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Energy Policy WA

Review of the Participation of Demand Side Response in the Wholesale Electricity Market

Consultation Paper

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Working together for a brighter energy future.

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Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
DER	Distributed Energy Resources
DSP	Demand Side Programme
DSR	DSR
DSRRWG	DSR Review Working Group
EPWA	Energy Policy WA
ESR	Electricity Storage Resource
ESS	Essential System Services
IRCR	Individual Reserve Capacity Requirement
MAC	Market Advisory Committee
MDT	Minimum Demand Threshold
MW	Megawatt
NCESS	Non-co-optimised Essential System Services
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RoCoF	Rate of Change of Frequency
SRC	Supplementary Reserve Capacity
STEM	Short Term Energy Market
SWIS	Southwest Interconnected System
WEM	Wholesale Electricity Market

Executive Summary

The DSR Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the rules for participation of Demand Side Response (DSR) in the Wholesale Electricity Market (WEM) in Western Australia under clause 2.2D.1 of the WEM Rules (the DSR Review).

DSR will play an important role in the WEM in the future, because of:

- the changes to the nature of the demand profile and generation in the South West Interconnected System (SWIS) since the commencement of the WEM in 2006;
- the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation; and
- the important flexibility/firming service DSR can provide in a market with ever increasing levels of intermittent and distributed generation.

Therefore, it is important to ensure that there are no barriers to the participation of DSR in the different WEM components.

The purpose of this review is to ensure that DSR has adequate incentives to participate in the WEM and is compensated appropriately for the provision of its services. The importance of DSR as a flexibility/firming resource in the WEM has also been highlighted during the Reserve Capacity Mechanism (RCM) Review modelling work.

The MAC has constituted the DSR Review Working Group (DSRRWG) to support the DSR Review. More information on the DSR Review is available from the Energy Policy WA (EPWA) website[1], including the Scope of Works for the review, the Terms of Reference for the DSRRWG, papers for the DSRRWG and relevant MAC meetings and detailed minutes for each meeting.

[1] DSRRWG: https://www.wa.gov.au/government/document-collections/demand-side-response-review-working-group

MAC: https://www.wa.gov.au/government/document-collections/market-advisory-committee

Proposals and Rationale

Table 1 lists the proposals outlined in this consultation paper and provides a high-level summary of the rationale for each proposal.

Table 1: Proposals from the first stages of the DSR Review

Design Proposal	Rationale
Proposal 1: Transparency regarding constrained access connections should be provided for and, to the extent practicable, constrained access loads should be integrated into the processes in the WEM rules. The WEM Rules should set out: • the requirements for Western Power to share information on constrained access loads with AEMO; • the manner in which AEMO integrates curtailable loads in determining the Reserve Capacity Target and Network Access Quantities; and • how curtailment of constrained access loads is considered in the Real-Time Market and constraint equations/optimisation processes. Changes to the commercial and regulatory framework to set out the information that must be made available to a customer seeking to connect on a constrained basis will also be developed.	Constrained access connections for loads are becoming more commonplace. The disconnect between the constrained access connections and the WEM may have an impact on the overall efficiency of both the RCM and the Real-Time Market. It is important to consider these matters now, before constrained access connections increase, while striking the right level of transparency and integration. It is also important that parties seeking to connect a load on a constrained basis have visibility about the terms and conditions of their connection.

Design Proposal	Rationale
Proposal 2: The WEM Rules should be amended to clarify the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.	A hybrid facility comprising a load and an Electric Storage Resource (ESR) component cannot register as both a Demand Side Programme (DSP) and as another facility type (e.g. a Scheduled Facility). Further, this hybrid facility may not have a choice whether to register as a DSP or a Scheduled Facility i.e. the Australian Energy Market Operator (AEMO) may require it to register as a Scheduled Facility. As a result, this hybrid facility can only receive capacity credits for its ESR component and not for its DSR. The WEM Rules should be clear about the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.
Proposal 3: Currently, participants with hybrid facilities are restricted in the way they operate their facilities in the energy and the ESS markets due to metering and settlement limitations. More flexibility should be provided to hybrid facilities that are registered in the WEM by enabling them to use Western Power installed sub-metering for the purpose of settlement in the STEM and the Real-Time Market, including the ESS markets.	Providing hybrid facilities (capable of providing DSR) with the choice of what services they provide and with access to a variety of possible revenue streams has the potential to provide market-wide benefits. With Western Power revenue quality metering on each component, it would be possible to use the same DSR in a hybrid facility to participate across the different markets (Real-Time Market, Essential System Services (ESS), RCM) to provide different services. However, revenue quality metering comes at a cost, so it should not be something all hybrid facilities are required to install.

Design Proposal	Rationale
Proposal 4: The dynamic baseline for DSR participation will be based on an ex-ante 'X of Y' methodology incorporating a 'day of adjustment'. A cap will be placed on upward adjustment but uncapped for downward adjustment. Ex-post mitigation through examination of data could still be followed to detect any undesirable behavior that is not being mitigated through ex-ante measures.	One of the Review Outcomes of the RCM Review was that the performance of DSPs should be measured against a dynamic baseline, rather than the static baseline in the status quo[2]. The rationale for this move can be found in the Reserve Capacity Mechanism Review Information Papers (Stage 1) and (Stage 2). During the RCM Review, it was noted that the introduction of a dynamic baseline increases the potential for gaming. This proposal will assist to prevent gaming of the baseline.
Proposal 5: No change to the SRC mechanism is proposed, as the SRC framework already provides for the effective participation of DSR.	A recent procurement of Supplementary Reserve Capacity (SRC) and subsequent review of this mechanism by the Coordinator of Energy indicates that the SRC framework already provides for the effective participation of DSR.
Proposal 6: Amend the *Electricity Industry (Metering) Code 2012* (Metering Code) so Western Power must share metering data on request to AEMO, to the extent necessary for market purposes, and with AEMO keeping that information confidential.	One of the issues raised in DSRRWG discussions was that Western Power is currently limited in the metering information it can provide to AEMO because of the confidentiality obligations in the Metering Code. This issue has also been raised in the recent SRC Review. During the SRC Review, it was identified that AEMO's ability to measure the performance of some of the services provided by DSR, for example in relation to demand response aggregations, was impeded.
Proposal 7: Take steps to remove impediments from the WEM Rules to allow direct participation by DSR in the STEM.	DSR participation in the Short-Term Energy Market (STEM) could increase activity and provide more opportunities for flexible loads. STEM participation is not mandatory, thus only willing DSR would participate. Additionally, the STEM is a 'simple' market so facilitating DSR participation is not expected to require large implementation changes.

[2] Review Outcome 4, Reserve Capacity Mechanism Review Information Paper (Stage 1) and Consultation Paper (Stage 2), 3 May 2023.

Design Proposal	Rationale
Proposal 8: No changes are proposed to DSP participation in the Real-Time Market.	Following discussions with the DSRRWG, EPWA considers that flexible loads are already provided with the opportunity to participate in the Real-Time Market, and DSPs are required to be available during the day time hours. Further changes to Real-Time Market to allow bidding by DSPs are likely to be complex and costly without significant benefits to justify such changes.
Proposal 9: No change is proposed to DSR participation in the Real-Time Market as the participation of flexible loads is already provided for.	DSRRWG members acknowledged the ability for scheduled loads to participate but were also of the view that direct participation by DSR in the Real-Time Market is likely to have low uptake due to the costs and effort outweighing the benefits. It was also noted that the willingness to patriciate in the Real-Time Market may change over time or could appeal to hybrid facilities (such as a large load with on-site generation).
Proposal 10: No changes are proposed to be made for a specific service to address the minimum demand issues in the SWIS at this time.	DSRRWG members discussed the need for developing a standard service to address minimum demand in the context of AEMO having already triggered Non-Co-optimised Essential System Services (NCESS) twice to procure minimum demand services. While there was some support for this, it was ultimately concluded that it is best to see if the increasing penetration of ESR, the new flexible capacity product and the Real-Time Market pricing will address this issue in the medium-term.
Proposal 11: The size and potential technical limitations (such as the telemetry requirements) for providing ESS should be reviewed to ensure that there are no unnecessary barriers for the provision of ESS by technically capable DSR.	Based on discussions by DSRRWG, EPWA considers that the size and potential technical limitations (such as the telemetry requirements) for providing ESS, currently detailed in the relevant AEMO WEM Procedure, need to be reviewed. The focus of this review should be to ensure that there are no unnecessary barriers for the provision of ESS by technically capable DSR. The review should also consider, among other things, whether some of these limitations (for example, size limitations) should be moved from the relevant WEM Procedures to the WEM Rules.

Design Proposal	Rationale
Proposal 12: No changes are proposed to be made to the ability of DSR to register as both an Interruptible Load and a DSP, and provide Contingency Reserve Raise services at the same time it receives capacity credits. However, methodology for the rotation of DSP dispatch will be developed.	On the basis of the DSRRWG and MAC discussion, EPWA considers that DSR, capable of providing the relevant services, should be able to stack value by receiving capacity credits as a DSP as well as being paid for providing Contingency Reserve Raise services. The review also needs to consider how to rotate the dispatch of DSPs in the market.

1. Introduction

Under Clause 2.2D.1(h) of the WEM Rules, the Coordinator of Energy (Coordinator) has the function to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the Wholesale Electricity Market (WEM) and the WEM Rules.

The Coordinator, in consultation with the MAC, is reviewing the rules for participation of Demand Side Response (DSR) in the WEM under clause 2.2D.1 of the WEM Rules (the DSR Review).

1.1 Background

1.1.1 Current Participation of DSR in the WEM

Currently, the direct participation of DSR in the WEM is limited to participation as a:

- Demand Side Programme (DSP) or part of a DSP in the Reserve Capacity Mechanism (RCM); and
- Interruptible Load.

Loads also participate indirectly in the WEM as they:

- pay for the consumption of energy either through retail contracts or the Balancing Market; and
- pay for Reserve Capacity based on their Individual Reserve Capacity Requirement (IRCR).

While loads will be able to register as Scheduled Facilities in the New WEM to provide other market services, analysis of the WEM Rules must be undertaken to ensure that they can provide services and extract value in the different WEM components in the same way as other facilities.

1.1.2 The Need for the DSR Review

DSR will play an increasingly important role in the WEM in the future because of:

- the changes to the nature of the demand profile and generation in the South West Interconnected System (SWIS) since the market start; and
- the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation; and
- the important flexibility/firming service DSR can provide in a market with ever-increasing levels of intermittent and distributed generation.

Therefore, it is important to ensure that there are no barriers to the participation of DSR in the different WEM components.

The purpose of this review is to ensure that DSR has adequate incentives to participate in the WEM and is compensated appropriately for the provision of its services. The importance of DSR as a flexibility/firming resource in the WEM has also been highlighted during the RCM Review modelling work and relevant key observations made from this review with respect to DSR have been summarised in Appendix C.

1.1.3 Guiding Principles

The guiding principles for the review of the participation of DSR in the WEM are that any recommendations should:

1. meet the Wholesale Market Objectives;

2. enable the orderly transition to a low greenhouse gas emissions energy system;
3. be cost-effective, simple, flexible and sustainable;
4. allocate risks to those who can best manage them;
5. provide investment signals and technical capability signals that support the reliable and secure operation of the power system;
6. ensure that the value of DSR can be maximised for the benefit of those who provide it and the WEM as a whole; and
7. ensure that DSR is not under- or over-compensated for its participation and treatment in any of the WEM components.

1.1.4 Scope of Review

The Coordinator, in consultation with the MAC, set the following objectives for the DSR Review:

- identify the different ways DSR can participate across the different WEM components;
- identify and remove any disincentives or barriers to DSR participating across the different WEM components; and
- identify any potential for over- or under-compensation of DSR (including as part of "hybrid" facilities") as a result of its participation in the various market mechanisms and provision of Network Services.

The following aspects related to the participation of DSR are out of scope for this review:

- certification of DSPs; and
- treatment of IRCR.

The scope of this Review only includes contestable customers. Distributed Energy Resources (DER), also known as 'behind the meter' devices, also fall outside of the scope of this review. DER has been separately addressed under the WA Government's 'Distributed Energy Resources Roadmap' of April 2020.

1.2 Key observations from the RCM Review

DSR participation in the RCM is mostly out of scope of this review. However, the RCM Review flagged three areas of consideration for the DSR review:

1. Ongoing procurement of Non Co-optimised Essential System Services (NCESS) for minimum demand services by the Australian Energy Market Operator (AEMO) highlights that minimum demand remains an ongoing concern (refer to Section 3.7.3).
2. Rules will be needed to ensure that a Capability Class 2 facility with co-located load and storage cannot self-discharge its storage so as to reduce its IRCR exposure while also receiving capacity credits for that capability (refer to Section 3.3).
3. The implementation of the dynamic baseline as an important element relevant to DSP participation (refer to Section 3.3.1**Error! Reference source not found.**).

1.2.1 Staged Approach

The review of the participation of DSR in the WEM is being conducted in three stages:

Table 2: Stages of the DSR Review

Stage	Description	Refer Section
Stage 1	High level assessment of the participation of DSR across all WEM components based on:	
	• A review of the participation of DSR in other markets in the context of what problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements relate to the WEM. Jurisdictions to be investigated include: - The National Electricity Market (NEM); - The United Kingdom (UK); - The Pennsylvania-New Jersey-Maryland Interconnection (PJM); and any other jurisdictions identified by the MAC or Energy Policy WA (EPWA).	Appendix A
	• The outcome of the system stress analysis from Stage 1 of the RCM Review.	3.3.1 and 3.7.3
	• Identification of typical flexible loads (e.g. large cold stores) that exist in the WEM and don't participate	3.7.3
	• Assessment of possibilities for over- or under compensation for different scenarios of DSR participating in the various market mechanisms and Network Services provision.	3.2.1, 3.3, 3.4, 3.5, 3.6 and 3.7.3
Stage 2	A gap analysis identifying any barriers and disincentives for DSR to participate across the different components of the WEM and provide the services identified under Stage 1, including in: • the registration framework; • the RCM; • the Short Term Energy Market (STEM); and • the Real-Time Market, including the Essential System Services (ESS) market and NCESS. This includes assessment on why the flexible loads identified under Stage 1 do not currently participate.	3.2.1, 3.3, 3.4, 3.5, 3.6 and 3.7.3
Stage 3	Formulations of recommendations for further action, if any, and development of Rule changes if necessary.	To be completed during Stage 3

The MAC has constituted the DSR Review Working Group (DSRRWG) to support this review. More information on the review is available from the EPWA website[3], including the Scope of Works for the review, the Terms of Reference for the DSRRWG, papers for the DSRRWG and relevant MAC meetings and detailed minutes for each meeting.

1.3 Purpose of this paper

This consultation paper sets out the findings and proposals arising from Stage 1 and Stage 2 of the DSR Review and presents proposals to enable the participation of DER in the various components.

This paper is structured as follows:

- Chapter 2 describes the role that DSR can play in liberalised energy markets;
- Chapter 3 discusses the areas of the new market (post 1 October 2023) that DSR is able to participate in based on the new WEM Rules[4] and makes proposals for change.
- Appendix A provides information on international jurisdictions investigated.

1.4 Stakeholder Consultation

Stakeholder feedback is invited on the proposed changes to DSR participation in the WEM, as outlined in this consultation paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au.

Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm (WST) on 2 November 2023. Late submissions may not be considered.

[3] DSRRWG: https://www.wa.gov.au/government/document-collections/demand-side-response-review-working-group

[4] Based on the 29 April 2023 version of the new WEM Rules

2. The Role of DSR

2.1 Traditional roles of DSR

Demand response in energy markets takes many traditional forms:

- ***Curtailable/Interruptible load*** - demand competing for varying reserve products with other resources and avoiding investment in other types of reserve capacity (e.g. generation facilities);
- ***Demand side bidding and forecasting*** - requirement for the demand side of the market to forecast and bid in its requirements in order to improve system demand accuracy;
- ***Dispatchable demand*** - incentive to use less electricity when prices are higher and more when prices are lower (subject to elasticity), sometimes called Energy Arbitrage;
- ***Demand reduction*** - call option given to the network operator in order to manage outages and maintenance or to defer investment. It can also be provided to retailers to mitigate high price periods when under hedged;
- ***Ripple Control*** - relinquishing some control over consumption to the retailer and/or the network operator (direct load control). The rollout of Advanced Metring Infrastructure (AMI) is expanding these opportunities;
- ***Real time response*** - giving control to the retailer, the network operator or, in some cases, aggregator to use demand response for frequency (regulation) control. A discounted tariff will typically be provided for this.
- ***Load shedding*** - when system supply is insufficient to meet demand.

2.2 Realising the potential of DSR

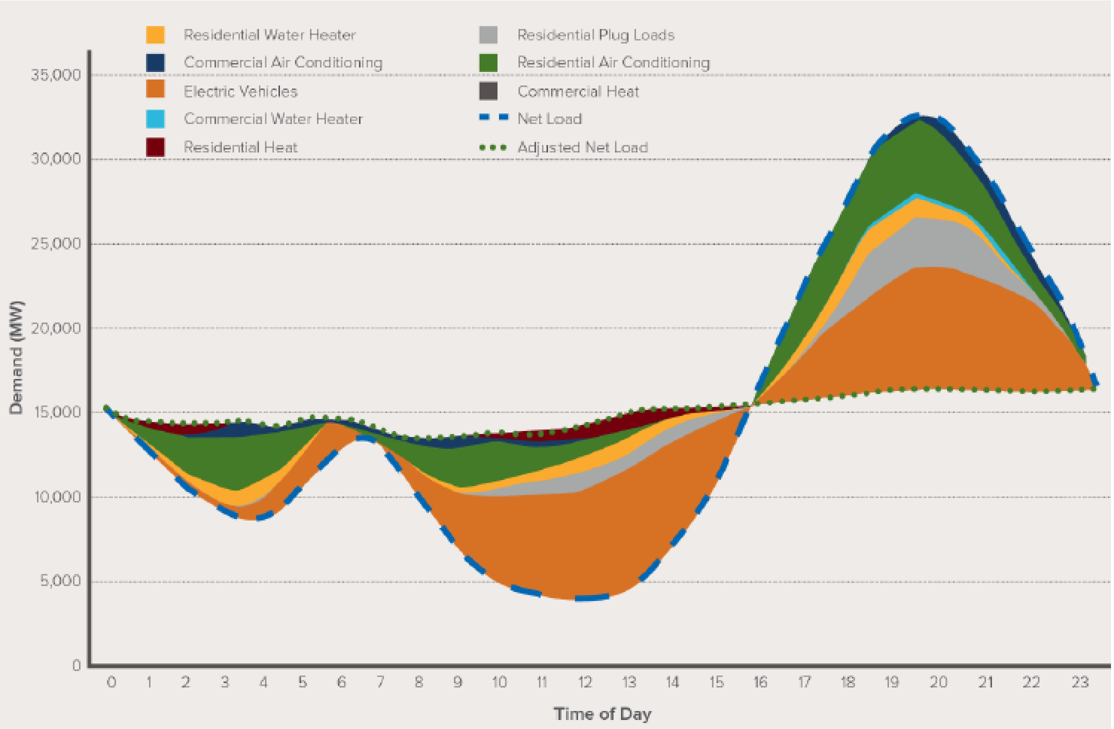
Demand response has the potential to add value in two broad areas:

- system security & reliability (contributing to ancillary/essential system services); and
- enhanced efficiency, through:
  - deferring investment in network and reserve capacity;
  - shifting usage away from peak periods (improve capital resource utilisation) and to minimum demand periods; and
  - reducing system and market costs through increased competition (demand and supply sides competing among and with each other).

DSR has the potential to provide a wide range of flexibility and load shifting services. This can be in response to a price signal or a direction, due to a technical requirement or a constraint.

The potential for demand shifting is illustrated Figure 1, which projects the potential net load and changes due to demand flexibility for an average day:

Figure 1: Value of Demand Flexibility (load shifting)



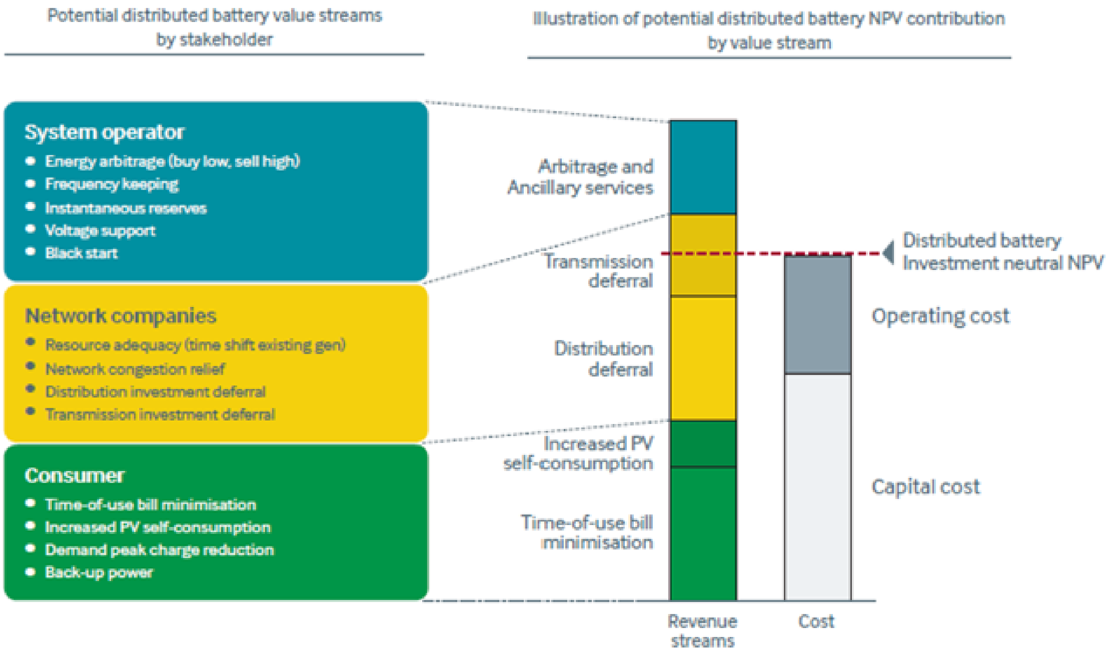
Source: Using a hypothetical 2050 generation mix in ERCOT. Demand Flexibility - The key to enabling a low cost, low carbon grid. Rocky Mountain Institute, February 2018

Greater participation of DSR is anticipated in many electricity markets around the world. This is made possible through:

- The roll out of AMI, “smart” appliances and batteries;
- Improved control systems;
- The emergence of aggregators;
- Electric vehicles that can both withdraw and inject into the distribution network (combining a ”smart” load and a battery).

New technologies are presenting a more diverse range of potential solutions to energy sector challenges. The value propositions that these technologies bring will vary depending on how they are deployed, and the perspective of the stakeholder being involved. For example, the utilisation of energy storage presents differing value propositions depending on the perspective of the System Operator, Network Operator or the Consumer as illustrated in Figure 2.

Figure 2: Potential distributed battery value streams by stakeholder.

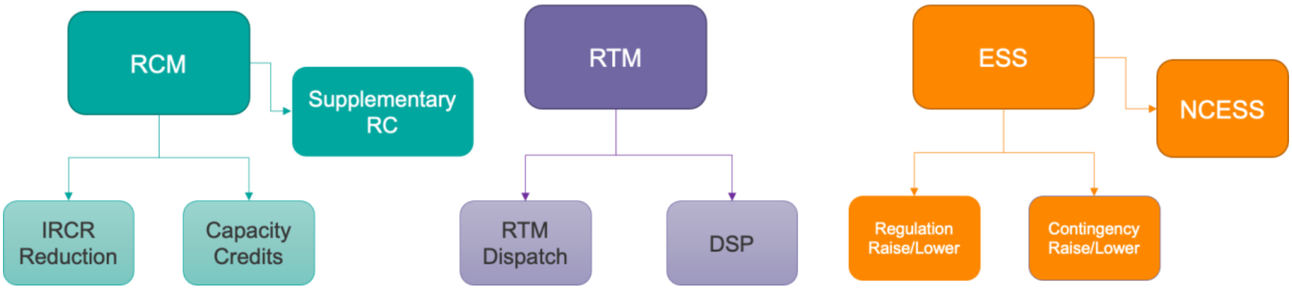


Source: Based on The Economics of Battery Energy Storage, Rocky Mountain Institute

3. DSR Participation in the new WEM

The following sections explore all the opportunities for DSR participation, based on the WEM Rules[5] for the new market. The paper steps through the various WEM components and considers the barriers and incentives to DSR participating in each component. It also discusses how matters such as network connection and metering arrangements may affect DSR participation.

Figure 3: DSR Participation in the WEM



3.1 Network connection

While the DSR Review is concerned with the participation of DSR in the WEM, it is also necessary to consider how the network connection arrangements influence WEM participation. One matter that has been identified through the DSRRWG discussions is the framework for managing constrained access loads, and the transparency regarding these arrangements.

3.1.1 Constrained Access for Loads

As a general principal, customers have unconstrained network access. They can consume electricity as desired. Some new customers connecting in congested parts of the network are being placed on 'runback schemes' by Western Power. These customers' consumption can be limited when the network is congested. These customers are referred to here as 'constrained access loads'.

Connecting constrained access loads is cheaper if it avoids or delays reinforcing the network. These customers can also be connected earlier. The number of new constrained access loads is expected to increase over time, as more regions are expected to become congested in the transition to a lower emissions system and as more customers pursue electrification. While there are many benefits to this, there are some issues with the operations of these schemes as they currently stand, including:

- Runback scheme connections currently lack transparency and are not fully integrated in the market. For example, the number, the demand and location of these constrained access loads is not transparent to the market.
- Effective integration into the market is also not currently provided for. For example:
  - the triggers for curtailment are not transparent to AEMO and the WEM; and
  - whether and how the effect of this curtailment is considered in system planning, or in the RCM processes more generally, is not clear.

While it is acknowledged that Western Power does share some information about constrained access loads to AEMO, there is no clarity about what must be provided across planning and operational timeframes. The disconnect between the constrained access connections framework

5 Based on the 29 April 2023 version of the new WEM Rules

and the WEM may have an impact on the overall efficiency of both the RCM and the Real-Time Market. Integrating this process in the WEM Rules will add certainty and transparency.

It is important to consider these matters now, before constrained access connections increase, while striking the right level of transparency and integration.

It is also important to consider the types of information that could be provided to participants to help inform their decision of whether to connect on a constrained access basis. Such information may include:

- system operating conditions under which a participant's load would be curtailed;
- the maximum number of hours per day and per year a customer's load can be curtailed, and by how much each time;
- how often and when, during the day or the year, they may be curtailed;
- what notice a customer will be given that their load will be curtailed;
- what effect agreement to connect on a costrained basis will have on their network payments; and
- how a customer's application for constrained access connection will be assessed.

As constrained access connections become more common, it may be of benefit to make these a reference service so that there is a standard product available to anyone who qualifies. This would provide transparency to potential network users, enabling due consideration of the costs and benefits of different connection options as part of investment decision making. It would also avoid the need for lengthy negotiation between each individual network user and Western Power on the terms and conditions of constrained access, and ensure consistency in terms and conditions across users.

Proposal 1:

Transparency regarding constrained access connections should be provided for and, to the extent practicable, constrained access loads should be integrated into the processes in the WEM Rules. The WEM Rules should set out:

- the requirements for Western Power to share information on constrained access loads with AEMO;
- the manner in which AEMO integrates curtailable loads in determining the Reserve Capacity Target and Network Access Quantities;
- how curtailment of constrained access loads is considered in the Real-Time Market and constraint equations/optimisation processes; and

Changes to the commercial and regulatory framework to set out the information that must be made available to a customer seeking to connect on a constrained basis will also be developed.

Consultation Questions:

1. Do stakeholders support integrating constrained access loads in the WEM and the WEM Rules?
2. Are there any circumstances in which it would not be efficient or practical to integrate constrained access loads into the WEM Rules?

3.2 Registration

The new WEM registration taxonomy defines a facility by its technology type and then by its class. The technology types in the new WEM are:

- a distribution system;
- a transmission system;
- an Intermittent Generating System;
- a Non-Intermittent Generating System;
- an Electric Storage Resource; and
- a Load.

Technology types must be registered into a facility class. The facility classes in the new WEM are:

- a Network;
- a Scheduled Facility;
- a Semi-Scheduled Facility;
- a Non-Scheduled Facility;
- an Interruptible Load; and
- a Demand Side Programme.

Loads (which are not part of a hybrid facility) can register as one of the following:

- a Scheduled Facility consisting of a Load[6];
- a Semi-Scheduled Facility consisting of a Load;
- a Non-Scheduled Facility consisting of a Load;
- an Interruptible Load consisting of a Load;
- a Demand Side Programme consisting of a Load; and
- a Demand Side Programme consisting of Non-Dispatchable Load(s)[7].

For clarity, a DSR cannot be registered as a Load. It can either apply to be registered in one of the facility classes or left unregistered. AEMO will consider the 'controllability' of a facility when determining its facility class.

Overall, the registration framework in the new market provides appropriate flexibility for DSR which wishes to participate in the WEM. However, the DSRRWG has identified that the metering arrangements that apply to hybrid facilities may pose a barrier to flexibility in registration, and therefore participation in other WEM components. This is discussed further below.

[6] In the WEM, loads are defined as one or more electricity consuming resources or devices, other than Electric Storage Resources, located behind a single network connection point or electrically connected behind two or more shared network connection points.

[7] A non-registered load by default is a Non-Dispatchable Load.

3.2.1 Registration of hybrid facilities

The presence of hybrid facilities in energy markets is increasing to support renewable energy resources in the energy transition. The SWIS is no different in this regard and is equally expected to see an increase in hybrid facilities, many of which may include a load.

A hybrid facility is a facility compromising two or more different technology types. Often it is a combination of a generating system and an Electric Storage Resource (ESR). However, the WEM Rules allow for a hybrid facility to include a load, to form:

- A load and an ESR hybrid facility; or
- A load and on-site generating system (intermittent or non- intermittent) hybrid facility; or
- A load, on-site generating system (intermittent or non- intermittent) and an ESR hybrid facility.

Registering a hybrid facility in the WEM is based on injection and withdrawal capacity and direction of energy flows. A load can be collocated with another technology type provided they share a common connection point (i.e. a single Western Power meter) and then register as a Scheduled Facility, Semi-Scheduled Facility or a Non-scheduled Facility, depending on the size of the technology type(s).

As part of this review, EPWA analysed the range of hybrid configurations to test their value proposition. The hybrid configurations considered were:

- ESR and on-site load;
- ESR and on-site load (on-site load turning off or reducing to reduce IRCR);
- ESR and on-site load (on-site load supplied by ESR to reduce IRCR);
- ESR and DSP;
- ESR and DSP (on-site load turning off or reducing to reduce IRCR);
- ESR and DSP (on-site load supplied by ESR to reduce IRCR); and
- ESR, Intermittent Generation and DSP.

Through the above analysis four likely viable operational models emerged:

- ESR and load not participating in the RCM, and using the ESR to reduce IRCR costs;
- only ESR participating in the RCM and load reduced to reduce its IRCR;
- load operating as a DSP and ESR not particiapting in the RCM; and
- both components participating in the RCM.

Hybrid facilities are most viable when there is opportunity to 'value stack'. Value stacking is when multiple services are provided by the same facility. This is different from the potential for 'double dipping' in which multiple payments are received for the same action. Double dipping needs to be considered carefully and prevented if it does not add value to the market.

The ability to value stack depends on the level of flexibility available to facilities to choose how to engage the different facility components with the different market components at any given time. Hybrid facilities are treated differently in the energy markets and the RCM, as discussed below.

Hybrid facilities in the RCM

Hybrid facilities are eligible to apply for certified capacity. Each technology type in hybrid Scheduled or Semi-scheduled Facilities is assessed separately. Hybrid Non-scheduled Facilities are assessed as a single component under the Relevant Level Methodology.

Capacity Credits assigned to a hybrid facility are the sum of each component's certified capacity, capped by the facility's Network Access Quantity (NAQ). If the NAQ value is less than the total certified capacity, the Market Participant will advise AEMO of the number of capacity credits for each component it receives.

A hybrid facility with a DSP component is certified based on its relevant demand. All of a DSP's associated loads must be associated with a common Transmission Node Identifier (TNI).

The Reserve Capacity Obligation Quantity (RCOQ) for a hybrid facility reflects all technology types of the separately certified components. A hybrid facility must meet the RCOQ for each certified component.

However, the hybrid facility reserve capacity refunds are not separately calculated. This means that one of the components (e.g. an intermittent generator) can meet the RCOQ of another component (e.g. the ESR). An under-performing component may also affect the facility total capacity revenue.

Hybrid facilities (apart from intermittent generator components) are subject to capacity testing, with each component tested independently. A testing failure resulting in capacity credit reduction will only lower the capacity credits of the failing component.

Overall, hybrid facilities are offered sufficient flexibility for their participation in the RCM.

The DSRRWG identified one potential issue with the registration of hybrid facilities. Currently, a DSP cannot also register in another facility class. The only exception is an Interruptible Load, which can also register as a DSP.

As a consequence, a hybrid facility comprising a load and an ESR component cannot register as both a DSP and as another facility type (e.g. a Scheduled Facility). Further, this hybrid facility may not have a choice whether to register as a DSP or a Scheduled Facility i.e. AEMO may require it to register as a Scheduled Facility. As a result, this hybrid facility can only receive capacity credits for its ESR component and not for its DSR.

EPWA considers that the WEM Rules should be clear about the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.

Proposal 2:

The WEM Rules should be amended to clarify the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.

Consultation Questions:

3. Do stakeholders support providing clarity in the WEM Rules regarding the registration requirements applying to a hybrid facility comprising a load and an ESR component?

Hybrid facilities in the energy market

Currently, the WEM considers a hybrid facility as a single Facility for dispatch. This is because the *Electricity Industry (Metering) Code 2012* (The Metering Code), standard metering practices and national legislation require the meters used for settlement to be installed, owned, and operated by Western Power. However, in practice, under the WEM Rules a facility currently can only elect to have a Western Power meter installed at its connection point. This may be limiting the opportunity for hybrid facility participation in the energy markets.

Participants are restricted in the way they operate their facilities in the STEM and Real-Time Market due to the metering limitations placed on them. More flexibility could be provided to hybrid facilities that are registered in the WEM if they were able to use Western Power installed sub-metering for the purpose of settlement in these markets[8]. For clarity, this would require the creation of a new National Metering Identified (NMI) associated with the sub-meter as this is the only way settlement amounts can be calculated separately.

With Western Power revenue quality metering on each component, it would be possible to use the same DSR in a hybrid facility to participate across the different markets (Real-Time Markets, RCM) to provide different services.

Providing hybrid facilities (which include flexible DSR) with the choice of what services they provide and with access to a variety of possible revenue streams has the potential to provide market wide benefits. However, revenue quality metering comes at a cost, so it should not be something all hybrid facilities are required to install. Detailed design of this proposal will also need to give consideration to the practicalities of installing such sub-meters, in particular the arrangements if the meter needs to be on a user's private network.

Proposal 3:

More flexibility should be provided to hybrid facilities that are registered in the WEM by enabling them to use Western Power installed sub-metering on individual components of their facility, thereby allowing each component to be settled separately in the STEM and Real-Time Market.

Consultation Questions:

4. Do stakeholders support providing the option for hybrid facilities to install settlement grade sub-meters?

3.3 RCM

Loads can participate in the RCM in two different ways.

The first is indirectly through reducing demand during expected peak demand periods to reduce their IRCR. If the load can successfully match its demand reduction to the peak demand IRCR intervals, it will be allocated a smaller IRCR cost.

The second is through direct participation in the RCM and receiving capacity payments. A load must be part of a DSP to be eligible for capacity payments.

The DSR Review examined the potential for a DSR to 'double dip' by seeking to reduce its IRCR cost while receiving capacity payments for the same flexible load. It concluded that for a load that is not collocated with another technology type (e.g. ESR), the WEM Rules prevent this from occurring by reducing its capacity payments in subsequent years.

A recipient of capacity payments must make its capacity available for dispatch by AEMO. The availability requirements vary depending on the facility class. For example, DSPs must be available from 8am to 8pm, whereas scheduled facilities must be available all of the time.

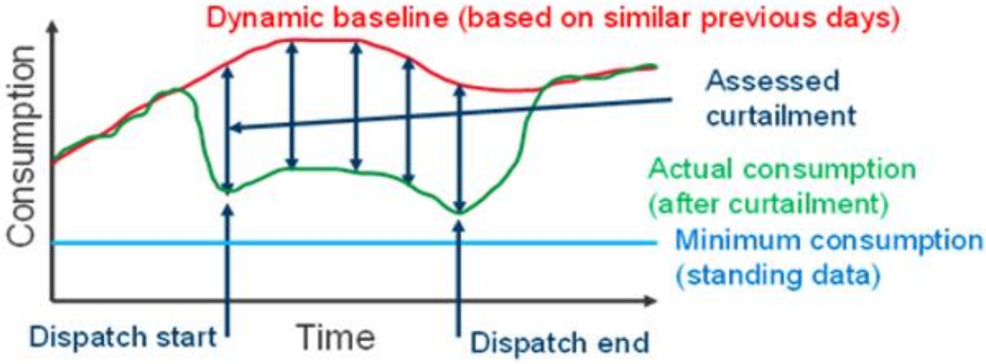
[8] The *National Measurement Act 1960* requires that meters used for the purposes of settlement are Western Power revenue quality meters.

3.3.1 Measuring the performance of DSPs

One of the Review Outcomes of the RCM Review was that the performance of DSPs should be measured against a dynamic baseline, rather than the static baseline in the status quo[9]. The rationale for this move can be found in the RCM Review Information Papers (Stage 1) and (Stage 2)[10].

A dynamic baseline more accurately reflects the actual curtailment delivered by the DSP compared to its level if not dispatched. A dynamic baseline also allows better forecasting of the actual response expected from dispatched DSPs, which allows more reliable operation of the power system.

Figure 4: Dynamic Baseline



Source: RCM Review, Consultation Paper (Stage 2)

During the RCM Review, it was noted that the introduction of a dynamic baseline increases the potential for gaming. For example, if the baseline were set by interpolating between consumption immediately before and after the dispatch period, a DSP could artificially increase its consumption in the preceding periods to increase its baseline.

The DSR Review is considering the detailed design of a dynamic baseline that mitigates this risk. This can be achieved in two ways:

- ex ante (before the fact) measures such as stricter calculation guidelines; or
- ex post (after the fact) measures such as regulatory monitoring and penalties.

Some examples of ex-ante measures to reduce opportunities for baseline manipulation by participants include[11]:

- using a baseline calculation method that is fair on average on likely event days, absent any gaming;
- ensuring that baseline calculation data include recent "similar" days, and are limited in how far back the "look-back" period can be so that data from another season cannot be used to overstate the baseline;
- using rules that have the effect of limiting participants' ability to control or predict what days they will be called on to reduce withdrawal;

9 Review Outcome 4, Reserve Capacity Mechanism Review Information Paper (Stage 2), 2 August 2023.

10 https://www.wa.gov.au/system/files/2023-08/reserve_capacity_mechanism_review_-_information_paper_stage_2.pdf

11 Measurement and Verification for Demand Response - Prepared for the [USA] National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group , KEMA, February 2013

- investigating load and bidding patterns that seem perverse based on customer characteristics; and
- requiring advance notice of scheduled shut-downs.

In the DSRRWG deliberations on the potential for gaming, a member noted that:

> *"In the WEM, most energy users that participate or would participate in a demand side programme are commercial or industrial businesses with production targets and/or service levels to meet. While it is feasible that such a business would chase an opportunity to game its baseline, it would not do this if it posed any risk or distraction to the achievement of its primary business objective".*

It was further noted that there are technical limitations to running equipment harder and contractual demand limits in participants' connection agreements that would limit any opportunity for gaming.

However, if provided with a sufficient incentive, some participants may look to push the boundaries of what is deemed as acceptable behaviour by DSPs. An example of this is how participants in the UK 'gamed' the way Transmission Use of System (TUoS) charges were allocated during peak times. Known as 'triad avoidance schemes' (refer Appendix **Error! Reference source not found.**), participants tried to predict which three periods each Winter would be used by the Transmission Operator as the basis to allocate peak system charges and to reduce their usage during these three periods. This created a significant cost transfer to those participants who did not, or could not, play this 'game'.

There are four general types of possible baseline designs:

- the "X of Y" baselines,
- the weighted average (or current and preceding day),
- regression; and
- matching day-pair[12].

The most common type of baseline is the "X of Y". This methodology loosely translates as looking at 'X' of the last 'Y' days. In practice, an adjustment is often made if there were atypical load days in the preceding 'Y' period, such as a public holiday or facility outage. Such atypical days can be removed from both the 'X' and the 'Y'. Five of the USA markets use this methodology, as shown in Table 5 below.

Table 3: 'X' of 'Y' baselines adopted in the US Markets

Market	Baseline Name	Average of	Out of
CAISO, MISO	10-in-10	10 most recent weekdays	10 most recent weekdays
ERCOT	Mid 8-of-10	10 most recent weekdays, dropping highest and lowest kWh days	10 most recent weekdays
NYISO	5-of-10	5 highest kWh days	10 most recent weekdays
PJM	4-of-5	4 highest kWh days	5 most recent weekdays

[12] Development of DR Mechanism, Baseline Consumption Methodology – Phase 1 Results, AEMO/KEMA, July 2013

Given that DSPs are most often called to respond when demand is at its highest, it is common practice to apply ‘day-of adjustments’ to the raw baseline. Day-of adjustments apply so that the baseline more accurately reflects the load conditions of the event day.

Such an adjustment is also used in the NEM. The NEM, both in its Reliability and Emergency Reserve Trader (RERT) mechanism, and its Wholesale Demand Response Mechanism, has adopted the “10-in-10” baseline methodology.

To further mitigate any concerns of gaming, a cap can be placed on positive adjustments for the day-of-adjustment. However, negative adjustments should be uncapped to allow the baseline to reflect, for example, a load being out on maintenance during the response day.

Ex-post examination of data could still be used to assess whether gaming is taking place.

Proposal 4:

The dynamic baseline for DSR participation will be based on an ex-ante ‘X of Y’ methodology incorporating a ‘day of adjustment’. A cap will be placed on upward adjustment but uncapped for downward adjustment.

Ex-post mitigation through examination of data could still be followed to detect any undesirable behavior that is not being mitigated through ex-ante measures.

Consultation Questions:

5. Do stakeholders agree that an ex-ante ‘X of Y’ methodology incorporating a ‘day of adjustment’ is an appropriate baseline design for DSP participation?

3.4 Supplementary Reserve Capacity (SRC)

Six months before the start of a capacity year AEMO can seek SRC if AEMO considers there will be inadequate reserve capacity. All facilities, including demand side providers, are eligible to participate if they:

1. do not hold Capacity Credits in the current Capacity Year; and
2. have not held Capacity Credits in the current Capacity Year or a previous Capacity Year; and
3. hold Capacity Credits in a subsequent Capacity Year; or
4. provide evidence satisfactory to AEMO, prior to a Supplementary Capacity Contract taking effect, that:
   a) costs have been incurred to enable the provision of the capacity through the installation of physical equipment; and
   b) the capacity is in addition to the sent-out capacity of the Energy Producing Systems, or the maximum amount of load that can be curtailed, that existed prior to the installation of the physical equipment.

AEMO dispatches any procured SRC in line with the agreed contractual terms.

Proposal 5:

No change to the SRC mechanism is proposed, as the SRC framework already provides for the effective participation of DSR.

Consultation Questions:

6. Do stakeholders agree that the existing framework of the SRC mechanism already provides effective incentives for DSR participation?

3.5 Metering Code – Amending Confidentiality Obligations

During the DSRRWG meeting of 5 July 2023, there was discussion on the prospect of DSR being integrated into the WEM from the beginning to the end of its life cycle.

One of the issues raised in that discussion was that Western Power is currently limited in the metering information it can provide to AEMO because of the confidentiality obligations in the Metering Code.

This issue has also been raised in the recent SRC Review[13]. During the SRC Review, EPWA identified that AEMO's ability to measure the performance of some of the services provided by DER, such as demand response aggregations, was impeded due to the following issues with meter data availability:

- Confidentiality prevented Western Power from providing AEMO with meter readings for some of the relevant NMIs.
- Some of the relevant meters were either not capable of providing, or were not set up to provide, interval meter data.

Energy Policy WA proposed to make amendments to the WEM Rules to require and enable Western Power to provide AEMO with the information necessary for the performance measurement of SRC services, including the interval meter data needed to measure the performance of SRC services.

Stakeholder feedback in the SRC Review was supportive of the intent of the proposed changes, with suggestions that an additional clause is required in the Metering Code to overcome issues and challenges with confidentiality.

Following the similar discussion in the DSRRWG, EPWA agreed to propose changes addressing these issues. The changes will provide clarity about the obligations for Western Power to provide the information AEMO needs to measure SRC services and align the definitions of confidentiality between the WEM and the Metering Code.

Proposal 6:

Amend the Metering Code so Western Power must share metering data on request to AEMO, to the extent necessary for market purposes, and with AEMO keeping that information confidential.

Consultation Question:

7. Do stakeholders support amending the Metering Code so Western Power must share data (which AEMO shall keep confidential) with AEMO upon request?

3.6 STEM

DSR is not currently able to participate in the STEM. While participation is not explicitly prohibited, DSR is not able to comply with STEM bidding requirements. The STEM is a small market with few participants, some of which are quite active. STEM participation could be extended to DSR allowing it to purchase energy and optimise its contract position.

Members of the DSRRWG were asked for their views on the benefits of extending STEM participation to DSR. One member noted that historically a retailer had purchased energy from the STEM on behalf of its customers and sold it to customers at STEM prices plus a margin. This

[13] More information can be found at: https://www.wa.gov.au/government/document-collections/supplementary-reserve-capacity-review

arrangement was possible because the retailer had bilateral contracts with the customer which allowed this. Members suggested that STEM participation should be allowed for customers without a bilateral contract.

DSR participation in the STEM could increase activity and provide more opportunities for flexible loads. STEM participation is not mandatory. Thus, only willing DSR would participate. Additionally, the STEM is a 'simple' market so facilitating DSR participation is not expected to require large implementation changes.

Proposal 7:

Take steps to remove impediments from the WEM Rules to allow direct participation by DSR in the STEM.

Consultation questions:

8. Do stakeholders agree that DSR should be allowed to directly participate in the STEM?

3.7 The Real-Time Market

DSPs and Loads are treated differently from Energy Producing Systems (i.e. generating systems and ESR) in the Real-Time Market.

3.7.1 DSP participation

The WEM Rules set out specific requirements for DSP dispatch and these do not provide for Real-Time Market participation. For example, DSPs do not submit bids in the Real-Time Market.

A DSP is required to be available for dispatch between 8am – 8pm on each day. AEMO would issue Dispatch Instructions to a DSP if it reasonably considers that the dispatch of that DSP is required to restore or maintain Power System Security or Power System Reliability (clause 7.6.5A of the Market Rules). As DSP providers do not submit bids, AEMO does not factor in prices when selecting DSP for dispatch.

Dispatch Instructions to DSPs are different from those issued to other facilities. For example, Dispatch Instructions for DSPs are issued in accordance with the required notice period for the facility (two hours) while Dispatch Instructions are issued to other facilities every five minutes.

The meaning of a Dispatch Instruction is also different for DSPs:

- a non-zero MW quantity means that the consumption of the DSP must be curtailed to less than or equal to the specified level by the start time shown in the Dispatch Instruction;
- the market participant is expected to maintain at least this level of curtailment until the start time of the next dispatch instruction;
- a zero MW quantity dispatch instruction means that the consumption of the DSP no longer needs to be curtailed from the start time shown in that dispatch instruction; and
- the DSP when dispatched must be at or below the required level by the start time of the dispatch instruction, and must remain at or below that required level until the start time of the next dispatch instruction. This may either be to increase or decrease curtailment, or return to uncurtailed levels.

Following discussions with the DSRRWG, EPWA considers that flexible loads are already provided with the opportunity to participate in the Real-Time Market, and DSPs are required to be available during the daytime hours. Further changes to the Real-Time Market to allow bidding by DSPs are likely to be complex and costly without significant benefits to justify such changes.

Proposal 8:

No changes are proposed to DSP participation in the Real-Time Market.

Consultation questions:

9. Do stakeholders agree that there is no need or benefit that would justify changes to DSP participation in the real lime energy market?

3.7.2 DSR participation

Loads that are not part of a DSP[14] have the option to participate in the Real-Time Market by registering as a scheduled facility or semi-scheduled facility (if part of a hybrid facility). Scheduled facilities and semi–scheduled facilities can bid withdrawal quantities/prices into the Real-Time Market. They are then included in the Real-Time Market dispatch algorithm.

AEMO centrally dispatches facilities using the Wholesale Energy Market Dispatch Engine (WEMDE), based on bids and offers submitted by facilities. Scheduled facilities are given a dispatch target, while semi-scheduled facilities are given a dispatch cap.

From a market perspective dispatchable DSR can be valuable in two scenarios:

1. Dispatched 'on' during low load periods to increase demand; and
2. Dispatched 'off' during high load periods to reduce demand.

When demand is low, DSR can be valuable by increasing demand to avoid the risks associated with insufficient system demand. Further, when prices are negative DSR can benefit by effectively being paid to consume.

Alternatively, when demand is high DSR can be valuable by reducing demand. This could help reduce prices or avoid load shedding if generation is insufficient.

DSRRWG members acknowledged the ability for flexible loads to participate in the Real-Time Market but were also of the view that direct participation by DSR in the Real-Time Market is likely to have low uptake due to the costs and effort outweighing the benefits. It was also noted that the willingness to participate in the Real-Time Market may change over time or could appeal to hybrid facilities (such as a large load with on-site generation).

Proposal 9:

No change is proposed to DSR participation in the Real-Time Market as the participation of flexible loads is already provided for.

Consultation questions:

10. Do stakeholders agree that the Real-Time Market has sufficient opportunity for DSR participation?

[14] A load cannot be registered concurrently as both a DSP and as another Facility, apart from an Intermittent Load.

3.7.3 Minimum demand services

An increasing challenge in the SWIS is that minimum operational demand is falling as inverter-based generation (e.g. rooftop PV generation) increases. With less synchronous generation available, alternative response is required to counter:

- low levels of inertia;
- lower operational flexibility; and
- reduced system strength.

The lowest SWIS demands typically occur in the following circumstances:

- mild weather periods when there is little demand from heating or cooling;
- weekends when there is less commercial/industrial demand - less businesses are open or operating; and
- the middle of clear, sunny days (say from 10am to 2pm) when behind-the-meter solar PV installations are generating most and reducing consumer demand.

In response EPWA is already coordinating and leading the Low Load Project[15]. This project is to ensure appropriate responses, frameworks and mechanisms are in place to manage low demand when it occurs.

This Review has identified that DSR can contribute in two ways:

1. help to keep demand above the minimum demand threshold; and
2. provide alternative response to maintain system stability.

DSR can contribute to keeping demand above the minimum demand threshold in the following ways:

- load shifting from peaks to troughs (both reducing exposure to high prices during the evening peak and taking advantage of low prices in the middle of the day); and
- increasing demand in low load periods/high PV output periods.

If discretionary demand exists, the real time energy price during low demand periods should provide a signal for load to increase. However, this may happen only if discretionary loads are not fully hedged (e.g., through fixed tariffs or their bilateral contracts) and are thus exposed to the pricing signals.

Retail and network electricity price signals have already moved some demand to low demand periods overnight.

Some large customers are on energy supply contracts with peak and off-peak pricing, with higher peak prices applied during the day. Over many years some of these customers adapted and shifted some of their consumption to the overnight ‘off-peak’ period.

Customers which have flexibility around the time of their consumption may be able to shift consumption to the emerging off-peak times, now in the middle of the day. While the STEM or Real-

[15] https://www.wa.gov.au/system/files/2022-08/EPWA-SWIS%20Low%20Demand%20Project%20Stage%201.pdf

Time Market prices are low or negative during the low demand periods, just a few of these customers may currently receive direct price signals to encourage them to do so.[16]

The types of loads that could increase their demand during the SWIS minimum demand periods typically:

- do not need to operate 24/7;
- do not currently operate in the middle of the day or weekends; and
- can do some type of "batch" process resulting in storage of their "product".

Examples of this include:

- conveyors carrying material to a stockpile;
- milling or grinding of ore or other material to a stockpile or storage;
- production of chilled water (stored in a specially designed chilled-water storage system) for later use;
- ice storage for shifting air-conditioning load;
- pumping of water to storage or for irrigation, and similarly for other pumped products;
- desalination of water;
- cooling of large cold stores (warehouses) which can be over-cooled during off-peak periods and then the cooling can be turned off during peak periods and still maintain the required temperatures due to the large thermal mass of cooled product and good cold store insulation;
- electric-heat-pump-heated aquatic centres;
- ice production – although demand for ice will be lower in mild weather; and
- on-site load that is supplied by on-site generation.

Retailers and wholesale market customers that are benefiting from the low or negative prices during the minimum demand periods, however, may not want to encourage increased demand. Increasing demand during these times may increase market prices.

Barriers and Incentives

DSR participation in the Real-Time Market can help to support the system stay above minimum operational demand by increasing consumption during low load periods.

The Real-Time Market provides price signals to the demand side to incentivise the desired response. The price floor of the Real-Time Market is negative $1,000 which means that load would be paid to consume during times of over-supply.

However, only some demand will be sufficiently flexible to respond in this way, and a portion of this flexible load will not be exposed to real time energy prices due to the protection of its contractual arrangements against volatile spot prices. Further, if flexible load responds to this price signal demand will increase and result in higher market prices.

Given this 'dampened' effect on the market price signal it may be necessary to provide some other form of incentive, for example compensation for the provision of a minimum demand service.

[16] It is only recently that some new network tariffs have been introduced by Western Power – from 1 July 2023 - to focus price signals specifically to encourage more consumption in the middle of the day – the new super-off-peak tariffs. Some retailers are starting to offer retail tariffs to a few customers on this basis.

However, such a measure may be premature with more ESRs likely to enter the market which may help to resolve the problem.

DSRRWG members discussed the need for developing a standard service to address minimum demand in the context of AEMO having already triggered NCESS twice to procure minimum demand services. While there was some support for this, it was ultimately concluded that it is best to see if the increasing penetration of ESR, the new flexible capacity product and the Real-Time Market pricing will address this issue in the medium-term.

EPWA, therefore, proposes that no specific changes to introduce a minimum demand service be made at this time.

Proposal 10:

No changes are proposed to be made for a specific service to address the minimum demand issues in the SWIS at this time.

Consultation questions

11. Do stakeholders agree that no changes should be made to introduce a minimum demand service at this time?

3.8 DSR participation in the ESS markets

There are two types of ESS services:

- Frequency Co-Optimised ESS (FCESS); and
- NCESS (see the section above).

3.8.1 FCESS

DSR can provide a variety of FCESS. When the system is short on synchronised generation DSR can assist in maintaining system stability. Table 4 shows the possible ways DSR can support system stability.

Table 4: Potential DSR roles to maintain system stability

Required response	Potential synchronous generation response	Potential DSR role
Frequency control	• Greater volume creates higher inertia ⇨lower frequency disturbance from events. • 6 second pulsing. • Governor response. • Out-of-merit dispatch.	• Direct load control • Rate of Change of Frequency (RoCoF)
Raise frequency nadir	• System inertia, both actual and synthetic.	• RoCoF
Ramp management (from min. demand to peak demand)	• Multi-period dispatch planning. • Out-of-merit dispatch.	• Dispatchable demand.
Voltage stability	• Reactive power	• Pre-contingent load management.

Required response	Potential synchronous generation response	Potential DSR role
		• Post-contingent load management (immediate response).

The new co-optimised energy and ESS market includes five FCESS services:

- Regulation Raise;
- Regulation Lower;
- Contingency Reserve Raise;
- Contingency Reserve Lower; and
- RoCoF.

The WEM Rules do not provide for a DSP to provide FCESS, unless also registered as an Intermittent Load.

For DSR to be accredited for providing FCESS, the DSR must be registered as either a Scheduled or Semi-Scheduled Facility or an Interruptible Load. Subject to meeting the size and technical requirements, DSR registered as a Scheduled or Semi-Scheduled Facility can provide any of the FCESS services.

However, there are technical and size limitations to the DSR ability to provide FCESS. For example, in order to provide Regulation Raise or Regulation Lower, the DSR must have an Automatic Generation Control System (AGC) installed, which enables it to automatically receive and respond to signals from AEMO. AGC is the system into which Dispatch Targets or Dispatch Caps are entered and processed by AEMO for facilities operating on automatic generation control.

Interruptible Loads, on the other hand, already provide Contingency Reserve Raise services in the WEM without AGC. However, there are size limitations to the DSR ability to provide these services, which are enshrined in the relevant AEMO WEM Procedure.

Members of the DSRRWG discussed telemetry requirements as a possible barrier to participating in the Contingency Reserve Raise services in the WEM. One member noted that:

> *"In other interruptible load markets, there are no telemetry obligations, only compliance with dispatch instructions. Offers reflect what loads can actually provide in a frequency event, with local response to locally measured frequency deviation."*

International experience supports the DSRRWG's view. Observations from the NEM demonstrate that the Reliability and Emergency Reserve Trader (RERT) with lower telemetry and more notice lead time had higher uptake than the Wholesale Demand Response Mechanism (WDRM) which has stricter requirements. In the UK, a survey by the energy regulator, the Office of Gas and Electricity Markets, raised telemetry as one of the higher obstacles to DSR participation.

A DSRRWG member representing AEMO acknowledged the views regarding telemetry and noted that:

> *"AEMO plans to consult on this as part of updating the FCESS Accreditation WEM Procedure"* and *"that the real time SCADA is not necessary to provide those services but some level of visibility of the service availability should be required."*

Based on the above, EPWA considers that the size and potential technical limitations (such as the telemetry requirements) for providing ESS, currently detailed in the relevant AEMO WEM Procedure, need to be reviewed.[17]

The focus of this review should be to ensure that there are no unnecessary barriers for the provision of ESS by technically capable DSR. The review should also consider, amongst other things, whether some of the limitations (for example, minimum size) should be moved from the relevant WEM Procedures to the WEM Rules.

Proposal 11:

The size and potential technical limitations (such as the telemetry requirements) for providing ESS should be reviewed to ensure that there are no unnecessary barriers for the provision of ESS by technically capable DSR.

Consultation questions:

12. Do stakeholders agree that there may be potential barriers to the participation of DSR in the ESS markets?
13. Do stakeholders agree that the size and potential technical limitations (such as the telemetry requirements) for providing ESS should be re-examined?

3.8.2 Intermittent Loads

Currently, a DSP can also register as an Interruptible Load and be accredited to provide Contingency Reserve Raise services. Members of the DSRRWG queried whether a DSR should be allowed to register as both a DSP and an Intermittent Load given that, historically, Intermittent Loads have provided Contingency Reserve Raise services only and have not been dispatched as a DSP.

In the new WEM:

- Interruptible Loads would be bidding in the Contingency Reserve Raise market;
- If they are not dispatched because they are not in merit, they would be treated as any other DSP and dispatched when necessary (noting that a DSP providing capacity would not be providing Contingency Reserve Raise service at the same time).
- the WEM Rules will require a participant to reduce its Interruptible Load offers to zero if dispatched as a DSP, and if it is registered as both an Interruptible Load and a DSP at same connection point; and
- AEMO would need to know how to rotate loads in such circumstances.

Members of the DSRRWG considered that Interruptible Loads offering Contingency Reserve Raise are valuable to the market because their response is fast and they do not need to have ACG. A member also noted that, if an Interruptible Load is interrupted at peak times, it is no longer providing Contingency Reserve Raise but demand reduction and, therefore, the remaining generator output is reduced by the same amount thus maintaining the level of spinning reserve.

[17] The WEM Rules do not prescribe the requirements for telemetry, instead the WEM Rules give AEMO authority to detail the requirements (clause 2.35.4 of the WEM Rules)

Based on the DSRRWG discussion, EPWA considers that DSR, capable of providing the relevant services, should be able to stack value by receiving capacity credits as a DSP as well as being paid for providing Contingency Reserve Raise services.

This topic was discussed further at the MAC meeting of 31 August 2023. No stakeholders were opposed to EPWA's position outlined above. However, one stakeholder concurred that the WEM Rules need to provide for the rotation of DSPs that are dispatched by AEMO.

Proposal 12:

No changes are proposed to be made to the ability of DSR to register as both an Interruptible Load and a DSP, and provide Contingency Reserve Raise services at the same time it receives capacity credits. A methodology for the rotation of DSP dispatch will be developed.

Consultation questions

14. Do stakeholders agree that no changes are required to the ability of DSR to simultaneously participate as a DSP and as an Interruptible Load providing ESS?

Appendix A: Review of demand side participation in other jurisdictions

Energy Policy WA undertook a review of the participation of Loads and DSR in other jurisdictions, including:

- The National Electricity Market (NEM) in Australia;
- the United Kingdom;
- the Pennsylvania New Jersey Maryland Interconnection (PJM) in the United States of America (USA); and
- New Zealand.

Each of the jurisdictions studied have a degree of DSR participation with varied outcomes and success. However, it’s clear that each jurisdiction is looking at DSR as a suitable option to fill their required specific need. The needs range from helping to manage and reduce peak demand, to improving energy market pricing and to contributing to system reliability. The WEM is facing all these challenges plus more, such as minimum operational demand dropping closer to thresholds below which AEMO will need to intervene to ensure power system security and reliability. The range of applications of DSR in other jurisdictions demonstrates its flexibility and the possible uses in the WEM.

The following information supports the consideration of issues and recommendations in this Consultation Paper.

A.1 National Electricity Market, Australia

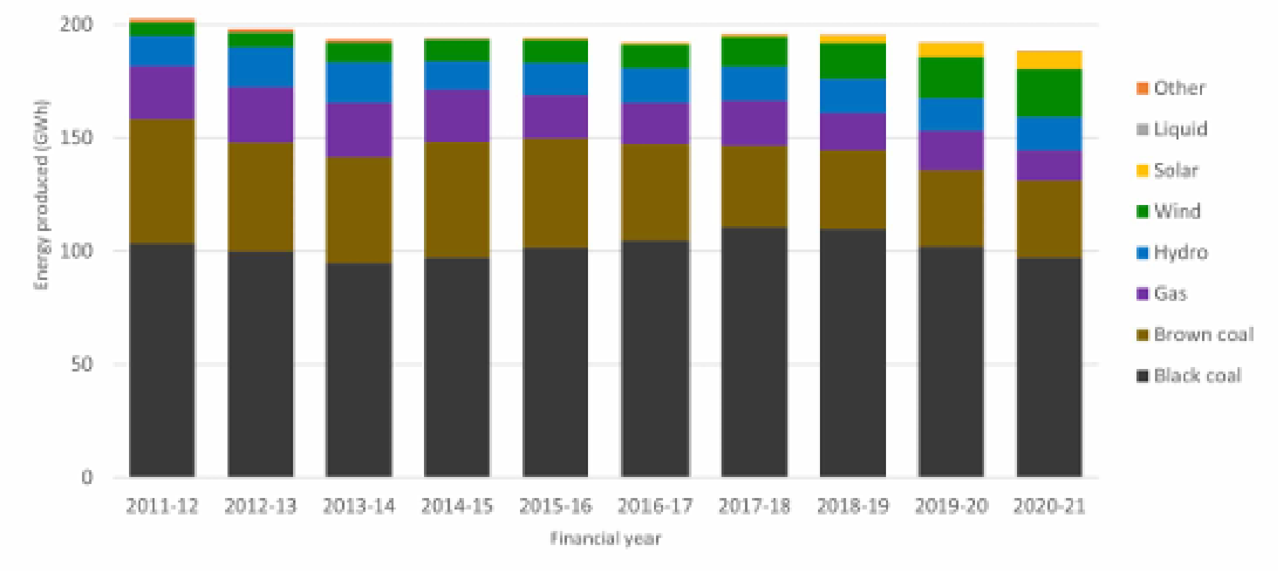
A.1.1 Jurisdiction overview

The National Electricity Market (NEM) is comprised of five physically connected regions on the east coast of Australia: Queensland, New South Wales (which includes the ACT), Victoria, Tasmania and South Australia. It is an energy-only market with a capacity backstop.

Annual electricity consumption in the NEM has declined from a peak of 210.5TWh in 2008/09 to 188.4TWh in 2002/23[18]. The system remains supplied by predominately thermal (coal) generation resources (refer Figure 5). Much of this coal is expected to retire over the coming 25 years (as shown in Figure 2), and this process is expected to be expedited as the transition towards net zero greenhouse gas emissions gathers pace. These coal generators will be replaced with renewable generation resources, which will need to be accompanied by firming resources.

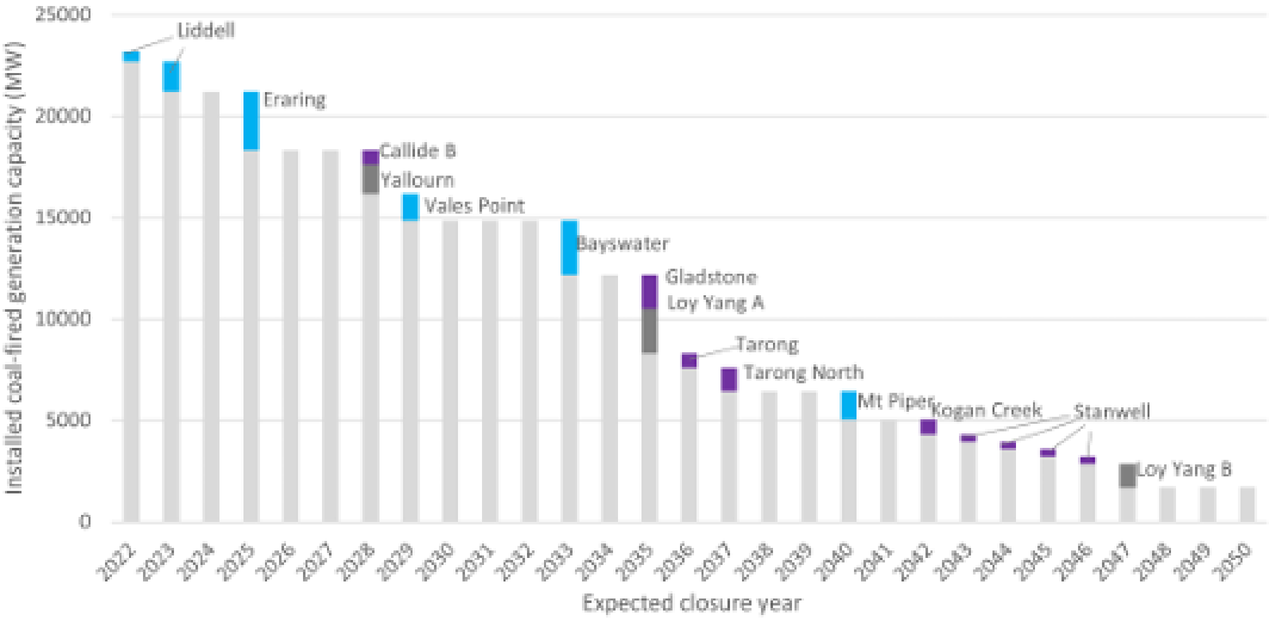
[18] Annual electricity consumption – NEM, AER website https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-electricity-consumption-nem

Figure 5: NEM, energy produced by grid-scale generation technology



Source: AEMC Reliability Panel, 2021 Annual Market Performance Review, April 2022

Figure 6: NEM announced coal closures by year

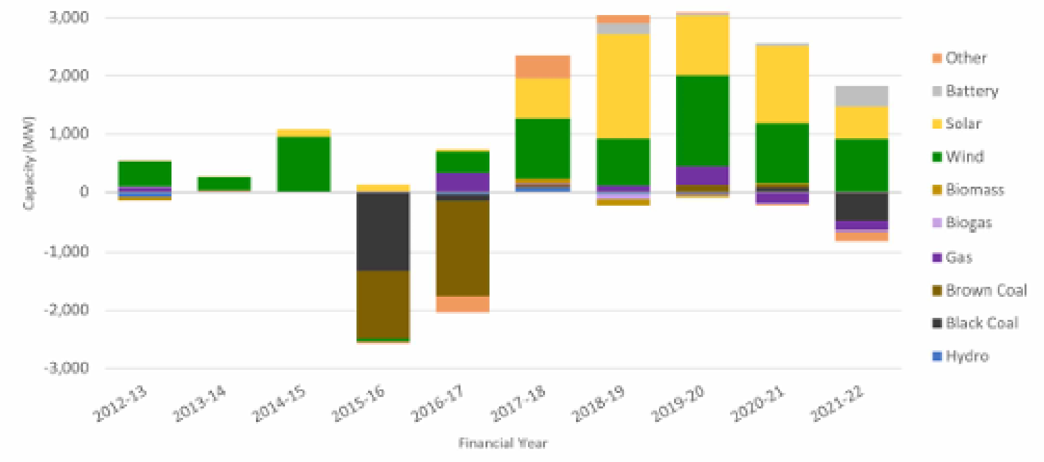


Source: AEMC Reliability Panel, 2022 Annual Market Performance Review, March 2023

The increasing penetration of intermittent renewable generation in the NEM (refer Figure 7), in particular distributed PV (refer Figure 9), has led to a change in the shape of electricity demand, in particular:

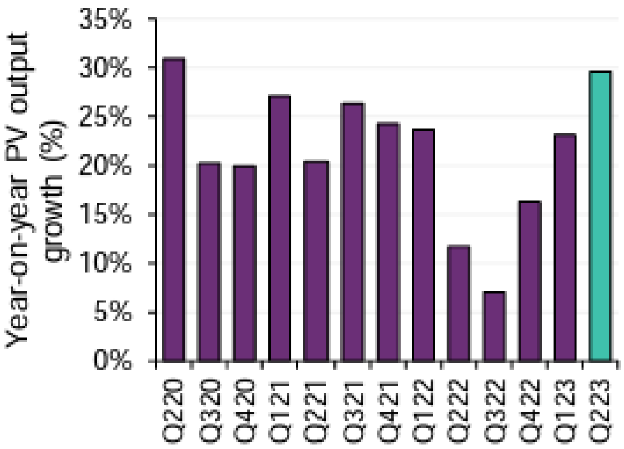
- intra-day demand has become more volatile; and
- there has been a significant reduction in daytime operational demand (refer Figure 9).

Figure 7: NEM utility-scale Generator Entry & Exit



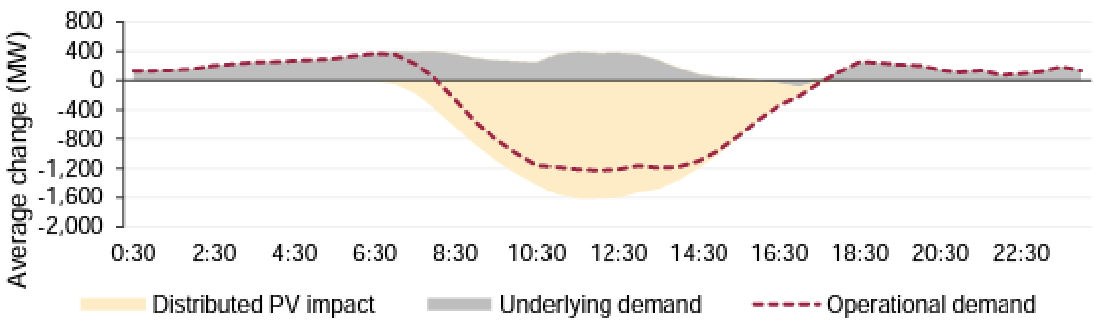
Source: AEMC Reliability Panel, 2022 Annual Market Performance Review, March 2023

Figure 8: Year-on-year growth in distributed PV output



Source: Quarterly Energy dynamics, Q2 2023, AEMO

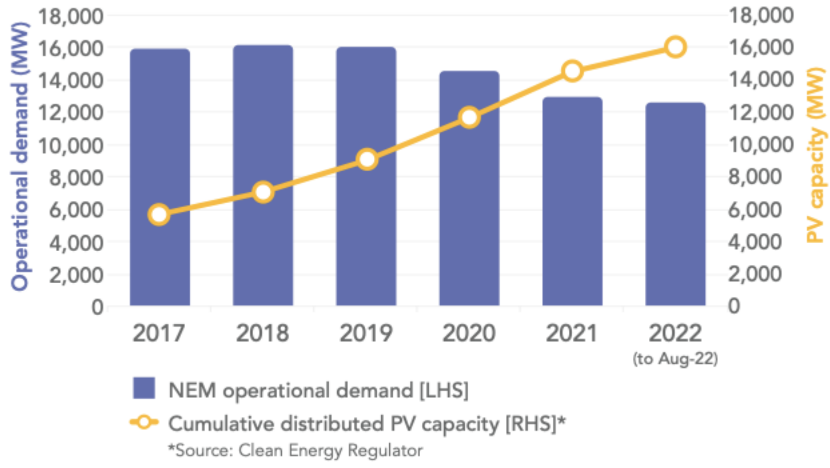
Figure 9: Distributed PV reduced daytime operational demand (Q2 2023 vs Q2 2022)



Source: Quarterly Energy dynamics, Q2 2023, AEMO

The increase in distributed PV is resulting in the system operational demand reducing, as demonstrated in Figure 10. This has seen the operational demand peak around 2018 and then reduce each year. The increasing amounts of underlying demand being supplied by distributed PV is displacing large generators, who have historically provided essential system services. In the absence of other firming resources, this is making it more difficult to manage power system security and reliability.

Figure 10: Minimum operation demand decline as rooftop solar installations increase



Source: AEMO Minimum operational demand factsheet (https://www.aemo.com.au/-/media/files/learn/fact-sheets/minimum-operational-demand-factsheet.pdf?la=en)

A.1.2 Use or planned use of Loads and Demand Side Response in the NEM

Demand side resources can participate in the NEM through the:

- Wholesale Demand Response (WDR) Mechanism.
- Reliability and Emergency Reserve Trader (RERT) mechanism; or
- Retailer Reliability Obligation (RRO)

The key differences between participating in the two primary mechanisms, the WDR and RERT, is shown in Table 5, and explained further below.

Table 5: Comparison of WDR and RERT mechanisms

	WDR	RERT
Type of mechanism	Market	Out of market
Dispatch timeframes and communication	Scheduled in 5 min dispatch timeframe through standard bidding and dispatch process.	Planned ahead (several hour lead time) through verbal communications and agreement
Dispatch trigger	Bid is at or below market price	AEMO operational decision
Technical requirements	Standardised capability assessment through registration to meet obligations of NER and ensure no system security issues	Procurement-based service provision to meet reliability need
Market interactions	Bid information included in PASA and pre-dispatch	PASA outputs feed into decisions on the need for RERT to protect market
Settlement & Baselines	Baselines calculated at NMI level for settlement	Baselines calculated at aggregated level for settlement
Dispatch compliance	Baselines aggregated to Dispatchable Unit Identifier level for dispatch compliance assessment	Aggregated baselines used to assess demand response provided against contractual commitment

	WDR	RERT
Who pays for response?	Retailer pays for demand response at its NMI	All Market Customers pay for RERT service
Telemetry	Established based on size and location	Large loads typically have telemetry, no additional requirements for RERT

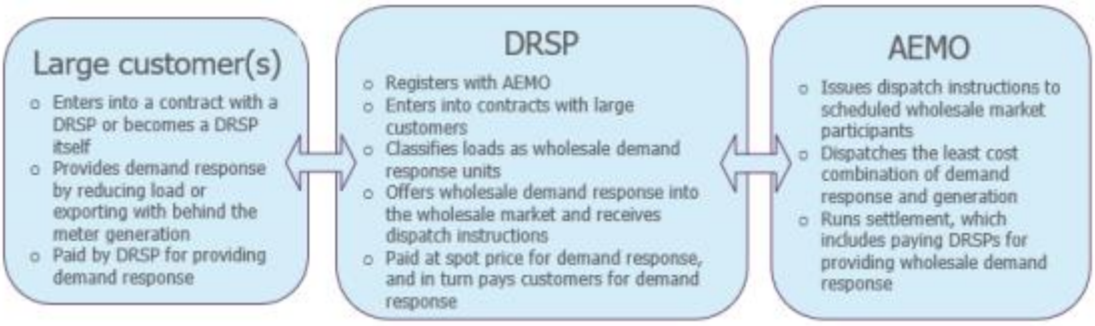
Source: AEMO website, WDR Frequently Asked Questions

WDR Mechanism

In June 2020, the AEMC released a rule change report setting out a series of changes to the National Electricity Rules that would establish a wholesale demand response mechanism.[19] Under this rule, large consumers would be able to sell demand response in the wholesale market, either directly or through specialist aggregators. It was designed to suit larger customers who have loads that are controllable and predictable for the purposes of scheduling.

The rule introduced a new market participant category, a demand response service provider (DRSP). Obligations on DRSPs, as much as practicable, replicate those applied to scheduled participants (for example, similar information provision and scheduling obligations). DRSPs can participate in market at anytime and are settled at the prevailing spot price.

Figure 11: below indicates how the WDR mechanism works at a high level.



Source: Wholesale Demand Response: High-level Design, AEMO 2020

Demand response can be a single load or an aggregation of loads. To qualify for participation in the WDR mechanism, a load must:

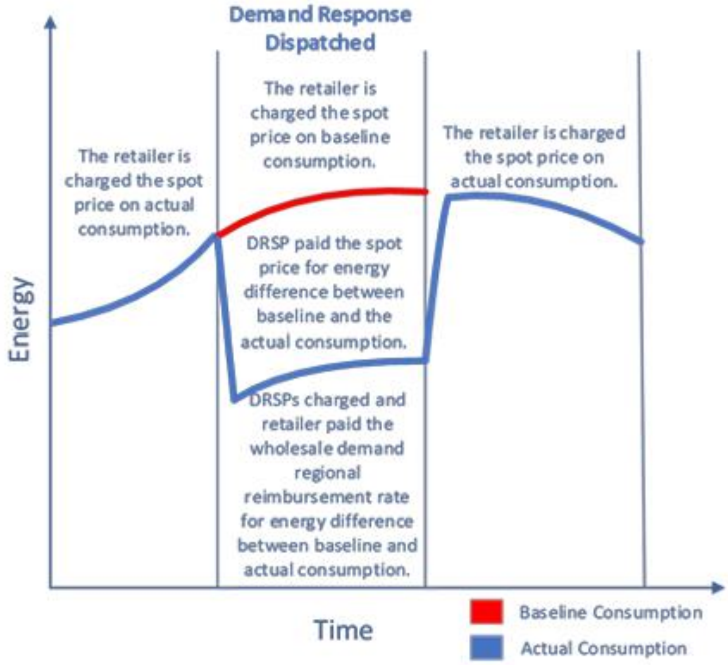
- have retail customer consent;
- have a type 1 to 4 metering installation;
- not be a scheduled load;
- be at a market load connection point;

[19] The establishment of a wholesale demand response mechanism was previously considered through a rule change process in 2015 and 2016, but the AEMC recommended not to make the rule at that time. In their determination, the AEMC acknowledged the benefits of a wholesale demand participation, but concluded that the design that had been put forward was costly and would add little benefit to consumers. https://www.aemc.gov.au/sites/default/files/content/68cb8114-113d-4d96-91dc-5cb4b0f9e0ae/ERC0186-DRM-and-ASU-Final-rule-determination-FINAL.PDF

- not be a small customer load; and
- be capable of providing a wholesale demand response.

Compensation paid to a participating load as illustrated below:

Figure 12: Illustration of demand response financial flows relative to baseline and actual consumption



Source: Wholesale Demand Response: High-level Design, AEMO 2020

AEMO is required under the NER to publish an annual report on the operation of the WDR mechanism. The second annual report was released in June 2023, noting that:

> *"There has been a slow build of WDR capacity registered since the start of the mechanism. Most of the WDR events to date have been in the NSW and VIC regions, concentrated in the May to October periods, with very little WDR over summer seasons".*

Total demand response registered was a modest 65.3 MW, with 222MWh dispatched during the year. Uptake, arguably, to date has not delivered on the ambitions of the WDR which was to 'allow meaningful volumes of demand-side participation in dispatch and associated system operation benefits'[20]. No conclusions have been drawn to date as to why this may be the case.

Table 6: WDR operation – key statistics as of 13 June 2023

Key statistic	Value
Baseline methodologies available	4
Baseline methodologies used by participants	3
Total DRSP registered	1
Total WDRUs registered	13

[20] Rule Determination National Electricity Amendment (Wholesale Demand Response Mechanism Rule 2020, page iii, https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf

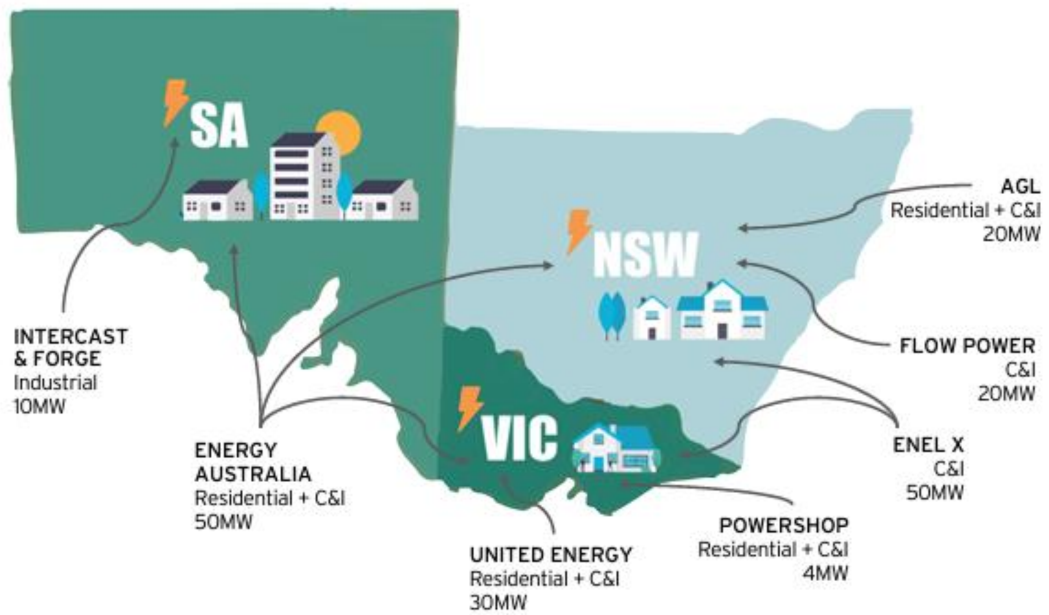
Key statistic	Value
Total NMIs registered	34
Regions in which NMIs are registered	NSW, VIC, SA, QLD
Total capacity registered (MW)	65.3 MW
Number of NMIs not passing compliance testing – July 2022 to June 2023	4 (Summer 2022-23), 3 (Winter 2023)
WDR event days – July 2022 to June 2023	26 days
Region of WDR events	NSW, QLD, SA, VIC
Total WDR dispatched – July 2022 to June 2023 (MWh)	222 MWh
Average Volume Weighted Price for WDR - July 2022 to June 2023 ($/MWh)	284 $/MWh to 2,193 $/MWh
Non-conformance frequency – July 2022 to June 2023	None
Non-conformance extent – July 2022 to June 2023	9 MW

Source: Wholesale Demand response, Annual Report, June 2023

RERT

AEMO and the Australian Renewable Energy Agency (ARENA) jointly developed a series of 'proof of concept' projects to support demand response participation in the RERT. A three-year trial took place from 2017 to 2020 with participation spread over NSW, Victoria and South Australia (refer Figure 13).

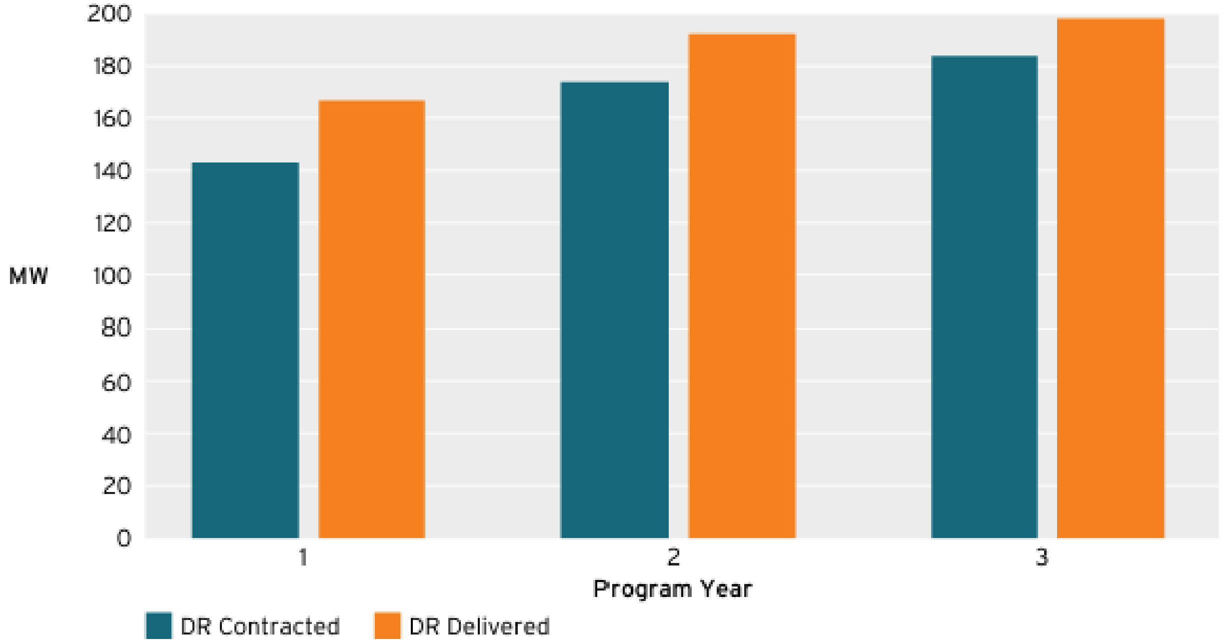
Figure 13: demand response contracted resources



Source: Demand Response Short Notice RERT Trial Year 3 Report, ARENA

Over the three-year pilot the amount of demand response delivered exceeded that contracted (see Figure 14). This suggests that demand response providers procured excess demand response to ensure they are able to satisfy their contractual requirements. This practice is valuable in avoiding contractual shortfalls in the event some demand response loads do not respond when required.

Figure 14: demand response capacity contracted vs delivered in each program year (MW)



Source: Demand Response Short Notice RERT Trial Year 3 Report, ARENA

Retailer reliability obligation

To address the increasing intermittency and reliability issues, and in response to the power outages suffered by South Australia in 2016, the RERT was augmented with the Retailer Reliability Obligation (RRO) from July 2019

The RRO only comes into effect if AEMO identifies a reliability gap in a specific area of the NEM, and the AER makes a Reliability Instrument in response to this[21]. Once triggered, the RRO requires retailers to demonstrate sufficient contracting of dispatchable capacity to cover their share of demand during potential capacity shortfall periods. Demand response is eligible to be contracted as dispatchable capacity. Demand response providing RRO liability is based on demand rather than price. These requires those using demand response to be monitoring demand in the relevant region to be informed about timing of when demand response action is required.

However, only limited aspects of the RRO have been used to date and consequently, the current AEMC review of the RRO has been extended with a final report now not due until early 2024[22].

Unlocking CER benefits through flexible trading

In August 2023 the AEMC published a directions paper[23] setting out intentions to improve the flexibility and trading of consumer energy resources (CER). CER includes responsive/ flexible load and generation at customer premises such as rooftop solar panels, batteries, home and businesses energy management systems, and electric vehicles, as well as 'smart devices' such as controllable

[21] The South Australian Minister also has the ability to trigger the RRO within South Australia.

[22] Consultation Paper – Review of the Operation of the Retailer Reliability Obligation, 23 March 2023 (https://www.aemc.gov.au/market-reviews-advice/review-retailer-reliability-obligation)

[23] https://www.aemc.gov.au/sites/default/files/2023-08/ERC0346%20CER%20Benefits%20Directions%20paper%20-%20rule%20change.pdf

hot water systems. CER can also include responsive load at large customer sites such as refrigeration and heating ventilation and air conditioning (HVAC).

Following initial consultation, there are three key areas that were raised in the rule change request from AEMO that the AEMC will be taking forward. These include:

1. Optimising the value of CER flexibility by examining opportunities for separately identifying and managing flexible CER.
2. Flexible trading of CER with multiple energy service providers at residential and/or commercial premises.
3. Opportunities to improve how energy use is measured for street lighting and other street furniture (such as park BBQs).

AEMC has commenced consultation ahead of developing a rule change by December 2023. The first two elements of the rule change proposal that relate to demand side response are discussed below.

Optimising the value of CER flexibility

AEMC considers there are opportunities to improve how CER are separately identified and managed. By separately identifying CER it would allow it to be managed and enable specific products and services to extract value from CER, for example:

- different CER network and retail pricing offers
- direct payments for CER use as a source aggreated demand reposone
- potential to participate in the provision of network or wholesale market services
- reduce network congestion and augmentation costs, as well as increased network efficiency

AEMC notes that seperately identifying and managing CER will have benefits on its own. With additional benfits to be realised by allowing for flexible trading.

Flexible trading of CER

AEMO proposed allowing all customers the opportunity to offer CER services. However, the AEMC concluded that it should be limited to large commercial and industrial customers only. AEMC determined that the breadth of changes needed exceeded the benefits for small customers and also that only some small customers would receive a benefit while all customers would face the development costs.

A.1.3 Lessons for the WEM

The three-year RERT pilot provided some useful lessons for further deployment of demand response in the NEM that are equally as relevant to the WEM.

Key outcomes from the three-year trial highlighted[24]:

- The amount of demand response delivered was higher than contracted. Demand response providers tend to procure more demand response than contracted as this provides them options when dispatching while also providing a buffer in avoiding delivery shortfalls.
- In relation to residential customers:
  - Behavioural demand response was highly popular. Its success was largely due to

[24] Demand Response Short Notice RERT Trial Year 3 Report, ARENA

- » the large pool of possible participants;
  - » not requiring any significant financial outlay of customers; and
  - » allowing customers to retain full control over their energy use.

  This demonstrated that customers can and are willing to change their behaviour under the right conditions.
  - Direct load control was less popular. Despite high incentives very few customers expressed interest in participating in these programs as customers were not particularly willing to cede control of their end-use equipment.
- In relation to commercial and industrial customers:
  - Automated technologies yielded better demand response delivery. Where automated technologies have been accepted by commercial and industrial customers (as compared to the use of manual curtailment), there has been a significant improvement in the delivery of contracted demand response and a high level of customer satisfaction.
  - Participants indicated that the trial had given them and their end-customers valuable experience with demand response and provided the opportunity for the participants to improve their processes and to identify more fit-for-purpose demand response technology solutions with a view to increase the value of demand response to the market. This demonstrates that demand response providers and their loads need time to develop familiarity and sophistication.
  - Lessons learned in the trial have influenced participants to move demand response from a peripheral activity to business as usual. For instance, interest has been expressed in exploring the potential for demand response to shift loads and encourage new loads that address minimum operational demand conditions in the generation market, as well a localised over-voltage conditions in the distribution network.

While the off-market RERT has been quite successful, within the first two years of operation, the market-based WDR has yet to achieve the same level of participation. The relative age of the mechanism may be a factor. However, it is likely the less stringent telemetry requirement and greater lead time for dispatch are the key drivers that favour participation through the RERT. It appears that, given option, demand response providers tended to preference arrangements which has the least operational disruption. This may be the reason for the low levels of participation in the WDR mechanism.

Looking to the future, the AEMC noted in their rule change report that the WDR mechanism will eventually be outgrown by the market because it is reliant on a centrally determined baseline. They considered that a move to a two-sided market, characterised by the active participation of the supply and demand side in dispatch and price setting, would both allow for smaller customers to participate and more accuracy in compensating demand side resources.

The recent AEMO rule change proposal for flexible CER participation and AEMC's determination demonstrated the usefulness of separating and identifying DER data. It showed that just making the data available can lead to changes in behaviour. This is worth considering for the WEM, both as an option to improve immediate behaviour and also as a catalyst for further participation.

A.2 United Kingdom (UK)

A.2.1 Jurisdiction Overview

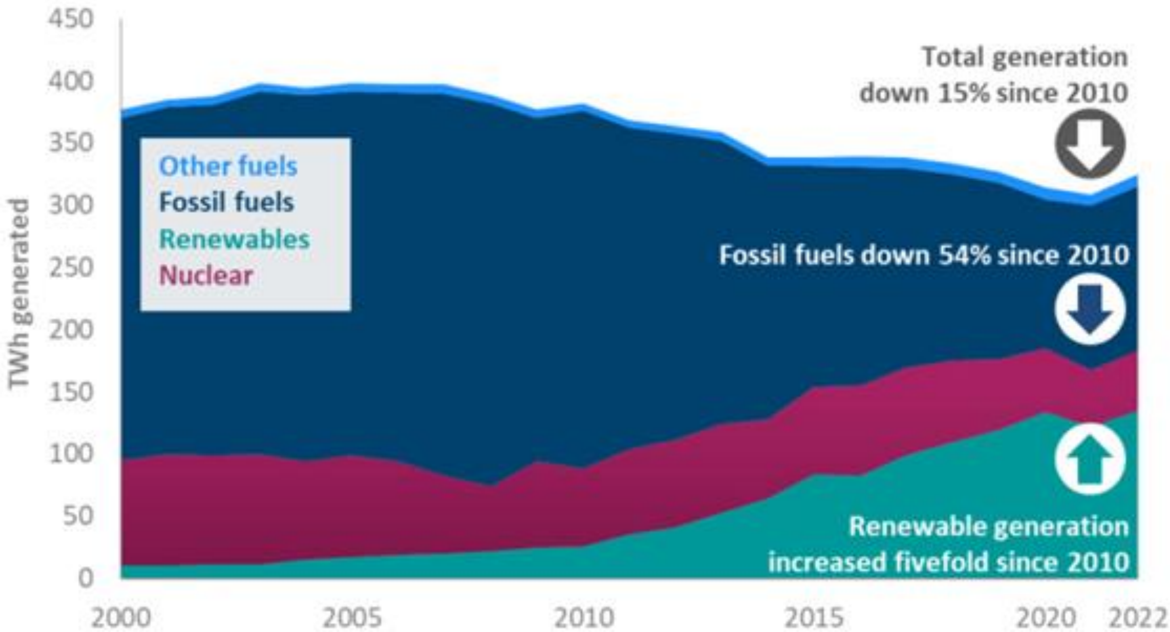
The UK is a thermally dominated system in transition towards renewables as seen in Table 7 and Figure 15. It moved from an energy only market to an energy and capacity market in 2014, with first capacity contracts commencing delivery in 2018. Like many jurisdictions, the UK electricity system is in a period of transition with the shift towards large volumes of distribution connected generation, flexible demand and storage.

Table 7: Generation Mix, June 2023

Fuel Source	(%)
Gas	38.5%
Wind	26.8%
Nuclear	15.5%
Biomass	5.2%
Coal	1.5%
Solar	4.4%
Imports	5.5%
Hydro	1.8%
Storage	0.9%

Source: Britain's Electricity Explained: 2022 Review, National Grid ESO

Figure 15: Electricity generated by fuel type 2000 to 2022



Source: Electricity Statistics, energysecurity.gov.uk

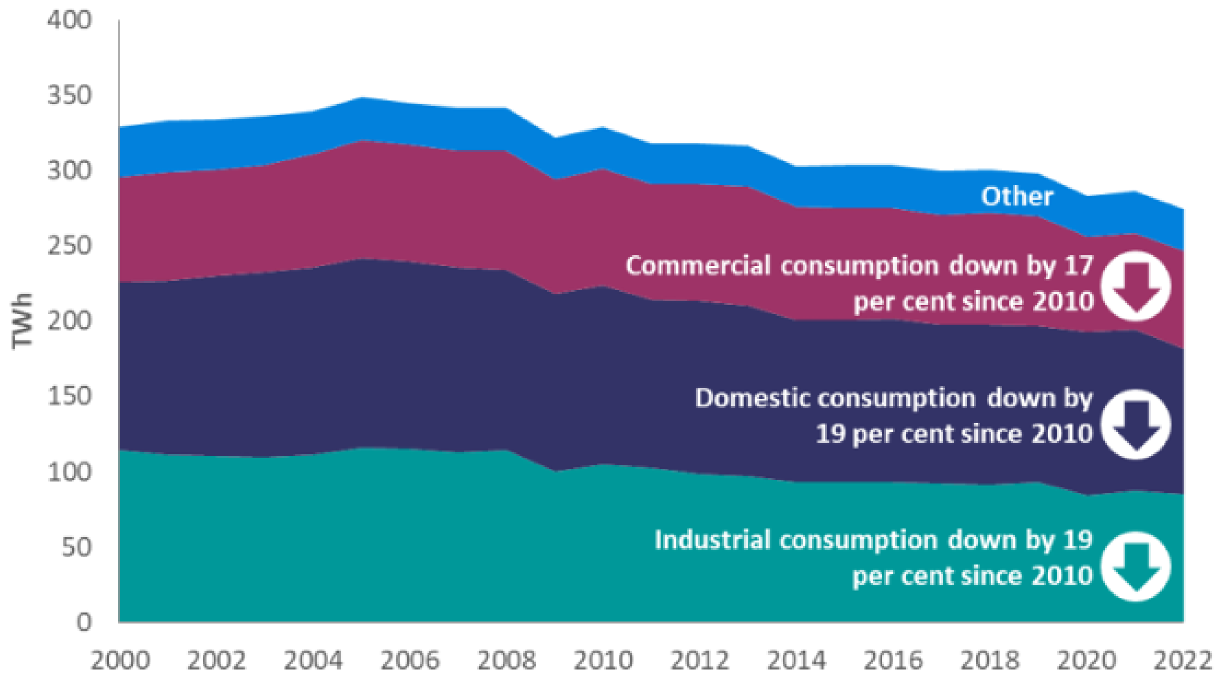
Electricity demand has been declining since 2005 (see Figure 16). Britain saw a 4% drop in electricity demand from 2021 – that's the third largest year-on-year reduction after 2008 (caused by the shock of the global financial crash) and pandemic-affected 2020. It takes Britain's overall electricity demand back to values last seen in the 1980s, an 18% reduction from its peak in 2005.[25]

[25] https://theconversation.com/britain-is-a-net-electricity-exporter-for-first-time-in-44-years-197506

The reduction in demand is attributed to four main reasons:

- More energy efficient devices;
- Industry moving outside of the UK;
- Increased cost of energy leading to lower consumption; and
- Public awareness of environmental impact of energy emissions.

Figure 16: Electricity consumption by sector, 2000 to 2022[26]



Source: Electricity Statistics, energysecurity.gov.uk

While demand has reduced electricity generation is increasing, primarily in response to increased demand from other European countries. In 2022 the UK became a net exporter of electricity.

Despite overall falling demand (refer Figure 16), the UK is experiencing issues in managing their system through high demand periods (typically winters). The National Grid ESO has established the Demand Flexibility Service[27] in winter (22/23) to access additional flexibility typically over winter peak days when national demand is at its highest. This new service incentivises consumers for voluntarily flexing the time when they use their electricity. In approaching consumers, National Grid floated a price range for potential payments, ranging from £100 a megawatt-hour to as high as £6,000. This service reduced the 2022/2023 winter demand by over 3,300MWh.[28]

26 Electricity consumption (Figure 16) is lower than Electricity generated (Figure 15) due to station load and system losses.

27 https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility-service-dfs

28 https://www.nationalgrideso.com/news/demand-flexibility-service-delivers-electricity-power-10-million-households#:~:text=The%20Demand%20Flexibility%20Service%2C%20put,million%20homes%20across%20Great%20Britain.

A.2.2 Use or planned use of Loads and Demand Side Response

History of demand response

In the pre to mid-2000's there was limited demand response usage in the UK. From the mid 2000's an increase in demand response began to help achieve climate change targets and address security of supply and efficiency concerns.[29]

The Short Term Operating Reserve (STOR) operated by the UK National Grid System Operator is the primary market for demand response, with STOR capacity awarded by tender. However, demand response can also provide frequency response through:

- Firm Frequency Response (FFR): firm provision of dynamic (continually matching) or non-dynamic response (set points) to changes in frequency; or
- Frequency Control by Demand Management (FCDM): frequency response through automatic interruption of demand when frequency transgresses the low frequency relay setting on site.

Table 8: Market programme participation parameters[30]

Programme	Response time	Duration (max)	Minimum MWs	Trigger
FFR - Primary	2 to 10 seconds	1 to 2 minutes	10	
FFR - Secondary	Up to 30 Seconds	30 minutes	10	
FCDM	2 to 10 seconds	30 minutes	3	
STOR	Up to 20 minutes	2 hours	3	National Grid Request

Source: M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

Demand response payments from these mechanisms are as follows:

- FFR and FCDM run 24/7 with revenues based on an hourly availability payment;
- STOR has two daily operational windows (~07:00-14:00 and ~16:00-22:00), with revenues comprised of an availability payment and a utilisation payment; and
- STOR demand response capacity is provided via 150-250MW of load reduction and 300-500MW from load replacement (e.g. using backup generators).

The following deployment examples[31] highlight issues related to demand response participation in the UK.

[29] M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

[30] Frequency Response Services are currently being updated with the Dynamic Firm Frequency Response (FFR) service being replaced with new dynamic services and phased out over FY23/24 (https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/new-dynamic-services-dcdmdr)

[31] Taken from M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

Example 1 uses client's backup generator to replace grid demand. This effectively appears as grid 'Demand Reduction' and is how the majority (>80%) of demand response in the UK was being provided.

Table 9: Example 1 - STOR using Generator Load Replacement

Benefits	Issues
Creates revenue from an expensive non-revenue generating asset	Reliability of the generator: backup generators are often not maintained (or not fuelled)
Can replace the need for monthly testing -and cover costs of testing	Client trust: the building manager is often not happy with allowing external control of a building's generator
Can meet the 2 hour duration requirement and 20 minute response time	Running costs: no revenue from the STOR utilisation payment given assumed 'no load' running costs
Easy to install control and monitoring equipment	Meeting demand response expectations: the STOR programme requires committed reduction, 7 days a week in operating windows (~07:00-14:00 & ~16:00-22:00), reducing site's potential to the lowest demand level at these times

Example 2 temporarily turn downs (or off) assets to reduce demand on the grid. This can be through turning off large HVAC systems, manufacturing lines, refrigeration etc.

Table 10: Example 2 - STOR – turndown

Benefits	Issues
Often can be implemented with no noticeable user impact - e.g. HVAC can be turned off for an hour without users knowing	Hard to meet programme conditions: event durations can last up to 2 hours (normally less than an hour in practice) therefore risking non-delivery penalties or user impacts
Creates a new revenue stream and also savings from a reduced electricity bill	Installation costs: installation can often be expensive due to individual asset control and each asset will only provide a small amount of turndown
Promotes 'green' business credentials	Client trust and meeting demand response expectations issues, as per Example 1

Example 3 is a frequency response based programme using an onsite frequency relay which triggers mains disconnection within seconds of meeting the trigger conditions – normally 49.7 Hz. Batteries are an obvious choice if available - or any asset that can respond within 30 seconds. Sometimes a combination is used, with short term response being handled by a battery while larger assets are turned down (e.g. as an HVAC system might take 5 minutes to meet reduction levels, a battery system is used for those first 5 minutes).

Table 11: Example 3 - FFR – Battery or Turndown

Benefits	Issues
Greater flexibility for participation through allowing for variable demand response targets, set a week ahead	Meeting response times: fast response times (within 30 seconds) can make it difficult to find suitable assets

Benefits	Issues
Fast response requires direct controls therefore drives fully automated solutions	Client trust: can be hard to build trust in client's base given concerns about losing control of their assets
Short event duration minimises any potential impact	Monitoring requirements: frequency demand response requires second by second monitoring -hard to achieve, without specialised monitoring hardware

Recent changes to demand response participation

Overall, recent changes to demand response participation have not brought about favourable outcomes for large customer (commercial and industrial) take-up.

The original design for the UK capacity market included provisions for demand response. Initially this saw little success with only 174MW of demand response capacity awarded contracts, of a total 49,258 MWs in 2014 (for 2018 delivery). Contract terms of only 1 year disadvantaged demand response, with supply-side contracts receiving 15 years. Recent awards for the winter 2022/23 period show demand response participation in the capacity market declining even further.

In attempts to increase demand response activity the system operator facilitated the introduction of "Power Responsive". Power Responsive is a stakeholder-led program, facilitated by the National Grid ESO, to stimulate increased participation in demand response and storage by:

- raising awareness of DR; and
- shaping growth of the market in a joined-up way to ensure demand has equal opportunity with the supply side to participate when it comes to balancing the system.

Power Responive also publishes a comprehensive annual report on developments in demand side flexibility markets in the UK[32].

The Major Energy Users Council presented the following 'scoresheet' on demand flexibility services (comprising of demand side response and batteries) usage in the UK at the Power Responsive Summer Event in July 2022.

Table 12: DSF Scorecard

Product	Demand side flexibility results
Dynamic Containment	980MW of batteries
Firm Frequency Response (FFR)[33]	Coming to the end of its life
STOR day-ahead	1.7GW, mainly gas fired generation (onsite CHP or backup generation to cover own load)
Balancing Mechanism	Very small amount of demand side flexibility
Distribution System Operator's (DSO) schemes	Growing, but through batteries and non-renewable generation
Capacity Market	Winter 2022/23: T-3; zero DSR; T-1; 154MW DSR, but mostly batteries (25MW true DSR)

[32] Power Responsive Annual Report 2022 (https://www.nationalgrideso.com/document/282066/download)

[33] FFR is being phased out over 2023/24 and being replaced with New Dynamic Services.

Product	Demand side flexibility results
Triad Avoidance	1.3GW of reduction 2021/22 1.7GW of reduction 2020/22 Will end in April 2023

Source: Major Energy Users Council, 13 July 2022

Ofgem noted at this event that:

> *Flexibility from DER remains nascent, both in access to markets, liquidity, and coordination. Visibility is poor, control is patchy, contracts are long-winded, baselining is complicated. Performance risks are borne by buyers with no existing liability trading*[34]

The most successful demand side product, Triad Avoidance (based on trying to bring down energy usage during the three highest demand points in each winter period[35]) ended in April 2023 due to the introduction of the Targeted Charging Review which saw a shift towards fixed Transmission Network Use of System (TNUoS) charging, and the reduced variable component no longer being based on winter peak usage. Ofgem decided to replace the Triad system with a series of fixed 'charging bands' because it considers this will spread the cost of recovering residual charges more fairly among all energy users.

While demand side involvement in the Balancing Mechanism (BM) was "very small" it is interesting to note that since 2016 Demand Turn-up has been available as a non-BM balancing Service to encourage large energy users and generators to either increase demand (through shifting) or reduce generation when there is excess energy on the system – typically overnight and weekend afternoons. Uptake of the initial trial was quite low at approximately 300MW. However, it did demonstrate that loads exist that are willing to alter their operations given the correct incentive.

At the Distribution System Operator level there have been a number of recent initiatives such as the Interoperable Demand Side Response Programme but these are aimed more at small consumers to take advantage of an expected increase of EVs and smart appliances.

The UK are currently in the process of launching new reserve and frequency response markets[36] to provide the system flexibility required with the shift towards net zero emissions. It is too early to see whether these changes will be effective in attracting a greater amount of demand response.

A.2.3 Lessons for the WEM

In 2016, Ofgem surveyed large industrial and commercial consumers to assess the potential for demand response in Great Britain and to identify barriers preventing greater flexibility. The survey found[37]:

- most commercial and industrial consumers providing demand response are industrial customers and have relatively high electricity consumption and peak demand;

34 https://www.nationalgrideso.com/document/263811/download

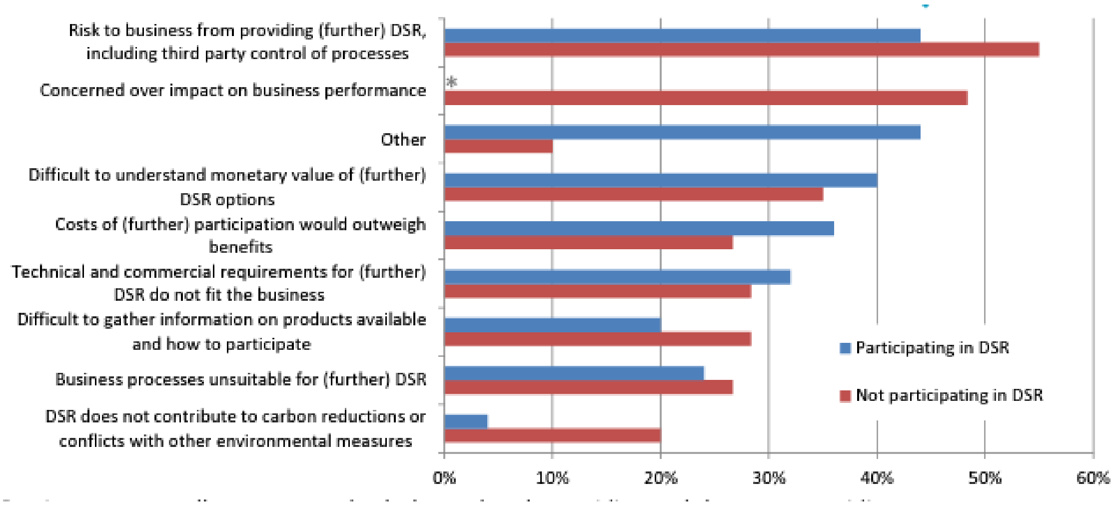
35 The triad periods are used to determine the allocation of peak TNUoS charges. To mitigate against these charges companies and supplies tried to predict when the triads would occur and turn down their energy usage during these periods. demand response was a key part of these Triad avoidance schemes.

36 New Dynamic Services (https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/new-dynamic-services-dcdmdr)

37 I&C demand-side response in GB: barriers and potential, Ofgem, October 2016

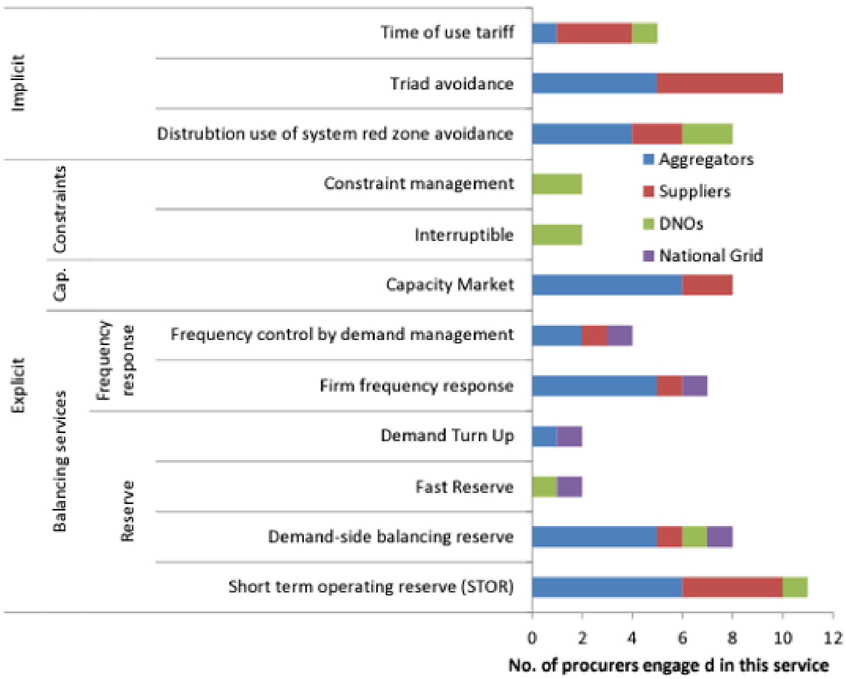
- respondents cited a wide variety of sources for flexibility provision within their processes;
- respondents provide around 350 MW of demand reduction with over 400 MW of technically and commercially viable additional demand reduction potentially available;
- translated to a Great Britian scale, the survey responses suggest a far greater untapped flexibility potential (~3 GW for reducing demand and ~2 GW for increasing demand);
- several barriers are preventing a greater provision of flexibility, principally;
  - a perceived risk to primary business;
  - difficulty in understanding the monetary value of DSR options; and
  - commercial and technical DSR requirements not fitting the business.
- from a financial point of view, the majority of DSR providers value availability payments over utilisation payments, while for nearly half of non-providers there currently seems to be no financial incentive that would lead them to offering DSR services, possibly owing to concerns about potential disruption to business; and
- Commerical and industrial customers generally have multiple routes to market for DSR service).

Figure 17: Barriers to (further) DSR provision tend to be common to providers and non-providers (survey results)



Source: Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

Figure 18: DSR services provided by procurers (survey results)



Source: Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

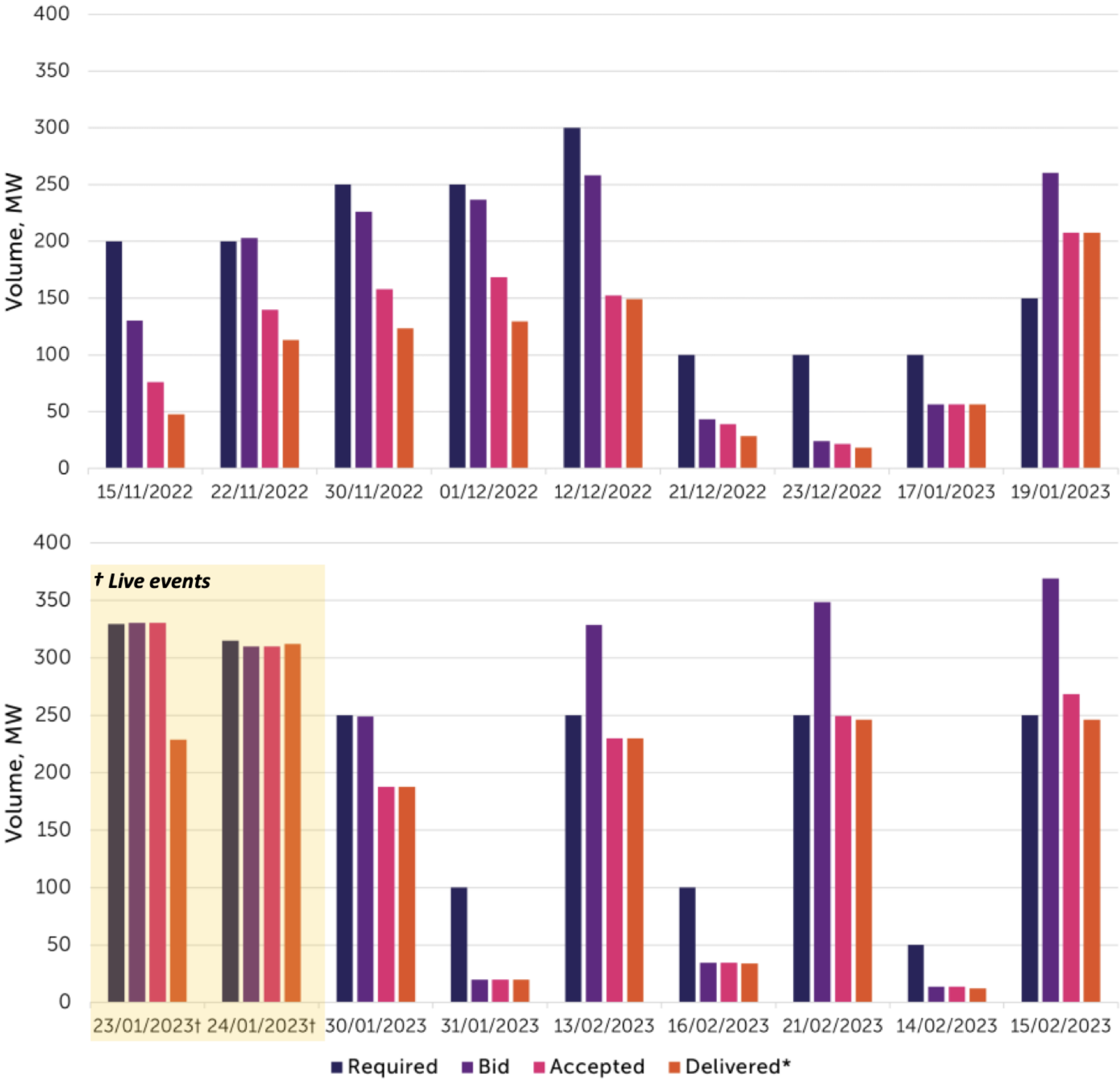
The 2016 Ofgem survey which highlighted the perceived barriers to greater demand response participation echoes similar comments that were heard from DSRRWG members.

The UK also highlights the need for greater customer awareness of the potential for DR. The stakeholder-led programme “Power Responsive” is a useful illustration of how such an awareness campaign might work in the WEM.

The introduction of the Demand Flexibility Service in 2021 saw the direct participation of end consumers in providing demand response services. In 2022 1.6 million households and business were involved in providing Demand Flexibility Services. Power responsive is looking at building on the success of this and look for improvements to enhance participation.

20 events that occurred between the launch of the service in November 22 and March 2023 delivered between 12 and 312 MW of demand reduction to the grid, see Figure 19. Just two ‘live’ events have been run to date, on the 23rd and 24th of January 2023. Both set a requirement of over 300MW and delivered the majority of that. 219 MW was delivered on the 23rd against a 330 MW requirement, and perhaps due to having an extra day’s warning, providers were able to deliver 312 MW on the 24th, just a few MW shy of the 315 MW requirement.

Figure 19: Demand Flexibility Service activity



Source: Power Responsive Annual Report 2022

Also noteworthy, is how changes to one part of the market design (the TNUoS charging methodology in the case of the UK) can have large consequential impact on demand response participation. While this was successful from a demand response point of view, it was resulting in many large customers being able to avoid transmission charges by reducing usage during the winter peak. It has been ceased as Ofgem considers that every consumer should contribute to the cost of building, maintaining and operating the transmission network.

A.3 Pennsylvania-New Jersey-Maryland Interconnection (PJM), United States of America (USA).

A.3.1 Jurisdiction Overview

PJM is a regional transmission organisation that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is one of the largest interconnected systems in the world (refer Table 13 below).

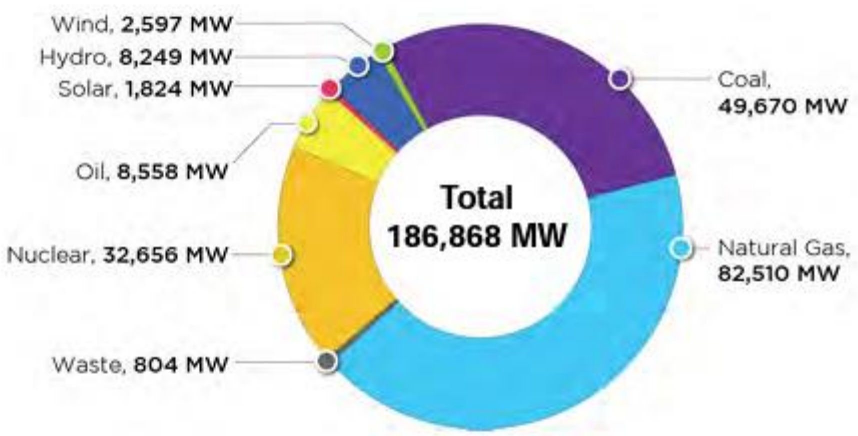
Table 13: Key statistics for PJM

Key Statistics	
People served	65,000,000
Miles of transmission lines	88,115
Generation of capacity in MW	183,254
Square miles of territory	368,906
Area served	13 states + District of Columbia

Source: PJM Factsheet

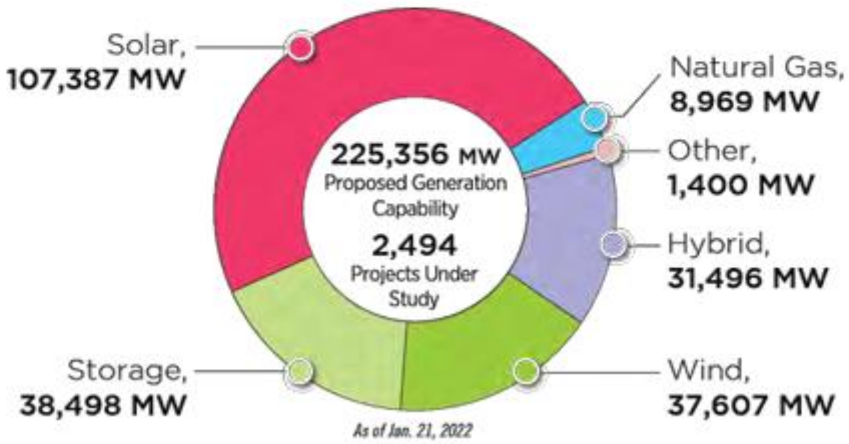
PJM operates a primarily thermal (coal, gas and nuclear) system with a small proportion (7%) of renewables (refer Figure 20). However, a significant shift to cleaner resources is expected in the future (refer figure 21).

Figure 20: Generation Mix – Installed Capacity



Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

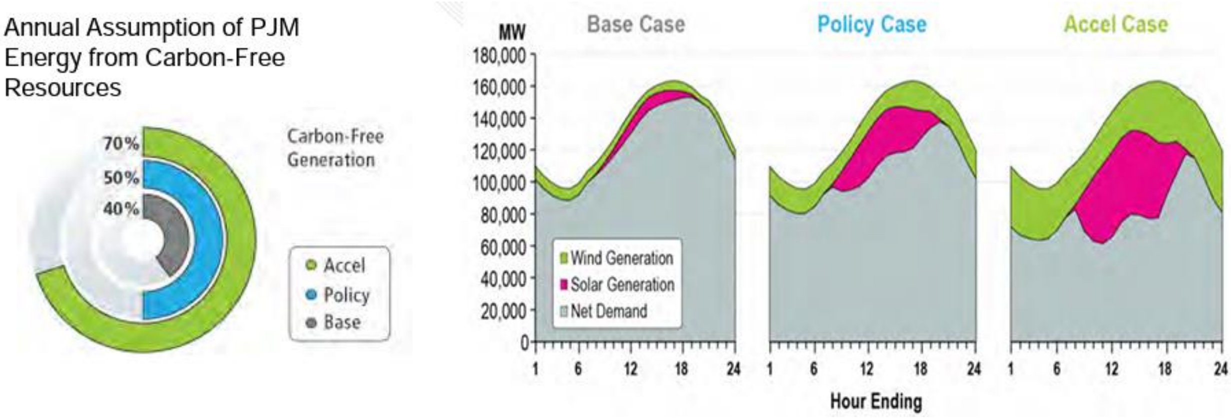
Figure 21: Current Interconnection Queue



Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

It has been identified that peak load levels and ramping needs will shift with an increase in renewables (refer Figure 22).

Figure 22: PJM Study – Importance of Flexibility



Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

To cope with these challenges the PJM has noted the importance of having more flexible services available to the market and system, including demand response.

A.3.2 Use or planned use of Loads and Demand Side Response

Beginning with customer trials in the early 2000s, PJM has been an early proponent of demand response. Demand response is now offered by numerous Curtailment Service Providers (CSPs) which pool smaller customers into a monitored demand response system and bid capacity on their behalf. These service providers were initially large energy service companies, but many have emerged which are specific demand response services.

Significant review of demand response in 2017[38]

The 2010s brought significant change to the PJM markets, including:

- changing operational needs for the grid;
- an increased focus on resilience; and
- increased penetrationg of behind-the-meter technology changing the dynamics of market and grid operations.

Therefore, in 2017, PJM undertook a review to consider the future direction of how demand response was integrated into PJM operations, markets and planning.

The review findings were split across short-term goals (one to two years), medium-term focus (three to five years) and longer-term direction (five-plus years). PJM's strategic objectives for demand response were to:

- ensure that demand response was a predictable, reliable and transparent resource with which to manage the grid;
- enable more efficient market outcomes through price-sensitive demand; and
- increase alignment of wholesale and retail market incentives through coordination with state retail regulatory authorities.

[38] Demand Response Strategy, PJM Interconnection, 28 June 2017

The conclusion from the review was that the CSP model of demand response participation in PJM wholesale markets had been successful, and this approach should be preserved for the foreseeable future.

It was recommended that demand response should remain as a supply-side resource in the capacity and ancillary service markets. This approach was seen as a more effective way for customers to manage their costs and for the wholesale market to incorporate these load-reduction actions.

It was determined that the long-term view should be for demand response capability to participate on the demand side of the energy market (i.e. they would not be compensated by the market but instead by the load-serving entity, typically being their retailer). PJM would look for opportunities to evolve in this direction through collaboration with load-serving entities and the state retail regulatory authorities.

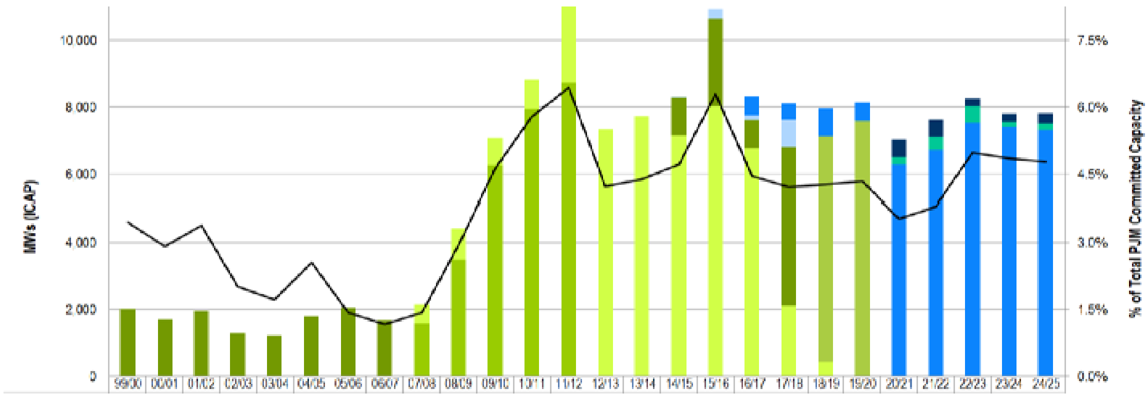
It was reasoned that if retail customers received payments through the wholesale market then this would result in a subsidy when customers were already on a dynamic retail rate (i.e. they had already received the benefit of a lower energy price through their demand response activity).

The implementation of capacity performance would be a major change in the demand response capacity market availability requirements. Capacity performance requires demand response resources to be available on an annual basis with the potential to dispatch for several hours during a day. PJM's short-term focus was on:

- transitioning demand response to Capacity Performance (CP) requirements;
- developing a demand response dispatch model to optimise dispatch and release of demand response;
- reviewing demand response and Price Responsive Demand rules and consider integrating into one approach;
- continuing to increase PJM operational visibility of demand response;
- implementing broader energy market changes (e.g., five-minute settlements, hourly offers, price caps);
- identifying any needed enhancement for Distributed Energy Resources that operate as demand response; and
- implementing mandatory training to ensure all CSPs are ready when demand response is dispatched.

Following the 2017 review the performance obligations on demand response were strengthened (to provide greater visibility and control to the RTO) but this does not appear to have significantly affected the level of demand response participation as seen in Figure 23.

Figure 23: PJM demand response committed MWs by delivery year



Source: 2022 demand response Operations Markets Activity Report, PJM, 11 July 2023

As PJM transitioned away from customer-specific capabilities to portfolio capabilities (based on the new annual CP requirements), PJM committed to review the existing rules and procedures and make changes where necessary to ensure PJM fully understood the demand response capability. In the medium term, PJM aimed to:

- ensure demand response commitments reflect demand response capabilities by developing and implementing:
  - more robust and comprehensive capacity testing requirements; and
  - synchronised reserve testing with enhanced performance measurement using the Customer Baseline Load approach;
- work with states and other stakeholders on other options to recognize the value of seasonal resource flexibility; and
- refine their ability to dispatch demand response by quantity and location.

In the long term PJM planned to work with retailers to determine how to enable more dynamic retail contracts to help align wholesale market prices with retail market prices or incentives and to help transition from wholesale energy market revenue on the supply side to retail energy cost savings on the demand side. In support of this PJM intended to:

- collaborate with load serving entities to support contracts/pricing that foster demand elasticity;
- explore and develop opportunities to move demand response in the energy market to demand side (cost savings) by modifying or eliminating energy compensation;
- expand participation in ancillary services markets where performance is comparable to generation;
- foster or support investment and implementation of demand response automation; and
- evaluate transitioning energy efficiency to the demand side (retail electricity cost savings) by eliminating capacity compensation.

How demand response works in PJM

There are three broad categories for customers to participate in PJM markets as demand response, with the ability to participate as both:

- Load management (Pre-Emergency and Emergency demand response) providers make a commitment in the capacity market to reduce load when required by the system or receive a financial penalty.

- Economic demand response providers participate in the energy and ancillary services markets when it is economic for them. If the economic demand response offer price is less than the marginal price, they will be deployed similar to a generator.
- Price responsive demand are consumers that control their energy consumption by changing their electricity use in response to wholesale electricity prices.

The choice to participate in demand response programs is voluntary. Participants must meet certain requirements to qualify for payments for reducing their demand for electricity. Demand response does not include reductions in electricity use that follow normal operating patterns or behaviour.

Qualified PJM Market Participants who act as CSPs, help eligible customers identify opportunities and determine the equipment and systems required to benefit financially from demand response participation in PJM markets.

CSPs aggregate customers' curtailment capability, register that capability with PJM, offer it in the appropriate market, submit load data to verify the reductions and receive payment from PJM. Subsequent allocation of PJM payment between the CSP and the retail customer contractual matter.

Most demand response activity in PJM takes place in the capacity market, called the Reliability Pricing Model. Both demand response resources and Energy Efficiency resources participate in PJM's capacity market. These resources can receive payments for committing to reduce electricity demand or for implementing energy-efficiency measures, such as more efficient lighting, heating and other building systems, up to three years in the future.

The ability to dispatch demand response gives PJM greater flexibility to manage the grid during summer heat waves and other challenging conditions. In the capacity market, demand response participants must reduce load when requested by PJM or receive a significant financial penalty.

Customers may participate as Economic Demand Response in the energy and ancillary services markets through a CSP. CSPs will offer the load-reduction capability into the PJM Day Ahead or Real-Time energy markets. They may also offer into the ancillary services markets for shorter periods of curtailment flexibility – such as minutes or seconds.

Economic demand response participants in the Energy Market will only be compensated for load reductions that are not part of normal operations. In other words, if the customer already manages their electricity usage to help lower their retail electricity bill, these reductions would not be eligible for compensation through PJM's energy markets.

PJM clears the energy and ancillary services markets on a least-cost basis based on the resources that are available. If a demand response resource is competitive, it will clear in the market in the same way as a generator. Ancillary services participation includes Synchronized Reserve, Regulation and Secondary Reserves markets.

Level of demand response utilised by PJM

DR participation is spread over many locations with a contribution over 10GW (refer Table 14 below).

Table 14: PJM Demand Response Report, May 2023

Type of demand response	# of locations	Capacity in MW
Economic	511	2,489
Load management	14,532	9,074
Price responsive	2,680	443

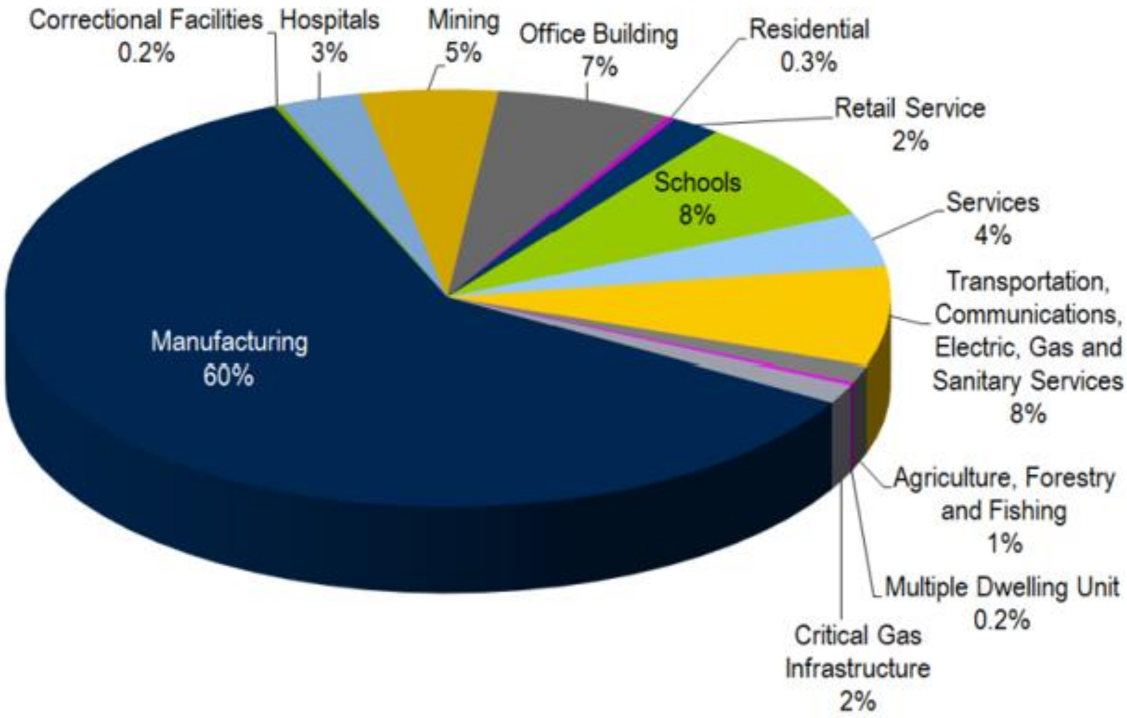
Type of demand response	# of locations	Capacity in MW
Total (unique[39])	17,425	10,595

Source: Load Response Activity Report, May 2023, PJM

PJM has seen its DR program expand and diversify into many sectors and customer segments. DR capacity in manufacturing now represents 60% of the total demand response in the market. This is largely because it is comparatively easy for them to shift the timing of manufacturing activities.

Other important sectors for providing DR services are transportation, communications and other public services (8%), office buildings (7%) and mining (5%) (refer Figure 25).

Figure 24: DY 22/23 Confirmed Load Management demand response Registrations Business Segments

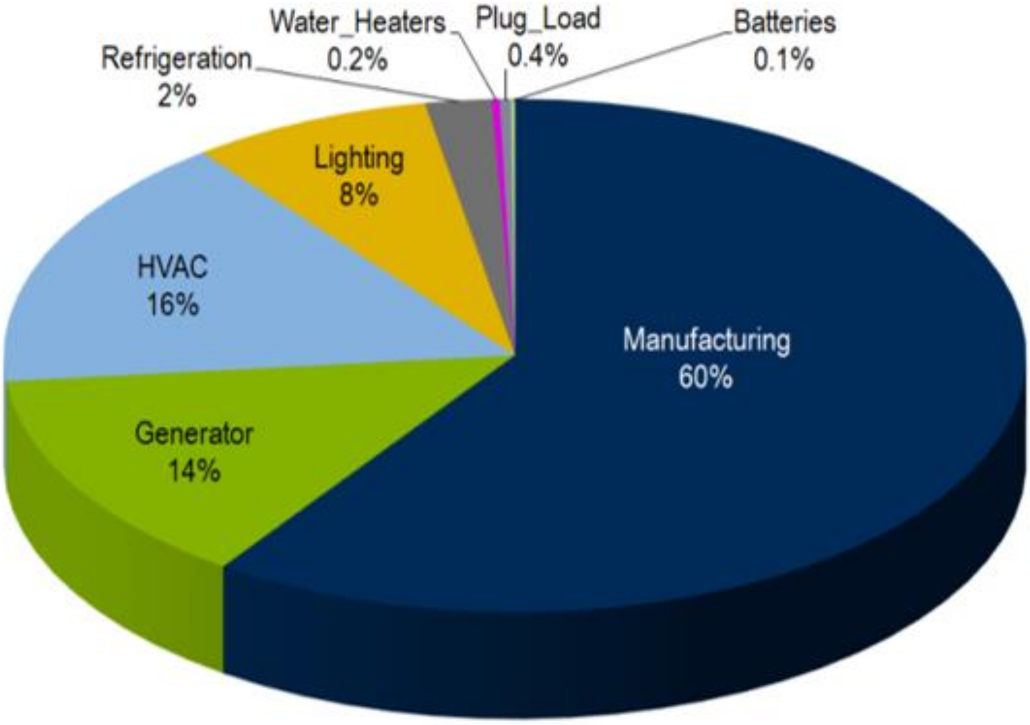


Source: Load Response Activity Report, May 2023, PJM

Participants can use a range of methods to provide DR services. Adjustment of the timing of manufacturing activities is the most prominent method at 60%, in line with the percentage of load response provided. Other key methods are: HVAC (16%), Generator (14%), Lighting (8%) (refer Figure 25).

39 Locations may participate in more than one type of demand response.

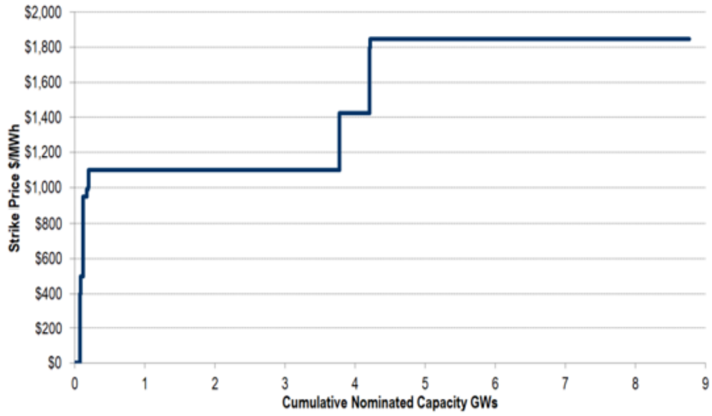
Figure 25: DY 22/23 Confirmed Load Management demand response Registrations Customer Load Reduction Methods



Source: Load Response Activity Report, May 2023, PJM

The energy supply curve for demand response registrations (Figure 26 below) shows the range of strike prices for cumulative nominated capacity, with a majority bidding at either USD$1,100/MWh or USD$1,850/MWh.

Figure 26: DY 22/23 Confirmed Load Management Full demand response Registrations Energy Supply Curve



Source: Load Response Activity Report, May 2023, PJM

A.3.3 Lessons for the WEM

PJM has been able to achieve a sizable demand response in its markets with 10.6GW of available capacity spread over more than 17,000 locations. This has been largely premised on using a Curtailment Service Provider (CSP), or Aggregator model.

Similar to the WEM, most demand response participation takes place in the capacity market (9,074MW of demand response). However, PJM demonstrates that meaningful volumes can also participate in the real time markets (2.932MW of demand response).

During its 2017 review, the performance obligations on demand response were strengthened in order to provide greater visibility and control to PJM. However, this change did not seem to adversely impact demand response participation. This is useful to note for the WEM, but some caution is required to ensure an understanding of how participant's operations may be affected is undertaken before attempting such changes.

While PJM tried to distinguish between how demand response is compensated in Capacity and Ancillary Service markets vs Real-time markets as part of its 2017 review, it has not significantly advanced this. Demand response is still compensated by PJM (via the CSP) for the day-ahead and real-time markets, and is cleared on a least-cost basis in the same manner as other generators[40]'. It is unclear whether this reluctance to change was due to an unwillingness of retailers to absorb this responsibility or whether having a single channel (the CSP or Aggregator) to manage demand response services and payments was preferred.

A.4 New Zealand

A.4.1 Jurisdiction Overview

New Zealand is a small contained (no regional connectors) system. It operates an energy and reserve co-optimised market (i.e. no capacity market) with 30-minute trading intervals. It has very recently moved from ex-post pricing to real-time pricing (ex ante).

The system is primarily renewable energy powered with a high dependency on hydro (refer Table 15). Demand growth is virtually non-existent with electricity consumption of 43.5GWh in 2022 being almost identical to that of 2010 (43.6GWh)[41].

Table 15: Energy Mix

Fuel	Mar 23 Quarter	
	(GWh)	(%)
Net Generation (GWh)	10,134	-
Hydro	6,018	59.4%
Geothermal	1,932	19.1%
Biogas	62	0.6%
Wood	109	1.1%
Wind	641	6.3%
Solar3	102	1.0%
Oil	1	0.0%
Coal	172	1.7%
Gas	1,086	10.7%

[40] Economic demand response participants in the Energy Market will only be compensated for load reductions that are not part of normal operations. In other words, if the customer already manages their electricity usage to help lower their retail electricity bill, these reductions would not be eligible for compensation through PJM's energy markets.

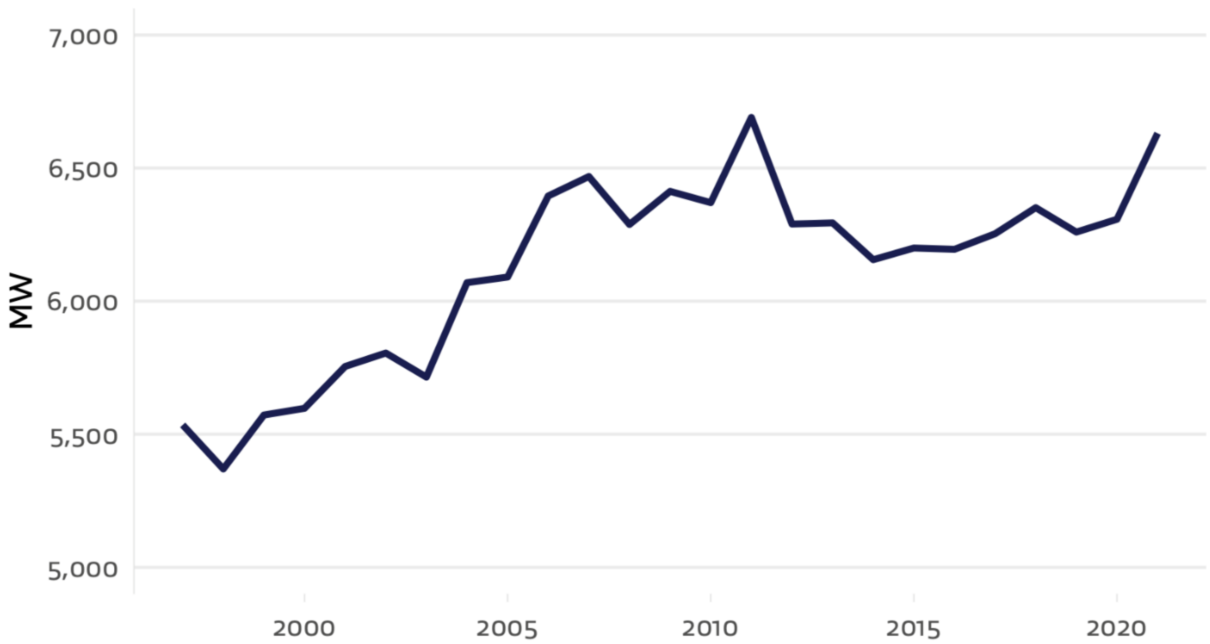
[41] MBIE Electricity Statistics

Fuel	Mar 23 Quarter	
Waste Heat	11	0.1%
Renewable Share (%)		87.5%
Renewable Share (%) – Four-Quarter Moving Average		88.2%

Source: MBIE Electricity Statistics

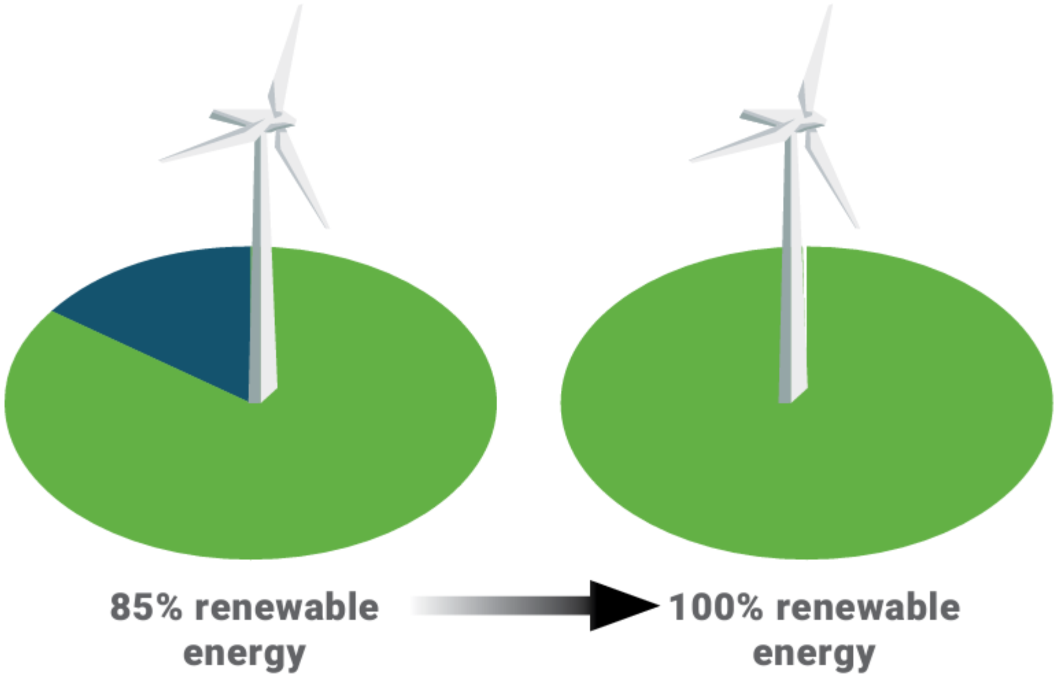
Peak electricity demand has been increasing in the recent years, driven by higher winter demands. Summer peak demand has been trending down but is expected to increase in the future due to anticipated demand for cooling. Much like the WEM peak demand occurs in the mornings and early evenings. However, unlike the WEM minimum system demand is not a concern due to large volumes of hydro generation. Rather NZ has experienced problems with insufficient capacity. For example, on 9 August 2021 the system operator requested consumers reduce consumption in order to maintain system security.

Figure 27: Annual NZ peak electricity demand



Similar to many jurisdictions, NZ has ambitions towards greater low emission sources of electricity production.

Figure 28: Aspirational Renewables' Target



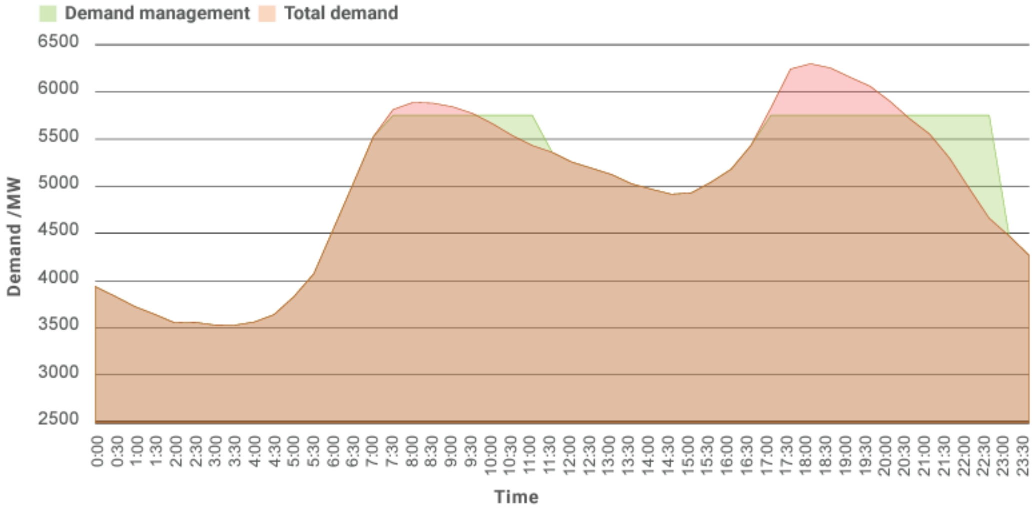
Source: Real Time Pricing, Electricity Authority, 2022

New Zealand already has very high levels of renewable energy but during times of peak demand requires coal and gas generation to meet demand. New Zealand has aspirations to move to 100% renewable. However, with approximately 65% of generation hydrologically sourced, New Zealand's energy mix is prone to El Niño weather patterns. With increased solar and wind energy the problems of intermittency, including more volatile spot market pricing, are significant.

Demand response has been identified as a cost-effective way to manage volatility. By enabling demand response and Distributed Energy Resources (DER) to signal their price sensitivity in the wholesale market, spot market prices are expected be more stable and, on average, lower than they would otherwise have been[42]. Figure 29 demonstrates the effect that DER could have to reduce the steepness of load reduction. By slowing the rate demand reduces, spot prices are expected to be less volatile.

[42] Real Time Pricing, Electricity Authority, 2022

Figure 29: Potential for demand management in New Zealand



Source: Real Time Pricing, Electricity Authority, 2022

A.4.2 Use or planned use of Loads and Demand Side Response

Current Usage of DR

At the smaller consumer level, New Zealand deploys ripple control of hot water cylinders (operating since the 1950s). This provides 987 MW of connected load for centralised control. At peak times, this is estimated to be 644 MW of controllable load.

At the large industrial end of the scale, demand response takes the form of bidding Interruptible Loads into the market and contracting with gentailers for reduced rates in power supply agreements in return for relinquishing some demand flexibility.

An example of this is the demand response agreement between generator-retailer Meridian Energy and manufacturer New Zealand Aluminium Smelters Ltd (NZAS). This smelter is the largest single load on the New Zealand electricity grid, accounting for approximately 11-13% of national demand. This was negotiated as part of the overall preferential supply agreement and allows for Meridian Energy to give notice to NZAS to reduce consumption according to specified terms.

Voluntary demand reduction

New Zealand also operates a voluntary demand reduction scheme through Official Conservation Campaigns (OCC). An official conservation campaign is a period during which the system operator calls on New Zealanders to voluntarily reduce their electricity usage. An OCC is required when the risk of electricity supply shortage exceeds 10% and is forecast to continue to do so for at least one week.

Running in conjunction with official conservation campaigns is the Customer Compensation Scheme (CCS). This is enforced through the Electricity Industry Participation Code which requires electricity retailers to have CCS. The CCS requires retailers to pay their qualifying customers financial compensation for their reduction in electricity usage if the system operator has commenced an OCC. Passing the obligation for compensation to the retailer is intended to:

- incentivise retailers to manage their spot price risk appropriately through appropriate hedges to avoid an OCC, and therefore avoid paying compensation; and
- incentivise generators to invest in last-resort dry-year generation to fulfil their hedge obligations.

Proposed Enhancements to DR

As part of moving to real-time pricing in 2022-23 more demand response and DER participation were seen as a key value contributor (refer Table 16and Table 17).

Table 16: Staged rollout of Real-Time Pricing

Date	Introduces
1 November 2022	From 1 November 2022 wholesale market pricing is calculated in real time. The settlement price for each trading period will be calculated at the end of the trading period and published immediately. Retailers are able to reliably develop new products and **consumers who are on plans where they buy from the spot market, will for the first time be able to make decisions on prices that they will actually pay.**
27 April 2023	From April 2023 the dispatch notification product will enable the inclusion of Distributed Energy Resources and aggregated demand management in the wholesale market, subject to approval by the system operator. Enhancements to dispatchable demand will allow large industrial consumers to bid in demand management in a way that better suits the physical constraints of their plant and processes.

Source: Real Time Pricing, Electricity Authority, 2022

Table 17: Expected benefits

Area/Consumer Group	Benefit
Residential and light industrial customers–	Can reduce their electricity bill, by the use of smart technology that will give retailers or a third party the ability to adjust their consumption according to cost.
Large industrial customers	Can manage their exposure by having part of their load based on fixed price and the other part on demand response and bidding that demand response into the wholesale market.
Improve price forecasting	Actively participating in the market, as opposed to passively responding to published prices, will lead to more stable and certain pricing outcomes.

Source: Real Time Pricing, Electricity Authority, 2022

It is too early to assess what level of demand response these market changes will attract (if any).

A.4.3 How these arrangements relate to the WEM

It is useful to see that New Zealand has identified demand response as a cost-effective way to manage the increased system volatility caused by the transition to increased levels of intermittent renewables. However, much of the ability for demand response to play this role was only introduced very recently with the April 2023 shift to real-time pricing in the wholesale market.

The voluntary demand reductions through the OCC are useful to note as a potential way for incentivising demand response participation in the WEM. Also, interesting to note is the way the obligation is placed on retailers to compensate customers during these campaigns. However, anecdotal evidence would suggest that the level of response is more due to a willingness to make a social contribution rather than any incentive paid.

New Zealand's high proportion of hydro generation leaves the system vulnerable during dry periods. Demand response is being looked to assist with maintaining system security during the morning and early evening peaks by shifting consumption and being more dynamic to align with generation availability. This is relevant for the WEM which also has a clear morning and early evening consumption peaks.

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