mode or Dispatch mode, depending on its ability to fulfill the eligibility criteria and comply with the obligations associated with each mode. Visibility mode is a mode of operation designed to facilitate the visibility of price-responsive distributed resources in market processes and systems, including the integration of the market intentions of distributed resources within AEMO demand forecasts. Dispatch mode is a mode of operation to facilitate participation of LSUs in central NEM dispatch, which includes the submission of a bid, receipt of dispatch instructions and conformance with those instructions. Detailed information on the obligations for participation in each mode may be found in sections 3 and 4.

As Figure 8 shows, it is proposed that there will be flexibility in participation across both modes to recognise the capabilities of traders participating in Scheduled Lite, including options to opt out of participation over both operational and longer timeframes. These options include:

- Over operational timeframes:
  - LSUs registered in Dispatch mode may opt out of participation in Dispatch mode and are required to comply with the obligations of Visibility mode for the duration of opt-out (see section 4.2.93.2.7)
  - LSUs registered in Visibility mode may opt out of participation and will not be required to submit indicative bids for the duration of opt-out (see section 3.2.7)
- Over longer timeframes, traders with LSUs registered in either Dispatch mode or Visibility mode may ‘self-hibernate’ over a longer period, such as a whole season, without needing to re-register and re-establish their LSUs when they re-commence (see Portfolio Management section below).

Figure 8 Proposed structure of LSU modes and operational obligations



Zonal aggregation

To support forecasting and system security requirements, AEMO proposes that aggregation of NMIs would be enabled on a sub-regional zonal basis. AEMO is developing a zonal load forecasting process, which is expected to support the full network model proposed as part of the Short Term Projected Assessment of System Adequacy (ST PASA) replacement project[20], and it is anticipated that Scheduled Lite aggregations would be required to align with these zones once developed.

AEMO recognises feedback from submissions that zonal (rather than regional) aggregation may introduce additional cost and complexity for Scheduled Lite traders, and that it may lead to VPP customers in some zones having access to market value streams more quickly than others[21]. However, enabling regional aggregation for Scheduled Lite would require AEMO to develop a methodology to disaggregate LSU bid information and forecasts to zonal level to align with the new zonal load forecasting approach. This process of 'shoehorning' regional aggregation into zonal load models would introduce error into AEMO's forecasts. Where Scheduled Lite aggregations are large in size, the error introduced through disaggregation could exceed that of normal forecast error managed by AEMO, creating risks to system security and undermining the benefits of the mechanism. In addition, if aggregation is not enabled at the zonal level from the commencement of the Scheduled Lite mechanism AEMO may need to retrospectively change the approach when these risks can no longer be managed appropriately, adding complexity. AEMO anticipates that zonal changes will be infrequent and accompanied by a consultation process.

It is proposed that the zonal approach to aggregation is supported by automated processes including disaggregation and re-aggregation of NMIs, to assist in managing large aggregations within a trader's LSUs. This is discussed in the next section on the portfolio management process.

Until the zonal load forecasting process is further developed, it is anticipated that at a minimum, an approach consistent with that used for the WDR Mechanism may be appropriate for Scheduled Lite. The NER require that proposed aggregations of Wholesale Demand Response Units (WDRUs) be connected within a single region and must not materially impact power system security. Additional requirements set by AEMO include the requirement that all WDRUs within a proposed aggregation be contained within a single load forecasting area as defined in AEMO's Power System Operating Procedure—Load Forecasting (SO_OP_3710)[22]. These load forecasting areas reflect key transmission constraints and provide consistency with demand forecasting and current Projected Assessment of System Adequacy (PASA) processes. There are also key constraint zones relevant to the demand forecasting process which need to be considered. AEMO may require aggregated WDRUs to be disaggregated for a number of reasons[23], including following an update to the load forecasting area boundaries where the aggregation includes loads on either side of one or more boundaries; or where AEMO determines that it must represent the WDRUs within the aggregation as two or more dispatchable units in constraints used in central dispatch in order to maintain power system security.

As such, AEMO proposes similar conditions for aggregations participating in Scheduled Lite could apply. For example: all connection points classified within a single LSU would need to be contained within a single load forecasting area; if an update to the load forecasting area boundaries results in an LSU containing NMIs on either

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[20] AEMO, 2022. *ST PASA Replacement Project*, at https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

[21] See Appendix B.2 for a detailed summary of feedback from submissions.

[22] AEMO, 2022. *Load forecasting procedure (SO_OP_3710),* at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3710-load-forecasting.pdf?la=en.

[23] AEMO, 2021. *Wholesale demand response guidelines*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/wdr-guidelines/final-stage/wholesale-demand-response-guidelines-mar-2021.pdf?la=en.

side of a boundary, AEMO may automatically re-aggregate the trader's portfolio to ensure compliance; and if a proposed aggregation is partly in a constrained zone, AEMO may automatically re-aggregate the LSU.

Portfolio management

Traders participating in Scheduled Lite – particularly those participating with aggregated CER – will require efficient processes to self-manage their portfolios within AEMO's systems. It may be possible to leverage the existing Portfolio Management System (PMS), which is currently administered by AEMO to enable management of WDRU and ancillary service load portfolios, to support these functions.

Key portfolio self-management functions may include:

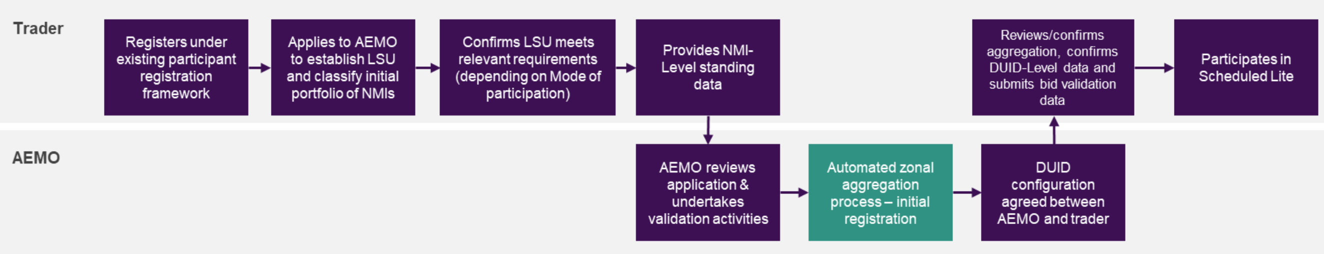
- **Application for initial establishment of new LSUs**.
- **Management of existing LSUs**.
  - Adding NMIs into LSUs.
  - Removing NMIs from LSUs.
  - Amending bid validation data, NMI standing data or other information.
  - Moving a NMI from one LSU to another.
- **Customer churn between existing LSUs**: The existing PMS flags NMIs no longer eligible for classification as an Ancillary Service Load, with the most common cause a customer changing retailer. AEMO proposes leveraging this capability to enable customer churn to be flagged with Scheduled Lite traders for portfolio management functions. A trader would be responsible for the addition or removal of the NMI from its portfolio, confirming the amended DUID configuration, and updating bid validation data where required. It may also be necessary to establish an enforcement process to ensure traders are updating their portfolios in response to customer churn within specified timeframes.
- **Self-hibernation (or long-term opt-out) for existing LSUs**: 'hibernation' arrangements are proposed to enable traders the flexibility to opt out of Scheduled Lite participation beyond operational timeframes. For example, if a trader does not intend to operate over the winter season with a subset of its NMIs, it could flag the hibernation status of those NMIs for a specified period, rather than de-classifying and re-classifying them.
- **View status of AEMO validation processes**: to support portfolio maintenance, participant self-management functions would be accompanied by validation processes to ensure, for example, that the NMI in question exists and is active in market systems and that CER is registered at the site, as well as processes to recognise customer switching and abolishment/ deactivation of NMIs. Appropriate validation processes will need to be considered as part of detailed implementation.
- **Review and agree on new DUID configuration following changes** (associated with automated zonal aggregation process): each time a trader adds or removes a NMI from its portfolio, automated zonal aggregation processes would allocate the NMI to the relevant zone. The trader and AEMO would then agree on the configuration of the DUID prior to participation.

To enable the self-management functions and automated zonal aggregation processes proposed above, AEMO will need to develop additional portfolio self-management capabilities; for example, to be able to make automated portfolio changes on behalf of traders or automatically assign NMIs into zonal DUIDs. There are also future opportunities to link to other sources of data, such as AEMO's DER Register, to streamline these processes.

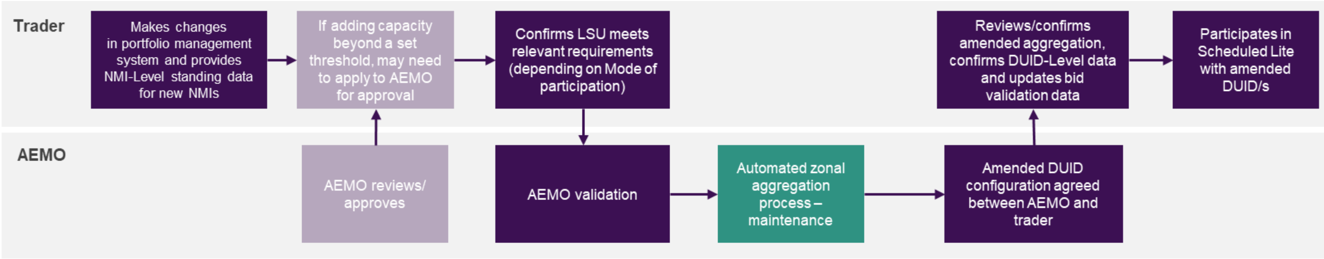
High-level proposed process diagrams for these functions are provided in Table 3.

Table 3 Proposed processes for LSU management functions

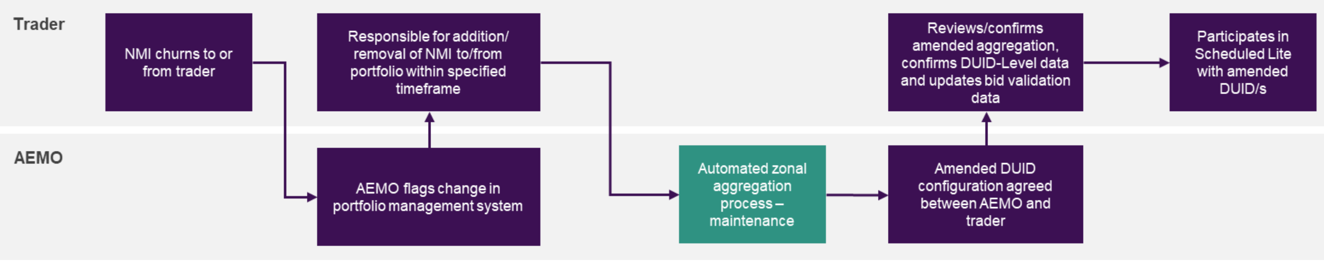
Initial registration of LSUs – proposed process for the first time a trader establishes an LSU and classifies NMIs into the LSU.



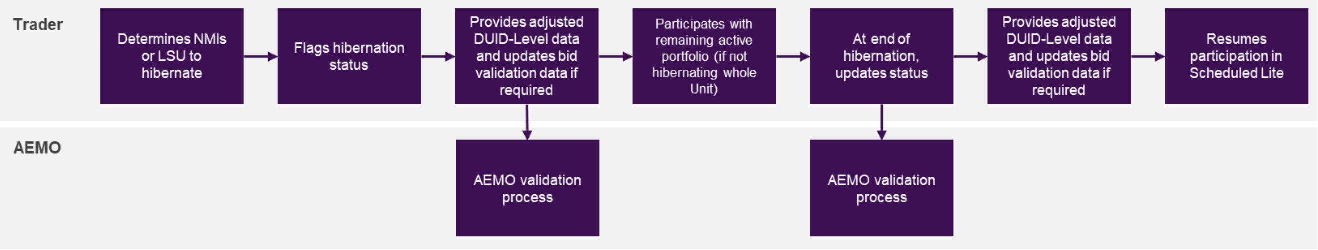
Management of existing LSUs – proposed process for trader to self-manage its portfolio, including adding NMIs, removing NMIs, amending bid validation data, and moving a NMI from one DUID to another



Customer churn for existing LSUs – proposed process for AEMO to flag customer churn and seek action from trader to move NMI into or out of its LSU



Hibernation – process to enable traders to opt-out of Scheduled Lite participation for periods beyond operational timeframes



Automated zonal aggregation process – automated, bottom-up zonal aggregation processes for Scheduled Lite to support management and participation of aggregations and reduce the administrative complexity of portfolio management. It is anticipated that:

- as NMIs are added to LSUs, AEMO would assign them to the applicable zone for the trader, the DUID configuration would be agreed between the trader, and the DUID-Level price-responsive component (PRC) would be recalculated,
- automated zonal aggregation processes will be required for both initial registration and maintenance of LSUs, as well as instances where zonal boundaries need to change.

DNSP information and data access

Consideration will need to be given to the appropriate data and information access requirements for distribution network service providers (DNSPs) to enable an appropriate level of visibility to support DNSP functions. The draft high-level design proposed that an appropriate starting point for the required level of information access would be similar to that provided for the WDR Mechanism, which generally enables DNSPs to access WDR data and information including:

- NMIs providing WDR;
- NMI metering data on the DNSP's network;
- Mapping of DUID:NMIs for Transmission Node Identifiers (TNIs) of the DNSP; and
- Information on NMI-level maximum responsive component.

Given feedback received from submissions, AEMO retains its view that data sharing of a similar nature to WDR is likely to be an appropriate starting point.

Minimum aggregated portfolio threshold for Dispatch mode

AEMO proposes an approach whereby traders may initially register and participate in Visibility mode before 'graduating' into, or becoming eligible to participate in, Dispatch mode once their portfolio meets a certain capacity threshold.

No minimum participation threshold is proposed for Visibility mode. For Dispatch mode, a minimum aggregated portfolio threshold may be required to support participation of aggregated portfolios in the scheduling and dispatch process; for example, a minimum threshold may help to avoid a large number of DUIDs overwhelming the NEM Dispatch Engine (NEMDE). AEMO proposes that 5 MW may be a suitable initial threshold setting to support operational requirements associated with preparing scheduling inputs. As recommended by the VPP Demonstrations Final Report[24], this initial threshold also leverages the guidelines developed for the WDR Mechanism which impose requirements on both individual and aggregated units to provide telemetry and communications beyond a 5 MW threshold[25].

Participation in Dispatch mode will require more sophisticated operational capabilities compared to Visibility mode. While a trader may commence participation in Visibility mode, a transition to Dispatch mode should be encouraged and supported.

It is possible that changes to a trader's portfolio could result in an LSU dropping below the minimum size threshold for Dispatch mode participation (for example, as a result of NMIs moving out of a portfolio). AEMO intends to consult on the management of such cases. For example, it may be possible to enable participation of sub-threshold portfolios for a limited period of time or with different requirements until the size threshold is achieved.

Participation of aggregated CER and separation of resources

AEMO is considering the connection and metering arrangements that would facilitate participation in Scheduled Lite, including the value in having flexible or price-responsive resources separated from passive resources. These considerations are particularly relevant for the participation of small customer connection points which may have multiple resources (including passive load and generation) behind a single network connection point, only some of which may be under the control of the participating trader.

It is proposed that customers and their trader will have optionality around the connection and metering arrangements that are established at connection points within their portfolios, including whether or not flexible

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[24] See Appendix B.1 for an overview of relevant lessons from the VPP Demonstration initiative.

[25] Applying to individual units and cumulative capacity behind an individual transmission node.

resources are separated from passive resources for participation in Scheduled Lite. AEMO considers that separation or ‘unbundling’ of a customer’s flexible resources could support more accurate forecasting and bidding of resources which are price responsive and under the control of the trader, while AEMO retains responsibility for forecasting the passive component. That is, traders may face lower risk around the accuracy of their forecasts and bids because they do not need to account for the customer’s passive resources, making compliance easier.

The establishment of flexible trading arrangements provides an avenue to enable a customer’s flexible resources to be recognised and managed independent of passive generation and load in wholesale settlement. These arrangements would also enable the customer to engage a separate provider to trade their flexible resources while remaining with a traditional retailer for rest of their electrical installation if they choose. Two flexible trader models, both of which would enable this arrangement, have been outlined by the ESB and could provide a framework for participation in Scheduled Lite:

- **Flexible trader model 1 (FTM1)**, which is an extension of the existing arrangements for SGAs, involves establishing a second connection point to the network for the controllable resources. As part of the IESS rule change[26], the second connection point in the FTM1 arrangement will be able to connect stand-alone small bidirectional units in addition to small generating units and participate in FCAS markets.
- **Flexible trader model 2 (FTM2)** is an alternative arrangement which would enable customers to establish a secondary NMI within their electrical installation. FTM2 offers similar benefits to FTM1, while overcoming some of the barriers which make FTM1 inaccessible to many small customers. FTM2 is the subject of a rule change request submitted by AEMO to the AEMC for consideration, recently published for consultation[27][28]. The rule change also includes a proposal around updating the NEM metering framework to support the proposed connection arrangements.

Appendix B.1 provides further background on the flexible trading arrangement reforms which form part of the ESB’s Post-2025 Market Design Final Advice.

AEMO considers that where a trader is capable of forecasting and controlling its energy flows (for both flexible and passive resources) at a single ‘standard’ connection point within the appropriate performance tolerance band, this type of participation should be facilitated and that the separation of resources (via establishment of FTM1 or FTM2 arrangements) will not be required for participation in Scheduled Lite. However, participation via the standard connection point may require use of an energy management system to firm passive load and generation and may limit participation in Scheduled Lite to larger or more advanced installations, whilst FTM2 provides a more accessible alternative.

The lessons derived from Project EDGE trials are expected to inform AEMO’s understanding of the participation capability (such as visibility, forecastability and dispatchability) of each of these models in Scheduled Lite, including the participation capability of flexible resources managed independently via establishment of flexible trading arrangements (FTM1 or FTM2). The project is trialling two different models:

- ‘Flex Only’, whereby aggregators submit bids representing the aggregation of all controllable CER assets at a site measured at a common measurement point (not individual devices); and

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[26] AEMC, 2021. *Final determination: Integrating energy storage systems into the NEM*, at https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

[27] AEMC, 2022. *Flexible trading arrangements for distributed energy resources*, at https://www.aemc.gov.au/rule-changes/flexible-trading-arrangements-distributed-energy-resources?utm_medium=email&utm_campaign=New-rule-request-template-2&utm_content=aemc.gov.au%2Frule-changes%2Fflexible-trading-arrangements-distributed-energy-resources&utm_source=cust49597.au.v6send.net.

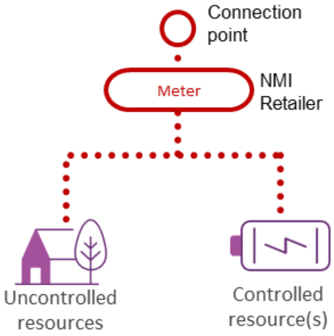
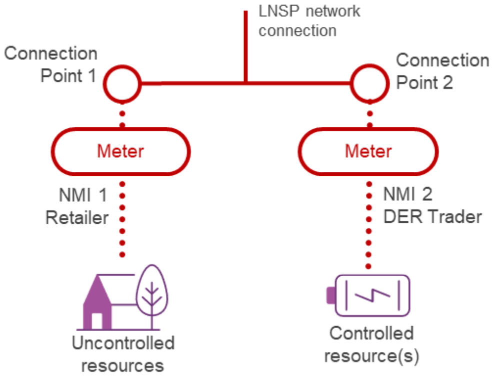
[28] AEMC, 2022. *Consultation Paper National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule*, at: https://www.aemc.gov.au/sites/default/files/2022-12/Consultation%20paper%20-%20Unlocking%20CER%20benefits.pdf

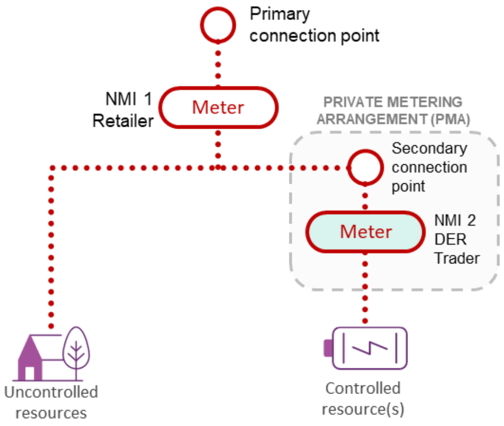
- Net Connection Point Flow ('Net NMI'), whereby aggregators submit bids for net energy flows measured at the connection point, including both controllable and passive resources at the site.

Further detail on Project EDGE may be found in Appendix B.1.

Table 4 outlines the proposed participation models for aggregated CER at customer connection points in Scheduled Lite. Regardless of which participation arrangement is established for a given site, the trader participating in Scheduled Lite is responsible for providing data, forecasting, bidding and dispatch (as applicable to the mode of participation) associated with the resources sitting behind the NMI for which it is responsible.

Table 4 Proposed connection and participation arrangements for aggregated CER at customer connection points participating in Scheduled Lite

Participation via	Diagram	Description
Standard connection point arrangement		**Participates via standard connection point for the whole site.** In this participation model, the customer has a single connection point to the distribution network. This is the standard connection arrangement that currently applies to most small customers in the NEM. In this arrangement, the customer's retailer is also the CER trader and takes responsibility for all energy flows at the site (both flexible and passive resources) in forecasting and bidding processes.
Flexible trader model 1 (FTM1)	 LNSP = Local Network Service Provider	**Participates with flexible resources at second connection point.** FTM1 enables a second connection point to the distribution network to be established, for separate management of the customer's controllable resources. The end user may nominate a separate provider as the CER trader to manage the controllable resources, whilst retaining a traditional retailer for passive load. The CER trader is responsible for the resources connected at the second connection point only, managing these independently from the customer's passive load. This is the typical connection arrangement for an IRP (Small Resource Aggregator) seeking to classify a small resource connection point; however a Market Customer may also operate at the second connection point.

Participation via	Diagram	Description
Flexible trader model 2 (FTM2) *(this arrangement is subject to a rule change consultation process)*		**Participates with flexible resources at secondary connection point established within customer's electrical installation.** In FTM2, a secondary connection point is established within the customer's electrical installation (a 'Private Metering Arrangement'), enabling controllable resources to be separately managed and independently recognised in wholesale settlement. As with FTM1, the customer may nominate a separate provider as the CER trader, whilst retaining a traditional retailer for its passive load. This arrangement is likely to be less costly and easier to retrofit relative to FTM1. Note that the flexible trading arrangements rule change request also includes a proposal to enable 'minor energy flow' metering, providing for a more flexible metering framework for such arrangements.

Connection requirements for large loads

AEMO is progressing a review of technical requirements for connection under clause 5.2.6A of the NER. Under this clause, AEMO must conduct a review of some, or all, of the technical requirements in NER Schedules 5.2, 5.3 and 5.3a at least once in every five-year period to assess whether those requirements should be amended. Among other matters, this review is considering technical requirements for the connection of large loads and may result in AEMO initiating a Rule change with the AEMC to amend Schedule 5.3 requirements relating to these connections. New loads large loads intending to participate in Scheduled Lite would need to adhere to any new connection requirements determined by the AEMC.

Related projects (see Appendix B.1)

- Integrating Energy Storage Systems Rule Change – providing a future registration model for the NEM.
- Flexible trading arrangements – an enabler for separation / aggregation of price-responsive resources.
- Wholesale Demand Response – providing a framework for registering/managing portfolios of assets.

Metering

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. The trader would need to establish operational metering/telemetry comply with the Power System Data Communication Standard if participating in the Dispatch model. If providing FCAS, the trader would need to comply with the metering requirements outlined in the MASS.

2.2 Consumer perspective

Scheduled Lite provides an opportunity for CER and flexible demand to play a role in the provision of security and reliability services in the NEM. Participation of customers in Scheduled Lite will lead to better utilisation of resources and will increase competition for the provision of services, lowering the cost of energy for all customers.

It is important to recognise that while household, business and other consumers will not directly participate in Scheduled Lite, it is their 'CER' that we are ultimately seeking to reward for being a part of the mechanisms.

Consumers invest in CER for a range of financial and non-financial reasons, and that may or may not include participating in the market for reward. Scheduled Lite will need to have a clear value proposition for consumers to make participation (via their trader) worthwhile.

The way consumers manage their energy use and CER also reflects their household and business needs and practices, and there are limits to how they can plan or manage their CER or energy use. It would not therefore be appropriate to expect consumers to directly participate in Scheduled Lite.

The Scheduled Lite mechanism will only work if there is a foundation of trust between customers, traders and AEMO. Principles around privacy and social licence will need to be core to its design, with the information that is shared to be limited strictly to what is agreed and necessary for the intended purpose.

Scheduling Options

Table 5 outlines different connection point configurations and the market scheduling mechanism that could be applicable.

Table 5 Scheduling options for different connection point configurations

Service	Aggregated CER portfolio	Large User – Retailer	Large user – Market Customer	Small Generator
Visible	Scheduled Lite Visibility mode			
Dispatchable	Scheduled Lite Dispatch mode	WDR Mechanism	Scheduled Load	Scheduled Generator
		Scheduled Lite Dispatch mode		

Scheduled Lite is intended to facilitate the participation of controllable, price-responsive resources that are not currently involved in the scheduling of the market. The Scheduled Lite mechanisms outlined in this paper would co-exist alongside existing market and non-market mechanisms that currently exist; these mechanisms include:

- Market Customers: most customers in the NEM do not buy electricity directly from the spot market. They contract with a retailer and the retailer purchases electricity on their behalf in the wholesale electricity market. In comparison, a Market Customer is a customer that purchases its load directly from the wholesale electricity market. A Market Customer may either be scheduled or non-scheduled within the wholesale market.
- Scheduled Loads: scheduled load participates in the central dispatch process by submitting bids, receiving and conforming to dispatch instructions. The rules associated with scheduled loads are similar to those that apply to scheduled generators and currently there is only a small number of customers in the NEM that participate as a scheduled load.
- WDR Mechanism: the WDR Mechanism introduced baselining provisions that allow large customers that purchase their electricity through a retailer to separately trade the flexible, price-responsive component of their load in the spot market through a third party (DRSP).
- Demand Response contracts: many large users may already participate in a demand response arrangement with their retailer or DNSP. Large users (or their retailer) could share information about the volume and price points at which they intend to reduce their demand through the Visibility model.
- VPPs: VPP services exist today, however they operate outside of the market scheduling processes. A VPP service typically involves an agreement with a retailer or third-party service provider for the use of their CER

to maximise returns from energy and ancillary service markets or to minimise energy and network tariff charges. The trader coordinates a portfolio of CER, changing the withdrawal or injection of energy to the grid in anticipation of, or in response to, energy prices or tariff rates.

- The trader could share information about the volume and price points at which they intend to consume or produce energy through the Visibility model. Alternatively, a trader could register their VPP to participate in the Dispatch Model.

Customer story

This section outlines two customers and their potential experience of participating in Scheduled Lite.

Table 6 Visibility mode customer story

Customer type	Household
Customer story	• Customer enters agreement with their retailer to install rooftop solar and battery at their home. As part of the agreement, the customer will receive a fixed payment from the retailer for conditional use of their CER in the wholesale market.
Trader	• The Retailer has a portfolio of CER customers (VPP) that it trades in the wholesale electricity market. The retailer registers the portfolio of CER to participate in Scheduled Lite. • The Retailer operates the portfolio of CER it has contracted to optimise electricity spot market revenue. The retailer adjusts the withdrawal or injection of energy to the grid in response to energy prices signals.
Scheduling model	• The retailer registers the portfolio of CER it has contracted as an LSU -Visibility mode.
Trader actions	• The retailer provides AEMO with an indicative bid outlining the volume of injections and withdrawals it forecasts at different price points for its CER portfolio. • The retailer aggregates operational metering information and communicates aggregate real-time flows to AEMO every 5 minutes.
Impacts on customer	• Participation in the Visibility mode would have no direct impact on the customer. Use of the CER would be in accordance with their agreement with the customer. The retailer simply informs AEMO of how it intends to use the CER over the operational horizon.
Incentive for customer	• In this example the retailer has estimated the reduction in non-energy costs and additional service revenue it could earn through participating in the Visibility mode and factored those benefits into the fixed price it pays to the customer.

Table 7 Dispatch mode customer story

Customer type	Small business
Customer story	• Enters agreement with a third-party service provider to establish a second connection point under flexible trading arrangements to trade the battery storage in the wholesale electricity and ancillary service markets. • Under the agreement: – The trader has the right to operate the battery 5 times per day and must maintain a minimum level of charge, and – The trader pays the customer the amount it earns by trading the battery in the wholesale market less a service fee.
Trader	• The trader is required to hold a retail licence (as per current arrangements – the AER is currently reviewing retailer authorisations and exemptions). • The trader operates a portfolio of CER it has contracted in the electricity and ancillary service markets.
Scheduling model	• The trader registers the portfolio of CER it has contracted as an LSU -Dispatch mode
Trader actions	• The trader bids its LSU -Dispatch mode into the energy, Regulation and Contingency FCAS markets. • The trader receives dispatch instructions from AEMO and ensures conformance by its portfolio of assets.
Impacts on customer	• Operation of the customer's battery would be in accordance with the dispatch instructions issued to the trader. • Use of the CER would be in accordance with their agreement with the customer. In this scenario, if the trader has reached the maximum operation of the battery, then it would adjust the availability of its

Customer type	Small business
	Dispatch LSU to ensure it does not receive any further dispatch instructions in respect of that resource for the day.
Incentive for customer	• In this example the trader passes on the revenues received in the energy and ancillary service markets. • In future these revenues could include Operating Reserves and Capacity certificates.

Customer risks

While the introduction of Scheduled Lite would provide an opportunity for CER and flexible demand to participate in scheduling processes and maximise the value of their resources, participation in the mechanism could carry risks for the customer. These risks will need to be carefully considered as the rules for Scheduled Lite is developed. The Retailer Authorisation and Exemptions Review that is currently being undertaken by the AER provides an opportunity to consider the risks associated with the new business models and operations that could be associated with the implementation of Scheduled Lite.

Initial engagement with stakeholders has identified the following risks to customers associated with participation in Scheduled Lite:

- Trader is suspended from participation: as outlined in sections 3.2.6 and 4.2.8, poor operational performance by a trader would result in their suspension from participation in Scheduled Lite. Suspension may impact the returns that could be available to the customer and as such there may be circumstances where the customer should have the right to change service providers.
- Trader’s liability associated with participation: while the proposed compliance arrangements are lighter than those for scheduled resources, there may be circumstances where the trader has breached the NER and incurs a liability. It is important that the customer is appropriately protected from any consequences from a trader’s breach of the rules.
- Multiple service providers and potential for financial mismatch between service offers: a customer may establish a second connection point and enter into an agreement with a third party (not their retailer) to separately trade CER in the market. Where a customer has multiple service providers, it is possible for there to be a financial mismatch between the agreements it enters with its service providers. For example, if a customer enters a spot price passthrough arrangement at its primary connection point and a fixed rate payment for its battery storage at a secondary connection point, it could incur a loss during high price events. As such, it is important that a customer receives adequate information about the risks associated with participating in the wholesale market to ensure it makes informed decisions.

3 Visibility model

3.1 Overview

The proposed Visibility model would establish a voluntary framework, which aims to deliver visibility of price-responsive distributed resources by enabling the provision of real-time information, forecasts and market intentions to AEMO for use in forecasting and market scheduling processes. The Visibility model builds on the outcomes from the VPP demonstrations[29], where AEMO recommended that additional visibility of new types of resources is required to meet operational needs.

As outlined in section 1.21, AEMO expects that information relating to price-responsive resources will become increasingly important to the accuracy and effectiveness of short-term operations for AEMO, Network Service Providers and market participants as these types of resources reach material thresholds. Traders will be required to provide a forecast of generation and consumption at various price points over the short-term operational horizon called ‘indicative bids’, described further in section 3.2.2.

Load forecasting[30] is an important short-term operational function that also provides information to market participants. Existing load forecasting models rely on underlying diversity in consumer behaviour which means not all appliances are used at the same time in the same ways. For those that are used widely at the same time, such as air-conditioners, use is correlated to weather patterns, meaning it has predictability. Some distributed resources are undiversified and predictable, such as rooftop PV, and other resources are diversified and unpredictable.

Unpredictable distributed resources are not correlated with predictable patterns such as the weather, leading to unexpected variability, making load forecasting an increasingly challenging task. Even though rooftop PV is considered undiversified and relatively predictable, AEMO has seen a progressive reduction in load forecasting performance during daytime hours as its penetration increases. The addition of large volumes of unpredictable distributed resources without appropriate visibility will result in increased variability and greater uncertainty in the load forecast. This will make it increasingly difficult to prepare accurate information for security and reliability functions as well as for market participants to support their coordination and commitment decisions.

The Visibility model would enhance visibility of the intentions of price-responsive resources, leading to a more accurate load forecast to support efficient, secure and reliable power system operations.

Features of the proposed Visibility model include:

- A flexible participation framework to facilitate broad participation.
- Data exchange facilitated by an Application Programming Interface (API).
- Traders will not be required to participate in dispatch or respond to dispatch instructions or directions.
- Compliance will be subject to performance thresholds.
- Incentives including enhancements in information available to traders and financial incentives.

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[29] AEMO, 2021. *VPP Demonstrations Knowledge Sharing Report #4.* Operational visibility – recommendations, p.9, at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en.

[30] AEMO’s central load forecast acts as a key market signal and is utilised in pre-dispatch and PASA processes.

The Visibility model would enable:

- AEMO to incorporate indicative bid information from price-responsive resources into load forecasting processes, and in turn, to be utilised in pre-dispatch and ST PASA as well as operational activities that include interventions for power system security[31]. This will help enhance the efficiency of scheduling processes, leading to lower system costs for all consumers.
- Greater transparency of price-responsive resources and more accurate short-term forecasts which will aid decision making by market participants across the short-term operational horizon.
- Potential data sharing opportunities with NSPs that would support the management of infrastructure within operational limits and efficient operation of the power system. It is expected that enhancements to network visibility as contemplated in related initiatives could sit alongside the Visibility model. Related initiatives include the DER Data Hub, which is being trialled in Project EDGE and aims to facilitate data exchange between AEMO, DNSPs and aggregators.

The Visibility model is expected to suit a range of participants, that includes but is not limited to:

- Non-Scheduled Generators and Non-Scheduled IRPs that do not currently provide forecast information to AEMO.
- Traders of aggregated portfolios of distributed resources.
- Traders of aggregated demand response who are not eligible for or not able to participate in the WDR Mechanism.
- Non-scheduled loads that do not currently provide forecast information to AEMO.
- Other third-party service providers like those engaged in the management of home energy management systems.

The proposed straw design for the Visibility model is shown in Figure 9, with each of the elements discussed in more detail in section 3.23.2.

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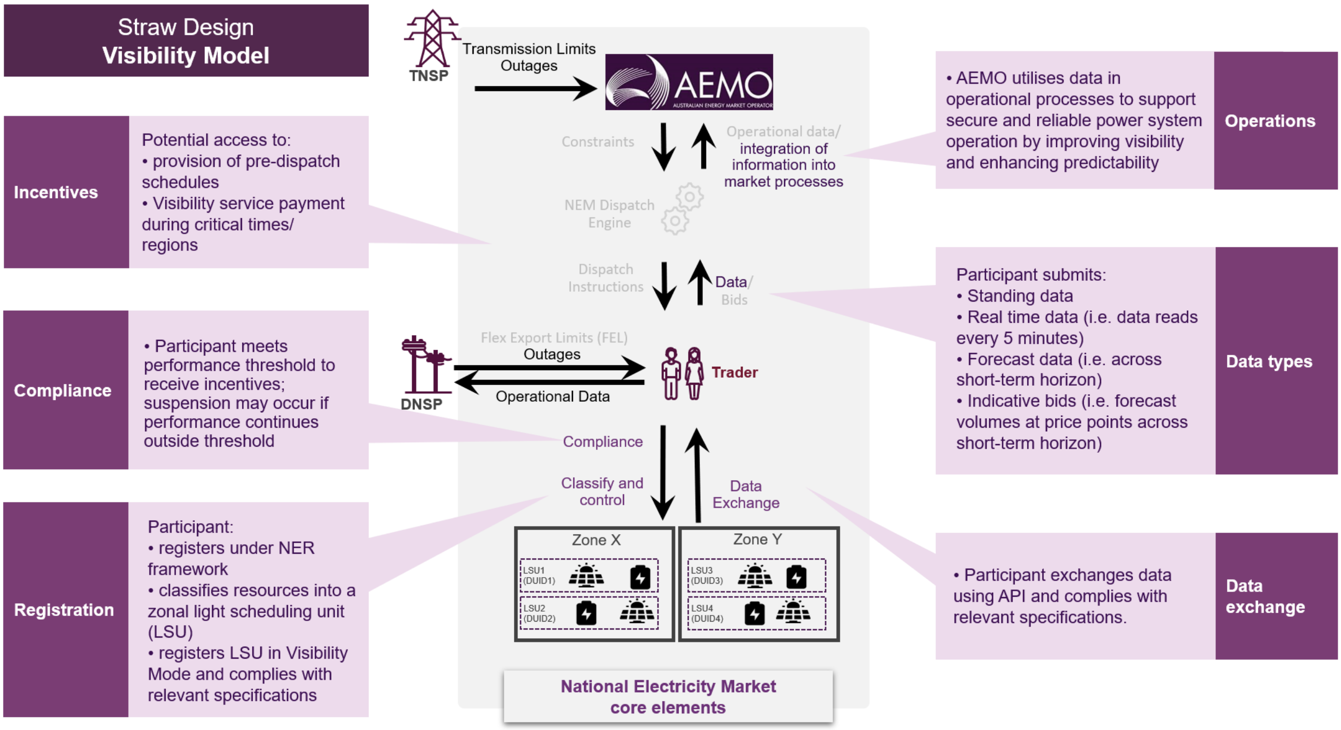
[31] See Appendix B.3 for an illustration of this.

Figure 9 Straw design for Visibility mode



Straw Design
Visibility Model

Incentives

Potential access to:
- provision of pre-dispatch schedules
- Visibility service payment during critical times/ regions

Compliance

- Participant meets performance threshold to receive incentives; suspension may occur if performance continues outside threshold

Registration

Participant:
- registers under NER framework
- classifies resources into a zonal light scheduling unit (LSU)
- registers LSU in Visibility Mode and complies with relevant specifications

Operations

- AEMO utilises data in operational processes to support secure and reliable power system operation by improving visibility and enhancing predictability

Data types

Participant submits:
- Standing data
- Real time data (i.e. data reads every 5 minutes)
- Forecast data (i.e. across short-term horizon)
- Indicative bids (i.e. forecast volumes at price points across short-term horizon)

Data exchange

- Participant exchanges data using API and complies with relevant specifications.

Note: only the core market elements relevant to the Visibility mode's objective have been highlighted in this straw design. For instance, a Visibility mode trader would not participate in dispatch processes, therefore elements inherent to dispatch processes such as 'NEM Dispatch Engine' and 'Dispatch instruction' are not applicable to the Visibility mode and are thus not highlighted in this straw design.

3.2 Design elements

3.2.1 Registration

The core registration and participation requirements for Scheduled Lite are described in section 2.12.1 above and are common across both the Visibility and Dispatch modes. Table 8 highlights considerations that are specific to LSUs operating in Visibility mode and should be read in conjunction with section 2.12.1.

Table 8 Registration considerations relevant to Visibility mode

Participation element	Description for Visibility mode
Voluntary participation	As described in section 2.12.1.
Participant registration	
Classification & zonal aggregation	
Minimum aggregated capacity threshold	It is proposed that no minimum aggregated capacity threshold would apply to participation in Visibility mode. Traders would be able to graduate from Visibility to Dispatch once they reach a certain threshold and capability.
Portfolio management	As described in section 2.12.1.
Participation models and separation of resources	
Technical standards	Resources at the connection point will be required to meet applicable technical performance standards. For example:

Participation element	Description for Visibility mode
	- CER traders seeking to participate in Visibility mode would need to ensure resources under their operation meet relevant technical standards (for example, AS/NZS4777.2.2020 Inverter Requirements[a], as specified in the NER, with compliance managed through distribution connection agreements). - Traders participating in Visibility mode with other resources (e.g. non-scheduled generating units) will need to ensure they meet the relevant technical requirements, e.g. performance standards agreed with their connecting NSP and/or any conditions imposed by AEMO.

a. Applies to systems installed after December 2021.

3.2.2 Data types

LSUs operating in Visibility mode will be required to provide information to indicate their price-responsive intentions. This section explains the types of data required when participating in Visibility mode and section 3.2.3 expands on the potential data exchange channel(s) that will facilitate the data communication.

Table 9 outlines the data types that have been identified for provision by traders operating LSUs in Visibility mode, noting that where the LSU represents an aggregation of resources, the data will be the aggregate of all of those resources.

Table 9 Data types

Type of data	Description	Visibility mode – information requirements		
		Element	Proposed requirement	Units
Standing data	Site data that changes infrequently is maintained and accessed within internal AEMO systems. This would include the provision of the total capacity of the resources at each connection point (consumption and generation) and price-responsive capacity at each connection point (consumption and generation)	Standing Data	Provide required data in the registration process	
Real time (or close to real-time)	Real time data consists of: - Actual generation - Actual consumption - Actual energy stored The real-time data provided by a trader is for each LSU (where is an aggregation, the data will be the aggregate of all of those resources)	Frequency of real time data provision	Data reads every 5 minutes	NA
		Granularity of Real Time data	At least 5 minutes granularity	NA
		Actual Energy Stored	Actual energy stored at the end of the last period	MWh
		Actual Consumption/ Generation	Actual charge/ load and discharge/ generation within the last period	MWh
Forecast capacity	Data set of anticipated capacity. The Forecast data provided by a trader is for each LSU (where is an aggregation, the data will be the aggregate of all of those resources)	Consumption/ Generation Capacity Forecast	Forecast capacity of charge/ load and discharge/ generation across short-term horizon	MW
		Stored Energy Capacity Forecast	Forecast capacity for energy stored across short-term horizon	MWh
Indicative bids **(See Box 3)**	Data set of indicative forecasts of the injections or withdrawals at different price points. The Indicative Bids provided by a trader is for each LSU (where is an aggregation, the data will be the aggregate of all of those resources).	Indicative Bids	Forecast volumes at price points across short-term horizon, including passive consumption and generation where relevant.	Price/quantity pairs i.e. $/qty ($/MWh, MW)

The proposed data types were informed by industry knowledge and experience developed from recent studies and trials. Traders will not be required to participate and provide additional information with respect to Medium Term Projected Assessment of System Adequacy (MT PASA). AEMO will use the information provided by traders as an input to medium-term demand forecasts.

Box 3: Indicative bid example

This example explores what an indicative bid submitted by a trader with an LSU might look like.

The table below shows a portfolio of resources along with its intentions for consumption and generation at different price points.

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	15	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				Above 4,000	Discharge 5 MW
Load	Pool pumps	10		>10,000	Reduce 3 MW of consumption
Generation	Rooftop PV	5		Negative	Turn off

*Note: for the purpose of this example, participation is via secondary connection point with only price-responsive resources .

The trader arranges its intentions of consumption and generation at different price points to define the indicative bid values, as shown in the table below. The aggregate bid sums all of the different resources that respond at different prices into a single bid.

Market Price Range ($/MWh)	Air conditioning (MW)	Bi-directional units		Pool pumps (MW)	Rooftop PV	Intention to be reflected in the Bid*
		10 MW profile (MW)	5 MW profile (MW)			
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

*Note: for the purpose of this example, only price-responsive resources are included in the bid.

Detail on the bid structure will be developed in the implementation stage. Examples can be found in The Project EDGE Bi-Directional Offer (Boffer) For Wholesale Energy Document[32].

Additional information

As part of detailed implementation, AEMO will consider whether additional information could be incorporated into the indicative bid that a trader would provide. The additional information could include (but is not limited to):

- Local services (active/inactive): is intended to indicate if a trader is actively providing 'local services' to support DNSPs to manage network power security and reliability, as considered in Project EDGE[33]. This

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[32] Project EDGE. *Bi-Directional Offer (Boffer) For Wholesale Energy*, at https://aemo.com.au/-/media/files/initiatives/der/2022/project-edge-boffer-for-wholesale-energy-hld.pdf?la=en.

[33] Further information on Local Services can be found in the Project EDGE document 'Summary classification of Local Services', at https://aemo.com.au/-/media/files/initiatives/der/2022/edge-data-specs-part-b.pdf?la=en.

would allow AEMO to better understand activity on the network, including a variation from forecast behaviour, and an opportunity to reflect this information in the load forecast.

- Uncertainty indication: would allow a trader to indicate any uncertainty associated with the forecast data being provided. For example, a Visibility mode trader might submit a flag highlighting that there is a % of uncertainty associated with the forecast data, which is expected to last for a period of time (for example, a number of hours). This would allow AEMO to treat data according to the associated level of uncertainty, within operational processes.

Additional operational modes for consideration

Outcomes from the consultation of the draft high-level design gave rise to the consideration of two additional potential operational modes to be explored, as described below.

Simple Visibility model

Stakeholder feedback suggested the consideration of a simpler model that acknowledges the potential value that could be derived from understanding the price-responsive behaviour of a broader range of distributed resources that would not have the operational capability to participate in the Visibility model. Accommodating this additional mode of operation would also be consistent with the principle of starting simple and evolving participation and the mechanism.

An entry-maturity level capability portfolio refers to a portfolio composed of price-responsive resources with limited remote-operational sophistication, however whose intentions may be forecastable. Therefore, this type of portfolio may provide value to current market systems, such as operational forecasting.

To allow the participation of these types of resources, there are design elements that would differ from the proposed Visibility mode, including:

- Data exchange: trader would be able to provide the data through a web portal. Noting that when graduating from the Simple Visibility model, the trader will need to comply with a higher data communications standard..
- Data types:
  - *Actual data:* provided as part of a regular energy metering and settlement process.
  - *Forecast information:* monthly profile of availability for all the resources in the portfolio (in aggregate).
  - *Indicative information*: indicative forecasts of the consumption or generation at different price points of all the resources in the portfolio (in aggregate), would need to be updated on a regular basis, or when required.
- Compliance: consistent with the Visibility model, a trader would need to comply with performance thresholds over an assessment period, including:
  - Monthly profile for availability accuracy: an allowable variation between the actual consumption or generation and the indicative field provided by the trader over a rolling period.
  - Consistency of provision of metering data.
- Incentives: a trader would be eligible for a service payment, which would reflect the nature of the service provided.

It is expected that the above differences will not require rule amendments, rather it would be facilitated through the rule change that enables the Visibility model.

Appendix B.3 contains a use case of a trader participating in the simple visibility model.

Aggregated DPV Visibility model

Stakeholder engagement to date has highlighted that price-responsive DPV is expected to grow with retail offers now available to customers to manage DPV in a more price-responsive manner. As such, visibility of these resources should be considered as a potential future model:

- Purpose: to provide visibility of price-responsive distributed PV behaviour in order to support critical operational events.
- Features:
  - Portfolio comprised of price responsive rooftop PV.
  - Initially a trader could provide AEMO with information about the portfolio of resources under its management (NMIs, capacity) and the price points at which it would reduce DPV generation.
  - AEMO would continue to prepare solar and load forecasts and would use the information from traders to adjust these forecasts.
- Considerations:
  - The information would support operations during minimum system load events.
  - Challenges in separating out rooftop PV from other technologies at the household level (these may be able to be mitigated through leveraging flexible trader model 2).
  - Integration of the DER Register may aid the administration of this model.
  - Potential costs incurred by the incremental changes required.

Provision of disaggregated data/resource level data

The VPP Demonstrations and AEMO’s DER Operations program of work sought to understand what operational data is required to enable visibility and to unlock value from large, aggregated distributed resource portfolios in the future. For example, the VPP Demonstrations Final Report noted that *“For the purpose of operational visibility, AEMO prefers to receive live operational telemetry about VPP activity as gross data, as occurred during the VPP Demonstrations. When live data is provided as net (net connection point flows), the information of activity behind the meter is lost.”*[34]

Whilst not facilitated by the initial design of Scheduled Lite, AEMO considers that there may be value in accessing disaggregated/resource level data from distributed resources in future. For example, this level of visibility could enhance accuracy in estimating DPV contingency and curtailment requirements during emergency conditions; helping to avoid interventions that would otherwise arise be required, including:

- Increasing frequency (FCAS) reserves: increasing contingency sizes will also increase the need for frequency reserves and system costs, particularly where the net DPV contingency exceeds the size of the largest

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[34] AEMO, 2021. *VPP Demonstrations*, section 3.2.2, at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en.

generator. This is already an issue in South Australia, where the DPV contingency risk exceeds the largest generator in some periods.

- Stability limits: if contingency sizes increase, network stability limits will need to be revised and may require constraining the network more heavily and more often. This has market impacts and may lead to issues in maintaining reliable electricity supply during times of high demand.

AEMO notes that there are existing initiatives trialling a decentralised model (like the DER Data Hub through Project EDGE) that would potentially enable access to disaggregated resource level data, but notes that if the initiatives do not progress, it may be practical to consider Scheduled Lite as an alternative to enable access to this type of data.

Related projects (see Appendix B.1)

- DER Trials i.e. VPPs, Project EDGE, Project Symphony - providing insights into operational data required from price-responsive resources, to facilitate its operation without negative impacts on power system reliability and security VPPs, Project EDGE, Project Symphony - providing insights into operational data required from price-responsive resources, to facilitate its operation without negative impacts on power system reliability and security.
- South Australia Smart Meter Backstop Mechanism- providing insights into technological capabilities.
- Semi-Scheduled Participant Self-Forecasting – provides an example framework for provision of self-forecasts.

3.2.3 Data exchange/telemetry

This section explores the potential data exchange channels being considered to enable communication of the data streams outlined in Table 9.

Currently AEMO is undertaking work to develop interfaces to enable data exchange for a high penetration distributed resource future, including the DER Data Hub being trialled in Project EDGE[35]. AEMO is aiming to leverage existing initiatives to enable data exchange channels for participation in the Visibility model. Under the proposed design, LSUs will need to provide the required information (see Table 9) through AEMO's designated API. This will be facilitated by the following ongoing initiatives:

- Industry data exchange (IDX): This initiative is part of the NEM 2025 Implementation Roadmap[36]. IDX is intended to establish unified access to AEMO services across all markets, using modern authentication and communication protocols, facilitating a cohesive approach to industry data exchange.
- DER Data Hub: This initiative is part of the NEM 2025 Implementation Roadmap and a similar interface is being trialled in Project EDGE[37]. The DER Data Hub is expected to provide efficient and scalable data exchange and registry services for CER, between industry actors.
- Power System Data Communication Standard Review[37]: AEMO conducted a consultation on the Power System Data Communication Standard. This consultation considered amendments to the Standard, both to address current issues with the content, application, and interpretation of the Standard; and to consider how the Standard could be adapted to accommodate communication needs effectively and efficiently for emerging changes in the power system. The review contains the changes required to accommodate Scheduled Lite.

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[35] Project EDGE Data Specification Part A, section 6, at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-a.pdf?la=en.

[36] AEMO, 2022. *NEM2025 Implementation Roadmap*, at https://aemo.com.au/initiatives/major-programs/nem-reform-implementation-roadmap.

[37] AEMO, 2022. Review of Power System Data Communication Standard webpage, at https://aemo.com.au/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard.

The proposed changes will enable the operation of the Visibility mode by facilitating a connection to AEMO over the public internet [38] via a non-NSP Intervening Facility[39].

Related projects (see Appendix B.1)

- Power System Data Communication Standard Review – AEMO is keen to ensure that, as far as practicable, the Standard can accommodate the significant changes expected as a result of the ongoing power system transition and reforms, e.g. developing more appropriate methods of data communication for smaller embedded generators and aggregators.
- Industry Data Exchange – providing the framework for data exchange across industry.
- Project EDGE – providing insights into what data communications method are fit for purpose for Aggregated DER.
- South Australia Smart Meter Backstop Mechanism- providing insights into technological capabilities.
- VPP Demonstrations – providing evidence-based learnings on the advantages/disadvantages of exchanging data over APIs via public internet.

3.2.4 Operations

This section outlines how the data received through the Visibility model (see Table 9) will be utilised by AEMO.

As noted in section 1.2, power system operation is becoming increasingly dynamic, complex and variable as the growing uptake of distributed resources reaches material thresholds. AEMO is concerned that a lack of visibility of significant amounts of price-responsive resources has the potential to increase operational uncertainty and risk[40] and awareness of the operation of distributed resources will be critical to managing the power system. Price-responsive resources have the potential to materially impact system operation and it is essential that they are accounted for in market processes and systems.

Traders taking part in the Visibility model will assist AEMO to navigate challenging operational conditions, by providing essential operational data to enhance existing market processes and enabling the development of new tools; therefore leading to operational efficiencies for market participants and the energy system.

AEMO anticipates the integration of data into market processes as described in Table 10.

Table 10 Integrating information into market processes

Information provided by trader	Used by AEMO in	Market system expected benefits
Forecast	Load forecasting processes	Provision of a price adjusted demand curve, supporting Market Information Forecast accuracy enhancement, supporting optimal operational decision-making via improved forecasts of reserve positions in PASA. Improved demand forecasts will support increased pre-dispatch scheduling accuracy for all traders, leading to reduced wholesale electricity prices and lower system service costs for all consumers.
Indicative bids	Price adjusted demand curve	
Real time data	Operational processes	
Standing data	Short-term forecasting and operations	

Note: The traders' data will be introduced in market systems in aggregate, rather than in isolation

The expected market system benefits from incorporating the data into market processes are as follows:

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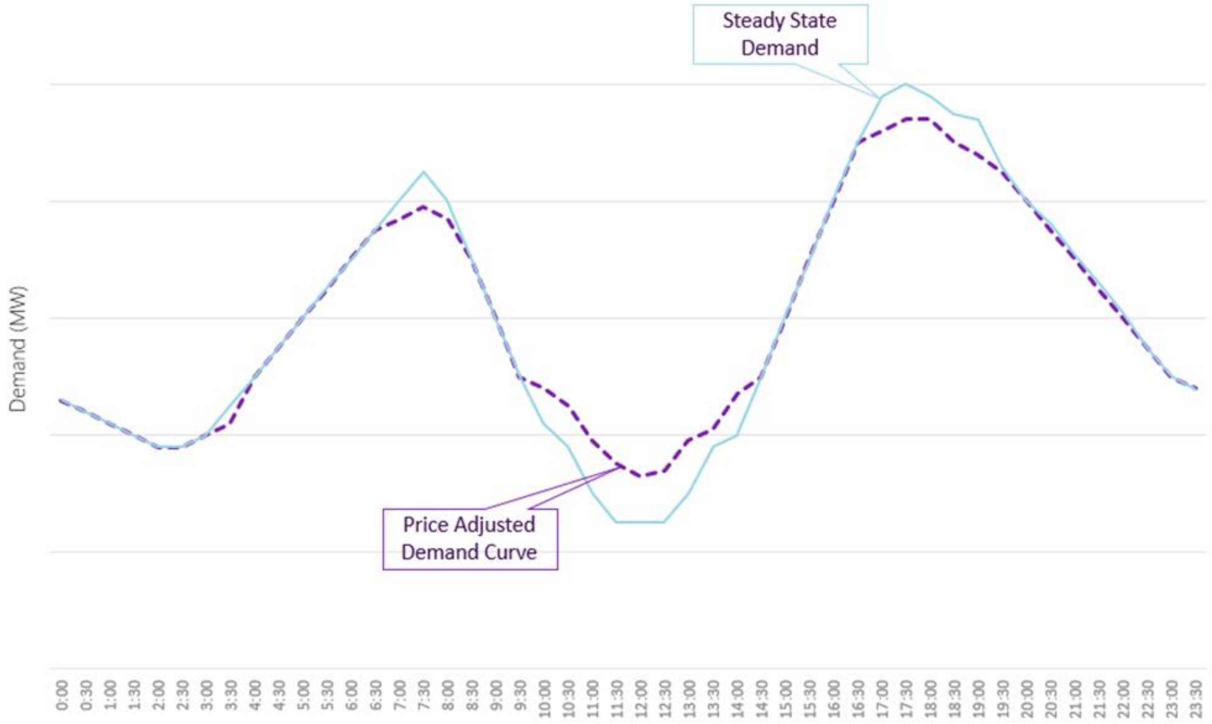
[38] This may be available in limited cases where no alternative transmission path is feasible and subject to review by AEMO including consideration of compliance with required cyber security measures and individual size limits and aggregation limitations in each region.

[39] A non-NSP Intervening Facility is a Data Communication Facility that is required or permitted to transmit Operational Data directly to and from an AEMO control centre under the Power System Data Communication Standard.

[40] AEMO, 2020. *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en.

- 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 a 'price adjusted' demand forecast (see Figure 10).
- The 'price adjusted' demand forecast represents an improved 'best estimate' on current demand forecasts, which do not include demand response and unscheduled generation. Market participants will be able to utilise the 'price adjusted' demand forecast and estimates of demand response and make decisions accordingly (see Appendix B.3).

Figure 10 Representation of a price adjusted demand curve



Note that:

- The 'Steady state demand' blue curve refers to the current demand curve provided to the market by AEMO, which disregards the behaviour of unscheduled resources in response to the forecast price.
- The 'Price adjusted demand' dashed purple curve refers to the 'steady state demand' curve when considering the behaviour of unscheduled resources, in response to the forecast price (i.e. indicative bids). This information would be provided to the market by AEMO.
- Note that, although the actual demand curve would by nature deviate from the 'Price adjusted demand' curve, the level of deviation is expected to be less than that which currently exists between the actual demand curve and the 'Steady state demand' curve.

- Forecast accuracy enhancement: AEMO will integrate forecasts provided by traders into the load forecasting process. Improved load forecasts will enable AEMO to manage challenging operational conditions more efficiently. For example, improving the management of minimum system load periods by providing forecasts of their intended charging during peak rooftop PV generation hours, increasing the accuracy of operational demand forecasts, and reducing any unnecessary DPV curtailment[41]. Real-time visibility of distributed resources would enhance situational awareness and allow AEMO to track and make any necessary adjustments to its demand forecasts, supporting the management of forecast ramp requirements[42].

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[41] AEMO, 2021. *VPP Demonstration Knowledge Sharing Report 4*, at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en.

[42] AEMO, 2020. *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf.

- Enhanced scheduling accuracy: information about distributed resources and their intended price-responsive behaviour will allow AEMO to prepare more accurate load forecasts. This will allow AEMO and market participants to make more efficient operating decisions, leading to reduced system costs for all consumers.

Related projects (see Appendix B.1)

- VPP Demonstrations – providing insights into the necessary collective capabilities for a high CER future.
- South Australia Smart Meter Backstop Mechanism – providing insights into technological capabilities.

3.2.5 Incentives

AEMO recognises that the provision of data comes at a cost to customers and their traders, so there should be an appropriate incentive to participate in the Visibility model that reflects the trade-off between accuracy and effort. AEMO believes the target resources for the mechanism are price-responsive and are managed by a trader that already has the capability to monitor and optimise a portfolio of resources. As such, the appropriate incentive does not need to be so high as to fund metering or other monitoring and control technology but it does need to at least compensate and reward a customer and their trader for incremental operational costs associated with sharing their visibility information with AEMO.

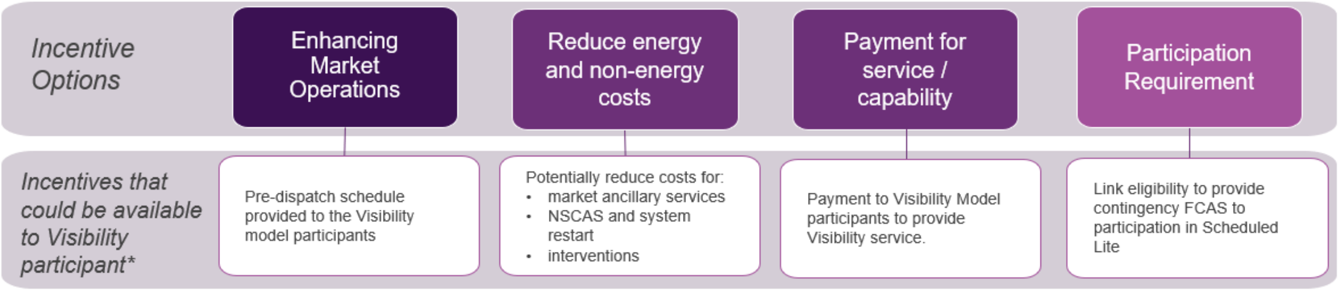
AEMO identified potential incentives that could be provided to customers and their traders to participate in the Visibility model. The potential incentives being proposed were identified based on the following key focus areas:

- **Value** of improved visibility, leading to more efficient operation of the power system.
- **Costs** of telemetry, metering, forecasting and monitoring to enable access.
- **Opportunities** to participate in the wholesale market, and the incremental cost to extend that participation to the Visibility mode.

The incentives considered during the preparation of the high-level design included enhancements to market operation and financial incentives through to an obligation to participate for certain customers or linked to their participation in other markets (for example, contingency FCAS markets).

Figure 11 below outlines the incentive options considered for the Visibility model.

Figure 11 Incentive options – Visibility model



Subject to participant performance, a participant could accrue some or all of the potential incentives

These incentive options are explored further below:

- **Enhancing market operations:** this incentive option aims to improve the trader's operation in the energy market. This includes the ability for traders to access pre-dispatch schedule information, supporting the trader to make informed decisions relating to their operations. Similar to that provided to scheduled resources, the pre-dispatch schedule would outline the trader's forecast consumption and generation based on their indicative bid information and would be published privately to the trader.

- **Reduce energy and non-energy costs:** this incentive option outlines potential benefits that traders may be able to access through participation in the Visibility model. Services that would be delivered by traders are expected to lower system service costs. Those reductions in non-energy costs would then be allocated to traders appropriate to their services delivered. This incentive option could include:
  - Avoidance or reduction of non-energy cost allocation: information provided by Visibility model traders is expected to reduce the procurement of non-energy services required, and in turn, the number of interventions. Thus, traders could potentially access a reduction in non-energy cost allocation as appropriate (subject to the nature of the non-energy service procured). This includes (but is not limited to) the cost of:
    - Market ancillary services.
    - Network support and system restart ancillary services.
    - Interventions.
  - Reduction in non-energy cost allocation associated with future/emerging market changes: traders may be able to access reductions in cost recovery allocations when future markets (for exa Operating Reserves) are established.
- **Payment for Visibility service:** this incentive option would make a payment to a trader for providing a Visibility service.
  - A payment for the Visibility service could be structured as a pre-determined payment to all resources participating in the model or could be procured by AEMO from time to time depending on the power system security outlook.
  - A tender process for the Visibility service could be triggered by the need for AEMO to receive visibility information in specific regions and time periods. AEMO could procure Visibility services for a determined aggregate resource quantity with a tender process setting the price received by traders for providing the service.
  - An alternative approach to setting the rate for the service payment would be to carry out a periodic review and benchmark costs associated with the provision of visibility information to AEMO.
- **Participation requirement:** this incentive category would place an obligation on Contingency FCAS providers (that are not scheduled resources) to participate in the Visibility model.
  - The rationale for such an obligation would be that to provide Contingency FCAS, the trader is likely to already have established the necessary metering and operations to support participation in the Visibility model.
  - However, the number of resources providing Contingency FCAS may only be a subset of those that could participate in the Visibility model. As such, this incentive option alone may not attract the desired levels of participation. Another potential drawback of this option is that it could act as a hurdle for CER participation in Contingency FCAS markets.

Assessment of options

Stakeholders raised concerns that a reduction in non-energy costs may not be sufficient to encourage participation in the Visibility model. A further concern raised by stakeholders is that this potential incentive may be complex to communicate to customers, impacting their ability to sign-up customers to their portfolio.

A further drawback of the reducing non-energy costs option is that the savings to a participant may not be reflective of the visibility benefits they provide. Non-energy costs are recovered based on the metered consumption or generation. However, the price-responsive quantity is more reflective of the visibility a participant provides. Consider the example of two large customers of equal size participating in the mechanism – one with a small price-responsive capacity and the other with a large price-responsive capacity. In this example, the participant with the small price-responsive capacity provides less of a visibility service but is likely to receive greater reductions in their non-energy costs.

In comparison, a payment for service approach would address the challenges associated with the complexity and settlement of non-energy cost reduction. In particular, the ability to structure a service payment on the price-responsive quantities provided by traders would allow payments to be reflective of the service provided. Based on this assessment, the payment for service option is recommended and has been incorporated into the rule change request.

Related projects (see Appendix B.1)

- Semi-scheduled Self-forecast – Providing insights into potential incentive arrangements based on performance.

3.2.6 Compliance

Stakeholder engagement to date has highlighted that the form and nature of compliance arrangements have the potential to act as a significant barrier to participation. While there is an opportunity to adopt lighter compliance to reduce this barrier to participation, it is important to establish arrangements that drive effective performance of traders and deliver reliable outcomes that provide confidence to AEMO and market participants to realise the benefits that flow from integrating distributed resource information into the operation of the market.

Impact of non-compliance on market operations

As part of its load forecasting process, AEMO would monitor the accuracy of indicative bid information against actual market outcomes. Indicative bid and real-time information from traders can help AEMO determine if variations between observed and forecast load are due to response by traders or due to forecast model error.

The submission and use of inaccurate information may also reduce confidence in the outputs (like the price-adjusted demand curve) from the Visibility model. If AEMO or market participants discount the demand forecast (and other dependent data like pre-dispatch pricing), then the value of the Visibility model would be greatly reduced.

As a result, if the forecast information is inaccurate, then the trader may be ineligible for incentive payments.

Compliance arrangements

There is a spectrum of potential compliance arrangements, ranging from light arrangements utilised in CER trials and demonstrations through to relatively strong arrangements currently applicable to scheduled and semi-scheduled resources in the NEM. Key components of the compliance arrangements include:

- The obligations placed on traders – how hard are they to meet and do they entail additional costs to be borne by the trader or end user?
- How is compliance measured?
- Consequences of not complying with participation obligations – is a trader penalised for not meeting its obligations?

Given the nature of the information provided by traders, and the stage of development, it is proposed that relatively light compliance arrangements are adopted for the Visibility model. Compliance with the participation obligations of the Visibility model would be determined by AEMO by measuring the accuracy and consistency of information provided a trader against a set of performance thresholds:

- 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.

If the trader does not meet the performance thresholds, it would not be rewarded for participation in the mechanism. A trader would not be penalised if it has not met the performance thresholds. However, it is proposed that a trader would be suspended from participating in the Visibility model if it deviates materially from the performance thresholds, including:

- A failure to submit indicative bid or real-time information for an extended period, or
- There is a large variation between the actual consumption or generation and the indicative bid provided by the trader for an extended period.

Additional considerations

The trader will need to ensure that it continues to meet eligibility requirements for participation in the Visibility model. A failure to meet the eligibility requirements would result in the suspension of the trader from the mechanism.

It is proposed that rules are introduced to safeguard the mechanism from the submission of false or misleading information. In the context of the Visibility model, an example of a rule breach would be the deliberate submission of incorrect information to gain an advantage in the energy market by the trader. The AER would be responsible for monitoring and enforcing compliance with this rule.

3.2.7 Opt-out arrangement

To recognise the maturity of traders' operational capabilities, an opt-in participation arrangement is proposed for Scheduled Lite. This approach was supported through industry engagement[43], with feedback recommending a principle of starting simple and evolving participation over time.

The opt-in arrangement aims to lower the barrier to entry for traders wishing to participate in Scheduled Lite, by enabling 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.

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[43] Further information on industry engagement that supported the development of this consultation paper is detailed in Appendix B.2.

The proposed requirements for the trader to opt out of the Visibility mode are for the trader to:

- Remain operating in Visibility mode for at least a specified amount of time[44].
- Provide a notification to opt out a minimum amount of time in advance[45].
- Remain opted out of the Visibility mode for no longer than a specific period of time[46], within operational timeframes. When the trader is opted out for longer than the specified timeframe, the trader will have to follow a reactivation process to recommence operation in the Visibility mode
- When a trader opts out of the Visibility mode, it will not be required to provide indicative bid information, and AEMO will adjust the use of the trader's information accordingly. A trader would provide an indication of the periods it expects to opt out and would be required to provide a forecast of its LSU for the horizon in which it will be opted out. Benefits would not accrue to a trader during periods it has opted out of participation.

To opt back into the Visibility mode, the trader will need to:

- Remain opted out for no longer than a specific period of time[49], within operational timeframes.
- Provide a notification to opt back into the Visibility mode a minimum amount of time in advance.
- Comply with Visibility mode operational requirements from the period from which they opt back in.

The self-hibernation function described in section 2.12.1 is designed to accommodate traders seeking to opt out of participation for periods which go beyond operational timeframes (for example, for a season).

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[44] The minimum amount of time for an LSU to remain in Visibility mode will be established in the implementation phase.

[45] The minimum amount of time in advance that a trader has to submit an opt out notification will be established in the implementation phase.

[46] The specific period of time that an LSU can remain opted out will be established in the implementation phase.

4 Dispatch model

4.1 Overview

The objective of the Dispatch model is to establish a voluntary framework that lowers barriers and provides incentives to encourage participation of distributed resources in the central dispatch processes of the NEM to support power system operation and market efficiency.

At present, when resources reach certain capacity thresholds (>30 MW or >5 MW for storage), they are required to participate in the central dispatch process as scheduled or semi-scheduled resources. Resources below this threshold currently operate outside the NEM dispatch and scheduling process. The Dispatch model is designed to encourage these resources to actively participate in the dispatch process by recognising the main engagement challenges and reducing barriers to enable wider participation.

Features of the proposed Dispatch mode include:

- A flexible participation framework to facilitate broad participation of distributed resources .
- Leveraging new SCADA arrangements ('SCADA for DER[47]) that are being progressed to better suit distributed and distribution-connected resources.
- Integration of aggregated distributed resources in the dispatch process, with these resources receiving and conforming to dispatch instructions and enabling co-optimisation of energy and FCAS from those resources.
- Participation in existing and future markets that require the scheduling of resources.

The Dispatch mode would enable:

- Distributed resources to contribute to the dispatchability (controllability[48], firmness[49], and flexibility[50]) of the power system to enable efficient and effective balancing of supply and demand.
- Traders to unlock additional revenue streams for price-responsive resources, including the potential to provide Essential System Services (ESS)[51] as well as providing a basis for eligibility to potential future markets (see section 4.2.7).
- Potential data sharing opportunities with NSPs that could support the management of infrastructure within operational limits

The design of the Dispatch model aims to suit a range of participants, including but not limited to:

- Aggregations of distributed resources including small batteries, EVs and other controllable devices.
- Aggregated portfolios of demand response.

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[47] Several initiatives undergoing development will contribute to the delivery of SCADA for DER. The initiatives include Project EDGE, requirements from Power System Data Communication Standard Review, and the SCADA Lite initiative.

[48] The controllability of a resource relates to the resource's ability to reach a set point (output target) requested by an AEMO dispatch process, whether that be zero megawatts, the maximum available capacity of the unit, or something in between.

[49] The firmness of a resource relates to the resource's ability to confirm its energy availability.

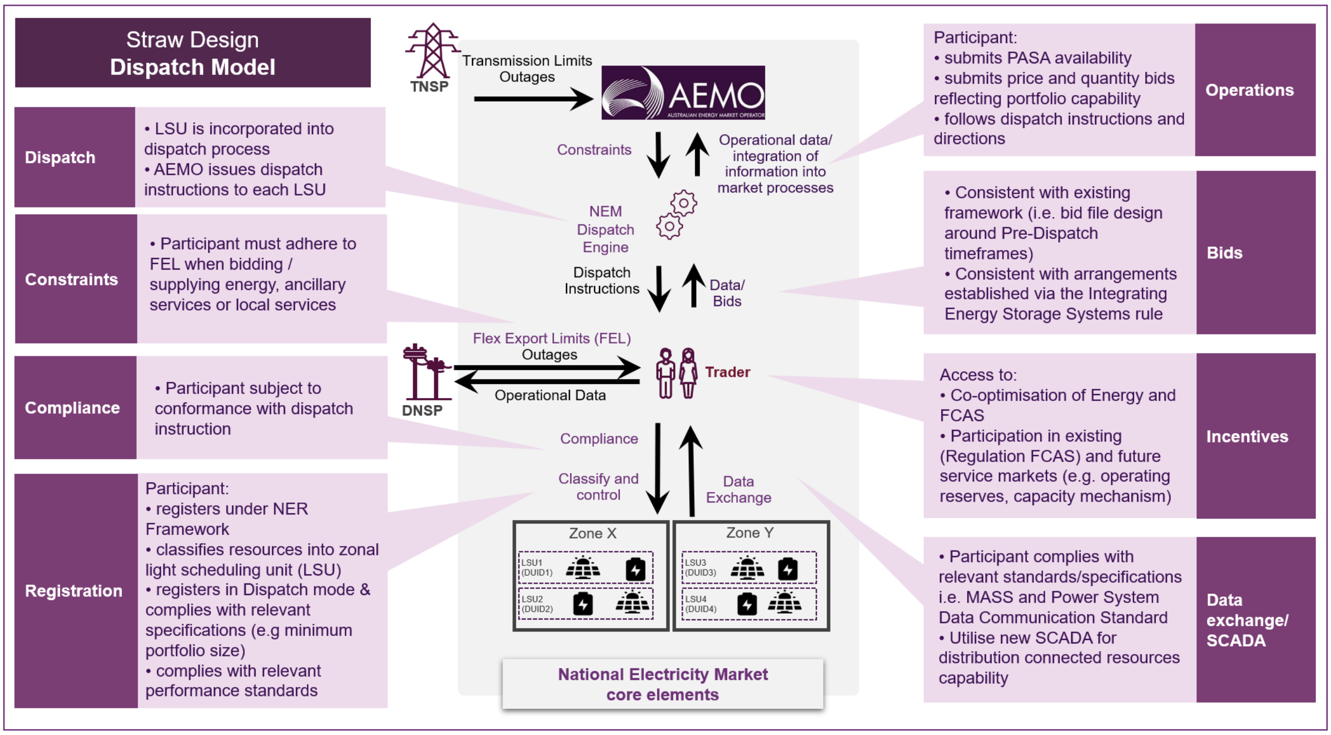
[50] The flexibility of a resource is the extent to which its output can be adjusted or committed in or out of service.

[51] ESS help keep the parameters of the electricity system within acceptable limits so it can reliably and securely deliver electricity. More on ESS can be found in the *Essential system services and inertia in the NEM Paper*, at https://www.aemc.gov.au/sites/default/files/2022-06/Essential%20system%20services%20and%20inertia%20in%20the%20NEM.pdf.

- Non-scheduled generation and bidirectional units.
- Large customers.

The proposed straw design for the Dispatch model is shown in Figure 12, and further detail for each of the design elements involved is outlined in this section.

Figure 12 Straw design for Dispatch mode



Dispatch
- LSU is incorporated into dispatch process
- AEMO issues dispatch instructions to each LSU

Constraints
- Participant must adhere to FEL when bidding / supplying energy, ancillary services or local services

Compliance
- Participant subject to conformance with dispatch instruction

Registration
Participant:
- registers under NER Framework
- classifies resources into zonal light scheduling unit (LSU)
- registers in Dispatch mode & complies with relevant specifications (e.g minimum portfolio size)
- complies with relevant performance standards

Operations
Participant:
- submits PASA availability
- submits price and quantity bids reflecting portfolio capability
- follows dispatch instructions and directions

Bids
- Consistent with existing framework (i.e. bid file design around Pre-Dispatch timeframes)
- Consistent with arrangements established via the Integrating Energy Storage Systems rule

Incentives
Access to:
- Co-optimisation of Energy and FCAS
- Participation in existing (Regulation FCAS) and future service markets (e.g. operating reserves, capacity mechanism)

Data exchange/ SCADA
- Participant complies with relevant standards/specifications i.e. MASS and Power System Data Communication Standard
- Utilise new SCADA for distribution connected resources capability

Note: only the core market elements relevant to the Dispatch mode's objective have been highlighted in the straw design. For instance, as a Dispatch mode trader will participate in dispatch processes, accordingly they will be involved in certain NEM Core elements such as 'Dispatch Instructions'; 'FELs and 'NEM Dispatch Engine'.

4.2 Design elements

4.2.1 Registration

The core registration and participation requirements for Scheduled Lite are described in section 2.1 above and are common across both the Visibility and Dispatch models. Table 11 highlights considerations and elements of the framework that are specific to Dispatch mode and should be read in conjunction with section 2.1.

Table 11 Registration considerations relevant to the Dispatch model

Participation element	Description of Dispatch model
Voluntary participation	As described in section 2.1.
Participant registration	
Classification & zonal aggregation	

Participation element	Description of Dispatch model
Minimum aggregated capacity thresholds	As described in section 2.1, it is proposed that a minimum aggregated portfolio threshold of 5 MW would apply for participation in the Dispatch model (below this threshold, the trader can only participate in Visibility model). This proposed threshold is required to support operational requirements associated with preparing scheduling inputs for LSUs, such as bids.
Portfolio management	As described in section 2.1
Participation models and separation of resources	
Technical standards	Further consideration during a detailed design phase will need to be given to the standards that LSUs participating in Dispatch need to adhere to (equivalent to a Generator Performance Standard (GPS) for LSUs). In the initial stages of Scheduled Lite, it is expected that a trader will be responsible for ensuring the resources in each LSU meet the relevant technical standards (such as voltage control and fault ride through capabilities) and comply with distribution connection agreements.

4.2.2 Data exchange/telemetry

This section describes the data streams and potential data exchange channels to enable data transfer between the trader and the market systems to facilitate participation in central dispatch processes.

Data streams required for participation in dispatch processes

Table 12 below summarises the data streams required to enable participation in dispatch processes from unscheduled price-responsive resources via LSUs in Dispatch mode. Where the LSU is an aggregation of resources, it will be the trader's responsibility to provide data representing the aggregate of all the resources within its portfolio.

Table 12 Data streams – Dispatch model proposed design

Type	Description	Data Stream – Dispatch mode proposed design			Comparison to Visibility mode (Table 9)
		Element	Unit/granularity	Use	
Static or Standing data	Site data that changes infrequently, is maintained and accessed within internal AEMO systems. This would include the provision of the capacity of the resources at each connection point (consumption and generation) and price responsive capacity at each connection point (consumption and generation)	Standing Data	Provide data required in the registration process	Information (e.g. NMIs) that would allow AEMO to map and utilise information provided in short-term forecasting and operations	Same requirement
Telemetry/ SCADA [Real time data]	Telemetry data consists of the aggregated instantaneous period ending measurement of active power flow at NMI. And actual generation, actual load and actual energy stored. The data provided by a trader is for each LSU (where is an aggregation, the data will be the aggregate of all of those resources)	Telemetry/ SCADA	As per requirements for distributed resources defined in the power system communication standard	Telemetry data is required by the market operator for operational visibility and dispatch conformance monitoring	Real time data for LSU in Visibility mode is read every 5 min with at least 5 min granularity

Bids (see section 4.2.4)	An Offer that includes both generation and load. May contain 20 price bands per LSU	Bid	- As per large-scale bi-directional units [a] - Price/quantity pairs [b] i.e. $/qty ($/MWh, MW) - Bid design around Pre-Dispatch timeframes - Granularity: 5 minutes	Bids are used for market participation by LSU	LSU in Visibility mode submits indicative bids
Availability forecast	Availability forecast data is to be provided for each LSU. This forecast represents the available capacity of generation, load and storage in an Aggregator portfolio.	Forecast consumption / generation capacity	- Submit availability, across short-term horizon - MW	- Used for power system reliability and security assessment ahead of time. AEMO is required to assess if there are sufficient reserves to meet demand. The forecasted generation capacity inputs into this calculation - Used for power system reserve assessments. For understanding how much could be made available if the assets are pre-charged, should it be required in an emergency [c]	Same requirement
		Storage forecast	- Submit availability, across short-term horizon - MWh		
FELs **(see section 4.2.3)**	FELs are calculated and produced by the DNSP. These distribution level limits are proposed to be shared with the trader and AEMO. Arrangements for sharing of FELs is out of scope for the Scheduled Lite high-level design. For Stage 1 of Scheduled Lite it is proposed that FELs are not integrated into the scheduling process.	FELs	- Active Power Import - Active Power Export - Reactive Power injection/absorption - Voltage (+/-) [c]	- Dispatch mode traders must adhere to FELs when bidding/ supplying energy, ancillary services or local services.	Not applicable
Local Network Services	Defined by the DNSP and Aggregators, not traded on wholesale markets [c]	Local Network Services	As required by DNSP		

a. AEMO, 2021. *IESS High Level Design,* at https://aemo.com.au/initiatives/submissions/integrating-energy-storage-systems-iess-into-the-nem.
b. Subject to Bid requirements; see section 4.2.4.
c. Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements, at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en.

At this stage of development AEMO has not specified all the data requirements associated with participation in the Dispatch model. It is expected that a trader would need to maintain data records to verify the performance of resources within a portfolio from time to time. AEMO will work with industry to determine the specification of these data requirements during the implementation phase of the project.

Potential data exchange channels

To date, data exchange between AEMO and market participants has been enabled by a centralised and highly specialised data exchange architecture, involving the use of a SCADA system. Most resources currently participating in dispatch processes (scheduled resources) are required to connect to SCADA to provide metered values of consumption and/or generation. This data flows into AEMO’s Energy Management System and is used for monitoring conformance to dispatch targets.

Resources are only included in central dispatch if AEMO is satisfied that adequate communication and/or telemetry is available to support the issuing of dispatch instructions and the audit of responses.

The objective of the Dispatch mode is to enable participation from distributed resources, resulting in the need to transfer telemetry data from a large number of smaller resources into operational control systems. As the cost of utilising the existing exchange system (SCADA) is unlikely to be economically feasible for potential Dispatch mode traders[52], AEMO is proposing alternative potential data exchange channels to enable the transfer of telemetry data from these types of resources.

Under this design, AEMO is also proposing potential data exchange channels for each identified data stream to enable participation in dispatch processes (see Table 12). A brief description of each data stream can be found below with respect to the potential data exchange channel that could enable it:

- **SCADA/telemetry**:
    - AEMO is working with industry to develop new and more cost-efficient forms of SCADA for distribution-connected resources, enabling AEMO and market participants to:
        - Lower the transactional cost for traders to connect and exchange data with the market.
        - Securely and efficiently connect and exchange data.
    - Traders will need to provide telemetry data complying with relevant standards/specifications (the Power System Data Communication Standard). AEMO conducted a consultation on the Power System Data Communication Standard, which considered how the Standard could be adapted to accommodate communication needs effectively and efficiently for emerging changes in the power system[53].
    - The review of the Standard contains the changes required to accommodate Scheduled Lite. The changes will enable operation of LSUs in Dispatch mode by enabling the exchange of operational data directly with an AEMO control centre via a non-NSP Intervening Facility[54].
- **Static or standing data**: **c**onsistent with the Visibility model, the trader provides information about its resources during the registration process. AEMO is aiming to leverage existing initiatives/tools where appropriate. Therefore, it is proposed that the provision of static or standing data is enabled through the DER Data Hub and Registry Services project which is being trialled through Project EDGE[55]. It is expected that the scope of this project will include an uplift of the existing DER Register.
- **Bids**: traders will need to have systems and processes to manage bidding and dispatch, including interfaces with AEMO's market systems aligned with scheduled resources. Section 4.2.4 contains the proposed design for the Bid element of the Dispatch mode.
- **FELs**: FELs will be communicated to traders and AEMO by DNSPs; this communication is outside the scope for the Scheduled Lite high-level design. Section 5.2.3 contains considerations in relation to system limits, including dynamic operating envelopes (DOEs).

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[52] GHD Advisory, 2021. *Assessment of Scheduling Costs for the AEMC*, at https://www.aemc.gov.au/sites/default/files/documents/ghd_report_-_assessment_of_scheduling_costs_-_final.pdf.

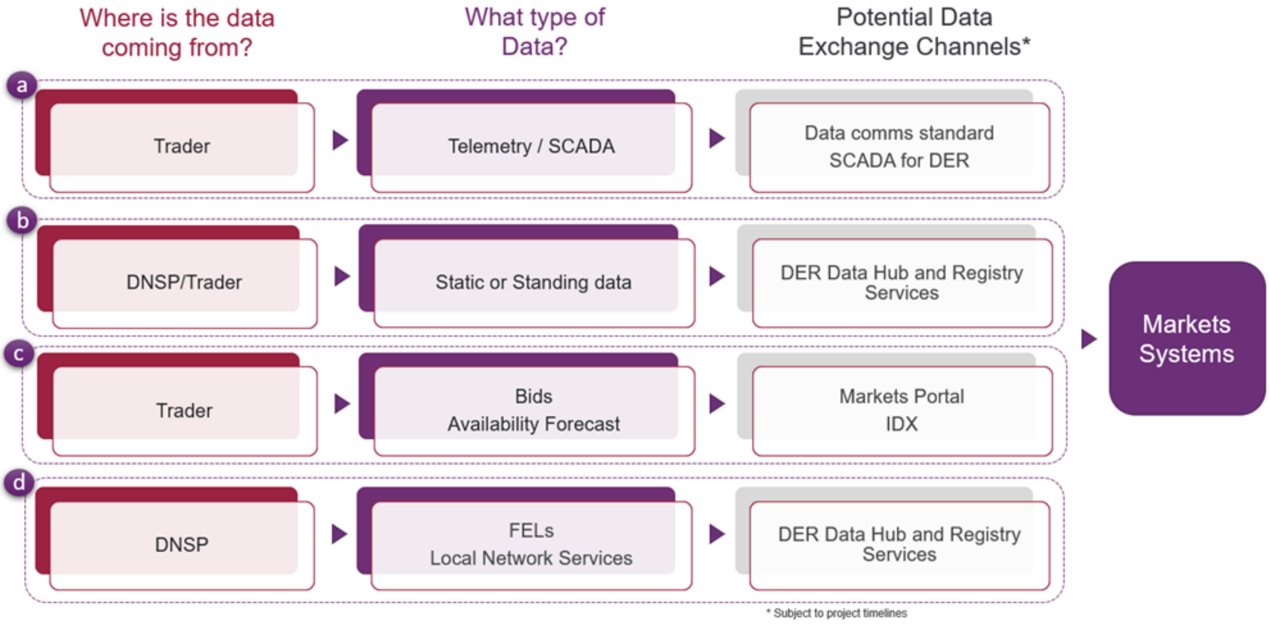
[53] AEMO, Review of Power System Data Communication Standard, at https://aemo.com.au/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard.

[54] A non-NSP Intervening Facility is a Data Communication Facility that is required or permitted to transmit Operational Data directly to and from an AEMO control centre under the Power System Data Communication Standard.

[55] Project EDGE Data Specification, Part A, section 6, at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-a.pdf?la=en.

Figure 13 below summarises the proposed flow of data, the actors involved, the data required, and the potential data exchange channels being considered.

Figure 13 Potential data exchange channels



Related projects (see Appendix B.1)

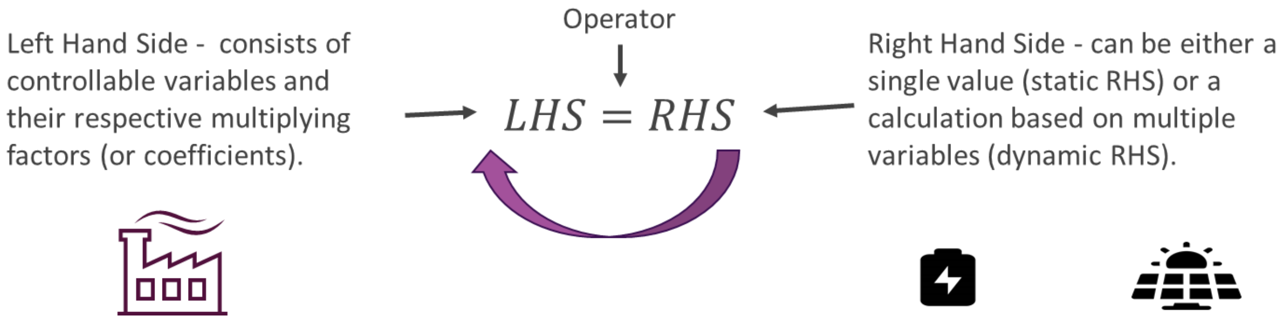
- Power System Data Communication Standard Review – AEMO is keen to ensure that, as far as practicable, the Standard can accommodate the significant changes expected as a result of the ongoing power system transition and reforms, e.g. developing more appropriate methods of data communication for smaller embedded generators and aggregators.
- Next generation SCADA development (SCADA for DER) e.g. Project EDGE's DER Data Hub; Project Edith – providing insights into what data communications method are fit for purpose for Aggregated DER.

4.2.3 Constraints

System constraints

Constraint equations are used in NEMDE to represent the network and ensure market solutions are within the physical limits of the power system. Distributed resources are currently captured in demand terms and sit on the uncontrollable right-hand side of constraint equations (see Figure 14). Integrating with market processes and systems will require aggregated distributed resources (represented by a Dispatch DUID) to be included on the left-hand side of constraints. As with other scheduled resources, AEMO would update constraint equations to incorporate an LSU at the time of registration.

Figure 14 Constraint equation formula



Constraints are updated from time to time as the network, resources or models change. For the WDR mechanism, units are required to re-register to split a portfolio across any new material transmission constraints that arise. In comparison, the aggregation of connection points for LSU is proposed to be by zone that will take account of material transmission limits.

Local constraints

FELs are being developed as a mechanism for DNSPs to maintain the integrity of the distribution network as customer exports continue to grow and push network capacity to its limits. The DEIP Dynamic Operating Envelope (DOE) working group defined DOEs as *variations to import and export limits over time and location based on the available capacity of the local network or power system as a whole*.

AEMO understands that the policy position in relation to FELs is that the trader will be responsible for managing their energy, FCAS and local service bids and dispatch to ensure they operate within their FEL. Under the proposed Stage 1 of the Dispatch model, AEMO will not integrate FELs into the market scheduling processes.

However, as aggregated portfolios of distributed resources increase in size and as a proportion of dispatchable generation and ancillary service provision, it may be necessary to integrate FELs into the market scheduling processes. An example of this integration of FELs in the market scheduling process would be the utilisation of the limits to produce a network constrained DPV forecast as part of the AEMO load forecasting process.

Development of FELs is occurring through the AER's policy and regulatory workstream. There are several interactions between the FEL and Scheduled Lite designs, and it is proposed that these design matters are determined within the FEL reform initiative. The Scheduled Lite design has identified the following requirements for the FEL workstreams:

- FELs are available to traders so they can manage their market bids.
- FELs are available for use in market systems where it is necessary to incorporate limits into short-term forecasts, security or reliability processes.
- Where there are multiple traders at a distribution connection point, a mechanism is required to coordinate, share and allocate limits between the traders.

Related projects (see Appendix B.1)

- DER Trials, e.g. Project EDGE; Project Symphony; Project Edith – to provide insights into FEL integration in traders' bids.
- DEIP – DOE – to provide insights from the latest considerations regarding FEL integration into the market.

4.2.4 Bids

This section provides a description of how a trader will submit bids to participate in dispatch.

The proposed design allows for a trader to submit bids for its LSU and participate directly in central dispatch processes. The design proposes that the inclusion of these resources in dispatch processes is aligned with the current dispatch systems, by scheduling in a manner analogous with scheduled resources – LSU in Dispatch mode will be treated consistently with other scheduled resources in that process. As such, bids (and the dispatch process) for Dispatch mode will need to recognise that and be robust to:

- In the case of aggregated CER, a trader can choose to operate via an aggregation of standard connection points (that is, where there is no separation of controllable resources at the site) or via flexible trading arrangements (where controllable resources are separated)[56], or a mixed aggregation of these. The single bid for the DUID would need to take into account the resources behind the relevant connection point, noting that when participating via:
  - A standard connection point, the trader would have to account for their passive resources before submitting a bid, ensuring it can comply with dispatch instructions. It is proposed that the bid includes information for the forecast of passive resources.
  - Flexible trading arrangements (for example, whereby a secondary connection point has been established at a site to separate controllable resources), the trader would only need to account for the resources that are associated with the connection point with which it is participating.
- The trader will submit bids for an LSU, which will be at a zonal level.
- The trader may set the market price if the LSU is marginally dispatched.
- In the draft high-level design consultation paper, 100 kW was considered as a potential minimum incremental bid quantity for Dispatch mode, which is lower than the current minimum incremental bid quantity for scheduled resources (1 MW). Stakeholder feedback suggested that due to the 5 MW participation threshold, considering a minimum incremental bid of 100 kW may not deliver significant value. AEMO proposes that for Stage 1 of implementation of the Dispatch mode, the 1 MW incremental bid quantity remains.

The bidding process for an LSU will be consistent with arrangements established via the IESS project for scheduled bi-directional units[57]; meaning that:

- Bids may be for resources that include generation, load and bi-directional resources, and therefore may contain up to 20 price and volume bands.
- Bids and dispatch instructions would be positive where the LSU is being dispatched to generate, or negative where it is being dispatched to consume[58].
- Bids will need to include all bid components applicable to other scheduled resources. This includes, for example, a ramp up and down rate, price-volume pairs, and maximum availability.

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[56] Subject to the flexible trading arrangements rule change; further detail on participation alternatives in section 2.12.1.

[57] AEMO, 2021. *IESS High Level Design*, section 3, at https://aemo.com.au/-/media/files/initiatives/submissions/2021/iess/integrating-energy-storage-systems-high-level-design.pdf?la=en. Note: Project EDGE is testing what is established in the IESS HLD in terms of participating in dispatch, i.e. bidding structure. See Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements Document, at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en.

[58] AEMO, 2021. *IESS High Level Design*, section 3.1.2, at https://aemo.com.au/-/media/files/initiatives/submissions/2021/iess/integrating-energy-storage-systems-high-level-design.pdf?la=en.

- Bids must reflect the physical capability of the LSU, such that the unit can respond to a dispatch target in required timeframes[59]. For example, the trader must understand and monitor the availability of the LSU and reflect this in its maximum availability bid. Similarly, the trader must consider any FEL restrictions prior to bidding and reflect any constraints within its bids.
- Good faith bidding will be applicable.

If the trader chooses to opt-out of Dispatch mode during the operational horizon, the trader will not be required to comply with the arrangements above (see opt-out arrangement in section 4.2.9).

Traders wishing to take part in the Dispatch mode will also be able to participate in all FCAS markets, provided they comply with the relevant technical requirements of those markets[60].

Related projects (see Appendix B.1)

- IESS Rule change – potential to leverage processes developed for energy storage systems.
- DER Trials, e.g. Project EDGE – learning from DER Trials to inform Dispatch mode.
- Wholesale Demand Response – potential to leverage processes developed for WDR.

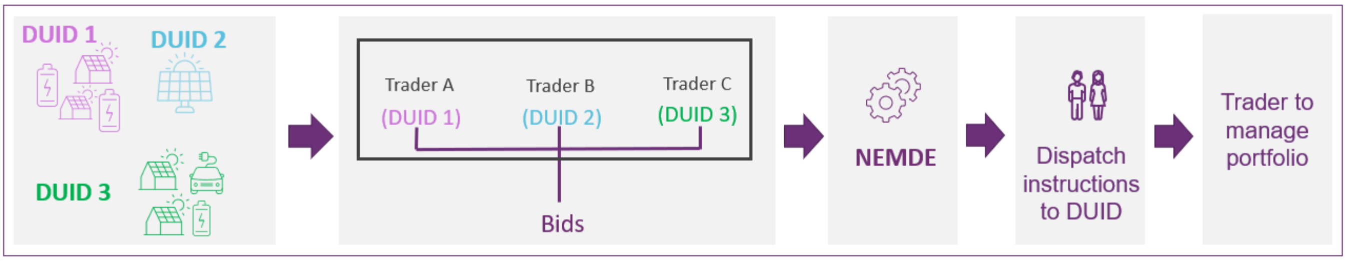
4.2.5 Dispatch process

LSUs operating in Dispatch mode will be incorporated into the existing NEM dispatch process. This section provides an overview of how LSUs will integrate with the dispatch process, including co-optimisation between energy and FCAS dispatch and how traders will receive and comply with dispatch instructions.

Overview of the dispatch process

As shown in Figure 15, 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 DUID. The trader of an aggregated portfolio corresponding to a DUID will then need to manage its portfolio and control its resources to respond to the dispatch instruction.

Figure 15 Dispatch process overview



Bids

As described above, an 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. As FCAS enablement is in a single direction only for each service, there is no

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[59] Subject to compliance requirements, see section 4.2.8.

[60] In contrast with the Visibility model, where participants would be eligible to participate in contingency FCAS; Dispatch model participants would be able to participate in all FCAS Markets, including Regulation FCAS.

bidirectional nature to these products, and treatment of FCAS bids and enablement for LSUs will be similar to other units[61].

Co-optimisation of energy and FCAS

The design proposes that NEMDE will co-optimise energy and FCAS for LSUs in the same method as scheduled resources, recognising that the trader will need to:

- Provide an FCAS trapezium per LSU[62].
- Comply with the requirements in the MASS[63] and the NER with respect to the services they will provide.
- Meet technical requirements such as an Automatic Generation Control (AGC) equivalent functionality[64] in case of regulation FCAS provision.

In accordance with the objective of maximising the value of spot market trading, the energy and FCAS bids of scheduled loads and scheduled generating units are co-optimised by NEMDE. NEMDE does this by minimising the value of the objective function[65], by applying the FCAS trapezium that defines the FCAS-energy capability curve of an FCAS provider. Therefore, when a trader submits an FCAS bid for an LSU, it must include an FCAS trapezium that defines the “as offered” frequency response capability of the FCAS provider in relation to its active power generation, consumption or load reduction levels (as appropriate)[66]. The maximum FCAS that can be enabled is bound by the FCAS offer trapezium for that service. The FCAS trapezium submitted by a trader can reflect the way in which it expects to manage its portfolio and delivery of energy and FCAS, whereby it can submit either:

- A trapezium that reflects its energy dispatch will need to be reduced to reserve headroom for FCAS, if that is the case, or
- A trapezium that reflects no relationship between its energy and FCAS dispatch, if it is managing its resources independently.

The trader’s bid may allow it to be dispatched for either energy or FCAS across the capacity of the DUID, subject to the FCAS trapezium. For example, if an LSU is able to deliver 5 MW, when co-optimising energy and FCAS this could allow it to be dispatched for 3 MW of energy and 2 MW of FCAS Contingency (raise) service. Importantly, when an LSU is providing FCAS, it will need to comply with the MASS, including ability to provide evidence that it is maintaining the appropriate headroom or footroom that would enable delivery of FCAS appropriately.

The technical requirements to enable the integration of distributed resources into FCAS related processes (such as co-optimisation) may vary as the capabilities and size of those resources evolve over time. This is being considered in a potential Stage 2 phase of development, as discussed in section 1.7.

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[61] AEMO, 2021. *IESS High Level Design*, at https://aemo.com.au/initiatives/submissions/integrating-energy-storage-systems-iess-into-the-nem.

[62] AEMO, 2021. *FCAS Model in NEMDE,* at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en.

[63] Under the ESB Post 2025 work, there will be opportunities to evolve the MASS to better integrate provision of FCAS by new types of resources.

[64] SCADA for DER may potentially enable this functionality.

[65] Objective function is the summation of the products of Dispatched Band MW and Band Offer price for scheduled generators, market network service providers, ancillary service providers and scheduled loads.

[66] AEMO, 2021. *FCAS Model in NEMDE*, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en.

Dispatch instructions

The proposed dispatch instruction design is consistent with that for scheduled resources, and aligned with the IESS High Level Design[67], for bi-directional resources. A trader will receive a single bi-directional dispatch instruction representing the net flow to be achieved by its DUID where relevant. Conventionally, this value would be positive where the unit is being dispatched to discharge, and negative where it is being dispatched to charge. A trader will also obtain an enablement for each FCAS as relevant.

Dispatch instructions would be generated every five minutes, consistent with the NEM spot market. The dispatch instructions will be issued for each DUID. This means that, for an aggregated portfolio, an LSU will receive a dispatch instruction per DUID, and will need to disaggregate this to its relevant portfolio accordingly. It is expected that the trader will, in aggregate, ramp their fleet linearly to meet the dispatch targets at the end of the dispatch interval[68]. Dispatch compliance considerations are being explored in section 4.2.8.

Project EDGE is currently trialling this concept and it is envisaged that the Scheduled Lite implementation will build on lessons from Project EDGE (see Appendix B.1). Project EDGE is also exploring potential data sharing collaboration by sending the dispatch instructions of each relevant DUID to the DNSP for their visibility.

Related projects (see Appendix B.1)

- IESS Rule change – potential to leverage processes developed for energy storage systems.
- DER Trials, e.g. Project EDGE – learning from DER Trials to inform Dispatch mode.
- Wholesale Demand Response – potential to leverage processes developed for WDR.

4.2.6 Operations

This section outlines the operational processes associated with the Dispatch model. As outlined in section 1.2, consumer uptake of CER is already redefining power system operations. This is posing challenges in preserving the critical dimensions required to support secure and reliable power system operation.

LSUs operating in Dispatch mode will be required to provide operational data through market systems in a similar manner to other scheduled resources. Such integration of data will support the operational requirements needed to navigate the challenges emerging from the increasing penetration of new types of resources, benefitting the market as whole by (but not limited to):

- Increasing controllability, which supports the development of dynamic operational tools.
- Helping to support system flexibility. For example, the provision of operating data from price-responsive resources will provide insight into the actual available capacity in the network, such as realising additional export capacity[69].

Table 13 below highlights the required capability of a trader among other market actors.

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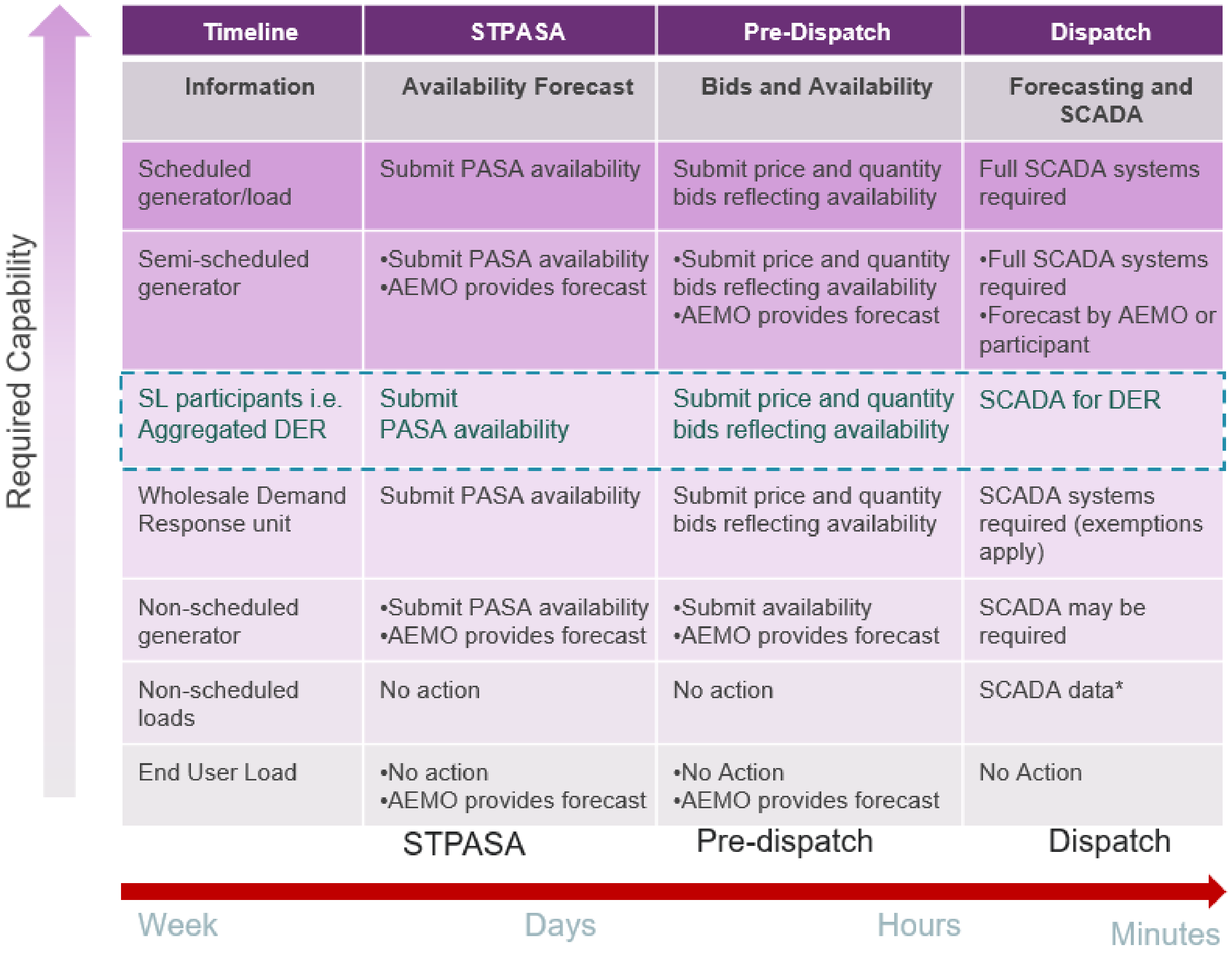
[67] AEMO, 2021. *IESS High Level Design*, section 3.1.2, at https://aemo.com.au/-/media/files/initiatives/submissions/2021/iess/integrating-energy-storage-systems-high-level-design.pdf?la=en.

[68] A dispatch interval refers to an interval frequency at which service dispatch instructions are sent and the minimum service duration (5 minutes).

[69] AEMO, 2021. *VPP Demonstrations Knowledge Sharing Report #4*, section 3.4.1, at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en.

Table 13 Operations Dispatch mode participants



Timeline	STPASA	Pre-Dispatch	Dispatch
Information	Availability Forecast	Bids and Availability	Forecasting and SCADA
Scheduled generator/load	Submit PASA availability	Submit price and quantity bids reflecting availability	Full SCADA systems required
Semi-scheduled generator	•Submit PASA availability •AEMO provides forecast	•Submit price and quantity bids reflecting availability •AEMO provides forecast	•Full SCADA systems required •Forecast by AEMO or participant
SL participants i.e. Aggregated DER	Submit PASA availability	Submit price and quantity bids reflecting availability	SCADA for DER
Wholesale Demand Response unit	Submit PASA availability	Submit price and quantity bids reflecting availability	SCADA systems required (exemptions apply)
Non-scheduled generator	•Submit PASA availability •AEMO provides forecast	•Submit availability •AEMO provides forecast	SCADA may be required
Non-scheduled loads	No action	No action	SCADA data*
End User Load	•No action •AEMO provides forecast	•No Action •AEMO provides forecast	No Action

Aligned with scheduled resources, traders within the Dispatch mode will be able to be directed/instructed by AEMO where necessary to maintain or re-establish system security (for example, system strength) and system reliability.

Traders will not be required to participate and provide information with respect to MT PASA. AEMO will use the information provided by the Dispatch mode trader to meet the medium-term forecasting requirements.

Related projects (see Appendix B.1)

- Wholesale Demand Response – potential to leverage processes developed for WDR
- DER Trials e.g. VPP, Project EDGE, Project Symphony – providing insights into DER integration within Market systems.

4.2.7 Incentives

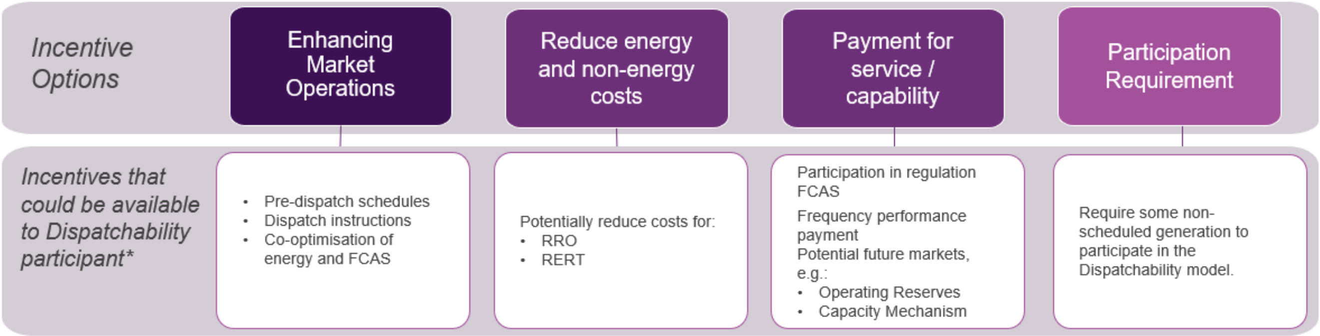
As with the Visibility model, the setting of incentives for participation in Dispatch is important, because most of the benefits accrue publicly to all consumers. Incentives that were considered as part of the draft high-level design aim to unlock additional revenue streams for price-responsive resources, recognising their contribution to the operability of the power system.

The proposed incentives were identified based on the Scheduled Lite principles outlined in section 1.5 and the following key considerations:

- **Value** of improved dispatchability, leading to more efficient operation of the power system.
- **Costs** of telemetry, metering, forecasting and monitoring to enable access.
- **Risks** of market exposure, including civil penalty regimes.
- **Opportunities** for, and implications of, staged measures for traders.

Figure 16 summarises the incentive options that were considered for the Dispatchability model as part of the draft high-level design.

Figure 16 Incentive options – Dispatchability model



Incentive Options	Enhancing Market Operations	Reduce energy and non-energy costs	Payment for service / capability	Participation Requirement
*Incentives that could be available to Dispatchability participant**	• Pre-dispatch schedules • Dispatch instructions • Co-optimisation of energy and FCAS	Potentially reduce costs for: • RRO • RERT	Participation in regulation FCAS Frequency performance payment Potential future markets, e.g.: • Operating Reserves • Capacity Mechanism	Require some non-scheduled generation to participate in the Dispatchability model.

**Subject to participant performance, a participant could accrue some or all of the potential incentives*

These incentive options are detailed further below:

- **Enhancing market operations:** similar to scheduled resources, traders would receive scheduling information to assist with optimising their operations, including:
  - Pre-dispatch schedules: similar to that provided to scheduled resources, the pre-dispatch schedule would outline the trader's forecast consumption and generation based on its bid information. The information may help the trader make better informed decisions relating to its operations. This information would only be published privately to the trader.
  - Dispatch instructions: a trader will receive a single dispatch instruction representing the generation or consumption for its portfolio. Dispatch instructions are set by NEMDE based on the trader's bid and the prevailing market conditions. Following dispatch instructions may improve operations for the trader in comparison to following or pre-empting price signals.
  - Co-optimisation of energy and FCAS: the design proposes that NEMDE will co-optimise energy and FCAS for Dispatchability model traders in the same fashion as scheduled resources. This was identified as a valuable incentive for market participants currently trading in FCAS markets.
- **Reduce energy and non-energy costs:** traders may be able to access a reduction in non-energy cost allocation, which covers costs that arise due to a number of services and regulatory mechanisms to ensure secure and reliable energy delivery. This may include the cost of:
  - Market ancillary services.
  - Network support and system restart ancillary services.
  - Interventions.
- **Retailer Reliability Obligation (RRO):** a trader could also potentially reduce costs associated with the RRO. For example, traders could choose to either:

  - Exclude responsive load from its liabilities under the RRO (as for scheduled load); or
  - Use responsive resources (with appropriate firmness factor) to underwrite qualifying contracts with retailers.

  Consistent with current arrangements for scheduled loads, a trader would be exempt from costs resulting from the activation of the Reliability and Emergency Reserve Trader (RERT) mechanism.

- **Payment for dispatch service/capability:** some markets and services require resources to be scheduled as a pre-requisite for participation. Scheduled Lite provides distributed resources with a mechanism for participation as a scheduled resource allowing the resource, subject to meeting technical requirements, to participate in:
  - Regulation FCAS: participation in regulation FCAS requires a resource to be scheduled so that a set point can be determined from which a response can be provided and managed[70]. The ability to participate in Regulation FCAS markets may provide an incentive for some distributed resources, particularly those with a high degree of control and established operational processes. Provision of regulation FCAS is subject to meeting technical requirements such as AGC equivalent functionality, which allows for both understanding of the current output of the DUID at four-second granularity, and for controllability away from this baseline to supply Regulation FCAS. To be eligible to provide Regulation FCAS, the resource must also comply with relevant standards and specifications including the MASS.
  - Frequency performance payment: the AEMC will introduce (on 8 June 2025) a financial incentive for market participants who help control the power system frequency required to keep the grid stable and keep costs down for consumers[71].
    - This is based on double-sided frequency performance payments, built on existing 'causer pays' arrangements for the allocation of regulation FCAS costs. Participants will be incentivised to ensure their activity aligns with their dispatch, and in doing so, are not exposed to the cost recovery for the residual costs of regulation FCAS. Participants will instead be able to access frequency performance payments.
    - Scheduled Lite participants will be able to access frequency performance payments if they comply with relevant requirements, such as having appropriate metering.
  - Potential future markets:
    - Capacity mechanism: In December 2022, Energy Ministers endorsed in principle a new Capacity Investment Scheme (CIS). The CIS is a Commonwealth revenue underwriting scheme available to all jurisdictions nationally to bring on the right mix of zero emissions dispatchable generation and storage, to meet the needs of the system into the future, at maximum value to communities and consumers[72]. The CIS will seek to complement existing state and territory schemes and be open to those eligible projects under existing state-based schemes as well as on-grid, public and private utility scale projects that achieve financial close from 8 December 2022 onwards. While further details of the CIS are to be determined, participation in the Dispatch model could provide a basis for orchestration of distributed resources to demonstrate their eligibility. Capacity remuneration

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[70] AEMO, 2021. *MASS final report and determination*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/mass/final-determination/final-determination.pdf?la=en.

[71] See https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

[72] See https://www.energy.gov.au/news-media/news/capacity-investment-scheme-power-australian-energy-market-transformation

could be a material additional revenue stream for distributed resources, and as such would act as a strong incentive to participate in the Dispatch model.

    - Operating reserve: the power system requires operating reserves to balance demand and supply in response to changes in demand and generation across the operational horizon. The AEMC is currently considering the introduction of an operating reserves market that would procure reserves 30 minutes ahead on a rolling basis. Resources that can ramp quickly would offer spare capacity above their production (or ability to reduce demand) of energy into the reserves market. Resources scheduled to provide reserves would be required to offer their reserve quantity into the energy market, and as such, a resource would be required to participate in scheduling to be eligible to provide operating reserves. Participation in the Dispatch model (subject to any technical specification of the service) could enable the provision of operating reserves by distributed resources. Operating reserves would be an additional revenue stream for distributed resources that could act as a strong incentive to participate in the Dispatch model.

- **Participation Requirement:** This incentive category would place an obligation on some resources to participate in the Dispatch model.
  - Non-scheduled generators: The threshold for generators to participate in the scheduling process is set at 30 MW (5 MW for storage). The AEMC assessed a rule change request in 2021[73] to reduce the scheduling threshold for generators to 5 MW and made a determination to maintain the current 30 MW threshold. One of the main reasons highlighted by the AEMC in making their decision was the relatively high cost of participating in the scheduling process for small resources.
  - The introduction of Scheduled Lite would provide a lower cost pathway for small resources to participate in the scheduling process. The introduction of Scheduled Lite would provide an opportunity to consider if an obligation to participate in the Dispatch model should apply to generators with a nameplate capacity of less than 30 MW.

Assessment of options

Incentives to participate as a scheduled resource are an important consideration for the Dispatch model, because many distributed resources can participate off-market and accrue most of the benefits associated with active management and optimisation in the energy market. However, AEMO does not propose the introduction of a new incentive mechanism for the Dispatch model at this point in time. The introduction of a capacity mechanism or an operating reserve market would act as a strong incentive for distributed resources to participate in the Dispatch model. If these mechanisms do not proceed to implementation, or do not apply as envisaged to distributed resources across the NEM, then a new incentive mechanism specific to distributed resources should be considered.

Related projects (see Appendix B.1)

- Project Symphony – providing insights into enabling provision of services from DER.

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[73] AEMC, 2021. *National Electricity Amendment (Generation registrations and connections) rule*, at https://www.aemc.gov.au/sites/default/files/documents/generator_registrations_and_connections_-_erc0256_-_final_determination.pdf.

4.2.8 Compliance

Compliance arrangements are an important consideration for the Dispatch model, because stakeholders have consistently raised compliance as a potential barrier to participation.

Dispatch conformance

AEMO monitors conformance to identify and implement corrective measures if a market participant fails to follow a dispatch instruction. Conformance monitoring is an important tool in balancing energy demand and supply that would otherwise require AEMO to purchase larger quantities of ancillary services. This section considers the rules that apply to existing scheduled resources as well as other potential options that could be applied to LSUs operating in Dispatch mode.

Scheduled resources

If a scheduled resource fails to comply with dispatch instructions, AEMO may declare and identify it as non-conforming in accordance with NER clause 3.8.23. AEMO operates software that monitors conformance with dispatch instructions by scheduled resources. The module automatically flags any resources that have not followed their dispatch targets. The AER is responsible for compliance activities in accordance with the NER.

As set out in Dispatch Procedure (SO_OP_3705), a Small Error Trigger (3% of availability) and a Large Error Trigger (6% of availability)[74] are determined for each scheduled resource and trading interval. If the scheduled resource exceeds its Large Error Trigger, then it has a smaller number of consecutive trading intervals before corrective actions are progressed. Once non-conformance actions are triggered, the scheduled resource and AEMO are required to follow a process of communication, notifications, and monitoring. Non-conformance may result in AEMO applying a dynamic constraint to reflect the generation or consumption of the resource and AEMO is required to report the non-conformance to the market.

Regulation FCAS applies a ‘causer pays’ principle in its recovery from generators and customers. Under the causer pays methodology for generators, a contribution factor to allocate costs is based on four-second variation between dispatch target and actual generation in a dispatch interval.

Wholesale Demand Response mechanism

The dispatch conformance rules for WDRUs are lighter in nature than those for other scheduled resources and they are not monitored as part of real-time operations. A separate post-event dispatch non-compliance analysis is performed for WDRUs:

- The first trading interval of its dispatch is not assessed as the WDRU may have difficulty with ramping.
- There is an interval error of + or – 6 MW before non-conformance is flagged.
- As units may be relatively small, 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.

WDRUs are not subject to the recovery of Regulation FCAS costs.

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[74] The error targets also incorporate a factor for the resources ramp rate and the error target is a minimum of 6 MW.

Ability to opt out of Dispatch mode

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. An alternative could be to automatically switch a trader out of the Dispatch mode in the event the non-conformance actions outlined for scheduled resources are followed and the trader fails to take corrective action.

However, the suspension of a trader from the Dispatch mode may have implications for participation in other markets and as such requires careful consideration.

Proposed arrangements

There is a complex trade-off between reducing the barrier to entry associated with compliance against the reliable and effective participation of distributed resources in central dispatch processes.

Based on performance in DER trials and feedback from traders, AEMO understands that aggregated portfolios of distributed resources are capable of meeting a high standard for dispatch conformance. Further, traders could self-manage their compliance by opting out of Dispatch mode during periods where they are not confident of complying with dispatch targets.

For Stage 1 of the Dispatch model, it is proposed that arrangements consistent with those of the WDR mechanism are established for LSUs. These arrangements will need to be reviewed, in parallel with those for the WDR mechanism, for Stage 2 of the Dispatch model to ensure:

- 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 WDRUs) that may be permitted in a region due to the lighter compliance arrangements.

Other considerations

Traders will need to ensure that they continue to meet eligibility requirements for participation in the Dispatch mode. A failure to meet the eligibility requirements would result in the suspension of the trader from the mechanism.

Related projects (see Appendix B.1)

- WDR – providing a compliance framework that could be leveraged.
- DER Trials e.g. VPPs, Project EDGE, Project Symphony – providing insights into compliance arrangements based on performance.

4.2.9 Opt-out arrangement

To recognise the maturity of traders' operational capabilities, an opt-out participation arrangement is proposed for Scheduled Lite. This approach was supported through industry engagement[75], with feedback recommending a 'start simple, then evolve' principle.

The opt-out arrangement aims to lower entry barriers for traders wishing to participate in Scheduled Lite by enabling a trader to opt out of the Dispatch mode, rather than requiring 24/7 operational capability as is required for scheduled resources. It is proposed that during periods in which a trader has opted out of the Dispatch mode, Visibility mode obligations would apply.

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[75] Further information on industry engagement that supported the development of this consultation paper is detailed in Appendix B.2.

The proposed requirements for the trader to opt out of the Dispatch mode are for the trader to:

- Remain in Dispatch mode for a minimum amount of time[76].
- Provide a notification to opt out a minimum amount of time in advance[77].
- Be subject to Visibility mode obligations.
- Remain opted-out of the Dispatch mode for no longer than a specific period of time[78], within operational timeframes. When the trader has opted out for longer than the specified timeframe, the trader will have to follow a reactivation process to opt back into the Dispatch mode.

Benefits would not accrue to a trader during periods it has opted out of participation. Opting out of Dispatch mode may also impact a trader's eligibility to participate in related markets like a capacity mechanism or operating reserve market.

To opt back into the Dispatch mode, the trader will need to:

- Remain opted-out for no longer than a specific period of time[81], within operational timeframes.
- Provide a notification to opt back into the Dispatch mode a minimum amount of time in advance .
- Comply with Dispatch mode operational requirements from the period in which it has opted back in.

The self-hibernation function described in section 2.1 is designed to accommodate traders seeking to opt out of participation for periods which go beyond operational timeframes (for example, for a season).

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[76] The minimum amount of time for an LSU to remain in Dispatch mode will be established in the implementation phase.

[77] The minimum amount of time in advance that a trader has to submit an opt out notification will be established in the implementation phase.

[78] The specific period of time that an LSU can remain opted-out will be established in the implementation phase.

5 Glossary

The following is a list of abbreviations used in the Scheduled Lite Rule Change Proposal and its appendices. This document and appendices use many terms that have meanings defined in the NER; these NER meanings are adopted. Other terms are described in the body of the document as they arise.

Term	Definition
5MS	Five-Minute Settlement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting System
BDU	Bidirectional Unit
CER	Consumer Energy Resources
CIS	Capacity Incentive Scheme
COAG	Council of Australian Governments
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DPV	Distributed PV
DRSP	Demand Response Service Provider
DSP	Demand Side Participation
DUID	Dispatchable Unit Identifier
ESB	Energy Security Board
ESS	Essential System Services
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Service
FEL	Flexible Export Limit
FTM1	Flexible trader model 1
FTM2	Flexible trader model 2
GPS	Generator Performance Standard
IDX	Industry Data Exchange
IESS	Integrating Energy Storage Systems
IRP	Integrated Resource Provider
ISP	Integrated System Plan
LNSP	Local Network Service Provider
LSU	Light Scheduling Unit
MASS	Market Ancillary Service Specification

Term	Definition
MICF	Market Integration Consultative Forum
MRC	Maximum Responsive Component
MT PASA	Medium Term Projected Assessment of System Adequacy
MW/MWh	Megawatt/ Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Metering Identifier
NSP	Network Service Provider
ODP	Optimal Development Path
PASA	Projected Assessment of System Adequacy
PMS	Portfolio Management System
PRC	Price responsive component
Project EDGE	Project Energy Demand and Generation Exchange
PV	Photovoltaic
RDC	Reform Delivery Committee
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
SCADA	Supervisory Control and Data Acquisition
SGA	Small Generation Aggregator
ST PASA	Short Term Projected Assessment of System Adequacy
TNI	Transmission Node Identifier
V2G	Vehicle-to-grid
VPP	Virtual Power Plants
WDR	Wholesale Demand Response
WDRM	Wholesale Demand Response Mechanism
WDRU	Wholesale Demand Response Unit

Appendix B.1
Related Projects

January 2023

Appendix to the Scheduled Lite
Rule Change Proposal

Important notice

Purpose

This Appendix B.1 to the Scheduled Lite Rule Change Proposal outlines the range of related projects that have informed the proposed design of Scheduled Lite.

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B1.1 Introduction

This appendix outlines the wide range of projects and initiatives that have informed the proposed design for Scheduled Lite. It is provided to support stakeholders in understanding how the initiatives have influenced the high-level design. It is not intended to be a complete description of those individual projects and stakeholders should refer to the source information for further detail.

0 below provides a high-level overview of each related project and the Scheduled Lite design elements for which they are relevant. The rest of the appendix explores the relevance of each individual initiative/project to the Scheduled Lite design in more detail including references to further information.

Table 1 Overview of project/initiatives that have informed the proposed Scheduled Lite design

Key: 🟢 Visibility Model 🟠 Dispatch Model

Related[1] projects	Design elements									
	Participation & Registration	Data types	Data exchange/ telemetry	Bids	Dispatch	Constraints	Operations	Compliance	Incentives	Opt-out arrangement
B1.2.1 IESS	🟢 🟠			🟠	🟠					
B1.2.2 Flexible Trading Arrangements	🟢 🟠									
B1.2.3 Semi-scheduled Self-forecast		🟢							🟢	
B1.2.4 VPP Demonstrations	🟠	🟢	🟢 🟠	🟠	🟠	🟠	🟢 🟠	🟠		
B1.2.5 WDR	🟢 🟠		🟠	🟠	🟠		🟠	🟠		
B1.2.6 SA Smart Meter Backstop Mechanism		🟢	🟢 🟠				🟢 🟠			
B1.2.7 DEIP - DOE						🟠				
B1.2.8 AEMO DER Program – Project MATCH	🟠									
B1.2.9 Project EDGE		🟢	🟢 🟠	🟠	🟠	🟠	🟠	🟠		
B1.2.10 Project Symphony	🟠		🟠	🟠	🟠	🟠	🟠		🟠	
B1.2.11 Project Edith	🟠		🟠			🟠				
B1.2.12 Review of PSDCS			🟢 🟠							
B1.2.13 SCADA Lite			🟠							
B1.2.14 IDX			🟢 🟠							
B1.2.15 NZ -DNx										🟠

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[1] Noting that the relevant projects listed here are in most cases being informed by innovative industry trials/projects. For example, Project EDGE has been collaborating and interacting with complementary projects like Evolve DER.

B1.2 Summary of related projects

B1.2.1 Integrating energy storage systems (IESS)

In December 2021, the AEMC made a final determination on the IESS rule change[2] to better integrate storage and hybrid systems, taking a significant step towards a technology-agnostic market model for the NEM. Among other changes, the rule introduces a new universal participant category – the Integrated Resource Provider (IRP) – to accommodate participants with bidirectional energy flows, but which may also classify generating units and load. The rule change is being implemented in two releases:

- An initial release, commencing in March 2023, allows Small Generation Aggregators (SGAs) to participate in FCAS markets and introduces aggregate conformance for hybrid systems (noting implementation of aggregate dispatch conformance is delayed); and
- A final release, commencing in June 2024, for all other changes.

IESS would be an enabling tool for participation and registration in both Scheduled Lite models (see Table 2).

Table 2 IESS relevance to participation

Design element	Relevance to the design element		
	Area/item	**Description**	**Relevance**
Participation /registration	Providing the future registration model for the NEM	• Introduction of the IRP (near) universal registration category (from June 2024) underpins the new NEM registration model. The IRP: – Accommodates a range of participants with bidirectional energy flows that may produce and consume energy and ancillary services. – May classify bidirectional units, end user connection points, scheduled loads, generating units, small resource connection points and ancillary service units. – Subsumes the current Market SGA category, which will participate under the Small Resource Aggregator label. • Under the new Small Resource Aggregator label, IRPs will be able to aggregate small resource connection points (both small bidirectional units and small generating units). As part of the initial (March 2023) release, SGAs will be able to participate in ancillary service markets. • The rule change also explicitly integrates storage units by introducing a new unit type: the Bidirectional Unit (from June 2024).	The registration model developed for IESS may be used by Scheduled Lite traders

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[2] AEMC, 2021. *Final determination: Integrating energy storage systems into the NEM*, at https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem Integrating energy storage systems into the NEM | AEMC.

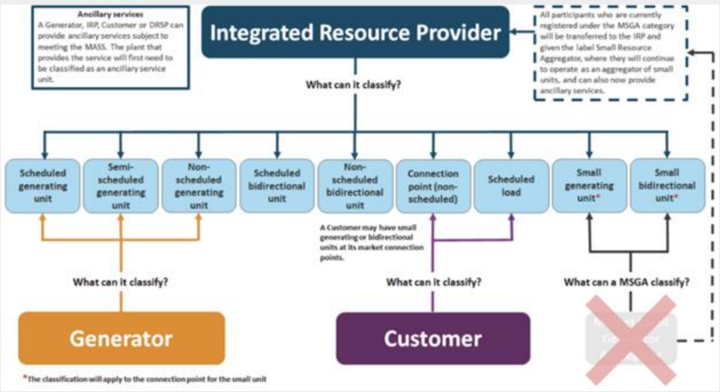
Design element	Relevance to the design element		
	Area/item	**Description**	**Relevance**
		Classifications and services that can be provided by Market Participants under the IESS rule change  Source: AEMC.	

Table 3 IESS relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Bids	Bid Structure	AEMO's IESS High Level Design outlines how bidirectional units would submit Energy Bids: • Bidding for energy: Up to 20 bid bands will be available to be submitted in respect of a scheduled bidirectional unit, with these being restricted to a maximum of 10 bands for capacity on the consumption side, and 10 bands on the generation side.	To inform proposed functionality/structure for dispatch processes.
Dispatch		AEMO's IESS High Level Design outlines how bidirectional units would be integrated into dispatch processes, this includes: • Bidding for FCAS: an ancillary service unit will be allowed up to 10 bid bands for each service – the same as for other ancillary service units. The FCAS trapezium for a scheduled bidirectional unit will be similar to that used by other units which are not bidirectional, recognising unique capabilities. • Dispatch instructions: Scheduled bidirectional units will receive a single (bidirectional) dispatch instruction representing the net flow to be achieved.	

Further information can be found in:

- AEMC's IESS Rule Change Final Determination[3].
- AEMO's IESS Draft High Level Design[4].

B1.2.2 Flexible trading arrangements

In its Final Advice on Post 2025 Market Design to Energy Ministers, the ESB detailed models for the development of flexible trading arrangements in the NEM. Flexible trading arrangements were proposed to enable greater choice and service access for customers, as well as supporting innovation and competition among service providers. Flexible trading arrangements enable the separation of controllable electrical resources (such as battery, solar PV and EV charging) from passively connected electrical resources (for example, household lighting and general appliances) in an end user's home or business. It enables end users to access competitive offers and

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[3] At https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

[4] At https://aemo.com.au/initiatives/submissions/integrating-energy-storage-systems-iess-into-the-nem.

services for their controllable resources independent from their general electricity supply, enhancing their ability to be rewarded for their flexibility and maximising the value of their CER.

Two flexible trader models have been developed:

- The first, flexible trader model 1 (FTM1), is an extension to the current arrangements for SGA connections and has been given effect via the recent IESS rule change (see section B1.2.1).
- The second, flexible trader model 2 (FTM2), is the subject of a current AEMC rule change process[5].

Flexible trading arrangements are expected to provide an avenue for Scheduled Lite traders to separate an end user's flexible resources for participation in Scheduled Lite (although participation via a 'standard' connection point will also be supported where a participant can meet the participation requirements).

Flexible trading arrangements would be an enabling tool for broader participation in Scheduled Lite; see Table 4.

Table 4 Relevance of flexible trading arrangements to participation

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Participation	Flexible trader model 1 (FTM1) – SGA+ *The AEMC has progressed FTM1 through the IESS rule change process*	**Second connection point to the distribution network** FTM1 allows a second connection point to the distribution network to be established, enabling the end user's controllable resources to be managed independently in wholesale settlement. The end user may appoint a different financially responsible Market Participant (FRMP) for the second connection point while retaining a traditional retailer for its passive load.	Scheduled Lite Traders may utilise the framework developed for FTM1 and FTM2 to enable the separation of controllable resources for participation in Scheduled Lite.
	Flexible trader model 2 (FTM2) *FTM2 arrangements are subject to a recent rule change process*	**Sub-meter connection point with end user's electrical installation** FTM2 would enable end users to establish a private metering arrangement (PMA), which includes a sub-metered connection point and separate National Metering Identifier (NMI), within their electrical installation. Resource(s) connected within the PMA are treated independently in wholesale settlement, with the option to nominate a separate FRMP to manage them. FTM2 may provide a more accessible model compared with FTM1 for many small users.	

Further information can be found in the following:

- FTM1: AEMC's IESS Rule Change Final Determination[6].
- FTM2: AEMO's Electricity Rule Change Proposal Flexible trading arrangements and metering of minor energy flows in the NEM [7]; and AEMC's Consultation Paper National Electricity Amendment (Unlcocking CER Benefits Through Flexible Trading) Rule[8].

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[5] See https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

[6] At https://www.aemc.gov.au/sites/default/files/2021-12/1._final_determination_-_integrating_energy_storage_systems_into_the_nem.pdf.

[7] At https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading?utm_medium=email&utm_campaign=New-rule-request-template-2&utm_content=aemc.gov.au%2Frule-changes%2Fflexible-trading-arrangements-distributed-energy-resources&utm_source=cust49597.au.v6send.net.

[8] At https://www.aemc.gov.au/sites/default/files/2022-12/Consultation%20paper%20-%20Unlocking%20CER%20benefits.pdf

B1.2.3 Semi-scheduled Self-forecast Program

In early 2018, AEMO and ARENA began undertaking a Market Participant 5-minute self-forecasting program to demonstrate the potential benefits of wind and solar generator self-forecasting for the operation of the power system. To date, participant self-forecasting has delivered system-wide benefits by providing greater autonomy to existing semi-scheduled generators and reducing generation dispatch forecast error, compared with Australian Wind Energy Forecasting System/Australian Solar Energy Forecasting System (AWEFS/ASEFS)[9] dispatch forecasts. This has led to reductions in generators' Causer Pays factors, in turn reducing participants' Regulation FCAS charges. Participants currently using self-forecasting have expressed positive feedback on the program.

Knowledge and findings generated from the Semi-scheduled Self-forecast Program informed the data types and incentive elements of the Visibility model, as shown in Table 5.

Table 5 Relevance of Semi-scheduled Self-forecast Program to the Visibility model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Data types	Reliability and performance requirements	Provides an existing framework for the provision of self-forecasts. • Participant self-forecasts are assessed in three categories: – Reliability: received self-forecast at least 70s before gate closure for >95% of dispatch intervals. – Sufficient Volume: Reliability and (Unit target ≥ Unconstrained Intermittent Generation Forecast [UIGF] OR SCADA Possible Power available) for > 80% of dispatch intervals over assessment window. – Performance: AEMO will assess self-forecast performance for all dispatch intervals that satisfy the above criteria over the current assessment window.	Informed data types/requirements to be of value to Visibility Model traders and market processes
Incentives	Incentive arrangement	Self-forecasting uses a performance equals incentive arrangement, where participants must consistently outperform AEMO in order to access the incentives. Before a participant self-forecast is eligible for use in dispatch, AEMO will assess its performance against the internal forecasts. Failure to meet minimum standards would then make the participant ineligible for incentives until performance improves.	Informed incentive arrangements formulation for Visibility Model Traders

Further information can be found in the following:

- ARENA's *Knowledge and findings generated from the short-term self-forecasting trial*[10].
- AEMO's *Semi-Scheduled Generation Dispatch Self-Forecast – Assessment Procedure*[11].

B1.2.4 Virtual Power Plant (VPP) Demonstrations

AEMO, in collaboration with ARENA, the AEMC, the AER, and members of the DEIP, established the VPP Demonstrations trial in March 2019. The VPP Demonstrations project was an initial step in AEMO's broader

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[9] See AEMO's *Solar and wind energy forecasting* webpage at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting.

[10] At https://arena.gov.au/assets/2021/10/arena-short-term-forecasting-funding-round-evaluation.pdf.

[11] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/semi-scheduled-generation-dispatch-self-forecast---assessment-procedure.pdf.

Consumer Energy Resources (CER)[12] Program[13], designed to provide early insights on integration of VPPs into market frameworks at scale, and develop empirical evidence to inform related changes to regulatory frameworks and operational processes.

The VPP Demonstrations aimed to:

- Allow VPPs to demonstrate their capability to deliver multiple value streams across FCAS, energy and potential network support services.
- Provide AEMO with operational visibility to help AEMO consider how to integrate VPPs effectively into the NEM.
- Assess current regulatory arrangements affecting participation of VPPs in energy and FCAS markets, and inform new or amended arrangements where appropriate.
- Provide insights on how to improve consumers' experience of VPPs in the future.
- Understand what cyber security measures VPPs currently implement, and whether their cyber security capabilities should be augmented in the future.

Participants in the VPP Demonstrations included:

- Eight VPP portfolios across all mainland NEM states.
- A total registered capacity of 31 MW (equivalent to a small scheduled hybrid solar farm plus battery). Although participation was open to any technology, all VPPs used batteries in their portfolios.
- Approximately 7,150 consumers who signed up in the VPP Demonstrations (almost 25% of residential customers with registered batteries in the NEM).

The VPP Demonstrations concluded following the final determination of the Market Ancillary Services Specification (MASS) consultation towards the end of 2021.

A brief description of how the lessons learnt by the VPP Demonstrations informed the proposed Scheduled Lite design is presented in Table 6 and Table 7 below.

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[12] 'Customer Energy Resources' are also commonly referred to as 'Distributed Energy Resources'

[13] See AEMO's NEM CER Program webpage, at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program.

Table 6 VPP Demonstrations relevance to the Visibility model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Data types	Data Specification	The operational visibility of VPPs obtained during the VPP Demonstrations[A] was instrumental in developing AEMO's understanding of VPP behaviour. All VPP demonstration participants were required to provide data including: • Actual performance data for aggregate controlled generation, load and energy in storage. • Granularity: All data was provided on a 5-minute basis via APIs. • Actual data for controlled load and generation could be aggregated to obtain the net position of the portfolio for each 5-minute interval. AEMO's analysis of this data verified the ongoing need for operational visibility of VPPs as they reach material thresholds. Drawing on evidence from the VPP Demonstrations, it is recommended that: • VPPs provide near real-time actual performance data at a portfolio level • VPPs provide forecasts of their expected operation and available capacity, potentially at different price points, to AEMO and have a requirement to meet that forecast. Data received in this trial demonstrated that VPPs are able to and are best placed to, provide forecasts with a schedule of discharge and charge activity over a variety of forecast horizons. The complex operating patterns of VPPs has made it clear that AEMO is not best placed to forecast the behaviour of these assets.	Provided valuable learnings relevant to defining the data requirements needed to fulfill Visibility model objectives
Data exchange/ telemetry	Data Ingestion Capability	APIs were built and deployed to ingest the following data into the VPP cloud application: • Enrolment data (site level NMI and device information, frequency injection test data for DUIDs and batteries) • VPP operational data (aggregated DUID data) – actuals and forecasts to provide AEMO with visibility of the VPPs in near real-time. • Telemetry data – device level data in 5-minute resolution received daily/weekly. VPPs use home wi-fi, 3/4G and public internet to source data from devices that could then be aggregated and sent to NSPs and AEMO. At any one time during the trial, AEMO received 70-98% of the telemetry data from each of the participants. This largely reflects house-to-VPP cloud communication dropouts due to issues with wi-fi or 3G networks.	Provided analysis on the advantages/disadvantages of exchanging data over APIs via public internet.
Operations	Operational Visibility Insights	The VPP Demonstrations highlighted key aspects to be considered once an energy resource such as a VPP is of a material size in a region to ensure appropriate scope of control and ability to accurately forecast grid conditions. The aspects related to the Visibility Model are: • Visibility: from an operational perspective, AEMO requires visibility of controllable resources in a VPP portfolio. AEMO sees this as being any CER that can be actively controlled by an aggregator, VPP, or relevant agent. This is not limited to demand side CER (such as batteries), with the potential for rooftop PV generation to be actively controlled via smart meter functionality or other elements such as pool pumps. • Forecast ability: AEMO requires accurate forecasts of any 'active' shifting of distributed load or generation so it can be reflected in load forecasts that are published to the market or generation scheduling	Provided insights into operational requirements for the Visibility model

A. AEMO, 2019. *VPP Demonstrations data specification,* at https://aemo.com.au/-/media/files/electricity/nem/der/2019/vpp-demonstrations/vpp-demonstrations-data-specification.pdf?la=en.

Table 7 VPP Demonstrations relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Registration	Participation Models	During AEMO's VPP trials, applicants applied to enrol their VPP as:	Informed consideration of registration framework

<table>
<tr><th rowspan="2">Design element</th><th colspan="3">Relevance to the design element</th></tr>
<tr><th>Area/Item</th><th>Description</th><th>Relevance</th></tr>
<tr><td></td><td></td><td>• Participating in FCAS markets and being exposed to energy market price signals (as a Market Customer), or
• Participating in FCAS markets only (as a Market Ancillary Service Provider [MASP]).
There were three models for participation in the VPP Demonstrations:
1. A retailer and a separate VPP coordinator (who may or may not be a registered participant) may jointly participate in the trial in respect to connection points where the retailer is the FRMP. This arrangement requires the retailer and the VPP operator to enter into a commercial agreement, and the retailer will participate as the Market Customer in contingency FCAS markets and be exposed to energy market prices.
2. A retailer, who is also the VPP coordinator, can participate as a Market Customer with respect to multiple connection points, at which it is the FRMP.
3. A VPP coordinator who is registered as a MASP may participate in the trial in contingency FCAS markets only.</td><td>alternatives to participate in the Dispatch Model.</td></tr>
<tr><td></td><td>Required Standards</td><td>Drawing on evidence from the VPP Demonstrations, it is recommended to explore mandating compliance with AS/NZS 4777.2.2020 for new (and potentially existing) DER, providing FCAS to mitigate risk of disconnections when enabled for FCAS.</td><td>Informed considerations around standards that Traders will need to comply with to participate/register in the Dispatch Model.</td></tr>
<tr><td></td><td>Minimum Threshold</td><td>Outcomes from the VPP Demonstrations suggest that, if VPPs can consistently follow forecast schedules, scheduling in central dispatch may be deferred until the capacity of VPPs reaches certain thresholds. It is recommended to leverage the guidelines that have been prepared for the WDR mechanism (see Section B1.2.5 below).</td><td>Informed considerations on an adequate portfolio capacity size threshold to unlock value of participating in dispatch processes.</td></tr>
<tr><td>Data Exchange/ Telemetry</td><td>Data Types</td><td>In addition to Table 6 above, outcomes from the VPP Demonstrations highlighted that participation in central dispatch would require VPPs to effectively be ‘self-forecast’ with bid-offer pairs submitted, 5-minute dispatch targets followed, and availability submitted at all times. This would require full integration into AEMO’s market systems with VPPs represented in Projected Assessment of System Adequacy (PASA) and pre-dispatch as both demand and generation.</td><td>Provided insights into the value of near real-time data to observe the responsiveness of VPPs to energy spot prices.</td></tr>
<tr><td></td><td>Quantity Definition</td><td>Outcomes from the VPP Demonstrations suggest that for the purpose of operational visibility, AEMO prefers to receive live operational telemetry about VPP activity as gross data, as occurred during the VPP Demonstrations. When live data is provided as net (net connection point flows), the information of activity behind the meter is lost.</td><td>Provided insights into the value of gross data – this is being pursued through other initiatives</td></tr>
<tr><td></td><td>MASS Review</td><td>At the beginning of 2021, AEMO launched a MASS consultation process, part of which sought to determine the appropriate ongoing arrangements for CER participation in FCAS markets.
In summary, consultation outcomes affecting CER FCAS Providers are[A]:
• A measurement time resolution of 200 ms is adequate to verify Fast FCAS delivery from Aggregated Ancillary Service Facilities with no inertial response, provided that:
– At least 25 Ancillary Service Facilities are aggregated: and
– A discount of 5% is applied to the quantity of Fast FCAS delivered, if at least 25 but less than 500 Ancillary Service Facilities are aggregated.
• Where those conditions are not met, the minimum acceptable measurement time resolution is 50ms for participation in the Fast FCAS markets.
• The measurement location will remain ‘at or close’ to the connection point of each Ancillary Service Facility.
• Transitional arrangements will apply for those participating in the VPP Demonstrations (Trial Participants) until 30 June 2023.</td><td>Informed the standards/specifications with which Dispatch Model Traders would need to comply when participating in FCAS markets</td></tr>
<tr><td>Bid/Dispatch</td><td>Responses to energy price signals</td><td>VPPs demonstrated that they are highly capable of responding to energy market prices in real time e.g. VPPs improved their algorithms during the trial to consistently charge during the day and discharge during evening peaks that often coincide with higher energy prices.</td><td>Provided insights into the ability of VPPs to value stack, by responding to energy spot price signals</td></tr>
</table>

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
		Drawing on evidence from the VPP Demonstrations, it was recommended to enable the ability for VPPs to be coordinated (or dispatched), potentially through VPPs participating in wholesale dispatch by submitting bi-directional bids/offers.	
Operations	Operational Visibility Insights	In addition to what is in Table 6 above, coordination is also a key aspect to ensure appropriate scope of control and ability to accurately forecast grid conditions, with high penetration of new energy resources such as VPPs. The VPP Demonstrations recommended that changes should be made such that VPPs are able to be considered and relied upon as a resource in the system, from a system adequacy perspective given their relative and potential size in the market, as well as ability to forecast accurately to ensure efficient dispatch and market outcomes. This would require full integration of VPPs into AEMO's market systems, represented in PASA and pre-dispatch as both demand and generation.	Provided insights into the requirements needed to operate the system with high penetration of new energy resources such as VPPs
Constraints	Flexible Export Limits (FELs)[14]	Drawing on evidence from the VPP Demonstrations, it is recommended to explore the implementation (over time) of tiered FELs, sent from the Distribution Network Service Provider (DNSP) to the VPP operator, in high CER areas. The tiers could represent one FEL for system normal operation and one for contingency events that would allow the system normal envelope to be exceeded temporarily when delivering contingency FCAS.	Informed consideration of the allocation and treatment of distribution network constraints/services in the Dispatch Model
	Local network services	Drawing on evidence from the VPP Demonstrations, it was recommended to explore an agreement between aggregators DNSPs on the control hierarchy of participating CER inverters and the prioritisation of services such as volt-VAR service (reactive power) ahead of FCAS (active power).	
Compliance	Compliance	As an on-market demonstration, it was important that VPPs complied with the rules and regulations applicable to market participants. Participants (including VPP Demonstration participants) are paid for FCAS upon enablement, however, if a Participant/VPP does not deliver what they have been enabled for, a financial clawback procedure may take place.	Informed considerations of compliance arrangements
Incentives	Provision of Contingency FCAS	Small battery VPPs, like utility-scale batteries, have proven to be highly effective at providing contingency FCAS, through various response methods[B].	Provided insights into the ability of VPPs to deliver contingency FCAS

A. Amendment of the market ancillary service specification – DER and general consultation, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/mass/final-determination/final-determination.pdf?la=en.
B. Responses characterised as either proportional, switched responses, and even dynamic switching controllers that deliver a proportional response.

Further information can be found at AEMO's VPP Demonstrations webpage[15].

B1.2.5 Wholesale demand response (WDR) mechanism

In June 2020, the AEMC made a final rule to facilitate demand response in the NEM through the WDR Mechanism. The WDR Mechanism allows demand side (or consumer) participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. Demand Response Service Providers (DRSPs) may classify and aggregate the demand response capability of large market loads for dispatch through the NEM's standard bidding and scheduling processes. The DRSP receives payment for a dispatched response, measured against a baseline estimate, at the electricity spot price.

The Scheduled Lite design aims to leverage tools/analysis developed to enable the WDR mechanism, as shown in Table 8 and Table 9.

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[14] Flexible export limits' are also commonly referred to as 'dynamic operating envelopes' or 'DOE'.

[15] At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations.

Table 8 WDR mechanism relevance to the Visibility model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Participation	Portfolio Management System (PMS)	The PMS enables DRSPs to view and manage their portfolios of Wholesale Demand Response Units (WDRUs) and Ancillary Service Units. The PMS allows DRSPs to: • Submit new application requests for AEMO's approval such as: – Classify new NMIs. – Declassify existing NMIs. – Aggregate. – Disaggregate. – Update baseline methodologies and parameters. – Request to reinstate a NMI following suspension due to non-compliance. • Continue application(s) from draft. • View the status of submitted requests. • Request to withdraw submitted requests. • Self-assess baselines associated to a NMI or by a Portfolio. • Identify their NMI as unavailable due to operational issues.	It is proposed that Scheduled Lite Traders would use the PMS to manage their portfolios
Participation/ Registration	Registration checks for constraints	• Threshold for requirement of SCADA – the following criteria is to be used to determine if a WDRU needs to have SCADA: – Any WDRU (individual or aggregated) >5 MW. – WDRUs connecting to a congested area (e.g. in north-west Vic or southern NSW). • Aggregated WDRUs crossing multiple constraint zones: – If the aggregate WDRU is partly in a congested constraint zone then it may be requested to disaggregate.	Informed Scheduled Lite participation building blocks, in terms of zonal aggregation considerations

Table 9 WDR mechanism relevance to the Dispatch model

Design element	Relevance to the design element		
	Area	Description	Relevance
Registration	PMS	As per Visibility model (see Table 8).	
	Registration checks for constraints	As per Visibility model (see Table 8).	
	Regional Threshold *Portfolio Capacity Threshold*	A threshold for a region of the total quantity of WDR for which no telemetry data is provided, in MW, that may be dispatched at one time. AEMO to determine a threshold for the total quantity of WDR in a region above which AEMO will impose additional or alternative telemetry and communications equipment requirements, for any load in the region seeking to be classified as a WDRU after the threshold has been reached.	Informed threshold considerations for the scheduling and participation of new types of resources e.g. VPPs in central dispatch.
Data exchange	Telemetry/Definitions	Quantity is defined as Net but is only for the devices controlled by the DRSP.	Informed data requirements to participate in dispatch processes.
	Telemetry/Thresholds	Requirements for Telemetry to apply to WDRUs when:	Informed threshold considerations for the scheduling

		• One NMI in the aggregation has a level maximum response component (MRC) of 5 MW or greater; • The aggregation of NMIs at or behind a single transmission node have an MRC of 5 MW or greater, regardless of whether or how the WDRUs are aggregated; or • individual or aggregated WDRUs below the 5 MW threshold in respect of a NMI-Level MRC or DUID-Level MRC, as applicable, are located in an area of the power system where existing scheduled plant: – Needs to be curtailed to maintain power system security; or – Is forecast to be curtailed as a result of committed investments and works, or other changes in the power system, for at least five hours per year.	and participation of new types of resources e.g. VPPs in central dispatch.
Bid/dispatch	Bid structure/functionality	When engaging with the market through Central Dispatch, DRSPs are obliged to meet some of the same requirements as Scheduled Participants, namely: • Providing bids for each interval in a trading day. • Providing a maximum availability bid that reflects the availability of the demand-responsive component of their load. • Respond to dispatch instructions.	Informed proposed requirements in dispatch processes, e.g. bid only considering the responsive component.
Compliance	Arrangements	WDRU conformance is completed in post-event analysis. If a WDRU has three separate events over three months where it had been deemed to be non-conforming, then it will be issued with a non-compliance.	Informed Dispatch Model compliance considerations.
Operations	Operations	Forecasts for Operational Demand are inclusive of WDR. The availability of WDRUs is considered in an identical fashion to other scheduled plant – therefore reserve assessments are inclusive of WDR availability.	Informed requirements in terms of data provided by Traders, as well as AEMO's utilisation of the data being provided.

Further information can be found in the following links:

- The AEMC's *Rule determination – National Electricity Amendment (Wholesale demand response mechanism) Rule 2020* [16] .
- AEMO's WDR guidelines[17].

B1.2.6 South Australia Smart Meter Backstop Mechanism Trial

To assist in understanding the capability of smart meters, the South Australian Energy Minister formally requested AEMO to run a trial testing this capability. The trial tested, via a simulated response, the technical capabilities and communication protocols for smart meters to be used in such a way that may support power system security in rare circumstances.

The trial was developed in two phases. Phase 1 demonstrated that residential smart meters have the capability to actively manage distributed PV (DPV) generation within the timeframes and reliability levels required to support power system security. Phase 2 sought to specifically demonstrate how this functionality could be harnessed to enable new energy markets and enhanced information, as well as choice for South Australian consumers.

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[16] At https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

[17] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/wdr-guidelines/final-stage/wholesale-demand-response-guidelines-mar-2021.pdf?la=en.

The proposed Scheduled Lite design was informed by the outcomes of the South Australia Smart Meter Backstop Mechanism Trial as outlined in Table 10.

Table 10 SA Smart Meter Backstop Mechanism Trial relevance to the Visibility model and the Dispatch model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Data Types	Multiple element metering	• A multiple element meter was able to provide aggregate gross visibility every 5 minutes, providing: – Consumer information: Enhanced data in a consistent form, quality, accuracy and timeliness. The functionality provides clear and simple information that could be accessed in near real-time, enabling consumers to make better choices delivering greater agency and control over their energy use and devices. – Situational awareness: an increase in data sets improves accuracy in the reconstitution of the supply/demand balance in a high CER system, providing an accurate understanding as to whether the power system is expected to remain in a secure state or further action is required. – Significant forecasting accuracy improvements: The trial highlighted that visibility is improved with additional near real-time aggregate data, with some forecast scenarios having indicated a variation in the order of 200 MW for a dispatch interval. Such visibility of these variations will be critical in managing real-time contingency events.	Demonstrated technological capabilities to enable provision of gross data.
Data Exchange	Metering capabilities	• The aggregate 5-minute DPV data from Smart Meters can be provided to AEMO without additional devices, communication modules or reliance on consumer internet access.	
Operations	Metering configurations	• Smart meters could be configured in a manner that could deliver: – Under-frequency load shedding (UFLS): Further testing is required but discussions indicate meters can be programmed to appropriately and automatically respond to an UFLS event. – Over-frequency generation shedding (OFGS). – System Restart Ancillary Service (SRAS): Smart meters offer near-instant management of DPV to deliver a stable load, while direct to inverter-based models of DPV control, generally utilise consumer wi-fi that appears to have a reconnection lag that may impact the utility of the inverter communications pathway to support system restart. – Cyber Security Safety Switch: Smart Meters offer redundancy via capability to disconnect DPV through a secure and independent switch.	Provided guidance on technological capabilities that enhance operational practises.

Further information can be found on AEMO's website[18].

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[18] At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/reference-information.

B1.2.7 Distributed Energy Integration Program (DEIP) – Dynamic Operating Envelopes Working Group

The DEIP DOE Working Group was established to explore the value that DOEs offer to the energy transition. The workstream aims to[19]:

- Build a shared understanding of the opportunities and challenges.
- Share insights on approaches currently under investigation.
- Identify reforms that could be implemented to establish DOEs.

The proposed Scheduled Lite design has considered the outcomes of the DEIP DOE Working Group, as outlined in Table 11.

Table 11 DEIP DOE Working Group relevance to the Dispatch Model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Constraints	DOE	The working group agreed on the principle that DOEs can be initially allocated at the connection point to the network (regardless of the number or configuration of devices behind the connection point) as a first step in DOE roll out. Highlighting that DOEs are expected develop further as CER penetration increases and markets or business models are created to provide customers with value.	To inform the DOE integration alternatives for the different stages of the Dispatch Model

Further information can be found in the following links:

- DEIP Dynamic Operating Envelopes Working Group Outcomes Report[20].
- ARENA's Dynamic Operating Envelopes Workstream webpage[21].

B1.2.8 AEMO CER Program – Project MATCH

AEMO has established a dedicated CER program to understand and integrate high levels of CER into the NEM. It aims to ensure a smooth transition from a one-way energy supply chain – starting with large-scale generation units to consumers – to a decentralised, two-way energy system.

AEMO's CER program contains several workstreams, including the CER Operation workstream which examines how CER assets behave during power system disturbances and develops models to predict and manage CER performance in the future power system, together with ensuring adequate tools are in place to manage a high-CER world.

Project MATCH is a project being developed under this workstream. Project MATCH aims to establish a robust monitoring and analysis toolbox to better understand the behaviour of CER and implications for power system security. It will investigate CER behaviour during power system disturbances and seeks to support secure power system operation under high penetrations of CER. The project is being led by the University of New South Wales

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[19] ARENA Dynamic Operating Envelopes Workstream webpage, at https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/.

[20] At https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf.

[21] At https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/.

(UNSW) in partnership with AEMO and Solar Analytics, supported by ARENA funding. The project is scheduled to be completed in March 2024.

The proposed Scheduled Lite design is being informed by the findings of the program, as outlined in Table 12.

Table 12 AEMO CER Program – Project MATCH relevance to the Visibility model and the Dispatch model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Registration	Standards	Findings highlight the relevance of conformance with the AS/NZS4777.2:2020 Standard, to enable required capabilities to support high level penetration of CER e.g. voltage ride-through capabilities	Informed relevant requirements that Traders will need to comply with, to participate/register in Scheduled Lite.

Further information can be found in the following:

- AEMO's CER Program webpage[22].
- ARENA's Project MATCH webpage[23].
- UNSW's Project MATCH webpage[24].

B1.2.9 Project Energy Demand and Generation Exchange (EDGE)

Project EDGE is a multi-year project to demonstrate an off-market, proof-of-concept CER Marketplace that efficiently operates CER to provide both wholesale and local network services within the constraints of the distribution network in a way that promotes the long-term interests of all customers. The project's primary intent is to identify NEM capabilities and to inform the development of a two-sided market that incentivises innovation and participation.

Project EDGE will demonstrate three key function sets that are vital to the efficient and scalable integration of DER, and that will ultimately deliver value to customers:

- CER wholesale energy market integration.
- Scalable CER data exchange.
- Local Service Exchange for network support services.

Project EDGE will test these functions and their interactions in a CER Marketplace. The field trial is expected to finish in Q1 2023.

The evidence base generated by Project EDGE will continue to inform the design of Scheduled Lite through a range of elements as shown in Table 13 and Table 14 along with other ESB Post-2025 reform items.

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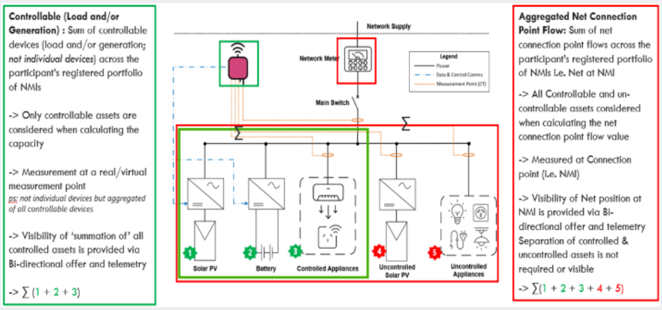
[22] At https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program.

[23] At https://arena.gov.au/projects/project-match/.

[24] At https://www.ceem.unsw.edu.au/project-match.

Table 13 Project EDGE relevance to the Visibility model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Data types	Data Specification *Progressive 'step/horizon'*	Project EDGE has defined data requirements with the purpose to enable visibility of CER aggregator portfolios in a way that provides value to the participant and to market systems. Data requirements are in accordance with the progressive 'step/horizon' that the participant is part of. The steps/horizons informing the Visibility Model are: - Step 1: Visibility. the aggregator is providing operational visibility via a forecast of anticipated operation and instantaneous 1-minute measurement, and submission of aggregated DUID level telemetry of actual operation. Main features include: – Providing operational visibility to AEMO. – No market participation. – Dispatch target sent by AEMO. – Aggregator is not required to act on or respond to the dispatch target. - Step 2: Self Dispatch. Features: – Aggregator participates in the Market by being a price taker and self-nominating their dispatch target by offering quantity in the Energy Fixed Loading[A] field only. Main features include: – Passive market participation. – Price taker and doesn't influence NEM clearing price. – Dispatch target sent by AEMO. – Aggregator is required to act on and respond to the dispatch target.	Informs data requirements in a progressive framework
Data Exchange	Real time data	Project EDGE is trialling two quantity definitions: Net Connection Point Flow (Net NMI) – measured at the connection point (NMI-level) and aggregated across the aggregator's portfolio, including both controllable and uncontrollable generation and load. As such, Net NMI is unlikely to provide clear visibility of the portion of the load pertaining to controllable CER devices. - Flex Only – measured at a common measurement point behind the meter – representing the aggregation of all controllable CER assets at a site – and aggregated across the aggregator's portfolio. Flex Only ignores uncontrollable customer load and generation at a site. Any CER asset that can be remotely and actively controlled – turned on, turned off, ramped–up or ramped-down is classified as a controllable asset. Project EDGE is trialling the collection of data as follows: - Granularity: All data to be provided on a 1-minute basis. - Data coverage: The data is provided for the whole of the portfolio (i.e. in Project EDGE, the DUID represents the entire aggregator portfolio). **Project EDGE quantity definitions**  Source*:* Project EDGE DUID telemetry overview.	To inform the participation capability of different participation options, including standard connection point participation and separation of controllable resources
	CER Data Hub	Project EDGE is examining the potential benefits and costs of a scalable data exchange hub approach. Two approaches are being tested:	Outcomes and learnings to inform what data communication methods

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
		- Centralised hub: all data is provided to, and stored in, a centralised hub which may be hosted within a single organisation's environment, into which parties integrate and can access required data, based on their role-based permissions and credentials. - Decentralised data hub: represents shared digital infrastructure where multiple parties host nodes that facilitate the exchange of data, messages, and services. This mitigates the risk of a single point of failure, as the loss of one node would not disrupt the ability of the decentralised hub to continue to operate.	are fit for purpose for aggregated DER

A. Fixed unit output in kW. This is the fixed level of load or generation offered by the Aggregator into the market.

Table 14 Project EDGE relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Data exchange	Data specification *Progressive 'step/horizon'*	The step/horizon informing the Dispatch Model is 'Step 3: Scheduled', see Design Element 'Bid' in this Table.	To inform data requirements needed to participate in dispatch processes
	Telemetry/Definitions	Refer to Table 13 above	
	CER Data Hub	Refer to Table 13 above	
Bid/Dispatch	Definition of Quantity	As noted in Table 13, Project EDGE is aiming to trial the use of aggregated net connection point flow (Net NMI) and controllable only (Flex Only) quantity definitions. Net NMI bidding is being contrasted with Flex bidding in Project EDGE to gain insight into the risk and operability in the market for aggregators where their bid, dispatch and telemetry quantity is different to FEL quantity adopted by industry as the starting point principle for the roll out of FELs (Net NMI connection point).	To provide evidence-based learnings on the value delivered from each approach to inform the design.
	Bi-directional Offer ('Boffer') *An Offer that includes both generation and load. May be referred to as "Boffer". May contain 20 price bands.*	Project EDGE is trialling the proposed dispatch functionality in the IESS High Level Design[A], through the Boffer structure, particularly in Step 3: Scheduled. In this Step, the Aggregator submits Price/Quantity pairs to offer quantity (i.e. provide intent) to deliver wholesale energy services. Step 3: Scheduled main features include: - Active market participation - Price Setter Boffer. - Data submitted is for 48 hours i.e. has data for all 576 5-minute intervals in the next 48 hours from time of submission - Dispatch target sent by AEMO and expectation on aggregator to meet dispatch target	To inform key bid structures/functionality parameters.
	Dispatch Instruction	Consistent with current NEM wholesale market arrangements, Project EDGE will provide dispatch instructions as follows: - Dispatch Instructions are generated and sent by AEMO to Aggregators every 5 minutes. – Aggregator on receipt of the Dispatch Instructions will send acknowledgement of successful receipt to AEMO - Dispatch Target is an absolute value - AEMO will send the dispatch instructions to DNSP for information only	To inform the design of the dispatch instruction process, including exploring potential data sharing collaboration.
Constraints	DOEs	In Project EDGE, FELs will be considered by participants prior to submission of bids and offers. DOE purposes include: - to enforce distribution level constraints in market clearing - to self-constrain Aggregator Boffer FELs are used in FEL Compliance by the DNSP after the fact.	To inform most effective way to integrate FEL and local network services into proposed Dispatch Model operation

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
	Local Network Services/ Local Services Exchange	Project EDGE is exploring how DNSPs could procure network support services from CER aggregators in a Local Services Exchange, where DNSPs post network service requirements and aggregators bid and respond via a Local Services Exchange (LSE).	
Operations	Roles and Responsibilities	Project EDGE is trialling a CER Marketplace, where roles and responsibilities are defined as follows[B]: • AEMO's role primarily relates to its statutory responsibilities in the National Electricity Rules (NER) to establish the spot market (NER 3.4), operate a central dispatch process (NER 3.8.1) and to determine and represent network constraints in dispatch (NER 3.8.10). As DNSPs are the experts in their distribution networks, AEMO must collaborate with DNSPs to gain confidence that wholesale dispatch will not lead to distribution network limits being breached. • DNSP (AusNet)'s transitioning to a Distribution System Operator (DSO) role, will dynamically optimise their network, calculate the network limits and communicate them as 'DOEs' to aggregators via the CER Marketplace. AusNet will also define local network services and engage aggregators to deliver them using the Local Service Exchange function. • Aggregators represent consumers in a CER Marketplace and deliver multiple services on their behalf, including wholesale services to AEMO and local network services to distribution networks. Aggregators are granted permission by consumers to use their CER and data to deliver services according to the consumer's preferences. Project EDGE anticipates testing the operation of the CER Marketplace with multiple aggregators.	To inform the identification of operational responsibilities of involved actors taking part in the Dispatch Model
Compliance	Dispatch Conformance	Assessment of conformance and compliance to the dispatch target is completed within post-dispatch interval by AEMO. DUID Telemetry data is used for monitoring conformance with dispatch instructions or self-dispatch targets.	To inform conformance arrangements being considered in the Dispatch Model.

A. AEMO, 2021. *IESS High Level Design*, Section 3, at https://aemo.com.au/initiatives/submissions/integrating-energy-storage-systems-iess-into-the-nem.
B. Project EDGE, 2022. *Project EDGE Research Plan*, at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en.

Further information can be found in the following:

- AEMO's Project EDGE webpage[25].
- ARENA's Project EDGE webpage[26].

B1.2.10 Project Symphony

Project Symphony is an innovative project in Western Australia (WA) where consumer CER such as rooftop solar, batteries, and other major appliances, like air-conditioning and pool pumps, will be orchestrated as a VPP to participate in a future energy market, unlocking greater economic and environmental benefits for customers and the wider community.

Project Symphony aims to provide key learnings to the development of the CER Orchestration Model in the WEM and nationally by:

- Demonstrating roles for AEMO, Distribution System Operator (DSO), and Aggregator.

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[25] At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge.

[26] At https://arena.gov.au/projects/project-edge-energy-demand-and-generation-exchange/.

- Building and piloting integration components between actors and simulated market systems, including demonstrating dispatch of DER.
- Demonstrating the capability of CER to participate in Wholesale Energy Market (WEM) markets (post WEM Reform), in parallel with providing network support services (NSS).
- Developing stakeholder understanding of expectations for CER orchestration.

Project Symphony is being part-funded by ARENA and is a collaboration between Western Power, Synergy, AEMO and Energy Policy WA (EPWA), working together with residential and small business electricity customers located in the pilot area of Southern River. It is scheduled to be completed in June 2023.

Project Symphony will continue to inform the design of Scheduled Lite as it progresses, as outlined in Table 15.

Table 15 Relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
Registration	Registration	CER aggregated groups will register facilities, meaning that an Aggregator will be able to combine the capacity of CER into one or more facilities in order to provide market services. The Aggregator registers the facilities via the Market Platform. This involves entering the required device standing data, facility operation data and validation tests. Once these are complete, the facility is registered by AEMO and is ready for market operations. Features, include: • 1 NMI will be part of only 1 registered facility. • A Facility exists to deliver one or more types of market services.	To support identification of relevant requirements for Traders wishing to participate in the Dispatch Model.
Data Exchange	CER Data Hub	Project Symphony is trialling the same data exchange platform as Project EDGE, refer to Section B1.2.9.	See Section B1.2.9.
	Telemetry requirements	Aggregator provides data with 4 second resolution.	To support identification of relevant data requirements to enable participation in dispatch processes.
	Data requirements	Features of data requirements, include: • Aggregator will determine the current operating capacity of each registered CER facility on a high frequency basis. – Calculation of the available flexible energy capacity for a facility, incorporating FEL constraints for all NMIs within the facility and the CER asset operating or opt-out constraints. • The Aggregator will monitor multiple aspects of the CER facilities, sites and CER assets during and outside of control events including: – Asset performance metrics. – Asset availability data. – Aggregated site performance metrics. – Aggregated facility performance metrics. • The Aggregator will provide: – View of current state of CER assets – availability and performance. – Behind-the-meter demand and generation forecasts. – Generation, load and flexible energy capacity forecasts. – Optimised control event schedule for each enrolled CER asset that will ensure fulfilment of market bids.	
Bid/Dispatch	Structure *Boffer*	Project Symphony is using the concept of Energy bi-directional offers from the Real Time Market. The bi-directional offers can be up to 10 bands with Load and Generation.	To inform desirable dispatch functionality where non-scheduled

Design element	Relevance to the design element		
	Area/Item	**Description**	**Relevance**
	Dispatch *Submitting bids and offers in a bi-directional energy market*	As the Aggregator, Synergy will submit bids and offers into the Real Time Market for energy services that take into account available capacity of CER facilities and market pricing. Bids and offers will be cleared by the Distribution Market Operator (DMO) (see Design Element 'Operation,' in this Table) and the Aggregator will be dispatched for the energy clearance shortly thereafter following requirements for a Scheduled Facility.	resources are actively participating.
Constraints	DOE	DSO (see Design Element 'Operation,' in this Table) will dynamically calculate, allocate and publish operating envelopes for the Aggregator to use in CER optimisation. The DSO will monitor compliance with published operating envelopes.	To inform integration considerations of constrains emerging in the distribution network, when participating in central dispatch.
	Network services	Project Symphony will trial different platforms and market simulation environments, including: • NSS, a contracted service provided by a market participant to the network operator/DSO (Western Power) to help manage localised network constraints. – The DSO and Aggregator will enter bi-lateral agreement(s) for NSS. – AEMO will have visibility of the contracted operational requirements and provide the pre-dispatch instruction to the Aggregator on receiving the operation request from the DSO.	
Operations	Roles and Responsibilities	Project Symphony will pilot a model for delivering a two-way power grid that supports better integration of CER. The model defines three key roles: • DMO: defined as a market operator that is equipped to operate a market that includes small-scale devices aggregated and is able to be dispatched at appropriate scale – Organise and operate the market and assess all bids and offers and optimises the dispatch of energy resources in consideration of transmission network and distribution network constraints. • Aggregator: defined as parties which facilitate the grouping of CER to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s). • DSO: enables the optimal use of CER within distribution networks to deliver security, sustainability, and affordability in the support of whole system optimisation.	To provide guidance on operational responsibilities to enable Dispatch Model functionality
Incentives	Market Participation	Project Symphony will trial different platforms and market simulation environments, including: • Wholesale energy services, a market for bulk energy that is cleared by AEMO's dispatch engine to determine the least-cost allocation of generation and load to meet system demand. • Constrain to zero, a pre-emergency service provided by a VPP to the market operator to constrain energy output from CER to zero export (net) or zero output (gross). • Contingency Raise ESS, a market-provided response to a locally detected frequency deviation to help restore (raise) frequency to an acceptable level in the case of a 'contingency event' such as the sudden loss of a large generator or sudden surge in load. Two secondary use case scenarios will be developed and tested subject to limitations, these being: • Contingency Lower ESS, a market-provided response to a locally detected frequency deviation to help restore (lower) frequency to an acceptable level in the case of a 'contingency event' such as a sudden surge in supply or a sudden drop in demand. • Regulation Raise ESS and Regulation Lower ESS, a market-provided response to automatic generation control signals to correct small deviations in frequency during a dispatch interval.	To inform how to unlock value to a Trader wishing to take participate in the Dispatch Model

Further information can be found at:

- ARENA's Western Australia Distributed Energy Resources Orchestration Pilot webpage[27].
- AEMO's Project Symphony webpage[28].

B1.2.11 Project Edith

Project Edith aims to demonstrate a decentralised and cost-effective way of managing network capacity in a growing two-sided market, where services are bought from distributed resources (such as rooftop solar and electric vehicles (EVs)) to deliver cleaner, cheaper and reliable energy for all consumers. Project Edith aims to achieve this by testing the extent to which dynamic pricing can be used to:

- Allocate distribution network capacity in a decentralised manner, and
- Reward network support, such as voltage support.

Project Edith is currently taking place in New South Wales. It is led by electricity distributor Ausgrid and technology provider and aggregator Reposit Power, in collaboration with the Australian National University and energy software developer Zeppelin Bend[29].

Project Edith will continue to inform the design of Scheduled Lite as it progresses, as outlined in Table 16.

Table 16 Relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/item	Description	Relevance
Participation	Other	Project Edith is trialling the application of dynamic network prices to tariffs on customers' imports and exports of electricity. This would enable innovation in developing simple customer offers, which adequately provides customers with transparency and shares value.	To provide lessons on innovation in consumer service offerings, to assess its influence on Scheduled Lite participation, e.g. facilitate Scheduled Lite participants to develop attractive consumer service offerings.
Data exchange	Platform	Project Edith is trialling a platform to publish FEL and dynamic pricing that could provide extensible capabilities.	To provide learnings that will inform what data communication methods are fit for purpose, for the integration of aggregated DER.
Constraints	DOE Distribution network services	Project Edith is trialling a decentralised approach to managing distribution limits that involve the use of: • DOE as an absolute capacity limit. • Network pricing to optimise VPP bids.	To inform the most effective way to integrate FEL and local network services into proposed Dispatch Model operation, including dispatch conformance.

Further information can be found at Ausgrid's Project Edith webpage[30].

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[27] At https://arena.gov.au/projects/western-australia-distributed-energy-resources-orchestration-pilot/.

[28] At https://aemo.com.au/initiatives/major-programs/wa-der-program/project-symphony.

[29] Ausgrid – Reposit, *Project Edith Overview Report*, at https://cdn.ausgrid.com.au/-/media/Documents/Reports-and-Research/Project-Edith/Project-Edith-2022.pdf?rev=eecbc81dcb9d4bc39d79362f8365de42&hash=DEC947ECB7113DD8737B9864AA8CE536.

[30] At https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith.

B1.2.12 Review of Power System Data Communications Standard (PSDCS)

The PSDCS for the NEM sets out the standards with which Data Communication Providers (DCPs) must comply when transmitting power system data to and from AEMO control centres. The PSDCS is currently undergoing a review to identify the changes required to make the standard fit for purpose, by addressing issues that were identified through engagement during October and November 2021 with internal and external stakeholders.

The Scheduled Lite design needs to consider the outcomes from the Power and Data Communications Standard review, as outlined in Table 17.

Table 17 Review of PSDCS relevance to the Visibility model and the Dispatch model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Data exchange	Relevant requirements	Outcomes from the current PSDCS review will define relevant requirements for transmitting power system data to and from AEMO.	Scheduled Lite Traders will need to comply with the PSDCS.

Further information can be found on AEMO's website[31].

B1.2.13 SCADA Lite

SCADA Lite is part of the NEM 2025 roadmap and has been identified as a foundational initiative. SCADA Lite aims to reduce entry barriers for smaller generators and demand side resources to provide greater visibility to AEMO and to participate in the market with SCADA that is fit for purpose for distribution-connected resources.

The scope of SCADA Lite is under development. It aims to enable capabilities for providing a service that aggregators or distribution network connected generators/loads can utilise if they cannot access the service through their network. This work is part of an operational data exchange strategy that includes cost, resilience and technology considerations for the changing system with a higher volume of active DER.

Table 18 SCADA Lite relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Data exchange	SCADA for DER	SCADA Lite will provide a mechanism for participants such as VPPs to exchange operational data with AEMO and provide visibility of their CER device activities.	Dispatch Units may be able to use SCADA Lite to communicate telemetry data .

Further information can be found in the *NEM2025 Implementation Roadmap – Initiative Briefs*, Section 6.4[32].

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[31] AEMO, 2022. *Review of the Power System Data Communication Standard*, at https://aemo.com.au/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard.

[32] At https://aemo.com.au/initiatives/major-programs/nem-reform-implementation-roadmap.

B1.2.14 Industry Data Exchange (IDX)

IDX is providing the framework for data exchange across industry and is intended to establish unified access to AEMO services across all markets, using modern authentication and communication protocols, facilitating a cohesive approach to industry data exchange. Table 19 outlines its relevance to proposed Scheduled Lite design.

Table 19 IDX relevance to the Visibility model and the Dispatch model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Data exchange	Data Exchange Framework	The standards, protocols and architecture delivered by IDX will enable the data exchange elements of all NEM2025 reforms. All reforms – particularly those introducing new markets and new cohorts of Participants – will use the new Identity and Access Management (IDAM) and IDX frameworks.	Scheduled Lite Traders will need to comply/follow the framework defined by IDX.

Further information can be found in the *NEM2025 Implementation Roadmap – Initiative Briefs*, Section 5.4[33].

B1.2.15 Dispatch Notification (DNx) by Transpower (NZ TSO)

The DNx Project is part of a broader project called the Real Time Pricing (RTP) project, which aims to enhance the spot market to improve retail competition and make spot prices more efficient in the New Zealand context.

DNx's purpose is to enable smaller-scale purchasers and generators to participate in dispatch and price setting processes, as part of implementing RTP. The NZ Electricity Authority considers that encouraging greater participation would strengthen the net benefits expected from the delivery of RTP. A new form of dispatchable demand for smaller purchasers, coupled with a new form of dispatch for smaller generators, is being proposed.

Scheduled Lite design considers best practices from related projects in an international context. Table 20 outlines considerations related to DNx and further information can be found on the NZ Electricity Authority's website[34].

Table 20 DNx Project relevance to the Dispatch model

Design element	Relevance to the design element		
	Area/Item	Description	Relevance
Opt-out arrangement **Dispatch model**	Dispatch Notification (DNx) — System and Market Operation Considerations	Features of the DNx project include: • No requirement to provide indications and measurements (SCADA). – Real-time compliance is assumed. – Compliance assessed on a monthly review basis. • Bidding and offering: – Able to bid/offer "non-dispatchable". – Dispatch notifications via web services over internet. – Participant has the ability to reject a dispatch notification under certain circumstances (physical or technical issues). • Instructions/directions – DNx not eligible for constrained off/on payments.	Informed potential parameters to enable the opt-out arrangement being proposed in the Scheduled Lite Design.

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[33] At https://aemo.com.au/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard.

[34] At https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/real-time-pricing-industry-engagement-sessions/.

Appendix B.2 Stakeholder Engagement

January 2023

Appendix to the Scheduled Lite Rule Change Request

Important notice

Purpose

This is Appendix B.2 to Scheduled Lite Rule Change Request.

Disclaimer

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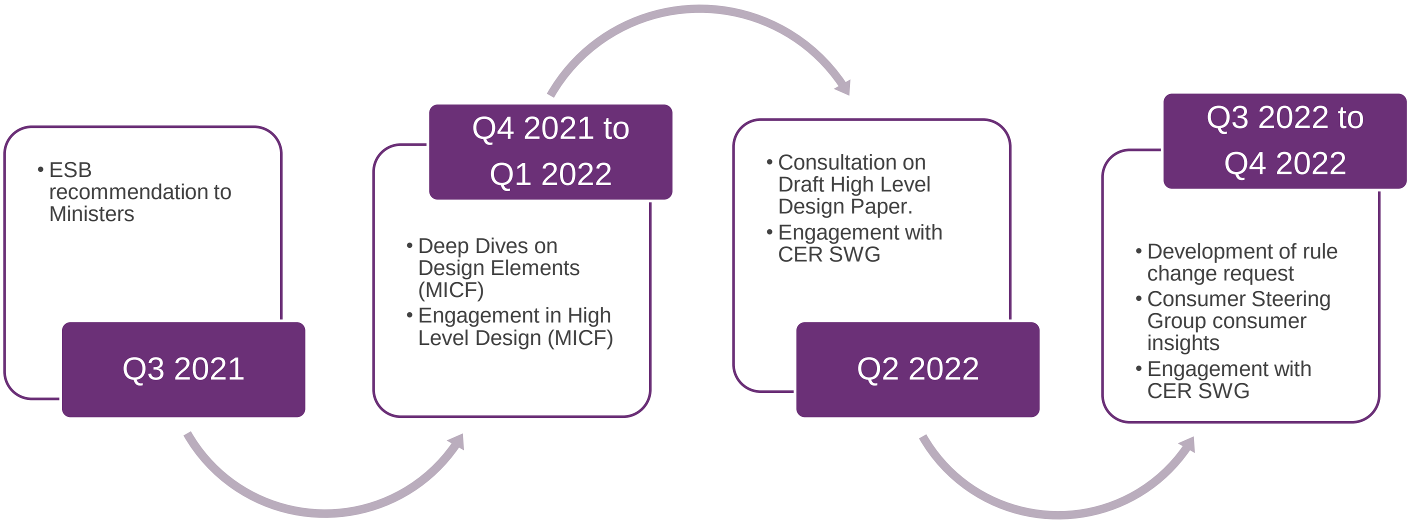
B2.1 Introduction

Gaining insights and perspectives from stakeholders has been a key activity in the design of Scheduled Lite. This appendix summarises the breadth of engagement undertaken during the development of the Scheduled Lite High Level Design, the feedback received, and how stakeholder input has informed the Rule Change Request.

B2.1.1 Stakeholder engagement journey

Figure 1 presents the stakeholder engagement journey since AEMO was tasked by the Energy Security Board (ESB) to develop the Scheduled Lite High Level Design and Rule Change Request.

Figure 1 Stakeholder engagement journey



B2.1.2 Stakeholder feedback and AEMO's responses

The sections below contain the high-level feedback received in each stage of the stakeholder engagement journey, along with AEMO's responses, highlighting how the feedback has been integrated into the design.

Consumer insights workshop – September 2022

In September 2022, AEMO and the ESB held a Consumer Insights Collaboration workshop exploring the consumer interface, barriers and opportunities for the Scheduled Lite mechanism, with an intentional focus on the potential experience for consumers. A summary of the workshop and key insights is provided in Appendix A.

Table 1 reflects how AEMO has considered feedback on important matters in respect of this rule change package.

Table 1 Consumer insights workshop feedback

Item	Summary of feedback	AEMO response
Voluntary participation	Communication and minimising complexity is key to gaining consumer interest and buy-in for Scheduled Lite and flexibility more generally.	The Scheduled Lite design carefully navigates the existing market framework to establish a voluntary mechanism that supports consumer choice (visibility or dispatchability) while opening access to markets and revenue sharing via traders. By placing obligations with traders (retailers and aggregators), consumers can choose to actively utilise their resources in the market, within their own tolerance, while avoiding the complexity of market operations.
Participation	Considering the system-wide benefits of high levels of participation, there may be a case for aspects of more mandatory participation within the framework.	Consistent with the ESB's proposed approach, AEMO considers that the initial design should focus on appropriate incentive structures, facilitating ease of participation and lowering barriers and transaction costs to support greater participation, prior to the consideration of mandatory elements.
Barriers and Incentives	Recognition of a need to unlock innovation in consumer service offerings, with Scheduled Lite a potential avenue to achieve this.	Efficient integration of distributed resources involves lowering barriers for participation – recognising resource capabilities such as tailored compliance arrangements – valuing the system benefits provided from these resources.
Consumer protections	Transparency and trust are linked, both through the information that is provided to consumers and commercial arrangements that might be agreed between consumers and traders.	Similar to current off-market demand response and VPP offerings, transparency of any participation arrangements made on behalf of consumers by traders for Scheduled Lite will need to be considered (i.e. AER Review of Consumer Protections for Future Energy Services)[1].
Consumer protections	Consumer protections need to be carefully considered to manage potential risks and provide traders with clear boundaries without limiting innovation.	Similarly, any likely risks of participation will need to be cognisant of the potential of harm to consumers. The AER's Review of Consumer Protections for Future Energy Services is considering both principles-based and outcomes-based forms of regulation, which seek to explore benefits of flexibility and innovation in service delivery and customer outcomes.
Benefits	Considering equity and how the system-wide benefits could be shared with non-CER customers.	Participation of distributed resources (such as coordinated DER storages) within Scheduled Lite would align with the ISP's ODP in the *Step Change* scenario. This in-market participation would minimise risks of overinvestment in grid-scale infrastructure.

Consultation Paper, Draft High Level Design – June 2022

AEMO released a Draft High Level Design paper for Scheduled Lite for consultation in June 2022, seeking feedback on the proposed mechanism to identify any challenges associated with participation within the mechanism and to inform a rule change request.

Key feedback and comments that supported the development of the final version of the Scheduled Lite design and the Rule Change Proposal, along with AEMO's responses, are summarised in tables 2, 3 and 4 below[2].

Submissions can be found on AEMO's dedicated webpage for Scheduled Lite[3].

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[1] AER, 2022, *Review of consumer protections for future energy services – Options Paper*, at: https://www.aer.gov.au/retail-markets/guidelines-reviews/review-of-consumer-protections-for-future-energy-services

[2] The tables address the associated comments by Model and Design elements. Please note that some comments were merged with other comments of the same nature, into an overview of feedback comment. Specific comments can be identified by quotation marks.

[3] AEMO, 2022, *Scheduled Lite Draft High Level Design*, at: https://aemo.com.au/initiatives/trials-and-initiatives/scheduled-lite.

Table 2 Consultation Paper, Draft High Level Design – participation feedback

Item	Summary of feedback	AEMO response
Visibility model	Consider a 'simple' visibility model that enables participation of lower sophistication business models with a focus on residential DER.	AEMO has proposed a 'Simple' Visibility model in the high-level design in response to this feedback. This would provide a simpler mechanism for distributed resources, in particular large customers, to provide information about their price responsive behaviour. See Section 4.2.2 in the high-level design for more detail.
Registration	"We would encourage AEMO to use the same aggregation approach as is currently used for FCAS registration where hundreds or potentially thousands of NMIs and customers are aggregated. It will not be feasible to register individual assets."	AEMO has considered the importance of an efficient system of portfolio management and aggregation of NMIs, particularly for large portfolios of small resources. As suggested, the proposed approach draws on that currently employed for FCAS registration. Section 3 of the high-level design has been expanded to provide more detail on a range of portfolio management functions that could be enabled to support Scheduled Lite.
Zonal aggregation	Concerns raised about potential unintended consequences of zonal aggregation approach e.g. adding operational complexities, and registration inefficiencies.	AEMO has expanded on the rationale for zonal aggregation in the high--level design to explain why this approach is required for managing forecast error. To manage the additional complexity, AEMO has proposed that the zonal approach to aggregation is supported by automated processes including disaggregation and re-aggregation of NMIs, to assist in managing large aggregations within a trader's light scheduling units (LSU).
Graduation from Visibility to Dispatchability once the 5 MW threshold is met	It should not be mandatory, considering that not all 5 MW portfolios are the same.	At this stage, AEMO is not proposing mandatory 'graduation' from Visibility to Dispatch model, only that the transition is encouraged and supported once portfolios exceed the proposed size threshold.
Standard connection point and secondary connection point	Participation via standard connection point is preferred.	AEMO's proposal seeks to provide optionality in the connection arrangements established for participation of customer energy resources. This may include standard connection point or flexible trading models 1 or 2 (noting the second model is currently subject to a rule change consultation)[4].
DNSP data sharing	Provision of information on NMIs that are participating in Scheduled Lite, as well as the NMI-level maximum reactive component is needed.	AEMO notes these pieces of information are consistent with the information provided to DNSPs for Wholesale Demand Response (WDR) and have informed AEMO's proposal.
Consumer perspective	AEMO should engage with the consumer insights developed by the ESB and its Customer Insights Collaboration and specify how it has applied these insights into the high-level design of Scheduled Lite.	A Scheduled Lite workshop has been run with the Consumer Insights Collaboration and the outcomes have been documented in detail in Appendix A and above in Table 1.
Other considerations	• Acknowledge different technology capabilities. • Flexibility to enable amend the models if needed.	AEMO has built the design to facilitate participation by a range of technology capabilities through flexible participation models with opt-out provisions, fit-for-purpose compliance and incentive mechanisms, and proposals for a Simple Visibility model and a potential future aggregated DPV model. AEMO considers that sufficient flexibility has been built into the design to enable it to evolve over time, including through planning for a Stage 2 phase.

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[4] AEMC, 2022, *Consultation Paper National Electricity Amendments (Unlocking CER Benefits Through Flexible Trading) Rule*, at: https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading#:~:text=Rule%20Change%3A%20Open&text=AEMO%20proposes%20to%20introduce%20flexible,providers%20if%20they%20choose%20to.

Table 3 Consultation Paper, Draft High Level Design – Visibility model feedback

Design element		Summary of feedback	AEMO response
Element	**Item**		
Opt-in arrangement	Participation	Overall support for an opt in arrangement that is truly voluntary.	AEMO welcomes this feedback and is keen to continue defining the voluntary/opt in arrangement in the implementation phase, in collaboration with market bodies and industry. More detail can be found in the high-level design.
Data types	Real time	The data sets proposed to be collected are reasonable, however, it is necessary to clarify if the data will be provided from individual resources or at the portfolio level. It was also noted that the cost of providing real time data should be factored into incentives.	The real-time data provided by a trader is for each LSU [A] (where in an aggregation, the data will be the aggregate the resources).
	Forecast	• An aggregator recommended limiting forecasting requirements to controllable load/ generation and using existing AEMO processes/ forecasts for passive solar generation and non-controllable customer load. • The impact of inaccurate forecasting needs to be considered. • Also consider the cost of providing forecast data, which should be factored into incentive design.	AEMO has updated the forecast data requirement for clarification as follow: *Forecast capacity*: Data set of anticipated capacity. The Forecast data provided by a trader is for each LSU (for a portfolio of resources the data will be the aggregate of all of those resources). More detail can be found in the high-level design, Section 4.2.2. Note, the design enables flexibility in the way the participant wishes to participate in the Visibility Mode. For instance, a participant could choose to participate via flexible trading model 2[B], which will enable the participant to separate controllable resources from passive resources, supporting the participant's ability to forecast more accurately.
	Indicative Bids	Preparation of an indicative bid may require a step change in sophistication.	The intent for the Scheduled Lite mechanism is to attract price-responsive resources that are actively managed. It is expected that many traders actively managing a portfolio of resources would already prepare a forecast of their generation and consumption at different price points to support their operational decisions and to optimise their returns in the energy market. Noting the spectrum of potential customers, and the degree to which their resources are actively managed, AEMO has proposed further consideration of a Simple Visibility model that acknowledges the potential value that could be derived from understanding the price responsive behaviour of a broader range of distributed resources, which would not have the operational capability to participate in the Visibility model. More details can be found in the high-level design, Section 4.2.2.
Data exchange	General	Overall support for API as the data exchange channel. However, it might be worth exploring alternatives e.g. web socket and stream data.	AEMO has proposed further consideration of a Simple Visibility model as mentioned above. It is proposed that the data exchange in a Simple Visibility model could be facilitated via WebSocket[C]). More details can be found in the high-level design, Section 4.2.2.
Compliance	General	Overall agreement with the proposed compliance approach. However, careful design of penalties for inaccurate forecasts is needed to avoid discouraging participation.	AEMO notes these comments. It is important to consider, as mentioned in the response to forecast data feedback, that the design is intended to allow flexibility in how a participant may choose to participate in the Visibility mode. For instance, a participant could choose to participate via flexible trading model 2[B], which will enable the participant to separate controllable resources from passive resources, supporting the participant's ability to forecast more accurately.

Design element		Summary of feedback	AEMO response
Element	**Item**		
Incentives	General	Incentives need to be clarified. The incentive design must consider the cost of participating e.g. real time data provision is costly.	AEMO has updated the incentive design to clarify the main incentives that a participant will be able to accrue in the Visibility model. These are: • Provision of private pre-dispatch schedules. • Access to Visibility Service Payments. The required rule amendments to allow the provision of these incentives are proposed in the Rule Change Request. Details on the assessment and considerations of incentives can be found in Section 4.2.5 of the high-level design.
	Participation requirement	Concerns were expressed regarding participation as an eligibility requirement for contingency FCAS provision. Noting that this would create challenges for the demand side participation already providing large volumes of FCAS, which could result in current participants choosing to no longer participate.	AEMO outlined a spectrum of potential incentive options in the draft high-level design. The rule change proposal does not include a requirement for FCAS providers to participate in the Visibility model. Note that the number of resources providing Contingency FCAS may only be a subset of those that could participate in the Visibility model. As such, this incentive option alone may not attract the desired levels of participation. Another potential drawback of this option is that it could act as a hurdle for DER participation in Contingency FCAS markets. Details on the assessment and considerations of incentives can be found in Section 4.2.5 of the high-level design.
	Visibility Service Payment	Overall agreement with the proposed incentive: Visibility Service Payment. Further details are needed e.g. how this payment would be structured or recovered.	The Visibility Service Payment has been recommended and has been incorporated into the rule change request. The proposal is intended to provide flexibility on how the payment structure will be implemented. Details on the assessment and considerations of incentives can be found in Section 4.2.5 of the high-level design.
	Reduce energy and non-energy costs	"The benefit here is nominal and will be challenging to pass through to end-use customers in any meaningful way."	Noting the complexity and drawbacks of progressing this incentive, AEMO has proposed that a Visibility Service payment would be available to participants rather than a reduction in non-energy costs. Details on the assessment and considerations of incentives can be found in Section 4.2.5 of the high-level design.

A. A new classification, ‘Light Scheduling Unit’, into which resources may be classified for participation and zonal aggregation of resources.
B. Subject to Rule Change consultation.
C. Communication protocol to enable data transfer from a user’s web browser to a server.

Table 4 Consultation Paper, Draft High Level Design – Dispatchability model feedback

Design element		Summary of feedback	AEMO response
Element	**Item**		
Participation	Minimum aggregated capacity threshold (5 MW)	Supportive if the proposed 5 MW threshold is useful for AEMO from a systems management perspective. However, noting that it could restrict flexibility in the aggregation process by potentially creating unnecessary disincentives to aggregate	AEMO notes these comments. The proposed threshold is required to support operational requirements associated with preparing scheduling inputs for LSUs.
Data Exchange	General	"Solution should be fit for purpose for residential DER, cost-effective and practical"	The design reflects the requirement for a trader to provide telemetry data as per requirements for distributed resources defined in the power system communication standard[5]. Further details can be found in section 5.2.2 of the high-level design.
Bid	To consider 100kW incremental Bids	This should be subject to: • Capacity portfolio threshold. If it is 5 MW then this may not be necessary, however if it is less than 5 MW it is worth exploring. • The cost to upgrade AEMO systems to enable it.	The minimum portfolio threshold of 5 MW will mean that smaller incremental bid quantities may not provide material additional benefit for traders. AEMO proposes that for Stage 1 of implementation of the Dispatch model, the 1 MW incremental bid quantity will continue. Further details can be found in section 5.2.4 of the high-level design.
Incentives	Payment for service / capability	Participation in future markets should not be restricted. Enabling provision of reg FCAS is a clear incentive and sends a strong signal to traders.	AEMO notes these comments. Participation in some future markets is likely to require participants to be scheduled. Participation in the Dispatch model will allow distributed resources to meet these eligibility requirements. Further details can be found in Section 5.2.7 of the high-level design.
	Participation requirement	The proposed mandatory participation for "certain non-scheduled generators" should consider that large generators typically run to a schedule whereas customers' consumption of energy of equivalent size is not known in advance. As such, generators and loads of equivalent size should not be treated as having the same scheduling capabilities.	AEMO notes these comments. No mandatory participation has been proposed in the rule change request prepared for the implementation of the Scheduled Lite mechanism.
Compliance	General	Overall agreement with the proposed compliance approach.	AEMO notes these comments.
Constraints	DOE	"We consider the proposed market design should necessarily account for these limits and constraints from the start, rather than integrating DOEs into the second stage."	AEMO notes these comments. Market bodies are coordinating the development of related initiatives to advance this matter. Scheduled Lite will leverage outcomes from ongoing work in these related reforms.
Dispatch	Ramp rates	"The ramp rates for active and reactive power responses for non-registered generating systems and loads should be defined."	The Dispatch model design is based on the principle that Scheduled Bidirectional Unit obligations apply similarly to participants in the Dispatch model. That includes ramp rate obligations. Further detail can be found in section 5.2.4 of the high-level design.

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[5] AEMO, 2022, *Draft Report Review of Power System Data Communication Standard*, at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/review-of-power-system-data-communication-standard/second-stage-submissions/data-communications-standard-consultation---draft-report---final.pdf?la=en

Distributed Energy Resources Market Integration Consultative Forum (MICF) – March 2022

AEMO held a series of workshops to engage with stakeholders via the Distributed Energy Resources Market Integration Consultative Forum (MICF)[6]. The engagement provided valuable feedback on the proposed design of Scheduled Lite.

Key feedback and comments[7] that supported the development of the proposed Scheduled Lite design, along with AEMO's responses, are summarised in tables 5, 6 and 7 below[8].

Table 5 Distributed Energy Resources Market Integration Consultative Forum – Visibility model feedback

Design element	Feedback provided	AEMO response
Participation	Please clarify the value of having a secondary connection point, and what is the value of separating of price responsive resources for the Visibility model?	Participants will not be required to establish a secondary connection point to participate in the Visibility model unless they choose to do so (that is, via flexible trading model 2 if a rule change is made by the Australian Energy Market Commission [AEMC] to enable it; or via flexible trading model 1 which is being implemented as part of the Integrating Energy Storage Systems [IESS] rule change). AEMO is considering a range of models to enable broad participation in the Visibility model and will continue to seek feedback from stakeholders on potential options as the model develops. AEMO expects that the value in separating controllable resources from passive resources is the ability for the participant to more accurately forecast those controllable resources (and in the case of the Dispatch model – to better conform to dispatch instructions); while also not being required to establish baselines. If a participant is able to forecast its consumption and generation at a single connection point (i.e. controllable and passive resources) within a performance tolerance band then AEMO expects this type of participation should be facilitated.
	"How does this deal with the fact that flex assets may not be accessible all of the time, and could switch between non-flex and flex depending on customer preferences?"	The proposed design enables two alternatives for this situation: • On a bottom-up basis - the participant could reflect the change in the forecast information through their indicative bids as appropriate. • At a portfolio level – the proposed operating model would provide the participant with the flexibility to opt-out within operational timeframes, which the participant can utilise as appropriate.
	"Parent/child type arrangements may throw up some commercial challenges with regard to impacts on network charges. Particularly as we see trials of new network tariff structures aimed at price responsive and exporting resources."	Allocation of network charges is a key consideration for the flexible trading arrangements rule change proposal. AEMO has noted a range of options in its high-level design for the AEMC's consideration.
	"Could you clarify: Are you saying that to participate you must be registered as a Market Customer, Integrated Resource Provider (IRP) or Generator? E.g. if you're currently a <5MW, unregistered generator, you'd have to register as a Generator to participate? "	Participants wishing to participate in the Visibility model would need to: • Register (or be registered) as a participant under the National Electricity Rules (NER) Framework according to its eligibility (e.g. as a Market Customer, IRP or Generator). • Register the resource(s) as a LSU (per zone). • Classify connection point(s) within portfolio into a LSU.
	"Would classification of connection point mean it could not be classified for other	AEMO proposes that this new classification 'LSU' be a non-exclusive classification, that is, each connection point can be classified for other purposes.

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[6] Transitioning from AEMO's existing VPP Demonstrations Frequently Asked Questions (FAQ) working group, this aggregator- and retailer-focused forum engages with aggregators, retailers, and stakeholders directly impacting or impacted by DER integration into markets.

[7] Emphasising the feedback received in the last DER MICF workshop on 30 March 2022, where an overview and high-level designs for the Visibility model and the Dispatchability model were presented to DER MICF members.

[8] The tables address the associated comments by Model and Design elements. Please note that some comments were merged with other comments of the same nature, into an overview of feedback comment. Specific comments can be identified by quotation marks.

Design element	Feedback provided	AEMO response
	purposes? E.g. classification as Wholesale Demand Response Unit (WDRU), or ancillary service load/generating unit? Framework appears to only deal with responsiveness to wholesale prices, not provision of other services. Unclear how this interacts with other services and market participant categories.”	
	What is meant by a zonal aggregation?	The model outlined proposes the aggregation of connection points by zone. A ‘zone’ for the purpose of Scheduled Lite has not been defined – however, we expect approach would be consistent with WDR – multiple zones per region reflecting key transmission constraints and consistency with demand forecasting and Projected Assessment of System Adequacy (PASA) processes. It is proposed that the zonal approach to aggregation is supported by a level of automation for registration processes as there could be thousands of connection points within a participant’s zonal aggregation. AEMO is assessing zone definitions as part of the Short Term Projected Assessment of System Adequacy (ST PASA) Replacement Project[A].
	Some stakeholders expressed a preference for a regional aggregation to take into account the relationship between data reliability, compliance and cost.	
Integrating Information into Market Processes	What are the benefits of improving visibility i.e. what are the Consumer Energy Resources (CER)[9] risks if such a model isn't introduced	AEMO expects information relating to price responsive resources will become increasingly important to the accuracy and effectiveness of short-term operations for AEMO, Distribution Network Service Providers (DNSPs) and Market Participants as aggregated portfolios of CER grow in size and as a portion of dispatchable resources across the NEM. While currently relatively small, the ISP forecasts that orchestrated portfolios of distributed resources will grow to over 1 GW by 2025 and over 4 GW by 2030. For AEMO, indicative bid information for price-responsive resources could be incorporated into demand forecasting processes, and in turn, utilised in pre-dispatch, ST PASA as well as operational activities that include interventions for power system security. For market participants, greater transparency of price-responsive resources and more accurate short-term forecasts are likely to aid commitment decision making across the short-term operational horizon. An inability to accurately incorporate price-responsive resources into the NEM short-term operations may result in a need to apply higher network limits, maintain higher security margins across the grid and hold higher operating reserves, and as a consequence such activities would result in higher costs to consumers.
Incentives and Compliance	There would be a cost to the customer and the CER trader associated with participation in the Visibility model. The potential incentives may not be sufficient to warrant participation, and it may be complex to communicate the benefits and participation requirements to customers. Clarity of the compliance arrangements are required so that participants can better assess the merits of participation.	AEMO notes these comments and agrees that the success of the mechanism will be dependent on establishing incentives and value to consumers and balancing these against the costs. This balance will be challenging for the Visibility model as the benefits of participation accrue to the market more generally (more accurate demand and price forecasts) rather than to participant or customer. The key focus areas for the high-level design process include: • **Returns** from market access, including potential provision of existing and future system services, reducing non-energy cost allocation. • **Costs** of telemetry, metering, forecasting and monitoring associated with participation. • **Risks** of market exposure, including civil penalty regimes. • **Opportunities** for and implications of a staged approach to the implementation of Scheduled Lite models. Further consideration is required of the appropriate incentives e.g. AEMO is

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[9] ‘Customer Energy Resources’ are also commonly referred to as ‘Distributed Energy Resources’

Design element	Feedback provided	AEMO response
		assessing the potential of a capability payment type for participation in the model which could apply at times / regions where greater visibility enhances secure power system operation. AEMO will also undertake further engagement with consumer groups to gain insights on Scheduled Lite communication and incentives.

A. See https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project#:~:text=The%20ST%20PASA%20Replacement%20Project,the%20progress%20of%20this%20project.

Table 6 Distributed Energy Resources Market Integration Consultative Forum – Dispatchability model feedback

Design element		Summary of feedback	AEMO response
Element	**Item**		
Participation and registration	Level of aggregation	A zonal aggregation could potentially be costly and complex to implement. Some stakeholders suggested a regional approach and then split to zonal if required.	AEMO recognises feedback from submissions that zonal (rather than regional) aggregation may introduce additional cost and complexity for Scheduled Lite traders. However, enabling regional aggregation for Scheduled Lite would require AEMO to develop a methodology to disaggregate LSU bid information and forecasts to zonal level to align with the new zonal load forecasting approach. This process of 'shoehorning' regional aggregation into zonal load models would introduce error into AEMO's forecasts. Where Scheduled Lite aggregations are large in size, the error introduced through disaggregation could exceed that of normal forecast error managed by AEMO, creating risks to system security.
	Threshold eligibility (e.g. minimum 1 MW size of aggregation for participation)	• Direct link to the level of aggregation that is decided i.e. "It depends on the size of the zones". • To take into account constraint areas (i.e. link to DOE).	
	Participation via Standard Connection Point or Secondary Connection Point	• The benefits/advantages of having a second connection point are unclear. • Participation via standard connection point should be an option.	The ability to establish a second connection point (through either flexible trading models 1 or 2) enables customers to separate their controllable resources and have them managed and recognised independently from their passive load in wholesale settlement, potentially by a separate provider. Whilst this is one potential model for participation in Scheduled Lite, AEMO has proposed optionality, including participation via the standard connection point (where technical requirements can be met).
Data exchange	Data Exchange	"Project EDGE Cost Benefit Analysis (CBA) is considering Data hub costs, will that analysis feed into this process?"	Project EDGE will continue to inform the Scheduled Lite design, rule development and eventual implementation.
Dispatch	Bid granularity	• Direct link to the level of aggregation. • Benefits definitely do not stack up at a small scale. • To consider NEMDE capabilities on managing large number of DUIDs and the associated cost of doing so • To consider consistency.	AEMO notes these comments to reinforce the ongoing work in defining zones, in order to ensure consistency between the different elements of the Dispatch model; i.e. the level of aggregation and threshold eligibility. (See answer Dispatchability model> Participation and Registration>level of aggregation)
Incentives and compliance	Incentives and Compliance	• Participation in future markets is not an immediate incentive. • Enabling participation in Regulation FCAS markets is potentially a valuable incentive.	AEMO takes note of these comments as part of ongoing work to assess/identify/ apply potential incentives to participants wishing to take part in the Dispatch model.

Design element		Summary of feedback	AEMO response
Element	**Item**		
		• Please clarify potential avoidance of RERT costs. • It may be challenging to settle benefits that accrue to a CER trader operating at a secondary connection point.	
		Please clarify who is going to undertake compliance.	AEMO expects that compliance with dispatch instructions will be monitored by the AER. However, further consideration of appropriate compliance arrangements is required – for instance, a participant may be compliant if it meets a certain performance threshold specific to LSUs.

Table 7 Distributed Energy Resources Market Integration Consultative Forum – opt-in arrangement and other considerations

Design element	Feedback overview	AEMO response
Operating model – opt-in arrangement	• As a voluntary scheme, opt-in/opt-out is essential. • Please give further consideration to the potential for a CER trader to switch between the Visibility model and Dispatchability model. • To consider the opt-in arrangement as an approach to addressing portfolio scale issues.	AEMO notes these comments. The opt-in arrangement has been updated, see Section 4.2.7 and Section 5.2.9 of the high-level design.
Other considerations	"The IEC Systems Committee on Smart Energy currently has two new pieces of work to look at Market Architecture including VPPs and bidding of DER."	AEMO notes this comment and will review the IEC work to guide future development of the Scheduled Lite models.

Appendix B.3
Use Cases

January 2023

Appendix to the Scheduled Lite:
High Level Design

Important notice

Purpose

This is Appendix B.3 to Scheduled Lite: High Level Design

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B3.1 Introduction

This section describes examples of use cases for each Scheduled Lite model. Each use case first describes the context of the trader in Scheduled Lite, including their main characteristics and scenario features that highlight any special events, measures or considerations that would influence performance. The expected treatment for each design element of the model for that scenario is then summarised in a table.

B3.2 Visibility model – use case examples

B3.2.1 Use case – CER aggregation response to energy spot prices

This use case is based on the participation of an aggregation of CER demand response in the Visibility model.[1]

Trader profile

ABC Energy is a retailer with a portfolio of large C&I customers. The portfolio includes shopping centres, factories, and processing facilities. The retailer contracts with its customers allow it to call on a reduction in demand (within limits relating to time of year, time of day, duration and frequency). The total demand response capacity of the portfolio is 20 MW across electrical equipment that can be controlled by the retailer.

Scenario features

Working assumptions

- ABC Energy has registered a light scheduling unit (LSU) in the Visibility model. ABC Energy classifies the (subset of) NMIs with demand response into the LSU.

Business model

- To maximise value and optimise device efficiency:
  - Intention of reducing 20MW of demand when the spot market price is equal or exceeds $1,000/MWh during a specific period of time.
  - Customer’s contract restricts consumption reduction to a maximum of 4 hours, before returning to average consumption regardless of spot prices.
  - The only incremental effort for ABC Energy to participate in the Visibility model is to share information on its market intentions with AEMO.

Weather conditions

- Demand ratings are for summer.

Design elements description

Table 1 summarises the expected treatment of ABC Energy participating in the Scheduled Lite Visibility model.

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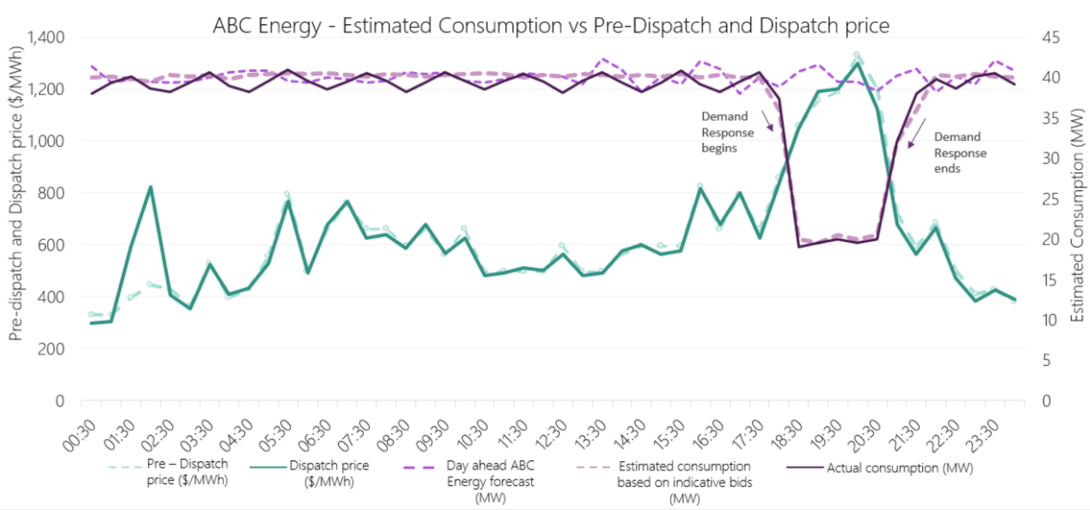
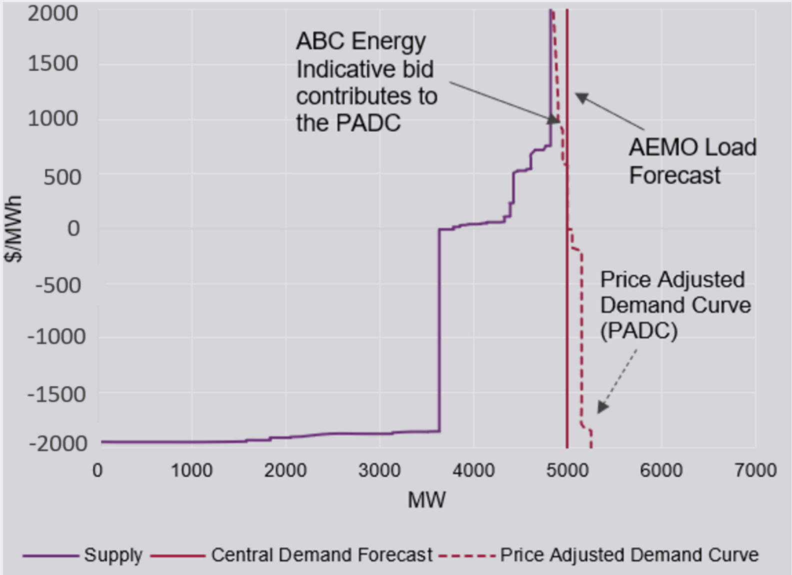
[1] Customer Energy Resources (CER) are also commonly referred to as ‘Distributed Energy Resources’ or ‘DER’.

Table 1 Visibility model use case – CER aggregation response to energy spot prices

Design element	Description
Registration	ABC Energy: • Is already registered in the NEM as a Market Customer and obtains a DUID for its LSU. • Is able to manage its LSU via AEMO's portfolio management functions, e.g. classify/declassify NMIs for each LSU.
Data exchange/ telemetry	ABC Energy exchanges data via AEMO's API.
Data types	ABC Energy submits the following data for the LSU: • Real-time information every 5 minutes with at least 5-minute granularity. • Forecast of capacity over a multi-day horizon. For ABC Energy this forecast would be aggregate forecast of all the resources in the LSU. • Indicative bids within pre-dispatch timeframes: reflecting ABC Energy's consumption intentions based on its business model (e.g. reflecting intentions to reduce consumption when prices exceed $1,000/MWh).
Operations	AEMO utilises the information provided by ABC Energy as follows: • Indicative bid information is incorporated, alongside that of other traders, into an adjusted demand curve. • The pre-dispatch process determines the forecast demand for LSUs based on the prevailing conditions, demand and bids for all resources. • This price adjusted demand curve is published to the market and a private schedule is provided to ABC Energy. **Figure 1 ABC Energy estimated consumption – pre-dispatch and dispatch price**  Figure 2 shows a 'zoomed in' view of the price adjusted demand curve for one 30-minute interval, representing the first 5-minute interval of energy spot prices at $300/MWh. ABC Energy's information (i.e. indicative bid) contributes to the price adjusted demand curve along with other LSUs, meaning that ABC Energy's information will not be disclosed to the market; rather it would provide insights to the market in aggregate.

Design element	Description
	Figure 2 Price-adjusted demand curve (PADC) 
Compliance	ABC Energy meets performance thresholds over the assessment period, therefore accessing relevant incentives.
Incentives	• ABC Energy utilises the pre-dispatch schedule as an input to its business decision-making tools. • If ABC Energy provides visibility service, ABC Energy obtains visibility service payment.
Expected market outcomes: ABC Energy's ability to coordinate price responsive resources to reduce energy usage may assist in the management of peak demand by flattening late afternoon-evening peaks. Through participating in the Visibility model, ABC Energy provides AEMO with enhanced awareness of its flexibility and price responsive intentions, supporting the accuracy of load and price forecasting. At a system level, this could benefit energy consumers through reduced system costs due to efficient system operation. ABC Energy is also able to utilise the pre-dispatch schedule to support efficient operation of its portfolio.	

B3.2.2 Use case – IRP (small resource aggregator)

This use case explores participation in the Visibility model by an IRP (small resource aggregator), which aggregates and trades the generation output of (exempt) small generating units in the spot market[2]. At present, AEMO does not have operational awareness of the price-responsive intentions of these small generating units[3] and thus they cannot be accurately reflected in demand forecasts. The Visibility model would address this by obtaining forecasts and indicative bids from the trader, providing greater awareness of its intended behaviour and incorporating this information to enhance demand forecasting and improve market efficiency.

Trader profile

- The trader, SRA Inc., is registered as an IRP (small resource aggregator) and has classified three exempt small generating units at its market connection points for the purpose of aggregating and selling the output into the spot market.

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[2] The IESS rule change folds the 'Small Generation Aggregator' category into the 'IRP' under the Small Resource Aggregator label. For an overview of SGAs, see: AEMO, 2021. *SGA Factsheet*, at https://aemo.com.au/-/media/files/electricity/nem/participant_information/registration/small-generation-aggregator/small-generator-aggregator-fact-sheet.pdf?la=en.

[3] Generating units <30 MW which AEMO has exempted from the requirement to register as a Generator.

- Its 25 MW portfolio of resources, which have a primary purpose to provide back-up generation to waste facilities, include two 10 MW gas-powered back-up generators and one 5 MW diesel back-up generator—all of which AEMO has exempted from the requirement to register as a Generator. All the small generating units have been established on separate connection points in accordance with flexible trader model 1 arrangements, and do not contain any retail load. All the generating units are located in the same zone.
- The trader has a contract with the waste facilities enabling it to sell the output of the generating units (through their separate connection points) into the spot market when the spot price exceeds $500/MWh and the generators are not required to provide back-up generation (for example, during a local network outage). The small generating units do not otherwise inject to the grid.
- The retail load connection points of the waste facilities are managed through separate retail contracts and are not spot price exposed (SRA Inc. is not an authorised retailer and is not the financially responsible Market Participant for any retail load).

Scenario features

Working assumptions

- SRA Inc. is registered with AEMO as an IRP (Small Resource Aggregator) and has classified the connection points that connect the small generating units in its portfolio as its market connection points.

Business model

- SRA Inc. aggregates small generating units and trades their output in the spot market when prices are high.
- Its contract with its customers enables it to sell generation from its connection points into the spot market when prices exceed $500/MWh and when the resources are not required for back-up supply.

Market scenario

- Spot prices exceed $500/MWh for a short period of time due to weather conditions impacting available generation in the NEM. There is no current requirement for the generating units to provide back-up generation to the waste facilities.

Design elements description

Table 2 summarises the expected participation of SRA Inc.'s portfolio participating in the Scheduled Lite Visibility model.

Table 2 Visibility model use case – participation of back-up generation via IRP (small resource aggregator)

Design element	Description
Registration	SRA Inc. is registered as an IRP (Small Resource Aggregator) and has classified its connection points into an LSU in the Visibility model. The trader is able to manage its LSU via AEMO's portfolio management functions, e.g. identify NMI as unavailable due to operational issues.
Data exchange/telemetry	SRA Inc. transfers LSU data via AEMO's designated API.
Data types	SRA Inc. submits the following data for its LSU: • Real-time information every 5 minutes with at least 5 minute granularity. • Forecast of capacity over a multi-day horizon. For SRA Inc. this forecast would be aggregate forecast of all the resources in its portfolio. • Indicative bids within pre-dispatch timeframes, reflecting generation intentions at different price points based on its business model (e.g. to sell output when prices exceed $500/MWh subject to operational restrictions).
Operations	AEMO utilises the information provided by the trader as follows: • Indicative bid information is incorporated, alongside that of other traders, into a price adjusted demand curve. This improves the accuracy of AEMO's load forecasts. • The pre-dispatch process determines the forecast demand for the LSU based on the prevailing conditions, demand and bids for all resources. • This price-adjusted demand curve is published to the market and a private schedule is provided to SRA Inc.

Design element	Description
Compliance	SRA Inc. meets performance thresholds over the assessment period, therefore accessing relevant incentives.
Incentives	• SRA Inc. utilises the pre-dispatch schedule as an input to its business decision-making tools. • If SRA Inc. provides visibility service, they obtain the visibility service payment.
Expected market outcomes: SRA Inc.'s ability to provide additional supply to the market when it is most valued (e.g. during peak demand or when available supply is low) supports efficient and reliable market operation. Through participation in the Visibility model, SRA Inc. provides AEMO with enhanced awareness of its flexibility and price responsive intentions, supporting the accuracy of the scheduling process. At a system level, this could benefit energy consumers through more efficient operational decisions and support reduced system costs for all consumers. SRA Inc. is also able to utilise the pre-dispatch schedule to support efficient operation of its portfolio.	

Alternative scenarios

As large users, the waste facilities in this use case could enter a spot price pass through contract and utilise their demand flexibility to reduce their consumption, or utilise on-site generation to offset their consumption, in response to high wholesale prices to reduce operating expenditure. These facilities could participate in Scheduled Lite directly (if they register as a market participant with AEMO) or via a trader to provide forecasts and indicative bids of their intended price responsive behaviour. By participating in the Visibility model, the participant would be able to accrue incentives such as receiving pre-dispatch schedules, which could support their operations, and potentially access visibility service payments.

B3.2.3 Use case – non-scheduled generator response to energy spot prices

This use case is based on the participation of a non-scheduled generator in the Visibility model.

Trader profile

CK Solar Farm is a 15 MW non-scheduled generating system.

Scenario features

Working assumptions

- CK Solar Farm complies with all relevant requirements (e.g. applicable performance standards) and therefore its registration application will be approved.

Business model

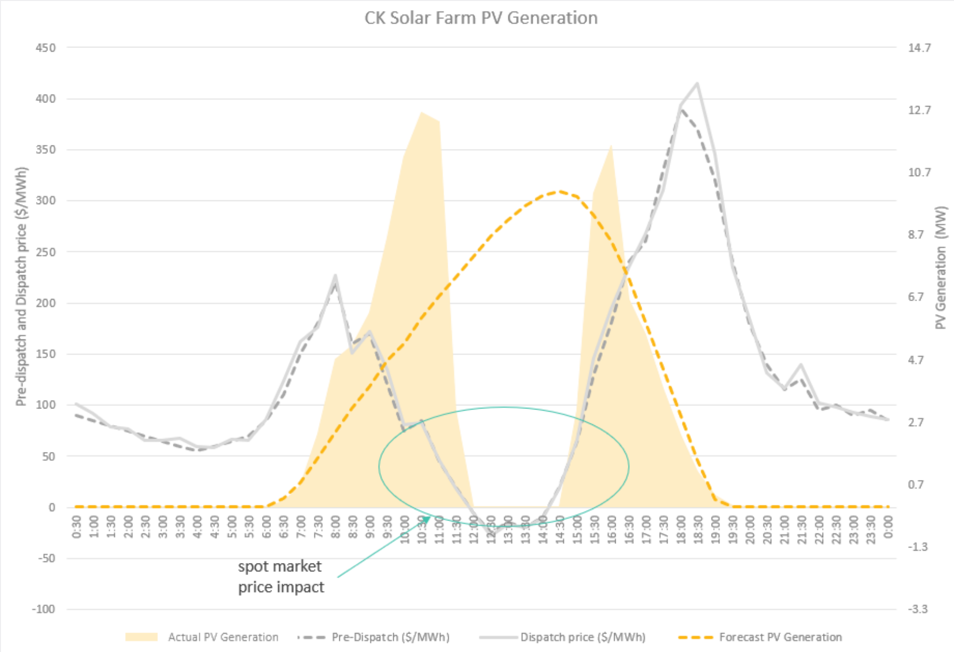
- To maximise profits.

Market scenario

- Negative spot market price.
- Scheduling and dispatch errors reach a threshold where AEMO decides to open a tender process to procure visibility to improve operational awareness.

Table 3 Visibility model use case – non-scheduled generator response to energy spot prices

Design element	Description
Registration	CK Solar Farm: • Registers as an IRP[A]. • Classifies non-scheduled generating unit NMI as an LSU in Visibility mode. • Is able to manage its LSU via AEMO's portfolio management functions, e.g. identify NMI as unavailable due to operational issues.

Design element	Description
Data exchange/telemetry	- CK Solar Farm transfers LSU data via AEMO's designated API.
Data Types	- CK Solar Farm submits the following data: – Real-time information every 5 minutes. – Indicative bids within pre-dispatch timeframes, reflecting its business intentions. – Forecast of capacity over a multi-day horizon. - Information submitted by CK Solar Farm would then be interpreted and utilised by AEMO as described in the Operations section below.
Operations	AEMO interprets information provided by CK Solar Farm as follows (see Figure 33): - Forecast information showing expected generation of the PV system, with real time information provided every 5 minutes. - Indicative bids reflecting CK Solar Farm's response to energy spot prices. It is expected that CK Solar Farm will turn off generation until spot prices increase to a positive value. - Real-time information showing CK Solar Farm is price responding i.e. turning off generation due to energy spot prices being negative. **Figure 3 CK Solar Farm PV generation**  AEMO utilises the information provided by CK Solar Farm as follows: 1. Indicative bid information is aggregated to the regional level and is used to produce an adjusted demand curve based on the pre-dispatch schedule. This price-adjusted demand curve is published to the market. 2. The forecast by CK Solar Farm is utilised in load forecasting with the intent to improve the accuracy of AEMO load forecasts. 3. AEMO is able to determine when CK Solar Farm is diverging from its forecast with the use of real time information, providing AEMO with improved operational awareness. e.g. enhancement of power system visibility as CK Solar Farm data shows its response to negative spot market price in accordance with its business model.
Compliance	CK Solar Farm meets performance thresholds, therefore accesses incentives.
Incentives	- CK Solar Farm utilises as an input to its business decision tools the price adjusted demand curve and pre-dispatch schedules provided by AEMO e.g. CK Solar Farm manages operations more cost-effectively. - If CK Solar Farm provides visibility service, CK Solar Farm obtains visibility service payment.

Design element	Description
Expected market outcomes: CK Solar Farm's participation in the Visibility model e.g. by providing its generation data and indicating its intention to switch off during negative prices, assists in reducing demand forecast errors associated with increased variability from growth in weather-dependant generation. Awareness of CK Solar farm's switch off action intention in response to market prices, rather than a disconnection-reaction to a disturbance/failure, enables AEMO to enhance operational planning for the afternoon period, when low reserve conditions and high prices are expected. This could potentially result in lower system services costs, benefiting all consumers.	

A. Could also be registered as a Generator.

B3.2.4 Simple Visibility model: retailer with a portfolio of small businesses with price-responsive resources

This use case is based on Retailer 'Libro Energy' participating in the Simple Visibility model[4].

Trader profile

'Libro Energy' is a retailer with a portfolio of commercial and industrial customers. Each commercial and industrial facility has price-responsive resources that can be controlled on-site. Libro Energy does not have direct control of these resources, but rather works with its customers to control these resources based on price expectations.

Scenario features

Working assumptions

- Libro Energy registers an LSU.
  - Libro Energy registers that it is operating in the Simple Visibility model.
  - Libro Energy classifies the (subset of) NMIs with price responsive resources into the LSU.

Business model

- **To avoid high prices.**
  - Intention is to have customers reduce consumption when prices exceed $10,000/MWh.
- **Customer's contract:**
  - Includes consumption guidance (e.g. cost efficient). Tailored to the consumption profile of the small business, Libro Energy provides:
    - A 'special rate' to the customer when they engage in consumption shifting.
    - Time periods where Libro Energy may request consumption shifting action[5] (i.e. time period and consumption shifting capacity).
    - Libro Energy to contact customers when a consumption shifting action is required.
    - Other applicable tailored requirements e.g. no shifting action on the weekend.
- The only incremental effort for Libro Energy to participate in the Simple Visibility model is to share information on its market intentions with AEMO.

Design elements description

Table 4 below provides an overview of the expected treatment of Libro Energy participating in the Scheduled Lite Simple Visibility model. The table also provides a comparison to the Visibility model.

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[4] Further detail can be found in section 4.2.2 of the Final version of the High-Level Design.

[5] Libro Energy develops a consumption profile for each small business in the portfolio and identifies for each small business a 'consumption shifting' profile based on wholesale electricity prices

Table 4 Simple Visibility model: retailer with a portfolio of small businesses with price responsive resources

Design element	Simple Visibility model	Comparison to Visibility model
	Description	**Description**
Registration	Libro Energy: • Is already registered in the NEM as a Market Customer and obtains a DUID for its LSU. • Is able to manage its LSU via AEMO's portfolio management functions, e.g. classify/declassify NMIs.	Same process.
Data Exchange / Telemetry	• Libro Energy exchanges data via web portal.	• Libro Energy exchanges data via AEMO's API.
Data Types	Libro Energy submits the following data for the LSU: • Actual data provided as part of regular energy settlement process. • Profile for availability of all the resources in the portfolio (i.e. in aggregate) provided once a month. • Data to be introduced in the 'indicative field': – Reflect intention to reduce a range of capacity (in aggregate) when the spot market price exceeds $10,000/MWh. – Update once per week or when required.	Libro Energy submits the following data for the Visibility Unit:: • Real time information: every 5 minutes with at least 5 minute granularity. • Forecast of capacity over a multi-day horizon. For Libro Energy this forecast would be an aggregate forecast of all the resources in the portfolio. • Indicative bids within pre-dispatch timeframes: reflecting Libro Energy's consumption intentions based on its business model (e.g. reflecting intentions to reduce consumption when prices exceed $10,000/MWh).
Operations	AEMO utilises the information provided by Libro Energy as follows: • Indicative field information is incorporated, alongside that of other traders operating in the Simple Visibility model, into an enhancement data treatment that would support operational forecast processes	AEMO utilises the information provided by Libro Energy as follows: • Indicative bid information is incorporated, alongside that of other traders, into an adjusted demand curve • The pre-dispatch process determines the forecast demand for Visibility LSUs based on the prevailing conditions, demand and bids for all resources • This price adjusted demand curve is published to the market and a private schedule is provided to Libro Energy
Compliance	Libro Energy meets 'Simple Model' performance thresholds over the assessment period, including: • Monthly profile for availability accuracy: an allowable variation between the actual consumption or generation and the indicative field provided by Libro Energy over a rolling period. • Consistency of provision of metering data. Libro Energy access relevant incentives.	Libro Energy meets 'Normal Mode' performance thresholds over the assessment period, including: • Forecast accuracy: an allowable variation between the actual consumption or generation and the indicative bid provided by Libro Energy over a rolling period. • Consistency of provision of real-time information. Libro Energy access relevant incentives.
Incentives	• If Libro Energy provides Visibility service, Libro Energy obtains 'Simple Visibility service payment'.	• Libro Energy utilises the pre-dispatch schedule as an input to its business decision-making tools. • If Libro Energy provides Visibility service, Libro Energy obtains 'Visibility service payment'.

Expected market outcomes:

Libro Energy's ability to coordinate price responsive resources to reduce energy usage (i.e. reducing electricity demand in response to a price signal), may assist in the management of peak demand by flattening late afternoon-evening peaks. Through participating in the Simple Visibility Model, Libro Energy provides AEMO with enhanced awareness of its flexibility and price responsive intentions, supporting the accuracy of load and price forecasting. At a system level, this could benefit energy consumers through reduced system costs due to efficient system operation.

B3.3 Dispatch model

B3.3.1 Use case – CER aggregation by a retailer via standard connection point participating in energy

This use case is based on the participation of a retailer, 'Ralph Energy', which participates via aggregated standard end user connection points in the Dispatch model.

Participation profile

Ralph Energy chooses to participate in the Dispatch model via standard connection point arrangements, meaning Ralph Energy is responsible for all resources (passive and controllable) behind the meter at each participating site. Ralph Energy has an aggregated portfolio of 1,200 households, which have behind-the-meter batteries with an aggregated capacity of 12 MW/15.5 MWh. Ralph Energy has an agreement with its customers to control the batteries.

When bidding and receiving dispatch targets, Ralph Energy will have to take into account the passive household load connected at the connection point.

Scenario features

Working assumptions

- Ralph Energy complies with all relevant requirements (e.g. applicable performance standards, minimum aggregated portfolio threshold[6]) and therefore its registration application will be approved.

Business model

- Maximising value of controllable resources by participating in energy dispatch.

Market scenario

- Batteries are in a neutral state of charge and have capacity to either discharge or charge at an aggregated rate of 10 MW in the next interval.
- 2 MW of the battery capacity is reserved to smooth out the passive load and manage unexpected changes to customers' load.
- Energy spot price spikes suddenly.

Design elements description

Table 5 summarises the expected treatment of Ralph Energy participating in the Scheduled Lite Dispatch model.

Table 5 Dispatch model use case – CER aggregation by a retailer via standard connection point participating in energy

Design element	Description
Registration	Ralph Energy: • Is already registered as a Market Customer[A]. • Classifies end user standard connection points into an LSU according to zone specifications. • Obtains a DUID per LSU. Ralph Energy would be able to manage its LSU via AEMO's portfolio management functions, e.g. classify/declassify NMIs.
Data exchange/telemetry	Ralph Energy: • Transfers real-time data for its LSU via SCADA for CER.

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[6] Subject to zone requirements, see Section 2.1 of High Level Design**Error! Reference source not found.**

<table>
<tr><th>Design element</th><th>Description</th></tr>
<tr><td></td><td>Submits bids via Market Portal.</td></tr>
<tr><td>Constraints</td><td>Ralph Energy adheres to Flexible Export Limits (FELs)[7] / local network services when bidding / supplying energy.</td></tr>
<tr><td>Bids</td><td><p>Ralph Energy reserves battery capacity of 2MW to smooth out the passive load and manage unexpected changes to customers' load. Ralph Energy reflects this in its bids, to ensure they will be able to comply with a dispatch instruction in aggregate.</p>
<p>Table 6 below contains Ralph Energy's intended use of the remaining 10 MW of the batteries, relative to market price.</p>
<p>Table 6 Ralph Energy intentions</p>
<table>
<tr><th>Market price range ($/MWh)</th><th>Ralph Energy intention</th></tr>
<tr><td>Negative prices</td><td>To charge batteries
Intention: Bids -10 MW</td></tr>
<tr><td>0 to 300</td><td>No battery action
Intention: Bids 0 MW</td></tr>
<tr><td>Above 300</td><td>To discharge batteries
Intention: Bids 10 MW</td></tr>
</table>
<p>Ralph Energy must reflect its intentions in its bid file.</p>
<p>Note: Detail on the bid structure will be developed in the implementation stage. It is expected this will reflect the controllable capacity, the passive forecast, and take into account any requirements for the controllable capacity to meet the passive forecast.</p></td></tr>
<tr><td>Dispatch Process</td><td><p>AEMO receives bids and uses NEMDE to determine the energy dispatch and issues a single bi-directional dispatch instruction.</p>
<p>As the energy price spikes suddenly to $3000/MWh, AEMO will issue a dispatch instruction to the LSU to generate 10 MW. This dispatch target reflects the generation the market will see from the aggregation once the passive load has been taken into account.</p>
<p>Ralph Energy receives a single bi-directional dispatch instruction against its DUID.</p>
<p>Ralph Energy disaggregates the dispatch instruction amongst the connection points in its LSU and controls all batteries to discharge.</p></td></tr>
<tr><td>Operations</td><td>Ralph Energy submits PASA availability for its LSU for future intervals
Ralph Energy price and quantity bids reflect availability for its LSU for future intervals</td></tr>
<tr><td>Compliance</td><td>Ralph Energy follows and complies with dispatch instructions, meeting performance thresholds</td></tr>
<tr><td>Incentives</td><td>Ralph Energy receives payment for energy generated</td></tr>
</table>

A. Ralph Energy could also choose to register as an IRP.

B3.3.2 Use case – CER aggregation by a CER trader via secondary connection point participating in energy and contingency FCAS

This use case is based on the participation of a CER trader, 'Botero Energy', in the Dispatch model via secondary connection point, which is enabled by flexible trader model 2[8]. Flexible trader model 2 allows unbundling of controllable resources through establishment of a secondary NMI within the customer's electrical installation. The resources associated with the secondary NMI are treated separately from the customer's passive resources for the purpose of wholesale settlement.

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[7] 'Flexible export limits' or 'FELs' are also commonly referred to as 'dynamic operating envelopes' or 'DOEs'

[8] Note flexible trader model 2 arrangements are subject to the AEMC consultation paper, AEMC, 2022, *National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule*, at: https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading.

Participation profile

Botero Energy has an aggregated CER portfolio of secondary connection points at 500 households with price responsive resources. The portfolio is comprised of 500 behind-the-meter batteries with an aggregated capacity of 5 MW.

Working assumptions

- Botero Energy complies with all relevant requirements (e.g. applicable performance standards, minimum aggregated portfolio threshold) and therefore its registration application will be approved.

Business Model

- Maximising value of controllable resources by participating in energy and contingency FCAS.

Market scenario

- Batteries are fully charged.

Design elements description

Table 7 summarises the expected treatment of Botero Energy participating in the Scheduled Lite Dispatch model.

Table 7 Dispatch model use case – CER aggregation by a CER trader via secondary connection point participating in energy and contingency FCAS

Design element	Description
Registration	Botero Energy: • Registers as IRP. • Classifies end user secondary NMIs into an LSU according to zone specifications. • Obtains a DUID per LSU. Botero Energy would be able to manage its LSU via AEMO's portfolio management functions, e.g. classify/declassify NMIs.
Data exchange/telemetry	Botero Energy: • Transfers real-time data for its LSU via SCADA for CER. • Submits bids via Market Portal.
Constraints	Botero Energy adheres to FELs / local network services when bidding / supplying energy, ancillary services.
Bids	Botero Energy will reflect through its bids that the LSU only has the capacity to generate (discharge batteries). This capacity would need to be split across energy and FCAS through its trapezium. • Energy bids reflect how much Botero Energy is willing to generate across its portfolio against market prices. • FCAS bids reflect Botero Energy's intention to provide Contingency FCAS raise for a slightly lower price, reflecting that is an enablement. Note: Detail on the bid structure will be developed in the implementation stage.
Dispatch process	AEMO receives bids, uses NEMDE to co-optimise between Energy and FCAS, ensuring that the LSU can reserve the required headroom if enabled for FCAS and does not over dispatch. AEMO issues dispatch instructions to the LSU to generate 2 MW and provide FCAS Contingency Raise of 3 MW. Botero Energy receives a single bi-directional dispatch instruction against its DUID, obtaining enablement for FCAS contingency provision Botero Energy disaggregates the dispatch instruction amongst its LSU
Operations	• Botero Energy submits PASA availability for its LSU for future intervals. • Botero Energy price and quantity bids reflect availability for its LSU for future intervals.
Compliance	Botero Energy: • Follows and complies with dispatch instructions. • Meets performance thresholds, including but not limited to, ensuring compliance with the MASS (i.e. maintaining the appropriate headroom that would enable delivery of FCAS contingency raise)
Incentives	Botero Energy receives payment for energy generated and for provision of FCAS Contingency Raise.

Alternative pathways for participation

- Opt-in arrangement: as a result of different factors, such as an unexpected communication fault, Botero Energy is unable to comply with performance thresholds (for example, to follow a dispatch instruction) and therefore decides to opt-out of the mechanism until capabilities return to normal. Consequently, Botero Energy performs as a Visibility LSU, submitting indicative bids, reflecting the intention of withdrawal/injection based on market price, without the requirement of following a dispatch instruction.
- Capacity threshold considerations: aggregations with a capacity less than 5 MW could choose to participate in the Visibility model where they would provide indicative bids – reflecting the intention of withdrawal/injection based on market price whilst it grows in size and refines capabilities, graduating from the Visibility model to the Dispatch model. As a Visibility trader, the participant will receive pre-dispatch schedules that they could use to mature their operations.

B3.3.3 Use case – IRP (small resource aggregator)

This use case outlines a 'Dispatch model' version of the scenario outlined in Section B3.2.2; that is, an IRP (small resource aggregator – SRA Inc.) with a 25 MW portfolio of small generating units which have a primary purpose to provide back-up supply to waste facilities. Participation in the Dispatch model would require SRA Inc. to establish more sophisticated operational capabilities relative to the Visibility model, including the ability to receive and conform to dispatch instructions. However, it would also provide an avenue for SRA Inc to deploy its portfolio to participate in new market services such as Regulation FCAS.

Trader profile

See Section B3.2.2. In this use case, SRA Inc.'s portfolio is willing to inject 15 MW at $300/MWh and its full capacity (25 MW) at $500/MWh, when the small generating units in its portfolio are not required for back-up supply (i.e. there is no local supply outage).

Scenario features

Working assumptions

- SRA Inc. is registered with AEMO as an IRP (Small Resource Aggregator) and has classified the connection points that connect the small generating units in its portfolio as its market connection points.
- SRA Inc.'s portfolio exceeds the proposed 5 MW minimum threshold for participation in the Dispatch model.

Business model

- SRA Inc. aggregates small generating units and trades their output in the spot market when prices are high.
- Its contract with its customers enables it to sell generation from its connection points into the spot market when prices exceed $300/MWh (15 MW) and $500/MWh (25 MW) and when the resources are not required for back-up supply.

Market scenario

- Spot prices exceed $500/MWh for a short period of time due to weather conditions impacting available generation in the NEM. There is no current requirement for the generating units to provide back-up generation to the waste facilities.

Design elements description

Table 8 summarises participation of SRA Inc. in the Scheduled Lite Dispatch model.

Table 8 Dispatch model use case – participation of back-up generation via IRP (small resource aggregator)

<table>
<tr><th>Design element</th><th>Description</th></tr>
<tr><td>Registration</td><td>SRA Inc. is registered as an IRP (Small Resource Aggregator) and has classified its small generating units into an LSU in the relevant zone. The trader is able to manage its LSU via AEMO’s portfolio management functions, e.g. classify/declassify NMIs.</td></tr>
<tr><td>Data exchange/telemetry</td><td>The trader:
• Transfers real time data for its LSU via SCADA for CER.
• Submits bids via Market Portal.</td></tr>
<tr><td>Constraints</td><td>• The trader adheres to FELs / local network services when bidding and supplying energy.</td></tr>
<tr><td>Bids</td><td>The trader submits bids in accordance with its price-responsive intentions.
Table 9 Summary of SRA Inc.’s bidding
<table>
<tr><th>Market price range ($/MWh)</th><th>Trader’s bids (cumulative)</th></tr>
<tr><td>Negative prices</td><td>Bids 0 MW</td></tr>
<tr><td>0 to 300</td><td>Bids 0 MW</td></tr>
<tr><td>300 to 500</td><td>Bids 15 MW</td></tr>
<tr><td>Over 500</td><td>Bids 25 MW</td></tr>
</table>
Note: Detail on the bid structure will be developed in the implementation stage.</td></tr>
<tr><td>Dispatch Process</td><td>AEMO receives bids and uses NEMDE to determine the energy dispatch and issues a single dispatch instruction.
As the energy price increases to $500/MWh, AEMO will issue a dispatch instruction to the LSU to generate 25 MW.
SRA Inc. receives a single dispatch instruction against its DUID.
SRA Inc. disaggregates the dispatch instruction amongst the LSU and generates in accordance with its bid.</td></tr>
<tr><td>Operations</td><td>• SRA Inc. submits PASA availability for its LSU for future intervals.
• SRA Inc.’s price and quantity bids reflect availability for its LSU for future intervals.</td></tr>
<tr><td>Compliance</td><td>• SRA Inc. follows and complies with dispatch instructions, meeting performance thresholds.</td></tr>
<tr><td>Incentives</td><td>SRA Inc. receives payment for energy generated.</td></tr>
</table>

Alternative scenarios

- The proposed opt-in arrangements in the Scheduled Lite design would enable SRA Inc. to opt out of the Dispatch model where, for example, its resources are required by the waste facilities for an extended period to manage local supply issues or where it considers it is not able to fulfill the obligations of participation in the Dispatch model.
- As a result of the recent IESS rule change, SRA Inc. could potentially participate in ancillary service markets with its portfolio in addition to energy (i.e. where it complies with relevant requirements including the MASS) and is also able to aggregate small bidirectional units in addition to small generating units. Where it provides FCAS, this would be co-optimised with energy using NEMDE.

Appendix C Mapping of Proposed Rule Amendments

January 2023

Appendix to the Scheduled Lite
Rule Change Request

Important notice

Purpose

This is Appendix C to Scheduled Lite Rule Change Request.

Disclaimer

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C Mapping of proposed rule amendments

This Appendix C to AEMO's *Scheduled Lite Rule Change Request* provides detailed mapping of the proposed rule amendments (see Section 6 of the Rule Change Proposal), against the relevant elements of the Scheduled Lite High-Level Design (Appendix B).

Table 1 provides a high-level description of how the proposed rule amendments seek to enable the design elements contained in the High-Level Design. In the event of an inconsistency with the rule change request, the rule change request should take precedence. This table is also not intended to provide a complete assessment of all consequential Rules amendments required to implement Scheduled Lite.

Table 1 Scheduled Lite high-level design and proposed rule amendments mapping

Scheduled Lite High-Level Design			Proposed rule amendments			
Design Element	**Area**	**Sub area**	**Chapter/ Rule/ Clause**	**Description of Rules clause**	**Type of Amendment**	**Description**
3. Participation	Classification	Light Scheduling Unit (LSU)	Chapter 2	Classification of generating units and bidirectional units	New Clause	A new resource classification is proposed to represent the participation of price responsive distributed resources in market systems. AEMO proposes to establish a new clause to accommodate the proposed new classification, the light scheduling unit (LSU). AEMO proposes that the new LSU classification references two alternative modes of participation (Visibility mode and Dispatch mode). Refer to Section 6.1.1 (NER Chapter 2: Registered Participants and Classification) of the Rule Change Proposal for further details.
			Chapter 3	Light Scheduling Unit Guideline	New Clause	The proposed Light Scheduling Unit Guideline will contain the operational requirements for an LSU (the new classification). Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Establishing LSU operation) of the Rule Change Proposal for further details.
			2.1A	Obligation to register (non-network categories)	Amendment	May require amendments to reflect the obligation to be a registered Market Participant in order to classify a unit as an LSU
			2.3	Connection point and connected plant classifications	Amendment	May require amendments to specify that a connection point can be classified as a LSU
			2.12	Interpretation of references to various entities	Amendment	May require amendments to include a reference to LSU

Scheduled Lite High-Level Design			Proposed rule amendments			
			3.7F	Generation information page	Amendment	May require amendments to include LSU. AEMO proposes that the generation information page includes LSUs on the basis that: •AEMO will publish updates as frequently as is reasonably practicable •the information will be published at zonal level, consistent with the proposed zonal aggregation guideline.
	Zonal Aggregation		Chapter 3	Zonal Aggregation Guideline	New Clause	The rule needs to accommodate participation of price responsive resources in aggregation. AEMO proposes a new clause to enable this, including providing for AEMO to establish a Zonal Aggregation Guideline. The enablement of participation in aggregation is required as: •economies of scale associated with participation will drive the need to aggregate in order to deliver value. •the proposed minimum participation threshold (of 5MW) to operate in Dispatch mode, would require most distributed resources to participate in aggregate. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Zonal Aggregation) of the Rule Change Proposal for further details.
	Minimum Threshold	Dispatch Mode	NA			This will be contained in the proposed Light Scheduling Unit Guideline. The Guideline will establish the operational requirements to classify an LSU in Dispatch mode, which provides for a threshold nameplate rating or combined nameplate rating of 5 MW or greater.
	Portfolio Management		NA			To be addressed in the associated procedures rather than in the rule. Procedures to include guidance on portfolio self-management functions, including: •Application for initial establishment of new LSUs •Management of existing LSUs •Customer churn between existing LSUs •Self-hibernation (or long-term opt-out) for existing LSUs •AEMO validation processes •Review and confirmation of new unit configuration following changes.
4. Visibility Mode	4.2.3 Data Exchange		NA			Data Exchange will be facilitated by the power system data communication standard
	4.2.2 Data Types		NA			This will be contained in the proposed Light Scheduling Unit Guideline. The Guideline will describe the Visibility Information, which includes the type of data along with the associated requirements a Market Participant will need to provide, in order to operate as a Visibility LSU
	4.2.4 Operations		NA			Data integration will be addressed in the associated procedures rather than in the rule, e.g. Load Forecasting procedure
	4.2.5 Incentives	Price adjusted demand curve	NA			Price adjusted demand curve definition; functionality and integration to be addressed in in the associated procedures rather than in the rule. The procedures involved includes: •Spot Market Operations Timetable procedure •Pre-dispatch procedure

Scheduled Lite High-Level Design			**Proposed rule amendments**			
		Visibility Service Provision	Chapter 3	Visibility Service Provision	New Clauses	AEMO proposes a new rule to establish a Payment for Visibility Service that would be made in respect of a Visibility LSU. Scheduled Lite is a voluntary mechanism and as a consequence its value to the power system is dependent on the volume and rate at which customer choose to participate in the mechanism. The development of incentives is particularly important for encouraging operation in Visibility mode because almost all of the benefits accrue publicly across all Market Participants and consumers rather than privately to the Market Participant and customers that participate in the mechanism. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Visibility mode incentive) of the Rule Change Proposal for further details.
		Enhancing Market Operations	NA			This incentive will be contained in the proposed Light Scheduling Unit Guideline. The Guideline will describe the provision of pre-dispatch schedules by AEMO to a Market participant with a Visibility LSU
	4.2.6 Compliance		NA			Visibility LSU compliance criteria and process will be contained in the proposed Light Scheduling Unit Guideline. Compliance consequences will be established in the proposed new clause on Visibility Service Provision, which will provide AEMO with the discretion over payments depending on compliance
	Data sharing with Distribution Network Service Provides (DNSPs)		NA			Data sharing with DNSPs will be contained in the proposed Light Scheduling Unit Guideline, noting that amendments to the rule might be required to enable appropriate data provision with DNSPs, to ensure effective market operation and power system security
	4.2.7 Opt-out Arrangement		NA			The opt-out arrangement will be contained in the proposed Light Scheduling Unit Guideline. The Guideline will describe the obligation and process to be followed by a Market Participant wishing to opt-out of the Visibility mode
5. Dispatch Mode	5.2.2 Data Exchange		NA			Data Exchange will be facilitated by the power system data communication standard
	5.2.5 Dispatch		3.8.2(a)	Participation in central dispatch	Amendment	This clause may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled Bidirectional Unit (BDU) obligations apply similarly to LSUs in Dispatch mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details
			3.8.3A	Ramp rates	Amendment	This clause may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details

Scheduled Lite High-Level Design			**Proposed rule amendments**			
			3.8.19	Dispatch inflexibilities	Amendment	This clause may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details.
			4.8.9	Power to issue directions and clause 4.8.9 instructions	No change	AEMO considers that during Stage 1 of the Scheduled Lite reform, it will be important to consider whether Dispatch s should be subject to AEMO-issued 'directions' to Market Participants in respect of Dispatch LSUs, and therefore whether this clause should apply in respect of them. Refer to Section 6.1.1. (NER – other matters for the AEMC's consideration) of the Rule Change Proposal for further details.
			4.9.2	Instructions to Scheduled Generators, Semi-Scheduled Generators and Scheduled Integrated Resource Providers	Amendment	This clause may require drafting updates to ensure Dispatch LSUs are included. It should be amended to refer to 'Market Participants' in respect of the specific scheduled resources covered by the clause, rather than listing all registration categories. Refer to Section 6.1.1. (NER – other matters for the AEMC's consideration) of the Rule Change Proposal for further details.
			4.11.1	Remote control and monitoring devices	Amendment	This clause may also require amendments to cover Dispatch LSUs. See also the note on rule 4.9.2 above regarding references to Market Participants. Refer to Section 6.1.1. (NER – other matters for the AEMC's consideration) of the Rule Change Proposal for further details.
	5.2.4 Bid	Dispatch Bid	3.8.6 (g1 and g2)	Dispatch bids - Scheduled bidirectional units	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details.
			3.8.6(h)	Bid requirements - Scheduled and semi-scheduled generating units and scheduled bidirectional units	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details
			3.8.22	Rebidding	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details
			3.8.22A	Bids and rebids must not be false or misleading	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details

Scheduled Lite High-Level Design			Proposed rule amendments			
	5.2.6 Operations	MT PASA	3.7.2	Medium term PASA	Exemption	Market participants will not be required to participate and provide additional information with respect to Medium Term Projected Assessment of System Adequacy (MTPASA) for Light Scheduling Units, as AEMO will internally process the data provided, to add value to the MTPASA process
		ST PASA	3.7.3	Short term PASA	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details
		EAAP	3.7C	Energy Adequacy Assessment Projection	Exemption	Market participants will not be required to participate and provide additional information with respect to Energy Adequacy Assessment Projection (EAAP) for Light Scheduling Units, as AEMO will internally process the data provided, to add value to the EAAP process
		Scheduled capacity	3.8.4	Notification of scheduled capacity	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details.
		Reliability and Emergency Reserve Trader	3.2	Reliability and Emergency Reserve Trader	Amendment	This rule may require amendments to include Dispatch LSUs. This is based on the principle that Scheduled BDU obligations apply similarly to LSUs in Dispatch Mode. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Integration into dispatch and scheduling) of the Rule Change Proposal for further details
	5.2.3 Constraints		NA			The proposed dispatch mode does not involve the integration of Flexible Export Limits (FELs) into the market scheduling processes, rather the Market Participant will need to manage their energy, FCAS and local service bids and dispatch, to ensure they operate within their FELs. Noting that a Stage 2 of the Dispatch Mode, which is not part of the rule change request, is likely to be required once further DER/CER reform initiatives have been delivered. For example, FELs are expected to be widely adopted following the implementation of Scheduled Lite, as such stage 2 would allow the integration of FELs into market operations
	5.2.8 Compliance		3.8.23	Failure to conform to dispatch instructions excluding wholesale demand response units	Exclusion	AEMO proposes that Dispatch LSUs are excluded from this clause; it is a similar treatment to wholesale demand response units. AEMO considers that rules for dispatch conformance should recognise the different capabilities of Dispatch LSUs. Therefore, AEMO proposes a new rule to establish dispatch conformance specific to a Dispatch LSU. Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Dispatch conformance) of the Rule Change Proposal for further details
			Chapter 3	Failure of Light Scheduling Unit in Dispatch Mode to	New Clause	AEMO considers that rules for dispatch conformance should recognise the different capabilities of LSUs. Therefore, AEMO proposes a new rule to establish dispatch conformance specific to an LSU.

Scheduled Lite High-Level Design		Proposed rule amendments			
			conform to dispatch instructions		Refer to Section 6.1.1. (NER Chapter 3 Market Rules - Dispatch conformance) of the Rule Change Proposal for further details
		4.9.4	Dispatch related limitations on Scheduled Generators, Semi-Scheduled Generators and Scheduled Integrated Resource Providers	Amendment	This clause should be amended to cover Dispatch LSUs, so that they are only permitted to send out energy in accordance with a dispatch instruction when actively participating in Dispatch Mode. See also the note on rule 4.9.2 above regarding references to Market Participants. Refer to Section 6.1.1. (NER – other matters for the AEMC's consideration) of the Rule Change Proposal for further details.
	Data sharing with DNSPs	NA			Data sharing with DNSPs will be contained in the proposed Light Scheduling Unit Guideline. Noting that amendments to the rule might be required to enable appropriate data provision with network service providers, to ensure effective market operation and power system security e.g. active NMIs in an LSU in Dispatch Mode
	5.2.9 Opt-out Arrangement	NA			The opt-out arrangement will be contained in the Light Scheduling Unit Guideline. The Guideline will describe the obligation and process to be followed by a Market Participant wishing to opt-out of the Dispatch Mode