AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

# Scheduled Lite: Draft High Level Design

June 2022

Draft Consultation Paper

A report for the National Electricity Market

# Important notice

## Purpose

AEMO has prepared this document to provide information and facilitate stakeholder feedback on a draft high-level design for a Schedule Lite Mechanism.

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### Version control

| Version | Release date | Changes |
|---|---|---|
| 1.0 | 14/06/2022 | Initial Consultation version |

AEMO recognises the First Peoples of this nation and their ongoing connection to culture and country. We acknowledge First Nations Peoples as the Traditional Owners, Custodians and Lore Keepers of the world's oldest living culture and pay respects to their Elders past, present and emerging.

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# 1 Executive summary

Scheduled Lite is a voluntary mechanism that aims to lower barriers and provide incentives for non-scheduled load and generation to provide scheduling information and participate in the scheduling process of the National Electricity Market (NEM). This consultation paper consolidates high-level design considerations with feedback from stakeholders to guide the Australian Energy Market Operator's (AEMO) preparation of a rule change proposal for Scheduled Lite.

Participation in the 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 distributed energy resources (DER) and flexible demand grow in both size and as a share of dispatch resources in the system.

Scheduled Lite provides an opportunity for DER 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/end users will not directly participate in Scheduled Lite, it is their 'DER' that we are ultimately seeking to reward for being a part of the mechanisms. Engaging in the wholesale market has been a challenge for many consumers and demand-based resources, and the intention is to reduce barriers to enable this participation as far as possible.

The Energy Security Board (ESB) prepared a DER Implementation Plan to support the effective integration of DER 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 DER Implementation Plan initiatives which includes flexible trading arrangements, interoperability, dynamic operating envelopes (DOE) and the Australian Energy Regulator's (AER) review of the retailer authorisation and exemption framework. Scheduled Lite will also provide an important building block for DER and flexible demand to participate in the provision of essential system services as well as a basis for participation in the proposed capacity mechanism.

The proposed design leverages existing market systems and processes. Two Scheduled Lite models are being developed for participants to opt into:

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

## Participation

Scheduled Lite is intended to facilitate the participation of a range of end users, traders and resources that are not currently scheduled in the market. This may include aggregated DER portfolios (e.g. Virtual Power Plants [VPPs]); non-scheduled generating units and non-scheduled bidirectional units; large users and aggregated demand response portfolios. Importantly, end users with DER 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 an 'opt-in' operating model.
- Flexible participant registration in accordance with the National Electricity Rules (NER) registration framework.
- Classification and zonal aggregation of resources into Visibility Units or Dispatchability Units, based on which model a Trader is opting into.
- A minimum aggregated capacity threshold enabling Traders to 'graduate' from Visibility into Dispatchability when their portfolio reaches an appropriate size.
- Self-management of aggregated resource portfolios, with automated re-aggregation of resources where required by constraints or changing zonal boundaries.
- Flexibility in participation models, with optionality around whether (and how) flexible DER resources are separately traded in accordance with flexible trading arrangement models.

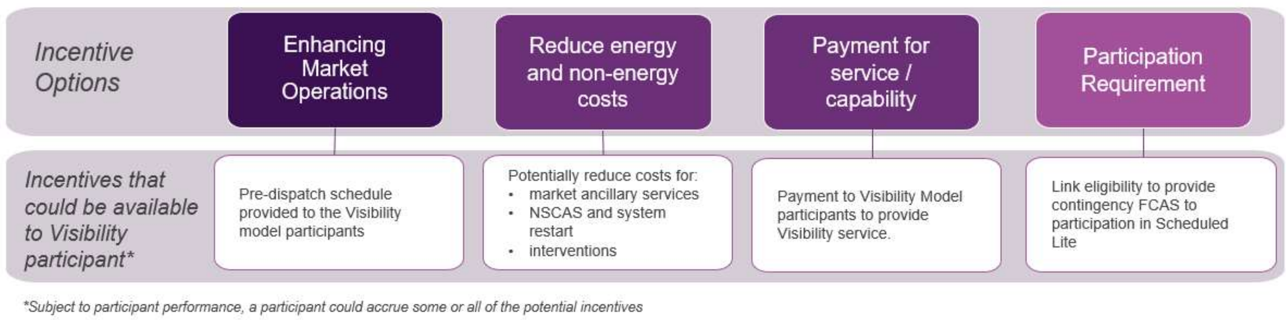
Participation in the Dispatchability Model will require more sophisticated operational capabilities compared to the Visibility Model. While a Trader may commence participation in the Visibility model, a transition to the Dispatchability model should be encouraged and supported.

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

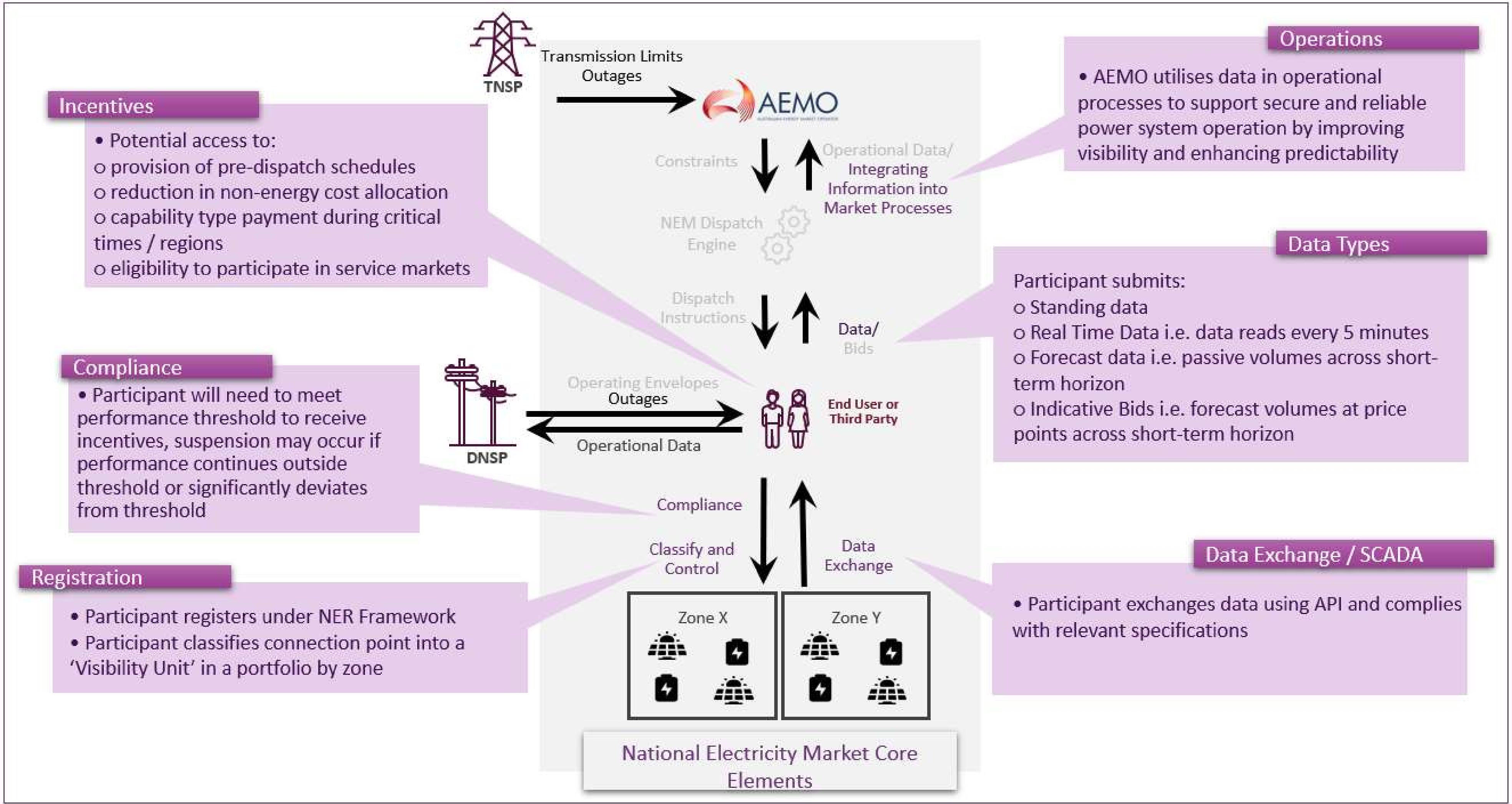
The benefits of participation in the Visibility Model largely accrue to the market rather than the individual Trader or end user, and as such a suite of incentives are proposed to encourage participation. As shown in Figure 1, these benefits range from enhancements in information available to a Trader, financial incentives or mandatory participation for specific resources or service providers.

**Figure 1 Potential Visibility Model incentives**




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 in the model if their performance continues outside threshold or significantly deviates from threshold. The framework would allow for the Trader to opt out of the model during the operational time horizon by submitting a forecast of their passive consumption and production 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**



## Dispatchability Model

Dispatchability services comprising of controllability, firmness and flexibility are essential requirements of the power system. As thermal generation exits the power system it will become increasingly important for dispatchability services to be provided by DER and flexible demand. The Dispatchability Model aims to establish fit-for-purpose arrangements for DER and flexible demand to participate in market scheduling processes.

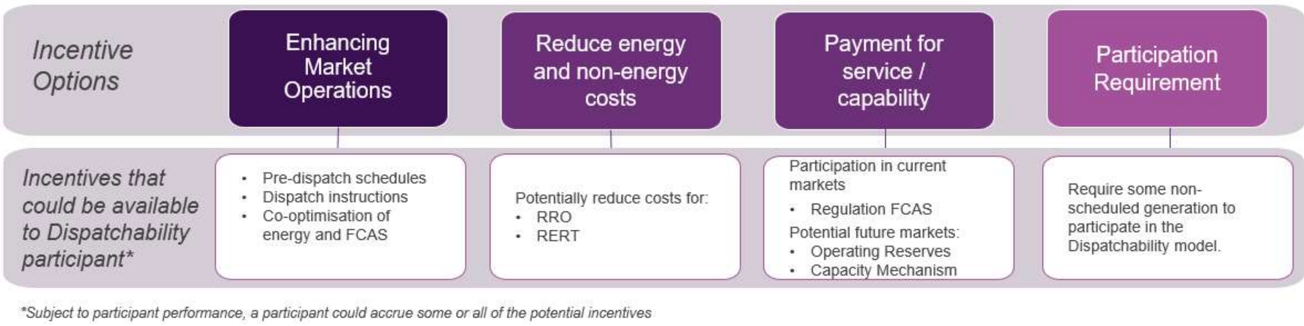
A minimum threshold of 5 MW is proposed for participation in the Dispatchability Model, and new SCADA arrangements will be leveraged to better suit distributed and distribution connected resources. Technical standards for communication and coordination of DER that will be developed through the ESB's interoperability policy will provide an important foundation for the implementation of Scheduled Lite.

AEMO will update constraint equations to incorporate a Dispatchability Unit 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 DOEs for their portfolio.

A Trader will bid into the NEM wholesale spot market for Dispatchability Units 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 will treat Dispatchability 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 Dispatchability Unit.

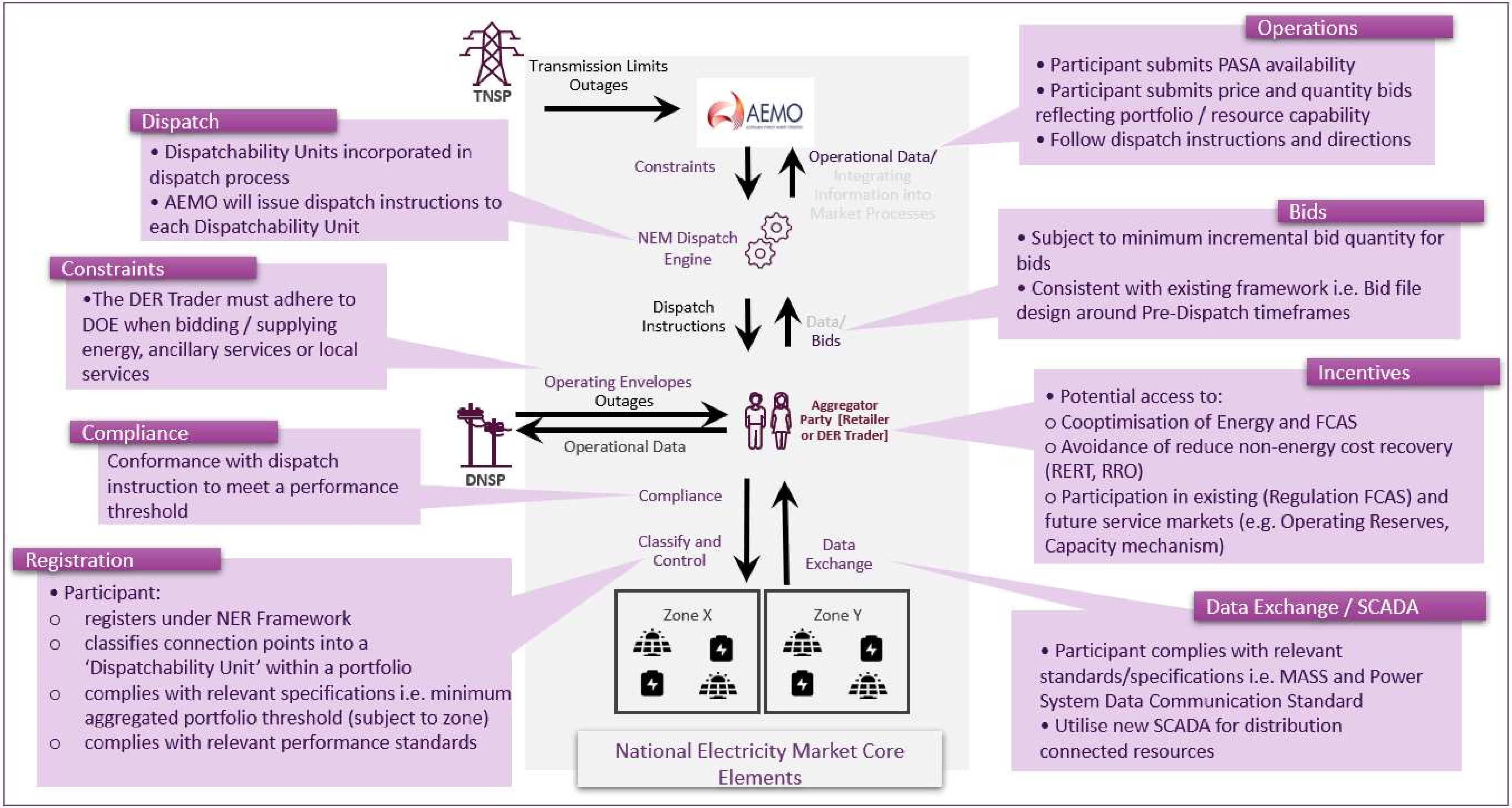
A suite of potential incentives to encourage participation in the Dispatchability Model is set out in Figure 3, ranging from the ability to co-optimise resources across energy and FCAS, financial incentives, and eligibility to participate in current or future service markets through to mandatory obligations for certain participant or resource types.

**Figure 3 Potential Dispatchability Model incentives**




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

**Figure 4 Straw design for Dispatchability Model**



# 2 Introduction

## 2.1 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 for a Scheduled Lite mechanism for the National Electricity Market (NEM). Since then, AEMO has prepared potential high-level design concepts for a Scheduled Lite mechanism in consultation with stakeholders. The purpose of this consultation paper is to consolidate high-level design considerations and to seek feedback on the potential designs from stakeholders. Feedback from stakeholders to this consultation paper will guide AEMO's preparation of a rule change proposal for Scheduled Lite.

Scheduled Lite is a voluntary mechanism that aims to lower barriers and provide incentives for unscheduled load and generation to provide scheduling information and participate in the NEM's scheduling processes. Through participation in Scheduled Lite, there is an opportunity for distributed energy resources (DER) and flexible demand 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 DER in the NEM scheduling processes, the mechanism will also be applicable to large users and small generators[1].

## 2.2 The need for greater visibility and dispatchability of DER and flexible demand

DER and flexible demand 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[2]. Consequently, visibility and coordination of these new types of resources are becoming increasingly important in maintaining secure and reliable operation of the power system.

Figure 5 shows the generation capacity projections from AEMO's draft 2022 Integrated System Plan (ISP) (Step Change scenario) over the next 30 years, highlighting the generation capacity expected from distributed PV, distributed storage and coordinated DER storage. Today around 30% of detached homes in the NEM have rooftop PV with a collective capacity of ~15 GW. The scenario outlines that by 2032 over half of the homes in the NEM will have rooftop PV, and by 2050 it will rise to 65% with 69 GW capacity[3]. It is forecast that most systems will be complemented by battery storage, with behind-the-meter domestic and commercial batteries expected to grow strongly in the late 2020s and early 2030s as costs decline.

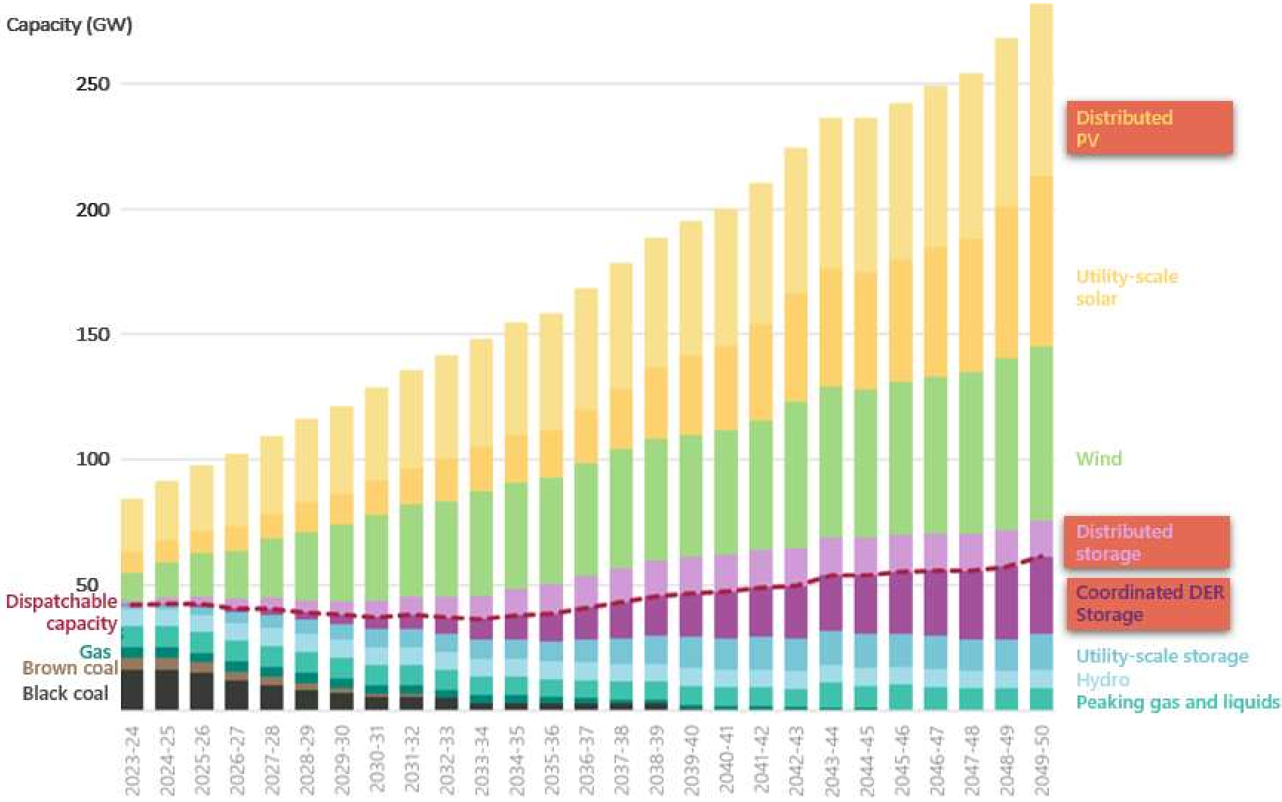
This represents a forecast of nearly a five-fold increase in consumer distributed PV systems and a substantial growth in distributed storage compared with today's level of capacity. These penetration levels imply a significant transformation for the operation of the power system.

[1] 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

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

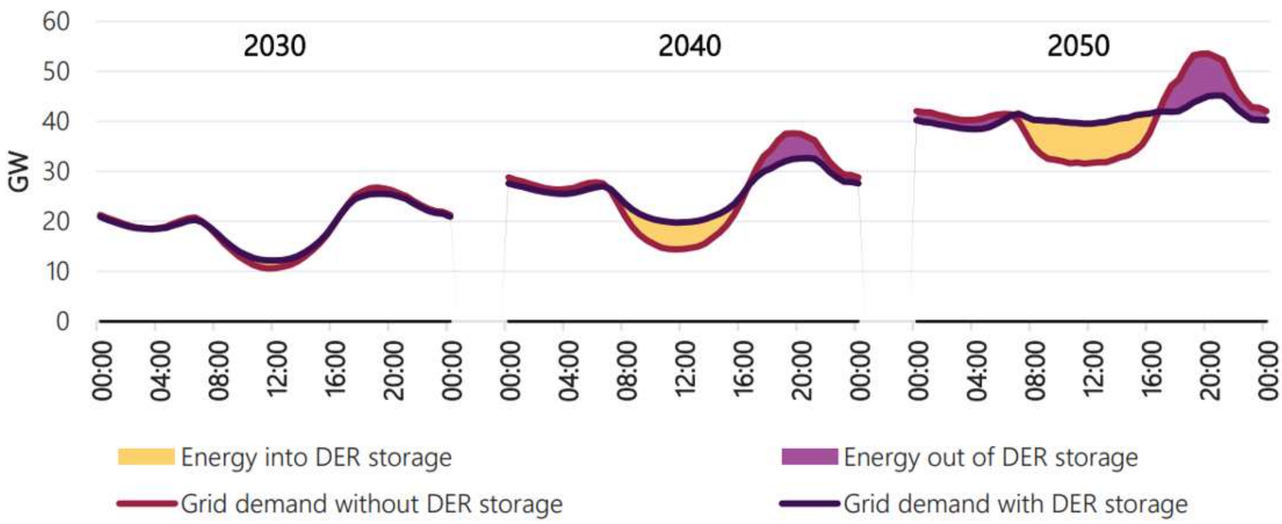
[3] AEMO, 2022. Draft 2022 Integrated System Plan. Available:https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en

Figure 5 Forecast NEM capacity by resource type to 2050, Step Change scenario




The efficient utilisation and coordination of DER would enhance peak demand operations by shifting abundant energy from the day to the evening. Figure 6 shows an example of the likely impact of co-ordinated distributed storage under the Step Change scenario.

Figure 6 Average time of day profile – impact of co-ordinated distributed storage, Step Change scenario




Note that:

- The red line represents grid demand without the impact of coordinated DER storage.
- The yellow shape represents excess PV generation through the daylight hours, which is sent into this distributed storage. After 4:00 pm, the evening peak can then draw on that stored energy.
- The black line represents the resultant grid demand after accounting for the charging and discharging of coordinated DER storage

### Visibility

A lack of visibility of price responsive DER[4] and flexible demand 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.

### Dispatchability

The NEM is entering a transitional period where both the generation and demand side are becoming more variable, decentralised, and digitised, as are all power systems around the world. In this context, power system requirements vary as new operational conditions[5] and scenarios emerge[6]. AEMO's Engineering Framework has identified potential gaps (300) and operational conditions (six), where increased industry focus is needed. For instance, by 2025 Virtual Power Plants (VPPs) and demand response is expected to reach a capacity of 1.6 GW leading to an operational condition identified as 'responsive demand'[7]. AEMO's Engineering Framework has highlighted that this operational condition would require incentives for responsive demand to be aligned with system needs. The Dispatchability model would be a vehicle to enable this alignment with systems needs through lowering barriers for DER and flexible demand to provide system-level flexibility through market participation.

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, whilst allowing future operational conditions to be navigated.

## 2.3 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 DER Implementation Plan setting out reform activities necessary to support the effective integration of DER and flexible demand. In October 2021, Ministers endorsed the ESB's recommendations and tasked ESB with delivery of the DER Implementation Plan over the next three years.

The reforms outlined in the DER 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 DER.

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4 Price responsive refers to DER that is controlled to optimise financial outcome for the customer around wholesale market or tariff price signals.

5 "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. Available: https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-march-2021-report.pdf?la=en

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

7 NEM Engineering Framework Operational Conditions Summary. Available: https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-july-2021-report.pdf?la=en&hash=04E2BEFE4A1A7281B6294B1C8228AD59

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

### Interaction with DER reforms

Engagement with stakeholders to date has highlighted the importance of coordinating the development of reforms across the DER 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 3.1 it is proposed that the Scheduled Lite mechanism utilises, and builds upon, the changes in registration framework established in IESS.
- 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 a rule change to implement model 2 has been submitted to the Australian Energy Market Commission (AEMC) by AEMO. As outlined in section 3.1, flexible trading arrangements would provide a mechanism, if required, for a Trader to separately trade its price responsive resources in the market.
- Interoperability: Technical standards for the communication and coordination of DER that will be developed through the ESB's interoperability policy will provide an important foundation for Scheduled Lite.
- Dynamic Operating Envelopes (DOE): Traders will need to adhere to operating limits in accordance with policy developed by the Australian Energy Regulator (AER) and the Australian Renewable Energy Agency's (ARENA) 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.
- Retailer Authorisation and Exemptions Review: The participation of DER in the market scheduling processes creates potential opportunities and risks for customers. The AER's Retailer Authorisation and Exemptions Review will provide an opportunity to give further consideration of the risks and the appropriate protections for customers participating in Scheduled Lite.

## 2.4 Objectives

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

**Figure 7 Scheduled Lite Objectives**

| | | |
|---|---|---|
| 1. Create a framework to encourage more responsive resources | Reduce barriers to participation | More resources visible to the market, available in dispatch and providing system services should lead to increased competition. |
| 2. Improve the efficiency of dispatch | Increase participation in scheduling, improve information | Additional information on likely behaviour or intentions, should improve dispatch outcomes. |
| 3. Improve efficiency of forecasting and scheduling | Utilise information about price responsive resources in demand forecast | More accurate forecast information and decisions making for AEMO, network operators and market participants. |

## 2.5 Principles

The ESB developed a set of principles to guide the development of the Scheduled Lite initiative as outlined in Figure 8 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 DER.

**Figure 8 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<br>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. |

## 2.6 Scheduled Lite Models

Two Scheduled Lite models are being developed for consideration:

- **Visibility Model**. The Visibility Model enhance visibility of 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'[8]. Traders will not be required to participate in dispatch or respond to dispatch instructions or directions. High level design considerations for the Visibility Model are outlined in section 4.

[8] Further information on Indicative Bids can be found in section 4.2.2

- **Dispatchability Model**. Dispatchability Model will integrate price responsive DER 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 the Dispatchability Model, Traders would gain access to existing or potential future markets that require the scheduling of resources. High level design considerations for the Dispatchability Model are outlined in section 5.

AEMO is developing two models for Scheduled Lite as proposed by the ESB. AEMO believes these two models are complementary and intends to implement both models if the rule change is approved by the AEMC.

## 2.7 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 DER increases. 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[9] published by AEMO:

- The Visibility Model would deliver changes to the registration framework, data exchange and incentives to enable Scheduled Lite.
- Stage 1 of the Dispatchability Model would build on the Visibility Model, adding functionality related to bidding and dispatch of DER. This stage of development would also rely on the delivery of appropriate Supervisory Control and Data Acquisition (SCADA) arrangements for DER.
- Stage 2 of the Dispatchability Model is not discussed in detail in this consultation paper. This potential phase of development is included to highlight that further development of the Dispatchability model is likely to be required once further DER reform initiatives have been delivered. For example, DOEs are expected to be widely adopted following the implementation of Scheduled Lite, as such stage 2 would allow the integration of DOEs into market operations.

**Table 1 Phasing of Reform Delivery**

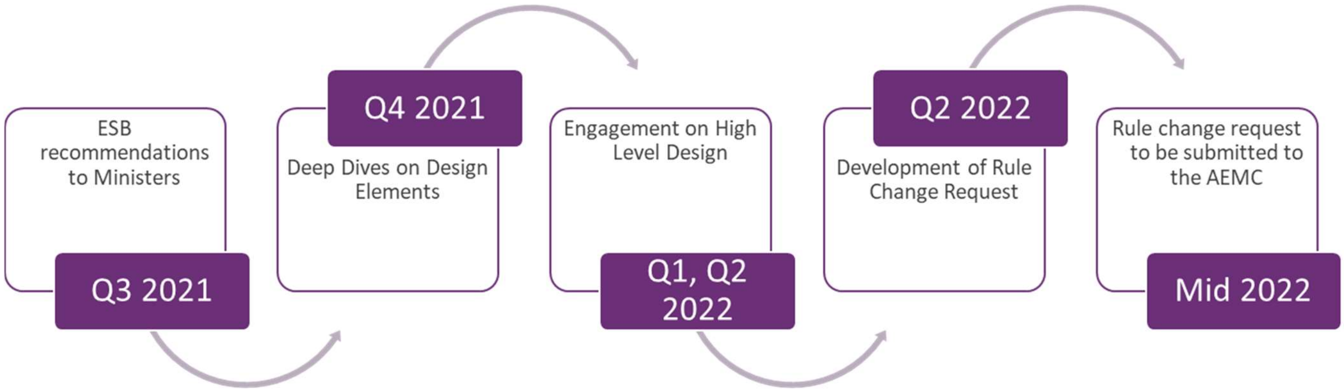
| Phase of development | Incremental development of Scheduled Lite design | | | Indicative timing |
|---|---|---|---|---|
| **Visibility Model** | Registration | Provide forecast and actual consumption and generation information | Incentives | November 2024 |
| **Dispatchability Model**<br>**Stage 1** | System limits | Short-term capacity and bids | Dispatch and compliance | October 2025 |
| **Dispatchability Model**<br>**Stage 2** | Integration of DER Register | Integration of DOEs into market operations | Enhancements to dispatch, including integration of technical limits for scheduling of Frequency Control Ancillary Services (FCAS) | Post 2025 |

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

## 2.8 Consultation and development timeline

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. 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 section 8).

AEMO is consulting with stakeholders on a draft high-level design to facilitate feedback on the proposed mechanism, identify any challenges associated with participation in the mechanism and to inform a rule change request.



# 3 Participation in Scheduled Lite

## 3.1 Participation building blocks

This section outlines the key building blocks for participation in Scheduled Lite. Most elements are common to both the Visibility and Dispatchability Models, with the proposed design focused on leveraging existing market systems and processes and enabling Traders to transition efficiently between models 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 aggregated DER portfolios (e.g. VPPs); non-scheduled generating units and non-scheduled bidirectional units; aggregated demand response portfolios which are not eligible for or do not wish to participate in Wholesale Demand Response (WDR)[10]; and large non-scheduled 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/operator to access additional value streams (energy or services) in accordance with system and network constraints (e.g. DOEs). This terminology recognises the ESB's proposed shift towards a 'Trader Services' participation framework whereby a single, universal registration category may be used for all entities seeking to engage in 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, end users with DER will generally not participate in Scheduled Lite directly and will instead be represented in the market by a Trader. Reforms to establish flexible trading arrangements will also provide end users with greater flexibility to engage different service providers to manage their flexible resources; for example, an end user may engage a specialist Trader to manage their solar and battery whilst remaining with a traditional retailer for the rest of their electricity consumption. Some large users may wish to participate in Scheduled Lite directly, particularly in the Visibility Model, but could also participate via a third-party Trader.

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

1. **Voluntary participation** supported by an incentive framework and an 'opt-in' operating model.
2. Flexible **participant registration** in accordance with the NER registration framework.
3. **Classification and zonal aggregation** of resources into Visibility Units or Dispatchability Units, depending on which model a Trader is opting into.
4. A **minimum aggregated capacity threshold** enabling Traders to 'graduate' from Visibility into Dispatchability when their portfolio reaches an appropriate size.
5. **Self-management of aggregated resource portfolios**, with automated re-aggregation of resources where required by constraints or changing zonal boundaries.
6. **Flexibility in participation models**, with optionality around whether (and how) flexible DER resources are separated for participation in accordance with flexible trading arrangement models.

[10] for example, they do not qualify for baselining and therefore need to participate at the connection point

These building blocks are explored in the sections below, with design elements specific to Visibility and Dispatchability Models outlined in sections 4.2.1 and 5.2.1 respectively.

## Voluntary participation

Scheduled Lite is intended to be a voluntary participation mechanism, offering incentives and lowering barriers for resources to provide greater visibility to the market and/or participate in scheduling 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. Simply mandating participation in Scheduled Lite may not result in effective participation in the mechanism. 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 DER and flexible demand in the scheduling of the market.

Voluntary participation is supported by a proposed ‘opt-in’ operating model which enables Traders to set active and passive operating modes rather than requiring constant operation (see section 0). 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 whilst voluntary participation does present a risk of low uptake, 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 (like operational metering for resources above a certain size). Voluntary participation underpinned by appropriate incentives is likely to be the most effective approach to encourage effective participation and operational behaviour that is aligned with market needs.

## 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, in accordance with eligibility requirements[11]. 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, Customer or Integrated Resource Provider (IRP – see Box 1 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.

[11] See Chapter 2 of the National Electricity Rules

Table 2 Potential registration categories for Traders participating in Scheduled Lite

| Participant registration | Label | Resource being classified | Classification |
|---|---|---|---|
| **IRP or Customer** | Market Customer | End user connection point (non-scheduled load) | Market connection point |
| **IRP or Generator** | Non-Scheduled Generator | Non-exempt generating unit with nameplate rating <30 MW[a] | Non-scheduled generating unit |
| **IRP** | Non-Scheduled IRP | Non-exempt bidirectional unit with nameplate rating <5 MW[b] | Non-scheduled bidirectional unit |
| | Small Resource Aggregator | Small resource connection point: (exempt) small generating unit[c] and/or small bidirectional unit[d] (on its own connection point) | Market connection point |

[a] Clause 2.2.3(a) of the NER requires a generating unit with a nameplate rating of less than 30MW (not being part of a group of generating units connected at a common connection point with a combined nameplate rating of 30MW 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 (<5MW) 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 <30MW 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 <5MW incorporated in an integrated resource system which AEMO has exempted from the requirement to register as an IRP.

A registered production unit must be classified as market or non-market based on whether its sent-out electricity is sold through the spot market. For the Visibility Model, AEMO proposes that both market and non-market production units will be eligible to participate, whereas the Dispatchability Model would require market classification.

### Box 1: Participation by IRPs

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 universal participation category and can 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).

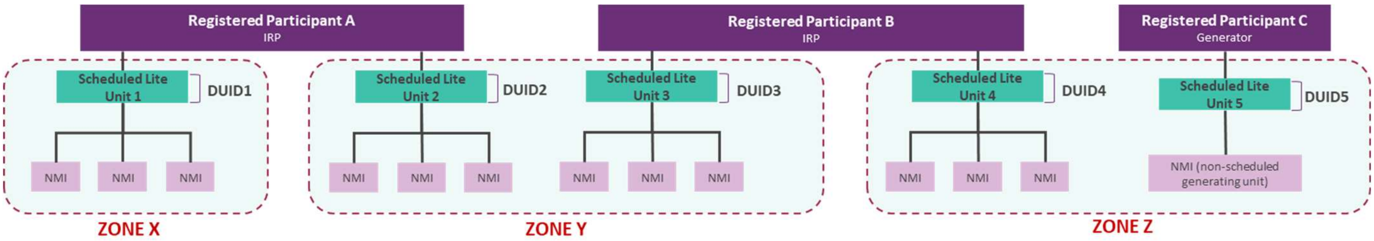
The IRP category subsumes the existing SGA role, which will participate under the new Small Resource Aggregator label. Upon commencement of the rule change, the IRP Small Resource Aggregator will be able to classify small bidirectional units in addition to small generating units, and is able to provide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

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

## Classification & zonal aggregation

This section provides an overview of the basic classification and resource aggregation framework proposed for Scheduled Lite. Figure 9 below illustrates the intended structure of this framework, with 'Scheduled Lite Units' denoting either Visibility Units or Dispatchability Units depending on the model in question.

**Figure 9 Proposed structure for the Scheduled Lite classification and aggregation framework**




Note: "NMI" = National Metering Identifier. Scheduled Lite Units will be either Visibility Units or Dispatchability Units depending on the model.

AEMO proposes the creation of Visibility Units and Dispatchability Units to enable aggregated portfolios to be represented in AEMO market systems for the purpose of participation in Scheduled Lite. The Trader would first apply for approval to establish a Visibility or Dispatchability Unit, and then classify its resources (National Metering Identifiers [NMIs]) within its portfolio into that Unit. Each Unit would be assigned a Dispatchable Unit Identifier (DUID) for identification purposes in AEMO market systems (Visibility Model) and for bidding, scheduling and dispatch processes (Dispatchability Model).[12]

Connection points would be aggregated on a zonal basis, with NMIs assigned to any given Scheduled Lite Unit required to be in a single zone (see Zonal Aggregation section below). Classification into a Scheduled Lite Unit would not be exclusive; for example, a market connection point could be classified as an ancillary service unit in addition to being classified into a Scheduled Lite Unit.

In the case of aggregated DER, AEMO considers that its existing process of manually assessing and approving applications to classify and aggregate each connection point into an aggregator's portfolio may not be fit-for-purpose at scale where a single aggregation may include thousands of individual connection points. AEMO is considering how this process can be streamlined to support participation in Scheduled Lite. For example, following participant registration and establishment of a Scheduled Lite Unit for aggregation, it is proposed that the Trader would self-approve and self-manage the classification of connection points into its portfolio, in accordance with conditions imposed by AEMO. The Portfolio Management section below provides further detail.

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 Scheduled Lite Units rather than being aggregated with other resources.

## Zonal aggregation

To support forecasting and system security requirements, AEMO proposes that aggregation of connection points would be enabled on a sub-regional zonal basis and is considering the definition of a 'zone' for the purposes of Scheduled Lite.

[12] Note that registered generating units are already assigned a DUID for settlement purposes.

As part of its Short Term Project Assessment of System Adequacy (STPASA) replacement project,[13] AEMO is considering zone definitions for STPASA zonal forecasts. AEMO considers that Scheduled Lite zones may be required to align with the STPASA zones once developed, as the process of disaggregating Scheduled Lite Unit bid information and forecasts to a zonal level would introduce error into the load forecasts for use in STPASA.

Until further detail in the STPASA replacement project is 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 requires 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)[14]. 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[15], 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 Scheduled Lite Unit would need to be contained within a single load forecasting area;
- if an update to the load forecasting area boundaries results in a Scheduled Lite Unit containing NMIs on either 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 Unit.

It is proposed that the zonal approach to aggregation is supported by an automated process for disaggregation and re-aggregation where required, given that there could be thousands of NMIs within a Trader's Scheduled Lite Unit. For example, where a zonal boundary changes, a bottom-up approach could enable AEMO to automatically re-aggregate NMIs in accordance with the new boundaries. A Trader could then confirm its re-aggregated portfolio, and update or re-register information such as bid validation data at an aggregate level where required.

### Portfolio management

Traders participating in Scheduled Lite—and particularly those participating with aggregated DER—will require an efficient platform to manage their portfolios within AEMO's systems. The existing Portfolio Management System (PMS), which is currently administered by AEMO to enable demand response service providers (DRSPs) to manage their portfolios of WDRUs and Ancillary Service Loads, could be leveraged to support Scheduled Lite

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

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

[15] AEMO, 2021. *Wholesale demand response guidelines*. Available 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

participation. The PMS could provide a platform for the following functions to be undertaken by participating Traders:

- View their portfolio of Scheduled Lite Units
- Submit, manage and view the status of actions including:
  - Classification of new NMIs into Scheduled Lite Units
  - Declassification of existing NMIs from Scheduled Lite Units
  - Aggregation and disaggregation of resources
  - Customer transfer between Traders (e.g. if a customer chooses to switch from one Trader to another)
- Identify NMIs as unavailable due to operational issues.
- Confirm re-aggregation following zone boundary changes or re-aggregation requests and update or resubmit standing data and bid validation data as required.
- View status of validation processes associated with portfolio changes.

To support portfolio maintenance, participant self-management functions could be accompanied by a validation process to ensure, for example, that the NMI in question exists and is active in market systems and that DER is registered at the site, as well as processes to recognise customer switching and abolishment/ deactivation of NMIs. This aspect of the design would be developed as part of AEMO's implementation process if a rule change is made to introduce Scheduled Lite.

The PMS is currently based on participants submitting applications requesting to make changes to their portfolios, which are then assessed and approved by AEMO on a per-application basis. To enable greater self-management and automated re-aggregation, AEMO will need to develop enhanced capabilities in PMS; for example, to be able to make automated portfolio changes on behalf of Traders or automatically assess classification of NMIs into zones.

### 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. It is proposed that an appropriate starting point for the required level of information access, would be similar to that provided for the WDR Mechanism. DNSPs are generally able 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 (MRC)[16].

[16] The MRC of each WDRU is the portion of the load at the connection point(s) which is controllable and able to provide the demand response in accordance with the requirements of dispatch. It may or may not be the total load of the WDRU's connection points.

## Minimum aggregated portfolio threshold for Dispatchability Model

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

For the Dispatchability Model, 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[17], 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[18]. AEMO is interested in stakeholders' views on whether an alternative threshold would be appropriate and the considerations around this.

Participation in the Dispatchability model will require more sophisticated operational capabilities compared to the Visibility Model. While a Trader may commence participation in the Visibility Model, a transition to the Dispatchability Model should be encouraged and supported.

## Participation of aggregated DER 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 end user 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 resources are separated from passive resources for participation in Scheduled Lite. AEMO considers that separation or 'unbundling' of an end user's flexible resources could potentially 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 end user's passive resources.

The establishment of flexible trading arrangements provides an avenue to enable an end user's flexible resources to be recognised and managed independent of passive generation and load in wholesale settlement. These arrangements would also enable the end user 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. FTM1 has been

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

[18] applying to individual units and cumulative capacity behind an individual transmission node.

progressed through the IESS rule change[19], which explicitly allows the second connection point to be bidirectional and participate in FCAS markets.

- **Flexible Trader Model 2 (FTM2)**, is an alternative arrangement which would enable end users to establish a secondary connection point within their electrical installation. FTM2 offers similar benefits to FTM1, while overcoming some of the barriers which make FTM1 inaccessible to many small end users. FTM2 is the subject of a rule change request recently submitted by AEMO to the AEMC for consideration[20]. The rule change also includes a proposal around updating the NEM metering framework to support the proposed connection arrangements.

Appendix 1 provides further background on the flexible trading arrangement reforms which form part of the Energy Security Board's Post-2025 Market Design Final Advice.

AEMO proposes that the separation of resources (via establishment of FTM1 or FTM2 arrangements) will not be required for participation in Scheduled Lite. AEMO considers that where a Trader is able to forecast and control its energy flows at a single 'standard' connection point (including both flexible and passive resources) within an appropriate performance tolerance band, this type of participation should be facilitated.

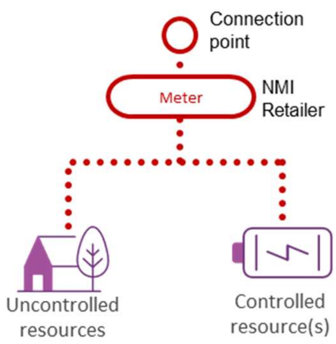
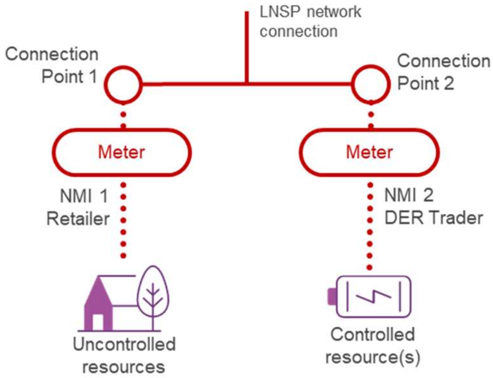
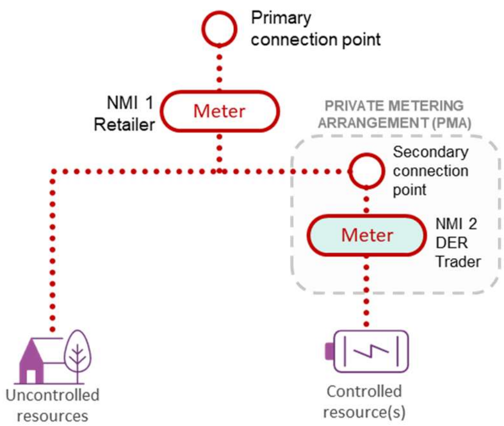
The lessons derived from Project EDGE trials are expected to inform AEMO's understanding of the participation capability (e.g. visibility, forecastability and dispatchability) of each of these models in Scheduled Lite, including the participation capability of flexible resources managed independently via establishment of flexible trading arrangements (FTM1 or FTM2). The project will trial two different models: 'Flex Only', whereby aggregators submit bids representing the aggregation of all controllable DER assets at a site measured at a common measurement point (not individual devices); and 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 1.

Table 3 outlines the proposed participation models for aggregated DER at end user 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 associated with the resources sitting behind the connection point for which it is responsible.

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

[20] AEMC, 2022. *Flexible trading arrangements for distributed energy resources*. Available 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

**Table 3 Proposed connection and participation arrangements for aggregated DER at end user connection points participating in Scheduled Lite**

| Participation via | Diagram | Description |
|---|---|---|
| **Standard connection point arrangement** |  | **Participates via standard connection point for the whole site.**<br>In this participation model, the end user 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 DER 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)** | <br>LNSP = Local Network Service Provider | **Participates with flexible resources at second connection point.**<br>FTM1 enables a second connection point to the distribution network to be established, for separate management of the end user's controllable resources. The end user may nominate a separate provider as the DER Trader to manage the controllable resources, whilst retaining a traditional retailer for passive load.<br>The DER Trader is responsible for the resources connected at the second connection point only, managing these independently from the end user's passive load.<br>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. |
| **Flexible Trader Model 2 (FTM2)**<br>*(this arrangement is subject to a rule change process)* |  | **Participates with flexible resources at secondary connection point established within customer's electrical installation.**<br>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 end user may nominate a separate provider as the DER 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.<br>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. |

## Participation of resources other than aggregated DER

For resources other than end user DER, participation in Scheduled Lite would be facilitated in accordance with standard connection and metering requirements specified in the NER and AEMO procedures. AEMO is seeking feedback on whether the proposed participation model is suitable for large energy users or whether alternative arrangements should be considered.

### Metering requirements

Participation in Scheduled Lite will require metering in accordance with the NER metering framework.[21] This includes, for example, applicable requirements around remote communications capability, device accuracy, interval length, design standards, compliance with the minimum service specification and data formats which are relevant to the required metering installation type.

**Related Projects (see appendix 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

**Participation Questions**

- Would AEMO's proposed participant registration process be suitable for large energy users, or should AEMO consider alternative means of registration for these participants?
- Are the proposed participation models for end user connection points appropriate to support participation of these resources? Are there other arrangements that should be considered?
- Do you agree with the proposed classification and zonal aggregation process? Are there any further considerations that should inform this aspect of the proposed design?
- Do you agree with AEMO's proposed approach to implementing an aggregated capacity threshold of 5 MW for participation in the Dispatchability Model, including the ability for participants to 'graduate' from Visibility to Dispatchability once the threshold is met?
- For DNSPs: do you consider that information access analogous to that provided for WDR is sufficient? If not, what other information on participating Scheduled Lite Units do you consider DNSPs should have access to?

## 3.2 Consumer perspective

Scheduled Lite provides an opportunity for DER 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/end users will not directly participate in Scheduled Lite, it is their 'DER' that we are ultimately seeking to reward for being a part of the mechanisms.

Consumers invest in DER – or as Energy Consumers Australia[22] has started to describe them, 'Consumer Energy Resources or '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.

[21] Refer to Chapter 7 of the NER.

[22] https://energyconsumersaustralia.com.au/news/death-to-der-why-we-need-to-change-the-language-we-use-for-the-energy-transition

## Scheduling Options for End Users

Table 4 outlines different types of end users, the different services they could provide to the power system as well as the market scheduling mechanism that could be applicable to them.

**Table 4 Scheduling options for different types of end users**

<table>
<tr><th>Service</th><th>Aggregated DER portfolio</th><th>Large User – Retailer</th><th>Large User – Market Customer</th><th>Small Generator</th></tr>
<tr><td>Visibility</td><td colspan="4">Scheduled Lite Visibility Model</td></tr>
<tr><td rowspan="2">Dispatchability</td><td rowspan="2">Scheduled Lite Dispatchability Model</td><td>WDRM</td><td>Scheduled Load</td><td>Scheduled Generator</td></tr>
<tr><td colspan="3">Scheduled Lite Dispatchability Model</td></tr>
</table>

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 DER to maximise returns from energy and ancillary service markets or to minimise energy and network tariff charges. The Trader coordinates a portfolio of DER, 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 Dispatchability Model.

## Customer story

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

**Table 5 Visibility Model 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 DER in the wholesale market. |
| Trader | • The Retailer has a portfolio of DER customers (VPP) that it trades in the wholesale electricity market. The retailer registers the portfolio of DER to participate in Scheduled Lite.<br>• The Retailer operates the portfolio of DER 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 DER it has contracted as a Visibility Unit. |
| 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 DER portfolio.<br>• The retailer aggregates operational metering information and communicates aggregate real-time flows to AEMO every 5 minutes. |
| Impacts on customer | • Participation in the Visibility Model would have no direct impact on the customer. Use of the DER would be in accordance with their agreement with the customer. The retailer simply informs AEMO of how it intends to use the DER 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 Model and factored those benefits into the fixed price it pays to the customer. |

**Table 6 Dispatchability Model 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.<br>• Under the agreement:<br>– the Trader has the right to operate the battery 5 times per day and must maintain a minimum level of charge, and<br>– 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).<br>• The Trader operates a portfolio of DER it has contracted in the electricity and ancillary service markets. |
| Scheduling model | • The Trader registers the portfolio of DER it has contracted as a Dispatchability Unit. |
| Trader actions | • The Trader bids its Dispatchability Unit into the energy, Regulation and Contingency FCAS markets.<br>• 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.<br>• Use of the DER 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 Dispatchability Unit 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.<br>• In future these revenues could include Operating Reserves and Capacity Credits. |

## Customer Risks

While the introduction of Scheduled Lite would provide an opportunity for DER 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 section 4.2.6 and 5.2.8, 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 (i.e. not their retailer) to separately trade DER 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, then 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.

# 4 Visibility Model

## 4.1 Overview

The proposed Visibility Model would establish a voluntary framework, which aims to deliver greater visibility of price responsive DER and flexible demand 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 considers the recommendations from the VPP demonstrations[23], where AEMO recommended that additional visibility of new types of resources (i.e. aggregated DER) is required to meet operational visibility needs.

As outlined in section 2, 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 unscheduled price responsive DER 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 4.2.2.

One key piece of information that AEMO provides to the market and utilises in short-term operations is the load forecast[24]. Load forecasting relies on the 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 DER are undiversified and predictable, such as rooftop PV, other resources are undiversified and unpredictable. These resources could include those that are part of an aggregation of DER being orchestrated to respond to wholesale electricity prices. Unpredictable DER are not correlated with predictable patterns such as the weather, leading to unexpected variability and making 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 from its increasing penetration. The addition of large volumes of unpredictable DER without appropriate visibility will result in increased variability and larger uncertainty for the load forecast. This will make it increasingly difficult to prepare accurate information for security and reliability functions as well as to the market for 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 will be 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
- A range of incentives including enhancements in information available to a Trader, financial incentives or mandatory participation for specific resources or service providers.

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

[24] 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 demand forecasting processes, and in turn, to be utilised in pre-dispatch and STPASA as well as operational activities that include interventions for power system security[25]. This will help to enhance the efficiency of scheduling processes, leading to reduced wholesale electricity prices and 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 Network Service Providers 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, such as the DER Data Hub being trialled in Project EDGE where data exchange between AEMO, DNSPs and aggregators is facilitated, could sit alongside the Visibility Model.

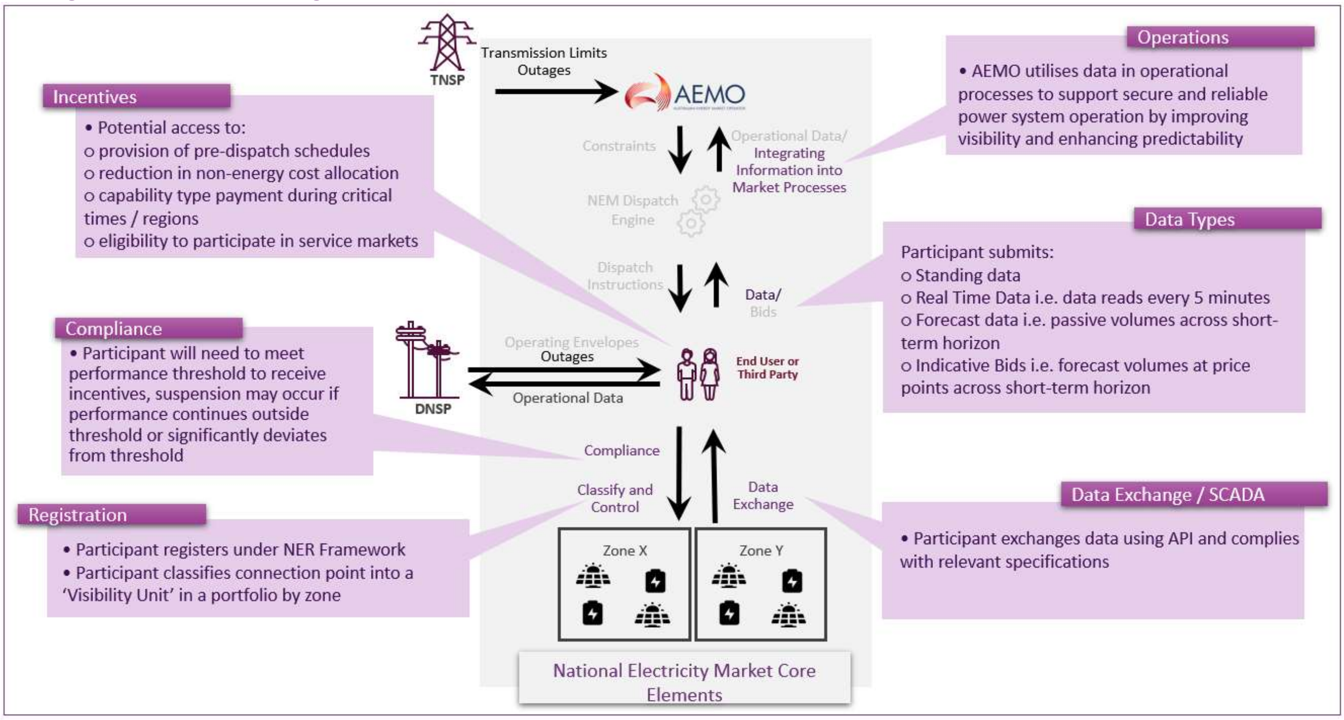
The Visibility Model is expected to suit a range of participants, that includes but is not limited to:

- Non-Scheduled Generators and Non-Scheduled IRPs that do not currently provide forecast information to AEMO
- Traders of Aggregated DER Portfolios
- 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 shown in Figure 10, providing a high-level description of the design elements of the Model. These elements are discussed in more detail in section 4.2.

[25] See Appendix 3 for an illustration of this through Visibility Model - Use cases

**Figure 10 Straw Design for Visibility Model**




Note that only the core market elements relevant to the Visibility Model's objective have been highlighted in the above Straw Design. For instance, a Visibility Model 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 Model and are thus not highlighted in the Straw Design above.

## 4.2 Design Elements

### 4.2.1 Registration

The core registration and participation requirements for Scheduled Lite are described in section 3.1 above and are common across both the Visibility and Dispatchability Models. Table 7 highlights considerations that are specific to the Visibility Model and should be read in conjunction with section 3.1.

**Table 7 Registration considerations relevant to Visibility Model**

| Participation element | Description for Visibility Model |
|---|---|
| Voluntary participation | As described in section 3.1 |
| Participant registration | |
| Classification & zonal aggregation | |
| Minimum aggregated capacity threshold | It is proposed that no minimum aggregated capacity threshold would apply to participation in the Visibility Model. Traders would be able to graduate from Visibility to Dispatchability once they reach a certain threshold and capability. |
| Portfolio management | As described in section 3.1 |
| Participation models and separation of resources | |
| Technical Standards | Resources at the connection point will be required to meet applicable technical performance standards.<br>For example:<br>• DER Traders seeking to participate in the Visibility Model would need to ensure resources under their operation meet relevant technical standards (for example, AS/NZS4777.2.2020 Inverter |

| Participation element | Description for Visibility Model |
|---|---|
| | Requirements[26], as specified in the NER, with compliance managed through distribution connection agreements).<br>• Traders participating in the Visibility Model 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 or any conditions imposed by AEMO. |

### 4.2.2 Data Types

The Visibility Model will require data to be provided by Traders to indicate the price responsive intentions. This section explains what types of data will be required within the Model and section 4.2.3 expands on the potential data exchange channel that will facilitate data communication.

Table 8 outlines the data types that have been identified for provision by Visibility Units.

**Table 8 Data Types**

| Type of Data | Description | Visibility Model Requirements | | |
|---|---|---|---|---|
| | | **Element** | **Proposed requirement** | **Units** |
| **Standing Data** | Information (e.g. NMIs) that would allow AEMO to map and utilise information provided in short-term forecasting and operations. | Standing Data | Provide data required in the registration process | |
| **Real Time** | Real time data consists of the instantaneous period ending measurement of active power flow at NMI. And actual generation/load/energy stored for controllable assets in the Visibility Unit. The data provided by a Trader is for each Visibility Unit. | Frequency of real time data provision | Data reads every 5 minutes | NA |
| | | Granularity of Real Time data | At least 5 minutes granularity | NA |
| | | Actual Consumption/ Generation | The aggregate actual charge/ load and discharge/ generation of resources in the Visibility Unit | MW |
| **Forecast** | Data set at the DUID level (i.e. per Visibility Unit) of anticipated active power flows. | Forecast Consumption/ Generation | The aggregate forecast charge/ load and discharge/ generation of resources in the Visibility Unit | MW |
| | | Storage Forecast | In the case of storage; the aggregate forecast for energy in storage of resources in the Visibility Unit | MWh |
| **Indicative Bids** | Data set at the DUID level (i.e. per Visibility Unit) of indicative forecasts from price responsive resources of the injections or withdrawals at different price points | Indicative Bids | Forecast volumes at price points across short-term horizon | Price/quantity pairs i.e. $/qty ($/MWh, MW) |

Note: Where the Visibility Unit is an aggregation of resources the data will be the aggregate of all resources.

[26] Applies to systems installed after December 2021.

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 (MTPASA). AEMO will use the information provided by Traders as an input to medium-term demand forecasts.

### Additional Information

As part of detailed implementation, AEMO will consider whether additional information could be incorporated into the indicative bid file 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[27]. This would allow interested parties (e.g. AEMO and DNSPs) to better understand activity on the network, including a variation from forecast behaviour.
- Uncertainty indication: would allow a Trader to indicate any uncertainty associated with the forecast data being provided. For example, a Visibility Model 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 (e.g. a number of hours). This would allow AEMO to treat data according to the associated level of uncertainty, within operational processes.

### Provision of disaggregated data/resource level data

The VPP Demonstrations and AEMO's DER Operations program of work have sought to understand what operational data is required to enable visibility and to unlock value from large aggregated DER 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."*[28]

Whilst not facilitated by the initial design of Scheduled Lite, AEMO considers that there may be value in accessing disaggregated/resource level data from DER in future. For example, this level of visibility could enhance accuracy in estimating distributed PV (DPV) contingency and curtailment requirements during emergency conditions; helping to avoid unnecessary 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 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 being trialled in Project EDGE) that would potentially enable access to disaggregated/resource level data, but notes that if the

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

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

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 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
- 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

**Visibility Model – Data Types Questions**

- Are there any hurdles to providing the data that has been identified? Are there other data types that are of value to the market and/or the networks that should be considered?

### 4.2.3 Data Exchange/Telemetry

This section explores the potential data exchange channels being considered, to enable communication of the various data streams outlined in Table 8 from the actors involved in market systems.

Currently AEMO is undertaking work to develop interfaces to enable data exchange for a high penetration DER future, including the DER Data Hub that is being trialled in Project EDGE[29]. AEMO is aiming to leverage existing initiatives to enable data exchange channels for participation in the Visibility Model. Under the proposed design, Visibility Units will need to provide the required information (see Table 8) 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[30]. 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[31]. The DER Data Hub is expected to provide efficient and scalable data exchange and registry services for DER, between industry actors.
- Power System Data Communication Standard Review[32]: AEMO is conducting a consultation on the Power System Data Communication Standard. This consultation aims to consider 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. This includes but is not limited to the inclusion/consideration of data communication from new types of participants (e.g. DER aggregator to market systems). The final version of Standard is due to be published in July 2022.

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

[30] AEMO, 2022. *NEM2025 Implementation Roadmap*. Available at https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/reform-delivery-committee/nem-2025-implementation-roadmap---initiative-briefs.pdf?la=en&hash=050682860B56F94913AAF1CA99129D58

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

[32] 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

**Related Projects (see appendix 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

**Visibility Model – Data Exchange/Telemetry Questions**

- Are there any hurdles to providing the data (see Table 8) via the proposed data exchange channels?

### 4.2.4 Operations

This section outlines how the different data collected (see Table 8) will be utilised by AEMO.

As noted in section 2.2, power system operation is becoming increasingly dynamic, complex and variable as the growing uptake of DER 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[33] and awareness of DER operation could be critical to managing the power system in high demand periods. Price responsive resources have the potential to materially impact system operation and it is essential that they are accounted for in market systems and processes.

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 enable the development of new tools, ensuring that the power system continues to deliver desired outcomes for consumers. This would allow AEMO to provide enhanced market information to Traders (e.g. price adjusted demand forecast) to support informed choices that are aligned with system needs; and leading to operational efficiencies for the Trader and the energy system.

AEMO anticipates the integration of data[34] into market processes as described in Table 9.

**Table 9 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<br>Forecast accuracy enhancement, supporting optimal operational decision-making via improved forecasts of reserve positions in PASA.<br>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 aggregation, rather than in isolation

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

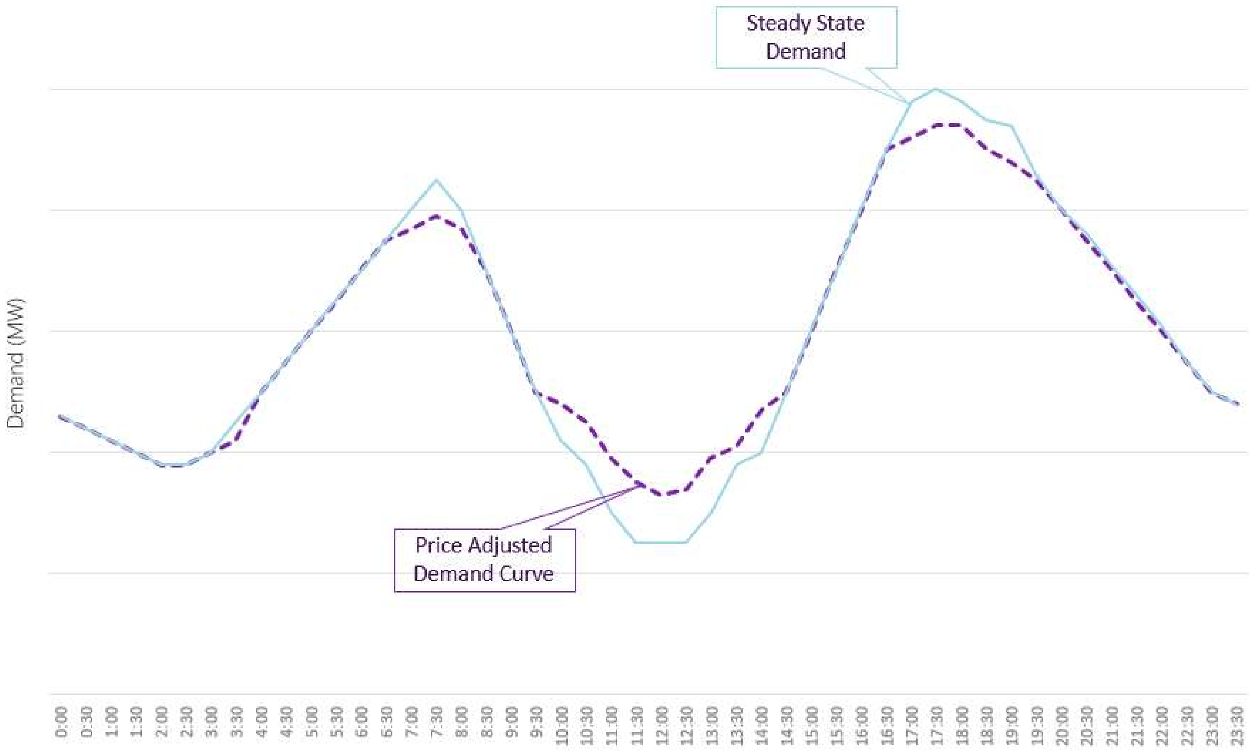
[33] AEMO, 2020. *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*. Available at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en

[34] Data identified in section 4.2.2

- The indicative bid information provided by Visibility Units will be incorporated into AEMO's demand curve. This adjusted demand curve will use the pre-dispatch schedule to produce a 'price adjusted' demand forecast (see Figure 11).

  The 'price adjusted' demand forecast represents an improved 'best estimate' on current demand forecasts, which do not include demand response and unscheduled generation (see Appendix 3). Traders can utilise the 'price adjusted' demand forecast and estimates of demand response and make decisions accordingly (see appendix 3).

**Figure 11 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 non-scheduled 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 non-scheduled resources, in response to the forecast price (i.e. indicative bids). This information would be provided to the market by AEMO.

Noting 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 self-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 the need for potential rooftop PV curtailment[35]. The provision of real time visibility of DER and flexible demand would enhance situational awareness and allow AEMO to track

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

and make any necessary adjustments to its demand forecasts, supporting the management of forecast ramp requirements[36].

- Enhanced scheduling accuracy: Increased information and confidence in price responsive resources injecting/withdrawing intentions will lead to more accurate load forecasts. This will allow AEMO and Market Participants to improve scheduling accuracy, helping to support more efficient operating decisions, leading to reduced system costs for all consumers.

**Related Projects (see appendix 1)**

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

**Visibility Model – Operations Questions**

- Is there value in understanding the sensitivities provided by the Price Adjusted Demand Curve during operational timeframes?
- Are there any further considerations for how this information should be made available?

### 4.2.5 Incentives

AEMO recognises that the provision of data comes at a cost to Traders, so there should be an appropriate incentive to participate in the Visibility Model that reflects the trade-off between accuracy and effort.

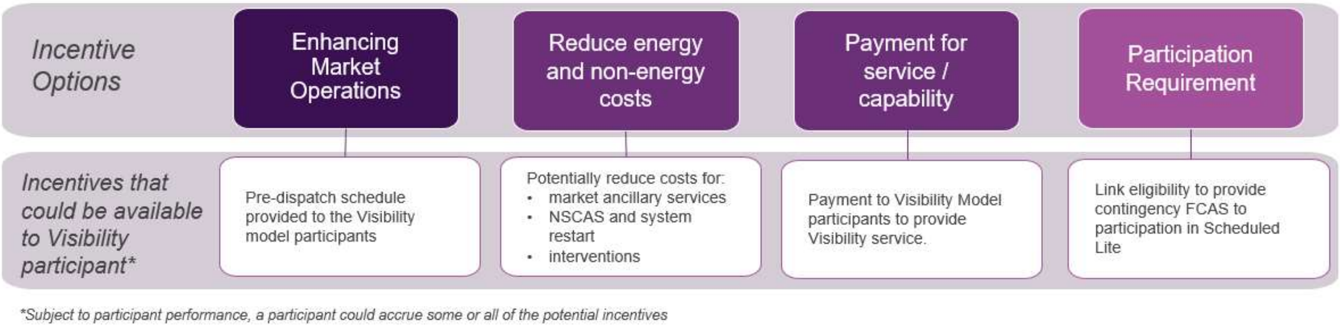
AEMO has identified potential incentives that could be captured by Traders and customers participating in the Visibility Model. The potential incentives being proposed were identified based on the following key focus areas:

- **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 Model.

Traders would access and be able to accrue incentives in accordance with the data they provide. The incentives proposed are designed to enable Traders to optimise their performance, provide valuable services to support market operation, and could be linked to eligibility for participation in contingency FCAS markets.

Figure 12 below outline the incentive options that Traders may be able to accrue.

**Figure 12 Incentive options - Visibility Model**




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

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: Visibility Model Traders may be able to access reductions in cost recovery allocations when future markets (e.g. Operating Reserves) are established.

    Stakeholders have 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 end users, impacting their ability to sign-up customers to their portfolio.

    A further drawback of reducing non-energy costs is that it may be challenging to settle the benefits to the Trader. Non-energy costs are payable by the financially responsible Market Participant, if a third-party Trader contracts with the end user to participate in the Visibility Model, it could be a challenge to determine the appropriate cost reductions, and for those amounts to flow to the correct party.
- **Payment for service/capability:** 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.
  - A payment for service approach would address the challenges outlined above associated with the complexity and settlement of non-energy cost reduction.

- **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 DER participation in Contingency FCAS markets.

**Related Projects (see appendix 1)**

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

**Visibility Model – Incentives Questions**

- Are there any additional incentives that could be considered to encourage participation in the Visibility Model?
- For market participants already providing contingency FCAS: do you consider that participating in the Visibility Model would add significant additional costs?

### 4.2.6 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 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 DER 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 assist AEMO in determining 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 the 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 DER 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, then they 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.

**Visibility Model – Compliance Questions**

- Do you agree with the proposed compliance arrangements whereby a participant would lose access to the incentives if they are not complying?

**Visibility Model – Straw Design Questions**

- Does the proposed straw design for Visibility Model represent a feasible model?
- Would there be any hurdles for a VPP to participate in the Visibility Model?
- Based on your understanding of participation requirements, would there be sufficient incentives to participate in the Visibility Model?

# 5 Dispatchability Model

## 5.1 Overview

The objective of the Dispatchability Model is to establish a voluntary framework that lowers barriers and provides incentives to encourage participation of DER and flexible demand in dispatch 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[37] below this threshold currently operate outside the NEM dispatch and scheduling process. The Dispatchability 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 Dispatchability Model include:

- A flexible participation framework to facilitate broad participation[38]
- New SCADA arrangements ('SCADA for DER[39]) to suit distributed and distribution connected resources
- Integration of DER and flexible demand 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 ancillary service markets

The Dispatchability Model would enable:

- DER and flexible demand to contribute to the dispatchability (controllability[40], firmness[41], flexibility[42]) of the power system to:
  - Enable efficient and effective balance of supply and demand
- Traders to unlock additional revenue streams for price responsive resources
- Potential to provide Essential System Services (ESS)[43] as well as providing a basis for eligibility within the proposed Capacity Mechanism, see section 5.2.7.
- Potential data sharing opportunities with Network Service Providers that could support work on managing infrastructure within operational limits

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

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37 This may include aggregated DER portfolios (e.g. VPPs); non-scheduled generating units and non-scheduled bidirectional units; large users and aggregated demand response portfolios

38 Subject to meeting registration requirements, section 5.2.1

39 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.

40 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

41 The firmness of a resource relates to the resource's ability to confirm its energy availability

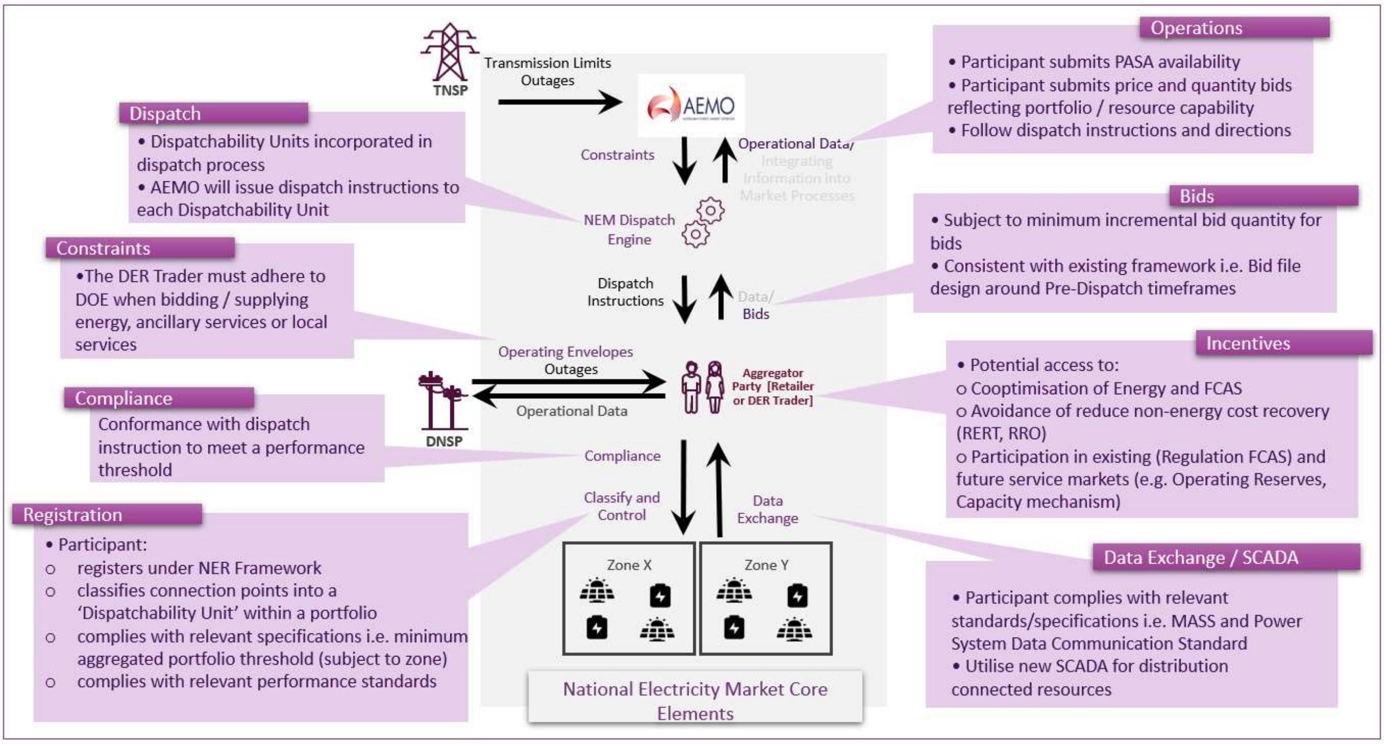
42 The flexibility of a resource is the extent to which its output can be adjusted or committed in or out of service

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

- Traders of aggregated DER portfolios
- Traders of aggregated demand response
- Non-scheduled generation and bidirectional units
- Large non-scheduled load

The proposed straw design for the Dispatchability Model is shown in Figure 13 highlighting the design elements involved in the Model along with a high-level description.

**Figure 13 Straw Design for Dispatchability Model**




Note that only the core market elements relevant to the Dispatchability Model's objective have been highlighted in the above Straw Design. For instance, as a Dispatchability Model Trader will participate in dispatch processes, accordingly they will be involved in certain NEM Core elements such as 'Dispatch Instructions'; 'Operating Envelopes' and 'NEM Dispatch Engine'.

The rest of this section provides details on the design elements involved in the Dispatchability Model.

## 5.2 Design Elements

### 5.2.1 Registration

The core registration and participation requirements for Scheduled Lite are described in section 3.1 above and are common across both the Visibility and Dispatchability Models. Table 10 highlights considerations and elements of the framework that are specific to the Dispatchability Model and should be read in conjunction with section 3.1.

**Table 10 Registration considerations relevant to the Dispatchability Model**

| Participation element | Description for Dispatchability Model |
|---|---|
| **Voluntary participation** | As described in section 3.1. |
| **Participant registration** | |

| Participation element | Description for Dispatchability Model |
|---|---|
| **Classification & zonal aggregation** | |
| **Minimum aggregated capacity thresholds** | As described in section 3.1, it is proposed that a minimum aggregated portfolio threshold of 5 MW would apply for participation in the Dispatchability Model (below this threshold, the Trader can only participate in the Visibility Model). This proposed threshold is required to support operational requirements associated with preparing scheduling inputs for Dispatchability Units, such as bids. |
| **Portfolio management** | As described in section 3.1 |
| **Participation models and separation of resources** | |
| **Technical standards** | Consideration will need to be given to the standards each Dispatchability Unit needs to adhere to, equivalent to a Generator Performance Standard (GPS) of Scheduled Units. In stage 1 of Scheduled Lite, it is expected that the requirements for Dispatchability Units, will be as per Visibility Units, and it will be the responsibility of the Trader to ensure the DER in each Dispatchability Unit meets the relevant technical standards with Distribution Connection Agreements expected to manage technical compliance.<br>As the proportion of DER grows, further consideration may need to be given to the standards which a Dispatchability Unit may need to meet, such as voltage control and fault ride through capabilities to ensure the system as a whole can continue to operate securely. This is expected to be addressed in Stage 2 of development of the Scheduled Lite Dispatchability Model, as discussed in section 2.7. |

### 5.2.2 Data Exchange/Telemetry

This section describes the data streams and potential data exchange channels to enable data transfer, from the Trader to market systems to facilitate participation in dispatch processes.

#### Data streams required for participation in dispatch processes

Table 11 below summarises the data streams required to enable participation in dispatch processes from unscheduled price responsive resources via Dispatchability Units. Where the Dispatchability Unit is an aggregation of resources, it will be the Trader's responsibility to provide data representing the aggregate of all the resources within the Unit.

**Table 11 Data streams – Dispatchability Model proposed design**

| Type | Description | Data Stream – Dispatchability Model propose design | | | Comparison to Visibility Model (Table 8) |
|---|---|---|---|---|---|
| | | **Element** | **Unit/granularity** | **Use** | |
| **Static or Standing data** | Site data that changes infrequently, is maintained and accessed within internal AEMO systems (e.g. NMI data) | 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 instantaneous period ending measurement of active power flow at NMI.<br>And actual generation, actual load and actual energy stored for controllable assets in the Dispatchability Unit.<br>The data provided by an Aggregator is for each Dispatchability Unit. | Telemetry/ SCADA | As per Scheduled resources i.e. 4s data granularity | Telemetry data is required by the market operator for operational visibility and dispatch conformance monitoring | Real time data for Visibility Unit is read every 5 min with at least 5 min granularity |

| | | | | | |
|---|---|---|---|---|---|
| **Bids (see section 5.2.4)** | An Offer that includes both generation and load. May contain 20 price bands per Dispatchability Unit | Bid | • As per large-scale bi-directional units[44]<br>• Price/quantity pairs[45] i.e. $/qty ($/MWh, MW)<br>• Bid file design around Pre-Dispatch timeframes<br>• Granularity: 5 minutes | Bids are used for market participation by Dispatchability Unit | Visibility Unit submits indicative bids |
| **Availability Forecast** | Availability Forecast data is to be provided for each Dispatchability Unit. This forecast represents the available capacity of generation, load and storage in an Aggregator portfolio. Availability forecasts are produced by DUID (i.e. per Dispatchability Unit) and only incorporates generation and load devices that are explicitly under control of the Dispatchability Model Trader[46] | Forecast Consumption/ Generation | • Submit availability, across short-term horizon<br>• MW | • To provide visibility of the aggregator portfolio free of any commitments<br>• 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<br>• 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[47] | Same requirement |
| | | Storage Forecast | • Submit availability, across short-term horizon<br>• MWh | | |
| **DOEs (see section 5.2.3)** | DOEs are calculated and produced by the DNSP. These distribution level limits are proposed to be shared with the Dispatchability Model Trader and AEMO | DOE | • Active Power Import<br>• Active Power Export<br>• Reactive Power injection/absorption<br>• Voltage (+/-)[48] | • Dispatchability Model Traders must adhere to DOE 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[49] | Local Network Services | As required by DNSP | | |

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

[45] Subject to Bid requirements, see section 5.2.4

[46] Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en

[47] Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en

[48] Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en

[49] Project EDGE Data Specification Part B: Market Participation & Operational Visibility Data Requirements. Available 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 of the data requirements associated with participation in the Dispatchability 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 Dispatchability Model is to enable participation from unscheduled 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 (i.e. SCADA) is unlikely to be economically feasible for potential Dispatchability Model Traders[50], 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 11). A brief description of each data stream can be found below with respect to the potential data exchange channel that could enable it:

a) **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 Dispatchability Model Traders to connect and exchange data with the market

   – Securely and efficiently connect and exchange data.

   Dispatchability Model Traders will need to provide telemetry data complying with relevant standards/specifications, i.e. the Power System Data Communication Standard.

b) **Static or Standing data.** Consistent 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 by the DER Data Hub, which is being developed under Project EDGE[51]; and Registry Services, which could utilise AEMO's existing DER Register.
   The NEM 2025 Implementation Roadmap identifies a project to uplift the DER Register, however the delivery of this uplift may be after Stage 1 of Scheduled Lite. As such it is proposed that integration of the DER register into the Dispatchability Model occurs within a Stage 2 implementation.

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

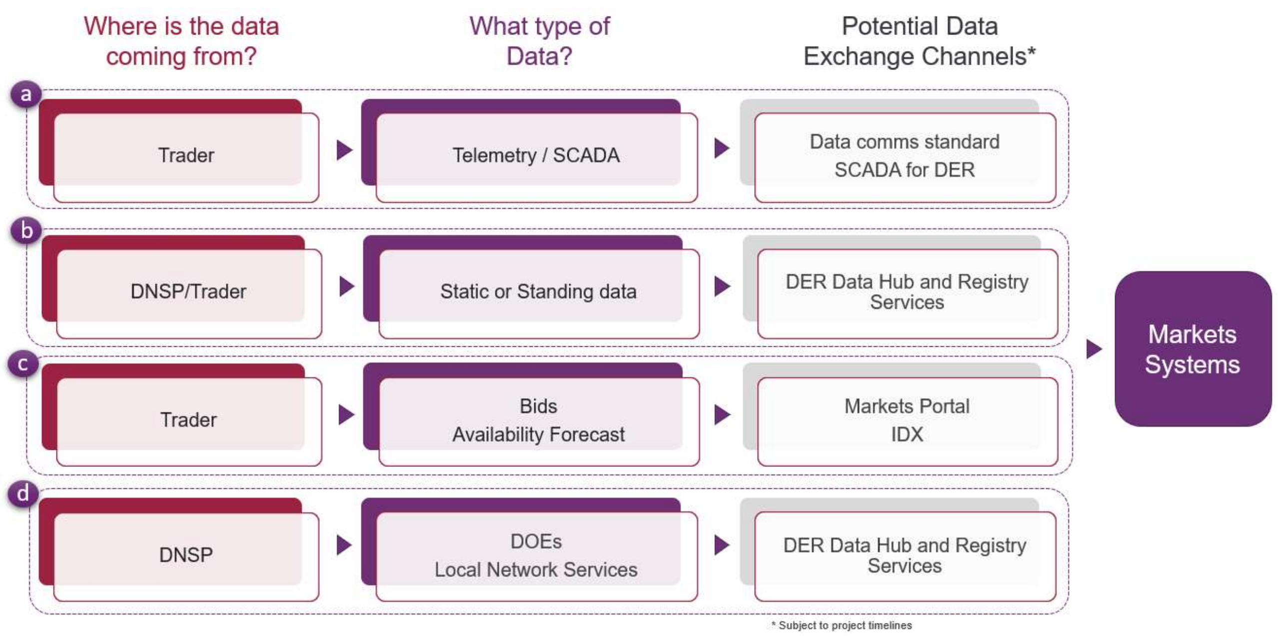
[51] Project EDGE Data Specification, Part A, section 6. Available: https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-a.pdf?la=en

c) **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 5.2.4 contains the proposed design for the Bid element of the Dispatchability Model.

d) **DOEs.** AEMO will build on the elements being tested in Project EDGE with respect to DOE communication[52] (i.e. DER Data Hub). Section 5.2.3 contains design considerations for the constraints element, including DOEs.

Figure 14 below summarises the proposed flow of data; the actors involved; the data required; and the potential data exchange channels being considered.

**Figure 14 Potential Data Exchange Channels**




**Related Projects (see appendix 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 - providing insights into what data communications method are fit for purpose for Aggregated DER

**Dispatchability Model – Data Exchange/Telemetry Questions**

- Are there any hurdles to providing the data (Table 11) via the proposed data exchange channels?

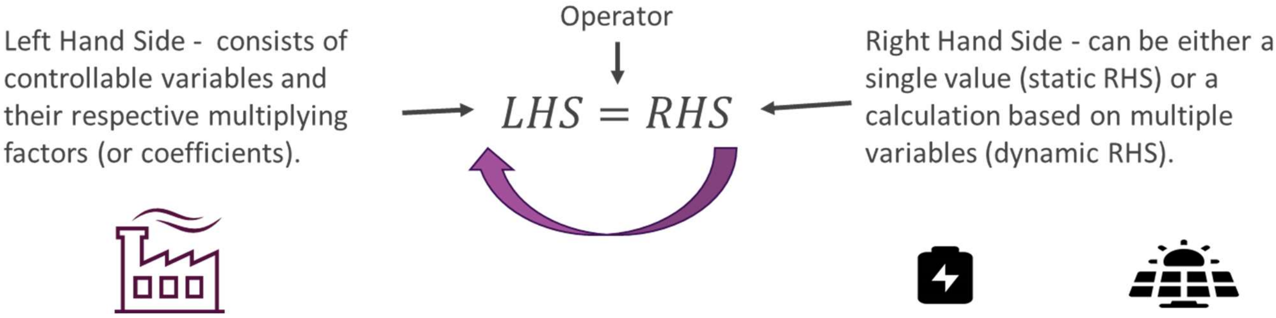
### 5.2.3 Constraints

#### System Constraints

Constraint equations are used in the NEM dispatch engine to represent the network and ensure that the market solutions are within the physical limits of the power system. DER is currently captured in demand terms and sits

[52] Project EDGE Research Plan. Available: https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en

on the uncontrollable right-hand side of constraint equations. Integrating with market processes and systems will require aggregated DER (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 a Dispatchability Unit at the time of registration.




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 constraint that arise. In comparison, the aggregation of connection points for Scheduled Lite units is proposed to be by zone that will take account of material transmission limits.

### Local constraints

DOEs 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 DOE working group defines 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 DOEs is that the Trader will be responsible for managing their energy, FCAS and local service bids and dispatch to ensure they operate within their DOE. Under the proposed Stage 1 of the Dispatchability Model, AEMO will not integrate DOEs into the market scheduling processes.

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

DOE development is occurring through the DEIP DOE workstream[53] as well as the AER policy and regulatory workstream. There are several interactions between the DOE and Scheduled Lite designs, and it is proposed that these design matters are determined within the DOE workstreams. It is proposed that Scheduled Lite will have the following requirements for the DOE workstreams:

- DOEs are available to Traders so that they can manage their market bids.
- DOEs are available for use in market systems where it is necessary to incorporate limits into short-term forecasts, security or reliability processes.

[53] DEIP, 2022. *Dynamic Operating Envelopes Working Group Outcomes Report*. Available at https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

- 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 1)**

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

**Dispatchability Model – Constraints Questions**

- Do you agree with the proposed requirements associated with DOEs? Are there any other relevant requirements associated with DOEs that should be considered, taking into account the scope of Stage 1 (see section 2.7)?

### 5.2.4 Bids

This section provides a description of how a Trader will submit bids to participate in the dispatch (the dispatch process is described in detail in the next section 5.2.5).

The proposed design allows for a Trader to submit bids for its Dispatchability Units and participate directly in central dispatch for energy via the Dispatchability Model. 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—Dispatchability Units will be treated consistently with other scheduled resources in that process. As such, bids for Dispatchability Units will need to recognise that:

- In the case of aggregated DER, a Trader can choose to operate via an aggregation of standard connection points (i.e. whereby there is no separation of controllable resources at the site) or via flexible trading arrangements (where controllable resources are separated)[54], 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 file includes a field for the forecast of passive resources.
  - flexible trading arrangements (e.g. 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 a Dispatchability Unit DUID, which will be at a zonal level.
- The Trader may set the market price if the Dispatchability Unit is marginally dispatched.
- 100kW is being explored as a potential minimum incremental bid quantity for Dispatchability Units, which is lower than the current minimum incremental bid quantity for Scheduled resources (1 MW)[55]. This consideration reflects the requirements that may arise from the inclusion of smaller resources into the dispatch process. For stage 1 of implementation of the Dispatchability Model, it is expected that the 1 MW incremental bid quantity will remain, with a 5 MW threshold for participation as explained in section 3.1.

[54] Further detail on participation alternatives in section 3.1

[55] Subject to further assessment of impacts on dispatch systems and assessment of value of reducing the incremental bid quantity. It is important to note that the implementation of 100kW as the minimum incremental bid quantity, will require changes to NEMDE and related systems as this differs from the current NEMDE functionality.

The bidding process for the Dispatchability Unit will be consistent with arrangements established via the IESS project for large-scale bi-directional units[56]; meaning that:

- Bids may be for resources that include generation and load and bi-directional resources, and therefore may contain 20 price and volume bands.
- Bids and dispatch instructions would be positive where the Dispatchability Unit is being dispatched to discharge, or negative where it is being dispatched to charge[57].
- 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.
- Bids must reflect the physical capability of the Dispatchability Unit, such that the unit can respond to a dispatch target in required timeframes[58]. For example, the Trader must understand and monitor the availability of the Dispatchability Unit and reflect this in their maximum availability bid. Similarly, the Trader must consider any DOE restrictions prior to bidding (see section 5.2.3) and reflect any constraints within their bids.
- Good faith bidding will be applicable.

If the Trader chooses to opt-out during the operational horizon, the Trader will not be required to comply with the arrangements above (see proposed operating model in section 0).

Traders wishing to take part in the Dispatchability Model will also be able to participate in all FCAS markets provided they comply with the relevant technical requirements of those markets[59].

**Related Projects (see appendix 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 Model
- Wholesale Demand Response – potential to leverage processes developed for WDR

**Dispatchability Model – Bids Questions**

- Taking into consideration the proposed minimum size requirements and minimum compliance arrangements, does the proposed threshold of 1 MW as the minimum incremental bid quantity represent a hurdle to participation?

### 5.2.5 Dispatch process

Dispatchability Units will be incorporated into the existing NEM dispatch process. This section provides an overview of how the Dispatchability Model will integrate with the dispatch process, including co-optimisation between energy and FCAS dispatch for Dispatchability Units and how Traders will receive and comply with dispatch instructions.

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[56] AEMO, 2021. *IESS High Level Design*, section 3. Available 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. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/edge-data-specs-part-b.pdf?la=en

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

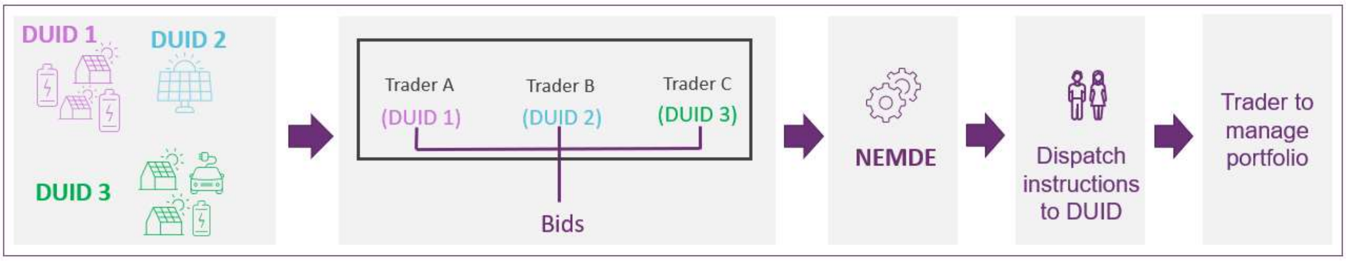
[58] Subject to compliance requirements, see section 5.2.8

[59] In contrast with the Visibility Model, where participants would be eligible to participate in contingency FCAS; Dispatchability Model participants would be able to participate in all FCAS Markets i.e. Contingency FCAS and Regulation FCAS

## 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 their portfolio and control their resources to respond to the dispatch instruction.

**Figure 15 Dispatch Process Overview**




## Bids

As described above, a Trader wishing to participate in the Dispatchability Model will be able to be dispatched for energy by submitting energy bids via 20 price and volume bands. Dispatchability Model Traders will also be able to participate in all FCAS markets (see section 5.2.7) 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 bidirectional nature to these products, and treatment of FCAS bids and enablement for Dispatchability Units will be similar to other units[60].

## Co-optimisation of Energy and FCAS

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

- Provide an FCAS trapezium per Dispatchability Unit[61]
- Comply with the requirements in the Market Ancillary Service Specification (MASS)[62] and the NER with respect to the services they will provide
- Meet technical requirements such as an Automatic Generation Control (AGC) equivalent functionality[63] 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[64], 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 a Unit, it must include an FCAS

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

[61] AEMO, 2021. *FCAS Model in NEMDE*. Available at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en

[62] 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.

[63] SCADA for DER may potentially enable this functionality

[64] 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.

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)[65]. 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:

- A trapezium that reflects its energy dispatch will need to be reduced to reserve headroom for FCAS if that is the case
- 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 a Trader’s Dispatchability Unit 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 a Trader 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.

As described in section 5.2.4, a reduced minimum incremental bid size of 100 kW is being explored and such a change would also be required for FCAS participation. This would allow Traders to manage their Dispatchability Units to a greater level of precision, and also to bid in and be dispatched for energy or enabled for FCAS for a quantity greater than a MW but less than the next MW. However, this needs to be considered in line with FCAS obligations which are to deliver at least the quantity of FCAS which a Trader has been enabled for, and the costs associated with changing systems and monitoring requirements to manage the increased granularity of data.

The technical requirements to enable DER integration into FCAS related processes (e.g. co-optimisation and bid size), may vary as capabilities and size of those resources evolve over time. This is being considered in Stage 2 of a potential ‘Phase of development’ discussed in section 2.7.

### Dispatch Instructions

The proposed dispatch instruction design is consistent with that for scheduled resources, and aligned with the IESS High Level Design[66], 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 5 minutes consistent with the NEM spot market. The dispatch instructions will be issued for each DUID. This means that, for an aggregated portfolio, a Dispatchability Model Trader 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[67]. Dispatch compliance considerations are being explored in section 5.2.8.

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[65] AEMO, 2021. *FCAS Model in NEMDE*. Available at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en

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

[67] A dispatch interval refers to an interval frequency at which service dispatch instructions are sent and the minimum service duration (5 minutes).

Currently, Project EDGE is trialling this concept. Scheduled Lite design will build on lessons from Project EDGE, (Appendix 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 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 Model
- Wholesale Demand Response – potential to leverage processes developed for WDR

**Dispatchability Model – Dispatch Process Questions**

- Are there any additional considerations that should be given to the Dispatchability Model for the dispatch process compared to utilising the existing processes for scheduled resources?
- Are there any alternative arrangements that should be considered for the types of resources expected to participate in Scheduled Lite?

### 5.2.6 Operations

This section outlines the operational processes associated with the Dispatchability Model. As outlined in section 2.2, consumer uptake of DER is already redefining power system operations. This is posing challenges in preserving the critical dimensions required to support secure and reliable power system operation.

Traders wishing to take part in the Dispatchability Model will be required to provide operational data through market systems in an identical fashion 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 an insight into the actual available capacity in the network e.g. realising additional export capacity[68].

Table 12 below highlights the required capability of a Trader among other market actors.

[68] AEMO, 2021. *VPP Demonstrations Knowledge Sharing Report #4*, section 3.4.1. Available at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en

**Table 12 Operations Dispatchability Model 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<br>•AEMO provides forecast | •Submit price and quantity bids reflecting availability<br>•AEMO provides forecast | •Full SCADA systems required<br>•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<br>•AEMO provides forecast | •Submit availability<br>•AEMO provides forecast | SCADA may be required |
| Non-scheduled loads | No action | No action | SCADA data* |
| End User Load | •No action<br>•AEMO provides forecast | •No Action<br>•AEMO provides forecast | No Action |

Required Capability

STPASA Pre-dispatch Dispatch

Week Days Hours Minutes

Aligned with scheduled resources, Traders within the Dispatchability Model will be able to be directed/instructed by AEMO where necessary to maintain or re-establish system security (e.g. system strength) and system reliability.

Traders will not be required to participate and provide information with respect to MTPASA. AEMO will use the information provided by the Dispatchability Model Trader to meet the medium-term forecasting requirements.

**Related Projects (see appendix 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

**Dispatchability Model – Operations Questions**

- Are there any barriers to providing availability forecast information?

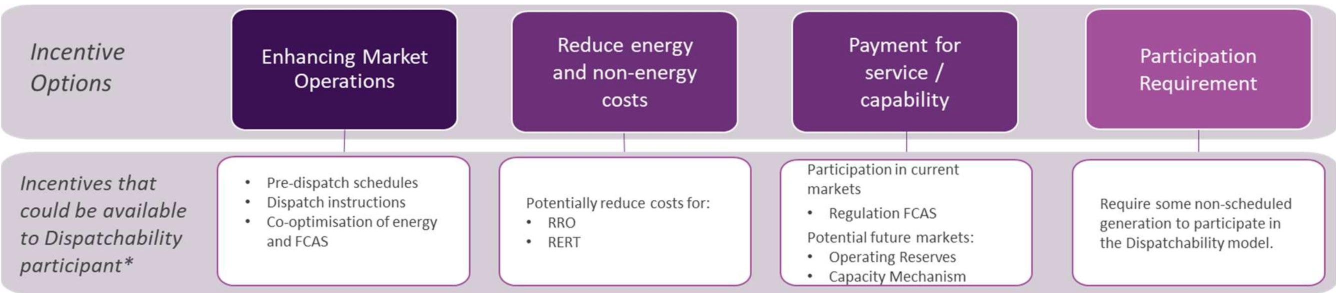
### 5.2.7 Incentives

The proposed incentives aim to unlock additional revenue streams for responsive resources, recognising their potential to support market operations. The proposed incentives were identified based on the Scheduled Lite principles outlined in section 2.5 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

The Figure 16 below, summarises the incentive options to those Traders wishing to take part in the Dispatchability Model.

Figure 16 Incentive options – Dispatchability 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:** 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 their bid information. The information may assist their ability to make better informed decisions relating to their 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 their 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.
- **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 their 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 RERT mechanism.

- **Payment for service/capability:** Some markets and services require resources to be scheduled as a pre-requisite for participation. Scheduled Lite provides aggregated DER and flexible demand with a model for participation as a scheduled resource allowing the resource, subject to meeting technical requirements, to participate in:

  – Existing markets:

    - 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[69]. The ability to participate in Regulation FCAS markets may provide an incentive for some DER and flexible demand, 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 4s 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.

  – Potential future markets

    - Capacity mechanism: The ESB is currently preparing a high-level design for a Capacity Mechanism for the NEM. While the structure of the mechanism is yet to be determined, it is possible that resources able to provide firm energy supplies are remunerated for the capacity they provide to the market. The capacity mechanism would require a procedure for assessing, allocating and monitoring the contribution of capacity by DER and flexible demand. Participation in the Dispatchability Model could provide a basis for DER and flexible demand to demonstrate their capacity entitlement and performance. Capacity remuneration could be a material additional revenue stream for DER and flexible demand, and as such act as a strong incentive to participate in the Dispatchability 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 Dispatchability Model (subject to any technical specification of the service) could enable the provision of operating reserves by DER and flexible demand. Operating reserves would be

[69] AEMO, 2021. *MASS final report and determination*. Available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/mass/final-determination/final-determination.pdf?la=en

an additional revenue stream for DER and flexible demand that could act as a strong incentive to participate in the Dispatchability Model.

- **Participation Requirement:** This incentive category would place an obligation on some resources to participate in the Dispatchability 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[70] 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 Dispatchability Model should apply to generators with a nameplate capacity of less than 30 MW.

**Related Projects (see appendix 1)**

- Project Symphony – Providing insights into enabling provision of services from DER

**Dispatchability Model – Incentives Questions**

- Are there any additional incentives that could be considered to encourage participation in the Dispatchability Model?
- For non-scheduled generators with a nameplate capacity of between 5MW and 30MW: do you consider that participating in the Dispatchability Model would add a significant level of additional costs?

### 5.2.8 Compliance

Compliance arrangements are an important consideration for the Dispatchability Model as 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 Dispatch units.

***Scheduled resources***

If a scheduled resource fails to comply with dispatch instructions, then 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 target. The AER is responsible for compliance activities in accordance with the NER.

[70] AEMC, 2021. *National Electricity Amendment (Generation registrations and connections) rule*. Available at https://www.aemc.gov.au/sites/default/files/documents/generator_registrations_and_connections_-_erc0256_-_final_determination.pdf

As set out in Dispatch Procedure (SO_OP_3705), a Small Error Trigger (3% of availability) and a Large Error Trigger (6% of availability)[71] 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 4 second variation between dispatch target and actual generation in a dispatch interval.

***Wholesale demand response***

The dispatch conformance rules for WDRUs are somewhat lighter in nature than those for 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.

***Switch participation to Visibility model***

As outlined in section 0, it is proposed that Traders would be able to manage their participation by opting out of the Dispatchability Model and effectively switch their participation into the Visibility Model. Traders could switch their participation if they’re concerned about their ability to conform with their dispatch targets. An alternative could be to automatically switch a Trader into the Visibility Model participation in the event the non-conformance actions outlined for scheduled resources are followed and the Trader fails to take corrective action.

The suspension of a Trader from the Dispatchability Model may have implications for participation in other markets.

***Proposed arrangements***

There is a complex trade-off between reducing the barrier to entry associated with compliance against the reliable and effective participation of DER in Scheduled Lite.

Based on performance in DER trials and feedback from Traders, AEMO understands that aggregated portfolios of DER could meet a high standard for dispatch conformance. Further, Traders could self-manage their compliance by switching out of the Dispatchability Model during periods where they are not confident of complying with dispatch targets.

[71] The error targets also incorporate a factor for the resources ramp rate and the error target is a minimum of 6 MW

For Stage 1 of the Dispatchability Model it is proposed that arrangements consistent with those of the WDR mechanism are established. These arrangements will need to be reviewed, in parallel with those for the WDR mechanism, for Stage 2 of the Dispatchability Model to ensure:

- they are fit for purpose, particularly if Dispatchability Units become a material share of scheduled resources, and
- to avoid any limits on the volume Dispatchability Units (and WDR Units) 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 Dispatchability Model. A failure to meet the eligibility requirements would result in the suspension of the Trader from the mechanism.

**Related Projects (see appendix 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

**Dispatchability Model – Compliance Questions**

- Are the proposed compliance arrangements for the Dispatchability Model workable for DER and flexible demand?

**Dispatchability Model – Straw Design Questions**

- Does the proposed straw design for Dispatchability Model represent a feasible model?
- Would there be any hurdles for a VPP to participate in the Dispatchability Model?
- Based on your understanding of participation requirements, would there be sufficient incentives to participate in the Dispatchability Model?

# 6 Operating Model - Opt-in Arrangement

An opt-in arrangement is proposed, due to considerations of potential Traders' capability maturity and recognition of feedback received through industry engagement[72], who suggested adopting a 'start simple, then add complexity' principle.

The opt-in arrangement aims to lower entry barriers for Traders wishing to participate in Scheduled Lite by enabling an active (on) operating mode and a passive (off) operating mode, rather than requiring 24/7 operation capability as is required of scheduled resources. Active (on) operating mode will correspond to the Trader performing functions as outlined in the previous sections for each model, while passive (off) operating mode will correspond to Traders having to perform less onerous functions while in that mode, as outlined below. The operating modes will apply to Traders taking part in the Visibility Model or in the Dispatchability Model and will require Traders to perform in accordance with the proposed terms established in the following subsections.

## 6.1 Visibility Model

The requirements and exemptions proposed here in this section are applicable only when a Trader is or chooses to operate in passive (off) mode; that is, when the Trader's Visibility Unit is not active. Otherwise, the Trader will be considered to be operating in an active (on) mode, in which case they will be required to perform as proposed in section 4.

The proposed requirements for the Trader to be in passive (off) mode are for the Trader to:

- Provide an opt-out notification
- Remain in active (on) mode for a minimum amount of time, and passive (off) mode for no longer than a specific period of time[73] (e.g. Trader chooses to operate in an active (on) mode only during business hours)

Visibility Model Traders will be exempt from providing indicative bids (see Table 8)[74] to market systems when operating in passive (off) mode and AEMO will adjust the use of the Traders' information accordingly. While it is expected that a Visibility Model Trader would provide a forecast for their Visibility Unit for the horizon in which they will be passive (off), they would not be expected to update this forecast while in passive (off) mode.

**Visibility Model – Operating Model Questions**
**Questions**

- Are the proposed opt-in arrangements for the Visibility Model workable for DER and flexible demand? Are there any further considerations that should inform the proposed opt-in arrangement?

## 6.2 Dispatchability Model

The requirements and exemptions proposed here are applicable only when a Trader operates in passive (off) mode, that is, when a Trader's Dispatchability Unit is not active. Otherwise, the Trader will be operating in active (on) mode and thus required to perform as proposed in section 5.

[72] Further information on industry engagement that supports the development of this consultation paper is detailed in Appendix 2

[73] To be established

[74] Note that Visibility Traders operating in passive (off) mode will need to provide all other 'Type of Data' contained in Table 8.

A Dispatchability Model Trader operating in passive (off) mode would differ from a scheduled resource bidding as ‘unavailable’ in that the applicable compliance and suspension terms are different in nature. At this stage, the system requirements to enable an Opt-in Arrangement for Dispatchability Model Traders are yet to be defined, and stakeholder feedback is sought on this proposal.

The proposed requirements for a Dispatchability Model Trader to operate in the passive (off) mode are to:

- Provide a non-dispatchable notification
- Provide Visibility service, providing data as per section 4.2.2, as if they were a Visibility Model Trader
- Remain contactable
- Remain in active (on) mode for a minimum amount of time, and passive (off) mode for no longer than a specific period of time[75]
- Do not switch between operating modes more than a maximum number of times[76] per day

Traders will not submit energy and FCAS bids when operating passive (off) mode, therefore their units will not be co-optimised by NEMDE, dispatch targets will not be generated and the Trader will not be subject to following a dispatch target.

**Related Projects (see appendix 1)**

- New Zealand – Dispatch Notification Project (DNx) – providing insights into considerations and requirements to enable an opt-in arrangement

**Dispatchability Model – Operating Model Questions**

**Questions**

- Are the proposed opt-in arrangements for the Dispatchability Model workable for DER and flexible demand? Are there any further considerations that should inform the proposed opt-in arrangement?

[75] To be established

[76] To be established

# 7 Consultation questions

AEMO welcomes stakeholder feedback on the draft high-level design for a Scheduled Lite mechanism. Feedback can be provided by email to StakeholderRelations@aemo.com.au by Tuesday 14 July 2022. Table 13 contains a summary of the consultation questions listed throughout this paper.

**Table 13 Summary of consultation questions**

| List of Consultation Questions | |
|---|---|
| *Participation in Scheduled Lite* | |
| *Questions* | |
| • Would AEMO's proposed participant registration process be suitable for large energy users, or should AEMO consider alternative means of registration for these participants?<br>• Are the proposed participation models for end user connection points appropriate to support participation of these resources? Are there other arrangements that should be considered?<br>• Do you agree with the proposed classification and zonal aggregation process? Are there any further considerations that should inform this aspect of the proposed design?<br>• Do you agree with AEMO's proposed approach to implementing an aggregated capacity threshold of 5 MW for participation in the Dispatchability Model, including the ability for participants to 'graduate' from Visibility to Dispatchability once the threshold is met?<br>• For DNSPs: do you consider that information access analogous to that provided for WDR is sufficient? If not, what other information on participating Scheduled Lite Units do you consider DNSPs should have access to? | |
| *Visibility Model* | |
| Design Element | **Questions** |
| Data Types | • Are there any hurdles to providing the data that has been identified? Are there other data types that are of value to the market and/or the networks that should be considered? |
| Data Exchange/ Telemetry | • Are there any hurdles to providing the data (see Table 8) via the proposed data exchange channels? |
| Operations | • Is there value in understanding the sensitivities provided by the Price Adjusted Demand Curve during operational timeframes?<br>• Are there any further considerations for how this information should be made available? |
| Incentives | • Are there any additional incentives that could be considered to encourage participation in the Visibility Model?<br>• For market participants already providing contingency FCAS: do you consider that participating in the Visibility Model would add significant additional costs? |
| Compliance | • Do you agree with the proposed compliance arrangements whereby a participant would lose access to the incentives if they are not complying? |
| General – Straw Design | • Does the proposed straw design for Visibility Model represent a feasible model?<br>• Would there be any hurdles for a VPP to participate in the Visibility Model?<br>• Based on your understanding of participation requirements, would there be sufficient incentives to participate in the Visibility Model? |
| *Dispatchability Model* | |
| Design Element | **Questions** |
| Data Exchange/ Telemetry | • Are there any hurdles to providing the data (see Table 11) via the proposed data exchange channels? |
| Constraints | • Do you agree with the proposed requirements associated with DOEs? Are there any other relevant requirements associated with DOEs that should be considered, taking into account the scope of Stage 1 (see section 2.7)? |
| Bids | • Taking into consideration the proposed minimum size requirements and minimum compliance arrangements, does the proposed threshold of 1 MW as the minimum incremental bid quantity represent a hurdle to participation? |
| Dispatch | • Are there any additional considerations that should be given to the Dispatchability Model for the dispatch process compared to utilising the existing processes for scheduled resources? |

| | |
|---|---|
| | • Are there any alternative arrangements that should be considered for the types of resources expected to participate in Scheduled Lite? |
| Operations | • Are there any barriers to providing availability forecast information? |
| Incentives | • Are there any additional incentives that could be considered to encourage participation in the Dispatchability Model?<br>• For non-scheduled generators with a nameplate capacity of between 5MW and 30MW: do you consider that participating in the Dispatchability Model would add a significant level of additional costs? |
| Compliance | • Are the proposed compliance arrangements for the Dispatchability Model workable for DER and flexible demand? |
| General – Straw Design | • Does the proposed straw design for Dispatchability Model represent a feasible model?<br>• Would there be any hurdles for a VPP to participate in the Dispatchability Model?<br>• Based on your understanding of participation requirements, would there be sufficient incentives to participate in the Dispatchability Model? |
| *Operating Model – Opt-in Arrangement* | |
| Visibility Model | • Are the proposed opt-in arrangements for the Visibility Model workable for DER and flexible demand? Are there any further considerations that should inform the proposed opt-in arrangement? |
| Dispatchability Model | • Are the proposed opt-in arrangements for the Dispatchability Model workable for DER and flexible demand? Are there any further considerations that should inform the proposed opt-in arrangement? |

# 8 Appendices

The appendices to the Scheduled Lite: Draft High Level Design Consultation Paper are provided as separate documents as outlined below.

**Table 14 Appendices**

| | |
|---|---|
| **Appendix 1** | Related Projects |
| **Appendix 2** | Stakeholder Engagement |
| **Appendix 3** | Use Cases |

# 9 Glossary

The following is a list of abbreviations used in this document. This document uses many terms that have meanings defined in the National Electricity Rules (NER), these NER meanings are adopted. Other terms are described in the body of the document as they arise.

| Term | Definition |
|---|---|
| **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 |
| **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 |
| **DUID** | Dispatchable Unit Identifier |
| **ESB** | Energy Security Board |
| **ESS** | Essential System Services |
| **FCAS** | Frequency Control Ancillary Service |
| **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 |
| **MASS** | Market Ancillary Service Specification |
| **MICF** | Market Integration Consultative Forum |
| **MRC** | Maximum Responsive Component |
| **MTPASA** | Medium Term Projected Assessment of System Adequacy |

| Term | Definition |
|---|---|
| **NEM** | National Electricity Market |
| **NEMDE** | National Electricity Market Dispatch Engine |
| **NER** | National Electricity Rules |
| **NMI** | National Metering Identifier |
| **NSP** | Network Service Provider |
| **PASA** | Projected Assessment of System Adequacy |
| **PMS** | Portfolio Management System |
| **Project EDGE** | Project Energy Demand and Generation Exchange |
| **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 |
| **VPP** | Virtual Power Plants |
| **WDR** | Wholesale Demand Response |
| **WDRU** | Wholesale Demand Response Unit |