NERA
ECONOMIC CONSULTING

SUMMARY AND ASSESSMENT OF INTERNATIONAL PRICE RESPONSIVE RESOURCES MECHANISMS

24 MAY 2023

Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
CAISO	California Independent System Operator
CM	Capacity Market (Great Britain)
CSP	Curtailment Service Provider (PJM)
DAM	Day Ahead Market
DFS	Demand Flexibility Service (Great Britain)
DG	Distributed Generation
DL	Dispatch Lite (New Zealand)
DNSP	Distribution Network Service Provider
DR	Demand response
DRAM	Demand Response Adequacy Mechanism (California)
DRP	Demand Resource Provider (New Zealand)
EDR	Economic Demand Response (PJM)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission (USA)
GB	Great Britain
GW	Gigawatt
HHI	Herfindahl-Hirschman Index
IOU	Investor-Owned Utility (California)
kW	Kilowatt
kWh	Kilowatt-hour
LMP	Locational Marginal Price
LR	Load Reduction (Texas)
LSE	Load-Serving Entity (California)
MOO	Must Offer Obligation (California)
MW	Megawatt
NEM	National Electricity Market
NZ	New Zealand
PDR	Proxy Demand Resources (California)
PJM	Pennsylvania-New Jersey-Maryland market
RA	Resource Adequacy (California)
RCM	Reserve Capacity Mechanism (W. Australia)
RES	Renewable Energy Sources
RTM	Real Time Market
RTP	Real Time Pricing (New Zealand)
SCADA	Supervisory Control and Data Acquisition (Telemetry)
SCED	Security-Constrained Economic Dispatch (Texas)
SL	Scheduled Lite
SO	System Operator
WDRM	Wholesale Demand Responcse Mechanism
WEM	Western Electricity Market

Introduction

- AEMO has put forward a new mechanism for incorporating price responsive resources into the NEM, called "Scheduled Lite".
  - Under "visibility mode", participants would be able to provide to AEMO details of their price-responsiveness, allowing AEMO to incorporate an adjusted demand curve for dispatch.
  - Under "dispatch mode", participants with a minimum aggregation larger than 5 MW would be able to submit bids and be dispatched, but under less restrictive rules than under the Wholesale Demand Response Mechanism (WDRM).

- We have been commissioned by the AEMC to review and assess a range of mechanisms designed to incorporate price responsive resources into energy markets around the world: California, Texas, PJM, Great Britain, New Zealand, and Western Australia.

- In the following slides, we summarise these mechanisms and draw lessons which could be applied to the new mechanism in the NEM:
  - In Section 1, we describe the overall dimensions and characteristics that define mechanisms for incorporating price responsive demand;
  - In Section 2, we provide a more detailed description of 7 relevant schemes which exist outside of the NEM;
  - In Section 3, we draw lessons from these case studies and apply them in the context of the Scheduled Lite proposal

1 | Overall Mechanism Characteristics

Price responsive demand mechanisms can be classified as being a market mechanism or operationalising existing responsive demand

Demand Response (DR) market mechanism

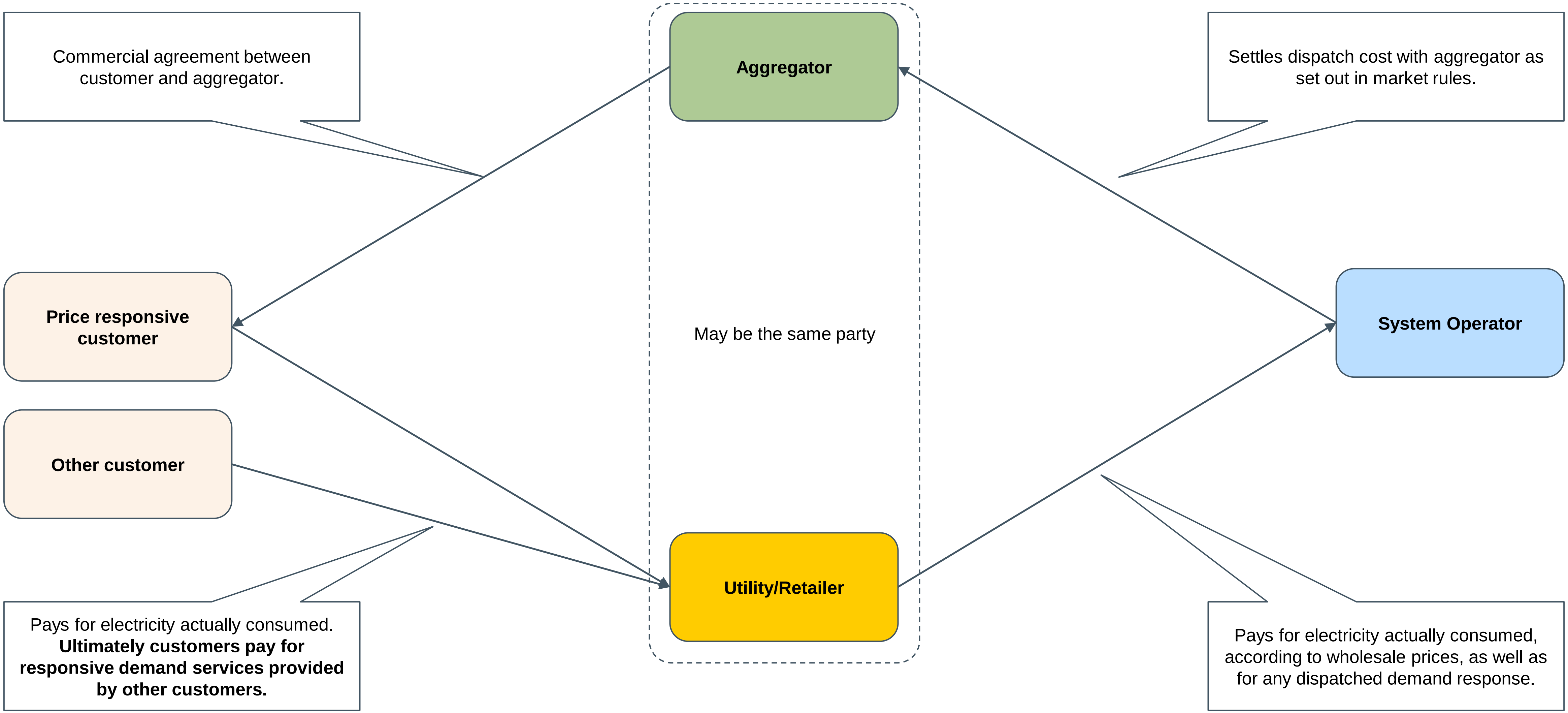
- Full DR mechanisms have been in place for several years in many mature markets.
- These rely on DR providers to act as pseudo generators in providing energy, capacity, or ancillary services.
- Generally, for the service that is being provided by DR, the intention in designing the regime is to obtain that desired service (e.g. energy, capacity, etc), but from a wider range of sources than just generation, as it would have traditionally been provided.
- Hence, these programmes have higher barriers to entry and penalties for failure to deliver, and can be relied upon more.
- Examples include:
  - WDRM in NEM
  - Load resources in Texas
  - Backstop capacity in Western Australia

Operationalising existing responsive demand

- More recently, some jurisdictions have begun to consider lighter-touch regimes to attract more casual participants to operationalise their existing flexibility, usually through a narrower, more tailored regime that has some of the same characteristics as a full DR market mechanism.
- Generally the intention is to encourage more uptake of demand response and to better incorporate existing responsive demand, with lower regard for how it contributes to reliability.
- Examples include:
  - New Zealand’s Dispatch Notification scheme
  - Great Britain’s Demand Flexibility Service

We discuss both kinds of mechanism in this report, with the latter more directly resembling the Scheduled Lite proposal

Across both kinds of mechanisms, the same overall cashflow pattern exists, with some local variation



2 | Case Study Findings

Mechanisms exist on a spectrum in whether their primary objective is to grow responsive resources, or to ensure that price responsive resources are reliable

Growth-oriented **Reliability-oriented**

- Most smaller scale mechanisms could be considered as “growth-oriented”, in that they are designed to encourage further uptake of price responsive demand, possibly to aid in meeting a policy objective.
- In these mechanisms, the exact performance of the resources is less important than encouraging the uptake in the first place.

- On the other end of the spectrum, most larger scale mechanisms could be described as “reliability-oriented”, in that they are designed to ensure that procured resources actually provide the desired services.
- In these mechanisms, policymakers are more agnostic as to how much uptake there is. Instead the focus is to procure the service from as wide a range of sources as possible.

In identifying which mechanisms are “growth-oriented”, we consider both the stated objective of the mechanism and how it has been designed.

Key findings/conclusions by case study

Growth-oriented ⟷ **Reliability-oriented**

California	New Zealand	Great Britain (Demand Flexibility Service)	PJM	Great Britain (Capacity Market)	W. Australia	Texas
• “Proxy demand resources” (PDR) can participate in wholesale markets and sell “resource adequacy” to the system. • Easy to earn up-front payments through Demand Response Adequacy Mechanism (DRAM), and to sell wholesale. • Successful in attracting large volumes of DR capacity. • However, few penalties for failing to deliver mean that DR is not very reliable, creating further reliability issues.	• “Dispatch notification” system requires participants to place a standing bid to dispatch their demand response. • Upon being notified, the participant can choose to act on it, or immediately withdraw for that period. Participant is paid based on actual dispatch. • Expectation is that the participant will respond, and participation can be revoked at discretion of the system operator (SO) if participant repeatedly withdraws.	• Retailers participate in scheme on behalf of customers. • SO will ask retailers to submit bids for demand reduction, which are then cleared on a pay-as-bid basis up to the balancing price. • End users are paid based on the actual reduction achieved when called (i.e. an “event”). • No penalty for non-compliance. • Pilot programme being rolled to other retailers in the coming winter.	• Economic Demand Response (EDR) acts as a third category of market participant. • SO compares and clears EDR offers in comparison with generation offers, but mechanically treats as a demand reduction. • End users paid for reduction actually achieved based on locational marginal price. • Load-serving entities can also offer different tariffs of price-responsive demand, allowing them to reduce load under some circumstances.	• DR units can sell to capacity market and/or provide balancing services. • General principle is to treat DR providers as similar to physical generators as possible. • Onerous testing/ demonstration requirements in order to participate in capacity and balancing markets. • Penalties are limited, placing more onus on the testing/verification process.	• Participation is limited to emergency capacity mechanism. • High barriers to entry due to large collateral requirements and potential to forfeit full payment due to occasional underperformance. • Little DR is provided through this mechanism, but it is generally reliable.	• DR providers can participate in wholesale markets, ancillary services, and emergency response services. • High barriers to entry because participants have to have telemetry to provide most services. • Many options for “baselining”. • Strong penalties for failing to deliver as promised, but consequently no ex ante testing procedure. • Can generally be relied upon to provide reliability.

Performance across the schemes

Growth-oriented ← → **Reliability-oriented**

California	New Zealand	Great Britain (DFS)	PJM	Great Britain (CM)	W. Australia	Texas
• **Uptake:** c. 200 MW of capacity covered by DRAM, around 0.5% of peak load (40 GW). • **Performance:** Lack of teeth in the mechanism means that c. 50% of demand may not respond in the manner expected by the SO. Responsiveness has declined over time. • **Penalty Regime:** No penalty for failure to respond to dispatch instructions.	• No results yet, has only just taken effect. • **Penalty Regime:** No immediate term penalty but participation can be revoked if participant repeatedly fails to respond to dispatch instructions..	• **Uptake:** Currently participating customers are served predominantly by one retailer, with a Herfindahl-Hirschman Index (HHI) of around 4,500 in the two events in which DFS was called. Unclear how much volume. • **Performance**: two events have taken place where customers were instructed to turn down. Unclear how effective the response was relative to what was submitted. • **Penalty Regime:** No penalty; simply paid for outturn performance.	• **Uptake:** DR providers earn almost all money through capacity market revenues (c. $500m), and hardly any (c. $0.5m) for their dispatch in energy markets. DR accounts for around 6-7% of capacity cleared in the capacity market. • **Performance:** Very infrequently called in the energy market, so little commentary on performance. Few capacity events in which the system operator instructs contracted capacity (inc DR) to respond. • **Penalty Regime:** Repeated non-performance may be referred to the Federal Energy Regulatory Commission for administrative penalties.	• **Uptake:** Roughly 1 GW out of 40 GW in the capacity market comes from demand side response. • **Performance:** Very few opportunities to demonstrate the level of performance due to the rarity of capacity events where the system operator instructs contracted capacity (inc DR) to respond. • **Penalty Regime:** Must repay a portion of CM revenue, capped at 1/6 of the annual revenue over a month, and by full annual revenue over a year.	• **Uptake:** Three aggregators act as backstop capacity providers, providing around 1.7% of total backstop capacity (as opposed to total capacity, which would be higher). • **Performance:** No evidence that they have failed to perform when called upon. • **Penalty Regime:** If participant fails to deliver on two occasions, they must pay back full capacity revenue.	• **Uptake:** High uptake, with about 5 GW of DR out of 140 GW of peak demand. • **Performance:** DR has been successful in reducing load at peak times, reducing system peak by around 4% in 2017. • **Penalty Regime:** Must purchase electricity shortfall at spot prices, and participation can be revoked if there are two failures in a year.

California (CAISO) – Proxy Demand Resources

Metric	Description	Source
Description	Through an aggregator, small-scale owners of flexible demand can act as a Proxy Demand Resource (PDR) in the wholesale energy markets (DAM, RTM, AS) by turning down demand relative to a defined baseline amount. An alternative mechanism exists that allows participants to provide only emergency services, e.g. in the form of interruptible load. In both cases, end-users contract with aggregators who receive payment from the system and then pay out to end-users according to the terms of the agreement. Additionally, DR aggregators can receive a type of capacity payment through the Demand Response Auction Mechanism (DRAM), in place at least through 2024, allowing the Load-Serving Entity (LSE) to meet some of its Resource Adequacy requirement, while committing PDRs to a Must-offer Obligation (MOO) in the wholesale markets.	
Justification	FERC Order 719 (2008), which requires a mechanism to incorporate DR into markets: "Our goal is to eliminate barriers to the participation of [DR] by ensuring comparable treatment of resources. … [DR] can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of [RES], [DG] and [AMI]" DRAM (2014) specifically targets using DR to help maintain local electric reliability. Auction mechanism allows utilities to pay up front for DR to contribute to Resource Adequacy (RA) requirements.	FERC Order 719 CPUC Decision 14-12-024
Unit size	100 kW minimum curtailment, with 10 kW granularity	CAISO DR summary
Baselining and Verification	Three approved approaches: • **Day matching:** Uses electricity usage data from 10 similar "non-event" days (default approach). • **Control groups:** Non-dispatched customers with similar profiles during curtailment periods. • **Weather matching:** Based on what electricity use would have been during non-event days with similar weather.	CAISO Business Practice Manual for Demand Response
Cashflows	In the DRAM scheme, the IOUs procure the capacity for each month of a delivery year through a pay-as-bid auction, the costs of which are recovered through regulated rates. Once participating in the DRAM, PDRs participate in the wholesale market as normal supply resources, and retain the revenues sold through that avenue.	2024 Demand Response Auction Mechanism (DRAM) (pge.com)
Spot price determination	Due to MOO, where DR is dispatched, it is treated as a supply-side resource which could set the price if it is the marginal unit selected.	
Telemetry requirement	Telemetry not required unless either (a) aggregated resource is > 10 MW; or (b) participating in AS. If telemetry is required, must provide data on a 4s interval.	CAISO DR Summary
Participation requirements	If Resource Adequacy is provided (through DRAM), must bid into day-ahead market, according to MOO): • 24 hours per day offered, or all available (e.g. business only open 14 hours per day) • 3 consecutive days dispatch • 24 hours per month dispatch • 4 hours per dispatch • If either of the above three are met, offers no longer mandated.	CAISO DR Summary
Provides reliability?	No, little requirement to actually respond more than just offer – acts more as a capacity procurement mechanism. CAISO finds that demand resources only curtail around 50% of their scheduled reduction on high load days.	(http://www.caiso.com/Documents/Comments-on-R21-10-002-Phase-3-of-Implementation-Track-Feb-24-2023.pdf)
Barriers/ incentives to entry	Strong incentives to participate, with up front payments available in the DRAM process. Otherwise acts as normal DAM or AS market participant.	
Penalties for compliance	Basically none – can cancel a DRAM contract easily, and MOO does not include obligation/penalty to actually respond to dispatch instructions.	

New Zealand – Dispatch Notification (aka Dispatch Lite)

Metric	Description
Description	Participating customers must submit a standing offer to respond to price signals in the dispatch process. If they receive a “dispatch notification”, they have the option to immediately withdraw their bid (within 4 minutes). Customers are paid based on the amount that they turn down relative to what they were expected to consume.
Justification	Introduced only in late April 2023. “It adds the flexibility to accommodate uncertain future shifts in technology and electricity services to consumers during a critical time for the sector”. “Helps increase the responsiveness of wholesale spot prices to participants. We do not have any particular expectation about the level of participation …, but we consider it an important option to offer”. – RTP decision paper, June 2019
Unit size	Generators: Up to 30 MW; Demand: No maximum capacity. Can be aggregated but given the lack of a minimum size and the requirement for a standing bid, there is less to be gained by engaging with an aggregator.
Baselining and Verification	Because SCADA telemetry is not mandated, metered volumes will be compared on a monthly basis with what should be consistent with dispatched behaviour (assuming dispatch instruction is not declined).
Cashflows	If dispatched, “Dispatch Notification Purchasers” are paid the appropriate spot price of electricity according to their grid connection location, relative to the amount that they would be expected to generate in that period. This is the same as how they would be treated as a generator. If load is managed by an aggregator or retailer, they may have a separate arrangement with end users to pass this payment on.
Spot price determination	Participating customers are treated as supply in the dispatch algorithm and are thus able to set the dispatch price as any generator would. Unlike traditional generation however, participating customers must submit a bid *but can then withdraw it* if selected, which could change the spot price relative to the SO’s provisional dispatch. The Electricity Authority is not concerned about the need to redispatch with a new clearing price, given the speed at which participating customers must decline the notification.
Telemetry requirement	Telemetry not generally required, though SO may require it in some circumstances.
Participation requirements	Will have a standing bid in place, and will receive a “dispatch notification”, e.g. through a web service. The unit can reject the notification by re-bidding immediately as a non-dispatch bid, but is not allowed to ignore the notification. The SO can suspend/revoke DL approval to participants who repeatedly say no.
Provides reliability?	Medium: Plant is incorporated into market through “Dispatch Lite”, so can be actively dispatched, but that notification can be declined.
Barriers/ incentives to entry	Medium barriers: No telemetry required, but has to participate in the wholesale market. Limited ability for aggregators to participate given nodal pricing in New Zealand – all demand would need to be connected at the same location on the grid.
Penalties for compliance	Limited. DRP can withdraw bid with only outside threat of a real punishment.

Sources: RTP Decision Paper: Implementing real-time pricing ; RTP Implementation Code: https://www.ea.govt.nz/documents/1981/253362019-RTP-decision-Appendix-A-Code-amendment.pdf

Great Britain – Demand Flexibility Service (DFS)

Metric	Description
Description	Rolled out in the winter of 2022/23 on a limited basis, the DFS scheme provides an opportunity for residential and small commercial users to participate in load flexibility without participating in the capacity or balancing markets (and in fact DFS is closed to anyone who provides those services). End users contract with their retailer to receive an incentive payment for participating, at which point they may choose to respond or not to respond, and receive payment accordingly. Similar to “Dispatch Mode” under AEMO proposal or Dispatch Lite in New Zealand.
Justification	Developed to allow the SO to access additional demand flexibility at times when demand is at its highest, namely cold winter days, when that demand is not already utilised for flexibility purposes.
Unit size	Each DFS unit must be between 1 MW and 100 MW, but this can be aggregated. Thus far, only one retailer (Octopus Energy) has acted as an aggregator, but it is hoped for 2023/24 that more retailers will offer the service.
Baselining and Verification	To be credited for responding, customers will be compared to a forecast based on their metered historical data, as per the “p376” Balancing and Settlement Code methodology. SO runs up to 12 tests of the service in a winter, which customers are entitled to but not required to respond to. In Winter 2022/23, they were paid for these tests at a rate of £3,000/MWh.
Cashflows	Aggregator submits bids to SO for each of its DFS units. These will be accepted on a pay-as-bid basis up to the balancing price, and then paid out to aggregators based on the amount of response actually provided. This is passed back to end users based on their individual response levels.
Spot price determination	SO treats estimated responses as a reduction in demand, potentially lowering the price of the marginal balancing unit. However, the DFS units are paid as bid, and hence do not influence the spot price.
Telemetry requirement	Telemetry is not required, though half-hour metering is. Settlement for response is conducted in the days following a notification.
Participation requirements	Limited participation requirements: Half-hour metered, not participating in balancing or capacity markets, must be able to respond for at least 30 minutes with day-ahead instruction.
Provides reliability?	No, aggregators submit bids which the SO may accept, and only then does the aggregator communicate the instructions to end users, who may decline. Aggregators and end users are paid for the reductions actually achieved, but are not penalised if they fail to respond.
Barriers/ incentives to entry	Low barriers to entry, due to limited infrastructure required. Must have a means for receiving the instruction to respond, and to accept or decline that notification.
Penalties for compliance	No penalty for non-compliance. Simply do not get paid for the response not provided.

Source: https://www.nationalgrideso.com/document/270361/download

Northeast US (PJM) – Economic Demand Response

Metric	Description
Description	PJM allows for the participation of Economic Demand Response (EDR) in the day ahead and real-time energy markets, provided through a Curtailment Service Provider (CSP). EDR is a separate category of market participant, alongside generation and load. End users have the ability to choose whether they respond to a high price event, but if they deviate from the scheduled amount often enough, they may be subject to enforcement. Price responsive demand programme allows utilities to curtail some users' demand in high price events in exchange for a lower capacity obligation. This may be passed on to the end user through rates.
Justification	Unclear
Unit size	No listed restrictions.
Baselining and Verification	Baseline demand is based on the end-user's average consumption during the 4 highest weekdays in the past 5, or 2 highest weekend/holidays in the past 3 before an event (e.g. the past 3 Saturdays before a Saturday event). A range of alternative approaches exist with the mutual agreement of all related parties. Verification is conducted based on actual metered demand during the dispatched period.
Cashflows	Demand response which is dispatched is paid at the locational marginal price (LMP) at which the demand is curtailed. This may be returned to the ultimate user according to the terms of the arrangement with the CSP. Participants also pay reduced retail rates due to lower consumption. Users are generally compensated on the demand actually reduced if their bid is accepted. If demand *increases,* they are charged based on the LMP, and they may be charged for ancillary services if their actual reduction deviates by a large amount from what was bid. The cost of EDR is borne by load serving entities in proportion with their consumption in that period.
Spot price determination	CSPs submit demand reduction bids to the SO, which may be dispatched if needed. Mechanically, these bids affect the demand curve rather than the supply curve.
Telemetry requirement	Telemetry not required.
Participation requirements	Participants will generally register with a CSP, who will then manage their interactions in the Day Ahead Market, Real Time Market, and the Capacity Market.
Provides reliability?	Medium-weak: Participants compensated based on their actual consumption, with no immediate penalties for deviating from the scheduled amount.
Barriers/ incentives to entry	Limited barriers to entry due to the wide range of available CSPs.
Penalties for compliance	Participants' registration is subject to review if they frequently deviate from their scheduled level of demand reduction. Participant registration can be revoked and the matter can be referred to the Federal Energy Regulatory Commission for further enforcement.

Source: PJM Open Access Transmission Tariff, Attachment K: Appendix, Section 3.3A.

Great Britain – Participation in Balancing and Capacity Markets

Metric	Description	Source
Description	Through an aggregator, there are up to three avenues that DR providers can earn money: • Providing one or more of the nine short term reserves and response services in the balancing market (e.g. frequency response or fast reserve). • Participation in the annual capacity market, with a commitment to respond to a system stress event. • Some DNSPs have their own pilot programmes to use DR for localised grid benefits.	http://powerresponsive.com/wp-content/uploads/pdf/Power%20Responsive%20Guide%20-%20v8.pdf
Justification	Need for system flexibility to accommodate increases in intermittent generation technologies, particularly as more of the capacity mix is driven by offshore wind.	https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive/demand-side-response-dsr
Unit size	Each balancing service has its own minimum size from 1 to 50 MW, but no minimum if aggregated. Capacity market has minimum size of 1 MW, but no minimum if aggregated.	http://powerresponsive.com/wp-content/uploads/pdf/Power%20Responsive%20Guide%20-%20v8.pdf
Baselining and Verification	Several different baselining approaches by market type: • For balancing services: A physical test must verify the ability to shift frequency on a short interval. • For capacity market: Physical test must be carried out demonstrating your ability to turn down. Compare demand during test period to the same half-hour in the previous 10 working/non-working days (depending on if test is on a working or non-working day), plus same half-hour of same day from last six weeks. The same procedures are used for verifying the response, if needed.	https://www.nationalgrideso.com/document/92406/download https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/107/DSR%20Test%20Guidance%20Document.pdf Capacity market rules
Cashflows	DR aggregator is paid by SO and/or DNSPs based on services provided. E.g. for fast-frequency response, payment is essentially a monthly availability payment. Individual units may be paid out based on private commercial arrangements. Demand users will still pay for the energy they consume. Because retailers benefit twice from end-users' response, there is limited participation from independent aggregators.	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf
Spot price determination	DR does not participate in the dispatch process, and so cannot set the spot price. However, it does act as a supply resource in the capacity auctions and in providing balancing market services, and so could set the price from a supply-side perspective.	
Telemetry requirement	Telemetry required for participation in balancing markets, but not in the capacity market.	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf
Participation requirements	Must be able to provide the balancing or capacity services contracted, or else it faces the relevant penalties for failure to do so. Rules are designed to treat DSR on an equal footing with physical generation, as much as is possible.	
Provides reliability?	Yes, due to onerous testing requirements, DR which is procured can generally be relied upon to provide the services contracted.	
Barriers/ incentives to entry	High barriers to entry: DR must periodically demonstrate their ability to respond to the services offered, which is itself costly. Several different ways to make money, but this is relatively uncoordinated across the different streams.	
Penalties for compliance	Although the participation requirements are onerous, the penalties for failure to deliver in the Capacity Market are limited. In a worst case scenario, participants will pay back all of the money they received, but is would require frequent system stress events throughout the year.	

Western Australia (WEM) – Backstop reserve capacity

Metric	Description	Source
Description	DR only participates in WEM in the reserve capacity mechanism (RCM), which provides last-resort capacity in the event of a system shortage event. Demand can also act as an interruptible load for a lower tariff.	https://www.wa.gov.au/system/files/2023-03/DSR%20Review%20-%20Scope%20of%20Work.pdf
Justification	Limited use of DR targeted at providing some reliability at lower cost than alternatives, rather than building a more efficient and integrated system.	
Unit size	Aggregated sites must be at least 1 MW.	https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/supplementary-reserve-capacity
Baselining and Verification	DSM is accredited based on its consumption during the fifth percentile of the 200 hours of highest consumption during the year.	https://www.energycouncil.com.au/media/xlab4zma/mja-final-report-generator-revenue-adequacy.pdf
Cashflows	Unclear	
Spot price determination	DR only provides reserve capacity in the event of a system shortage, and therefore cannot influence the spot price.	
Telemetry requirement	No telemetry required given the lack of participation in short-term reserves.	
Participation requirements	Must be able to provide reserve capacity for at least 200 hours in a year, and be available between 8 am and 8 pm on all business days.	Wholesale electricity market rules
Provides reliability?	Yes, target is on achieving reliability to the system even if there are few participants.	
Barriers/ incentives to entry	High barriers to entry, e.g. 25% of annual capacity payment must placed as collateral.	Wholesale electricity market rules
Penalties for compliance	High: If the participant fails to provide the full expected capacity in at least two trading intervals, the participant must return the full value of the capacity revenue earned.	

Texas (ERCOT) – Load Resources and Emergency Response Services

Metric	Description	Source
Description	Demand resources, or aggregated demand resources, can participate in the ERCOT real-time market (Security-Constrained Economic Dispatch or SCED), or in ancillary service markets. In SCED, bidders submit bids to buy power up to a specified level and are instructed to turn down if wholesale prices exceed that level. In AS markets, bids are scheduled in the day-ahead AS market and paid regardless of whether they are actually curtailed. Resources can also provide emergency response services, and are paid for their availability to respond to emergency events, regardless of if they happen.	https://www.ercot.com/services/programs/load/laar https://www.ercot.com/services/programs/load/eils
Justification	DR is viewed "as a means of enhancing competition, mitigating price spikes, encouraging the demand side of the market to respond better to wholesale price signals, providing for resource adequacy, and preserving system reliability".	Load Participation in the ERCOT Nodal Market, April 2015
Unit size	Individual units must be at least 100 kW to operate independently. If they are aggregated, the individual units must not be greater than 10 MW.	https://www.ercot.com/services/programs/load/laar
Baselining and Verification	Five approved types of baselining, up to ERCOT to determine which one or more is applicable: • Statistical regression model: Load = f(weather, calendar, daylight) • Meter-Before/Meter-After model – essentially read the change in metered volume when the dispatch instruction is given. Only appropriate for consistently flat loads. • Middle 8-of-10 Like Days Model. Select 10 most recent days of the same "day type" (i.e. weekdays or weekend/holiday). Discard highest and lowest. • Nearst-20 Like Days Model. Similar to 8-of-10 Model, but days both before and after are included, and none are discarded unless ERCOT identifies other abnormal events. • Matching Day Pair Model. Identify 10 days from previous year with demand most similar to yesterday's demand, and take the average of the next day's demand.	ERCOT Demand Response Baseline Methodologies document, September 2019
Cashflows	ERCOT compensates the aggregator for the service provided, who then will have a private commercial arrangement with the individual entities that it aggregates. SCED participation is treated as price-responsive demand, so there is no double-counting between load reduction and demand response.	Load Participation in the ERCOT Nodal Market, April 2015
Spot price determination	Unlike most models, participants are treated as demand rather than supply. Bids specify the price at which the user would no longer buy energy. If that price is exceeded, then the LR is instructed not to buy energy.	Load Participation in the ERCOT Nodal Market, April 2015
Telemetry requirement	Telemetry is required to participate for LR (i.e. SCED and AS), but not for participation in ERS.	Load Participation in the ERCOT Nodal Market, April 2015
Participation requirements	Resources can participate in both the energy market and in emergency response. In the energy market (SCED or AS), aggregators behave as any generator would, and are paid for the amount they reduce off of the system. For emergency response services, ERCOT procures quarterly DR capacity which must provide the agreed capacity within 10 or 30 minutes, when an emergency event occurs.	Load Participation in the ERCOT Nodal Market, April 2015
Provides reliability?	High: Rules are set up with strong penalties for failing to dispatch, so can be counted on to provide what is selected.	
Barriers/ incentives to entry	High revenues can be earned through providing load response and reserve products. However, barriers to entry are also high, because you essentially participate as a full part of the energy market. Must submit to an annual test, provide six months of metering data	
Penalties for compliance	High penalties if the you fail to deliver: must purchase shortfall you fail to deliver, and two failures in a year results in disqualification.	Load Participation in the ERCOT Nodal Market, April 2015

3 Lessons for the NEM

Overall lessons from the case studies

- Most of the existing schemes are targeted more towards attracting or managing demand response as a market participant, with fewer schemes which are targeted towards engaging smaller scale price responsive demand.
- Trade-off between attracting price responsive demand and providing reliability.
  - CAISO and New Zealand make it easy to participate but weak enforcement of performance, leading to high uptake (in California) but lower reliability.
  - WEM and ERCOT impose high barriers to entry and stiff penalties for nonperformance, probably limiting uptake but also ensuring reliability.
  - GB is in between, with onerous testing requirements but weaker performance incentives, so lower uptake and lower reliability.
  - Optimal choice depends on preference for attracting DR for its own sake (e.g. changing a mindset) vs ensuring better market outcomes to start with.
- More recent focus on schemes with low barriers to entry which encourage participation from smaller parties, e.g. GB's DFS and NZ's Dispatch Notification.
- Most jurisdictions have a role for aggregators due to customer opt out ability. Aggregator takes payment from system operator (or DNSP, etc) and distributes to the end user according to commercial contract. End user generally pays their retailer for the amount actually consumed, resulting in a small amount of double count (you turn down and pay less and get paid).
- It is more common for demand reduction to be treated as an increase in supply, but some jurisdictions, e.g. PJM, separately calculate a demand reduction.
- Baselining: A range of techniques exist, generally involving an average of historical consumption during similar days, against which a deviation can be measured. Some techniques are more complex, which may be more appropriate for end-users whose demand is less consistent. For Visibility Mode, incentives are around participation rather than response, so a simpler technique is more appropriate (e.g. compare to previous days' consumption). For Dispatch Mode, payment may be based on response to the signals, so a more complex technique may be more appropriate to ensure that response is appropriately remunerated, e.g. compare to consumption in similar days (not necessarily the most recent days).
- Testing vs penalties:
  - Only GB subjects DR providers to ex ante testing procedures.
  - WEM and ERCOT penalise underperformance to the extent that a DR provider would not want to offer an amount that it could not deliver.
- Some markets limit DR only to participating in reserve/capacity/emergency markets, e.g. WEM and GB.

Scheduled Lite – Visibility Mode

Metric	Description
Description	Visibility mode allows participating traders/retailers to submit a price-sensitive indicative bid to AEMO, who will then factor that shape into the dispatch algorithm. Depending on the final design, retailers could be paid a fixed fee for providing the bid in this fashion.
Justification	AEMO forecasts rapid growth in distributed resources, especially on a smaller scale, that will change the energy landscape of the NEM. Scheduled Lite is intended to facilitate/support “the participation of all resources in both a visible and dispatchable manner to maintain the secure and reliable operation of the power system”. In essence, AEMO views that the growth in distributed resources is going to happen, and that Scheduled Lite is necessary to incorporate these resources into the NEM.
Unit size	Can be large users or aggregated small resources. No minimum capacity threshold.
Baselining and Verification	Baseline not relevant, because it is simply a series of price and quantity pairs. Payment would not be made based on any reduction, but rather through the visibility provided.
Cashflows	A “visibility service payment” is proposed as an incentive for participation. Other non-payment incentives proposed, such as provision of pre-dispatch schedules, and setting participation as a prerequisite for other schemes. However, no decision has been made.
Spot price determination	Indicative bids feed into AEMO’s demand curve, and thus the clearing price is based on the adjusted demand curve.
Telemetry requirement	Telemetry is required to read and transmit data over 5 minute intervals
Participation requirements	Cannot otherwise be participating in the wholesale energy market, e.g. in the Wholesale Demand Response Mechanism.
Provides reliability?	No, limited penalty or verification in actually consuming the amount indicatively bid.
Barriers/ incentives to entry	Low barriers to entry based on opt-in principle, but telemetry may act as a substantial up front cost. Payments can be suspended, but further penalties not included.
Penalties for compliance	Traders would only receive incentive payments if their forecasts are reasonably accurate. They could be suspended from participation if performance deviates significantly from thresholds.

Scheduled Lite – Dispatch Mode

Metric	Description
Description	Dispatch mode establishes a framework for distributed resources to participate in the dispatch process on a voluntary basis, though if they are participating, they are expected to conform to the dispatch instructions provided to them. Aggregators are given dispatch instructions for the resources they cover, and will then allocate those instructions.
Justification	AEMO forecasts rapid growth in distributed resources, especially on a smaller scale, that will change the energy landscape of the NEM. Scheduled Lite is intended to facilitate/support “the participation of all resources in both a visible and dispatchable manner to maintain the secure and reliable operation of the power system”. In essence, AEMO views that the growth in distributed resources is going to happen, and that Scheduled Lite is necessary to incorporate these resources into the NEM.
Unit size	Aggregated units must be at least 5 MW, and all within the same subregional zone (these have not been defined yet, but would reflect key transmission constraints and demand patterns). Units above 30 MW are required to participate in the central dispatch process (i.e. fully scheduled rather than scheduled lite).
Baselining and Verification	Baselining not included as part of Scheduled Lite. Verification proposed to be the same as the Wholesale Demand Response Mechanism: First trading interval is not assessed due to possible ramping challenges. Non-conformance instance defined as +/- 50% of dispatch target over a full day. Three or more non-conformance instance leads to a unit being found to be non-conforming.
Cashflows	AEMO does not propose an incentive payment for participation in Dispatch Mode, although participants would benefit from consuming less energy at high spot prices.
Spot price determination	Bids will be treated like other scheduled resources (i.e. on the supply side), and therefore could set the price of they are marginal.
Telemetry requirement	Telemetry is required to read and transmit data instantaneously.
Participation requirements	Cannot otherwise be participating in the wholesale energy market, e.g. in the Wholesale Demand Response Mechanism. Customers can opt out for any period of time and not submit bids.
Provides reliability?	Limited reliability provided, due to lack of baselining and ability to opt out on a case by case basis.
Barriers/ incentives to entry	Low barriers to entry, though instantaneous telemetry is required.
Penalties for compliance	Aggregator can be found to be non-compliant and would not be eligible for benefits, but no apparent penalty beyond this.

Comparison of case study design dimensions to SL design dimensions – Visibility Mode

	Included in Scheduled Lite – Visibility Mode	Not Included in Scheduled Lite – Visibility Mode
Successes in Case Studies	• Integration of resources into the demand curve (PJM and ERCOT) – For Visibility Mode, adjusting the demand curve rather than supply curve is easier to integrate and does not require as much comparability to traditional supply resources.	• Baselining (All) – Even in schemes targeted at small customers, some form of demand baselining is performed, in order to provide an incentive to customers which matches the value they provide to the system. – However, this is not necessary in Visibility Mode, because customers simply pay for the energy consumed. Thus, they have the incentive to consume less in absolute terms rather than to reduce relative to a baseline demand.
Challenges in Case Studies	• Excessive telemetry requirements (ERCOT) – Telemetry can be an onerous barrier to entry. Given no real time monitoring/penalising of underperformance, it is difficult to see the benefit that telemetry would provide, unlike in Texas where DR faces steep penalties for underperformance. So long as five-minute intervals are measured, settlement can be done ex post. • Low penalties (CAISO, NZ) – Mechanisms with light penalties typically have performance problems, to the point where demand resources are viewed as less reliable than other resources.	• Attempts to procure *new* price responsive demand (CAISO and GB CM) – Generally capacity-type mechanisms designed to attract new price responsive demand have not produced reliably-performing units (e.g. CAISO and GB). More successful mechanisms have remunerated based on their performance rather than their existence.

Comparison of case study design dimensions to SL design dimensions – Dispatch Mode

	Included in Scheduled Lite – Dispatch Mode	Not Included in Scheduled Lite – Dispatch Mode
Successes in Case Studies	• Opt out mode (NZ, CAISO, GB DFS) – Reduces the reliability that can be provided but improves uptake. Probably important for the palatability of the rule. – Reliability can be maintained if there are strict rules around when opt out can occur, e.g. announced days in advance. E.g. in NZ, participation can be revoked if user declines notification when it is given, but it is possible to opt out in advance on an ad hoc or regular basis (e.g. only available during business hours).	• Baselining (All) – Even in schemes targeted at small customers, some form of demand baselining is performed, in order to provide an incentive to customers which matches the value they provide to the system. – In Dispatch Mode, performance incentives are limited to consumption savings at high prices, but the value of actually responding to an instruction is unpriced.
Challenges in Case Studies	• Excessive telemetry requirements (ERCOT) – Telemetry can be an onerous barrier to entry. Given no real time monitoring/penalising of underperformance, it is difficult to see the benefit that telemetry would provide, unlike in Texas where DR faces steep penalties for underperformance. So long as five-minute intervals are measured, settlement can be done ex post. • Low penalties (CAISO, NZ) – Mechanisms with light penalties typically have performance problems, to the point where demand resources are viewed as less reliable than other resources.	• Double counting of responsive demand dispatch and demand reduction (All) – Most schemes remunerate resources for the energy they didn’t consume as well as for the reduction they provide relative to the baseline. – This double counting does not exist in SL because customers only pay for the energy they actually consume, but they are not remunerated for the response they actually provide.

Conclusions

- In assessing the Scheduled Lite mechanism, AEMC should determine what its most compelling “problem definition” is:
  - If it is a lack of incentives / excess barriers to participate, then the Scheduled Lite mechanism as proposed makes participation easier and more attractive.
  - However, the mechanism may create its own challenges if it attracts participation in a haphazard, unreliable fashion.
  - If these operational challenges create more problems than the benefits provided by greater DR penetration, a more firm rule with stricter penalties for non-performance is preferable. It will shut out some participants who do not wish to comply with those rules, but that is the intention.

- NEM design is well set up for aggregators, with regional rather than nodal pricing. However, nodal nature of NEMDE may make it challenging to actually determine dispatch from aggregators. For example, if an aggregator were to submit a single price-quantity pair across many nodes, it may be challenging to determine which portion of that to dispatch. This could be remedied by requiring aggregators to only submit each bid across a single node. The proposed design aggregates across a single *zone*, but there may be instances where the node definition leads to a different outcome than the zone definition.

- No need for telemetry to participate, so long as meter readings can be settled on a regular basis. Compliance in Scheduled Lite (i.e. did you consume the amount that you said you would) can also be assessed ex post, so long as meter readings are collected on a short-interval basis.

- No need for onerous ex ante testing requirements, so long as compliance enforcement is sufficient to encourage customers to respond appropriately.

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