Pricing and Integration of DER
Webinar Summary

OCTOBER 2019

Oakley Greenwood
Developed with Oakley Greenwood

Australian Government
Australian Renewable Energy Agency

ARENA

In February 2019, ARENA awarded $9.6 million in funding to 12 projects and studies to investigate further integrating distributed energy resources (DER) into the electricity system.

The Oakley Greenwood 'Pricing and Integration of Distributed Energy Resources' study analyses the regulatory and economic environment for DER in the National Electricity Market (NEM) and internationally. The aim of the study is to determine the optimal way to provide price signals that reflect the value of services DER can provide to the electricity supply chain. Creating appropriate market signals can incentivise stakeholders to invest in locations where DER is most needed and deploy DER when and how it is of most value.

On 15 October 2019, Oakley Greenwood's Lance Hoch, Alex Cruickshank and Rohan Harris presented a knowledge sharing webinar on the study. This summary provides the key takeaways from the webinar.

Want to find out more? Read Oakley Greenwood's Pricing and Integration of DER study and listen to a recording of the webinar.

STUDY OVERVIEW

- The objective of the study was to develop a menu of useful pricing structures (rather than specific prices) that capture the economic value of DER services for the electricity supply chain.
- Oakley Greenwood undertook significant consultation throughout the study with a Stakeholder Reference Group and market bodies, including networks, retailers, new tech businesses and consumer advocates.

DER SERVICES

- DER services were defined as ways that DER can reduce the costs incurred along the electricity supply chain. This ensures that each of the services provides economic value to all electricity users, and not just to the DER asset owner or operator.
- While DER can provide many valuable services (e.g. reduction of carbon emissions), these services do not reduce costs to the electricity supply chain and therefore can only be priced where there is a policy direction to do so.
- Cost drivers within each part of the supply chain were investigated and 10 DER services for networks, wholesale markets and market operations were identified (Table 1).

Table 1: Summary of DER services

DER services for networks	DER services for wholesale market & market operations
Direct connection costs	Investment costs
Extension of existing shared network	Fuel and operating costs
Shared network augmentation costs	Market reserves
Replacement costs	Market ancillary services
Costs of voltage management	
Managing bushfire risk	

DEVELOPING PRICING STRUCTURES

- Tariffs, charges, rebates, and payments must be efficient in order to be consistent with economic theory and the National Electricity Rules (NER). Developing efficient pricing structures involves making trade-offs between administrative costs, complexity, and accuracy of the price signal. Importantly, it should be noted that more accurate price signals do not necessarily result in more efficient outcomes.
- Additional considerations for developing pricing structures includes:
  - geographic focus (e.g. regional-based or location specific)
  - temporal period (e.g. predetermined or dynamic)
  - price basis (e.g. set in advance based on the network's cost to supply or based on customers offering their services to the purchaser).
- With these considerations in mind, a menu of potential pricing structures were developed for each of the 10 DER services. Options ranged from providing static prices across a wide geographic area (e.g. an entire distribution network service provider (DNSP) service area) to options based on DER service providers bidding in prices at which they would be willing to deploy their DER.
- After developing pricing structures that reflect the value of identified DER services, each pricing structure was assessed for it's ability to be acted upon in the market, and whether the Rules and regulatory framework present barriers to the use of these pricing structures. A high-level cost-benefit assessment of the use of the pricing structures was then undertaken.
- Interestingly, there was a preference amongst the Stakeholder Reference Group for pricing signals that were as geographically and time specific as possible. While there was agreement on the benefits of being able to call for bids for DER services, challenges regarding the metering, communications and control of technology currently in the market were raised.

INTERNATIONAL EXPERIENCE

- Specific details were provided from examples in Belgium, France, United Kingdom, and California and PJM Interconnection (United States of America).
- There is a growing trend overseas to allow loads and distributed resources access to market pricing that allows informed choice in the use, curtailment, generation or storage of energy.
  - this requires market mechanisms to allow DER to participate in the market
  - third parties are allowed to access the market to provide DER services.

NEXT STEPS

- Next steps in the study include finalising the cost-benefit analysis, and release of the Final Report later in the year. Oakley Greenwood will brief market bodies and government departments on the Final Report.

Oakley Greenwood

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

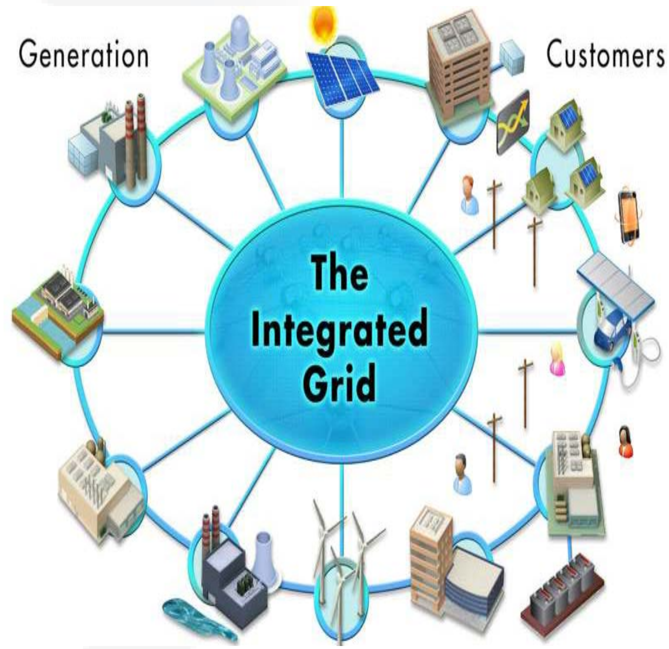
Webinar on the work and results of the study by Oakley Greenwood, part funded by ARENA.

Lance Hoch, Rohan Harris and Alex Cruickshank

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



Oakley Greenwood

www.oakleygreenwood.com.au

Overview of study tasks

- Convene Stakeholder Reference Group
- Establish the specific ‘services’ DER can provide to each part of the electricity supply chain
- Identify pricing structures that reflect (and therefore incentivise and properly reward) the value of these services
- Check that these pricing structures can be acted upon in the market
- Assess whether the Rules and regulatory framework present barriers to the use of these pricing structures and if experience elsewhere can provide any useful and applicable approaches
- Conduct a high-level cost-benefit assessment of the use of the pricing structures
- Prepare a project report and brief stakeholders and market bodies

Consultation

- We prepared papers on the key topics.
- These were reviewed and commented on by a Stakeholder Reference Group and by Market Bodies, including ARENA.
- The papers and comments will be included in the final report

Stakeholder Reference Group	
• AEC	• Enel X
• AEMO	• CEC
• ECA	• SEC
• Greensync	• EUAA
• OCEnergy	• ENA
• Reposit Power	• TEC

Market Bodies
• ESB
• AEMC
• AER
• AEMO
• ARENA

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

1. Direct Connection Costs
2. Extension of existing shared network
3. Shared network augmentation costs
4. Replacement costs
5. Costs of managing voltage within required levels on shared network
6. Managing bushfire risk

For Wholesale Market & Market Ops

1. Investment costs
2. Fuel and operating costs
3. Market reserves
4. Market ancillary services

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.

Oakley Greenwood

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).

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.

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

DEVELOPING PRICING STRUCTURES

Oakley Greenwood

www.oakleygreenwood.com.au

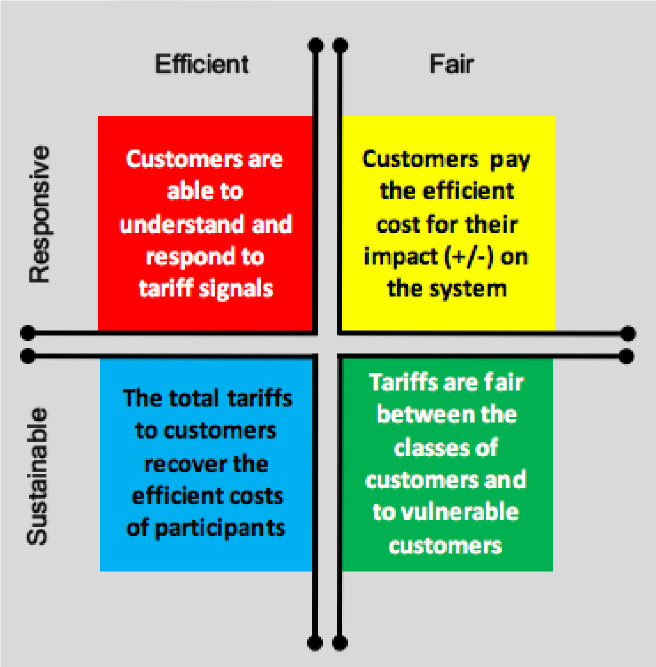
Developing candidate DER 'service' pricing structures

- 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
- 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

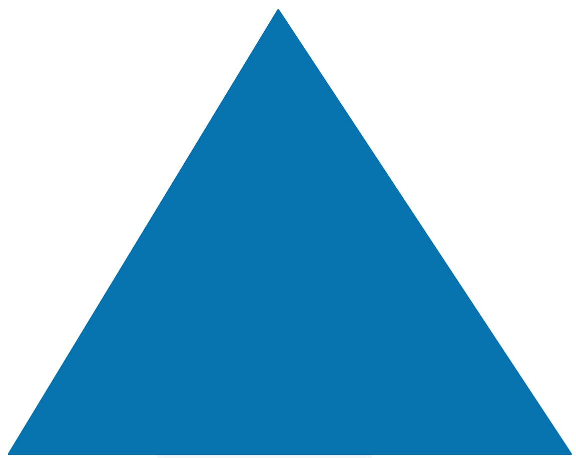
> *The ideal rate design should promote economic efficiency, enhance customer equity, ensure the financial health of the utility, be transparent to customers, and empower customer choice.*
>
> Bonright reloaded - Farugui, 2016



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

Oakley Greenwood

Recap of Network Cost Drivers outlined in Stage 1 report

1. Direct Connection Costs
2. Extension of existing shared network
3. Shared network augmentation costs
4. Replacement costs
5. Costs of managing voltage within required levels on shared network
6. Managing bushfire risk

Direct Connection Costs

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

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.

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

- 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.*

Extension of existing shared network

Key points made in Cost Driver Paper

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.

Objective of Pricing DER for this service

- 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

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).

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).

Shared network augmentation costs – Constraint driven by too much export

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
NETWORK EXPORT "TARIFF" OPTIONS (APPLICABLE WHEN DER EXPORT *CAUSES* CONSTRAINT ON NETWORK)				
Area-based Callable "Network export" tariff	Application is Dynamic / Price is static	LRMC of managing peak demand (for export services) in that area	Yes	Events "called" by network business in advance (NOTE: Likely to be short notice, given factors driving such an outcome – e.g., high prices outside of high demand periods). Would only be called for areas "at risk". NOTE: The actual export tariff amount would be pre-set by area.
Market for network support	Dynamic	Market-driven, capped for each area by capacity of network.	Yes	Bids for export rights "called" for by network business in advance (e.g., 30 minutes) for 'at-risk' areas, with final price based on marginal price that clears market, given capacity of the network.
Access rights	Various	Cap and trade, with ability to pay for augmentation, with rights to the new capacity	Yes	This is in the Rules (Rules 5.3 and 5.5) but has not been effectively implemented for generation sources due to fairness and other concerns. Can be physical and financial.

Oakley Greenwood

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.

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).

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

PRICING STRUCTURES FOR DER SERVICES TO MARKETS AND MARKET OPERATIONS

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

1. 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

2. **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*.

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.

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

INTERNATIONAL EXPERIENCE

Summary of overseas experience

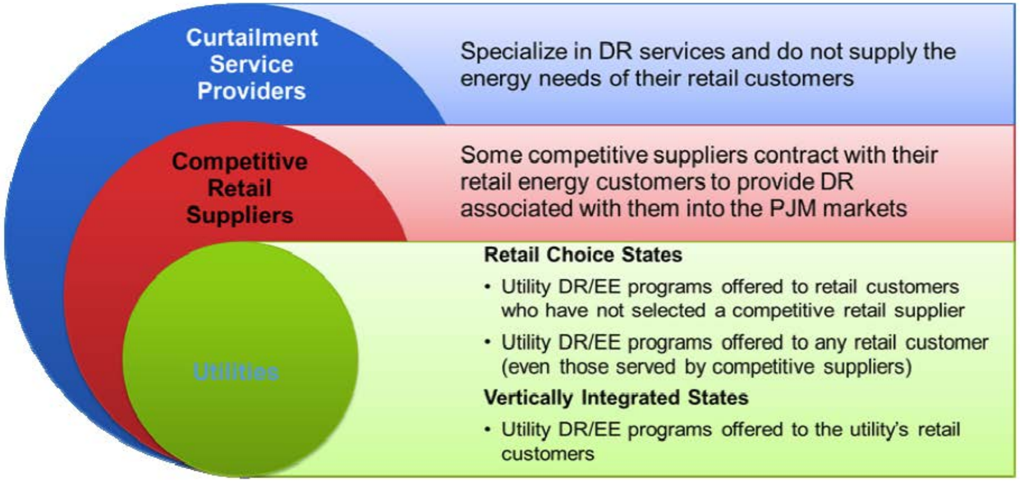
- Energy market participants overseas, like in Australia, routinely contract DER, primarily demand response, as part of normal business.
  - Load curtailment
  - Off-peak pricing
- The increasing trend is, however, to allow loads and distributed resources access to market pricing that allows informed choice in the use, curtailment, generation or storage of energy.
  - This requires market mechanisms to allow DER to participate in the market
  - Measurement of the DER is critical, and problematic where metering is not granular, leading to a push for advanced and short interval metering.
- Markets that allow third parties to access the market to provide DER services have shown a marked increase in the amount available.
  - PJM has 1,537MW of DR participating, compared to 200MW in California (2017). Note that California is now allowing third parties to provide DR.
  - Other European markets are using third party providers; UK, France, Ireland etc.

DER through load serving entities

- Energy retailers and energy networks in Australia, and their equivalents overseas, routinely contract DER, primarily demand response, as part of normal business.
- This has been achieved as part of normal business and includes:
  - Off peak tariffs for hot water and industrial loads;
  - Demand tariffs, where a site is charged more for using large amounts of capacity or, conversely, is able to gain reduced charges by remaining below a defined level of demand
  - Interruptible tariffs, where a site is offered a reduced tariff in exchange for the network or retailer having rights to interrupt supply;
  - Direct contracts, either network support or through retailers, to allow the market participant;
- The future trend is, however, to allow loads and distributed resources access to market pricing that allows informed choice in the use, curtailment, generation or storage of energy.
- This almost always include allowing third parties, or aggregators, to enter the markets to intermediate between the market and customers.

PJM Interconnection, USA

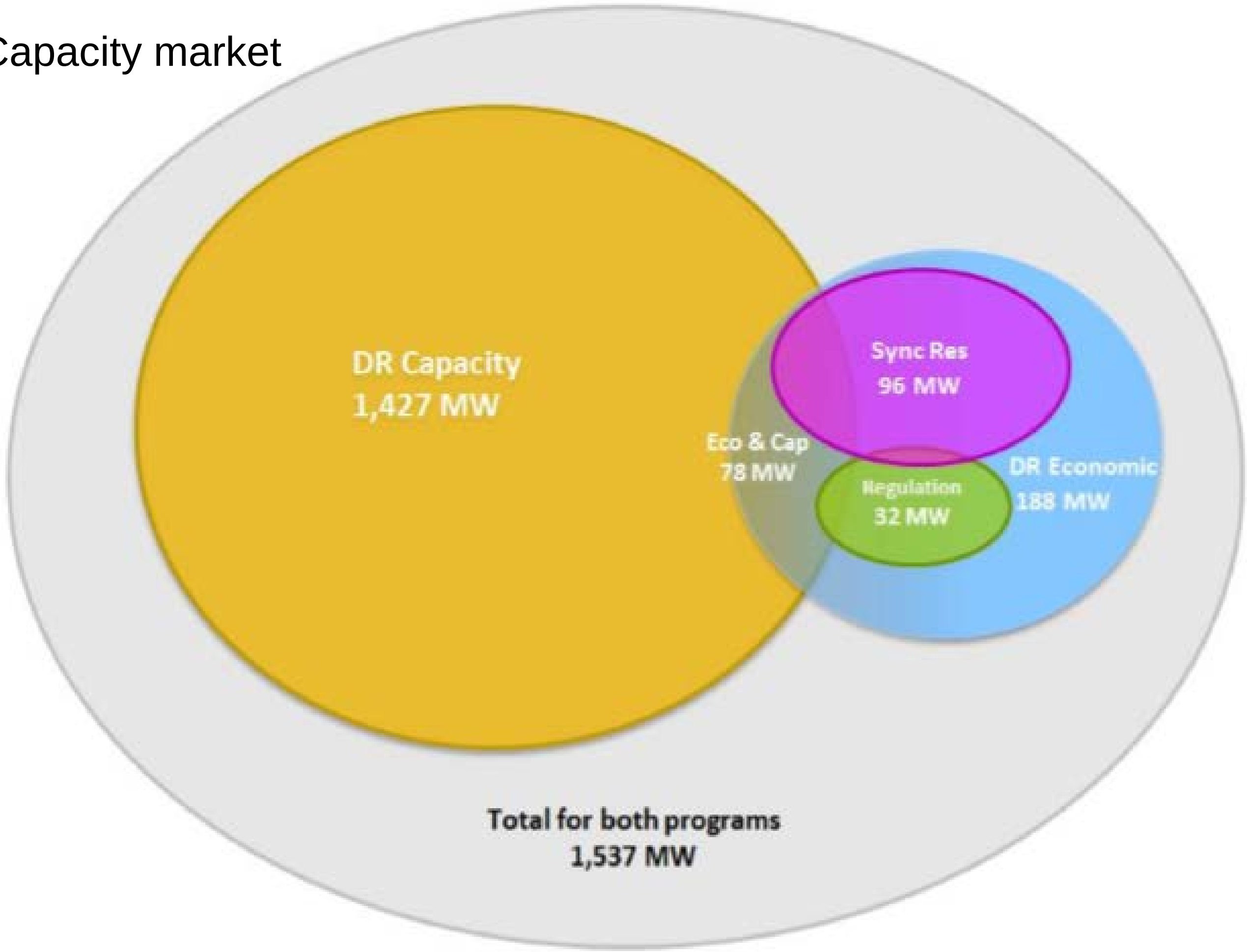
- PJM interconnection is one of the most successful markets for integrating DR, allowing participation in all aspects of its operations:
  - Retail market mechanisms (not strictly PJM)
  - Wholesale capacity mechanism & emergency capacity provision
  - Wholesale energy day ahead & balancing markets
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

	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

- Markets
  - Retail
  - Wholesale Capacity
  - Wholesale Energy
  - Network support
- Outcome
  - Trading has reached 1.6 GWh of energy
- 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

Belgium

- Only recently developed – 2013/4, no published results
- 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.
  - 2,750 MW was available for the winter of 2015-16

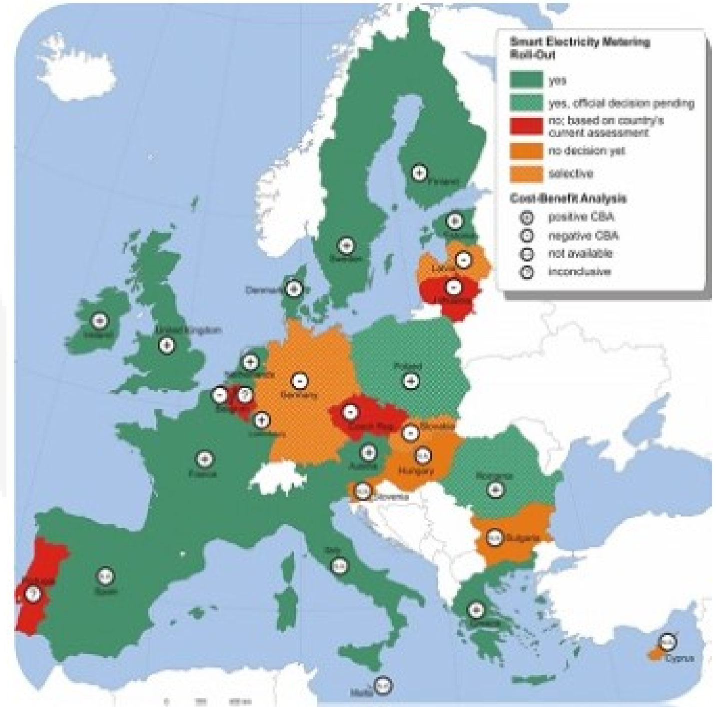
Overseas – United Kingdom

- 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
- Reviewed the approach recently
  - Changed approaches to valuation to increase accuracy
  - Allow third parties to enter the market

European Developments



- EU's "Clean energy for all Europeans"
  - Allow aggregators into the market (France already has this 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)

Oakley Greenwood

www.oakleygreenwood.com.au

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

NEXT STEPS

- Cost-benefit analysis
- Final Report
- Briefing to market bodies and Government departments

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

Thank you for your participation

This Project received funding from ARENA as part of ARENA's Advancing Renewables Program.

The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Lance Hoch
Rohan Harris
Alex Cruickshank
Oakley Greenwood Pty Ltd

Oakley Greenwood

www.oakleygreenwood.com.au