Pricing structures to assist the economically efficient integration of DER

prepared for:
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The report was prepared in consultation with a Stakeholder Reference Group and a Market Bodies Reference Group to assess the potential of economically efficient (i.e., cost-reflective) price signals as a means for integrating the use of distributed energy resources (DER) within Australia's National Electricity Market (NEM).

In particular, this report presents alternative pricing structures that could be used to provide economically efficient price signals regarding the value that the services identified earlier in the study that DER can provide to the electricity supply chain.

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1. Introduction and overview

1.1. Objectives of the study

From an economic perspective, the benefits accruing from the increasing uptake of DER in the National Electricity Market (NEM) will be maximised if the price signals and other aspects of the market arrangements incentivise:

- DER investment:
  - at the right *scale*, at the correct *location,* and at the right *time* (allocative efficiency), and
  - at the *least cost* (productive efficiency); and
- the operation of DER so that it is allocated to its highest value use in its location at any specific time, so as to maximise its economic value (allocative efficiency).

The appropriate signals to incentivise both efficient investment in, and operation of, DER are fundamental to the achievement of the National Electricity Objective. The corollary is that an uncoordinated approach to the deployment (i.e., one not driven by the underlying economic benefits and costs of DER) will almost certainly lead to DER being installed at an inappropriate scale, and potentially in the wrong locations and at the wrong times, as well as it being operated in a manner that does not maximise economic efficiency.

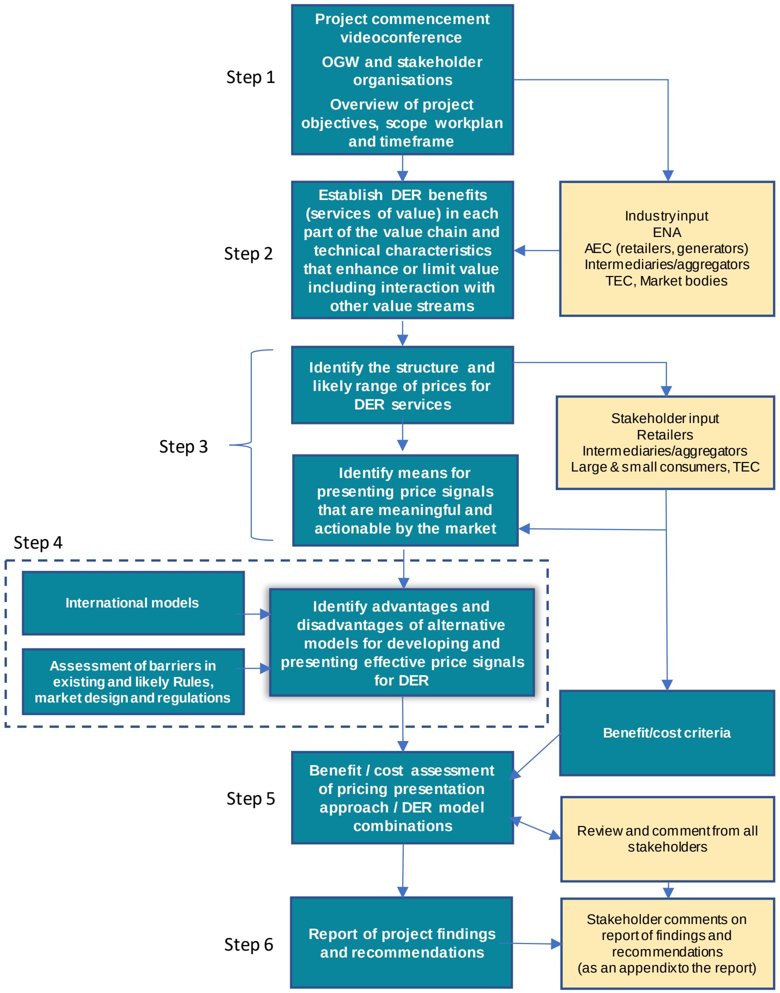
Accordingly, the overall objective of this study is to determine how price signals can be structured and presented so as to best reflect the value that DER at customer sites or elsewhere within the distribution can provide to the electricity value chain so that DER investment is driven by market forces, maximised at the appropriate points in the energy delivery chain and developed at the right scale within the NEM.[1]

1 For the purpose of this study, DER includes decisions on the use of energy, including load shifting and curtailment (DR), as well as co-generation, tri-generation, and embedded and behind-the-meter renewable energy generation technologies and storage.

1.2. Overview of approach and coverage of this paper

The study is organised in six major steps, as shown in the figure on the right, and includes a significant amount of stakeholder engagement and input from the industry, consumer groups, market intermediaries and market bodies. The six primary steps within the study are:

- Commencement of the project with a workshop to embed the stakeholder processes to be used through the remainder of the work (Step 1).
- Identification of the services that DER can provide to each part of the electricity supply chain with specific attention to those services that are not already valued/priced (Step 2).
- Development of the value range of each service that is not currently priced in the market, along with the units in which the value should be denominated and a description of the factors that govern the technical feasibility of the use of DER for the provision of each service and the extent to which the provision of each service may interact with other services or value streams (Step 3a).
- Translation of the values into price signals that can be readily understood and responded to by market participants, market intermediaries, DER investors and end customers (Step 3b).
- An assessment of the degree to which the current and likely near-term developments in the market design, Rules, market arrangements and regulatory framework will support the use of these price signals or will need to be modified to do so, incorporating learnings from other markets that are farther along in the integration of DER (Step 4).



- Prioritisation of the pricing options in terms of the magnitude of the value of the benefits they are likely to be able to realise as compared to the costs required to obtain them, using a set of criteria that conform with the National Energy Objective to assess their relative ability to increase economically efficient deployment and operation of DER and the complexity, costs and difficulty of implementing them (Step 5).
- Reporting of results to stakeholders for review and comment, and wider dissemination (Step 6).

This paper summarises the findings of Step 3. Step 2 identified and described the types of services that DER can provide to the electricity value chain.[2] Step 3 explored how the value of those services could best be reflected in the structure and nature of price signals provided by the various parts of electricity supply chain to investors in and owners/operators of DER.

2 See Oakley Greenwood, *Pricing structures to assist the economically efficient integration of DER*, prepared for ARENA, April 2019.

2. Principles of efficient pricing

2.1. Overview

In 1961, James Bonbright posited a set of basic principles (shown in Figure 1) that should be reflected in electricity pricing. His principles were developed within a context in which electricity was supplied by vertically integrated monopolies and the setting of tariffs was essentially an exercise in balancing the interests of capital attraction with those of customers within a 'public interest' framework.

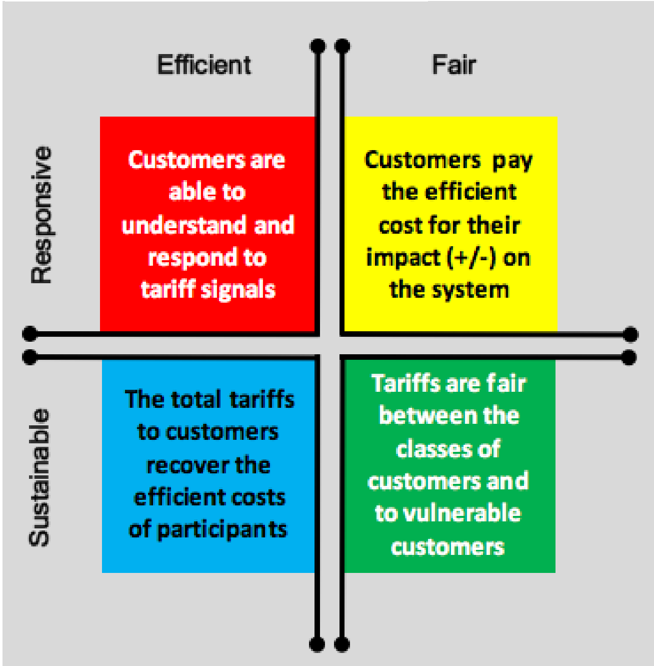
The advent of DER and bi-directional electricity flow introduces some new concerns, and various parties have sought to rephrase Bonbright's principles. Ahmad Faruqui of the Brattle Group re-cast them as follows:

> *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*[3]

Karl Rabago and Radina Valova of the Pace Energy and Climate Center, at the Pace Law School (White Plains, New York), have offered 7 specific principles that more specifically address the added players and concerns of a DER electricity world[4], as follows:

- Regulators should fully comprehend and reflect resource value in rates (tariffs).
- Rate making must account for the relative market positions of various market actors, and for the information asymmetries among different customers, utilities and market participants.

Figure 1: Principles of efficient pricing



3 Ahmad Faruqui," Residential Rates for the Utility of the Future", 13 May 2016, https://brattlefiles.blob.core.windows.net/files/7291_residential_rates_for_the_utility_of_the_future_final.pdf

4 Karl R Rabago & Radina Valova, "Revisiting Bonbright's principles of public utility rates in a DER world", *The Electricity Journal*, Volume 31, Issue 8, October 2018, pp 9-13.

- Sound rate design must be grounded in a careful assessment of practical economic impacts on all market participants, especially customers.
- Rates must support capital attraction for all resources that provide energy services, regardless of whether the affected investor is the utility, the customer or a third-party provider.
- Rates must be designed to account for the incentives they create for utilities, customers and non-utility market participants.
- Just and reasonable rates require accurate accounting for utility costs.
- Rate design and cost allocation are separate functions driven by distinct policy objectives.

2.2. Pricing in Australia's National Electricity Rules

The National Electricity Rules (NER) were developed to guide the operation of Australia's electricity supply chain as it was vertically disaggregated, and market forces were introduced. The NER are based on economic theory and specify that pricing within or from the electricity supply chain, whether expressed as tariffs, charges, rebates or payments, should be efficient. Examples can be found throughout the Rules including:

- Chapter 3 (Rules 3.4.1, 3.8.1, 3.11 and 3.15). These Rules describe and require energy market dispatch to be based on maximising the economic value of trading and that the market price be based on the marginal cost of supply. This requirement was a fundamental aspect of the market design, which is an economic platform for the trading of energy. The key aspects of dispatch are that:
  - The dispatch of energy represents the least cost of available supply to meet the demand. The market always intended that this would include DER and recent Rule changes to allow aggregation of DER will support this approach. This is covered in more detail in section 4.
  - Participants pay or are paid for the energy value measured at their connection point. The market design requires that all connected parties pay the value of the energy that is consumed at their connection point. This is mediated by the Financially Responsible Market Participant[5], who sees the marginal value of electricity each hour and on-charges the costs to end customers where there is net consumption or pays the customer where there is a net supply into the grid. This ensures that the value of energy is correctly communicated to customers.
  - Recent Rule changes will allow DER aggregators to participate in dispatch and ensure that the value of DER is integrated into dispatch.

5 For large generators, the FRMP is normally also the connected party. The Rules also allow large customers to be the FRMP but this is not currently being done by large customers.

  - The market also allows efficient dispatch and payment for ancillary services. Rule 3.11, which covers ancillary services, does not discriminate between supply side and DER resources and recently larger participants have entered this market.
- Chapter 5 (Rule 5.3 ff). Rules 5.3 to 5.5 of the NER cover access to the grid by participants. This approach is covered in more detail in section 3.
  - The Rules outline the requirement for applicants to pay the cost of providing them with access to the grid to ensure that the grid is extended efficiently to meet participant requirements.
  - The current review into the Coordination of Generation and Transmission Investment (CoGATI) seeks to improve these arrangements and ensure that the grid is developed efficiently with multiple applications for connection, and that access is assured on an equitable basis.
- Chapter 6 (Rule 6.18). This Rule requires network companies to develop their pricing for customers on an economically efficient basis and reflects efficient economic approaches to pricing. The AER assesses network prices using this Rule, inter alia. More detail on this Rule is provided in section 2.3, below.

2.3. Network pricing principles support efficient pricing

The NER include explicit statements regarding the principles that should guide the pricing of network services, as the following extracts from Rule 6.18.5 show:

For each *tariff class*, the revenue expected to be recovered must … [be between] the stand-alone cost of serving the *retail customers* who belong to that class; and … the avoidable cost of not serving those *retail customers*.

(e) For each *tariff class*, the revenue expected to be recovered must … [be between] the stand-alone cost of serving the *retail customers* who belong to that class; and … the avoidable cost of not serving those *retail customers*.

(f) Each tariff must be based on the *long-run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff …

(g) The revenue expected to be recovered from each tariff must:

  (1) reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff;

  (2) … recover the expected revenue for the relevant services … ; and

(h) A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* … having regard to: …

  (2) the extent to which *retail customers* can choose the tariff to which they are assigned; and

(3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.

(i) The structure of each tariff must be reasonably capable of being understood by *retail customers* that are assigned to that tariff, having regard to:

(1) the type and nature of those *retail customers*; and

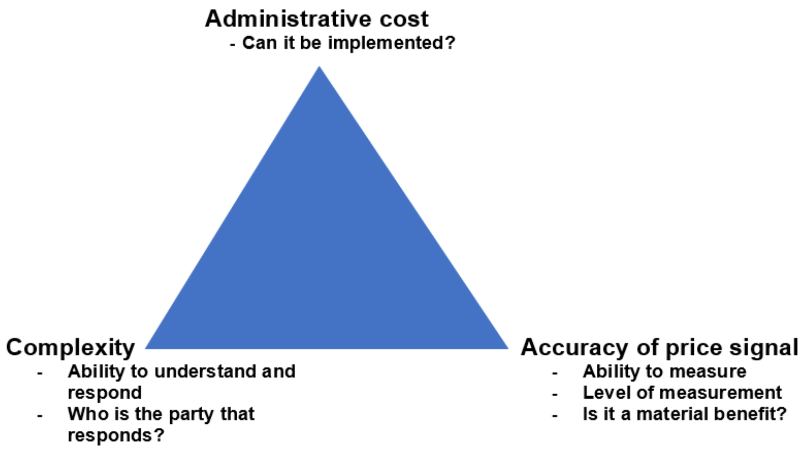
(2) the information provided to, and the consultation undertaken with, those *retail customers*.

2.4. Overarching considerations when it comes to pricing

At a general level, there is almost always a range of potential price signals that could be introduced in order to facilitate more efficient outcomes and that could be perceived as being consistent with the Rules and economic efficiency.

Generally, developing efficient pricing structures involves making some trade-offs, as depicted in Figure 2. And, while these may be the continua on which the most significant trade-offs need to be considered, other non-economic factors such as community, customer and Government acceptability generally also need to be taken account of.

Figure 2: Pricing trade-off considerations



In the remainder of this paper, we provide a spectrum of pricing options. However, there is some commonality in the spectrum of options presented, in that the approaches generally provide some choice around whether the tariff/rebate is:

- Regionally based (e.g., AusNet-wide) OR location-specific (e.g. Benalla ZSS);
- Linked to a pre-determined, "set" time-period (e.g., 2 to 6pm in summer) OR dynamic in their application (e.g., the purchaser "nominates" or "calls" exactly when it requires the services to be provided); or
- 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).

In each of these cases, the decision on how to structure the price signal must balance the three criteria discussed above. In each of the example above, the choice is between price signals that are less complex and costly but also less accurate, as compared to more accurate but also more costly and complex. In making the choices required, it is not as simple as saying that more accurate price signals automatically result in more efficient outcomes. In many cases, the benefits from any improved accuracy may be outweighed by the additional complexity and administrative costs required to provide that accuracy.

2.5. The impact of standards on pricing design

Technical standards can play an important role in delivering outcomes that are in the long-term interests of consumers because:

- They can 'hard-wire' the delivery of certain outcomes in situations where it is felt that the market, left to its own devices, may not deliver those outcomes to the community; and
- They are particularly relevant where there is some form of market failure.

There are numerous examples of standards being applied in the electricity industry. For example, inverter standards (AS4777) assist in managing voltage by disconnecting a PV system to stabilise network voltage. This standard is designed to protect the network and its customers.

In the context of this project, a key question is:

> If the network gets the services that result from the application of a particular standard for free ("voltage management" in the example above), does the network still need to send a price signal?

The answer, in our view, is 'yes' in that:

> There is an argument that networks should still send a price signal with regards to the economic costs avoided (or the economic value created) by the service the standard delivers (e.g., voltage management in the example above).

The rationale for our view is that we want to ensure that economically efficient investments are made by the market (including networks). Understanding the underlying economic costs of a decision allows the market to arrange itself in a way that should deliver the most efficient outcomes. In the voltage example, above it may be that there are other, more efficient ways of managing voltage as compared with the network simply relying on the "free-service" provided by the inverter. For example, it might be more efficient for batteries to be installed and charged during periods of potential over-voltage (as opposed to relying on inverters to disconnect PV systems).

Notwithstanding the above, the desire to price the underlying cost driver that may be being managed by an existing standard needs to be considered in light of the:

- Administrative costs associated with implementing the price signal, versus
- Gross efficiency benefits (which will be a function of the materiality of the economic benefit being priced and the elasticity of demand for DER services).

In summary, the existence of standards and their ability to deliver benefits to the electricity system (by potentially reducing *the network's* costs) does not, in and of itself, mean that the underlying cost driver should not be priced so that the broader market's decisions can reflect that value.

3. DER Pricing for networks

3.1. Recap of Network Cost Drivers outlined in *Cost Driver* report

The following network cost drivers were outlined in the *Cost Driver* report.

- Direct connection costs
- Extension of existing shared network
- Shared network augmentation costs
- Replacement costs
- Costs of managing voltage within required levels on shared network
- Managing bushfire risk.[6]

6 This has been incorporated into the "replacement cost" section below, and hence, is not discussed separately.

3.2. Direct Connection Costs

Key points made in the 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.

Figure 3: Direct connection cost pricing

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.*

3.3. Extension of existing shared network

Key points made in the 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.

Figure 4: Upfront cost of augmenting the 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".

3.4. Shared network augmentation costs

Key points made in the Cost Driver Paper

1. The efficient investment in, and use of, DER requires both efficient variable consumption and export tariffs.
2. The structure of these variable tariffs should, in theory, reflect the fact that at present some shared network assets are driven by deterministic planning criteria, whilst others are driven by probabilistic planning.
3. Either way, 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.
4. 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 (although we acknowledge that there are Rules preventing this happening at present).

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 to 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);

Figure 5: Shared network augmentation costs (driven by energy at risk)

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. Includes: HV and Sub transmission in the main*	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).

**Energy at risk is generally the cost driver for larger (in capacity) and more expensive network assets, hence the reference to HV (High Voltage) and Sub Transmission "in the main"*

- 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).

Figure 6: Shared network augmentation costs (driven by exports)

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.

As alluded to above, pricing structures may need to have regard to whether shared network augementation costs are driven by peak demand or energy at risk. It may be conceptulised that slightly different pricing arrangements might be required to align with the diffeerent underlying cost driver (peak demand c.f energy at risk). Moreover, pricing structures in theory, should also send price signals relating to any forecast costs they expect to incur in upgrading their network to accommodate future levels of exported energy from DER (e.g., high wholesale price events leading to rapid increase in the discharge of batteries to the grid). The principle being that where (export) capacity is scarce, that capacity should be allocated to its highest value use. The following figure highlights a number of potential pricing options in this regard.

3.5. Replacement costs

Key points made in the Cost Driver Paper

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.

Objective of pricing DER for this service

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).

Figure 7: Replacement costs price signalling

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.

3.6. Costs of managing voltage within required levels on shared network

Key points made in the 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., incentivise west-facing orientation)

Figure 8: Costs of managing voltage

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 summer 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). NOTE: Defining what types of response are eligible will be important (e.g., battery, PV)?

Note that there are automated means for doing this that would mean that 'calls' would not need to be made, and dispatch decisions could be made with less lead time. But there would need to be an agreement with the customer and equipment installed. This is the subject of a number of trials and small-scale programs.

3.7. A summary of stakeholder comments on the network pricing options presented

The following table summarises the key comments on the network pricing options that were presented to the Stakeholder (SRG) and Market Bodies (MBRG) Reference Groups (collectively RGs).

Table 1: A selection of key comments from Stakeholders

Comments	Response
The Stakeholder and Market Bodies Reference Groups (SRG and MBRG) were generally very supportive of the general suite of pricing approaches contemplated (and presented) by OGW. More specifically, the SRG expressed a general preference for: ▪ Location-specific, as opposed to DB-wide, DER price signals, with a number of members expressing the view that a DB-wide, or averaged, price signal would deliver very few if any economic benefits, given that future network costs will differ significantly by location; and ▪ Posted price signals, as opposed to “market-driven” outcomes whereby DER service providers offer services into a market (and a dispatch schedule and market-clearing price is established via that process), is preferable, particularly in the short-to-medium term.	OGW notes this preference and considers it to be a very a strong foundation for the development of future DER pricing arrangements. The subsequent analysis that OGW has adopted as part of this project (in particularly, the CBA), has sought to align with these strongly stated preferences.
In relation to voltage, the SRG noted that it may be economically efficient to adopt different price levels and different pricing structures for voltage-rise services as compared to voltage-lower services (and that these may differ by location).	OGW agrees with this comment. The outturn price structure should reflect the underlying cost-driver as well as variances in the cost of dealing with that cost driver, whilst at the same time being cognisant of the administrative and implementation costs associated with adopting more granular price signals (as compared to relying on more simplified, but potentially less cost-reflective, price signals).

In relation to charging (or providing rebates for) direct connection costs, it was noted "*Is doing this through the connection charge the most efficient approach? Isn't it likely that DER could either increase or decrease connection costs depending on how the DER is used, in which case it may be efficient to include some form of rebate or increased charge, but it will be hard to know what that rebate or charge should be without linking it to how the DER is used? One possible way to do it through connection charges could be to have a range of connection products available to the customer with different export limits and levels of access, e.g., like SAPN is proposing with different limits and static vs dynamic limits (i.e., you can have a higher export limit if you give SAPN the power to reduce export at peak times)*".

We agree with the general thrust of the comment and in particular that "*it will be hard to know what that rebate or charge should be without linking it to how the DER is used*". However, in saying this, it should be noted that this comment was provided in relation to direct connection costs (not shared network augmentation costs). In this context, the locus of control should be with the customer. For example, if they are confident that their DER can be used to supply their entire load, and hence, alleviate the need to connect to the network in the first place, then they can choose to not connect to the network (and not pay any upfront direct connection costs that would have otherwise been levied upon them by the network business). However, if, subsequent to their original (non) connection decision, they conclude that their DER systems are not in fact able to provide them with the required level of service, hence necessitating them to subsequently connect to the shared network, then they would incur the costs associated with that subsequent connection decision.

If, however, a connecting customer choose to rely on DER to "downsize" the size of their direct connection assets, then presumably these downsized assets would place a physical limit on the amount of energy that that customer could consume from the grid (or export to the grid), and to the extent that their requirements change in the future, then this would require them to upsize those connection assets (or incur a cost equivalent to such an investment).

An example of how one business has operationalised this concept already is AusNet Services, which imposes a "capacity charge" on medium and large customers. For low voltage customers, the capacity charge is "*based on the nameplate rating of the transformer supplying the customer's installation. For sites where the transformer is not dedicated to the customer installation the charge will be established as the portion of the transformer that is allocated to the customer's requirements*". For High Voltage & Sub transmission customers, capacity is "*based on the rating of the cabling and switchgear that makes the customer connection point*". AusNet Services states that a condition for the review of the Capacity Value is *"(a) Increase to Capacity. Where a customer requires increased capacity, application may be made to AusNet Services for the network to be augmented to cater for the new requirements. Any variation will be made in accordance with AusNet Services' supply extension policy.*" In short, a customer could use DER to reduce its initial capacity charge, but if their requirements change in the future, they will be charged accordingly. The analogue of this type of price signal could be adopting a "range of connection products" with, for example, different export limits, as the comment suggests.

In relation to the potential use of "area-based" connection charges to signal the cost of extending the shared network, it was noted that *"similar to the previous comment, it's likely to be hard to estimate this at the time of connection, and it should allow for it to be either a rebate or a charge depending on whether DER increases or reduces these costs*"	Again, from an operational perspective, the extent that this type of price signal (i.e., regarding the costs of extending the existing shared network to a new area) needs to be operationalised through charges that provide for a "range of connection products", then we completely agree with the comment.
In relation to the use of SAPS in lieu of replacing network assets (e.g., SWER lines), it was noted that the AEMC "*considered and rejected this option in its SAPS review as it would raise a lot of consumer protection issues around ensuring the customer is making an informed decision, and the DNSP using a SAPS solution to deliver a replacement is likely to be a better alternative"*…. If the "*recommended law rule changes in the AEMC's SAPS review are made ….then DNSPs will be able to use SAPS for replacements so the rebate should only be based on the avoidable cost of the DNSP using a SAPS solution not a traditional grid-connected solution and may mean this option isn't needed".*	We note the AEMC's proposed law change that would allow DNSPs to potentially use SAPS as an alternative to a network replacement solution. We would however note that conceptually, the adoption of any rule change in relation to the use of SAPS does not change the *potential* for a DNSP to adopt such a pricing approach. However, as is alluded to in the comment, what it does change is the potential economic benefits that might ensue from adopting such a pricing approach. For example, if the majority of customers who may be able to change their behaviour in response to an economic price signal regarding the cost of replacing the existing infrastructure used to service their property with a SAPS system were instead provided with a SAPS under the AEMC's proposed Rule change, then the gross economic benefits that are likely to ensue from implementing that price signal diminish. It would be up to individual businesses to assess whether the gross economic benefits of adopting such a pricing structure exceeds the implementation costs. having regard to the impact that the AEMC's proposed law change (assuming it is adopted) might have on the magnitude of those economic benefits.
"*The Network is responsible to establish and maintain the safe operating parameters for connected customers. At present this is provided via a fuse, or an export agreement for PV customers. In the future this may move to the "operating envelope" style of connection agreement and may become dynamic. The objective here would be to maximise the size of this operating envelope to support the broadest level of market operations that is economically feasible. The slides on direct connections and extensions could be improved to discriminate between these two roles.*"	We agree with this comment, and in particular, the comment that the "*objective here would be to maximise the size of this operating envelope to support the broadest level of market operations that is economically feasible*". In fact, we would argue that the only way this can be achieved is if DNSPs price DER services appropriately so that the market facilitates efficient outcomes. To the extent that this *doesn't occur*, it is impossible to know whether or not the industry has met the dual objective of "maximising the size of this operating envelope to support the broadest level of market operations" at a level that is "economically feasible". The objective of the slides is not to outline in minute detail exactly what roles and responsibilities the DNSP plays – we have assumed that readers understand these roles.

"*As the network increases visibility and understanding of the LV system, it may seek to procure support services of the types described in the slide deck. These services may in the future be competing with other market services for access to the consumers DER - as such there is a clear need to ensure separation of these two roles*".	We completely agree with this. Theoretically, DER facilities could provide services into both network and wholesale markets. This is why, in our discussion, we have attempted to clearly separate out network services from wholesale market services – they need to be considered separately, and in theory, priced separately, so that providers of DER services see price signals related to each of these markets, and as such, can allocate their services to their highest value use (which may lead those services to be allocated to networks at certain times, and the wholesale market at other times).
"It may be useful to note that consumers also see value streams from DER around PV self-use and backup. It is important to keep these in mind when we are looking at how consumers may choose which external markets to participate in".	We agree that customers will see value from DER around PV self-use and back-up. The important point to note is that for customers to make efficient decisions regarding the amount of these services they procure (and the trade-off between those services), they need to face cost reflective tariffs / rebates.
"Connection costs. There is a long history of residential customer connections being provided without upstream charges if the consumer was connecting to the "line of mains". This has historically been a major contributor to augex. In addition, are we conflating new connections with connection alterations? A new air-conditioner or PV is not a new connection, but it is an alteration. The contract/agreement between the new customer and the network will establish the maximum demand (import and export) that the consumer will have access to".	It is our understanding that there has not been one common approach to charging connection costs historically. Rather, various approach have been adopted, depending on the jurisdiction. These range from providing for direct connection and augmentation costs to be included in an NPV analysis, via the adoption of an incremental revenue less incremental cost approach (e.g., Guideline 14 in Victoria) – which led many customer-specific direct connection costs to *not* be charged to the connecting customer upfront - through to connecting customers being required to use accredited service providers to provide direct connection works (at their own upfront cost). We agree that a new air-conditioner or PV system is not a "new connection" per se, however, if their load (or export requirements) were to lead the network business to incur addition shared network costs, then that should be signalled to that customer via the adoption of (a) cost-reflective shared network consumption tariffs in relation to the additional load from the air-conditioner (which is outside of the scope of this project) and (b) cost-reflective price signals for DER-services (which have been described earlier in this report). To the extent that such additions cause "connection alterations", that is, changes to the assets that are only used to serve them, then these should be priced in a similar manner to a new connection. That is, the customer causing the cost to be incurred should face a price signal that reflects the full economic cost of that decision, so that they are then able to trade-off that cost against other potential options (e.g., the use of on-site DER). The AusNet Services capacity charge (mentioned earlier) is a good example of such a price signal.

"Shared network extensions are most commonly made to an individual or company, not to a group of future connected customers. As such, the extension agreement will usually be tied to a caveat on the subdivision (future customers) that dictates DER requirements. The future contracts/agreements between the new customers and the network will establish the maximum demand (import and export) that these consumers will have access to".	This may be the case, and we see no reason why the strawman pricing arrangements presented in this document wouldn't align with this. For example, "the individual or company" (noting that the company may be a developer, who in turn sells land to end customers to construct houses on) could be sent a price signal regarding the cost of extending the network to service their development, and that individual or company would make a decision regarding the costs and benefits of extending the shared network under the "with" and "without DER" scenario. If the customer chooses to downsize their connection to reduce their upfront connection costs, then this would be reflected in the physical assets constructed. If, at some point in the future, the customer chooses to increase their loads above the physical capacity of the (extended) network that they originally funded, then they should face the incremental costs of upsizing those assets. Where the customer is a developer, then they may not directly incur the costs of the DER solution that is required to keep demand within the physical constraints imposed by the (downsized) extension asset that they have chosen – despite reaping the benefits of the lower upfront extension costs. However, they will indirectly incur those costs, by virtue of the fact that end customers will factor this into their willingness to pay for land in that development.
"Note that DER can create increased export and import demands on the network. Deferred augmentation is a service that DER can provide to networks; noting that there will be competition for access to the DER resource".	Agree. All services provided to DER facilities and received from DER facilities (by network businesses) should be priced.
"P19&20 - These slides are repeating the same constraint driven issues already covered in p13 to p16. Voltage in the network is now limited by (modern) inverter operations to 256V (AS4777). At this point, all recent and new PV and battery systems will disconnect and the network voltage will stabilise at this point. There is not a constraint driver here for the network to manage, however there is now an opportunity for the network to create additional voltage headroom to provide customers with increased export capacity. *This is a complex area as the costs of managing the constraint (over-voltage) have essentially been socialised through the AS4777 inverter standard rather than the traditional network method."*	The comment appears to indicate that the respondent considers that the slides related to voltage are akin to the same constraint driven issues already covered in p13 to p16, which relate to shared network augmentation costs. Whilst both relate to the shared network, it is our understanding that the drivers of investment in the shared network could be either voltage driven, or capacity driven (thermal rating), which is why we have treated them separately. Put another way, a price signal that is designed to incentivise the efficient discharge of batteries when capacity constraints are experienced on the shared network may not be the same as what is required to incentivise the charging of that battery to alleviate over-voltage issues. This is because the costs imposed on the network are likely to be different in the two situations.

We agree that voltage issues may be being ‘managed’ by modern inverter operations (including through throttling down and throttling off PV systems during over-voltage events). However, as the comment suggests, “*there is now an opportunity for the network to create additional voltage headroom to provide customers with increased export capacity*”. Moreover, whilst inverters are a way of ‘managing’ voltage issues, they are not the only way, and given current pricing arrangements, it is impossible to be assured that they are the most efficient means of managing those issues now, and into the future. For example, it could be that by signalling the economic cost of managing these voltage issues now and into the future to the market (including the economic cost to existing PV owners of having their invertor throttle their PV production down or off), the market may be able to provide a more efficient solution than current reliance on inverters (or an alternate network solution). For example, batteries are a feasible (and potentially cheaper) means of managing over-voltage issues. If no price signal were presented to the market in relation to the management of these over-voltage issues, there would, everything else being equal, be (a) under investment in batteries (because the market could not monetise the potential economic benefit that the use of those batteries may provide to network businesses or the PV owners that are in effect managing those over-voltage issues via their inverters), and (b) under-utilisation of any batteries that have been installed (again, because of the absence of the price signal regarding voltage support).

4. Markets and market operations

4.1. Wholesale market integration

DER has always, to some extent, been integrated into the wholesale dispatch of energy. Retailers have used demand response and distributed generation to offset their costs and to retain customers with favourable tariffs. However, neither this[7] nor the range of available pricing options is always visible to the market.

Recent retail entrants have begun to offer different pricing approaches to reward flexible loads that allow customers more control over their costs. This commercial differentiation has only had limited success at the domestic level, but Flow Energy has achieved some penetration in the commercial sector.

This section, therefore, may describe some current practices as well as different alternatives. However, because DER arrangements between retailer, aggregators and customers are not published (like network tariffs), it is difficult to identify which approaches are used and how many customers are providing DER.[8]

Wholesale market characteristics

In section 2, we described the four characteristics of efficient pricing; sustainable, responsive, efficient and fair and noted that these principles are reflected in the Rules, particularly the rules for wholesale market operation. The key underpinnings of the market are:

Efficient dispatch characteristics support efficient pricing:

- The Financially Responsible Market Participant (FRMP), who pays (or is paid) for energy sees the efficient price at their connection point. The market operates so that the all parties see the marginal price, adjusted for losses. Therefore, for energy the efficient price is always borne by the market participant. This party can:
  - Reduce the price variability (risk) for their customers and price efficiently or not. This can be an issue if the user of the product does not see the efficient price but the FRMP always has the ability to charge in ways that reflect the efficient price;

7 Retailers are required to report their DER activities against key peak load periods as part of SOO preparation. This is, however, a subset of the actual DER in use. In addition, the separation of networks from generation and retailing, can reduce the ability of both purchasers and sellers of DER services from “stacking” the services to optimise the outcome.

8 The ARENA funded programme to provide additional RERT resources using demand response does contain some information but pricing is not included.

- Manage prices so that the signal is enhanced, for example peak price rebates, which provides a better and more focused reward for DER.
- Use DER as part of their own risk management. Rather than contract an energy supplier to financially cap a price for a period, DER can provide the general cap or even very focused support during times of high demand and high prices. Incorporating DER into the FRMP risk management practices can reduce costs overall, reducing costs to customers in a competitive market.

While there is some evidence of increased competition between retailers using creative pricing approaches that incorporate DER, evidence from overseas shows that allowing third party advisers and aggregators (often called "intermediaries") to access the wholesale markets dramatically increases the use of DER in markets. For example, the high level of DER in the PJM market compared to the Californian market demonstrates that third parties that can access the wholesale market price will increase the participation of DER providers. This is also seen in other markets, notably the French[9], UK and Irish markets.

A lot of the pricing approaches covered in this paper may already be in place. This paper covers the approached that could be used and increased activity on the part of aggregators will increase their use. The key points are that the market operates efficiently from an economic perspective and that the retailer or aggregator can convert the price for end users.

As discussed above, the wholesale market, and the surrounding contracts, are economically efficient by design. The issue for this paper is therefore in the translation from the efficient exchange market to the retail market.

DER (including DR) can potentially reduce investment and operational costs in the wholesale market both by providing a lower cost of supply during dispatch and also by being contracted for future supplies of energy thereby avoiding investment.

DER can also reduce system losses by reducing central system demand but this is a second order effect and difficult to quantify.[10]

9 The French representative to CIGRE Study Committee C5 commented that allowing third parties into the market was more important than tariffs in increasing DER penetration.

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

4.2. Issues in translating wholesale market costs

There are issues with the use of DER, particularly DR or process-based generation, as an alternative to investment in normal supply side generation. The key issues relate to how the costs are recovered, given their nature. The costs are:

- Cost of investment, which occurs at the time of investment and connection, which is a long time before the plant operates and gains income from the market. These costs include:
  - Construction and commissioning;
  - Land and related costs;
  - Cost of connection (mainly network costs but recovered in the market); and
  - Establishment of market facilities.

These costs are capitalised and recovered as fixed costs in the market via the margin between the operating costs of the plant and the plant income.

Figure 9: Approaches to wholesale pricing to integrate DER

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

The income comprises pool (and contract) income and ancillary services income.[11]

- Cost of operations, which occur at the time plant generates. These costs include:
  - Fuel, a fully variable cost. Fuel, as a concept, includes the wind that drives wind turbines, solar insolation, diesel/distillate, coal and gas. The use of fuel is directly proportional to energy production.
  - Operations and maintenance costs. These costs are also proportionate to usage but not perfectly, and factors such as the number of starts the plant experiences and time-based maintenance are included.
  - Licence and participation (both generation and retail).

4.3. Pricing approaches

As shown in Figure 9 above, DER can be used in the wholesale market to displace other generation and can allow a reduced cost of dispatch. As noted in section 4.1, above, this can be done by the FRMP or an intermediary with access to the pool. Importantly, the actual relationship between the customer and the FRMP or intermediary is not important to the pool outcome.

11 In an energy only market, like the NEM, the pool price represents the efficient long run costs of the industry, both operating and capital. Facilities enter the market if they expect their cost of operation to be below the long-term average pool price and leave the market if their costs are above that price. The NEM has always had a capacity remuneration mechanism as a backstop – the Reliability and Emergency Reserve Trader (RERT). In recent years, the RERT has become a permanent fixture in the market, allowing some facilities, primarily demand response, to gain a second income stream. The recent adoption of the Retailer Reliability Obligation, which is a form of forced contracting, raises the potential for supply sources, including DER, to gain an additional, stable income stream. This should allow increased use of DER in the market as income will be more predictable.

While pool dispatch allows a lower price, and there is some debate in the literature about the real impact of just impacting pool price[12], the use of contracts to firm up the arrangements between suppliers, as shown in the last row in Figure 9, would allow FRMPs to incorporate DER into their risk management, reducing the need for contracts with generation. This would lead to a lower cost of supply to customers by reducing the operational costs of retailers and it could also potentially displace generation augmentation (or hasten plant shut down).

In some overseas markets (PJM for example), the use of DER (primarily responsive loads) in capacity markets has allowed the reduction of installed capacity. In others (France and the UK), DER provides a more flexible response in dispatch, allowing a reduced reliance on other fast responding plant.

The NEM currently allows FRMPs to operate in the pool using DER contracts with customers and DER providers. In addition, new Rules are coming into force that allow intermediaries to operate in the pool. There are therefore few restrictions on the application of these pricing approaches and, since direct contracts between parties in the NEM are confidential, some or all may already be in use, unbeknown to the authors.

12 There is little direct research on pool price impacts of DER but some renewable supply studies are relevant. For example, Salo et al (2013), Ketterer (2012) and Martinez-Anido et al (2016) examined the impacts of renewable supplies on market prices and volatility. Ketterer (2012) and Martinez-Anido et al (2016) both examined single markets and found that the price is reduced on a long-term basis but with increased volatility. Analysis by Salo et al (2013) showed, however, that the impacts were market/country specific. Where the renewable supply coincided with peak demands and was relatively stable during those periods (as in the case of Denmark) both prices and volatility were decreased. Where the supply was not coincident or more variable (as in Germany and by inference, New England), while price was depressed, volatility increased. The former outcome is stable, while the latter is not (and is similar to the Australian experience).
It could be argued that DER can be channelled to the peak price periods and be stable when used, which should provide an outcome like that experienced in Denmark in the Salo and Siddiqui study, which would be both economically efficient and market stabilising.

4.4. Market operation cost drivers

Key points made in the Cost Driver Paper

1. The market operator must ensure the correct amount of reserves in the market. The level of reserves required is forecast and calculated by AEMO based on the USE standard set by the Reliability Panel.
2. 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. This is discussed in section 4.1 above.
3. DER (particularly DR through load reduction or the use of behind-the-meter standby generation) has been proven to be the main source of emergency reserves for the NEM.

Objectives of pricing DER for this service

Provide a more flexible and cheaper source of reserves than traditional, supply-side options.

- The true value of the DER needs to be identified and paid to the DER provider:
  - This may actually be an intermediary, who receives the economic cost but has an alternate arrangement with the customer that is providing the energy source or curtailing their load.

Figure 10: Potential pricing approaches for 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*.

- Valuing what could have happened, in the case of load curtailment, is fraught and the provider and the receiver of DER need to agree on the rules that apply to the purchase – see issues below.

4.5. Pricing approaches for market reserves

Figure 10 shows some approaches to reserve pricing. These are in use in various markets in Australia and internationally.

The simplest way for a market operator to ensure reserves is to purchase capacity centrally up to an amount determined by themselves or some regulatory body. This approach is used in Western Australia and overseas markets, for example PJM. In this approach, the relevant level of capacity is remunerated, and the actual energy market operates to recover the operational costs of the participants. This approach can either focus on the value of the capacity to be purchased (Row 1) or the amount of capacity to be purchased (Row 2) in Figure 10.

In the NEM, capacity is remunerated in the energy market (discussed in section 4.2 above), including in the new Retailer Reliability Obligation. The role of the market operator in the NEM is therefore to purchase additional reserves.

Methods for pricing this additional reserve are shown in rows 2 and 4 of Figure 10, which are similar to the Reliability and Emergency Reserve Trader in the NEM, where both permanent and optional approaches are used. The only variant is that in the pricing approach in Figure 10, any pool income is retained by the market operator and the reserve provider only gets the contracted amount for their service. Note that this may vary from the simple energy value and is often a combination of availability and operational payments.

In some overseas markets, and from 1 July 2019 in the NEM, rather than the market operator providing the reserves, retailers are obligated to provide a level of reserve in proportion to their expected customer load. This is a mandated form of the contracting that they would already do under normal circumstances with the addition of a set level of reserves over and above the level that the retailer would contract for its own risk management purposes. This is the Retailer Reliability Obligation that commenced last July in the NEM. This approach is shown in row three of Figure 10.

Issues in using DER for market reserves

There are a number of issues in using DER, particularly load reduction, for the provision of market reserves. These include:

- Measurement. While most supply side and generation solutions can be readily measured (via metering) and are often monitored every six seconds, demand side generation and load reductions are not so easily measured. There are two main concerns:
  - Metering on the demand side measures energy and, in most cases, reports the energy use over a 30-minute period. Demand can vary substantially during this period and therefore, while capacity provision can be inferred from energy use changes, there is an unknown error. Five-minute metering[13] will reduce this problem but that will not be universal in Australia for a long time
  - Measurement of small variations in demand, particularly estimating energy not used, is difficult. While there are a number of approaches to measure a change due to a specific event (for example, control groups and baselining), the measures are prone to large errors if the load is not predictable.[14] This is a known problem with incorporating DER into markets but is particularly acute where the market operator is purchasing the energy on behalf of customers as the risk is borne by retailers and customers.
- Firmness. Market reserves are purchased for emergency and reliability needs and therefore need to be available when required. Most DER, particularly load reduction and storage, are either not firm or do not have a high level of reserve. Therefore, unless aggregated efficiently, DER can be less effective for reserves. This is particularly a problem for behavioural reserve that responds to a call rather than being centrally controlled as any particular site may not respond to a particular call. This issue can be reduced if a larger amount of reserve is contracted than actually required, so the shortfall does not prevent the provider from meeting the reserve requirement.
- Not included in forecasts. DER needs to provide additional energy to the market to be considered as reserves. This means that:
  - DER which reduces the load on the market, rather than in response to a direction of the market operator, cannot count. This is because the market forecasts that identify the need for reserves already assume stochastic variations in demand. For the purpose of reserves, DER must respond to a call.
  - DER that is already contracted in the market, even if not for a specific moment, cannot be used for reserves as the load reduction is already included in forecasts.

13 Five-minute settlement will not resolve this issue unless it is supported by five-minute metering as the use of a profile for settlement provides no information about a change of energy use at a site.

14 Studies such as “California ISO Baseline Accuracy Assessment” (2017) by NEXANT explain the measurement issue in detail. A study for AEMO (then NEMMCO) regarding measurement for the Wholesale Demand Response Mechanism – “Development of Demand Response Mechanism, Baseline Consumption Methodology” (2013) by DNV KEMA - also discusses this issue and included the method that is used by AEMO for the RERT.

4.6. Pricing approaches for ancillary services

It had always been thought that DER, particularly highly flexible loads, would be able to be used in the NEM Ancillary Services markets and this is now occurring to a limited extent. This paper provides some pricing approaches that can be used.

Key points made in the Cost Driver Paper

1. The cost driver paper noted that the market operator must ensure that sufficient ancillary services are available to the market at all times. To this end, Frequency Control Ancillary Service (FCAS), which are readily supplied from a number of market sources, are provided by a market that is co-optimised with the energy market.
2. DER is a good source of FCAS and, as noted above, some integration is already occurring.[15]
3. Other forms of Ancillary Services are less amenable to DER but DER could, with the right conditions and Rules be involved in the provision of these services. These are:

Figure 11: Pricing approaches for Ancillary Services

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.
Ideas welcome for SRAS and Reactive Support				

15 Frequency control and regulating ancillary services require high speed metering to be measured and assessed for payment, which is only now becoming available cheaply. One SRG member reported that they are currently doing 6 second FCAS (high speed metering) in the market on DER sources as small at 2.5kW (and could economically go lower). They have high-speed FCAS compliant meters installed on 99% of their sites at a cost less than $100 per site. Further, they expect the next generation of meters to be capable of 3 phase FCAS for less than $60. With competition in metering, and the need for DER metering, it is expected that this form of metering will be readily available in the near term.

a. System Restart Ancillary Service (SRAS);

b. Regulation services and Fast Frequency Response FFCAS); and

c. Reactive power (Voltage support).

SRAS requires that the supplier is able to provide a significant amount of capacity to allow restart of a major part of the grid. This means that most forms of DER are not able to participate. Storage is, however, able to provide this service if of sufficient size (e.g., the TESLA battery in SA) or where it can be linked to a larger facility.[16] This is a tendered service – AEMO seeks suppliers every 5 years and offers a 5-year contract.

Regulation and FFCAS both require highly responsive plant and storage devices have been shown to be able to provide this service but, as yet, the storage technologies (e.g. batteries) and distributed generation, have not proved economic in these roles.

Reactive power requires an energy source (storage) and power electronics. To date this has not been economic. This service is purchased by AEMO as required.

Objective of pricing DER for this service

To allow DER to be available for this service it must be treated the same as other sources; that is, to compete on an equal footing to supply side services on technical and performance grounds, where possible.

Figure 11 shows some potential approaches but until the technical issues are resolved there is little opportunity for DER to participate in the provision of Ancillary Services other than FCAS. SRAS service is an opportunity, which could be explored during the next tender by AEMO.

16 There are a number of examples of plant combinations being used for SRAS service, including Dry Creek PS and Torrens Island PS (TIPS). Dry Creek PS has three 1MW diesel gensets that can be started without external power, these units then start the main station (30MW), which can then start a TIPS unit (either 120MW or 200MW) which is sufficient for SRAS.

5. References

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