Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Meeting Agenda

Meeting Title:	Demand Side Response Review Working Group (**DSRRWG**)
Date:	Thursday 2 August 2023
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Competition Law Statement	Chair	Noting	2 min
4	Minutes			
	(a) Minutes of Meeting 2023_07_05	Chair	Noting – Already approved	2 min
5	Action Items	Chair	Noting	2 min
6	**(a)** DSP Participation in RTM and ESS	EPWA	Discussion	40 min
	(b) Non-DSP Load Participation in RTM and ESS	EPWA	Discussion	40 min
	(c) International Case Studies	Lantau Group	Discussion	20 min
7	General Business	Chair	Discussion	10 min
	Next meeting: TBA			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the Demand Side Response Review Working Group (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the Demand Side Response Review Working Group is capable of being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

Minutes

Meeting Title:	Demand Side Response Review Working Group (DSRRWG)
Date:	5 July 2023
Time:	9:33 AM to 11:31 AM
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	(Chair) EPWA	
Toby Price	AEMO	
Alicia Volvricht	AEMO	
Devika Bhatia	Economic Regulation Authority	
Claire Richards	Enel X	Joined 10:13 AM
Thomas Marcinkowski	EPWA	
Mitch O'Neill	Grids	
Bobby Ditric	Lantau Group, Consultant	
Dave Carlson	Lantau Group, Consultant	
Tom Higgins	Perth Energy	
Erin Stone	Point Global, observer for EPWA	
Tessa Liddelow	Shell Energy	Joined 10:01 AM
Graeme Ross	Simcoa Operations	
Chris Alexander	Small-Use Consumer Representative	Joined 9:44 AM
Noel Schubert	Small-Use Consumer Representative	
Justin Ashley	Synergy	
Peter Huxtable	Water Corporation	
Valentina Kogon	Western Power	
Apologies	**From**	**Comment**
Oscar Carlberg	Alinta Energy	
Dimitri Lorenzo	Bluewaters Power	
Jake Flynn	Collgar Wind Farm	
Michael Zammit	Integrated Management Services	
Wayne Trumble	Newmont Mining	
George Martin	Starling Energy	Apology

Item	Subject
1	**Welcome** The Chair opened the meeting at 9:33 AM with an Acknowledgement of Country.
2	**Meeting Apologies/Attendance** Noted as per the attendance record above.
3	**Consumer Law Statement** The Chair drew members' attention to the *Competition and Consumer Law Obligations* document circulated prior to the meeting. The Chair encouraged members to read the document carefully, and to raise any issues with the Chair immediately should they arise during the course of the working group deliberations.
4	**Agenda** The Chair outlined the four broad issues for discussion by the working group at this meeting: • Constrained access for loads – Consideration of the future role of runback schemes and the required level of transparency in their integration in various market components. • Hybrid facilities – Consideration of potential current and future configurations of hybrids, whether each scenario is possible and how any barriers to those configurations can be removed where appropriate. There will also be discussion on how to provide the opportunity for value-stacking but not allow double-dipping. • Minimum demand support – Consideration of what services could address minimum demand issues, and whether we need to do more to incentivise load shifting and/or increasing load during low demand. • Demand Side Programme (DSP) obligations – Consideration of how we should design an efficient dynamic baseline and address the potential for gaming.
5	**Constrained access** The Chair invited Mr Ditric to provide an overview of the issue to the working group. Mr Ditric stated that: • Western Power has been connecting customers (generators and loads) in congested areas of the network under runback schemes for some time. These customers are connected and curtailed on a pre-contingent basis (i.e. curtailed before a network constraint occurs). • Constrained connections are likely to occur more in the future as loads seek connection in more congested parts of the network, and connecting a customer to a runback scheme is quicker and cheaper than reinforcing the network. Mr Ditric asked Ms Kogon whether connection constraints for electric storage resources (ESR) would affect a customer's ability to inject and/or withdraw. • Ms Kogon answered that constraints for customers with ESR would affect both withdrawal and injection depending on the mode of operation (i.e. whether they are operating as a load or generator at the time would determine the requirements that apply under the Technical Rules). She noted that Western Power is currently considering certain concessions when it comes to hybrid facilities. The Chair asked Ms Kogon to elaborate on situations in which ESR would be constrained in future for withdrawal rather than injection.

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- Ms Kogon answered that withdrawal could be constrained if a load was to withdraw/consume during the peak when there is a risk of the network being overloaded.

The Chair asked whether, in the unlikely event an ESR's withdrawal is constrained during peak, when prices are at the highest, whether Western Power would connect the customer under a runback scheme that both constrains injection at certain points and their withdrawal during the peak period.

- Ms Kogon took the question on notice on behalf of Western Power.

ACTION: Western Power to advise how constrained access schemes would work for ESR if it is required to constrain both their injection at certain times and their withdrawal during the peak period

Mr Ditric stated that, as the volume of constrained access schemes increases, the transparency around these schemes needs to increase so AEMO can have more visibility and more information can be made available to the broader energy sector.

The Chair asked whether thermal limits used in constraint equations for the purposes of the Reserve Capacity Mechanism (RCM) and the real time market (RTM) both take into account the presence of these schemes.

- Mr Price stated that real time constraint equations reflect a facility's contribution to network constraints given the operational condition. These may result in the constrained operation of the facility for both injection and withdrawal.

The Chair asked how this is taken into account in the Long Term (LT) PASA.

- Mr Price responded that the LT PASA reliability assessment applies for any facility, in that it considers the impact of network constraints on a facility's ability to supply demand.

The Chair asked whether, when projecting demand in the LT PASA, it may be necessary to consider that ESR may be constrained to serve that demand under certain scenarios at peak times.

- Mr Price confirmed that this was the case.

The Chair asked how this is done.

- Mr Price took the question on notice highlighting that the assessment for the 2023 LT PASA was still being finalised, and that it is the first cycle in which storage was participating.

ACTION: AEMO to advise how an ESR with constrained consumption is, or will be, taken into account in the reliability modelling as part of the LT PASA

- Mr Schubert asked whether there was a situation in which a constraint may bind where an ESR is withdrawing from the network but the local load is not, and how that would be accounted for in constraint equations.

The Chair responded that constraint equations account for withdrawals or load on the left side of the constraint equation and injections or supply on the right.

- Mr Price added that:
  - Constraint equations are capable of managing withdrawal and injection of ESR.
  - RTM constraint equations include line flows and relative changes for facilities participating in dispatch, and make sure any thermal and non-thermal limits are respected based on the change in dispatch.
  - Load is reflected in the line flow meaning the operation of a facility would be limited by the demand at the time.

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The Chair noted that Mr Alexander had asked: “How widely used are runback arrangements now?” in the meeting chat. The Chair answered that the network is constrained in many of the sub-regions and, therefore, it is likely that until the network is reinforced constrained operation may become more prominent.

- Ms Kogon noted she has an outstanding action to provide statistics on curtailable loads under runback schemes, but there have been unforeseen delays in obtaining such information. Ms Kogon addressed Mr Alexander’s question, stating her understanding was that:
  - runback arrangements are not particularly prevalent and are done as an exception rather than the rule;
  - Western Power offers runback arrangements to customers if the choice is whether to connect or not, however, the customer decides whether this is acceptable; and
  - ultimately, runback arrangements only apply in parts of a network where there is a need to handle a specified network event.

ACTION: Western Power to provide information on the prevalence of curtailable load arrangements

Mr Ditric suggested that curtailable loads should be integrated all the way from the beginning to the end of their life cycle.

Mr Ditric asked the group to consider whether there is a need to:

  - standardise the treatment of curtailable loads in the LT PASA, system adequacy planning or capacity targets, and provide direction for AEMO in the WEM Rules;
  - investigate how curtailable loads work in network access quantity (NAQ) calculations to ensure there is neither allocation of more capacity credits than is possible nor inaccurate reduction of the capacity credits or NAQs; and
  - provide more clarity, direction, standardisation and transparency in relation to how curtailable loads are factored into the RTM optimisation and dispatch.

- In relation to information provision, Ms Kogon provided a summary of how this information is currently communicated:
  - For transmission connected customers under a runback scheme, operational information such as the size of the constraint, the size of the load and the constraint triggers is provided to AEMO by email.
  - In respect of distribution connected customers or non-market loads, Western Power is limited by confidentiality obligations in the Metering Code, and the information able to be captured by the type of meter (e.g. accumulation or deemed accumulation meters).

The Chair highlighted the need to change the Metering Code so that confidentiality is not applicable to exchanges between Western Power and AEMO, as the system cannot be secure and reliable without full transparency. The Chair noted this issue had also been raised in relation to Supplementary Reserve Capacity.

The Chair asked for any objections to her suggestion, but there were none.

- Mr Schubert reiterated that curtailable load arrangements, particularly those affecting peak and low demand periods, must necessarily be considered in all aspects of planning and forecasting from the RTM to the LT PASA. Mr Schubert stated his view that ~~-~~there is a deficiency when such arrangements affect important loads such as peak load and minimum load, yet are not taken into account in planning for more capacity~~the current arrangements are deficient~~.

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	Action: EPWA to propose changes to the Metering Code to allow confidential information to be shared between Western Power and AEMO for market purposes and for these to be consulted on in the DSR Review consultation paper

6 **Hybrid Facilities**

Mr Ditric asked the working group to consider:

- Whether the rules currently allow hybrids with DSR to provide multiple services and give participants a number of options in choosing how to participate across markets and maximise value.
- Issues of double-dipping and inefficiencies in respect of hybrids.

Mr Ditric noted he would take the group through a number of examples to facilitate the discussion.

Example 1.1: ESR and on-site load (ESR no CCs, load reducing IRCR)

Mr Ditric stated that this scenario consists of an ESR and load. The ESR chooses not to receive capacity credits and the load seeks to reduce IRCR. Mr ~~Dirtic~~ Ditric noted his view that this scenario is currently possible and should continue, and invited the group to provide views. The following points were raised:

- Mr Alexander asked if this scenario was hypothetical, given there are currently no registered hybrid facilities.

The Chair confirmed that there were currently no hybrids commissioned but they may exist in the future.

- Mr Alexander stated that while rules may allow certain things to be done, there are not many instances of anybody making use of them.
- Mr Schubert stated that this scenario should be encouraged because locating storage behind the meter provides demand leveling benefits for the whole system.
- Mr Schubert stated that locating storage only at strong transmission nodes does not help loads downstream in terms of evening out demand.

Mr Ditric asked how this should be encouraged.

- Mr Schubert responded that investors and retailers need to be incentivised by the right price signals, highlighting that the rules currently allow this and yet nothing is being done.

The Chair stated that there are questions as to how expensive it is to locate storage behind the meter vs how high the cost is of covering one's IRCR. If the equation is right, participants will invest. However, it is first necessary to check for barriers in the WEM Rules.

Example 1.2: ESR and on-site load ESR with CCs, load reducing IRCR

Mr Ditric explained this scenario as follows:

- The ESR has capacity credits but the load does not.
- The load switches off during intervals to reduce its IRCR and the ESR does not supply the load behind the meter.
- The ESR is available to the market and achieving all its capacity credit obligations and expectations.

Mr Ditric asked the working group to consider whether the rules allow for this scenario, and whether anything else needs to be done in respect of it.

The Chair referred to the discussion on this scenario at the previous working group meeting when it was agreed that a facility should not be able to receive capacity credits

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	for the ESR as well as the ESR supplying ~~charging~~ the load to reduce IRCR. The Chair posed the question of what needs to be added in the WEM Rules and procedures so this particular behavior is identified in advance when the ESR is provided capacity credits.
	
	The Chair posed a related question of what information AEMO would need to in the certification process to assure itself that the storage facility is not going to double-dip in this way.
	
	• Mr Price suggested two options:
	  1. That load already exists and there would be information about the ability of that load to curtail.
	  2. There is information provided to demonstrate the curtaila~~i~~bility of that load. Perhaps there needs to be more explicit data provision to support that in the WEM Rules.
	• Mr Price added that when a hybrid facility is operating in the market, the ability to meet the Reserve Capacity Obligation Quantity (RCOQ) means it will need to offer into the market to inject. This is net of any behind the meter consumption.
	
	The Chair stated that there is a need to provide clarity in the WEM Rules and procedures what is expected of hybrid facilities.
	
	• Mr Schubert stated that one way AEMO can know storage is meeting its obligations is to ensure AEMO can see its state of charge.
	
	The Chair responded that the problem is that AEMO only looks at the next interval, rather than over the duration of the storage obligation.
	
	• Mr Huxtable stated that loads currently have no obligation to reduce consumption for the purpose of IRCR, noting that sometimes a load may try this and fail.
	• Mr Huxtable reiterated his concern that the WEM Rules should be amended to allow load and ESR to be measured and treated separately.
	
	The Chair said that if upfront visibility is needed then proper measurements must be in place to ensure a storage facility is not used to reduce IRCR for load and at the same time receive capacity credits under the linear de-rating methodology.
	
	• Mr Price stated that the current sub-metering arrangement do not capture load behind the meter because the facility is dispatched as a whole, net of that load.
	• Mr Price stated that his understanding was that if there is more than one technology type behind the meter each becomes a separately certified component.
	
	The Chair summarised the discussion as follows:
	
	• There is a need to examine the procedure, subject to making sure participants have the choice to avoid the cost of a second revenue meter behind the connection point meter if that would be cost prohibitive.
	• If participants are given a choice, metering and settlement calculations must change.
	• Alternatively, provide a choice but ensure the facility does not benefit both from capacity credits and IRCR reduction if the storage facility is supplying ~~charging~~ the behind the meter load during IRCR intervals.
	
	Action: EPWA to propose changes to allow a load and storage connected at the same NMI to be measured and treated separately, to be consulted on in the DSR Review consultation paper
	
	Example 1.3: ESR and on-site load (on-site load supplied by ESR)
	
	Mr Ditric explained that under this scenario an ESR with capacity credits is supplying the co-located load to reduce its IRCR. Mr Ditric noted that this scenario clearly fits within the

definition of double dipping, and that it has been discussed by the working group before and clearly should not be allowed.

The Chair stated that the working group needs to ensure the rules and procedure properly treat this arrangement.

Example 1.4: ESR and on-site load (ESR and load dispatched independently)

Mr Ditric introduced this scenario stating that it is using submetering to dispatch and settle individual components separately. Mr Ditric asked for views on whether that option should be allowed. The following points were made:

- Mr Price identified three options of metering and settlement for separate components:
  1. A single meter with multiple components behind that meter, all collectively settled and all having combined obligations. Everything is netted through that meter.
  2. A single settlement point but multiple components being allowed to participate in the market as separate dispatchable units (the model used in the NEM), with settlement determined for each component. For example, a battery offers its injection and withdrawal into the market separately from a non-dispatchable load.
  3. Separate sub-metering owned and operated by Western Power, which allows registration of multiple facilities behind a single connection point.
- Mr Price asked which option the scenario was trying to address.

Mr Ditric answered that it was number 2.

The Chair stated in respect of Mr Price's three options:

1. A hybrid that has a storage facility and a load may still register as a scheduled facility, and the storage facility is able to offer and be settled in the market. However, it needs to be measured at the interface because this is an actual measurement of energy injection or withdrawal.
2. Two components separately metered behind the same connection point by sub-metering not owned by Western Power are not allowed to be settled separately as they are not measured by revenue-grade metering.
3. Option 3 is currently not provided for but would be allowed because the sub-metering is Western Power metering, so it would be suitable for settlement.

Example 2.1: ESR and DSP (ESR – no CCs, smaller than registration threshold):

Mr Ditric introduced this scenario stating that:

- it is a hybrid facility not receiving capacity credits for the ESR but having a DSP component which is receiving capacity credits; and
- the ESR therefore has no obligations but the DSP has capacity credits and associated obligations.

Mr Ditric noted his view that this is possible under the WEM Rules and should continue as there are no obvious problems.

The Chair compared this scenario with diesel generators behind the connection point in that the ESR can supply ~~charge~~ the load so the load receives capacity credits and its response is measured at the connection point.

The Chair asked for views on this scenario continuing to be allowed. There were no objections.

Example 2.2: ESR and DSP (ESR – no CCs, larger than registration threshold):

Mr Ditric introduced this scenario as the same as the previous scenario.

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	• Mr Price said that the only situation that could pose problems for this scenario is if the ESR is larger than the mandatory registration threshold. The facility would need to register as a scheduled facility and once it does that, it cannot have a DSP associated with it. The Chair asked if there is a DSP at the connection point, whether the participant should be given a choice as to whether to register as a scheduled facility or DSP. • Mr Price said that he would need to take the question on notice, highlighting that for a very large facility there is a question as to whether a DSP would be appropriate. Mr Price highlighted that the obligations around DSPs and scheduled facilities are dramatically different. The Chair noted that a DSP has the more stringent obligation as it has to be available for 12 hours versus 4 hours for an ESR. • Mr Schubert suggested that the obligation period should be based on what the system needs, rather than simply being a strict 12 hour time period. The Chair stated that this had already been consulted on and there was support for keeping the 12-hour obligation period. There was presently no proposal to change that period. The Chair asked AEMO to consider whether participants can be given the choice of registering a DSP with capacity credits instead of a scheduled facility if they have an ESR and a load behind the meter, and whether that poses any threat to system security. • Mr Price stated that while having flexibility for proponents to structure their facilities and their business cases to suit them is important, there is a need to establish whether there is industry appetite for those arrangements. The Chair asked how this is different to having a diesel generator in a building that is registered as a DSP, if the diesel generator capacity is higher than the maximum demand of that building. • Mr Price stated that in that scenario, it is only ever the diesel that delivers the DSP response. Here, there is controllable load that can reduce at any time but might prefer to use a battery, yet cannot deliver response solely from the battery because of the 12 hour obligations. **Action: AEMO to provide views on whether participants can be given the choice of registering a DSP with capacity credits instead of a scheduled facility if they have an ESR and a load behind the meter, and whether that poses any threat to system security.** <u>Example 2.3: ESR and DSP(ESR – no CCs, load also reducing IRCR:</u> Mr Ditric stated that in this scenario the ESR is not certified, and there is a DSP with capacity credits that is also trying to reduce its IRCR. Mr Ditric asked whether this scenario should be allowed, particularly whether it is double-dipping for the same load to receive capacity credits and IRCR reduction if the IRCR reduction period is outside the DSP 12-hour obligation. There was discussion between the Chair, Mr Ditric and Mr Schubert as to when 12 hour intervals would occur and whether the IRCR intervals could ever feasibly occur outside the DSP obligation intervals. Mr Ditric concluded the discussion by stating that it is not worth allowing this as it may never occur. No further views were provided. <u>Example 2.5: ESR and DSP (ESR – no CCs, supplies on-site load):</u>

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Mr Ditric described this scenario as a facility using ESR to assist in DSP dispatch outside the ESR's 4 hour obligation periods.

- Mr Schubert said that this should be allowed.

The Chair noted the need to confirm whether or not this scenario is currently allowed.

No further views were provided.

Example 2.6: ESR and DSP (dispatched and settled independently):

Mr Ditric explained that this scenario as using revenue grade metering to allow separate settlement of the ESR and the DSP for the facility.

The Chair said that the ESR and DSP in this scenario need to be considered as two separate facilities. The Chair noted that the calculations WEM Rules need to be changed to allow settlement for the two meter values to be subtracted from each other.

No further views were provided.

Example 3.1: ESR, Intermittent Generation and DSP (all have CCs):

Mr Ditric introduced this scenario as a hybrid facility with capacity credits but which is using intermittent generation to provide some self-supply while the DSP is dispatched.

The Chair said that, for the purposes of the discussion on dispatch, there was nothing stopping this in the WEM Rules.

- Mr Price asked whether the DSP is the right construct in this circumstance.

The Chair noted that an ESR and a DSP cannot both have capacity credits if they are behind the same meter, as they cannot register two facilities. Participants may have a choice if AEMO agrees system security allows them to, either to register the DSP or ESR but they can't both be registered.

The Chair stated, in respect of dispatch, that it is not relevant which component meets the obligation.

- Mr Price confirmed that the obligation is injecting energy and unless there is an outage for a component, there is no stipulation which component needs to deliver this.

The Chair stated that there is no recourse if the intermittent generator happens to fulfil part of that obligation and the ESR does not fully meet the obligation. The Chair added that the obligation can be met by either of those components.

- Mr Schubert stated that, if there was Western Power metering on each component and that was used for settlement, capacity credits could be allocated for each component.

The Chair clarified that, in that situation, there would be separate facilities that happen to be behind same connection point.

- Mr Schubert stated that the intermittent generator does not have obligations but because it has been allocated capacity credits there is an unwritten expectation ~~it is expected~~ that it will be providing megawatts to the extent of these credits. If the intermittent generator happens to be generating at the time, the expectation is that it might be producing ~~have~~ extra megawatts it could do what it likes with, for example charging its battery or helping the DSP to meet its obligations.

The Chair asked whether Mr Schubert was saying that for hybrids that do not have metering on each component, the intermittent generator can fulfil the DSP obligations because it does not have obligations itself.

- Mr Schubert confirmed this was what he was saying, but it does not seem fair unless the intermittent generator uses output above its capacity credit allocation to do so.~~.~~

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7	**Minimum demand support**

Mr Carlson provided a summary of the issue, highlighting that the working group needed to look at the role DSR can play to minimise the impact of low load of the system, including to:

1. avoid or reduce the impact of minimum load; and
2. provide an alternative response to maintain system stability.

Mr Carlson said that minimum demand can be avoided through load shifting, but highlighted that there must be the right incentives on the demand side. He noted that during low load times prices usually fall, so hopefully that will create a price incentive.

Mr Carlson asked whether, in the south west interconnected system it is normal for large loads to respond to price signals or fixed tariffs are more common.

- Mr Schubert answered that a lot of the large flexible loads do not currently receive a price signal to increase demand on minimum demand days.
- Mr Carlson~~He~~ posed further questions to the working group:
  - What kinds of loads exist in WA that can take advantage of lower prices?
  - How prevalent are high elasticity demand users, and what types of loads are they typically?
- Mr Schubert stated the following:
  - There are quite a few loads that could assist in increasing minimum demand, but this requires an aggregator or retailer to arrange this with customers and provide them with sufficient incentives. This would require tariffs and/or contracts to change to reflect minimum demand times.
  - AEMO should provide more information to the market closer to real time to indicate when there is likely to be an issue to incentivise response.

The Chair summarised the issues:

1. Whether the price is sufficient to incentivise the necessary behavior.
2. Whether a subset of the loads are capable of delivering what is required.

The Chair highlighted that the working group needed to know how many loads can actually reduce their own internal generation to expose the load to the system, and questioned whether:

  - these loads should be provided with additional incentives to do so and how much of an incentive would change the behavior; and
  - there are loads that can either reduce internal generation or increase their load to provide these services, and if so, what type of loads they are.

- Mr Schubert stated that there is already a retail tariff being offered to disadvantaged customers for free electricity at midday. That could be done by a number of aggregators and retailers.

The Chair asked if there were any obstacles to this that could be addressed by a change to the WEM Rules, noting it was not possible to interfere with commercial contracts.

- Mr Schubert stated that he was not aware of any barriers in the WEM Rules.
- Mr Graeme Ross stated that prices he has seen are in the RTM and most contracts are bilateral, so signals may not be reaching users except for large users. He, therefore, highlighted that aggregators and retailers needed to be incentivised to pass the signals through to users.

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The Chair noted that AEMO has triggered Non-Cooptimised Essential System Services (NCESS) twice to provide these types of services, highlighting that if the price signal was sufficient they would not need to trigger an NCESS to get a response.

- Mr Price noted that the increase in intermittent generation in the future needs to be supported by a similar increase in discretionary demand, particularly when there is an over-supply situation. Mr Price asked whether such an imbalance is expected to be transitional, or a longer-term problem.

The Chair asked whether storage charging during the day to fulfil its evening obligations would negate the need for other loads to increase their demand during low load periods.

- Mr Schubert responded that this would depend on whether the amount of storage exceeded the reduction in the minimum demand. He highlighted that there is not enough storage to keep up with the rate of solar PV growth but that, if the messaging to solar PV owners was right~~,~~ to encourage them to own the low demand problem, some ~~consumers~~ would be prepared to respond to requests to reduce solar PV output.

The Chair asked whether we need an incentive, or just effective communication.

- Mr Schubert responded that~~-~~ we need communication and an incentive may also be needed providing that the cost of the incentive is less than the cost of procuring minimum demand services (through NCESS)~~an incentive would be more cost effective~~.

The Chair noted that, in the chat, Mr Huxtable had asked what AEMO is paying for NCESS. The Chair noted that AEMO would publish the costs of NCESS when the process was complete.

The Chair noted that the group wanted to understand what flexibility existed in the contestable customer space to manage minimum demand, including the types of load and its size, to better understand whether the market needs services that are more regular in this space.

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8 DSP obligations

Mr Carlson noted that the issue of dynamic baselines was already familiar to the group, highlighting that there had been significant discussion at the Market Advisory Committee (MAC) and other forums. He highlighted that the general consensus was that a dynamic baseline was more efficient and effective than a static baseline.

The Chair reiterated that a dynamic baseline was strongly supported, but asked the group what would be required in the WEM Rules to avoid gaming.

Mr Carlson stated that there were two ways to achieve this:

1. limit the loopholes to limit the possibility for gaming; or
2. relay on the regulator of deal with non-compliance after the fact.

The Chair highlighted that the primary goal of the new market arrangements is to prevent behaviour like this by design, i.e. to not rely on enforcement actions by the Regulator.

- Ms Richards considered that the potential for gaming is overstated, noting that with the long activation window there is no guarantee of dispatch, so it is unlikely the load will artificially increase consumption for such a sustained period of time. Ms Richards suggested referring to the NEM and making sure there is a rigorous baseline methodology.

The Chair asked Ms Richards to provide examples of how this works in other markets.

Action: EnelX to provide examples of how dynamic baselines work in other markets in which there are~~is~~ proactive rules and incentives as opposed to reactive compliance-based regimes.

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9 Next Steps

Item	Subject
	• Prepare slides for 2 August 2023 meeting and issue a week prior

The meeting closed at 11:33 AM

Government of Western Australia
Department of Mines, Industry Regulation and Safety
Energy Policy WA

Agenda Item 5: DSRRWG Action Items

Demand Side Response Review Working Group (**DSRRWG**) Meeting 2023_08_02

Shaded	Shaded action items are actions that have been completed since the last PAC meeting. Updates from last PAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
1	Provide the working group with a table of average utilisation values for typical network circuits	Western Power	Meeting 2023_06_07	**Open** There have been unforeseen delays in Western Power obtaining this information
2	Advise how constrained access schemes would work for ESR if it is required to constrain both their injection at certain times and their withdrawal during the peak period	Western Power	Meeting 2023_07_05	**Open** At the previous meeting, Ms Kogon (on behalf of Western Power) took a question on notice regarding this item.

Item	Action	Responsibility	Meeting Arising	Status
3	Advise how an ESR with constrained consumption is, or will be, taken into account in the reliability modelling as part of the LT PASA	AEMO	Meeting 2023_07_05	**Open** Mr Price (on behalf of AEMO) took a question regarding this item on notice at the previous meeting. Mr Price highlighted that the assessment for the 2023 LT PASA was still being finalised, and that it is the first cycle in which storage was participating.
4	Provide information on the prevalence of curtailable load arrangements (“runback schemes”)	Western Power	Meeting 2023_07_05	**Open**
5	Propose changes to the Metering Code to allow confidential information to be shared between Western Power and AEMO for market purposes and for these to be consulted on in the DSR Review consultation paper	EPWA	Meeting 2023_07_05	**In Progress** EPWA is about to commence drafting the proposed changes for consultation, to be approved by the Minister
6	Propose changes to allow a load and storage connected behind the same NMI to be measured separately by Western Power meters and settled separately	EPWA	Meeting 2023_07_05	**Open** To be consulted on in the DSR Review consultation paper
7	Provide views on whether participants can be given the choice of registering a DSP with capacity credits instead of a Scheduled Facility if they have an ESR and a load behind the meter, and whether that poses any threat to system security	AEMO	Meeting 2023_07_05	**Open**

Item	Action	Responsibility	Meeting Arising	Status
8	Provide examples of how dynamic baselines work in other markets, in which there are proactive rules and incentives as opposed to reactive compliance-based regimes	EnelX	Meeting 2023_07_05	**Open**

Government of Western Australia
Department of Mines, Industry Regulation and Safety
Energy Policy WA

DSR Review Working Group

Meeting 4

2 August 2023

Working together for a **brighter** energy future.

DSP Participation in RTM and ESS

DSPs only participate in the RCM and are required to be available to satisfy their reserve capacity obligations

DSP don't offer quantities/prices into the RTM but can be dispatched by AEMO during the RCOQ intervals of 8am – 8pm

- AEMO would issue Dispatch Instructions to a DSP if it reasonably considers that its dispatch is required to restore or maintain Power System Security and Reliability
- **Discussion questions:**
- Are there any obligations/requirements that prevent DSP participation in the RTM that we should consider changing?
- Should the WEM Rules be changed to allow (and/or require) DSP to bid into the RTM or are we extracting the most value from/for DSP by them only participating in the RCM?
- Should there be any corresponding requirements to provide AEMO with confidence in dispatch?
- If DSP RTM bidding were to be allowed (and/or be required), and some or all quantities bid at the Energy Price Limit what tiebreak should be applied?
- Can DSPs take advantage by buying energy in the RTM at negative prices in the middle of the day?
- Would a dynamic baseline make RTM bidding and dispatch more attractive to DSPs?

DSPs under the WEM Rules cannot provide ESS

- **ESS providers require AGC to offer ESS due to the need for fast response**
- **AEMO dispatching DSPs via the DSP aggregator communicating dispatch instructions is likely too slow and inefficient for ESS purposes**
- **Discussion questions:**
- Are there any ESS that DSPs could provide that would be valuable to the SWIS and/or to the DSPs?
- Would it be practical and possible to allow DSP to provide ESS? If so, are there any corresponding requirements that would need to be imposed, for example to prevent double-dipping, to provide AEMO with confidence in dispatch?
- Are there any overlaps or competing incentives for DSPs that could limits DSP participation in ESS if we were to allow them to participate?

Non-DSP Load Participation in RTM and ESS

Loads that are not part of a DSP have the option to participate in the RTM

Register as a Scheduled Facility or Semi-Scheduled Facility

- **Scheduled Facilities and Semi–Scheduled Facilities can bid Withdrawal quantities/prices into the RTM and are included in the merit order**
- **A load cannot be registered concurrently as both a DSP and as another Facility, apart from an Intermittent Load**
- **AEMO centrally dispatches Facilities based on RTM Bids and RTM Offers using the Dispatch Algorithm to minimise the cost of RTM trading and issues:**
    - For a Scheduled Facility a Dispatch Target
    - For a Semi-Scheduled Facility a Dispatch Cap

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

1. **Dispatched on during low load periods to increase demand**
2. **Dispatched off during high load periods to reduce demand**

Can/will Loads to participate in the RTM – low demand periods

In low load periods when energy prices are low or negative large flexible loads are incentivised to increase demand, or shift demand

- **Discussion questions**
- The RTM price floor is -$1,000. Is the level and/or frequency of negative prices enough for this to be a feasible option for certain types of loads (or their retailers) to register, bid and be dispatched in the market?
- What types/sizes of loads would have sufficient incentive to increase or shift demand in response to negative prices?
- What additional requirements/obligations would need to be introduced to ensure effective participation?
- Are there any barriers for load participation in the RTM that need to be removed?
- What is the role of aggregators and/or retailers in this space?

Loads that can assist with minimum demand

- **Received information in response to our request regarding the type of loads that exist in the SWIS that could assist during minimum or low demand periods**
- **Types of loads that could increase their demand during SWIS low demand periods:**
  - Do not need to operate 24/7
  - Do not currently operate in the middle of the day or weekends
  - Can do some type of “batch” process resulting in storage of their “product”
- **Examples 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 is also used in other jurisdictions.
  - 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
  - On-site load that is supplied by on-site generation.

Can/will Loads participate in the RTM – high demand periods

Flexible loads may benefit from reducing their withdrawal in high demand period to reduce their exposure to high prices

- **Discussion questions**
- Are the RTM price limits (based on distillate fuel in the future) sufficiently high to drive this behavior?
- What types/sizes of loads would have sufficient incentive to reduce demand in response to high prices?
- Are there any barriers for load participation in the RTM that need to be removed?
- What is the role of aggregators/retailers in this space?
- Are DSPs or IRCR reductions better suited to these types of loads to drive the right behavior? Given there are multiple different drivers with different incentives, how do they compare? Do we need both? Need alignment?

Flexible loads providing ESS

Loads registered as Scheduled Facility or Semi-Scheduled Facility can provide the following ESS:

- **Regulation Raise and Regulation Lower (require AGC)**
- **Contingency Reserve Raise and Contingency Reserve Lower (require AGC)**

In addition, certain types of loads registered as Scheduled Facilities may also be able to provide RoCoF

Alternatively, a Load operating as an Interruptible Load can provide Contingency Reserve Raise

- **Discussion question:**
- Do the current technical and other requirements prevent effective participation of flexible loads in ESS?
- What types/sizes of loads would have the ability and sufficient incentive to participate in ESS?
- Are there any barriers for load participation in ESS that need to be removed?
- What is the role of aggregators/retailers in this space?

Load/DSP participation in the STEM

- **Loads are currently not able to participate in the STEM**
- **Their participation is not prohibited, rather, loads are not able to comply with STEM requirements in a few ways:**
  - Market Participants can only sell energy and must identify the contracted Market Participant purchasing the energy through a bilateral contract (a contract formed between any two persons for the sale of electricity)
- **A Market Participant must not specify quantities in a Bilateral Submission or a Standing Bilateral Submission which exceed the quantity of energy that the Market Participant is contracted to supply to the relevant Market Participant**
- **Discussion question:**
- Is there any reason Loads/DSPs should not be able to participate in the STEM? If no, what needs to be done to facilitate their participation?

The role of Curtailable Loads in dispatch

- **During previous working group meetings we discussed the concept of loads connecting via runback schemes whereby, Western Power can curtail consumption to resolve network constraints**
- **Western Power and AEMO already share some details of the arrangements for curtailable loads however, this isn't transparent to the WEM processes**
- **Discussion questions:**
- Should the curtailment of these loads continue to be administered by Western Power?
- Should AMEO manage the curtailment instead and have the curtailment included in dispatch optimisation? or
- Should AMEO manage the curtailment instead and have the curtailment included as a part of a constraint equation?

International Case Studies

New Zealand’s demand-side of the electricity market is mostly energy efficiency, rather than dynamic customer involvement.

Three roles identified for demand-side flexibility in New Zealand’s wholesale electricity market:

1. Short-term shifting of consumption between time periods.
2. Reduction of demand for a range of periods (days, weeks, months).
3. Increase in demand during low-price periods.

At the household level, the opportunities for demand-side flexibility uptake lie with EVs and home batteries, and may extend to smart appliances if a residential customer is exposed to wholesale prices or a strict time-of-use tariff.

An example opportunity for demand-side flexibility by a third-party is the 987 MW of hot water cylinder load connected to ripple control. At peak times, this is estimated to be 644 MW of controllable load.

Demand response agreement between New Zealand's largest retailer and largest single load

- **A demand response agreement was presented in early 2023 between generator-retailer Meridian Energy and manufacturer New Zealand Aluminium Smelters Ltd (NZAS).**
- **Only one aluminium smelter exists in New Zealand, at Tiwai Point in the far south.**
- **This smelter is the largest single load on the New Zealand electricity grid, estimates suggest it accounts of an average of 13% of national demand.**
- **The agreement states that Meridian Energy can order a notice to NZAS to reduce consumption according to specified terms:**
- An option identified as 1-5 (see next slide)
- MWh per half hour by which NZAS is required to reduce consumption
- Commencement date of the ramp-down period
- The first day of the demand response period.
- The last day of the demand response period, which must be no more than 60 days after the first day of the demand response period.
- **The notice must be received by NZAS within 2 or 3 business days before the ramp-down period, depending on the option identified.**
- **The amount payable is a fixed monthly premium, and a half hourly rate during demand response instances, neither rate is disclosed in the online version of the agreement.**
- **The consequence of non-compliance by NZAS will be non-payment or reduced payment of the amount payable**

PJM, one of the largest grid systems in the world, are a notably mature market for demand response activity

- **Beginning with customer trials in 2006, PJM has been an early proponent of demand response, and is now offered by numerous "curtailment service providers" who each pool smaller customers into a monitored demand response system and bid capacity on behalf on them. These service providers were initially large energy service companies, but many have emerged which are specific to demand response services.**
- **Per the PJM activity report dated May 2023, participants have access to three distinct types of demand response:**

Type of demand response	# of locations	Capacity in MW	State with highest capacity load zone
Economic	511	2,489	Maryland (273 MW)
Load management	14,532	9,074	Illinois (1,315 MW)
Price responsive	2,680	443	Maryland (202 MW)
Total (unique*)	***17,425***	***10,595***	***Illinois (1,320 MW)***

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

PJM, one of the largest grid systems in the world, are a notably mature market for demand response activity

Figure 3: DY 22/23 Confirmed Load Management DR Registrations Business Segments

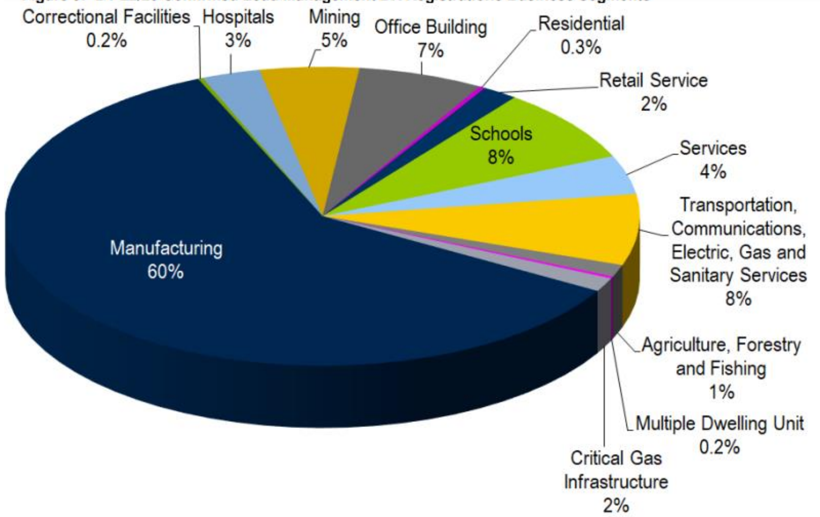
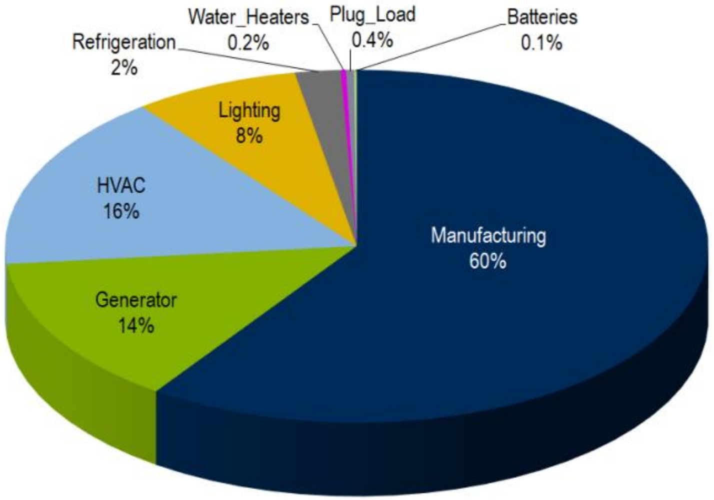
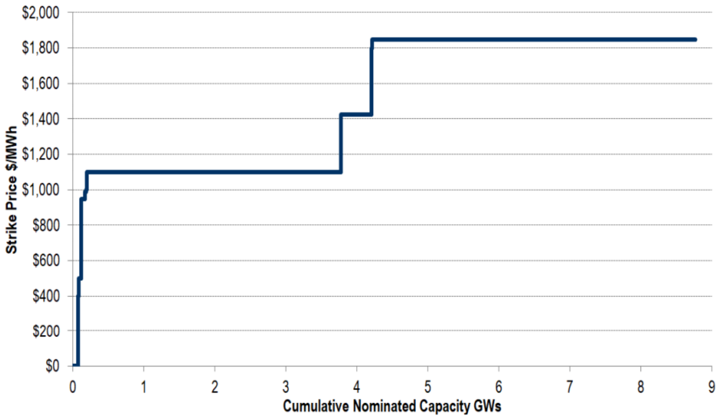


Figure 5: DY 22/23 Confirmed Load Management DR Registrations Customer Load Reduction Methods



- PJM has seen its demand response program expand and diversify into many sectors and customer segments [Fig. 3].
- On a megawatt basis, Manufacturing accounts for the highest demand response capacity in PJM's area, 60% of the total.
- Other important sectors for providing demand response services are Transportation, Communications and other public services (8%), Office Buildings (7%) and Mining (5%).
- Participants also employ a range of sources to carry out demand response [Fig. 5], although again Manufacturing (specifically adjustment of timing of manufacturing activities) is the most prominent method at 60%.
- Other sources and methods employed are: HVAC (16%), Generator (14%), Lighting (8%).
- The energy supply curve for demand response registrations [Fig. 9] shows the range of strike prices for cumulative nominated capacity, with a majority bidding at either $1,100/MWh or $1,850/MWh.

Figure 9: DY 22/23 Confirmed Load Management Full DR Registrations Energy Supply Curve:



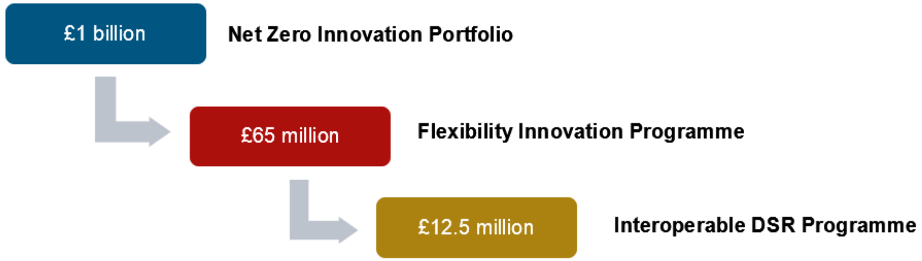
Source: PJM Interconnection LLC.

Current state of demand side response in the UK market

- Various types of DSR have been implemented for the UK power system since 2015.
- The most relevant market for DSR is the “flexibility’ market, which encompasses other sources such as interconnection, storage, local supply network balancing and multi-vector energy integration.
- After several years of procuring “demand turn-down”, UK Power Networks in 2023 will also introduce “demand turn-up”, which has the advantage of incentivizing solar and wind to connect to the grid. They believe they are the first operator to run such a scheme at such a large scale.
- Building on previous tenders from 2017-2022, the most recent tender includes 1,000 key areas in London, South-East region and East region of England. The tender is for 500 MW of capacity flexibility over a three year period.
- UK Power Networks is calling for flexibility in local areas where electricity demand or generation is expected to outstrip the capacity of substations and cables, sometimes only for a few hours per year. This flexibility can come from large electricity generators, grid-connected batteries or from homes and businesses that are able to change their usage patterns. Participants earn payments for supporting the network, while lowering costs and connection times for everyone.
- The scheme is open to businesses with at least 10kW of flexibility in a constrained area. Households may participate through registered energy suppliers or aggregators.
- An article by S&P Global estimates the UK needs 8-10 GW of demand side response capacity to guarantee a secure supply of low-carbon electricity.

UK government support to demand response

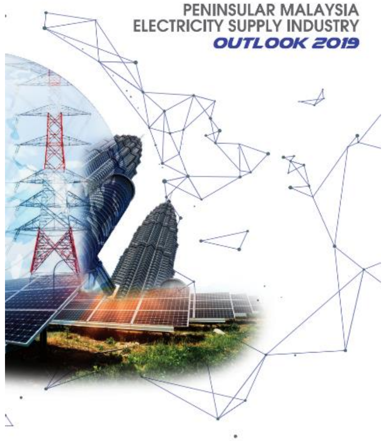
The UK government allocated funding for demand response innovations through the following channel:



With three streams covering themes within the Interoperable Demand Side Response Programme, the following projects were granted funding in January 2023 to pursue innovation:

Stream 1	Stream 2	Stream 3
• **Energy Smart Heat Pump**: Design a solution for Samsung heat pumps to provide DSR.	• **SmartDSRFlex:** Development of smart metering to transport DSR commands and data.	• **LV EMS:** Assess the technical and functional requirements for LV Energy Management Systems to enable remote and dynamic load control.
• **Project DSRR:** Connect households and their smart appliances/EVs to a customer energy management system run by DSR service providers.	• **ChameleonFIP:** Take an off the shelf EV charger and integrate it into a compliant DSR-ready system that leverages UK smart metering infrastructure.	• **OpenDSR for all:** Commercialisation opportunities for a domestic DSR aggregator service.
• **PAS-DSRFlex:** Investigate how DSR can help to manage a renewables-based electricity grid, citing British Standards.		• **Project Open IC:** An architecture that supports independent but implicitly coordinated control of multiple energy smart appliances.
• **Zen Smart:** Enable consumers to flexibly alter their energy usage using a cloud-based system.		• **Lab Testing:** Design and deliver lab testing schemes for demand side response systems from a conformance and performance standpoint.
• **Tommorow's Homes Today:** Feasibility study of DSR from both smart and analogue appliances via. cloud and retrofits.		• **Real-World Demonstration:** Deliver performance testing and demos of smart appliances and DSR service platforms in public settings.

Demand Response schemes in the pipeline with"*Grid of the Future*" launched in 2021 to accommodate solar additions of 5GW by 2025



RE Target of 31% RE at 12,916 MW

2025

- Large Hydro 5,862 MW
- Biomass 862 MW
- Small Hydro 1,153 MW
- Biogas 333 MW
- Solar 4,706 MW

**Current Solar penetration limit at 24% of peak demand. Grid enhancements needs to cater for 30% and beyond*

Modernisation investments for better and more resilient, smart and flexible national grid to meet energy transition needs :

- MYR 22 billion from 2022-2024 to be invested for a resilient, consistent, digital and flexible smart grid to manage high renewables and solar to support dynamic two-way energy flow, while maintaining voltage stability
- Accelerate collaboration with ASEAN power utilities to realise interconnected ASEAN Power Grid

Expect more participative demand response schemes to be introduced within the next 2-3 years as Malaysia enters its 4th Regulatory Period (RP4) which takes effect from 2025-2027