MAKING THE MOST OF DEMAND RESPONSE
– OPPORTUNITIES AND RISKS IN THE MARKET AND IN THE MARKET RULES

Australian Energy Week, 24 May 2021

The facilitators

Lance Hoch,
Executive Director

Lance has over 35 years of experience in policy, regulation and business strategy as it applies to electricity and gas distribution and retail businesses.

Much of his work has focused on energy efficiency, demand-side management and integrated resource planning as means for ensuring the reliability and adequacy of supply, and reducing customer's costs for electricity while also reducing costs for the utility company.

Alex Cruickshank,
Principal Consultant

Alex is a very experienced public policy and regulatory executive with broad experience in energy markets, having worked in both public and private sectors for 30 years.

His key areas of expertise include market design, advocating and advising on the application of the rules and working to identify new technologies and the market and organisational changes required to exploit them.

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Who we are – Oakley Greenwood

- We are known internationally for our expertise in economic regulation, market rules and industry governance
- One of our core strengths is consulting on all matters to the electricity supply sector domestically and internationally. This is from end to end – generation to final sales and end use.
- Key projects:
  - DER integration
    - Examining how DER can be economically integrated into the NEM
    - Pricing, rebates, payments combined with markets and control equipment.
  - ARENA – Demand Response Knowledge Sharing Agent for its demand response funding initiative.
    - New approaches for RERT provisions and Issues with those approaches
  - AEMO
    - Audit of RERT purchasing of demand side resources
    - Baseline approaches for the Wholesale Demand Response Mechanism
  - CIGRE Technical Brochure: "Regulatory aspects of demand side response"
    - International perspective on current approaches and issues

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Running sheet for today

Session	Topics	Timings
Introduction	Backgrounds and experience of attendees Objectives for the day	9.15 to 9.45
Background of demand response	What is Demand Response (DR) How has it been applied and used	9.45 to 10.30
Morning tea		10.30 to 11.00
Regulatory developments in Australia	Australia - NEM, mainly, and WEM	11.00 to 12.30
Lunch		12.30 to 1.30
Issues and considerations for Changes in Australia	Establishing value for DR Measurement of DR	1.30 to 3.00
Afternoon tea		3.00 to 3.30
Final reflections: the future of DR in Australia	Current activities Overseas Related developments	3.30 to 4.15
Review of the day	Summary of the day Check expectations	4.15 to 4.30

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INTRODUCTION TO DEMAND RESPONSE

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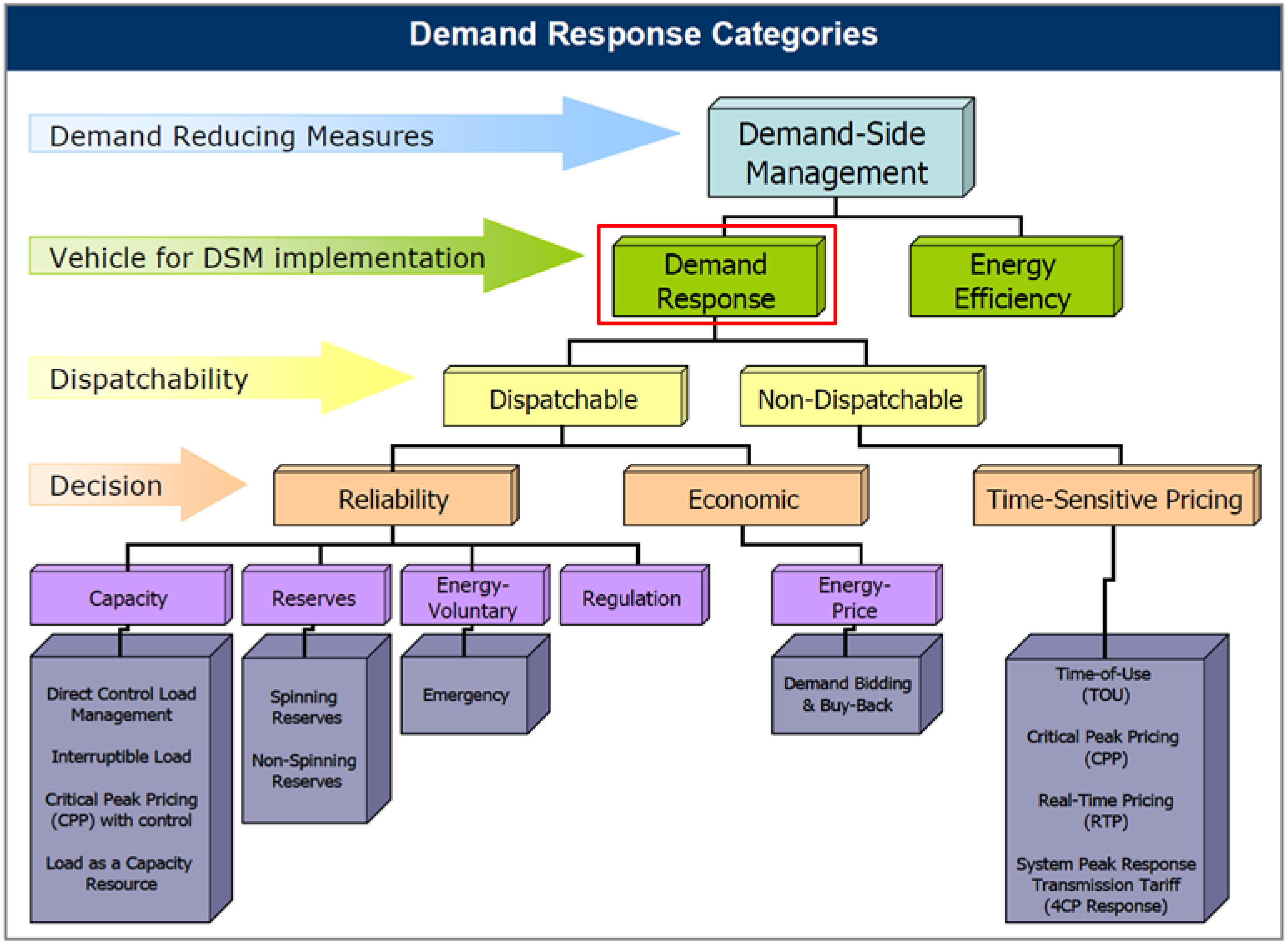
Taxonomy of DR (note the use of the term DSM)



Demand Response (DR)

- What is Demand Response (DR)

Action resulting from management of the electricity demand responding in a coordinated fashion to electric power system or market conditions. Demand Response is a potential source of flexibility for power systems.

- IEC definition

→ the key is responding to conditions not just changing demand

→ Increase and decrease in use

- Changes in demand that occur due to normal activities are already accounted for in the forecasting process
- The next two slides discuss how Demand Response relates to:
  - Energy Efficiency (EE)
  - Demand sided management (DSM)

Energy Efficiency is different to Demand Response

- Not dynamically responsive to conditions, rather an overall reduction in use
- Reduces overall demand - does not focus on peaks or other specific periods
  - Not necessarily linked to market
  - May increase unit costs
- Example – home insulation
  - Reduces energy use during extreme weather
  - Less gas or electricity for heating and cooling
  - Improved comfort
- Example – improved appliances and equipment
  - Lighting changes → LED, CFL
  - New fridges/motors etc. → more efficient
  - Activity based energy use
- Example – Use most efficient fuel for the task

~~They~~ use gas ~~to create steam to generate electricity, which is then sent through the transmission system and the distribution network to your house so that you can use a kettle~~ to boil water.

\- SAGASCO ad, circa 1994

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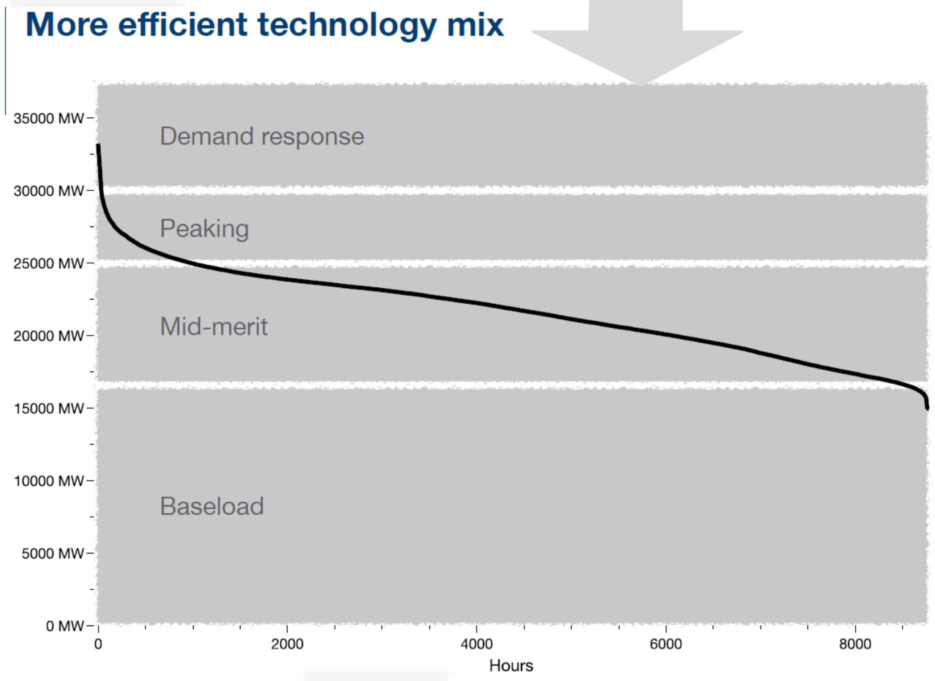
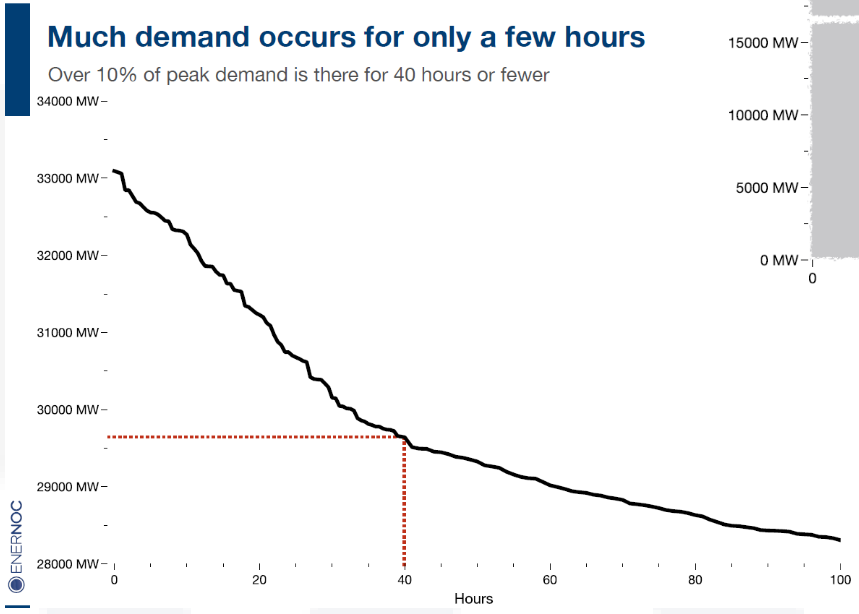
Demand Response vs Demand Side Management vs Distributed Energy Resources

- Terms that are overlapping
  - includes co-generation, storage, control schemes
- Often one term is used and defined to cover all of the others – we will do that but ...
- DR is about the decision making for the efficient operation of a connection or site
  - how responsive the site or customer is to the congestion or price in the system.
- Customers that respond in ways that reduce economic costs to the industry and therefore all customers.
  - It may be as simple as tariffs
  - It could be control schemes
  - It could be rebates or payments for services
- Today is about mechanisms and approaches that empower, support and/or reward customers that interact with the markets by varying their load

Where does DR fit in the wholesale, network and retail electricity market?

- Can be in both the wholesale or retail markets
- Reduce price by displacing high price plant
- Flexible response for services to support the market
- Reduce augmentation requirements
- Address local events and issues – particularly networks
- May be **retailer or network** driven
- Some large customers – e.g. Smelters – are **direct participants**
- **Aggregators of Customer** DR entered the market – with new business models – and forced or benefited from changes





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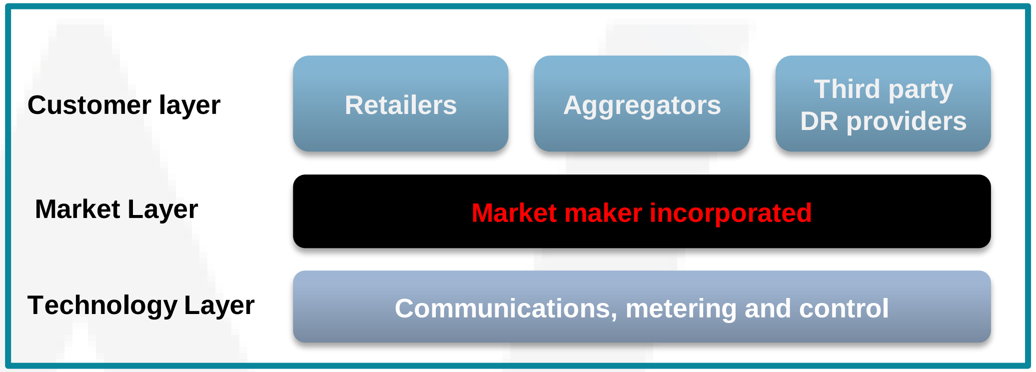
Drivers and enablers (from CIGRE Technical Brochure)

- **Drivers**
  - For the consumer
    - Cost of supply: Reduced costs, short and long-term
    - Political & social factors: Feeling of doing our bit
  - For the industry
    - Supply demand imbalance: fear of supply shortfall
    - Need for flexibility and to control variability
- **Enablers or barriers**
  - Technology
    - Metering
    - Control systems
  - Markets
    - Access to prices
    - Ability to value DR
  - Attitudes
    - Knowledge
    - Policies and regulation



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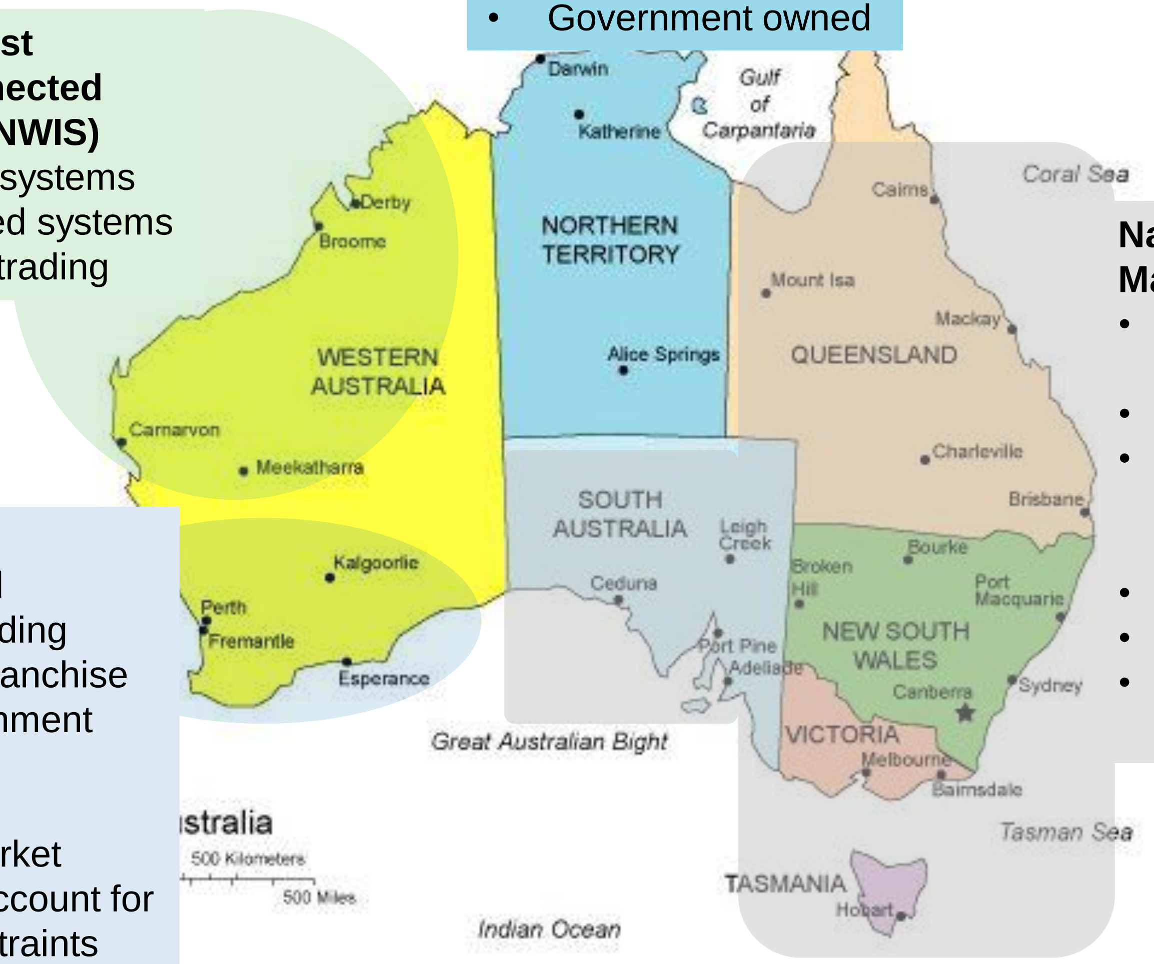
Markets and electricity systems in Australia



NT Systems
- NTEM
- Isolated systems
- Government owned

North West Interconnected System (NWIS)
- Small systems
- Isolated systems
- Local trading

National Electricity Market (NEM)
- Market based wholesale trading
- Full retail franchise
- Mix of government and private ownership
- Energy only market
- RERT and RRO
- Moving to a new design

WEM or SWIS
- Market based wholesale trading
- Some retail franchise
- Mainly government owned
- Capacity and balancing market
- Reforms to account for network constraints and to include storage

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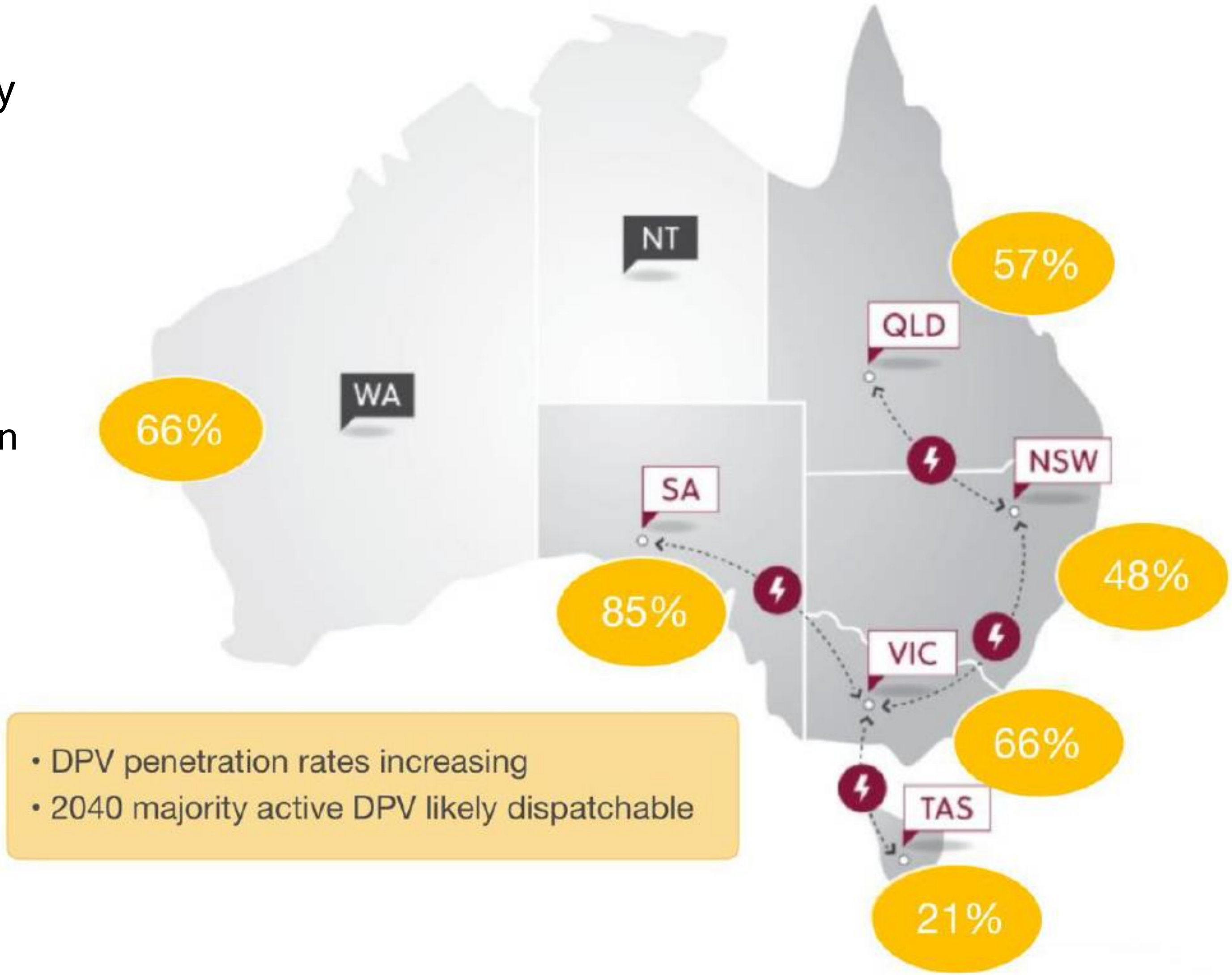
Power system changes

- Intermittent penetration is increasingly significant
  - Forecast of 2025 situation from the ESB consultation document
- Increase in curtailable solar and storage
  - Ability to firm up intermittent generation
  - Loss of inertia and system strength
- Increased interconnection
  - Larger system for control has is more stable but harder to correct



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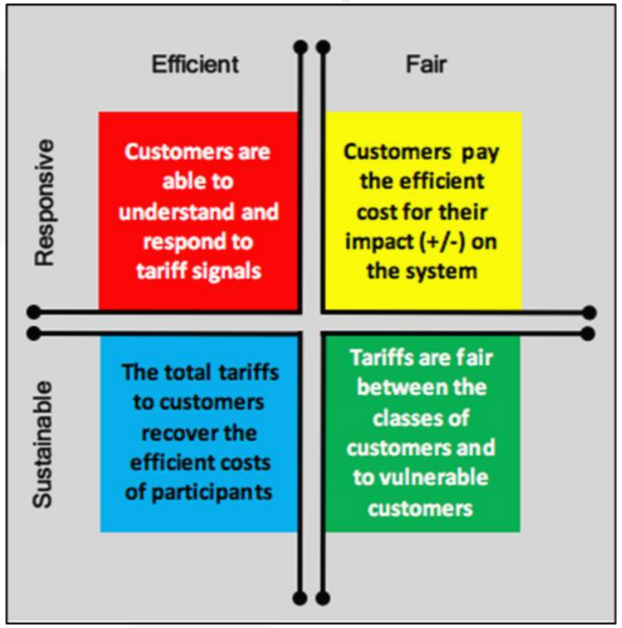
History of demand response

- Not a new concept – Bonbright on tariffs circa 1960:
  - Responding to issues of the day
    - Generator management
    - Transmission and distribution costs
  - Depended on relative costs of energy
- Pre market in Australia
  - Interruptible tariffs (industrial customers)
    - Often a surprise when used
    - Still used - smelters - although via a contracted service (or direction)
  - Two rate pricing for larger customers
  - Off-peak hot water at the smaller customer level
    - Limited by metering and control
    - Still used – in fact factored in to current distribution asset requirements



- National Grid Protocol (1992) – for the design of the NEM

  "Demand management and renewable energy options are intended to have equal opportunity alongside conventional supply options to satisfy future requirements. Indeed, such options may have advantages in meeting short lead-time requirements…".

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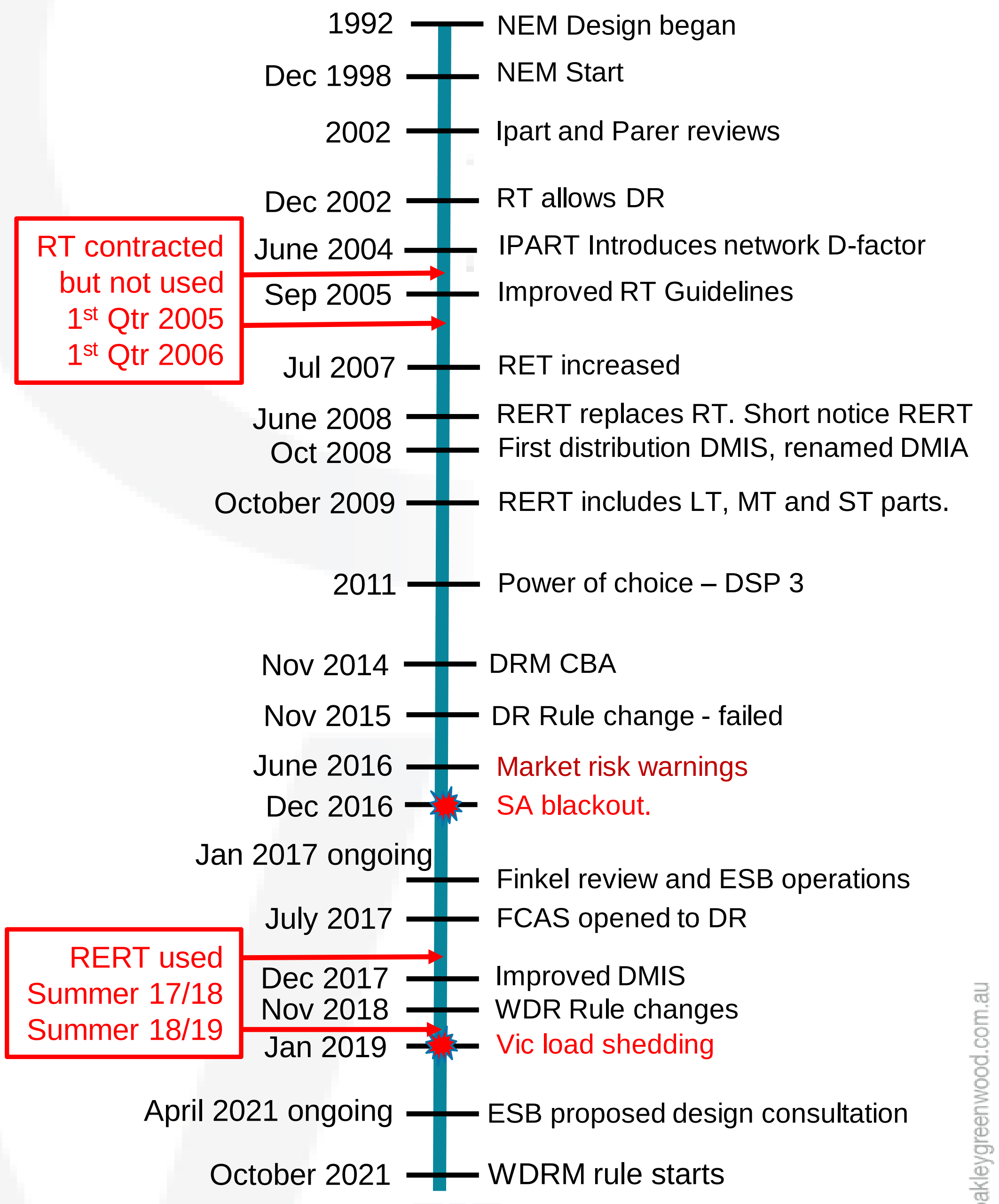
Timeline for DR use in Australia

- At the start of the NEM
  - Retailer schemes, based on interruptible tariffs remained
  - Hot water tariffs were in place
- Reserve Trader developed to include DR
  - Opposed by sections of the industry
  - IPART introduces D-factor
- RERT commenced 2008 (mainly DR)
  - Little use until after the SA Blackout
  - Use in the summer of 17/18 cost more than the VCR
  - Use in the summer of 18/19 cost less than the VCR
- Multiple proposals to incorporate DR
  - Rapid actions to address reliability
  - Develop a strategic reserve including DR
  - Include DR in the NEG(R), a capacity obligation on retailers
  - Network DR scheme introduced
- **Note** that DR has been more integrated into the **WEM**
  - Nett market design from 2006
  - Capacity mechanism and market
  - Reduced as DR required to be available 12 hours
  - Now impacted by constraints (aggregation)



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Relative integration of demand response

Less efficient ⟷ **More efficient**

Simple DR	Responsive DR	Integrated DR
Focus on direct costs	Focus on participant costs	Focus on economic benefits

- **Simple** DR ➔ Respond to tariffs from retailers and networks
  - Optimise the cost of energy for a site (based on an all-in tariff)
  - Reliant on efficient energy charging (retail and network charges – which may conflict)
  - Queensland had a DR programme that increased costs!
- **Responsive** DR ➔ Respond to price signals via retailers and networks
  - Optimise the costs of energy use at the site and for retailers and networks
  - May be separately applied by retailers and networks (or together)
  - Requires efficient translation of market signals to price or rewards
- **Integrated** DR ➔ Send and respond to price signals to and from the market and networks
  - Economically integrate the cost and benefits of services to the system
  - Sophisticated markets: Energy, ESS (e.g. FCAS, synthetic inertia)
  - Network services: congestion, voltage etc.
  - DR owner or aggregator manages the trade off for highest value

NEW DEVELOPMENTS IN AUSTRALIA

NEM

- WHOLESALE DEMAND RESPONSE MECHANISM
- THE POST 2025 DESIGN

WEM

- 2022 REFORMS

Other

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WHOLESALE DEMAND RESPONSE MECHANISM

Key documents

- AEMC, *Wholesale demand response mechanism, Rule determination*, 11 June 2020
- AEMO, *Wholesale Demand Response Guidelines*, 25 March 2021
- AEMO, *Baseline Eligibility Compliance and Metrics Policy, Final Report and Determination*, 20 May 2021
- AER, *Wholesale Demand Response Participation Guidelines, Notice of Consultation and Issues Paper*, March 2021
- Oakley Greenwood, *Phase 1 WDRM Baseline Methodology Analysis Results and Recommendations*, December 2020
- Oakley Greenwood, *Phase 2 WDRM Baseline Methodology and Participant Testing*, March 2021

KEY PROVISIONS OF THE RULE CHANGE

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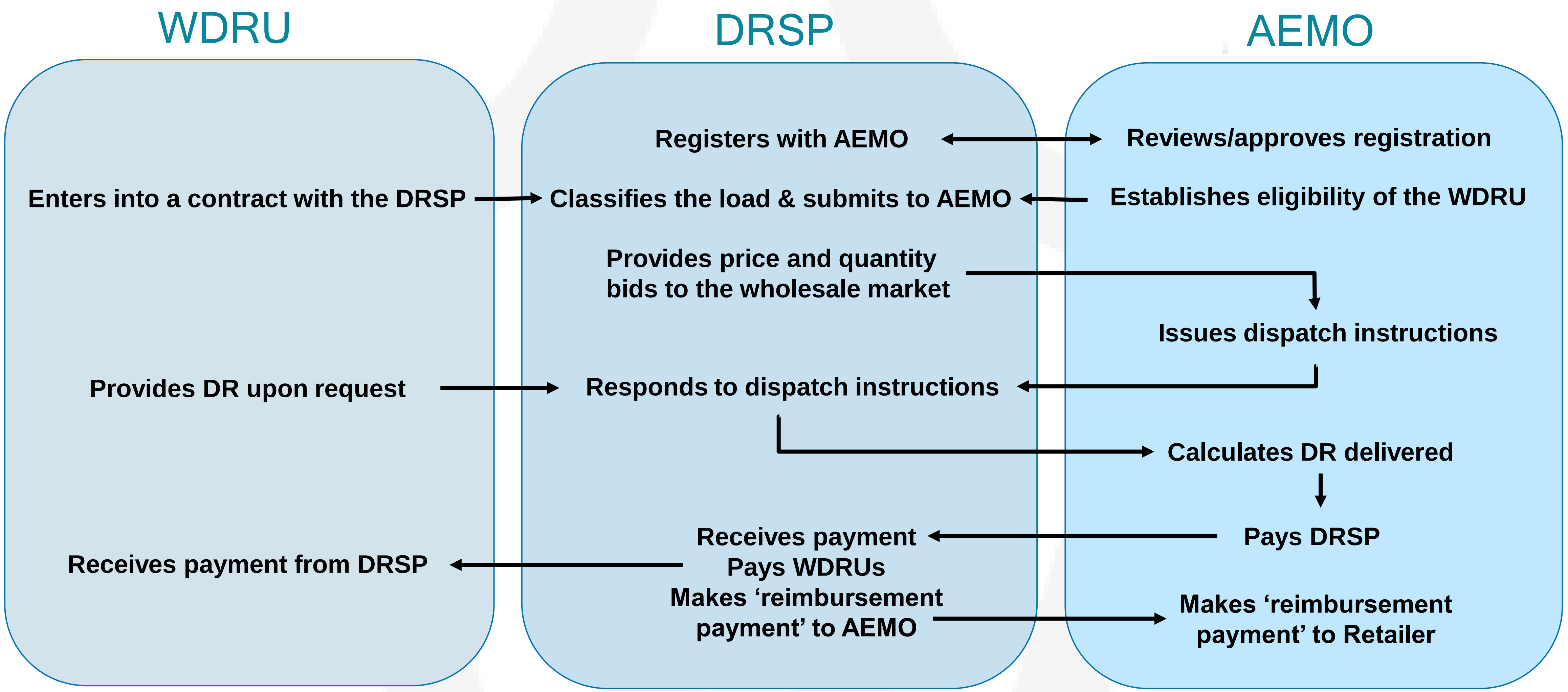
The WDRM Rule change makes a number of specific changes

- Introduces a new market participant category – DRSP
  - Can bid end-use customer DR into the wholesale market (the only category of market participant that can do so)
  - The DRSP category will subsume the existing MASP category
    - DRSP can classify each WDRU for either or both DR and/or FCAS (note: the applicable technical requirements are different)
    - DRSP (rather than AEMO) co-optimises
- Puts obligations on DRSPs that are as similar as possible to those that apply to scheduled participants, in particular: scheduling and information provision
- Sets out a process for establishing the baselines to be used for:
  - Determining the eligibility of WDRUs
  - Settling the DR delivered by the DRSP at the spot price
- Makes changes to other aspects of the NER, including:
  - The RERT
  - Demand side participation information provisions to improve integration of the demand side
- Sets out the implementation timeframe for the mechanism
  - WDRM to commence on 24 October 2021

AEMC intentions in enacting the WDRM

- Promote greater demand side transparency and assist with power system reliability
- Promote the ability for consumers who participate in the mechanism to change their level of consumption in response to the wholesale electricity price
- Increase the level of consumer choice in relation to wholesale demand response
- Minimise the impacts of any distortions introduced under the mechanism, particularly to the wholesale market as well as retailers' hedging and positions in the contract market
- Reduce administrative costs to AEMO and the market, particularly retailers

Roles of key players - overview



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Further (non-exhaustive) detail on roles - AEMO

- Develop DRSP registration requirements
- Develop baseline methodology and metrics
- Review/approve DRSP registrations
- Test candidate WDRUs for baseline (and other) compliance
- Monitor / check WDRU baseline compliance
- Consider (including upon request from DRSPs) and assess additional baseline methodologies
- Issue dispatch instructions
- Settle WRDM in the market
- Can:
  - Set a prudential requirement for DRSPs
  - Set a limit on the amount of non-SCADA DR capacity per NEM region
  - Issue ‘instructions’ (not ‘directions’) to DRSPs under Cl 4.8.9

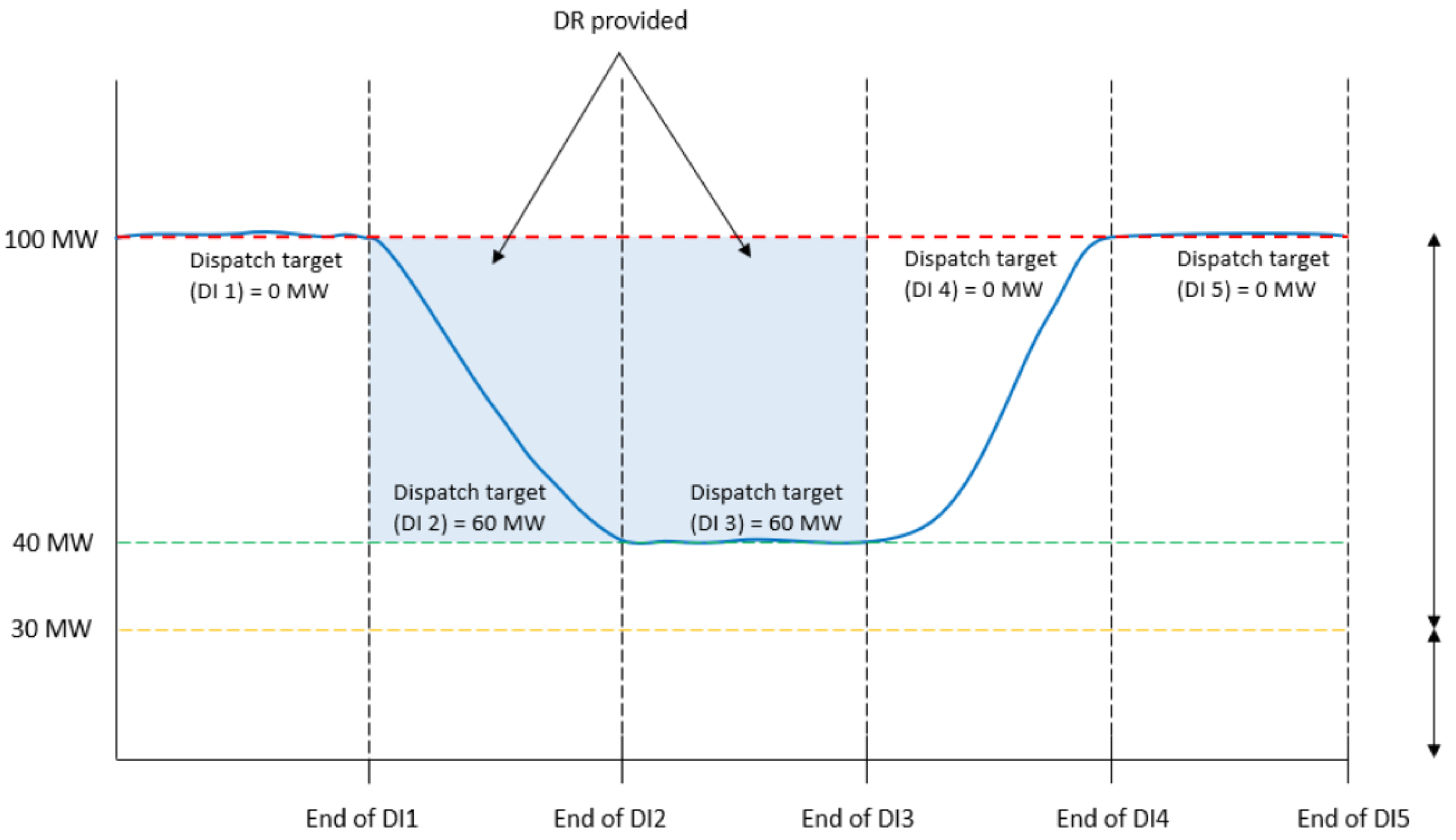
Further (non-exhaustive) detail on roles - DRSP

- Classify loads for either or both DR and/or FCAS
- Identify maximum responsive component (MRC) of each WDRU; submit info for eligibility testing by AEMO
- Select most appropriate BM from the BM Register
- Provide information required for ST PASA, ESOO and DSP Portal
- Provide (at least one) price and quantity bid for each interval
- Bids must
  - Be made in 1MW increments (1 MW minimum) and include ramp rates both down and up
  - Be based on no more than the aggregate MRC of the WDRUs included in the bid
  - Comply with AEMO dispatch instructions
- Monitor and maintain information regarding the continuing compliance of the WDRU with the applicable baseline and participation in other DR arrangements that could impinge on incrementality
- At settlement is responsible for
  - Remitting reimbursement payment amount due to Retailer(s) of participating WDRUs
  - Payment for consumption above baseline

Further (non-exhaustive) detail on roles - WDRU

- Must
  - Meet the baseline and other requirements of the WDRM and the DRSP (including minimum DR capacity)
    - Note that baseline compliance will be checked at sign-up, at settlement, periodically and at the discretion of AEMO
  - Nominate the relevant NMI, qualifying load, and MRC of its load
- Must be located at (and will be settled at) an on-market point of connection (loads at child meters are not eligible)
- During the intervals it is bid, it cannot:
  - Be exposed to wholesale spot price
  - Be subject to or participating in any other arrangement through which its WDRM capacity may be called upon
  - Offset the reduced consumption at the WDRU with consumption at another facility within the same region
- Note that SCADA is required for:
  - Any WDRU with DR capacity > 5MW
  - All WDRUs within an aggregation that includes a WDRU with DR capacity > 5MW
  - (Workaround is to separate WDRUs with more and less than 5MW)

How DR will be dispatched and expected to respond (simplified)

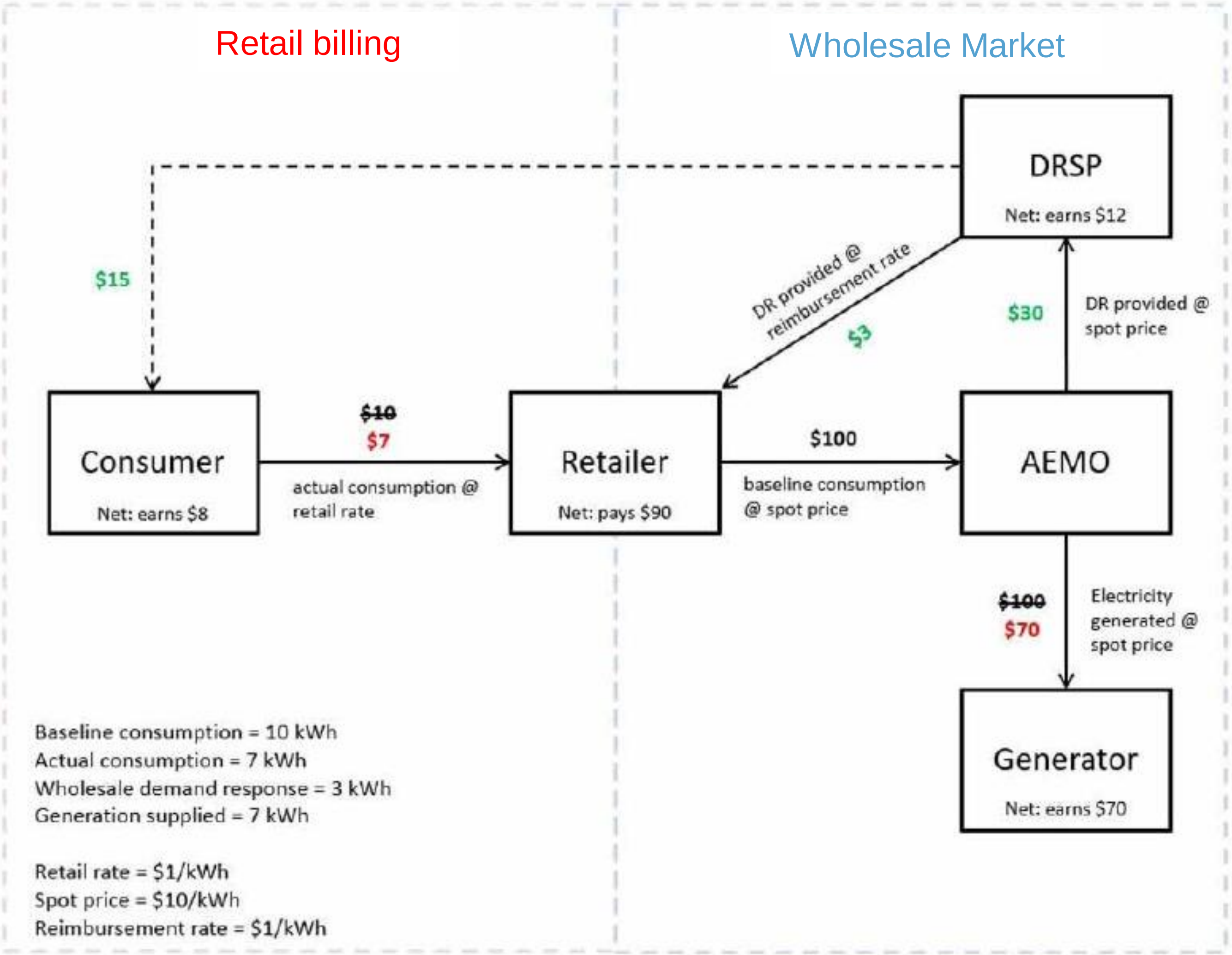


The dispatch instruction is for "a specified deviation from the baseline". It is:

- Applied (and settled) at the WDRU level
- Capped at the level of the maximum responsive component of the WDRU

Source: AEMC

How DR will be settled under the WDRM



Source: AEMC

- Undertaken at the WDRU level in each interval
- Customer is charged by retailer according the customer's retail electricity market contract
- Retailer is charged by AEMO for customer's baseline consumption
- DRSP is paid by AEMO for the WDRU's (customer's) DR consumption (baseline minus actual) capped at the maximum responsive component of the customer
- DRSP pays customer based on the contractual arrangements with the customer
- To make the retailer whole:
  -- DRSP pays AEMO (who on-pays the retailer) for the difference between the customer's baseline and actual consumption at a set reimbursement rate
  -- Reimbursement rate is calculated quarterly by AEMO based on the peak period load weighted average spot market prices over the previous 12 months

RELEVANT GUIDELINES

AEMO WDRM Guidelines

- Requirements for registration as a DRSP (not yet finalised)
- Requirements for classification of a load as a **WDRU**
- Requirements for aggregation of WDRUs
- How AEMO will assess whether power system security could be materially affected by a WDR aggregation
- Requirements for telemetry and communications equipment for WDRUs
- Methodology for determining the total quantity of WDR within a region that can be dispatched without telemetry and communications
- The process for developing baseline methodologies (BMs), including how a proposal for a new BM can be made
- The process for a DRSP to apply for approval to apply a BM and related baseline settings to a WDRU
- The process for a DRSP to apply for approval to change the maximum responsive component (MRC) of its WDRU, and information about how AEMO will assess that application
- Arrangements for the provision of baseline data applicable to the WDRU

Requirements for classification of a load as a WDRU

- Type 1, 2, 3 or 4 meter, capable of 5-minute settlement
- The load has not been classified as a WDRU or an ancillary service load by a different DRSP
- The load is served through a single connection point and cannot be switched between multiple connection points
- The load is not contracted under the RERT
- The DRSP has declared that it will provide an available capacity of zero for the load (or any DUID it is part of) if it will or is likely to be exposed to spot price

Requirements for aggregation of WDRUs

- All of the WDRUs within the proposed aggregation must be within a single load forecasting area
- For any aggregation of 5 MW or more within a TNI
  - The proposed aggregation of the WDRUs has been endorsed by the DNSPs within the area, or
  - That endorsement had been applied for at least 25 days prior to the date of the aggregation application
- The DUID MRC must be lower than the aggregate of the NMI-Level MRCs for the aggregated WDRUs, and will be rounded down to the nearest whole MW
- AEMO may require disaggregation where:
  - The boundaries of the load forecasting area changes
  - Such disaggregation is required in order for AEMO to maintain system security in central dispatch
  - One or more of the WDRUs within the aggregation have not conformed to the WDR Dispatch Compliance Framework
- If AEMO requires disaggregation for system security concerns it will advise the applicant of one or more alternative aggregations that will not materially affect power system security, and any constraints to be applied to the operation of them

Requirements for Telemetry and Communications

- SCADA is required for
  - Any individual or aggregated WDRUs with a total MRC of 5 MW or more
  - Any individual or aggregated WDRUs with a total MRC of less than 5 MW located in an area where curtailment may be needed to maintain power system security for at least 5 hours per year
- Proponents can apply for exemptions
- AEMO will determine a threshold for each region – the maximum MW of WDR for which no telemetry data is provided that can be dispatched at one time
  - This threshold will be applied as a dispatch constraint
  - AEMO will publish an initial threshold for each region; revisions will be considered monthly
  - There are specific conditions under which a revision must be undertaken and a methodology for doing so

AER role

- The AER is required to issue guidelines on and enforce requirements related to, the retention of information, including on the following topics:
  - Dispatch bids and declared available capacity
  - Compliance with AEMO notices relating to non-conforming WDRUs
  - Baseline non-compliance, spot price exposure, and additionality
- An Issues Paper was published in late March
- Submissions closed on 23 April
- Draft WDRP Guidelines will be published by 16 July 2021

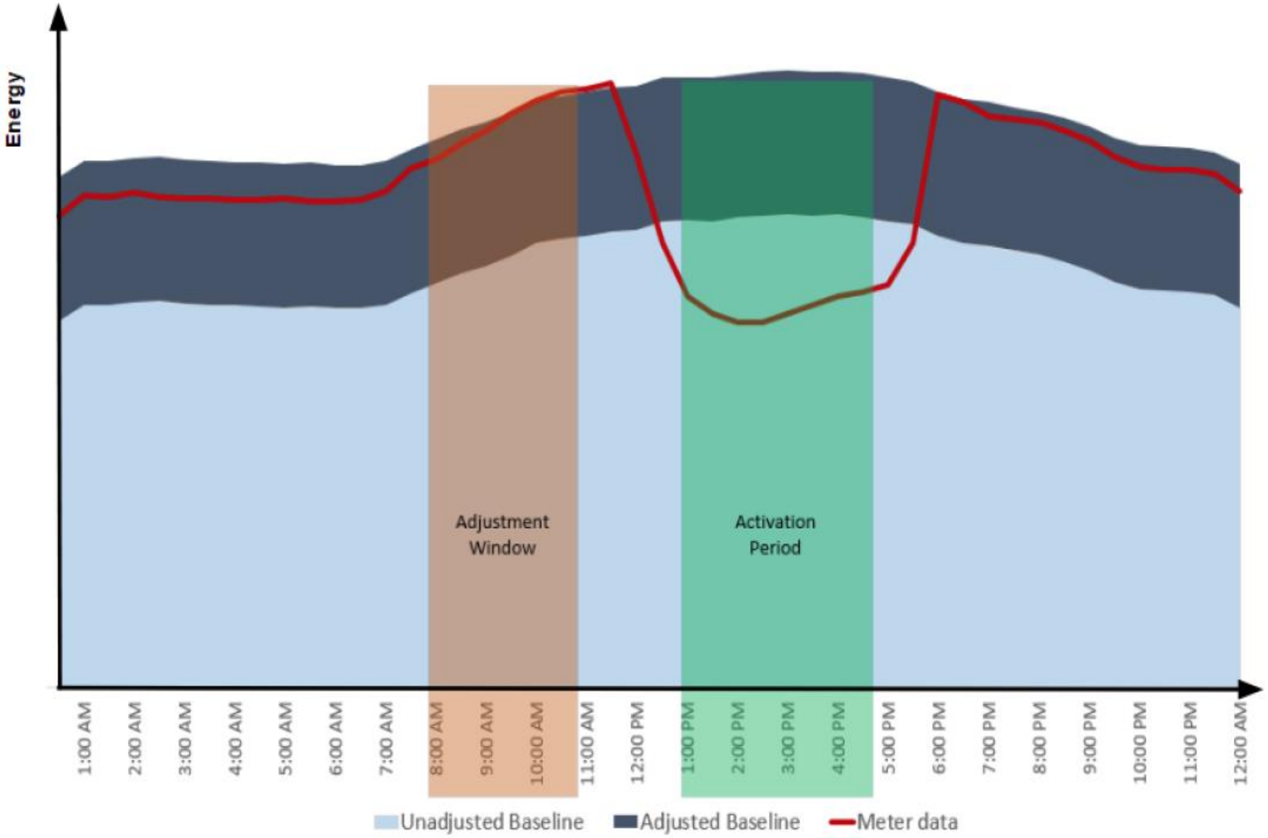
BASELINE METHODOLOGY AND METRICS

Baseline – why and what

- Measuring demand reduction requires a counterfactual
  - A means for estimating what consumption would have been if the actions undertaken to reduce demand had not been undertaken
- Baselining is one way of providing that estimate (there are others)
- AEMO has chosen the '10 of 10' approach with pre-period adjustment (there are others)
  - AEMO uses the 10 of 10 in the RERT
- It works best for:
  - Loads that are relatively consistent in shape from day to day
  - Facilities in which the DR to be provided is a material percentage of the facility load
- It is not particularly good for:
  - Loads that are significantly weather dependent
  - Loads that have net metered DER behind the meter
- It is tried and true, providing a solid method for the launch of the WDRM
- There is a process for assessing and approving additional baseline methodologies

10 of 10 – how it works

- For any particular day, the baseline is established by taking the average of the WDRU's consumption on a trading interval by trading interval (TI) basis on each of the previous 10 days
  - Excluding public holidays, weekends (or weekdays), days on which the WDRU provided DR or had scheduled maintenance, etc
- It provides an estimate of the shape and magnitude of the WDRU's consumption in those TIs
- The baseline is adjusted to account for the difference in consumption in the adjustment window on the event day as compared to the baseline
- DR is calculated at the trading interval level and summated



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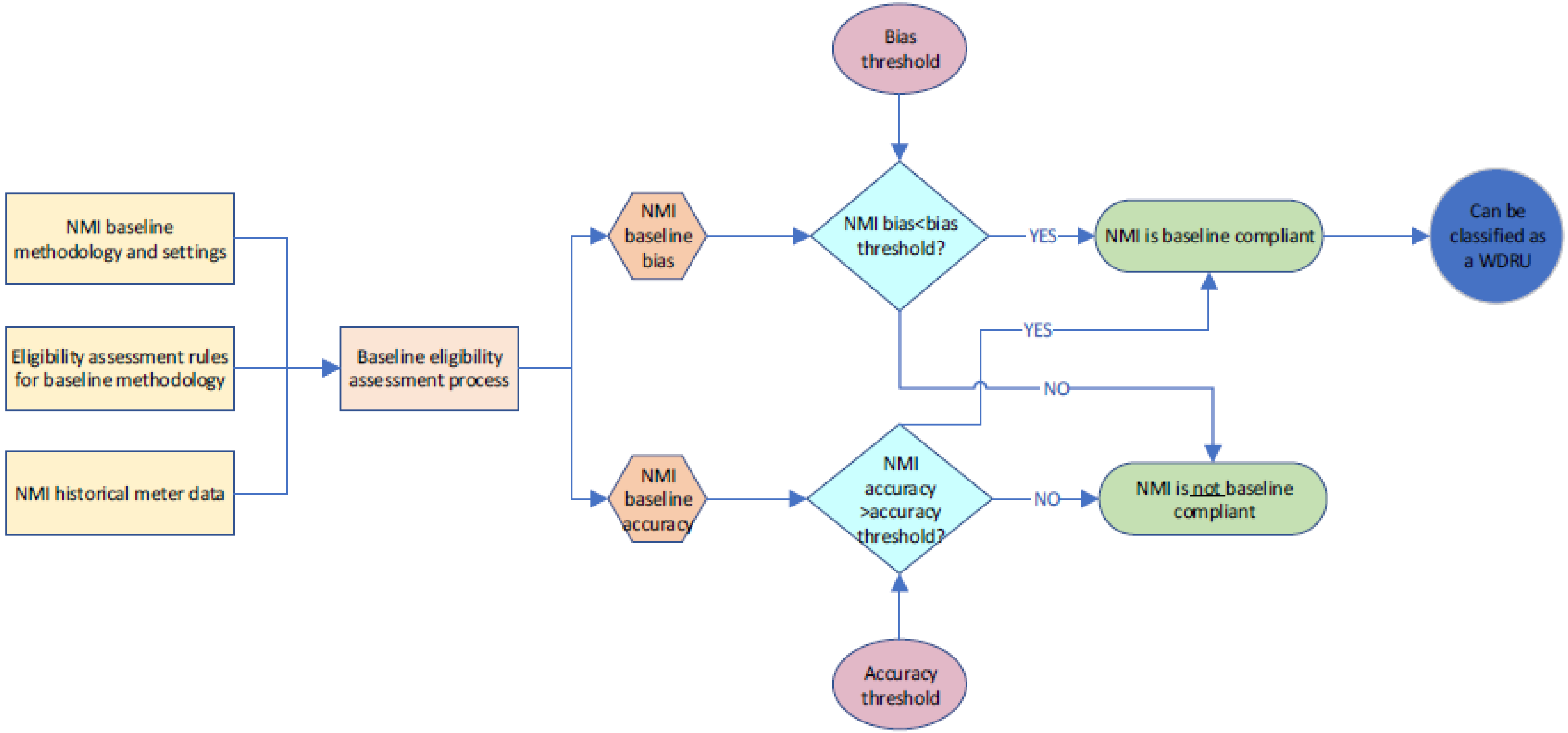
Metrics and thresholds to be used in the WDRM

Metric	What it measures	Threshold	Statistical test
Accuracy	How closely the consumption in the TI matches the level predicted by the baseline	±20%	RRMSE
Bias	Whether the predicted consumption is consistently higher or lower than the actual	±4%	ARE

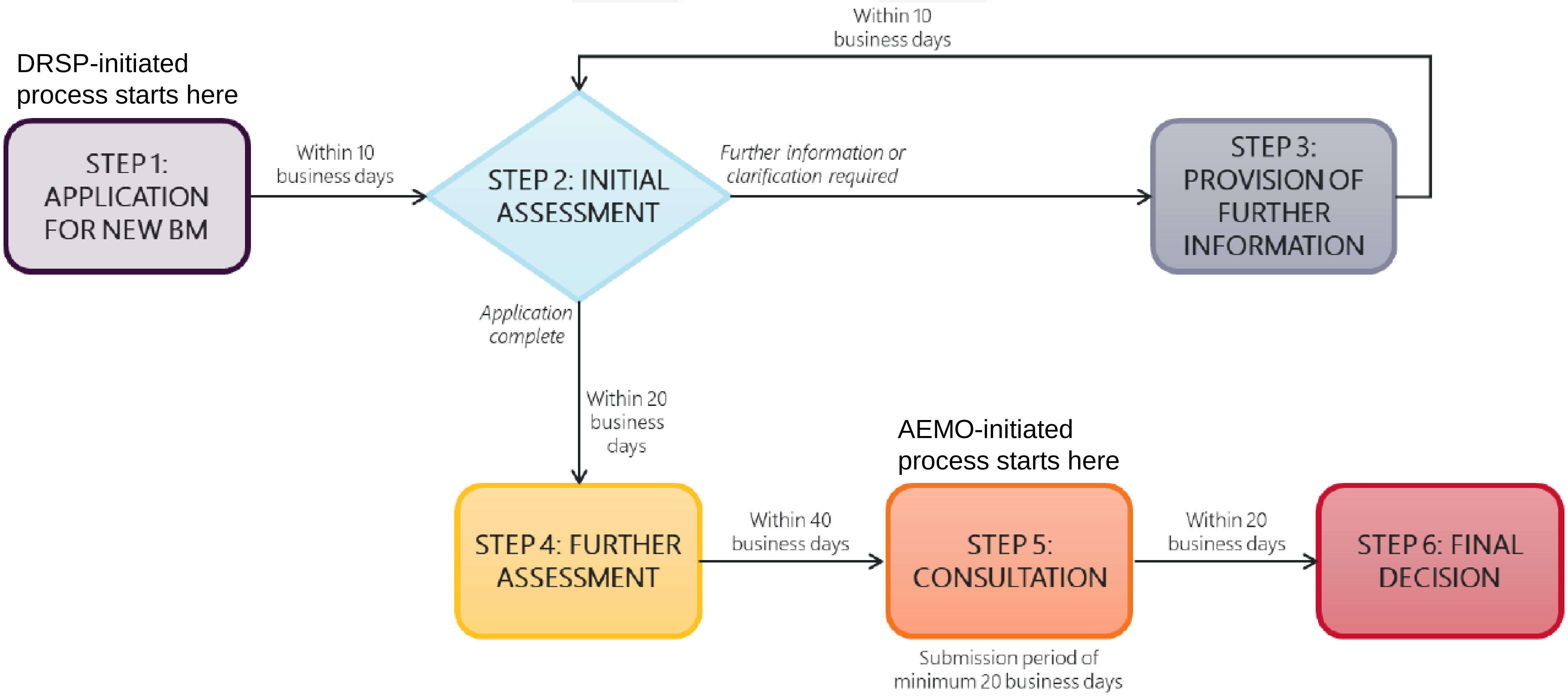
Other key features of the baseline approach

- Baseline conformance will be tested
  - On registration
  - At least twice a year, most likely
    - June
    - Late November/early December
- Eligibility days – TBD
- Adjustment factor - capped at 20%

Baseline eligibility assessment framework



Process for developing a new baseline methodology



OAKLEY GREENWOOD EXAMINATION OF THE 10 OF 10 BASELINE

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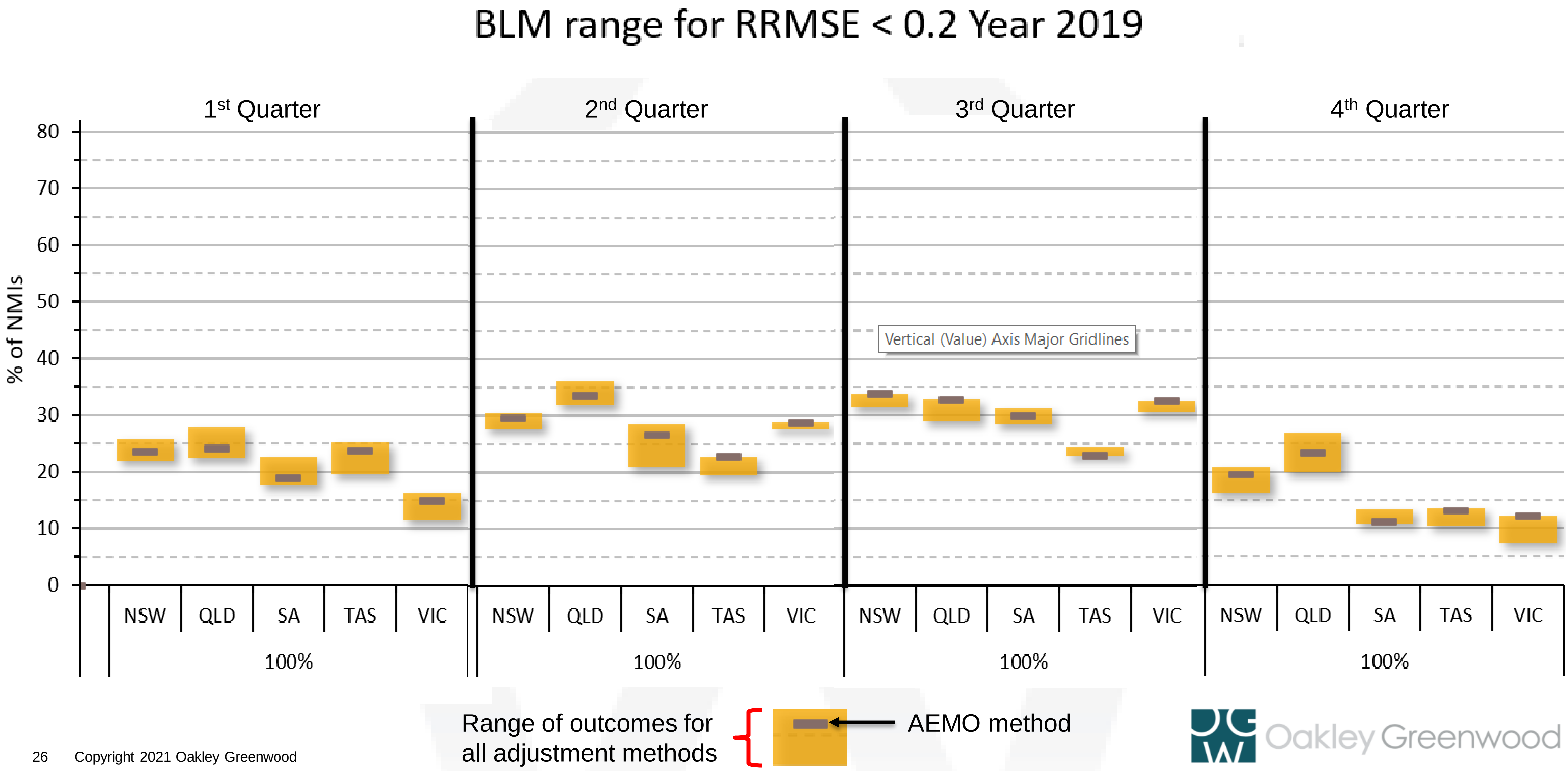
Practical implications for AEMO in using the 10 of 10 approach – participation



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Impact of 5 minute settlement

- With 5 minute settlement, the ability of a site to meet the accuracy standard will reduce
  - The standard may need to be reviewed

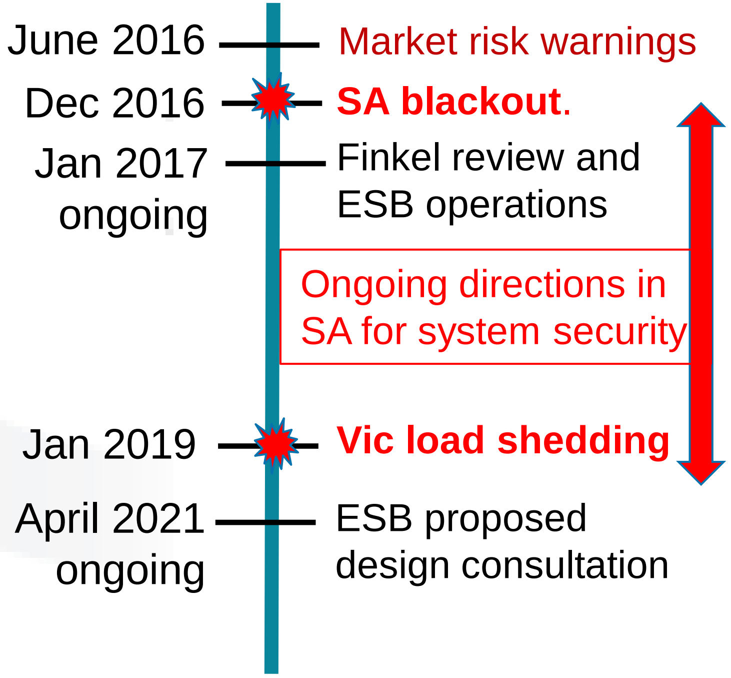
Case		5-minute interval						Mean Square Error (MSE)	Root MSE
		1	2	3	4	5	6		
1	Error	5	5	5	5	5	5		
	Squared Error	25	25	25	25	25	25	25	5.0
2	Error	10	4	4	4	4	4		
	Squared Error	100	16	16	16	16	16	30	5.5
3	Error	20	2	2	2	2	2		
	Squared Error	400	4	4	4	4	4	70	8.4
4	Error	25	1	1	1	1	1		
	Squared Error	625	1	1	1	1	1	105	10.2

POST 2025 DESIGN

— **Based on the ESB consultation documents, specifically:**

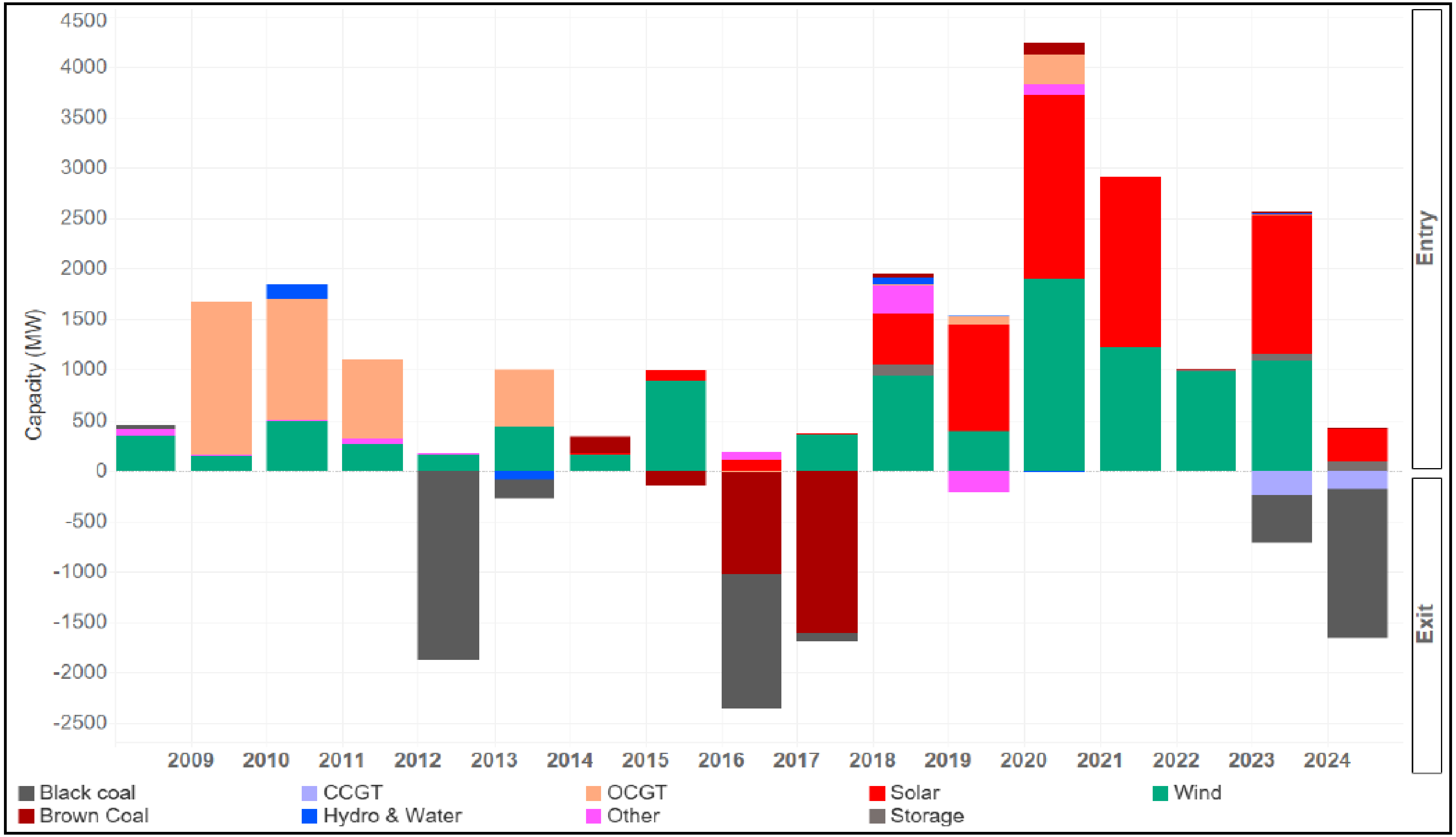
Energy Security Board, "*Post 2025 Market Design Options – A Paper For Consultation*", Parts A and B, April 2021

The Energy Security Board
– evolution of the NEM for new technologies



- **Resource adequacy mechanisms**
  - to provide the right signals which will drive investment in an efficient mix of new resources which will minimise costs and maintain reliability
- **Essential system services and ahead scheduling**
  - to ensure that the essential services required (frequency, control, operating reserves, inertia and system strength) are available to maintain system security
- **Integration of distributed energy resources and flexible demand**
  - to deliver benefits to customers through the integration of rooftop solar, battery storage, smart appliances and other resources into the system in an efficient way
  - Bi-directional supply chain – price and service integtration
- **Transmission and access**
  - to reconfigure the transmission system so that new renewable generation and large-scale storage can connect and be dispatched to meet customers’ demand

The loss of system inertia, capacity and system strength



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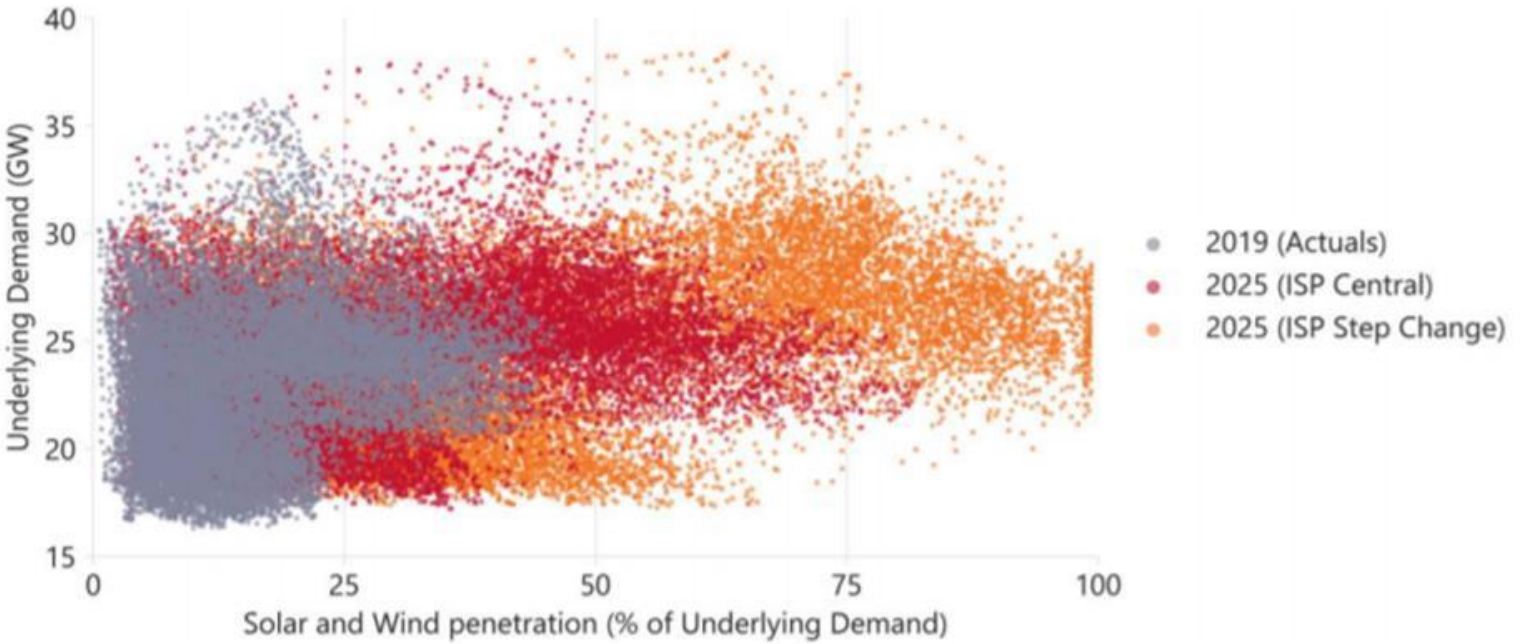
Instantaneous penetration of wind generation and solar



- High levels of intermittent generation destabilises energy systems
  - Management of supply demand balance – system reliability
  - Management of frequency – system strength
- Opportunity for demand side resources if suitable

Reform direction for 2025

- Resource adequacy mechanisms and aging thermal retirement
  - Objective: facilitate the timely entry of new generation, storage and firming capacity and an orderly retirement of aging thermal generation
  - This means: We have sufficient dispatchable resources and storage capacity in place in time to prevent significant price or reliability shocks to consumers
- Essential system services and scheduling and ahead mechanisms
  - Objective: availability of resources that provide essential system services and support for investment in necessary capability to balance the highly variable dynamics of the changing generation mix
  - This means we have the resources and services when needed to manage the complexity of dispatch and to deliver a secure supply to customers
- DER integration and demand side participation
  - Objective: enable the integration of DER (such as rooftop solar and distributed storage) and **value flexible demand** so they can provide services to networks, the wholesale market and other consumers
  - This means new opportunities for consumers about how they receive and use energy and are rewarded for doing so flexibly.

Timeline of ESB work

Timetable for each of the streams

- **Immediate reforms** – these are proposed measures for immediate implementation to address imminent problems in the NEM. As such they are reforms that are either underway or are being developed now for implementation as soon as possible.
- **Initial reforms** – these are reforms that we need to develop further in the near term for implementation. Many of these reforms will need to be implemented pre-emptively to solve emerging challenges.
- **Next reforms** – these are reforms that we may need to move to over time, given the trends and pace of the transition, or may need to be considered or revisited if certain preconditions arise.

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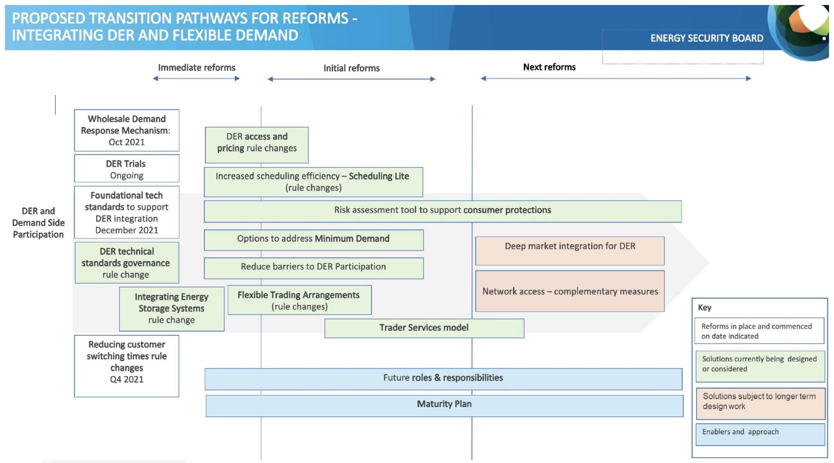
Integration of Distributed Energy Resources and Flexible Demand

> *"The ESB is focussed on driving value for all customers from the integration of DER into the overall power system."*
>
> — Energy Security Board, *Post 2025 Market Design Options*, April 2021

- Customers could benefit from using their resources to:
  - provide demand flexibility
  - compete into wholesale energy and essential service markets and
  - provide network services
  - ➔ lowering their overall cost
  - ➔ providing services to the system, lowering system costs
- Roles of the various parties need to be clarified
  - building on their current responsibilities
- Opportunities for DER are developing
  - important trials are underway
  - additional action to take now for DER integration
  - further reforms for later implementation
  - broadening potential uses of DER as new technologies emerge



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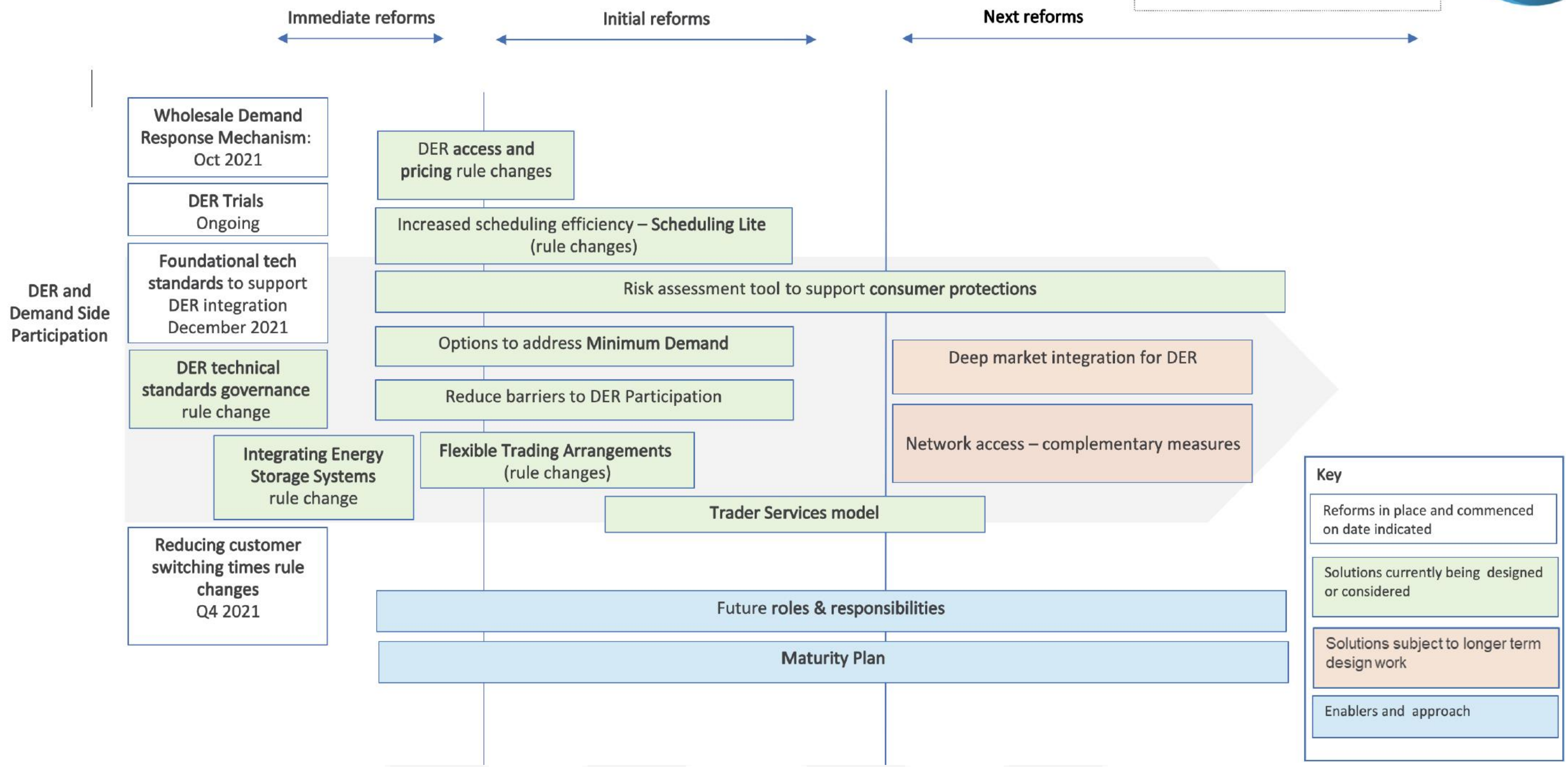
PROPOSED TRANSITION PATHWAYS FOR REFORMS - INTEGRATING DER AND FLEXIBLE DEMAND

ENERGY SECURITY BOARD



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Resource adequacy mechanisms

- Demand response is not a priority for the ESB reforms
  - WDRM and other reforms discussed below will potentially allow demand response to participate
  - Terms and approaches are not yet defined
- Extending the implementation of the Retailer Reliability Obligation
  - Make it permanent
  - Technically open to all technologies and sources
- RERT as a backstop
  - Traditional area where demand response is used
  - Needs to be reformed to clarify rules and regulations
- Operating reserve
  - Like the RERT, a potential opportunity for demand response

Making sure that sufficient capability is provided to the power system for dispatch for energy, essential system services and reserves.

Essential System Services and ahead scheduling

- Essential system services – primarily frequency control ancillary services – already use demand response
  - To be enhanced
  - This is discussed in the following slides
- Ahead markets usually favour demand side response
  - Variations against a known dispatch profile
- A fully two sided market will integrate dispatch from both supply and demand side
  - In theory will allow improved tariffs
  - Complicated in terms of implementation
  - Requires a change in thinking or new, creative participants
  - This is discussed in the following slides

Integration of DER and flexible demand

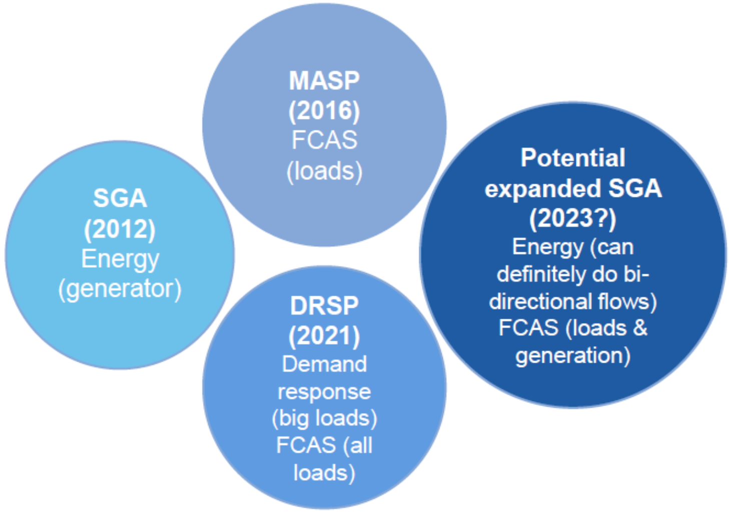
- Initial focus is on DER – particularly storage
- Changes to develop the Trader Service approach will also benefit demand response
  - registration and participant obligations are based on the services provided, not on participation categories and assets
  - aggregator will see less red tape and stronger regulatory clarity on how DERs can participate – simultaneously – in multiple services.
- Multiple trading relationships at a site
  - models enable the customer's controllable load (e.g. a battery or hot water system or pool pump) to participate via a separate aggregator
  - the aggregator provides services alongside – in addition to – the customer's existing retailer
  - two models are being examined, which differ in the configuration of the meter and the connection point
- Tariff reform – to be discussed later

Initial steps towards the "Trader-Services" model are being explored through the Integrating Energy Storage Systems into the NEM rule change, to recognise bi-directional flows, update registration and participation provisions, level the playing field between different participant categories for causer-pays penalties, and enable aggregators to participate in wholesale energy alongside ancillary markets

Trader services (from the ESB presentation dated May 2021)

Current Trajectory

- New business models or capabilities are often accommodated through new registration categories or extensions of existing ones
- This method is slow, not sustainable and creates gaps in their capabilities which creates barriers in the market while regulation adjusts to accommodate these new models



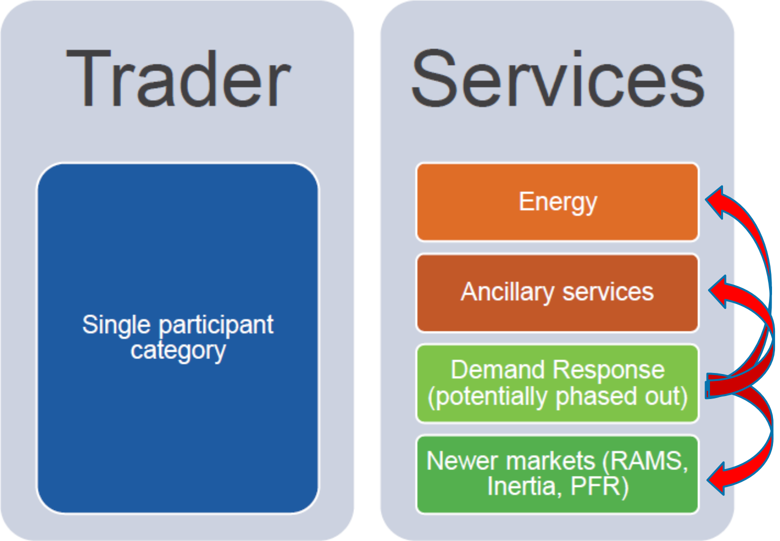
Interim arrangements during change over

New service-based regulations phased in over time

Demand response may integrate into the energy and ancillary services markets

Potential End Point

- Each connection point can provide/be provided one or more services
- These services can be provided by the end user directly, or by one or more Traders on the end user's behalf at a connection point (as long as two different Traders aren't providing the same service)
- The Traders may reflect these connection points in the market as individual connection points, or a group of connection points as an aggregated facility (if the service allows for aggregation)



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Demand Response and network support

- Successful implementation of tariff reforms is important
  - drive different behaviours in the deployment and use of DER assets
  - reduce the need for more structured procurement of network services by distribution businesses.
- Options Paper identified a range of approaches:
  - Manual structured procurement
  - Digital platform
  - Retailer portfolio tariffs
  - Dynamic locational price signals
- Some approaches are being trialled now
- Discussed in more depth in the next section.

STATUS OF DR IN THE WEM

Moving away from the “happy times” …

- In 2006, demand response was fully integrated into the Reserve Capacity Mechanism
  - Seven providers were active providing 550MW of DR
- In 2012, the obligation was changed to required the service to be available for 12 hours
  - Only two providers remained providing 66MW, one was Synergy, the government owned entity.

Requirement	2006 Rules	2012 and current Rules
Days of availability	All business days	All business days
Dispatch events per year	Once on at least 6 days[6]	200 hours
Hours per day	4 hours	12 hours
Total hours available per year	24 hours	200 hours
Earliest start	12:00 pm	8:00 am
Latest Finish	8:00 pm	8:00 pm
Minimum notice period of dispatch	4 hours	Near real time with 30 minute delivery period
Measure of availability	N/A	Real time telemetry
Capacity baseline	Median 32 intervals	5th percentile of top 200 hours and capped at the Individual Reserve Capacity Requirement level and calculated as a portfolio.

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Moving away from the “happy times” …
… but getting better again

- The 2021 reforms
  - Demand response is included in the Reserve Capacity Mechanism
    - Can get capacity credits for improving network access or directly assisting in meeting demand
    - No change to the rules for providing the service
  - Use of the “constrained network” reduces the ability of demand response to be aggregated
    - Can still be coordinated but less able to be integrated into a VPP
  - Improve access to the balancing market
- Virtual Power Plants allowed
  - Primarily storage
  - Can include DR
  - Need to be in the same electrical network (TNI)
- Demand Side Programs can be coordinated but cannot be scheduled.

Whole of System Planning	Foundation Regulatory Frameworks	Distributed Energy Resources
First Whole of System Plan (NEW)	Improving Access to the SWIS Delivering the Future Power System	DER Roadmap (NEW) Connection Requirements and Performance Standards (NEW) Visibility of DER

PRICING OF DER FOR ECONOMICALLY EFFICIENT INTEGRATION WITH THE ELECTRICITY SUPPLY CHAIN

Results of the study by Oakley Greenwood, part funded by ARENA.

Conducted by: Lance Hoch, Rohan Harris and Alex Cruickshank

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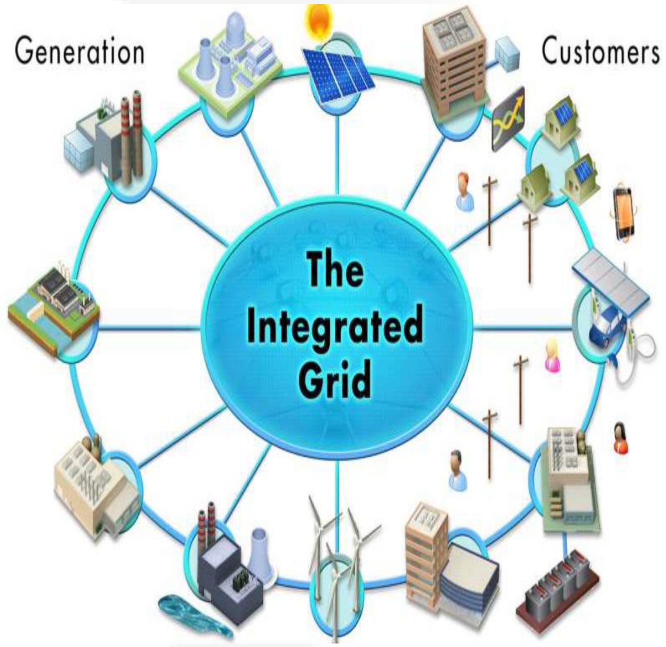
The Study – what it was about

- Developing economically based price signals of the value that DER can provide to each level of the electricity supply chain
- Integration of DER into markets and the value chain of markets
  - Wholesale (energy, ancillary services, reserves, etc)
  - Retail (energy, reserves)
  - Network (constraint management, voltage support)
  - Other – Embedded networks, Microgrids
- Price and other economic signals
  - Not a technical review unless the technology impacts on the economic signals.
- Right product, right location, right quantities, right time.
  - National Electricity Objective
    - Long Term investment signals
    - Short term dispatch



Pricing of DER for economically efficient integration with the electricity supply chain

DER SERVICES

DER 'services' - areas in which DER can reduce costs

For Networks

- Shared network augmentation costs
- Costs of managing voltage within required levels on shared network

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- Direct Connection Costs
- Extension of existing shared network
- Replacement costs
- Managing bushfire risk

For Wholesale Market & Market Ops

- Market ancillary services

- Investment costs
- Fuel and operating costs
- Market reserves

Key Network Cost Drivers and underlying objectives for pricing DER

Network Cost Driver	Underlying pricing objective
Direct connection costs to service new developments	Everything else being equal, we want a price signal that incentivises customers to install DER where it economically reduces upfront direct connection cost by, for example: • Customers making decisions to NOT in fact connect to the grid in the first place and instead, adopt a SAPS solution. • Customers making decisions to invest in DER that reduces the economic costs of connecting them to the existing network.
Extension of existing shared network to service new development	Everything else being equal, we want a price signal that incentivises customers to, amongst other things, invest in DER upfront if that reduces the costs of extending the shared network.

Key Network Cost Drivers and underlying objectives for pricing DER

Network Cost Driver	Underlying pricing objective
Shared network augmentation costs	Everything else being equal, we want a price signal that incentivises customers to, amongst other things: • Install batteries in constrained parts of the network so that they are available to provide network support services if efficient; • Discharge in-situ batteries during periods where they are of the most benefit to the network (which is when the network is, or is likely to be, constrained due to high consumer demand); • Efficiently ration the discharge of their batteries when the network is constrained (e.g., during high wholesale price events); • Orientate their PV systems having regard to the impact their orientation will have on the provision of network support (e.g., incentivise west-facing orientation in areas where network constraints are occurring in late afternoon to early summer evenings); and • Incentivise DER 'prosumers' to consume DER electricity where the marginal benefit of doing so exceeds the marginal value that they could otherwise derive from providing network support.

Key Network Cost Drivers and underlying objectives for pricing DER

Network Cost Driver	Underlying pricing objective
Replacement costs	Everything else being equal, we want a price signal that incentivises customers to invest in DER where it may, in the long-run, reduce a distribution business' replacement costs. An example of this might be on long rural feeders where it may be more efficient for a customer (or small group of customers) to install a SAPS system in lieu of the network business replacing the existing network (e.g., SWER feeder).
Costs of managing voltage within required levels on shared network	Everything else being equal, we want a price signal that incentivises customers to, amongst other things: • Charge batteries during otherwise high voltage events (i.e., to soak up energy that would otherwise have been exported to the grid, causing high voltage issues); • Discharge batteries during otherwise low voltage events; • Increase on-site consumption (in lieu of exporting DER energy) during otherwise high-voltage events; • Decrease on-site consumption (and in turn, increase PV export) during otherwise low voltage events; and • Orientate PV to account for the impact it has on voltage (e.g., incentivize west-facing orientation).

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Key Market Cost Drivers and underlying objectives for pricing DER

Market Cost Drivers	Description
Investment in and operation of the wholesale electricity market	Investment and operation cost of power stations in the NEM are recovered through the spot market. These costs can be avoided when lower priced DER is able to be sourced by retailers. This can be by: • incorporation of DER into retailer portfolios to reduce purchase costs • direct participation of DER providers and aggregators in the wholesale market that displaces higher cost plant; and • provision of contracts into the financial market, either OTC (including contracts to meet RRO requirements) or exchange-based products backed by DER. Each can reduce the need for the centralised supply of energy, thereby reducing the cost of electricity supply.
Provision of Market Reserves	AEMO has to ensure the correct amount of reserves in the market. The level of reserves required is forecast and calculated by AEMO on the basis of the USE standard set by the Reliability Panel. To the extent that the level is not achieved, AEMO must intervene based on its best judgement of the likely shortfall. DER (particularly DR through load reduction or the use of behind-the-meter standby generation) has been proven to be a good, economical source of emergency reserves.

Key Market Cost Drivers and underlying objectives for pricing DER

Market Cost Drivers	Description
Ancillary Services – Management of system frequency	The management of system frequency is a key market responsibility. DER may be able to provide cheaper management of system frequency and, with correct pricing, will lower the cost of these services to the market. Some DR, storage and backup plants can provide these services and are now being incorporated into the markets.
Ancillary Services – System restart and reactive support	A limited number of DER providers may be capable (including in conjunction with generators) of providing resources to restart the electricity system. Power electronics, backed by a power source allows DER resources to provide reactive support.

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Pricing of DER for economically efficient integration with the electricity supply chain

DEVELOPING PRICING STRUCTURES

Developing candidate DER ‘service’ pricing structures

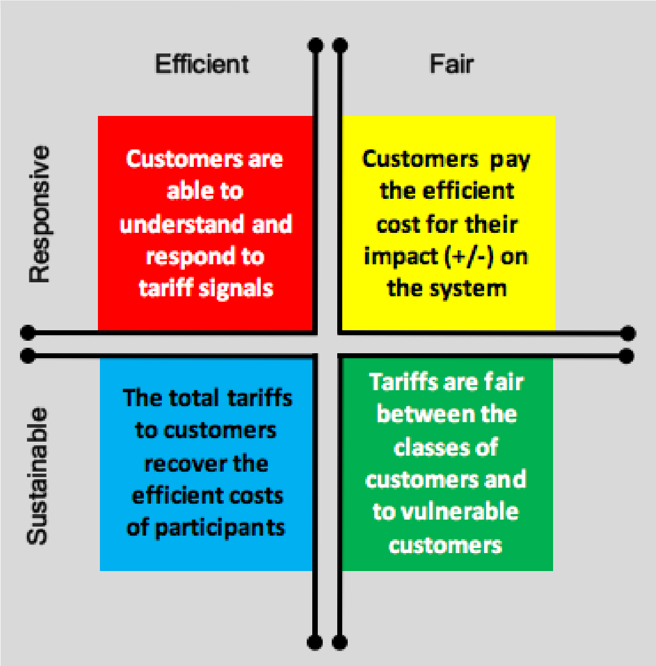
- Should be consistent with the NER, the existing regulatory framework and economic theory
  - In fact, the provision of economically efficient prices is explicitly supported in various section of Chapters 3, 5 and 6 of the NER
- But, more specifically, price signals need to address trade-offs between:
  - Accuracy/cost-reflectivity
  - Administrative cost
  - Complexity and the ability of DER owners/agent to understand and respond to them
- Development of pricing structures also needs to consider and make decisions regarding:
  - Their geographic specificity
  - The specific times at which they will apply
  - Whether they are based on the stated costs to be avoided (posted price) or the price at which DER agent/owners are willing to provide the service (auction)

Principles of pricing - NER, reviews and theory

- **Tariffs, charges, rebates and payments need to be efficient.** This is consistent with economic theory and in the NER:
  - Chapter 3 (Rules 3.4.1 and 3.8.1)
  - Chapter 5 (Rule 5.3 ff) - COGATI review supports
  - Chapter 6 (Rule 6.18)
- **Market energy pricing (Rule 3.8ff)**
  - **Least cost dispatch**
  - **Pay or be paid for value at the connection point**
- Contract or capacity pricing (not NER)
  - Unregulated DR access
- Ancillary services (Rule 3.11)
  - Payment for contingency (availability) and
  - Usage if measured.
- **Network access pricing (esp. Rule 5.3ff)**
  - **Connecting parties should pay or be paid the direct costs or benefits from system changes.**
  - **Access seekers should get rights to their access**

The ideal rate design should promote economic efficiency, enhance customer equity, ensure the financial health of the utility, be transparent to customers, and empower customer choice.

Bonright reloaded - Farugui, 2016



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Overarching considerations when it comes to pricing

- There is almost always a range of potential price signals that could be:
  - introduced in order to facilitate more efficient outcomes and
  - perceived as being consistent with the Rules and economic efficiency.
- Generally, developing efficient pricing structures involves making trade–offs:

Administrative cost
- **Can it be implemented without undue cost?**

Complexity
- **Ability to understand and respond**
- **Who is the party that responds?**

Accuracy of price signal
- **Ability to measure**
- **Level of measurement**
- **Is it a material benefit?**

NOTE: Other non–economic factors include community, customer and Government acceptability

Additional considerations in developing pricing structures

- We developed a spectrum of pricing options (generally 3-5 for each ‘service’)
- The approaches represent choices in 3 dimensions:
  - Geographic focus
    - Regional-based (e.g., AusNet-wide) OR location-specific (e.g., Benalla ZSS)
    - Less complex, costly and accurate → More complex and costly, but more accurate
  - Time period
    - A pre-determined, “set” time-period (e.g., 2–6pm in summer) OR dynamic in their application (e.g., the purchaser “nominates” or “calls” exactly when it requires the services to be provided)
    - Less complex, costly and accurate → More complex and costly, but more accurate
  - Price basis
    - Set in advance based on the network’s cost to serve, or based on customers “offering” in their services to the purchaser, with the purchaser dispatching these services based on some dispatch algorithm (capped at their opportunity cost)
    - Less complex, costly and accurate → More complex and costly, but more accurate
- But more accurate price signals do not necessarily = more efficient outcomes
  - The benefits of improved accuracy may be outweighed by the additional complexity and administrative costs leading to reduced response or use

Pricing of DER for economically efficient integration with the electricity supply chain

PRICING STRUCTURES FOR DER SERVICES TO NETWORKS

Shared network augmentation costs

Key points made in Cost Driver Paper

1. The efficient investment in, and use of, DER requires both efficient variable consumption and export tariffs.
2. These variable tariffs should in theory reflect the forward-looking costs of augmenting the shared network (and any incremental operating costs), which will most likely: (a) vary by location/region; and (b) differ depending on whether consumption or export is occurring.
3. Where the network needs to be upgraded to accommodate future levels of exported energy from DER, this should, in theory, also be signalled to all DER facilities via a cost-reflective variable tariff.

Objective of Pricing DER for this service

- Everything else being equal, we want a price signal that incentivises customers to, amongst other things:
  - Install batteries in areas where they are able support the network efficiently;
  - Discharge in-situ batteries during periods where they are of the most benefit to the network (which is when the network is, or is likely to be, constrained due to high consumer demand);
  - Efficiently ration the discharge of batteries where the network is constrained (e.g., high wholesale price events leading to rapid increase in the discharge of batteries to the grid);
  - Orientate their PV system, having regard to the impact that that decision will have on the provision of network support (e.g., incentivise west-facing orientation); and
  - Incentivise DER providers who are also consumers, to consume electricity where the marginal benefit exceeds the marginal value that they could otherwise derive from providing network support (NOTE: Under certain supply demand scenarios – at an individual customer level - the opportunity cost of consuming during a period where network support period is being financially rewarded, is that the DER provider can export less energy to the network)

Shared network augmentation

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
NETWORK SUPPORT "REBATE" OPTIONS (APPLICABLE WHEN DER EXPORT *ALLEVIATES* CONSTRAINT ON NETWORK)				
DB-wide "Network-Support" rebate	Static	**Average** LRMC of managing peak demand across network.	No	DB sets a (static) **rebate** for the **energy** discharged during a **small** set hours/months (e.g., 4-6pm during summer months), reflecting LRMC of managing peak--demand during the periods where capacity constraints **generally** occur on their network.
Area-based Static "Network-Support" tariff	Static	LRMC of managing peak demand by area NOTE: Definition of area up to DNSP	Yes	As above – but both the price and time periods could be differentiated by area to reflect their unique characteristics.
Area-based Callable "Network-support" tariff	Application is Dynamic / Price is static	LRMC of managing peak demand in that area	Yes	Events "called" by network business in advance (e.g., 2-hours in advance) - by area - as opposed to it being based on a pre-set time of day/month combination. NOTE: Rebate amount is still pre-set by area.
Market for network support	Dynamic	Market-driven, capped for each area based on SRMC (ie VCR).	Yes	Offers "called" for by network business in advance (e.g., 2-hours in advance) for 'at-risk' areas, with final price based on marginal offer of the network support that is dispatched in that area (given supply/demand characteristics in that area, up to network business' capped price for that area).

Costs of managing voltage within required levels on shared network

Key points made in Cost Driver Paper

1. Theoretically, if the network were to send a price signal regarding the management of voltage fluctuations on the network, customers would be faced with the correct economic price signals to inform their investments in, and operation of, DER equipment.

Objective of Pricing DER for this service

- Everything else being equal, we want a price signal that incentivises customers to, amongst other things:
  - Charge batteries during otherwise high voltage events (i.e., to soak up energy that would have been otherwise exported to the grid, causing high voltage issues);
  - Discharge batteries during otherwise low voltage events;
  - Increase on-site consumption (in lieu of exporting PV) during otherwise high-voltage events;
  - Decrease on-site consumption (and in turn, increase PV export) during otherwise low voltage events; and
  - Orientate PV to account for the impact PV has on voltage (e.g., incentivize west-facing orientation)

Costs of managing voltage within required levels on shared network

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
DB-wide Static Voltage Support Tariff/Rebate	Static	**Average** LRMC of managing voltage at feeder level across network	No	DB sets a (static) **tariff** for discharge during set hours/months (e.g., 2-6pm during spring months), reflecting LRMC of managing voltage during the periods where **over-voltage** issues **generally** occur on their network. DB sets a (static) **rebate** for discharge during set hours/months, reflecting LRMC of managing voltage during the periods where **under-voltage** issues **generally** occur on their network.
At-risk feeder Static Voltage Support tariff	Static	LRMC of managing voltage by at-risk feeder	Yes	As above – but differentiated by at-risk feeder (and no price signal for feeders where no voltage issues foreseen)
"Callable" voltage support tariff	Application is Dynamic / Price is static	LRMC of managing voltage by feeder	Yes	Events "called" by network business in advance (e.g., 2-hours), by feeder, as opposed to being based on a pre-set time of day/month combination. NOTE: Tariff/rebate amount is still pre-set, at a feeder level.
Voltage support market	Dynamic	Market-driven, capped for each feeder based on SRMC	Yes	Offers "called" for by network business in advance (e.g., 2-hours) on at-risk feeders, with final price based on marginal offer that provides required voltage support for that feeder (up to network business' capped price for that feeder).

Direct Connection Costs

Key points made in Cost Driver Paper

1. There are almost always costs associated with connecting a new customer to the existing shared network.
2. Customers should be charged up-front for any direct connection costs, being those costs that are only able to be affected by an individual customer’s connection decision.
3. This would facilitate the connecting customer making efficient upfront investments in DER, as, everything else being equal, they would invest in DER up to the point where the marginal benefit (being the reduction in their direct connection costs) exceeds the marginal cost.

Objective of Pricing DER for this service

- Everything else being equal, we want a price signal that incentivises customers to:
  - Install DER where it economically reduces upfront direct connection cost
  - This includes:
    - Customers making efficient decisions to NOT in fact connect to the grid in the first place and instead, adopt a SAPS solution
    - Customers making efficient decisions to invest in DER that reduces the cost of their direct connection costs.

Direct Connection Costs

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Direct connection charge*	Dynamic	Forecast actual costs	Yes	This would involve all direct connection charges being charged to the connecting customer. A connection charge reflects the costs the DB incurs in connecting a customer to their **existing** shared network, and which only that customers' upfront connection decision can influence (i.e., no other party is able to influence that cost). This would incentivise efficient investments in DER.
Deep(full) connection charge*	Dynamic	Forecast actual costs	Yes	This would include the direct connection costs plus any impact that a customer's connection decision would have on the timing of the distribution business' forecast investment in the shared network (i.e., as a result of development X, augmentation of asset Y needs to be 'brought forward' by 5 years, relative to the DB's original, least-cost planning scenario). Ed Note: So if a connection, or a development is "out of sequence", the connecting customer would be charged the bring-forward costs stemming from that out of-sequence development. To the extent that development in that area was planned for at that time, any future shared network augmentation costs should already reflected in the DuOS tariffs charged to customers. This would incentivise efficient investments in DER.

** This could be converted into a **rebate** to a connecting customer with DER, via the DB estimating the impact that a customer's investment in DER would have on their shallow / deep connection costs, as opposed to the customer doing it themselves and then deciding what is the most economic solution.*

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Extension of existing shared network

<u>Key points made in Cost Driver Paper</u>

1. New developments/service areas that require the shared network to be extended should be provided with an up-front price signal that reflects the size and timing of those up-front extension costs.
2. The signalling of these network extension costs upfront would facilitate prospective new developments making efficient upfront investments in DER, as, everything else being equal, they would invest in DER up to the point where the marginal benefit (being the reduction in the NPV of the upfront extension costs) exceeds the marginal cost of the DER.
3. Due to the bespoke nature of the costs, some form of area-specific developer or new customer connection charge may be appropriate.

<u>Objective of Pricing DER for this service</u>

- Everything else being equal, we want a price signal that incentivises customers to, amongst other things invest in DER upfront if that reduces the costs of extending the shared network

Upfront cost of extending existing shared network

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Area-based extension rebate (1)*	Static	Area-based estimate of benefit to DB of an individual connecting customer installing DER	Yes	A **rebate** to an individual customer reflecting the impact that that customer's upfront investment in DER is expected to have on the timing and/or size of any investments that the distribution business has forecast as being required in extending the shared network to service them.
Area-based extension rebate (2)*	Static	Area-based estimate of benefit to DB assuming some broader take-up rate of DER in that area by customers being serviced by extension asset.	Yes	A **rebate** to a customer reflecting the impact that that customer's upfront DER investment is expected to have on the timing and/or size of any investments that the distribution business is forecasting to have to make in extending the shared network. Further to this assumption, the rebate assumes that other customers in the area would also take-up some DER in the future.

**The choice may be a function of the DB's planning assumptions (e.g., does it assume, for the purposes of sizing an extension asset, that all future customers have DER or not). Use of rebates and charging to manage this issue.*

Future augmentations of assets that were originally extension assets are covered under "shared network augmentations".

Shared network augmentation costs - Driven by Peak Demand

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
NETWORK SUPPORT "REBATE" OPTIONS (APPLICABLE WHEN DER EXPORT *ALLEVIATES* CONSTRAINT ON NETWORK)				
DB-wide "Network-Support" rebate	Static	**Average** LRMC of managing peak demand across the **low voltage** network.	No	DB sets a (static) **rebate** for **maximum discharge (kW)** during a small set hours/months (e.g., 4-6pm during summer months), reflecting LRMC of managing peak--demand during the periods where capacity constraints **generally** occur in the LV part of their network.
Area-based Static "Network-Support" tariff	Static	LRMC of managing peak demand in LV network by area NOTE: Definition of area up to DNSP	Yes	As above – but both the price and time periods could be differentiated by area to reflect their unique characteristics.
Area-based Callable "Network-support" tariff	Application is Dynamic / Price is static	LRMC of managing peak demand in LV network in that area	Yes	Events "called" by network business in advance (e.g., 2-hours in advance) - by area - as opposed to it being based on a pre-set time of day/month combination. NOTE: Rebate amount is still pre-set by area.
Market for network support	Dynamic	Market-driven, capped for each area based on SRMC (ie VCR).	Yes	Offers "called" for by network business in advance (e.g., 2-hours in advance) for 'at-risk' areas, with final price based on marginal offer of the network support that is dispatched in that area (given supply/demand characteristics in that area, up to network business' capped price for that area).

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Replacement costs

<u>Key points made in Cost Driver Paper</u>

1. Where the amount of DER is such that it is able to offset the entire load of the shared network asset that is due for replacement, then it would allow the network business to avoid adopting a network replacement solution in totality.
2. This economic benefit – being the avoided cost of replacement – should be reflected in either the servicing solutions considered by distribution businesses at the time of replacement, or, to the extent that the locus of control is with customers, then this avoided cost needs to be signalled to end customers in order for them to make efficient investment decisions in SAPS.

<u>Objective of Pricing DER for this service</u>

- Everything else being equal, we want a price signal that incentivises customers to invest in DER where it may, in the long-run, reduce a distribution business' replacement costs. An example of this might be on long–rural feeders where it may be more efficient to use a SAPS system in lieu of replacing the existing network (e.g., SWER).

Replacement costs

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Rebate for disconnection	Static	Avoidable cost of supply	Yes	Publish a rebate for customers in certain areas where replacements are: • Likely to be required in the near-term; and • Likely to be uneconomic, related to an alternative distributed solution. The rebate amount would be linked to the DB's avoidable cost of supply (which should in theory be calculated under the Rules)
Market-driven rebate for disconnection	Dynamic	Market-driven, capped for each area by avoidable cost of replacing existing network.	Yes	Customers in certain areas allowed to provide "offers" to the DB to disconnect (i.e., I will disconnect, for $10,000). DB collates offers and assesses whether it is more efficient for them to accept disconnection offers (individually, or collectively) as compared to replacing the existing network.

NOTES

1. Any marginal impact on the sizing of any shared network replacement solution should be picked up in the shared network pricing.
2. The two options presented above in theory should achieve the same economic outcome, the difference relates to who shares in the economic surplus (customers under the first one; DBs in the second option)
3. The two approaches outlined above could also be extended to include the expected value of the **bushfire risk** that might be *avoided* if an existing customer disconnected from the grid.

Pricing of DER for economically efficient integration with the electricity supply chain

PRICING STRUCTURES FOR DER SERVICES TO MARKETS AND MARKET OPERATIONS

Pricing approaches for market ancillary services

Key points made in Cost Driver Paper

- The market operator must ensure that sufficient ancillary services are available to the market.
- DER is a good source of Frequency Control Ancillary Services (FCAS) and some integration is already occurring.
- Some forms of DER, batteries and distributed generation, are able to provide other ancillary services.
  - System Restart Ancillary Service, probably in association with a larger plant (i.e., a “starter motor”)
  - Regulation services and Fast Frequency Response
  - Reactive power (Voltage support)

Objective of Pricing DER for this service

- Ensure the DER is available to supply the service as required as prices are generally low.
- Allow DER to compete on an equal footing to supply side services where possible.

Technical issues for ancillary services

- Frequency control and regulating ancillary services require high speed metering to be measured and assessed for payment. This is now available cheaply.
- SRAS contracts require large capacities to restart the grid. Normal DER supplies could be used in conjunction with conventional power stations as the “starter motor”, like the Dry Creek/Torrens
- Reactive power from DER is only useful in the absence of alternative approaches due to network approaches and Rules limitations of connected entities.

Pricing approaches for Ancillary Service

Charges, rebates and payments	Static / Dynamic Price	LRMC/SRMC/ Market	Vary by location	Comment
Frequency Control Ancillary Services - allow access to the markets (status quo)	Dynamic	Market – offer availability	No	The FCAS markets allow any party that can access them to offer services for a price. In addition, it is possible to aggregate supplies, although the metering requirement limits this option.
Regulation Services - fixed contract approach	Static	LRMC	Yes	It could be possible to purchase low cost regulation, particularly from storage devices.

DER impact on wholesale investment and operation

Key points made in the Cost Driver paper

- The wholesale energy market must pay for investment in plant and the efficient dispatch of available plant.
- In the NEM, the energy-only design means that both of these costs must be met through pool trading, financial contracts, and to a lesser extent some bilateral, physical contracts
- One means for integrating DER with centralised generation and the grid would be via the pool, which could optimise the sources to meet the investment and operational costs associated with aggregate demand.
- DER (including DR) can potentially reduce these investment and operational costs both by providing a lower cost of supply during dispatch and also by being contracted for future supplies of energy.

Objective of Pricing DER for this service

- Provide DER as an alternative to investment in supply to avoid unnecessary construction of generation and network.
  - Timing is an issue as investment occurs well ahead of dispatch
  - Participants and AEMO need to know available capacity at least 12 months ahead
- Reduce the operational costs of the NEM by allowing cheaper alternatives to be
  - employed in the dispatch process; or
  - used to reduce Operational Demand*.
- DER can reduce system losses but this is a second order effect and difficult to quantify.

* Noting that Operational Demand is the requirement for dispatched plant to meet measured demand. Measured demand is actual demand net of DER provided outside of the dispatch process.

Issues in translating the costs

- Wholesale Market Costs
- Cost of investment → Arises at the time of investment not use
  - Construction and commissioning
  - Land and related costs
  - Cost of connection (mainly network costs but recovered in the market)
  - Establishment of market facilities
- Cost of operations → Arises at the time of use
  - Fuel
  - O&M
  - Licence and participation (both generation and retail)
- Issue is transfer to retailers, aggregators and customers vs DER alternative
  - Pool costs are a combination of:
    - Financial ($ per MW) based on expected demand
    - Pool costs ($ per MWh) based usage (includes allocated market operation costs)
  - Retailer direct purchases (dispatchable PPA or purchase from VPP)
    - Usually a combination of fixed capacity charges plus usage (similar to a cap)

Wholesale integration pricing approaches

Charges, rebates and payments	Static / Dynamic Price	LRMC/SRMC/Market	Vary by location	Comment
Integrate DER pricing into dispatch – pool impacts (expand status quo) - Contracts below	Dynamic	**SRMC** impact • avoided fuels and market costs **LRMC** impact • Dispatch of DER will be picked up in SOO and other forecasts and replace investment in other supply	Regional (vary with losses and constraints)	Allow FRMP to offer DER on a firm dispatch basis into the NEM dispatch process • Retailer to be the FRMP (simplest case) • Multiple FRMPs at a site to allow Aggregators/DER providers or customers to participate as well as retailers (requires Rule change) • Contracts between FRMP and customers or DER providers to be unregulated.
Regulated FIT for DER products imposed on FRMP (Status Quo)	Static or Dynamic	As above	Possible	Retailers (as FRMP) required to offer reduced charges or rebates. This could be to aggregators, DER providers.
Status quo but supported by efficient consumption and export tariffs for end users	Static or dynamic	As above with additional **LRMC** benefit that FRMP can incorporate contracts into its portfolio and reduce investments.	Possible	Retailers (as FRMP) charge efficient charges and can therefore customers can value DER correctly for capacity/demand and energy benefits. Aggregators, DER providers and customers supply services to the FRMP via unregulated contracts. FRMP to incorporate into its risk management process
Financial contracts	Static	Primarily **LRMC** to avoid investment but also **SRMC** as pure price risk management.	No	Allow DER providers as FRMPs to participate in the Exchange based and OTC contract markets, allowing the FRMP to incorporate the capacity and energy into its risk management process

Recap of market operation (reserves) cost drivers

Key points made in Cost Driver Paper

- The market operator has to ensure the correct amount of reserves in the market. The level of reserves required is forecast and calculated by AEMO on the basis of the USE standard set by the Reliability Panel.
- Ideally, the correct level of reserves should be met by normal market operations. To the extent that the level is not achieved, AEMO must intervene based on its best judgement of the likely shortfall.
- DER (particularly DR through load reduction or the use of behind-the-meter standby generation) has been proven to be a good source of emergency reserves.

Objectives of Pricing DER for this service

- Reduce the need for reserves by providing a pool of DER resources that can be used by market participants to enhance their reserves
- Provide a more flexible and cheaper source of reserves than traditional, supply-side options

Issues in using DER for market reserves

- Reserves are a capacity product not an energy product → need tools to measure or estimate capacity
- Market reserves are purchased for emergency and reliability needs → quantities need to be firm
- Emergency reserves need to be in addition to reserves otherwise available to the market
  - → Maximise the use of market available reserves first
  - → Additional reserve is not normally used (aka Strategic Reserve)
  - → Availability is the key (should there be penalties for shortfalls?)

Pricing options for market reserves

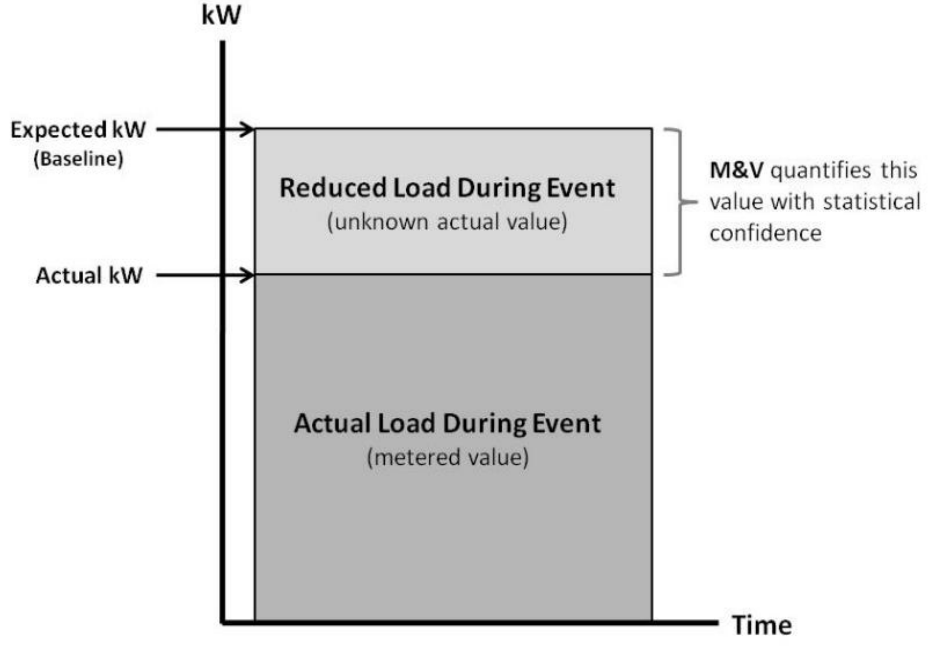
Charges, rebates and payments	Static / Dynamic Price	LRMC/SRMC/Market	Vary by location	Comment
Central purchase – price	Dynamic	Market – tender for supply	Regional	AEMO offers to purchase reserves (all types) for prices up to the VCR. The providers will only be paid an availability and usage payment. AEMO retains the DER income. The reserve can only be used if directed on by AEMO.
Central purchase – volume (RERT var.)	Static (contract)	Market – tender for supply	Regional	AEMO offers to purchase reserves (all types) price for a defined amount. The providers will only be paid an availability and usage payment. AEMO retains the DER income) The reserve can only be used if directed on by AEMO.
Capacity obligation (NEG var.)	Dynamic?	Market	No	Retailers are required to hold an fixed percentage of capacity above their predicted demand on a 10% POE basis. If a blackout occurs, retailers are assessed and penalties applied if sufficient capacity was not purchased. Capacity providers may be required to prove their capability on an annual basis
All of the options above, and other variants, can be optional, based on trigger events.				The optional approach is more like the current RERT (except for availability and pool income) and the suggested NEG.
An underlying principle is that the level of MPC could be set at or above the level of VCR. This would provide incentives for wholesale market participation up to the level of consumer desired demand				Would avoid the need for reserves by ensuring that capacity is available to the level that customers are willing to pay for, *on average*.

ISSUES WITH DEMAND RESPONSE — MEASUREMENT AND VERIFICATION

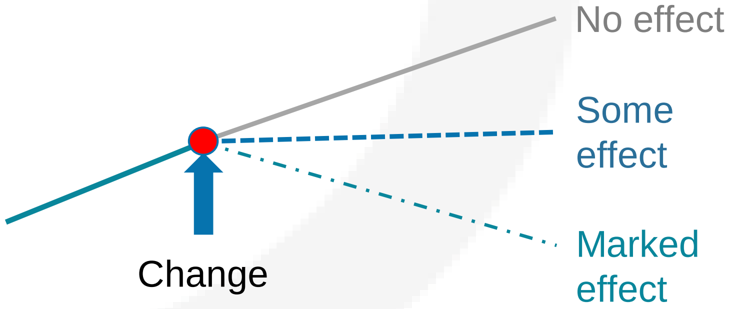
Issues with demand response – measurement and verification

- Measurement of changes is a field of study on its own
- For Demand Response, we are often measuring changes in a profile or array, not a point.
  - The measurement of actual consumption during the DR event period (requires interval metering)
- While subjective measurement can be used, for markets and settlement, an agreed objective measurement is required
- The issue is that we are measuring the counterfactual
  - Requires the development of a customer or portfolio baseline that provides the amount of energy that would have been used.
  - The load reduction is the mathematical difference between the Baseline and Actual Use
  - Baselines can be used at system operator level and individual customer level
- Three types of approaches are typically used
  - Before and after tests
  - Control group test
  - Statistical analysis (regression et al)

Measuring a counter-factual event



Before and after test

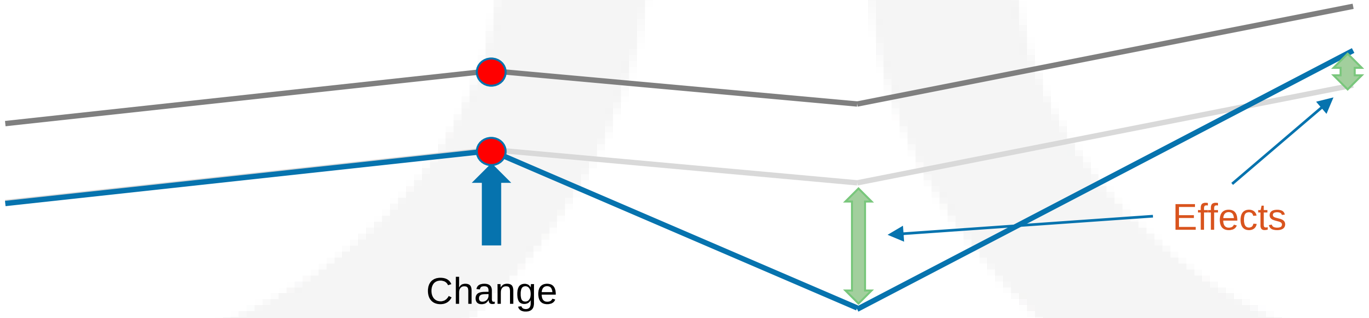


Example

- Supply FCAS in the market
- Objectives
  - Change in demand to reduce frequency drop
  - Lower cost of FCAS

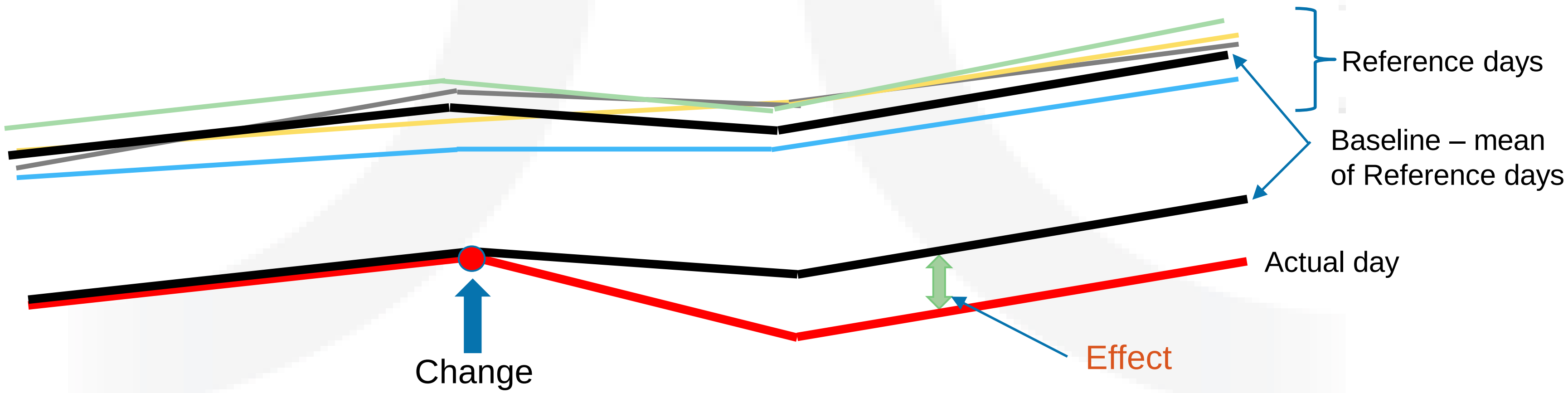
- How does the variable change at a point?
  - Metered value of load reduces and frequency recovers
  - FCAS is short duration, so profile is less relevant
- How would it have changed without the treatment?
  - System recovers on its own
  - How material was the DR in the frequency recovery
- What else has changed?
  - Other providers are also active

Control group approach



- How does a variable change when applied to one group in a matched pair?
- How effective is the matching?
  - Similar house type and environment
  - Similar fittings, cooling and heating
  - Similar households – number of people, ages, habits.
- Sampling becomes the issue
  - Cluster sampling based on suburb type
  - Metadata required
- Double blind studies

Baselining - statistical approach



- How does an event differ from similar, matched circumstances from the past?
  - Select relevant days
  - Develop a baseline by calculation
  - Adjust to make comparable to the actual day
  - Measure the difference
- Need to assess how representative the reference days are and how robust the adjustment is to the actual day
- These approaches have been studied in detail – by OGW and others …

Measurement and Verification in the NEM – initial development

- AEMC in its Power of Choice Report recommended a new Demand Response Mechanism that pays customers via the wholesale market for demand reductions
- AEMO was tasked with to develop demand response mechanism (DRM) and ancillary services unbundling (ASU) arrangements to be implemented in the National Electricity Market (NEM) n 2013.
- As part of the DRM detailed design a number of customer baseline methodologies were investigated to develop a baseline methodology.
  - DNV-GL KEMA were engaged to undertake the detailed study and examined methodologies used in US markets
  - These were then tested with regional data for application in the NEM.
  - Ultimately CAISO 10 of 10 selected as the most accurate.
- The DRM was not adopted – but the CAISO 10 of 10 is used in the RERT and will be used in the WDRM

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

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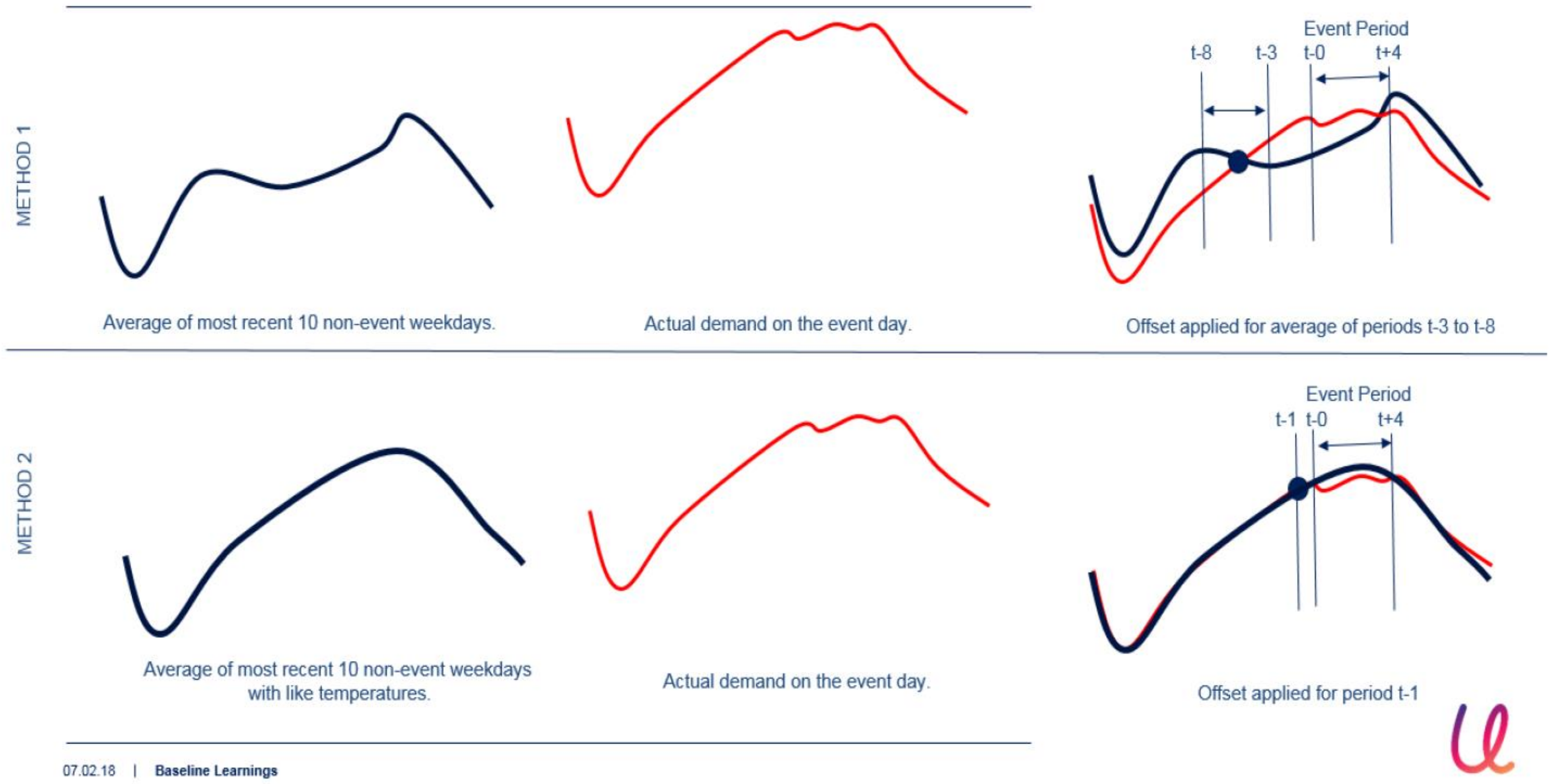
Measurement and Verification in the NEM

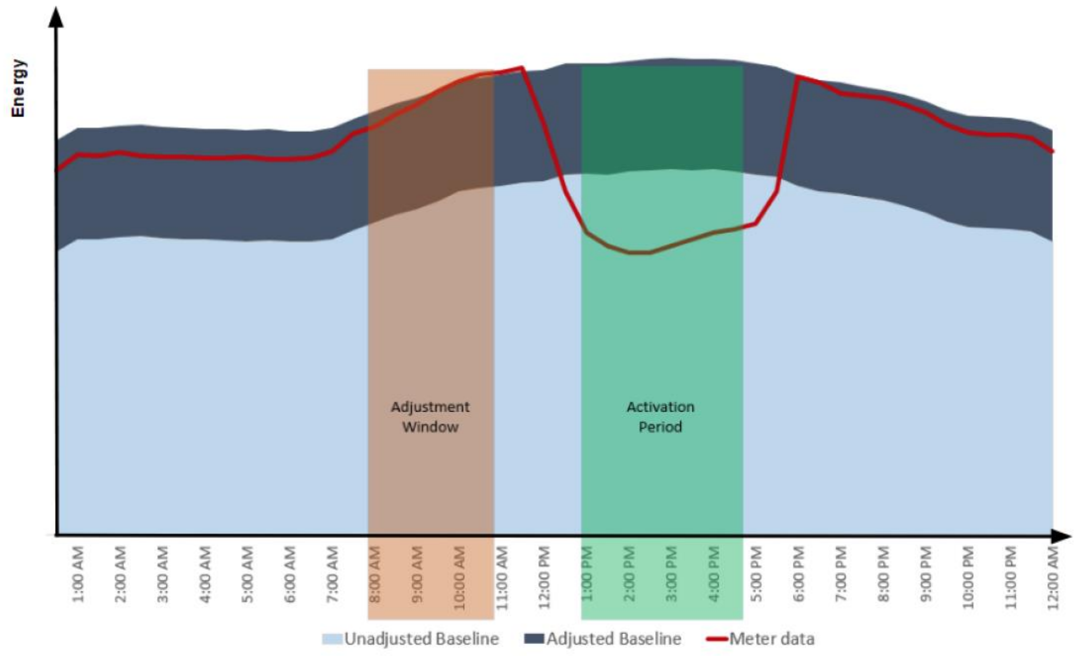
- Key Features of the CAISO 10 in 10
- Baseline window – The baseline window is the period of 45 days preceding the particular day on which demand response is activated.
- Qualifying days – Qualifying days include all days within the baseline window that are not weekends or public holidays, and that did not include a demand response event
- Selected days – Selected days are the most recent qualifying days. A maximum of 10 and a minimum of 5 selected days are required for the calculation.
- Unadjusted baseline energy – This is the average energy consumption for the duration of the demand response event during the selected days.
- Adjustment factor –The adjustment factor is calculated as the difference in the average energy consumption between the demand response day and the selected days across the six half-hour trading intervals   prior to the time at which the demand response activation starts. Often a cap is placed on the adjustment factor to limit gaming.
- Adjusted baseline energy – The adjusted baseline energy is calculated by adding the adjustment factor to each trading interval of the unadjusted baseline.

Suitability of the 10 in 10 methodology – ARENA Program



Measurement and Verification in the NEM

- Limitations of the CAISO 10 in 10
  - best suited to loads that remain relatively stable from day to day, such as certain large industrial and commercial loads. This reflects the nature of loads that have traditionally participated in demand response programs in Australia and the US.
  - Load shape remains consistent day to day – just varies in the amount
- Recruitment of different types of DR for ARENA program highlights the issues for loads where:
  - highly weather sensitive
  - influenced by the impact of rooftop PV generation
  - variable in a consistent pattern; for example, where the facility has a different level or schedule of operation on specific days of the week
  - highly intermittent; for example, where the facility or specific load providing DR is driven by internal business activity factors



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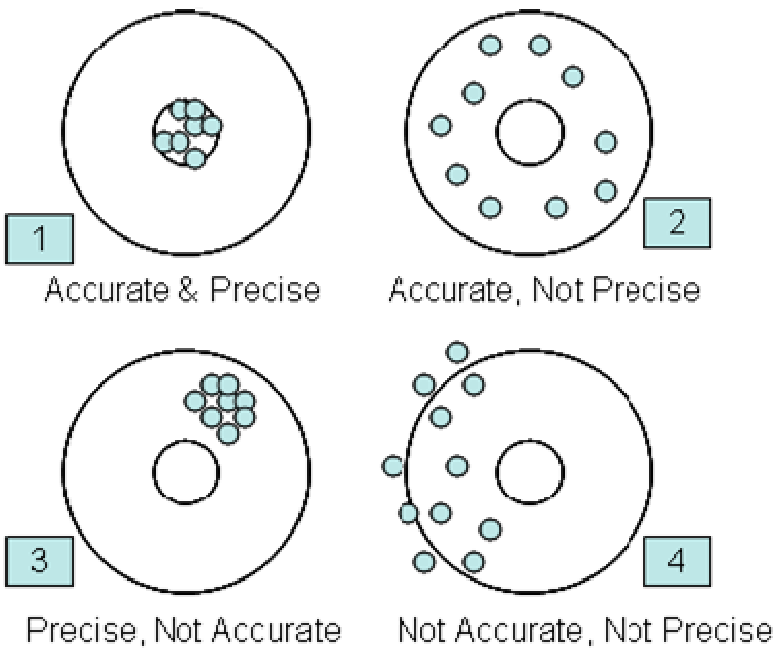
How do you measure the suitability of the baseline?

- Use of statistical tests commonly used to determine acceptability
- Always a compromise between accurate and precise and simplicity
  - never 100% accurate just what is considered statistically acceptable.
- Overall Accuracy and Precision – can use the Relative Root Mean Square of Errors (RRMSE)
  - RRMSE < 10% is considered a good match
  - RRMSE > 20% is considered a high variable load and AEMO uses this as the threshold to review the accuracy of a baseline.
- Accuracy – or bias – is measured by the Average Relative Error
  - The target is zero
- Precision is measured by the Relative Error Ratio
  - examines the variance of the samples.
  - 10 % is considered acceptable
  - Not separately reported as the RRMSE provides this information



How do you measure the suitability of the baseline?

- Interval Metering is also needed for good measurement of DR (5 minute to 30 minute intervals)
- “The almost real-time data of electricity flow allows Australians to take an active part in their energy consumption and control their usage, helping consumers to change their behaviour for the better.” - SMH
- roughly 3.3 million smart meters installed across the NEM, out of 13.6 million meters in total – 2.8 million in VIC.

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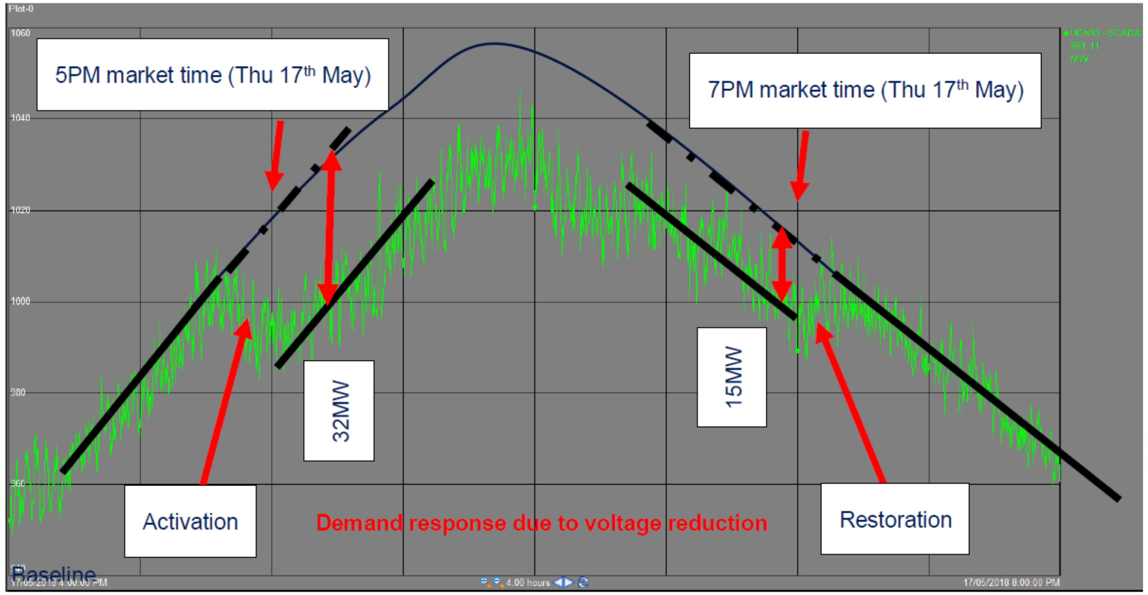
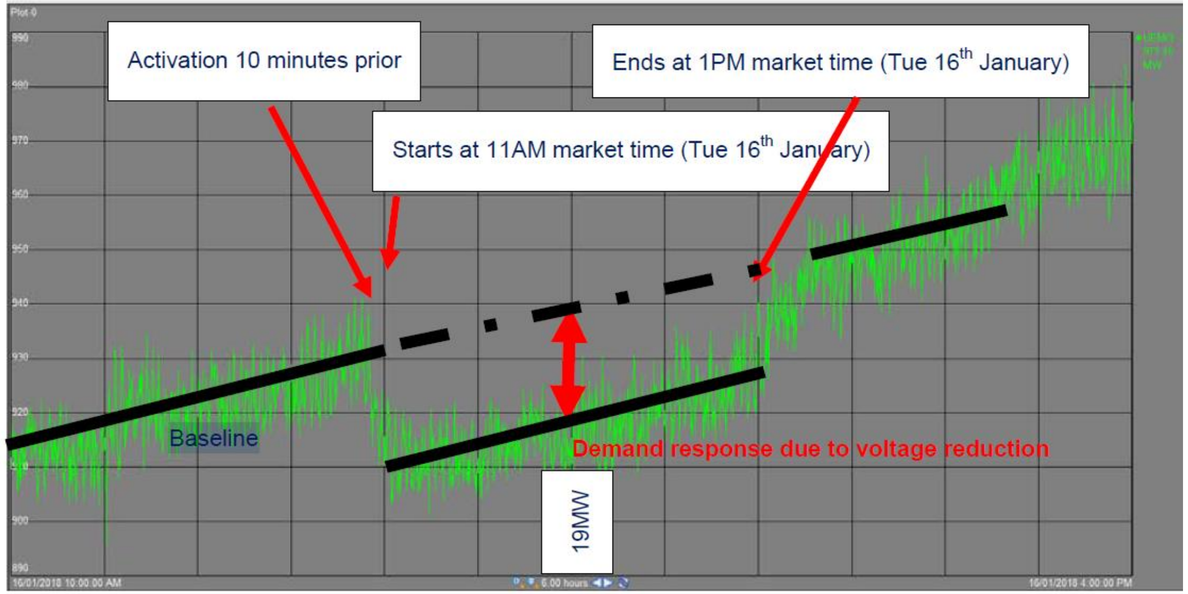
Suitability of the 10 in 10 methodology

- ARENA RERT purchase studies
  - Oakley Greenwood engaged in 2018 by ARENA to investigate and provide analysis on different baseline options following on discussion with participants in the ARENA funded scheme.
  - A year's worth of data of about 10,000 meters – mostly residential
  - Results showed variable effectiveness of 10 of 10
  - Overseas markets moving to more flexible baseline approaches
  - ARENA have published part of the work
- AEMO WDRM baselining studies
  - Examined whether variations to the 10 of 10 approach would improve accuracy
    - Time periods for assessing baselines
    - Methods of adjusting the baseline to the event day
  - Our report recommended some changes could be made
    - AEMO chose to go with minimal change
    - Reports and their determination on the AEMO website

Suitability of the 10 in 10 methodology – ARENA Program

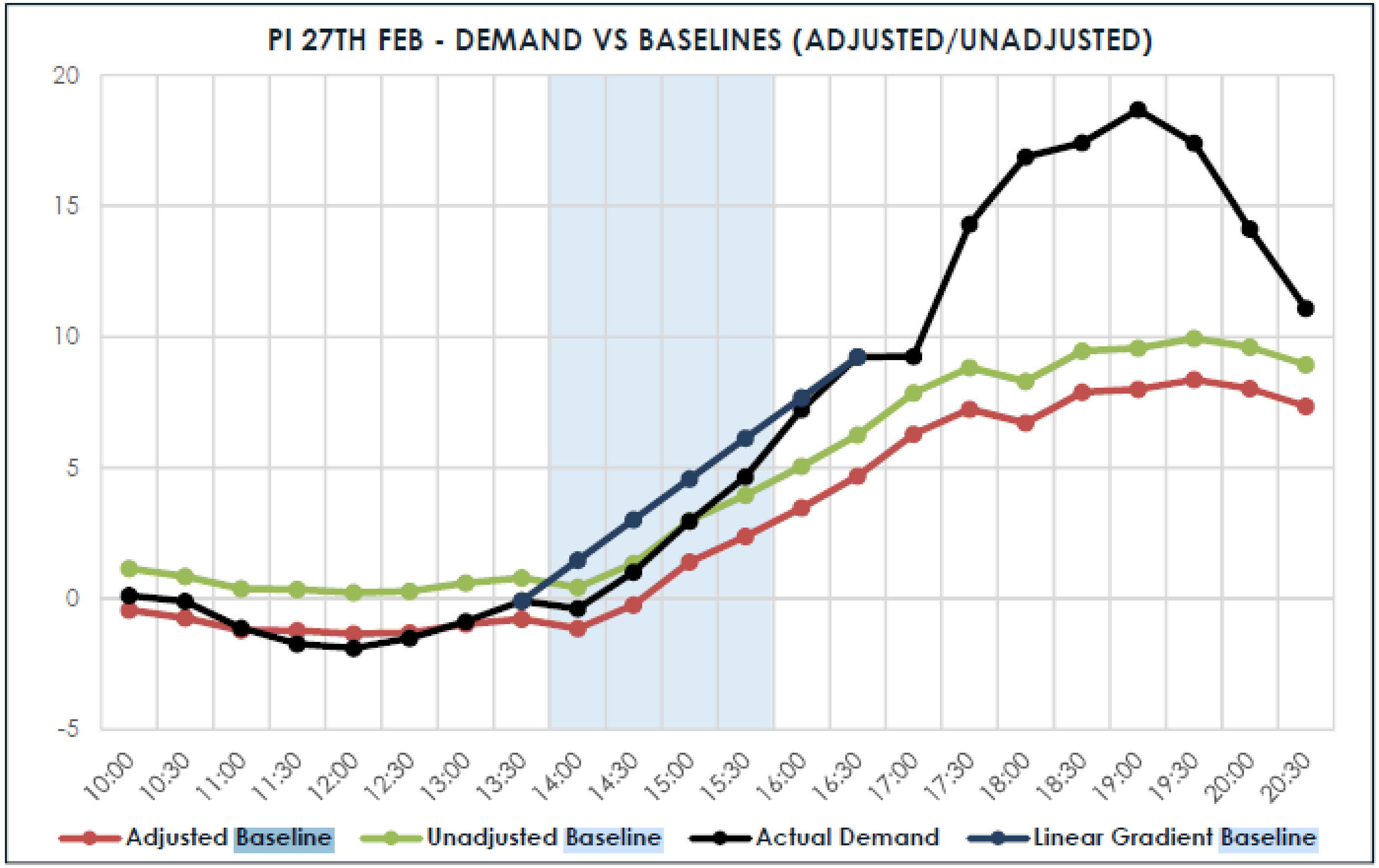




- United Energy – different from others – Direct Load Control.
- Relies on the reduction of voltage at transformer tappings to reduce the overall load (resistive loads)
- Precise measurement of effects using feeder meters
- Indiscriminate and a mix of C,I & R

Suitability of the 10 in 10 methodology – ARENA Program

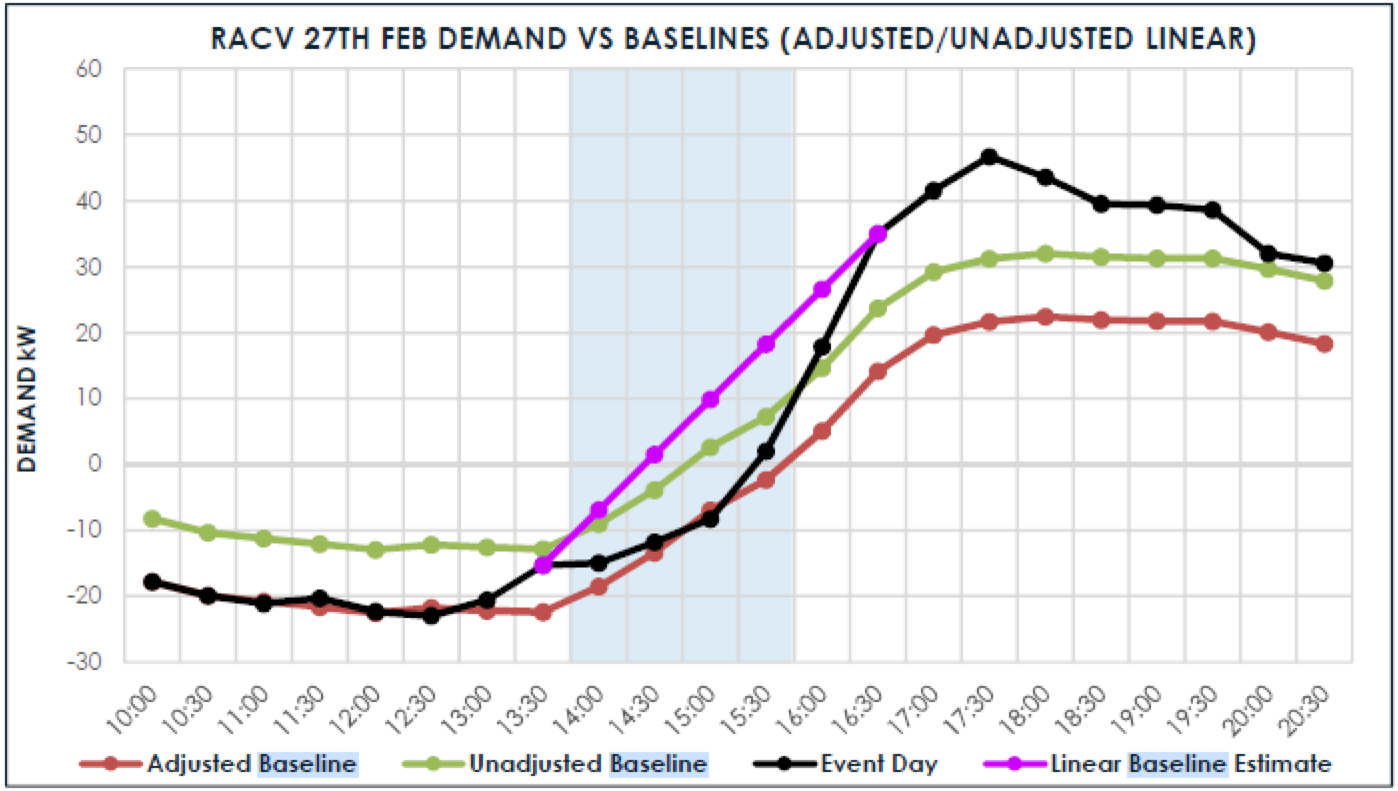
- Zen Ecosystems – issues with behavioural DR



27 respondents

Suitability of the 10 in 10 methodology – ARENA Program

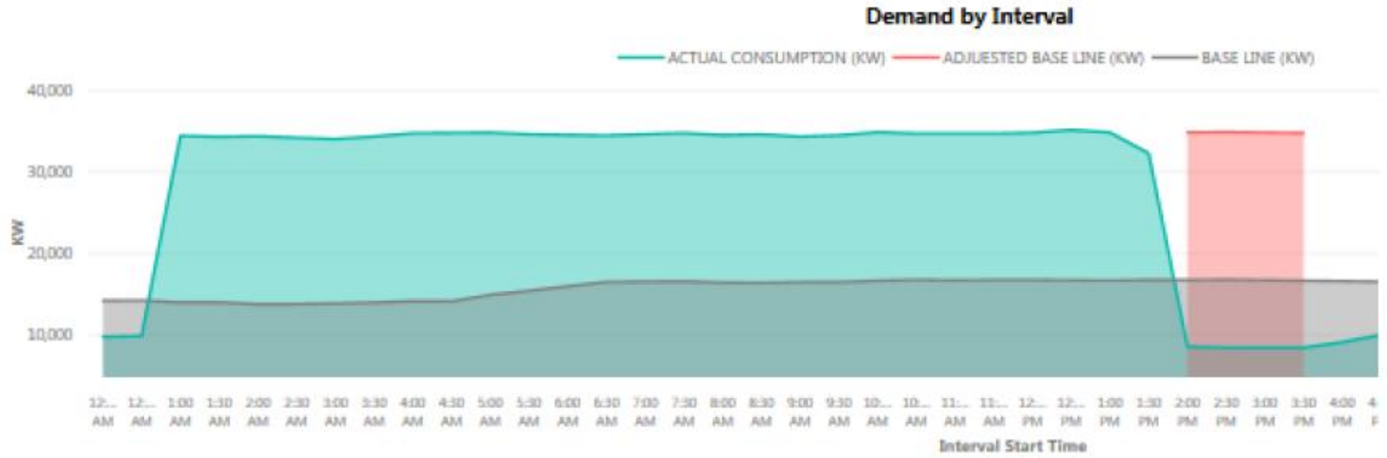
- Zen Ecosystems – issues with behavioural DR



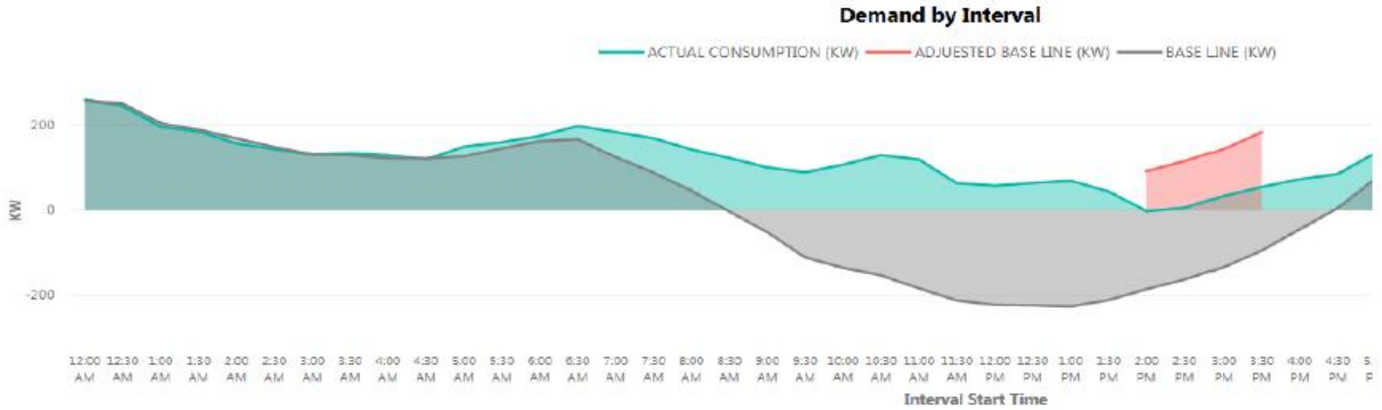
117 respondents – 27 Feb 2018 RACV program

Suitability of the 10 in 10 methodology – ARENA Program

- Energy Australia – C&I load types conform to 10 in 10



NSW Mass Market Test Performance



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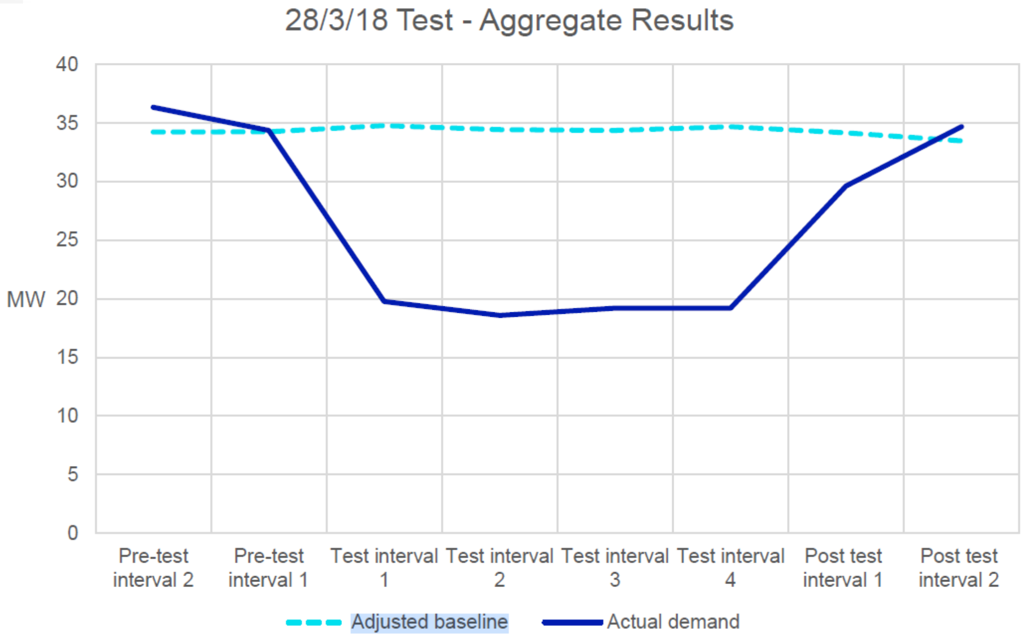
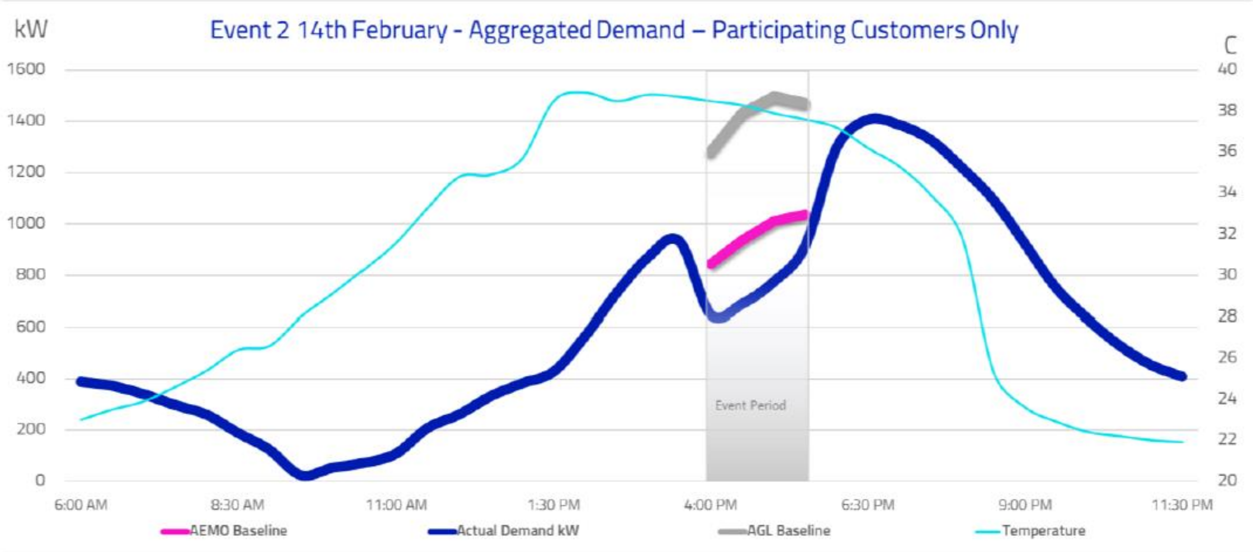
Suitability of the 10 in 10 methodology – ARENA Program

- AGL derived their own baseline for customer measurement.
- AGL – C&I load types conform to 10 in 10
- AGL – Residential loads are under different temperature and household energy use scenarios
  - different results will be achieved, ie the same behaviour change or action may produce a different monetary reward from event to event
  - highly temperature dependent.
  - Even more complexity with rooftop PV





Suitability of the 10 in 10 methodology

- Learnings from the ARENA program and baselining using AEMO 10 of 10 methodology
  - Works fine for constant loads that are not directly affected by other variables such as temperature
  - 10 of 10 methodology doesn't work for residential loads (individual and aggregate) due to high variability in load shape
    - Temperature AC systems
    - Solar PV systems
  - Other load types that are impacted are ones that vary in characteristics on different days
    - Shopping centres with different hours
    - Operations that have shifts or maintenance shutdowns.
- Learnings from the AEMO work
  - The 10 of 10 works best with medium size loads
  - Large loads need a more tailored approach
  - The more consistent the load the better the accuracy and precision of the baseline.

➡ What are the alternatives?

Further work by CAISO - BAWG

- As part of the work completed by OGW for ARENA alternative baseline options were investigated to assess their applicability.
- Recent work by CAISO Baseline Accuracy Working Group (BAWG) most current and well documented at the time and a natural extension of the AEMO 10 of 10 (based on CAISO 10 of 10).
- AEMO baseline method based on CAISO initial approach in 2009 (10 of 10):
  - calculation of an average baseline using the 10 most recent suitable days (out of the most recent 45 days), with an adjustment on the DR event day to correct for the load on the day. The daily adjustment is limited to 20% of the load on the day based on load prior to the event. This is often referred to as the "10 of 10" approach.
  - Excluded variable loads with as an accuracy measurement of >25% RRMSE
  - The Baseline Accuracy Working Group (BAWG) established to assess alternative base lines as 10 of 10 inaccurate for some load types and under reporting DR.
  - noted that the use of a control group was the most accurate method for all classes of customers and particularly for residential customers.
  - other methods provided acceptable accuracy.
  - Most current research and used as the basis for OGW baseline review for ARENA

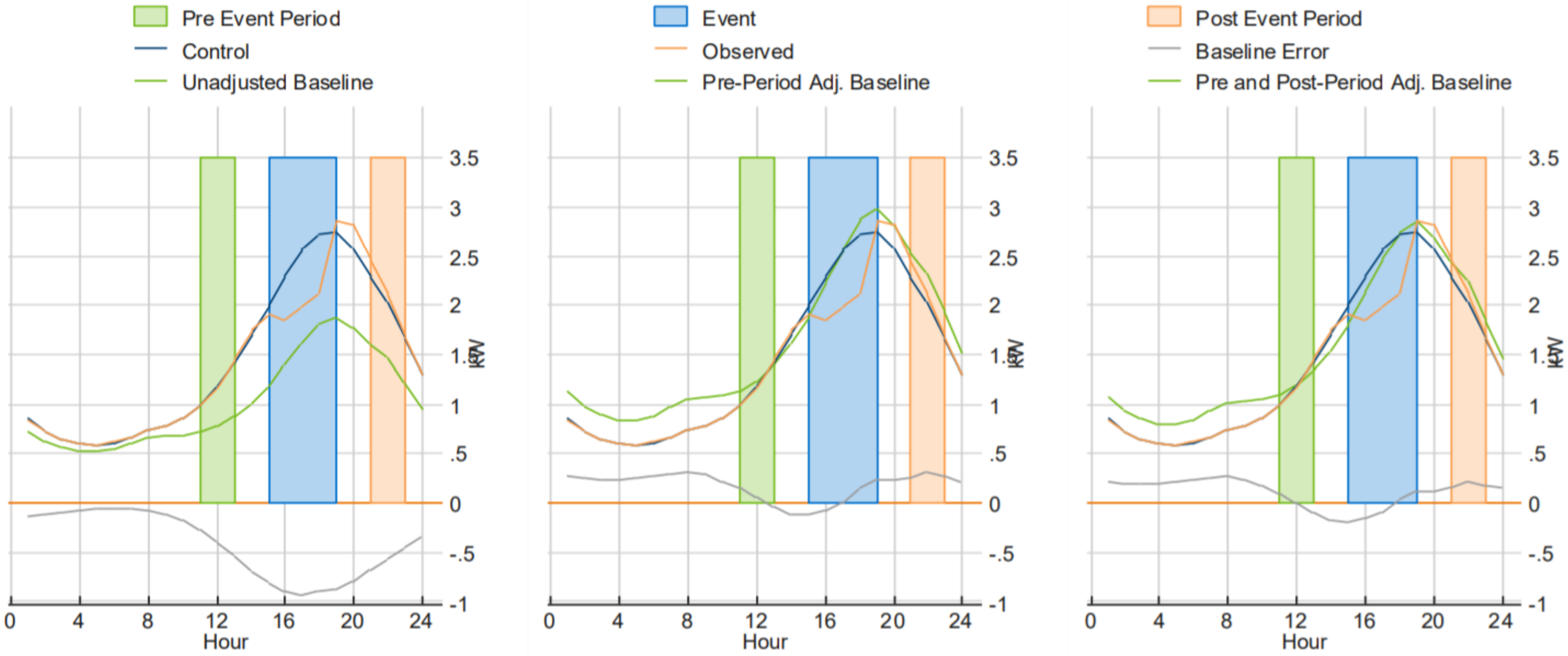
Further work by CAISO - BAWG

- CAISO proposed that:
  - The baselines for residential customers be based on a “4-day weather match” using a control group of similar customers; and
  - The 10 of 10 approach, as currently applied, remain for industrial and commercial customers but augmented by methods that use control groups and the average of the previous 5 days

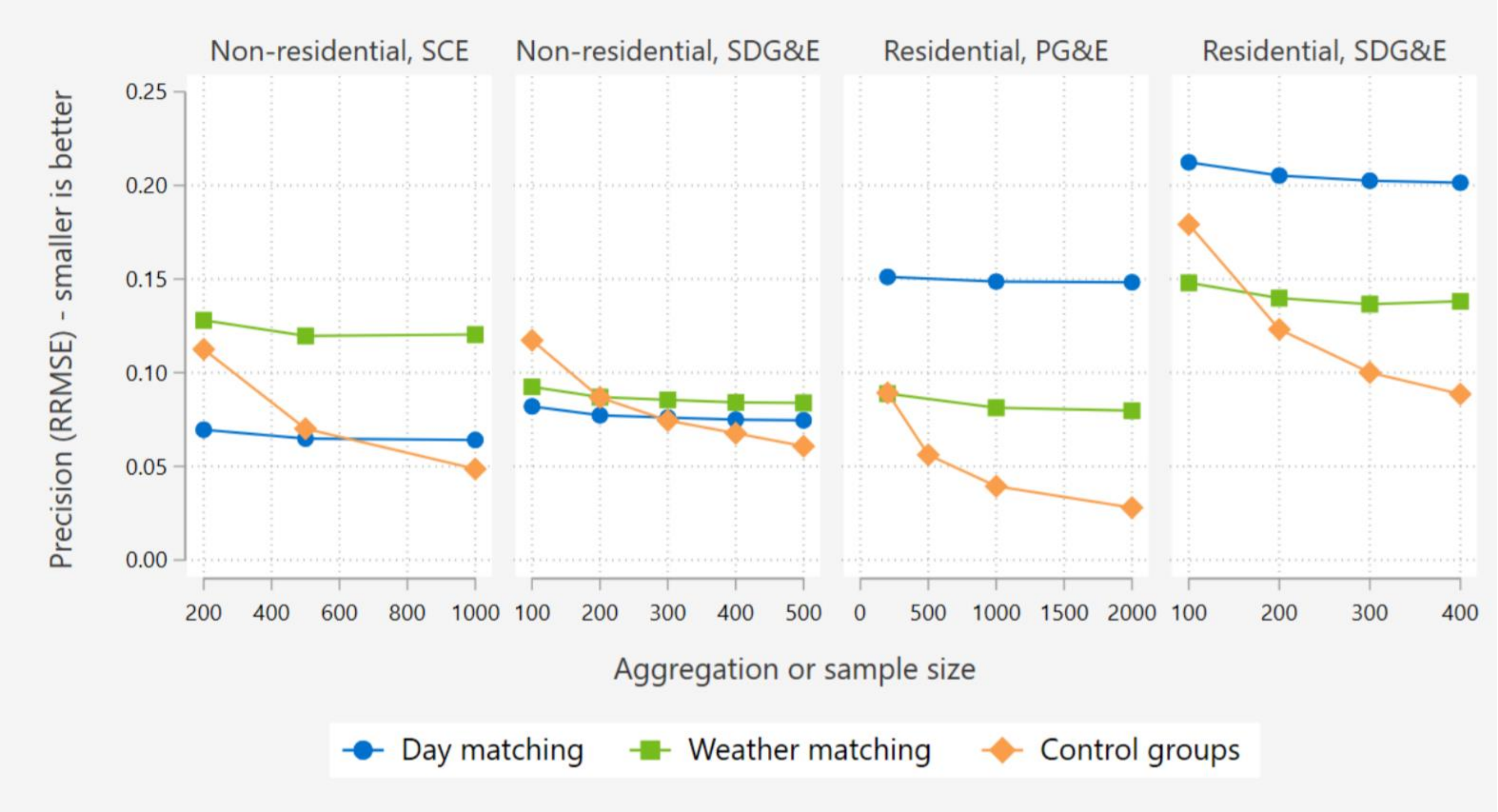
Customer Segment	Weekday	Baselines Recommended	Adjustment Caps
Residential	Weekday	Control group	±40%
		4-day weather matching using maximum temperature	±40%
		Highest 5 of 10, day matching	±40%
	Weekend	Control group	±40%
		4-day weather matching using maximum temperature	±40%
		Highest 3 of 5, day matching	±40%
Non-residential	Weekday	Control group	±40%
		4-day weather matching using maximum temperature	±40%
		Highest 10 of 10, day matching	±40%
	Weekend	Control group	±40%
		4-day weather matching using maximum temperature	±40%
		4 eligible days immediately prior (4 of 4)	±20%

Further work by CAISO - baseline differences

- Along with weather or day matching selection of days
- CAISO same day adjustment factor changes:
  - Moving from a pre only to pre- and post- adjustment factor
  - Adjustment factor increased from = +/-20% to +/-40%

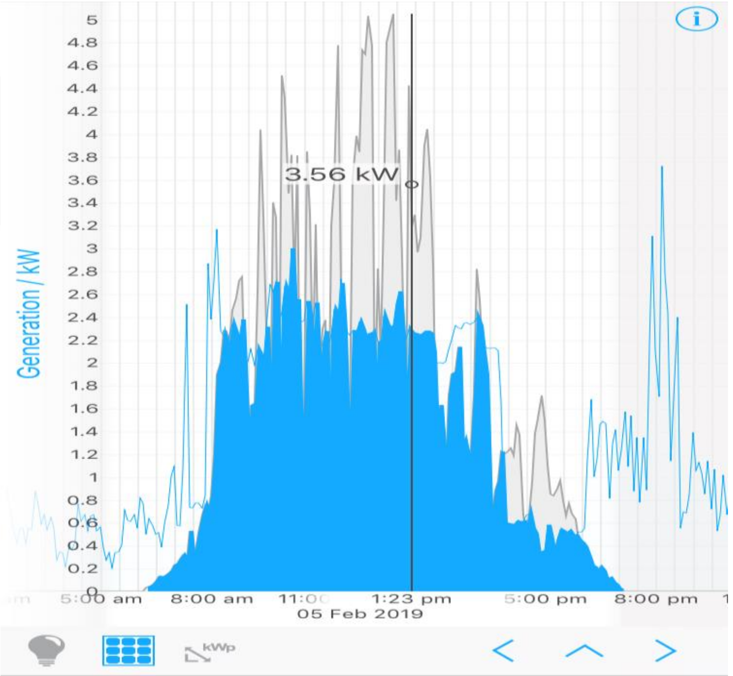


Further work by CAISO – Results



ARENA review

- Work with ARENA considered a number of different baseline options such as
  - weather variable (average and max temperature)
  - same day variable
  - 10 of 10 base case
  - similar outcomes as the BAWG with residentials and weather variables.
  - roof top Solar PV causes havoc with baseline methodologies.
    - Consider it a highly intermittent load of considerable size
    - Some numbers Assume:
    - 15% penetration 3kW average capacity @ nom 60% CF
    - 10000 participants
    - Delivery of 0.25kW reduction per connection DR average (Zen numbers)
    - 2.7MW of solar intermittent on a 2.5MW DR measurement
- Need to separate on-site generation from DR to get valid results
  - There is an issue with metering rooftop PV



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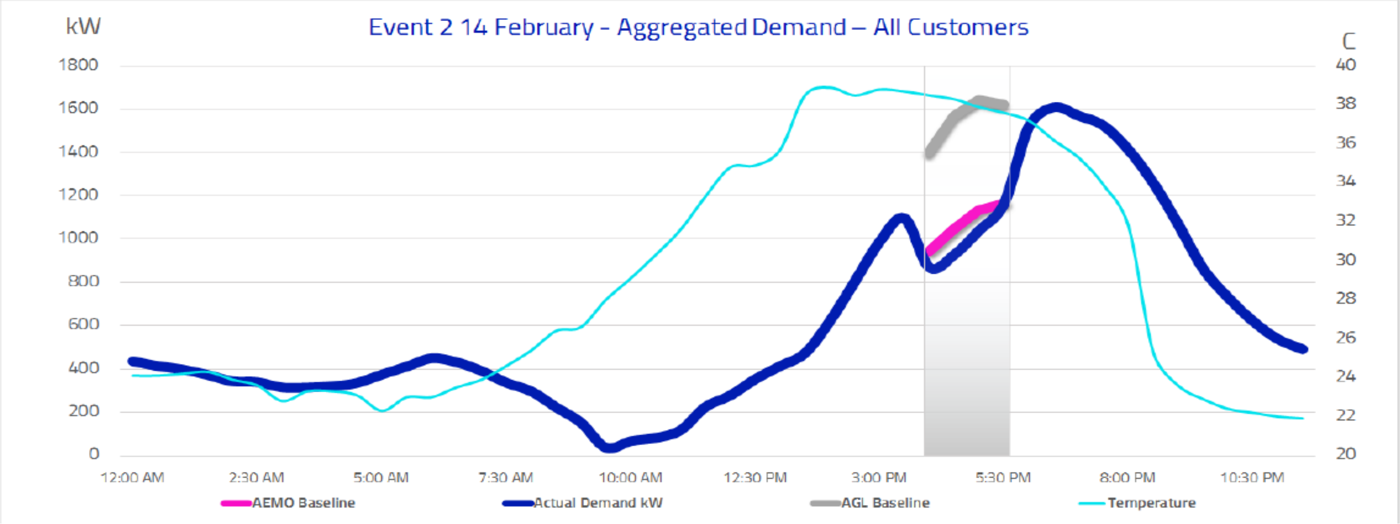
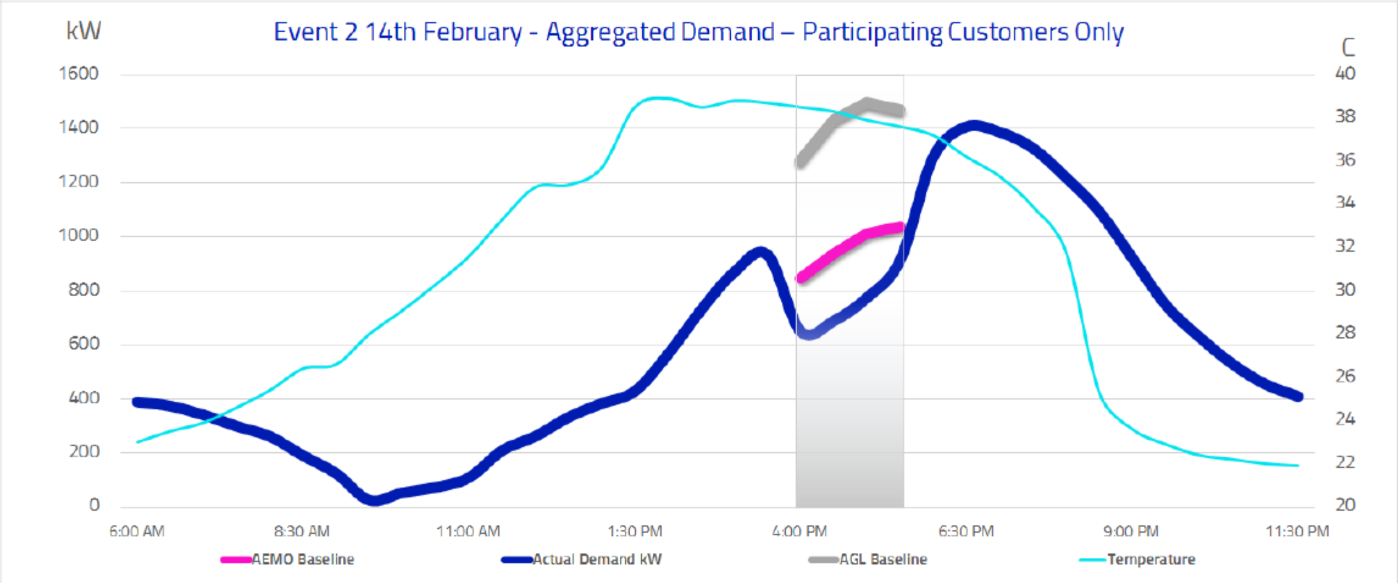
ARENA review - AGL

- AGL has done significant work in baseline investigation – particularly for residential loads
- use an in-house baseline methodology (IP) to calculate the result for individual customers
- averages the usage at a particular time of the day for days of a similar temperature over the last five weeks (week day/weekend) and anchors it to the actual consumption before and after the event. Steps:
  - Generation of a site level forecast based on regression of the previous five weeks net load (load – solar) excluding any controlled load channels against temperature, time of day and workday/non-workday
  - De-biasing by comparing the previous seven days forecasts against the actuals for the same time of day as the event period and adjusting the event period baseline forecast
  - Anchoring the predicted consumption outside the event period to the actual consumption on that day, based on smoothed consumption either side of the event period.
- A key benefit of the AGL baseline, however, is that it appears to perform equally well for both solar and non-solar households.

ARENA review - AGL





Who decides on the market parameters

- During the ARENA work we considered the question on who decides on measurement and verification
- In general, we resolved that it is the market maker – usually the purchaser – who makes the call
  - What are they willing to pay for?
  - What errors and accuracy will they accept?
  - What is their purpose in allowing DR?
- Where it is a retailer, network or aggregator, they
  - Receive the efficient market signal
  - Translate it into the signal they want to send to customers or connected parties
  - Accept a level of accuracy *across their portfolio*.
- The issue is more complex where the parties have different objectives and issues, for example
  - Networks wish to reduced load to avoid augmentation
  - Retailers wish to reduce peak only when it saves them money
- Integrated DR avoids this issue by allowing the customer – or their agent – to see all of the signals and make their own trade-offs.
  - Third party agents or aggregators with more sophisticated approaches
  - Trader model or the possible two sided market.

STATUS OF DR IN SELECTED OVERSEAS MARKETS

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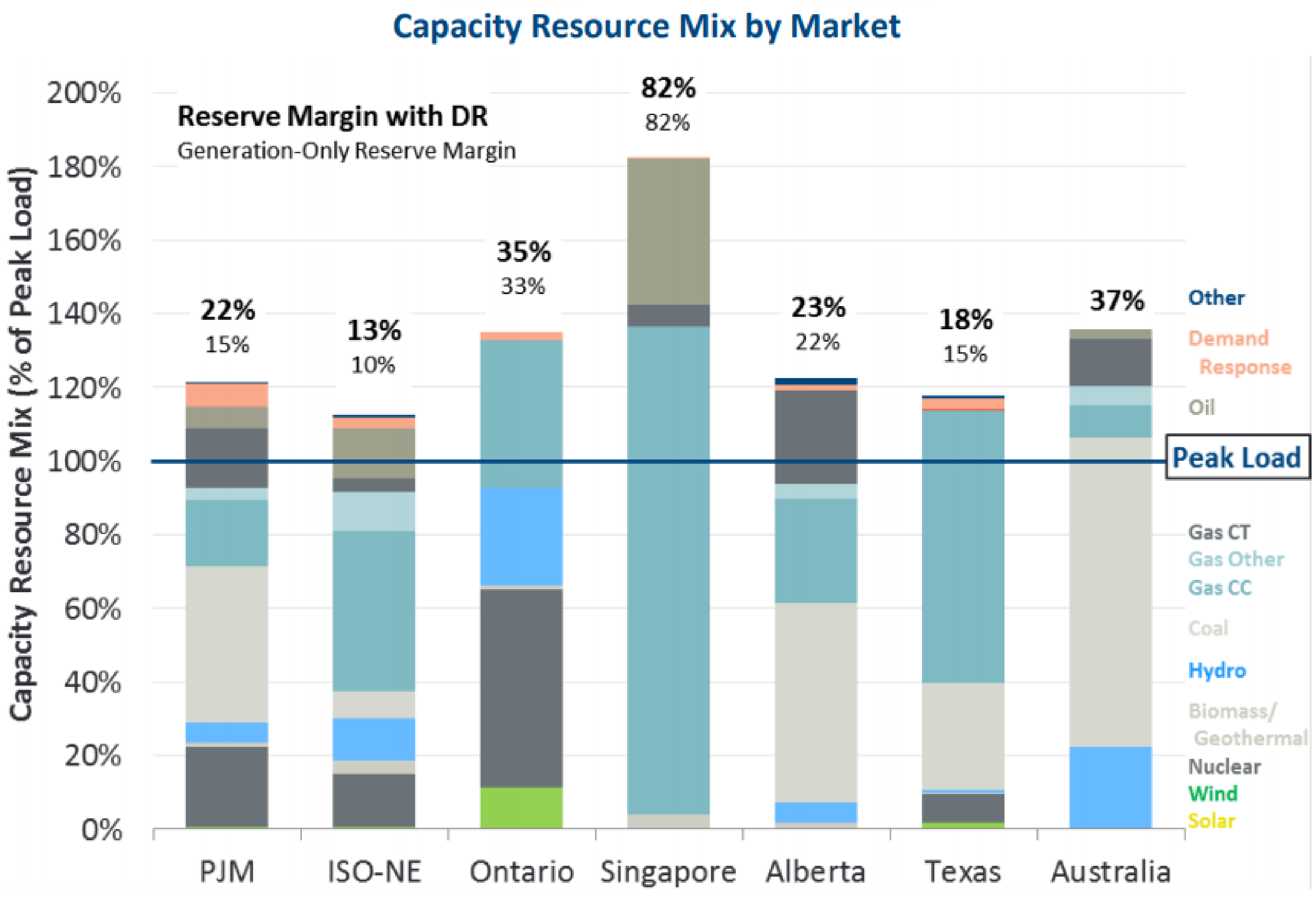
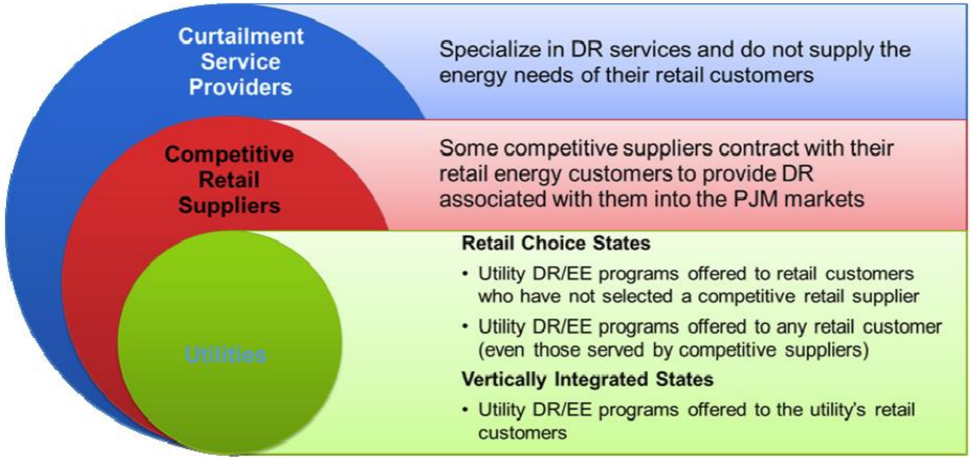
Overseas


Capacity Resource Mix by Market
Reserve Margin with DR
Generation-Only Reserve Margin
Capacity Resource Mix (% of Peak Load)
200%
180%
160%
140%
120%
100%
80%
60%
40%
20%
0%
22%
15%
13%
10%
35%
33%
82%
82%
23%
22%
18%
15%
37%
PJM
ISO-NE
Ontario
Singapore
Alberta
Texas
Australia
Peak Load
Other
Demand Response
Oil
Gas CT
Gas Other
Gas CC
Coal
Hydro
Biomass/ Geothermal
Nuclear
Wind
Solar

PJM Interconnection, USA

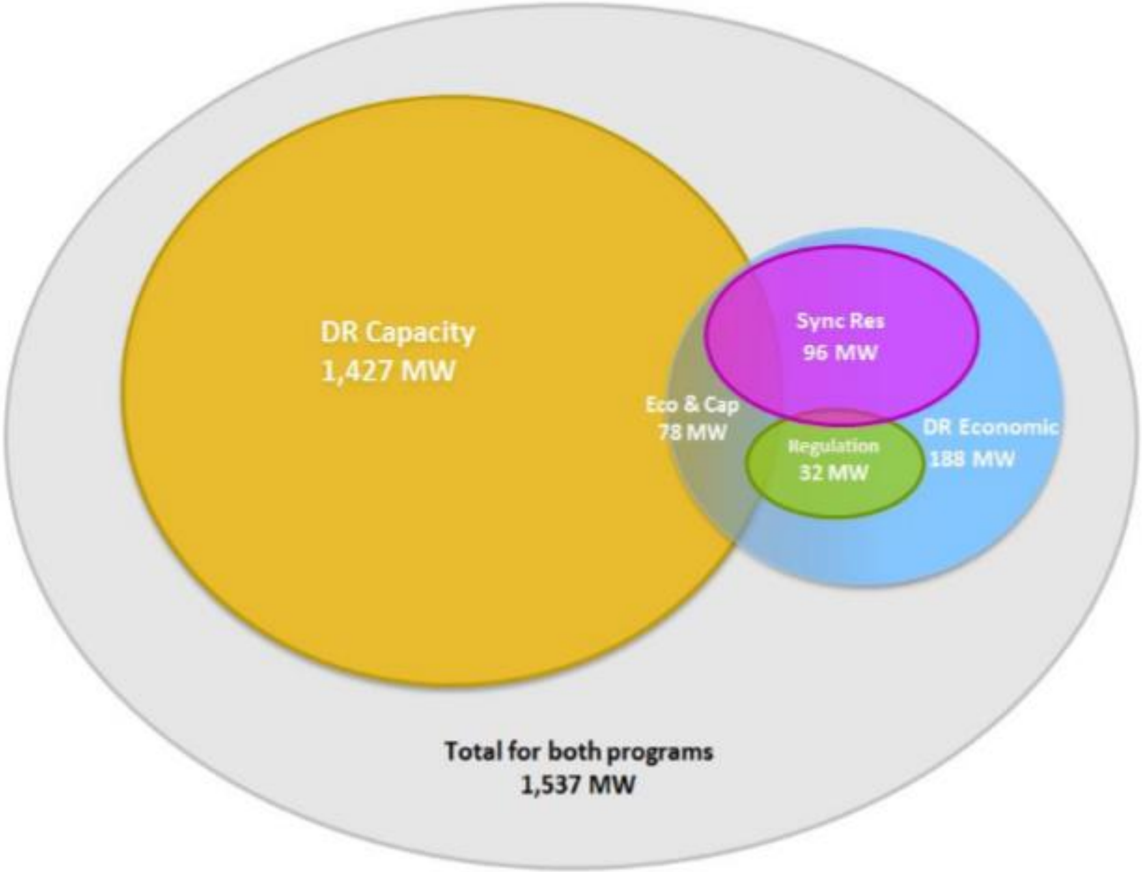
- PJM interconnection is one of the most successful markets for integrating DR, allowing participation in all aspects of its operations:
  - Retail market mechanisms (not strictly PJM)
  - Wholesale capacity mechanism & emergency capacity provision
  - Wholesale energy day ahead & balancing markets
  - Ancillary Services provision
  - Network support contracts.



- A key to the success is the use of Aggregators
  - Energy Distribution Companies
  - Curtailment Service Providers - wholesale market participants
- A range of mechanisms for measurement and verification
  - Hourly interval metering or load control as a minimum*

DR outcomes for PJM in 2018

- Total of 1,537 MW
- The bulk is in the Capacity market



Overseas - France

- NEBEF
  - Introduced to combat volatility due to intermittent generation
  - Highly interconnected with adjacent power systems
- Markets
  - Retail
  - Wholesale Capacity
  - Wholesale Energy
  - Network support

	For balancing and network services		For energy and capacity markets	
	FCR and aFRR primary/secondary res.	mFRR and RR tertiary reserves	Through markets	Within portfolio
Capacity	Provision of services open to consumption sites connected to the transmission network	DR participation to call for tenders for availability	Capacity certificates for DR	Reduction of the capacity requirement
		Implemented	Capacity mechanism	
Energy		Activation of DR-based available offers	Direct valuation in energy markets	Portfolio optimization for suppliers
	Implemented+ experimentation	Implemented	NEBEF	Implemented

- Key points
  - Separate Aggregator in NEBEF scheme (traded blocks of energy), operates in the capacity and energy markets.
  - DR deregulation occurred in 2013 and the capacity mechanism not long after.
  - Energy blocks are traded (in a scheme where the Load Balancing Entity or retailer) is compensated for the DR
  - Trading has reached 1.6 GWh of energy

Belgium

- Commenced in 2013/4
- Markets
  - Retail
  - Network support
  - Wholesale Capacity Mechanism: strategic reserves
- Allow aggregation for the Wholesale Capacity Mechanism
- The network support product, like the Australian AS products is a short acting frequency response.
  - It is called like generation and is limited to two calls per day to a maximum of 40pa
- The Strategic Demand Reserve is an obligation to lower demand to a predetermined threshold on demand.
  - There are two options:
    - Maximum of 40 calls per season of 4 hours duration, no closer than 4 hours apart; and
    - Maximum of 20 calls per season of 12 hours duration, no closer that 12 hours apart.
  - 2,750 MW was available for the winter of 2015-16

Overseas - United Kingdom

- Markets
  - Retail
  - Wholesale Capacity Mechanism

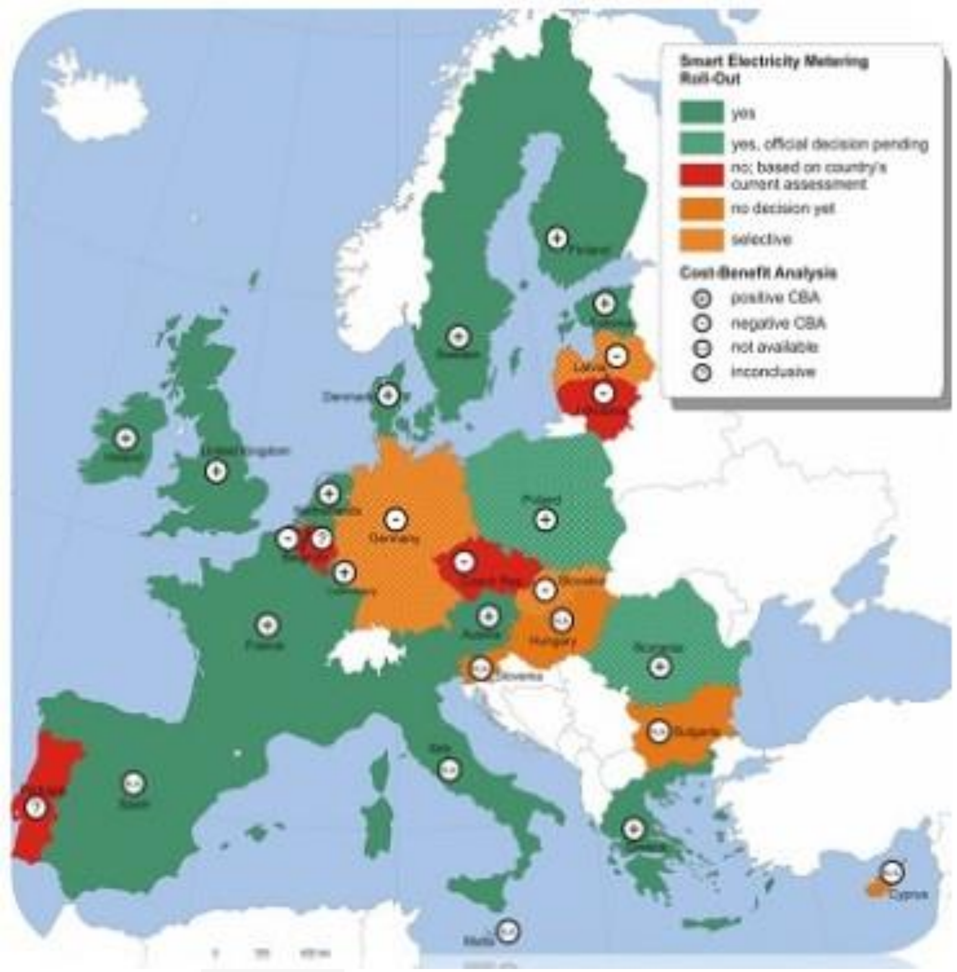
- Key points for Wholesale Capacity Mechanism
  - Aggregation is allowed
  - Market operator purchases verifiable demand reductions via an auction
  - Market operator defines verification processes
  - Reductions must be provided on demand and penalties apply for failure to deliver
  - Around 1,000MW participates in this mechanism

Overseas - USA, California

- Markets
  - Retail energy
  - Wholesale reliability/Capacity
  - Network support
- Current approach for wholesale participation
  - Through the two vertically-integrated load serving entities (retailers), who offer capacity into the Demand Response Auction Mechanism as callable capacity
  - Used to provide reliability to areas with issues
  - Measurement to be discussed later but is being improved to allow greater participation.
  - 200 MW contracted for 2018/19
- Changed approaches to valuation
    - Control groups
    - A variety of baselines (purpose and customer fit)
  - Allow third parties to enter the market

Overseas developments

- Europe – general
  - EU's "Clean energy for all Europeans"
    - Allow aggregators into the market (France has now);
    - Put generation, storage and demand resources on an equal footing;
    - Ensure access to the balancing market; and
    - Deliver appropriate signals for investment to generation, storage and demand resources.
  - Smart meter rollout – EU directive 80% by 2020:
    - Subject to value analysis (10 states out of 27 say no – red and orange);
    - Austria, Denmark, Estonia, France, Ireland, Italy, Malta, Netherlands, Spain, Sweden and United Kingdom either complete or expect to meet the target;
    - Others delayed (Greece, Poland and Romania)



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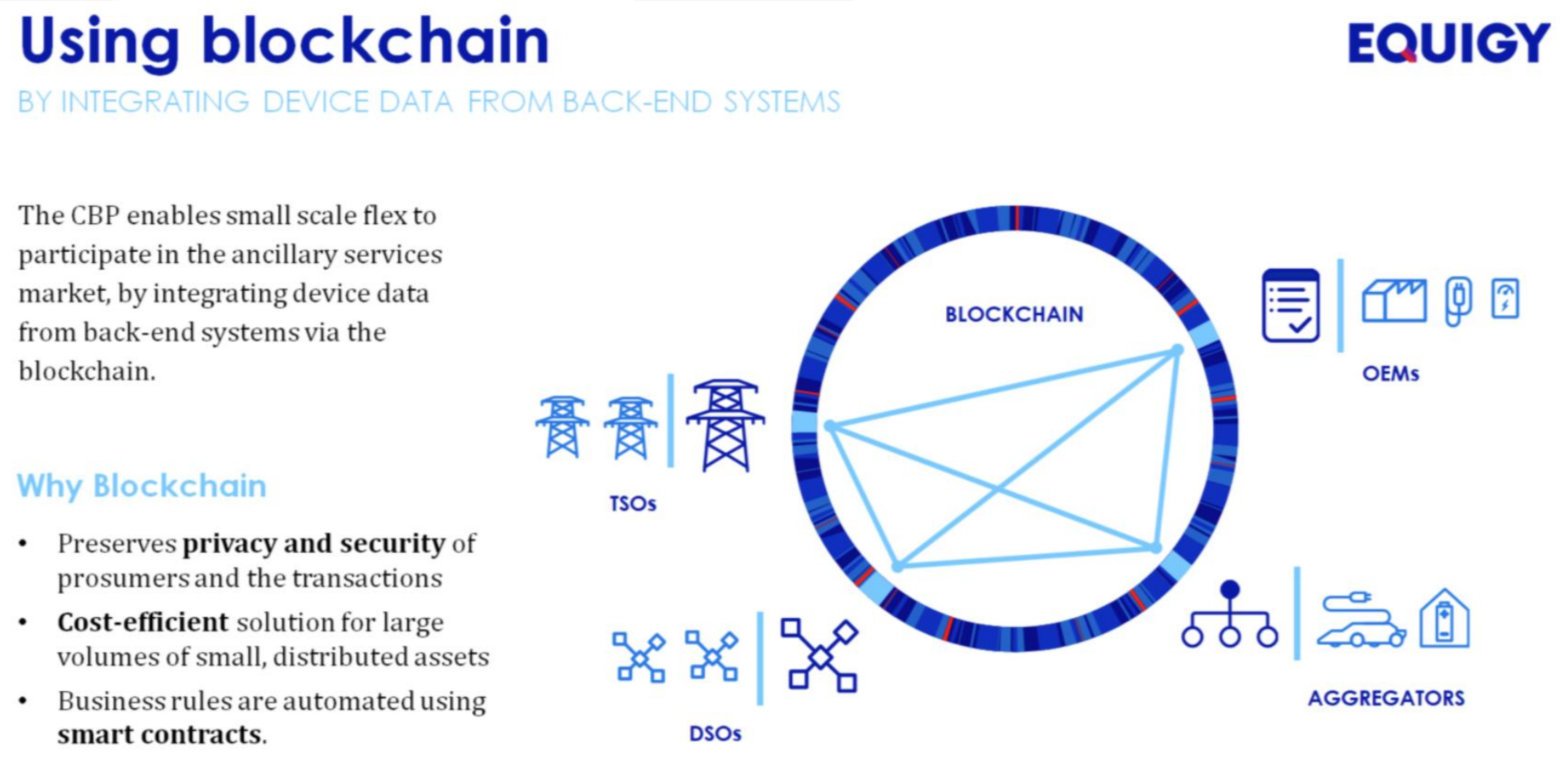
RELATED DEVELOPMENTS

— BLOCKCHAIN
— EMBEDDED NETWORKS
— MICROGRIDS

Blockchain – allows contractual arrangements directly between participants

- Markets using blockchain are emerging all allow bilateral trades without a market maker
  - Equigy is comprised of three TSO's operating in Europe working with large customers
  - Tennet, Swissgrid and Terna
  - All forms of DER, although storage and embedded generation dominate



Embedded networks – a form of aggregation

- Embedded networks are proliferating in Australia
- Mainly communities bound by an exempt network
  - Apartment buildings
  - Office blocks
  - Industrial Parks
  - Retirement villages
- The aggregated demand is usually services by commercial tariffs, with a demand component
  - The owners corporations or embedded network managers are seeking to harness the DR potential as a means of reducing costs
  - Also allows integration of storage and PV
- Have some of the characteristics of microgrids

Microgrids

- Allow self contained trading of energy and DR
- May be connected to other grids

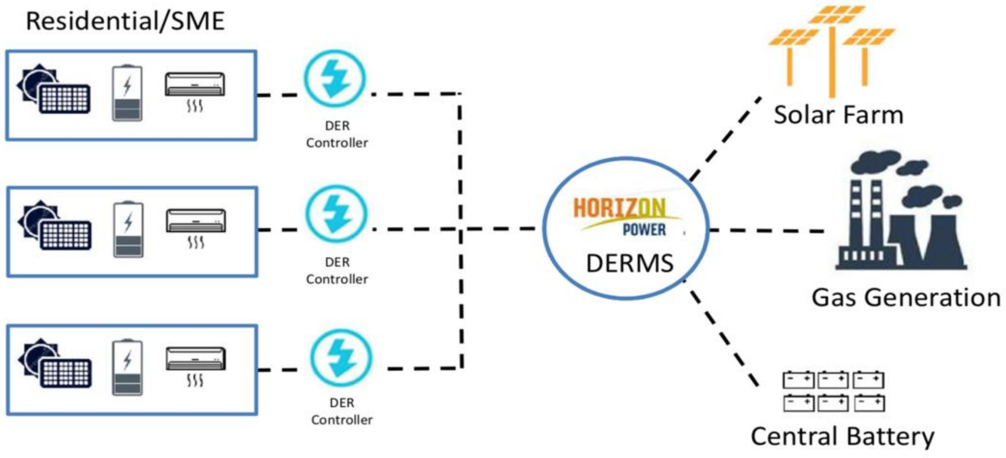
Europe

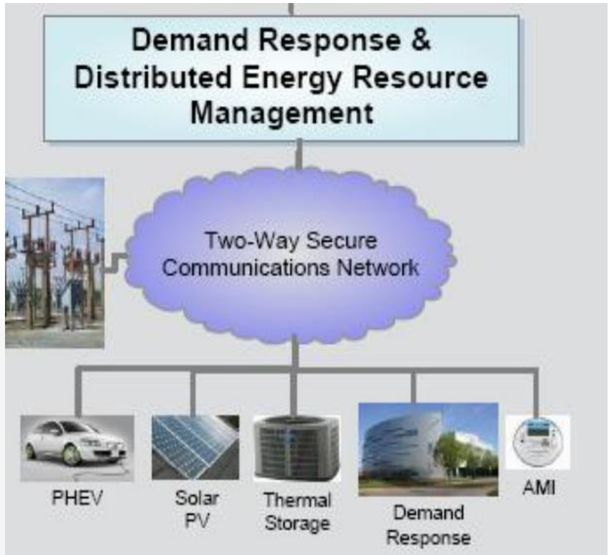
EcoGrid 2.0 is a demonstration project on the Danish island of Bornholm. Its predecessor, EcoGrid EU, ended in 2015.

- The Bornholm Island system is larger than a typical microgrid, but is capable of islanding from the main grid (the Nordic interconnected power system).
- When grid-connected, the system has a high penetration of wind and some solar power. When islanded, it depends significantly on fossil fuel generation.
- EcoGrid 2.0 is leveraging the previously installed equipment from EcoGrid EU, but is introducing a **market for flexibility** for residential heating.
  - 1,000 families on the island are participating in a flexible household heating program.
  - EcoGrid 2.0 **aggregates the heating load and responds to bid requests** from the system operators to **increase or decrease the amount of renewable energy exported** to the grid (for now, on a parallel trading platform to existing markets).
- **Bornholm's Energy & Supply** is the public utility and Distribution System Operator, and funded approximately 50% of the demonstration.
- The island is also host to a new **electric vehicle demonstration**, ACES (EVs selling frequency regulation services to the grid).

Source: EcoGrid

Australia





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WHERE TO FROM HERE

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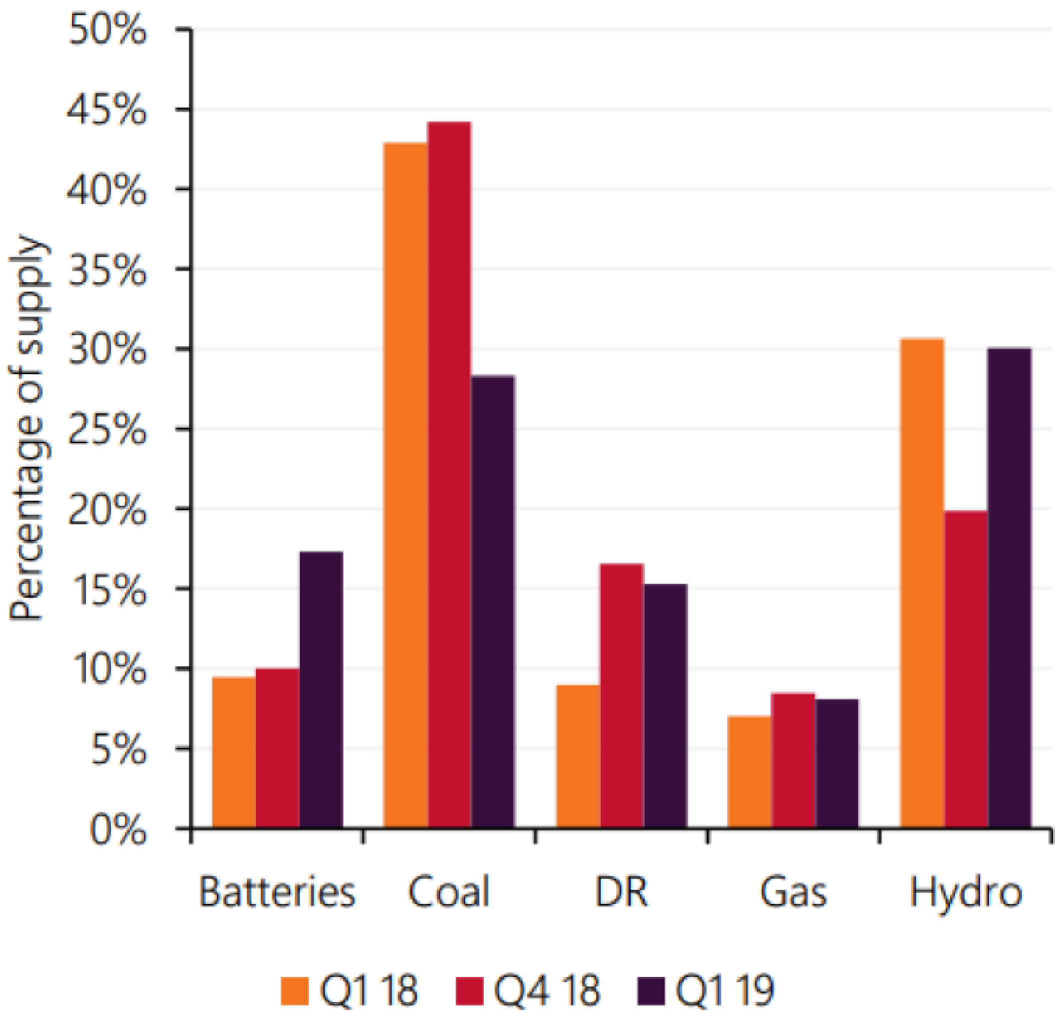
Key takeaways

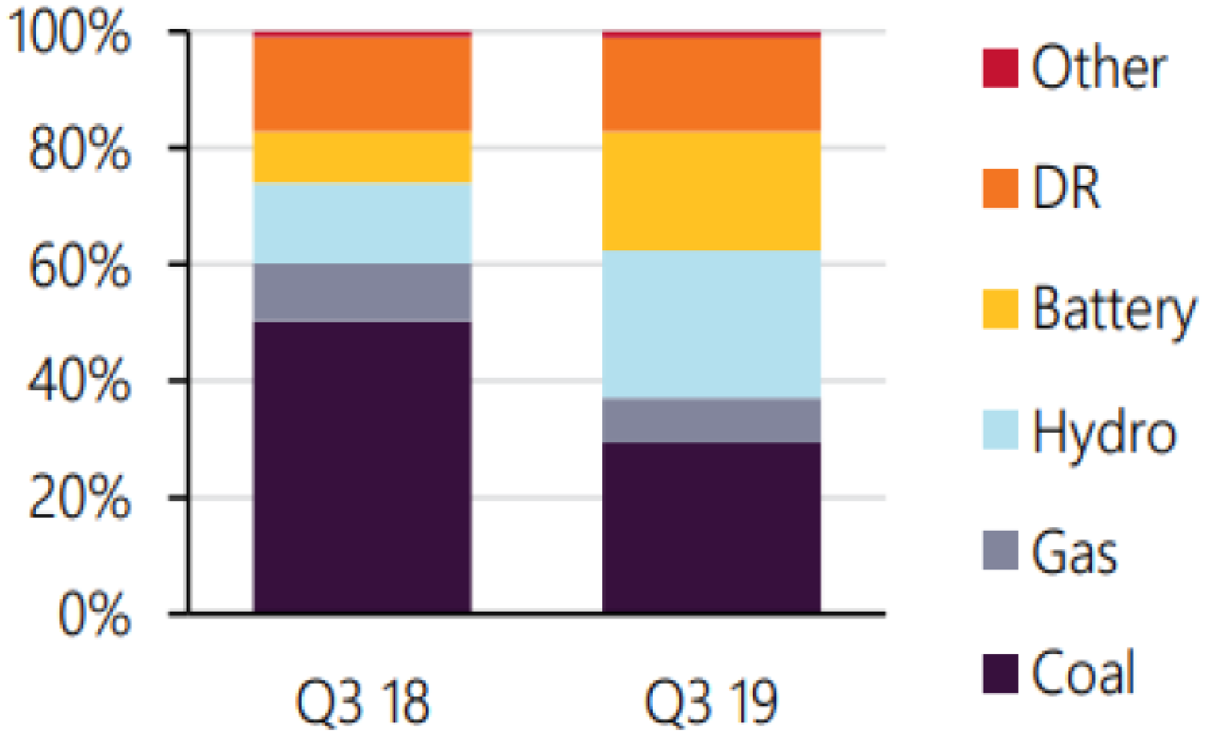
- Demand response is being utilised more as:
  - Metering and control systems develop
  - Intermittent resources penetrate traditional markets
  - Costs of energy increase
- Key factors that allow DR use are:
  - The presence of capacity mechanisms
  - The use of day ahead markets
  - Price signals for services DR can provide
  - Acceptance of aggregators
- New techniques and success with DR in markets will lead to greater adoption, particularly with improvements in measurement and verification
- Retailer contracted DR is still a major avenue for DR and Network DR is increasing.
- Integration is increasing

Present and future use cases (including for increasing demand) - and competitors

Present use cases	Future use cases	Competitors
Wholesale prices		DER export, batteries
FCAS		Batteries
Network augmentation		DER export, batteries
RERT		DER export
	Capacity provision via RRO	Batteries (?)
	Over-voltage control	Batteries
	Minimum demand	Batteries, storage water heating, any means for increasing demand
	Network replacement cost	DER
	Network extension	DER

Changes in sources of supply for FCAS





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Thanks for your attention

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