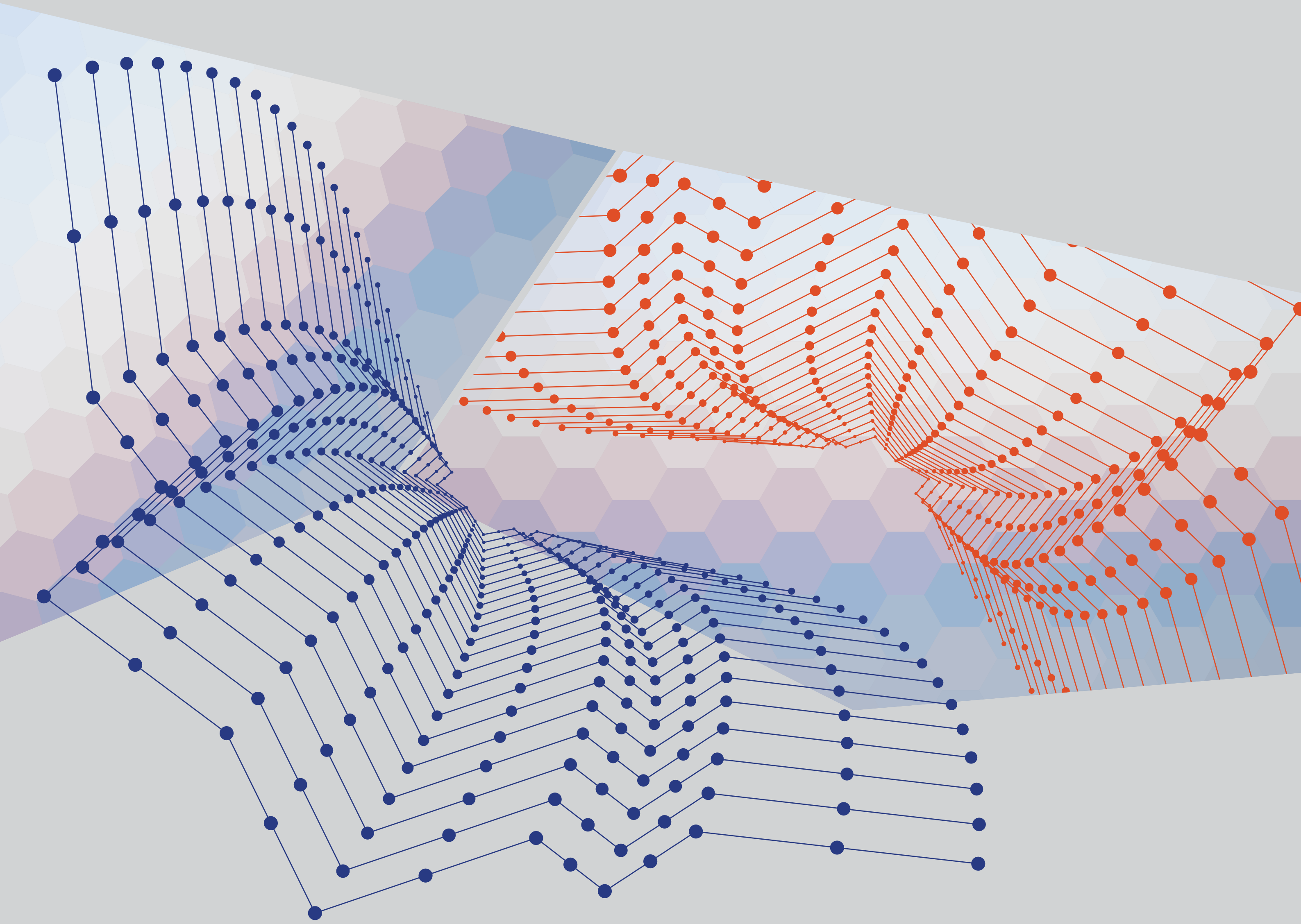
OPEN ENERGY NETWORKS

Consultation on how best to transition to a two-way grid that allows better integration of Distributed Energy Resources for the benefit of all consumers

A Joint AEMO and Energy Networks Australia Initiative



Contents

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Executive Summary

Australian consumers have, over the past 10 years, heavily invested in rooftop PV and the Australian Energy Market Operator (AEMO) forecasts this trend will continue for the foreseeable future. In addition, storage solutions (mostly household batteries) have entered the market and consumers are predicted to also adopt these enthusiastically.

Uptake of these technologies is leading to an increasingly decentralised energy system, where a significant amount of electricity is generated at a smaller scale. Some local areas already experience a high level of decentralisation, where the traditional one-way power flows from transmission through distribution to consumers have become two-way flows.

A number of opportunities and challenges arise with increased decentralisation. The emergence of Distributed Energy Resources (DER) as a resource to individual customers provides those customers with an opportunity to reduce their power bills. If, however, DER integrates into the power system as a resource, its presence provides further opportunities to delay or eliminate the need for certain network investments and function as competition to traditional large-scale generation for both energy and system support services. DER can also enable greater levels of renewable integration and supply additional resiliency to the networks.

DER can be both a passive or active participant on the network. Rooftop PV is an example of passive DER. While its production can sometimes be forecasted with a high degree of confidence, the lack of control over solar output means that the system and the local network need to be adapted to cater for solar penetration.

Active DER includes storage solutions such as household batteries. Batteries are controllable but their behaviour is harder to anticipate unless they interact with the system. Other examples of active DER include more sophisticated home energy management systems that can adjust electricity usage in response to price signals or dispatch signals.

Both active and passive DER create challenges for the electricity system. At a local level, distribution businesses are responsible for managing voltage levels within a regulated standard and traditional approaches to managing this can be ineffective. Local networks also have physical limits on the amount of DER they can host. When these limits are reached, fuses may blow or equipment may overheat. These challenges only increase with the arrival of active DER.

At a whole-of-system and market level, AEMO, the market operator, is responsible for economically optimising demand and supply and ensuring the secure and reliable operation of the power system. To do this, it requires visibility of current and forecast demand and supply, as well as power flows across the system. While in the past it was relatively easy to predict household demand, the arrival of millions of new DER over which it has no visibility makes this exponentially harder.

If no action is taken to address these issues, customers will suffer. The quality of their electricity may degrade, affecting the lifespan of their appliances (e.g. too high voltage). Their existing investment in solar or batteries may take longer to pay back if they are constrained regarding the amount of electricity they can take from, or feed back into the grid. They may not get permission to connect a new rooftop PV system if their street is already saturated. Or, if the distributor makes costly investments to enable more DER to connect, the network charges on their bill may rise.

Coordination of these distributed resources is essential to alleviate these challenges and convert what could otherwise be a challenge to the system into an asset. There are also significant financial benefits to be gained from optimising the behaviour of these resources. This paper refers to this optimisation as orchestration. Energy Networks Australia's Electricity Network Transformation Roadmap 2017, developed with the CSIRO, estimated this potential benefit to be $1.4 billion in avoided network investment and a lowering of household electricity bills by $414 a year.

Traditional strategies include limiting exports from DER to the grid, upgrading the network and reforming tariffs. While important, these approaches affect a large area over a long period, whereas these specific challenges are localised and for very defined periods of the year. The challenges require more active responses.

More modern approaches consider dynamic strategies, which include both using and limiting exports in certain locations at certain times to reduce the impact of the intervention for customers in an affected area and increased use of shared storage at the circuit level to increase the hosting capability of the network. Other technologies look at voltage management both across the system and in individual homes to help further support integration of DER and facilitate a two-way system. New investment for those customers who have existing DER may be required as their technology needs to be made 'smart' so it can receive signals and incentives to stop (or start) exporting. Additionally, more visibility of the network condition at the local, low voltage level is needed so these signals can be created.

There is no question that a coordinated approach that facilitates integration of DER, considering both transmission and distribution constraints, will deliver the best outcomes for customers. Rather than imposing limits on customers, orchestration can help provide financial incentives to coordinate all elements of the system to work together optimally – and delivered at least cost to all consumers. Since one household-sized DER set-up cannot significantly impact the system, larger aggregators will sign up many customers and deliver their combined power to the system. Combining many DER, such as in a virtual power plant (VPP), can provide services like peaking generation, which increases competition and lowers costs for all customers.

Increasing levels of variable renewable energy in the whole energy system requires flexibility and efficiency. DER can provide demand shifting, load and resource balancing and become an integral part of a reliable, lower cost, secure system. Incorporated into AEMOs current optimisation process, VPPs will reduce the need for peaking plant and enhance system level resiliency. It is imperative, however distribution networks are linked into these processes to ensure the inclusion of DER in the system considers local network limits.

Distribution network businesses are responsible for operating and maintaining their networks within technical and safety requirements. AEMO is responsible for grid reliability, system security and operating the market. In this paper, Energy Networks Australia and AEMO are exploring how best to facilitate the entry of DER into the market. Our objective is to identify both the system requirements that must be addressed in the formation of a two-way system and to understand from traditional and new market participants how from a network and market operator perspective, we can reduce barriers to entry into the system and best facilitate innovation and competition at the grid edge.

Informing these considerations are key principles:

1. Simplicity, transparency and adaptability of the system to new technologies
2. Supporting affordability whilst maintaining security and reliability of the energy system
3. Ensuring the optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER
4. Minimising duplication of functionality where possible and utilising existing governance structures without limiting innovation
5. Promoting competition in the provision and aggregation of DER, technology neutrality and reducing barriers to entry across the NEM and WEM
6. Promoting information transparency and price signals that encourage efficient investment and operational decisions
7. Lowest cost.

AEMO and Energy Networks Australia will explore DER dispatch with the wider sector. Matters to be explored include whether aggregators have direct access to the wholesale market alongside existing generation resources, or whether a level of sub-optimisation at the local distribution level should be undertaken prior to dispatch at a whole of system and market level. This would provide benefits, such as:

» Integration of the two-way system and reducing barriers to entry may be achieved with a central platform provided by AEMO that interfaces with aggregators, with network businesses linked to the platform

» Increasing the productivity of existing network investment through the use of DER as a tool to reduce operational costs and support greater system efficiency

» Increasing the resiliency of the system through the strategic development of DER.

AEMO and Energy Networks Australia recognise that business models are evolving along with the technology to provide value to customers. Through this work program, we want to explore how best we can integrate DER into the sector and recognise that in doing so we must be broadly enabling of multiple business models and approaches. In particular, DER will be both passive and active on the grid.

Customers and prosumers will want to participate directly with the wholesale market through aggregators, retailers, virtual power generation platforms and in sub-markets that include peer-to peer trading that utilise block chain technologies. Energy Networks Australia and AEMO view these as opportunities for customers to achieve greatest value as they see best. The responsibility of the network owners and system operators is to provide the platform designs that enable access to the networks and to the market by customers and their representatives in a manner that is accommodating of many different business models with an overall objective of achieving the positive system outcomes outlined above.

There are several ways the platform can be designed and delivered, and Energy Networks Australia and AEMO are seeking insights from the market on what design would be preferred by participants. Three options are described below with an initial assessment of relative advantages and disadvantages. These are described more fully in the paper.

Single Integrated Platform (SIP) - The single platform model envisages a unitary point of entry to the entirety of the National Energy Market (NEM) and Western Energy Market (WEM). Under this option, the platform would be a regulated entity and an extension of the wholesale market. AEMO could support the platform as part of its market and system responsibilities and along with the individual distribution utilities will develop a single integrated platform that will use a set of agreed standard interfaces to support the participation in the integrated multi-directional market by retailers, aggregators, and VPP platform companies. The SIP will then simultaneously solve local security constraints and support wholesale market entry. Under this configuration, access to the platform will be a one-stop shop that provides market participants the opportunity to participate anywhere in the NEM or WEM without having to develop separate systems or tools to integrate with the various individual distribution platforms. Network businesses will be linked into the platform, with distribution business providing information on local constraints to AEMO. AEMO would consider this information and economically dispatch these resources alongside other resources (transmission connected load, large scale generation etc.).

The SIP design the SIP design extends the wholesale market used today. It also has the advantage of other two-way platforms because it can push information to participants such as transparent system requirements, and can integrate other relevant services.

Two Step Tiered Regulated Platforms - A second alternative is a model where there is a layered distribution level platform interface operated by the local distribution network and an interface between the distribution network‘s platform and AEMO. Under this design, individual distribution networks can design interfaces that best meet their system requirements. Participants would then need to communicate directly with the distribution level platform for the local constraint issues and the distribution network would optimise these resources against local network constraints based on bids from the aggregators servicing the area.

Distribution networks would provide an aggregated view per the transmission connection point. AEMO would take this information and consider the overall system security and economic dispatch.

This tiered model has some advantage in terms of allowing potentially greater level of autonomy for individual distribution utilities and therefore greater levels of bespoke approaches. Network businesses are best placed to manage their distribution network constraints. However, this model loses the scale of a unified design and may add risk and complexity to market approaches. The tiered model would represent more of a one-way platform, since as a tiered approach the information would flow one way from the distribution operator to AEMO and then from AEMO to the market.

Independent DSO - A third option that is a variant of the second is for an independent party – a DSO that is separate from AEMO and the distribution utility. Under this model the independent DSO would work with the distribution utility to optimise the dispatch of the DER based upon local system constraints that are provided by the network business, provide the aggregated bids to AEMO for incorporation into the larger dispatch. This option will be more complex than the others and may be significantly more costly.

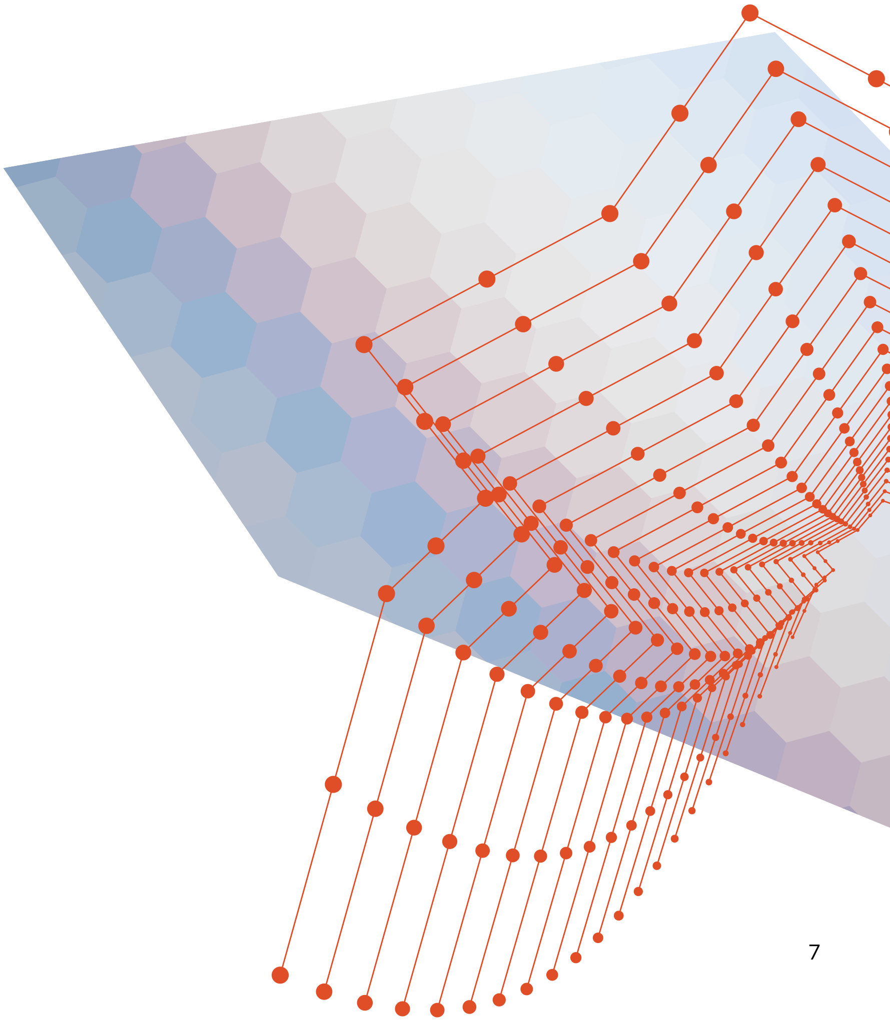
Various jurisdictions are examining these options. In the United States (US), the preference that has been identified in New York and other jurisdictions is for separate DSO’s for each utility. One aspect of this model under the US jurisdictional construct is that the DSO remains under the jurisdiction of individual states, while the Independent System Operator equivalent of AEMO is under the jurisdiction of the federal government. In the United Kingdom (UK) one of the five options being explored is considering allocating management of DER dispatch to another party; an independent distribution system operator. AEMO and Energy Networks Australia are considering this model, but given the need to establish a number of new organisations, the challenges of managing safety and reliability risks and associated cost, duplication and complexity of information flows, this approach is not favoured.

While the above options are thoroughly considered, there are actions we should take now. These include:

- Reviewing registration frameworks to allow large DER providers to participate in the central dispatch process
- Developing better criteria for the participation of VPPs in central dispatch
- Examining expanded information sharing between distribution network businesses and AEMO
- Continued work with local platform solutions to determine how best to integrated aggregated resources into the system
- Improved information sharing on the current bilateral agreements for DER services
- Building a better understanding of network constraints for individual distribution network business
- Developing standards for DER monitoring and management
- Continued development of market design to support demand based resource participation into the market.

We invite stakeholders, including partners, customers, innovators, businesses, policy makers and the wider industry, to respond to these proposed actions and engage with us in the coming months to further inform and guide the creation of a framework for the effective integration of DER. In partnership with stakeholders, the outcome of the process is to develop a white paper that will inform regulatory processes.

Comments on this consultation paper are welcome by 3 August 2018. A series of stakeholder workshops will work through various issues to inform the development of a White Paper. AEMO and Energy Networks Australia will communicate these in due course.



Glossary of Terms

Aggregator - A party which facilitates the grouping of DER to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s).

DER - Distributed Energy Resources; can refer to distribution level resources, which produce electricity or actively manage consumer demand e.g. PV solar systems, batteries, and Demand Response like hot water systems, pool pumps, smart appliances and air conditioning control.

Passive DER - Refers to resources such as solar, batteries, hot water services and other electrical equipment that operate under local algorithms and are not being remotely controlled by a third party (such as an aggregator).

Active DER - Incorporates external control inputs or data feeds that are being used to actively 'orchestrate' their behaviour in response to high prices or other conditions

DSO - Distribution System Operator; this term has been used to refer to the functions of Distribution Level coordination and optimisation of multiple DER aggregators in multiple markets operating at distribution level.

Optimisation - referred to here as the aggregation and prioritization of distribution level bids and offers; in other global markets also known as "orchestration".

1. Introduction

1.1 Context - A changing world

In the years since Australia's National Electricity Market (NEM) and Western Electricity Market (WEM) were designed, the system has gone from one that was dominated by central large-scale, synchronous power plants, and passive consumption, to one that includes a multitude of resources and technologies of various sizes. At the same time, customers are engaging with their electricity services in new ways, and with this, we are seeing a significant proportion of energy being generated at the customer premises – facilitating a move from a centralised to a decentralised system.

This trend is expected to continue – domestically and internationally.

These changes are expected to present operational challenges for AEMO and network businesses. With the right response and/or modifications to markets and technical mechanisms will encourage investments into the NEM WEM that will enable storage, generation and flexible demand to maintain reliability of the networks and the system for a lower cost to all customers. Figures 1 and 2 illustrate AEMO's forecasts for the installed capacity of distributed rooftop photovoltaics (PV) and distributed battery storage in the NEM and WEM, showing a forecast for ongoing steady growth.

Flexibility and rapid response will be an important operational characteristic as the power system transforms, and distributed energy resources (DERs) such as storage and demand side response can provide competitive sources of energy and system services. Unlocking the potential of DER can smooth the profile of grid demand and increase the utilisation network resources, resulting in a more productive and efficient power system for consumers – at both local and whole of system levels.

1.2 Australia in an International Context

Australia is leading the world in the decentralised transition as demonstrated in figure 3 below. It highlights that given current policy settings Australia will exceed the rate of decentralised generation in countries such as Germany in the next few years. Australia will be at the forefront of making the required changes to the market and systems to allow greater DER integration, and we will need to do so ahead of other countries and jurisdictions.

1.3 Technical challenges integrating DER

Australia's electricity system was originally designed to deliver large-scale centralised generation customers, rather than to integrate millions of customers owned generators. Traditional one-way power flows – from the transmission system, through the distribution networks to end consumers – are now increasingly two-way. The rise in distributed generation is leading to periods during which power is being exported from distribution networks onto the transmission system.

This growth in customer take-up of DER has already resulted in significant impacts to power quality in a number of jurisdictions, challenging existing approaches used by network businesses to manage voltage levels within regulated standards, and increasingly poses risks to network reliability and network security that networks must now manage, particularly with increasing deployment of virtual power plants.

Some of the system and market operation challenges include the lack of DER visibility, causing AEMO difficulty in operational forecasting and balancing the system and maintaining system strength. In addition, the response of DER to disturbances may also have significant impact on system stability and the high levels of DER hinder the successful operation of Emergency Frequency Control mechanisms. The increasing share of demand being met by Solar PV will make it more likely that AEMO will need to adjust normal market operations.

Figure 1: Projected installed capacity of rooftop PV and distributed battery storage in the NEM

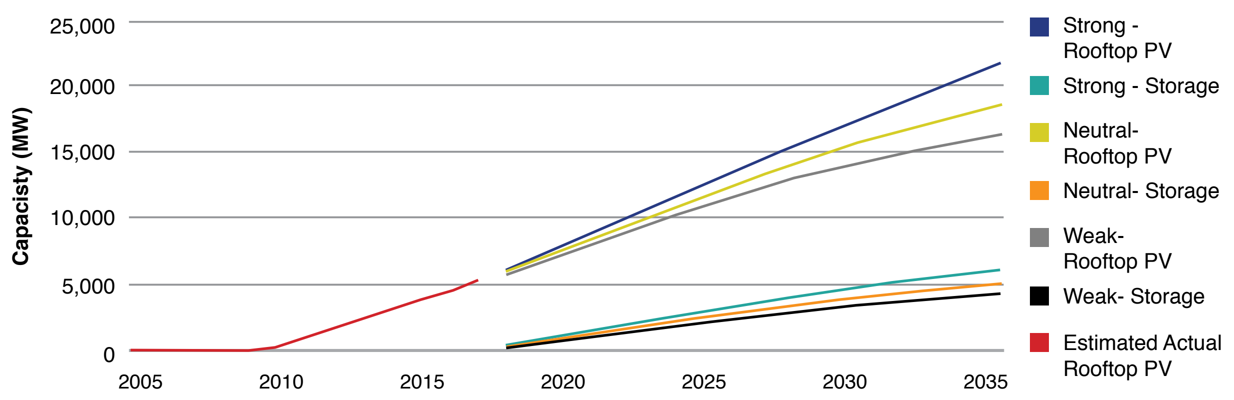


Figure 2: Projected installed capacity of rooftop PV and distributed battery storage in the WA

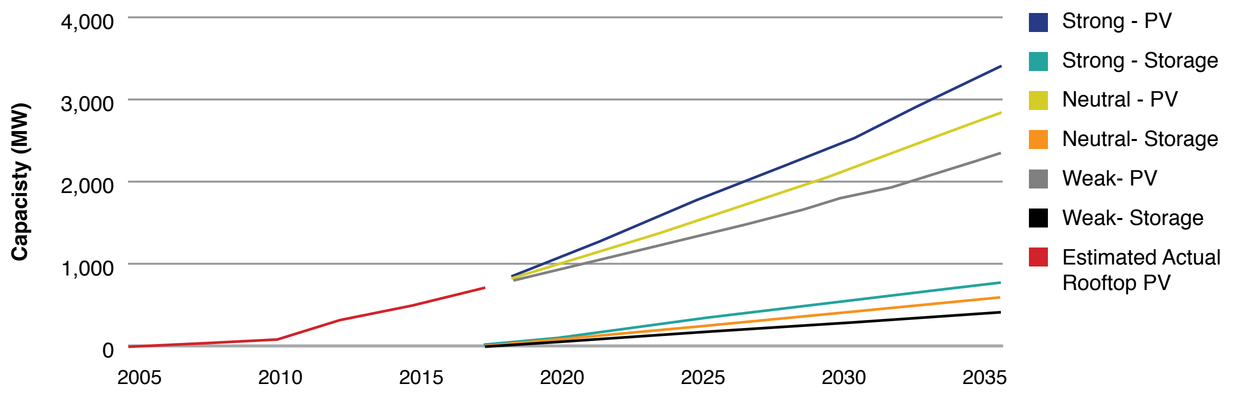
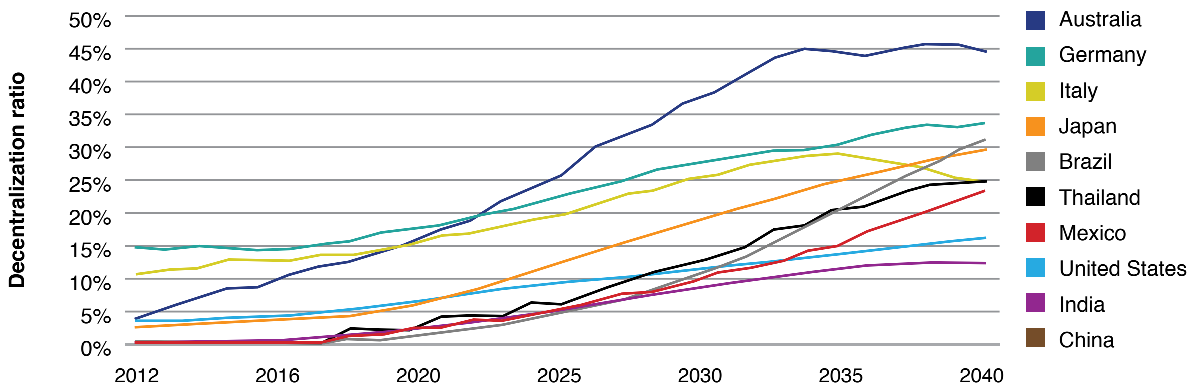


Figure 3: global rate of electricity market decentralisation



1.4 The importance of effective coordination

If these distributed resources are not managed well, it will result in increased network and system operation costs that will be borne by all electricity system customers.

Based on the modelling undertaken by CSIRO for the Energy Networks Australia-CSIRO Network Transformation Roadmap 2017, if the milestones and actions outlined in the Roadmap are followed in the establishment of optimisation and coordination of DER at the distribution level, it could provide a cumulative value of $158 billion by 2027 and be worth more than 50% of NEM value in 2050. This would be delivered through broad efficiencies to the system, improved system utilisation and customers being able to exchange value with the grid. This value will be provided, through the reduction in requirements, such as reduced requirements to build additional generation capacity and network solutions to deal with changes in demand, and providing customers with better value for the DER investments through access to new markets. For example, access of demand management services.

DER therefore provides both opportunities and challenges to the energy sector. If managed poorly it could increase cost, if managed well it could drive significant savings. Establishing effective frameworks to optimise the value of DER is therefore a critical contemporary challenge for the energy sector in Australia.

1.5 Purpose of the document

The purpose of this paper is to lay the foundations for the establishment of an agreed framework to facilitate increased levels of DER and particularly optimised DER. To assist in identifying the preferred pathway, this document is intended to set out some initial “straw man” frameworks to facilitate more concrete discussions with stakeholders.

Feedback on this paper is welcome from all market participants and stakeholders, and will be utilised to develop the subsequent White Paper. The White Paper will aim to identify a preferred high-level framework for a Distribution System Operator (DSO) or Distribution Level Optimisation.

While being undertaken by AEMO and Energy Networks Australia, this project is committed to ensuring all stakeholders can engage in the process to identify the preferred final framework.

The key question we would like all stakeholders to consider as they go through this document is:

“What new capabilities, functions and roles will be required to coordinate and optimise the value of customers’ DER investments whilst maintaining security and reliability across the NEM?”

2. Path-ways for DER to provide value

There is a broad range of DER technology sophistication ranging from simple passive DER such as residential solar PV to complex 'active' systems such as residential batteries with smart controllers that are capable of responding in a complex manner to price spikes.

These different types of DER release, or have the potential to release, value to customers in different ways.

Almost all DER currently installed is passive DER. Passive DER behaviour is likely to be diversified in time and location, and more likely to be relatively predictable provided that the weather (including cloud cover and temperature) and other local drivers such as retail tariffs, is known, for a given time of day and season.

Customers derive two primary sources of value from passive DER:

» Self-consumption (bill reduction) – by optimising local generation, storage and consumption of energy to reduce their electricity bills

» Passive exports (feed-in tariffs) – by selling surplus energy to their retailer to earn additional revenue.

These are the most common sources of value currently obtained by customers with DER.

Active DER incorporates batteries and demand response installations that are coordinated by an aggregator or retailer. Coordinated behaviour cannot be predicted purely based on weather and time of day or season.

Active DER provides additional potential sources of value to customers via:

» Participating in the National Electricity Market – with the assistance of an aggregator/retailer, customers can use active DER to participate in the NEM for energy, Frequency Control Ancillary Services (FCAS) and any other services.

» Bilateral agreements outside of the market – with the assistance of an aggregator/ retailer, customers can also establish bilateral agreements to sell DER services outside of the market. This could include network support (for example, for voltage control or to defer a need for network augmentation), services to AEMO (such as the emergency procurement services or system support), or peer to peer trading. Emerging blockchain or distributed ledger services may be used to value these DER services. Often these services have very high value, and only need to be utilised infrequently, so could potentially utilise spare DER capacity. They therefore have the potential to offer materially greater value to DER owners than purely passive operation. Currently very few customers have DER that is interactive, although many systems have active management capabilities.

Active DER therefore represents a significant untapped potential.

Consultation Questions:

1. Are these sources of value comprehensive and do they represent a suitable set of key use-cases to test potential value release mechanisms?
2. Are stakeholders willing to share work they have undertaken, and may not yet be in the public domain, which would help to quantify and prioritise these value streams now and into the future?

3. Maximising passive DER potential

The uptake of passive DER across the NEM has been dramatic. As of February 2018, the Clean Energy Regulator reports that there were more than 1.8 million registered small scale solar PV installations in Australia. In some states, notably South Australia, nearly one third of residential premises have roof-top solar PV.

Customer pay-back periods are based on value received in upfront incentives, feed-in-tariffs and substitution based on retail tariffs. These vary from state to state but typically, these have been in the 5 to 7 year range. Customers that have not yet installed systems have an opportunity to capture greater value as payback periods are projected to reduce due to that fact that cost of installation continues to decrease. In addition, industry consultants reported that one in eight Solar PV installations in 2017 included a battery.

Today's power system was designed for large synchronous generators and one-way electricity flow, not for high penetrations of DER and bi-directional power flows, and challenges are beginning to arise in areas with higher penetration. These have impacts at both the local network and whole-of-system levels, which are discussed below.

3.1 Local network challenges

Passive DER has significant implications on load profiles within local distribution networks. The diagram below illustrates the traditional demand profile for a group of 100 residential customers, and the impact on that demand profile of the addition of solar PV to each of those households.

The significantly increased range of power flows has impacts on:

» Voltage management – reverse flows tend to raise voltages in the network. The larger dynamic range of power flows challenges the capabilities of existing equipment and practices used to manage voltage. These issues can occur even up to the transmission level.

» Local network capacity – undiversified exports from solar systems may exceed peak demand levels that the local network infrastructure was designed for, potentially breaching capacity constraints on distribution transformers in particular.

Figure 4: Impacts of high penetration PV on customer demand profiles

SA Power Networks' Salisbury Battery Trial.

Networks only have a limited hosting capacity until these impacts result in the distribution business needing to either:

- Invest in network upgrades to increase hosting capacity;
- Restrict further applications for passive DER to be installed at those locations; or
- Implement more sophisticated means to manage DER impacts

These issues typically occur on the low voltage part of the network that has not historically been actively monitored or managed by distribution businesses. This being the case, the majority of distribution businesses have limited visibility and capability to manage these new types of challenges.

3.2 Security of supply challenges

As the penetration of rooftop PV increases, challenges are also projected to arise at system-wide levels.

Two states in Australia have increasing numbers of rooftop PV, the chart below chart illustrates how on minimum demand days in Western Australia, rooftop PV is forecast to provide all demand by as early as 2029.

The following chart illustrates how on minimum demand days in South Australia, rooftop PV is forecast to provide all demand by as early as 2025. Challenges will arise earlier than this date, because it is necessary to keep some synchronous capacity operating in South Australia to provide system strength and inertia. Even with the installation of synchronous condensers, some synchronous generation will need to remain operating for frequency setting purposes.

These units will need to operate at above their minimum loading levels. Furthermore, it is sometimes necessary to limit flows on interconnectors exporting from South Australia, if emergency conditions arise (such as severe weather, bushfires, or forced network outages).

Figure 5: AEMO minimum demand forecast for Western Australia

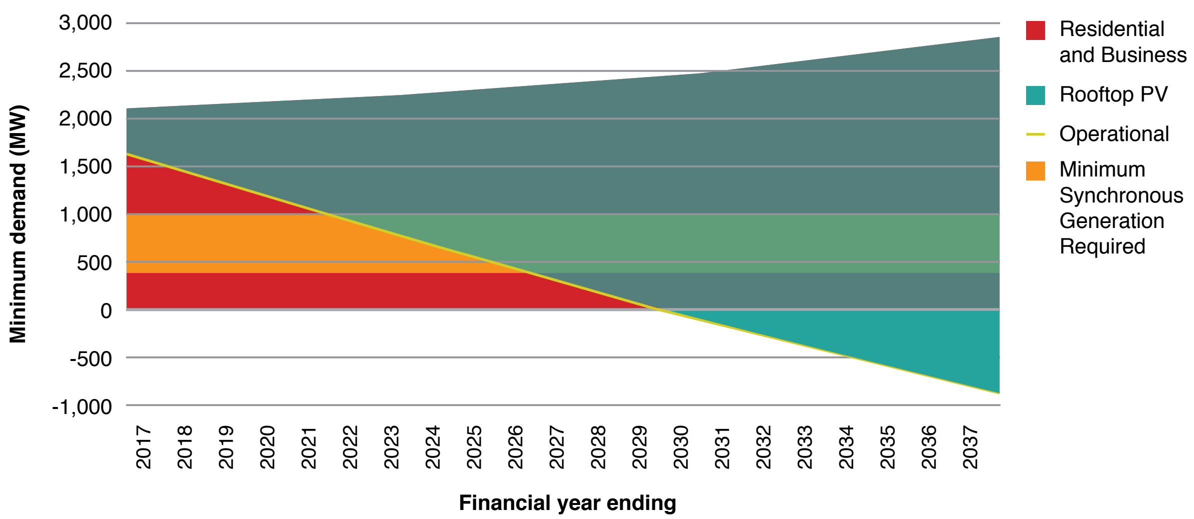
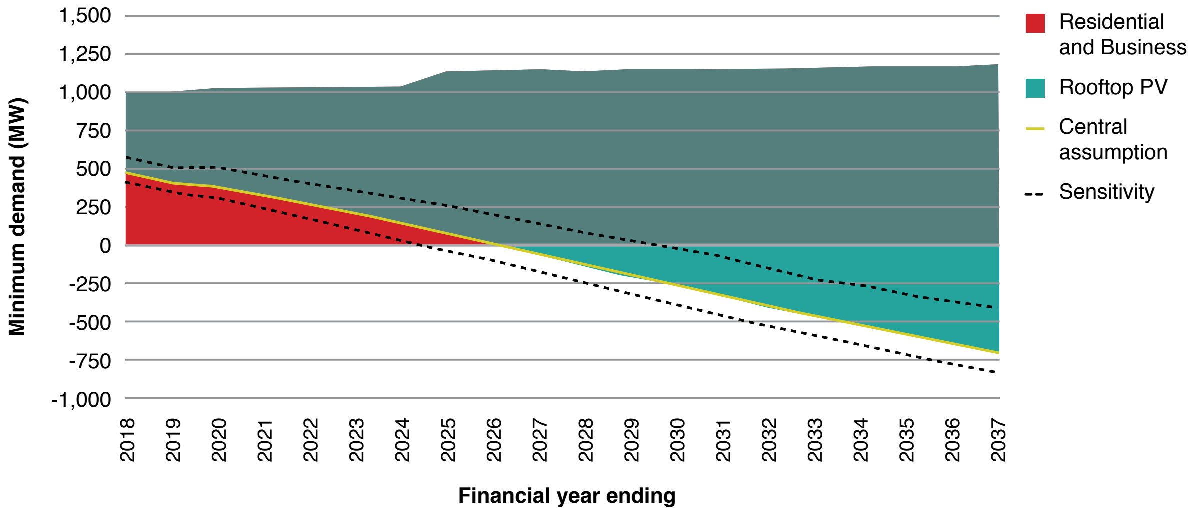


Figure 6: AEMO minimum demand forecast for South Australia



The following challenges are anticipated:

- From 2021–22, it may be necessary to curtail non-scheduled generation in South Australia in minimum demand periods, if it becomes necessary to reduce flows on interconnectors to zero. This represents an action outside of normal market operation, and highlights an emerging challenge.
- From 2024–25, it will no longer be possible to reduce flows on interconnectors to zero if required during certain periods. During emergency periods (such as bushfires, severe weather, or forced outages of network components) AEMO must be able to reduce interconnector flows to maintain the power system in a secure state.
- From 2027–28, it will become impossible to maintain flows on the Heywood Interconnector within the required limits during periods where South Australia has a credible risk of separation (planned or unplanned). Planned outages can be scheduled to avoid minimum demand periods, but unplanned outages may occur at any time. This means the South Australian power system will no longer be secure if an unplanned outage occurs at a time of minimum operational demand.
- From 2036–37, it will no longer be possible to maintain flows on the Heywood Interconnector within nominal limits and ±3Hz/s RoCoF limits. Beyond this point, it will become impossible to operate South Australia within secure limits even under system normal conditions, in the absence of intervention.

A suite of solutions are available to address these challenges, and can be implemented in parallel. These include promoting load shifting (aiming to increase demand in the lowest operational demand periods), promoting the use of centralised and decentralised storage, expansion of interconnectors, and network investment including synchronous condensers, voltage control equipment, and resistor banks.

The transition of rooftop PV systems from passive to active capabilities would also facilitate coordinated feed-in management, which could also address these challenges. It is anticipated that feed-in management for rooftop PV systems would be called upon very rarely (less than 1% of the time in 2025, and less than 4% of the time in 2035), and would only be necessary during "emergency" conditions to maintain power system security.

3.3 Managing passive DER to release value

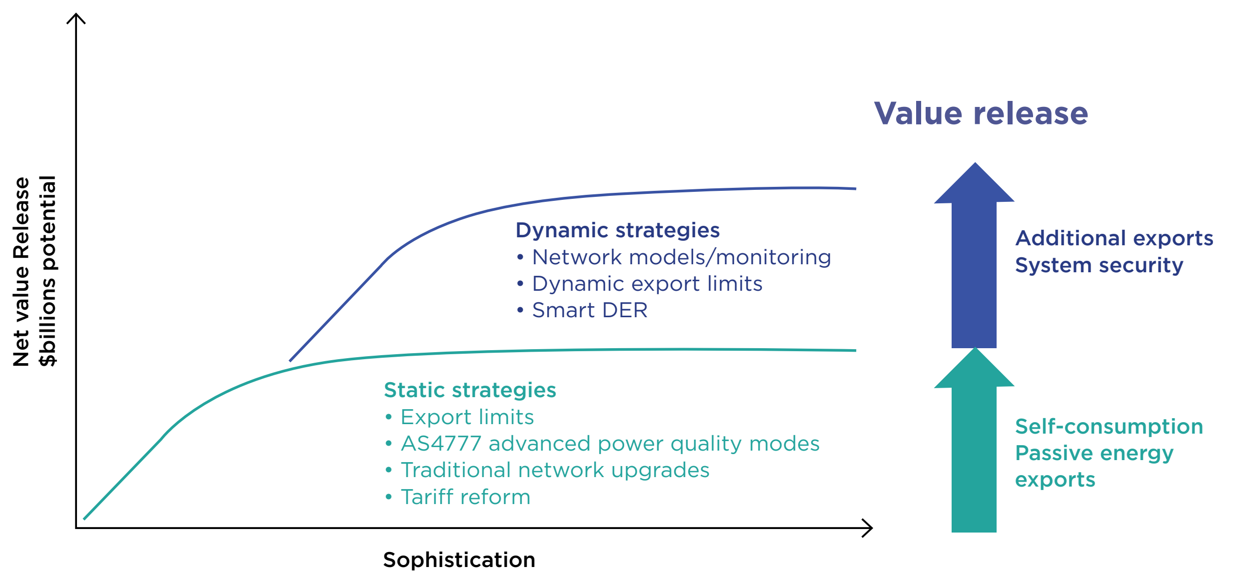
Although some of these challenges could potentially be resolved by blanket limits on grid export, either locally or globally, this would significantly reduce the value to customers investing in such systems – essentially limiting DER value to self-consumption alone.

Blanket restrictions are also highly inefficient in that passive DER tends to only cause issues for relatively small periods of time in the network or system. AEMO forecast that even by 2035, issues in South Australia caused by excess rooftop PV are likely to occur less than 10% of the time. Issues in distribution networks will typically be limited to mild Spring weekdays, and only in certain parts of the network which typically have older, lower capacity distribution infrastructure in place.

Equally, wide-scale investment in networks or grid-side solutions would seem imprudent to deal with issues that only occur for short periods of time in certain locations.

As presented in figure 7, an efficient strategy would be one that transitions from static management of DER, applying export limits and undertaking network upgrades, to dynamic management of DER where DER output is managed only at times, and in locations where issues are predicted to arise. Dynamic management on the rare occasions when system challenges occur will enable higher penetrations of passive DER to be securely integrated to the grid, and will increase the value of DER to the network, the system as a whole and ultimately to the customer.

Figure 7: Additional value release enabled by dynamic DER management



3.4 Capabilities to dynamically manage DER

Implementing dynamic control would require new capabilities to be developed within the distribution sector, DER vendors and AEMO. These would include:

» **Network modelling and monitoring** - which would need to be enhanced, particularly in the LV network. This would be required to understand local hosting capacity, determine where DER management may be required and where DER-related constraint remediation may be efficient.

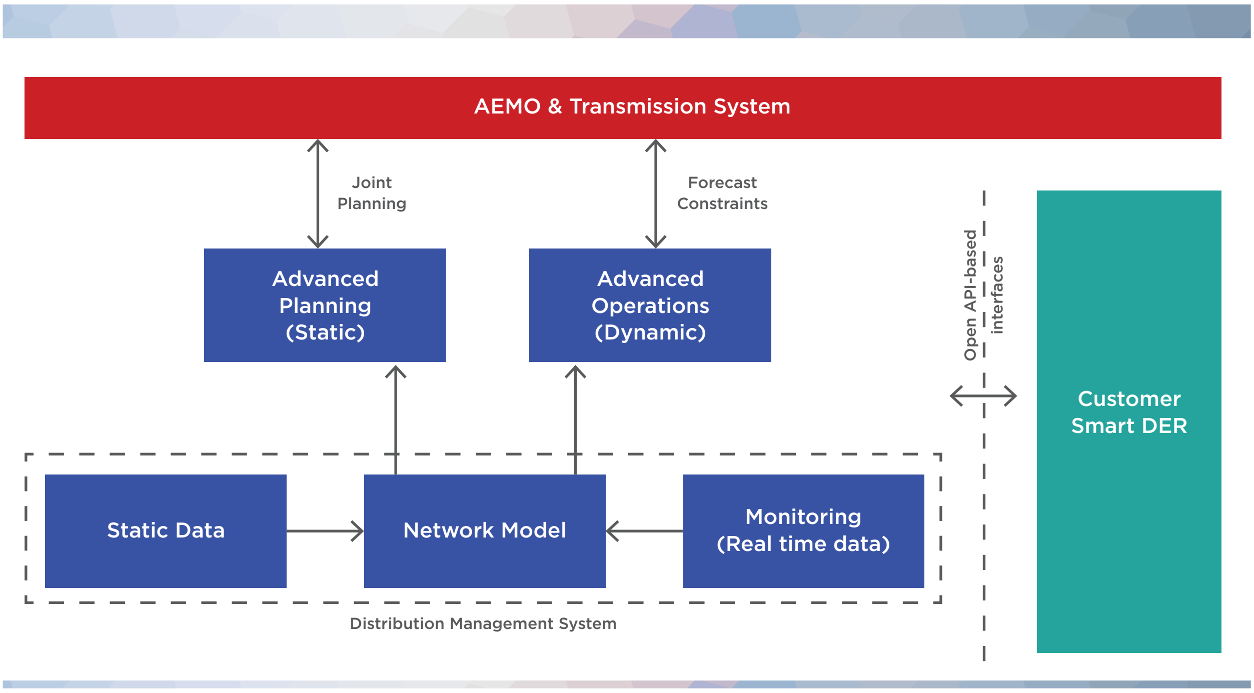
» **Advanced planning:** would be required to consider new scenarios that network planners have not needed to consider in the past such as performance under minimum demand scenarios and under different environmental conditions e.g. full or intermittent cloud cover. Planners would also need to consider the potential value of customer exports in undertaking investment decision making.

» **Advanced operations:** would be required to undertake management of DER where and when required; and

» **Active DER** - would need to be capable of receiving control signals from remote party (including AEMO and networks), and be able to, as a minimum adjusttheir output/inputs in times of emergency conditions.

As highlighted by the figure below, developing these capabilities would require material investment, which will need to be weighed up carefully against the increased value released from customers' DER.

Figure 8: Capabilities required to dynamically manage DER



3.5 Flexible Load

Further to these actions, consideration should be given to ensuring that customers with flexible load (including batteries) are provided with incentives to:

» Utilise their load to soak up excess PV generation and/or make new investments to increase load during low demand periods;

» Reduce their load at periods of high demand on the network to reduce the need to undertake network augmentation.

Incentives to encourage flexible load may be network based incentives, network tariffs or demand response programs that provide value when load is made available.

Network tariff reform and demand management is an area of active engagement and experimentation by distribution businesses and will not be considered further in this document other than to the extent that any proposed frameworks and mechanisms developed should be tested for their applicability and implications for traditional demand management as well as new technologies such as batteries.

Consultation Questions:

1. Are there additional key challenges presented by passive DER beyond those identified here?
2. Is this an appropriate list of new capabilities and actions required to maximise network hosting potential for passive DER?
3. What other actions might need to be taken to maximise passive DER potential?

4. Maximising active DER potential

Moving from passive to active DER, and particularly batteries, provides the potential for more value for the customer, network and the system. A number of industry proponents have recently commenced or demonstrated VPP projects including Reposit Power with a 250 battery VPP in the ACT, AGL with a 1,000-battery trial in SA, and most recently, Tesla with a 50,000 battery project and Simply Energy with a 1,200 battery trial, also both in SA.

In order to realise the value from active DER there are a number of challenges for distribution networks and security of supply. This will occur to a large extent because of their unpredictability. Whereas passive DER behaviour can be forecast with reasonable certainty, particularly when diversified across large numbers of customers, pool price spikes or requirements for FCAS response can sometimes occur unpredictably and without warning. Active DER may respond in unpredictable ways to these sudden signals.

Once again, these impacts can occur in both local networks and at system-wide levels.

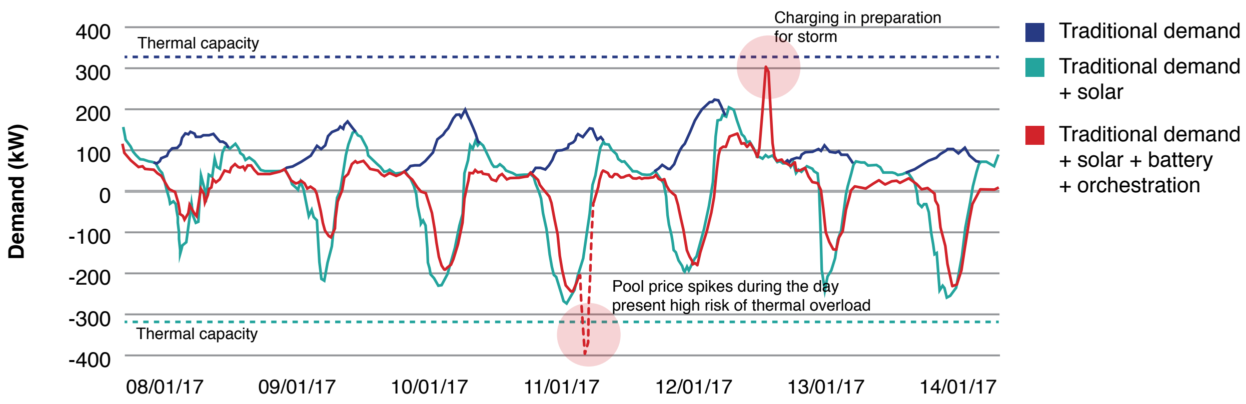
4.1 Local network challenges

At a local level, active DER causes similar issues to passive DER. However, the probability of causing issues is heightened due to rapid ramp rates and potentially very high output powers.

The chart below illustrates the rapid charging of batteries in preparation for a storm event, to ensure the availability of back-up power. Despite careful orchestration by the distribution business, the resultant demand approaches local network capacity.

Further, if the batteries had been discharged simultaneously with peak solar exports in response to, for example, a NEM price spike, local network capacity would have been easily exceeded in reverse flow, causing local distribution fuses to blow. Even if local network capacity were not exceeded, ramp rates would far exceed the speed at which traditional distribution voltage management techniques are designed to operate, resulting in large voltage swings.

Figure 9: VPP impact on network flows



SA Power Networks' Salisbury Battery Trial.

4.2 Security of supply challenges

If the operation of active DER remains small, then this will only impact distribution networks and will have no broader implications. For example, the Salisbury battery trial for which the data in earlier charts was taken only has a total capacity of around 300kW. This is unlikely to cause security challenges at a system-wide level.

However, the number and size of VPPs proposed is escalating rapidly. For example, the Tesla VPP is proposed to reach a capacity of 250MW (charging and discharging). This VPP could ramp up to 500MW almost instantaneously, if moving from discharging to charging (or vice versa). This has a similar operational impact to the trip of a large power station, and exceeds the typical contingency reserves enabled in South Australia.

If the VPPs are not managed as a part of a dispatch process, and operate unscheduled, this could have the following implications:

» AEMO would have little information on the expected operation of the VPP, particularly relating to active responses to changing power system prices. AEMO may have some ability to forecast this behaviour, but the limited information available would manifest as escalating demand forecast errors as VPPs grow.

» Escalating forecast errors would need to be managed by increasing enablement and use of regulation Frequency Control Ancillary Services (FCAS). The costs of this service are borne by consumers and market participants.

» Large, sudden VPP movements could exceed the capability of regulation reserves to respond, and would trigger the use of contingency FCAS to quickly rebalance the system. This means that growth in active VPPs may cause increasing triggering of contingency FCAS, increasing costs for the providers of those services.

» Very large VPP movements could exceed the capabilities of FCAS reserves to respond, and may threaten system security. For example, a sudden VPP movement in South Australia could cause a large and sudden increase in flows on the Heywood interconnector. If the Heywood interconnector was operating near its nominal limits, a 500MW movement could be sufficient to increase flows beyond the stable limits of the interconnector. In the absence of emergency protection schemes, this may lead to a loss of synchronism, and trip of the interconnector. To manage this potential outcome, in the absence of coordinated dispatch of the VPP, AEMO may need to limit flows on the Heywood interconnector to lower levels to make space for large VPP movements. This would have costs to the market.

The power system impact will depend upon the total capacity of active DER that moves. A single moderately sized VPP may not prove problematic, but the synchronised movement of many smaller VPPs (perhaps in response to the same price signals, weather events, or other stimulus) could exceed the ability of the power system to respond efficiently and remain secure.

It is clear there is a threshold above which VPPs will need to become a part of a coordinated dispatch process, to minimise unnecessary costs to consumers, and allow efficient and secure power system operation. The precise criteria for VPP participation in a coordinated dispatch process, and the specific obligations in doing so, need to be defined.

4.3 New and emerging DER services

In addition to participation in the wholesale energy and FCAS markets, active DER can also provide a range of other valuable services. For example, DER can provide voltage control services, or can be used to defer the need for network augmentation by locally supplying a growing load. These new services could form the basis for emerging DER markets.

Emerging DER services can be purchased bilaterally by various parties under the present framework. For example, AEMO can purchase DER services to assist with addressing shortfalls at time of peak demand as a part of the Reliability and Emergency Reserve Trader (RERT) mechanism. Distribution network service providers (DNSPs) and Transmission Network Service Providers (TNSPs) can purchase any kind of services from DER that would assist in meeting their obligations at lower cost than network augmentation, as non-network alternatives. These are considered "out of market" services, since they are negotiated and settled bilaterally between the parties involved, outside of the existing wholesale energy and FCAS markets.

It is expected that an aggregator facilitates negotiations with the customer and the DNSP on the services to be provided, and associated payments for those services. This includes agreeing on terms and conditions, including any penalties for non-delivery of the service. Due diligence by the aggregator and DNSP is required, ensuring that the services can actually be delivered when required, and are not likely to be inhibited by distribution level constraints, or any other technical limitations.

4.4 Evolving markets for new DER services

At present, the types of DER services involved are highly bespoke, and negotiated on a case by case basis, depending upon the specific needs of the situation.

In future, with growing experience and demonstration, some DER services could become more standardised. This could allow the contract negotiation process to become far more dynamic, with contracts negotiated on a near real-time basis. To ensure that this market for services develops efficiently and effectively a number of foundational items may need to be developed:

1. DNSPs, TNSPs and other parties could utilised software platforms to streamline the purchase of the desired DER services. These could involve conducting a near real-time auction process, resulting in near real-time prices being offered for a range of DER services.
2. Markets valuing the services from DER for reactive power, energy, generation following, ramping, voltage support and peer to peer trading will need to be expanded or established.
3. Aggregators would be able to offer their customers' DER into multiple markets, perhaps simultaneously providing DER services of different kinds to multiple parties (or providing different services at different times), where they are technically able to do so. Customers would also receive this value in addition to moderating their DER operation in response to wholesale energy market price signals, and potentially from offering into FCAS markets. This would allow aggregators to "stack the value" from multiple revenue streams for each DER owner, maximising the value of their portfolio in response to dynamic real-time price signals for each DER service.
4. Eventually, it may prove more efficient to coalesce procurement platforms into a single platform, facilitating DER services being procured by a range of parties without the need for separate platforms.

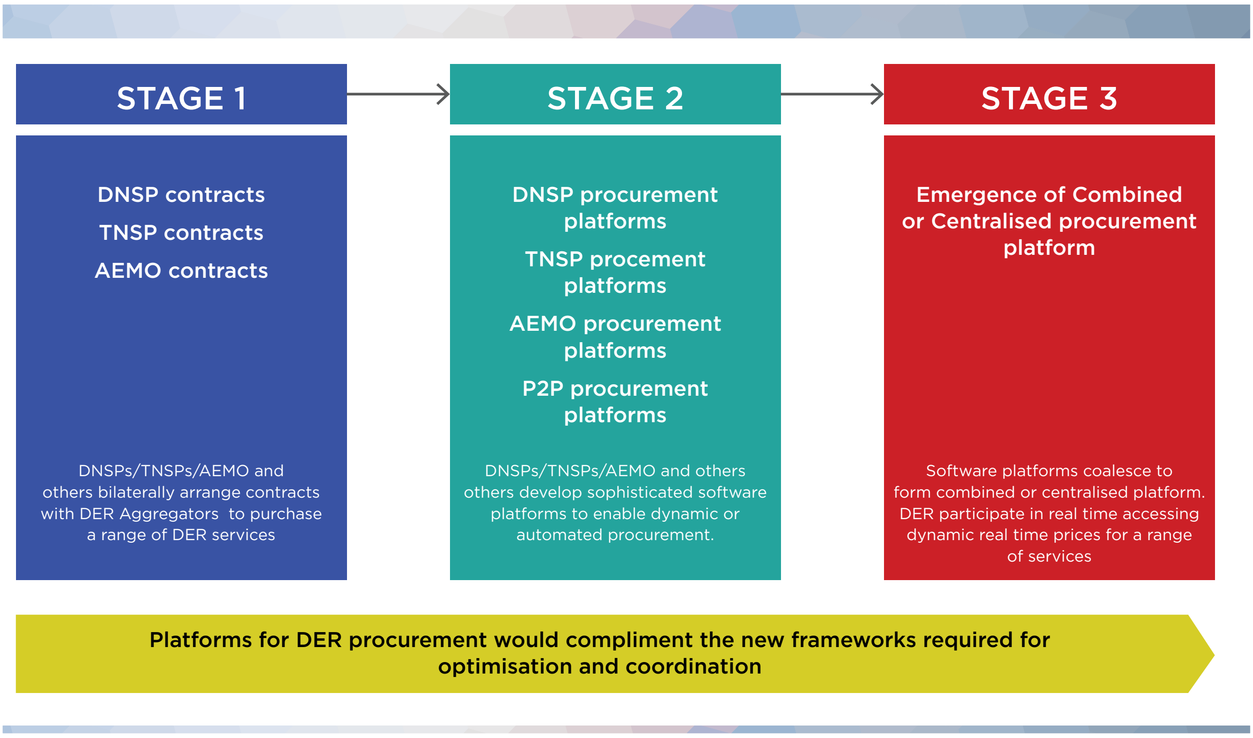
This framework allows “distribution level markets” to evolve in response to needs. The market evolution process is illustrated in Figure 10. If desired, this process could be accelerated through demonstrations and trials, especially where these aim to demonstrate new DER services, and streamline and standardise the contracts negotiation process.

4.5 Ensuring active DER can reach the market

We anticipate active DER resources will bid into the Wholesale and FCAS markets, and participate in central dispatch. However, there are a number of impediments:

1. Retailer offers and market platforms; DER owners may choose to work with aggregators or aggregation platforms but to reach these markets Retailers will ultimately need to make these value streams available.
2. An understanding of network constraints - As more active DER want to use the distribution network to access these markets they will likely come up against network limits. Understanding, and managing performance within these constraints will require similar capabilities to those required to dynamically managed passive DER, however, may need to be integrated into market processes.

Figure 10: Emergence of markets for new DER services



3. A decision making framework – is required that can determine whether active DER seeking to dispatch from within the distribution network are likely to breach local network or system constraints, and if so, which of the active DER operating behind the constraint should be dispatched.

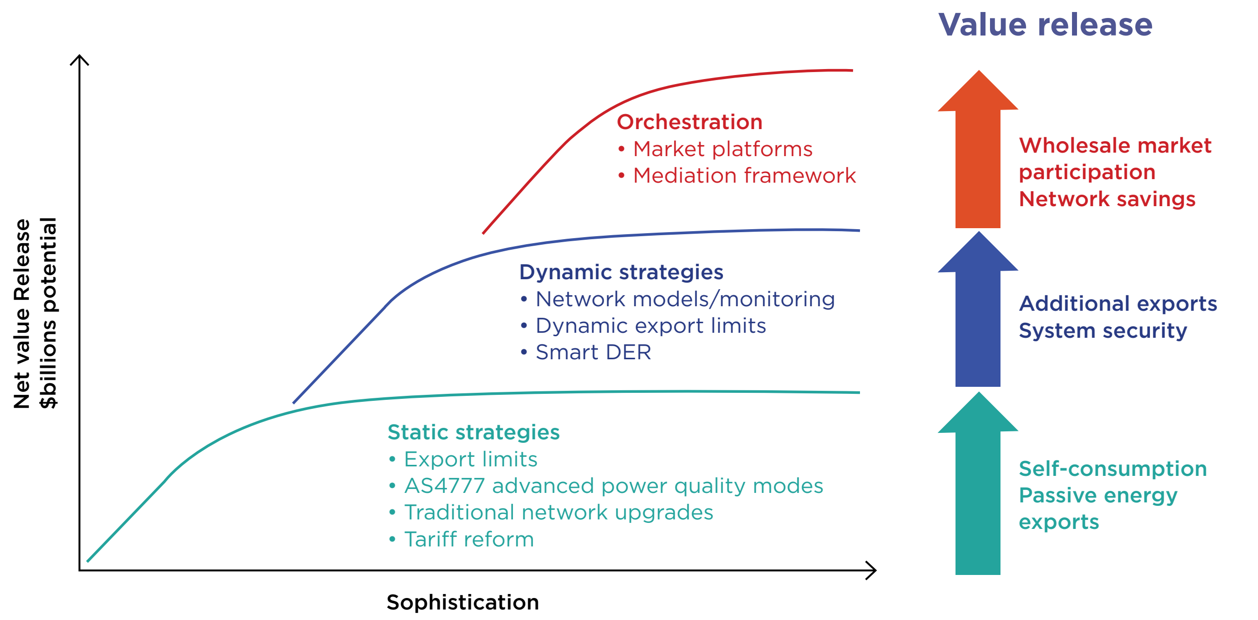
A number of technology vendors and retailers are active in developing aggregation and market platforms and retail offers. Although the platforms and offers are not yet mature, the market is developing rapidly and competition appears to be sufficient to drive it forward.

The following section of this paper deals with items 2 and 3.

Consultation Questions:

1. Are these the key challenges presented by active DER?
2. Would resolution of the key impediments listed be sufficient to release the additional value available from active DER?
3. What other actions might need to be taken to maximise active DER potential?
4. What are the challenges in managing the new and emerging markets for DER?
5. At what point is coordination of the Wholesale, FCAS and new markets for DER required?

Figure 11: Additional value release enabled by optimisation of active DER



5. Frameworks for DER optimisation within distribution network limits

Distribution network businesses are responsible for operating and maintaining their network within technical and safety requirement. AEMO is responsible for grid reliability and system security and operating the market. The key issues being considered in this consultation paper is how best to integrate DER into the grid and market and secondly, how best to undertake the economics dispatch of DER at the distribution level to inform broader optimisation of the system and market by AEMO.

This section discusses the high level functions, roles and responsibilities required to coordinate DER optimisation within distribution network limits, noting AEMO is responsible for optimisation of resources within transmission limits. The present framework for DER to access the NEM is outlined first, followed by the high level functions required to facilitate DER optimisation and dispatch within distribution network limits. Finally, the paper presents some options for allocating the responsibility to manage economic DER optimisation and dispatch.

5.1 The present framework

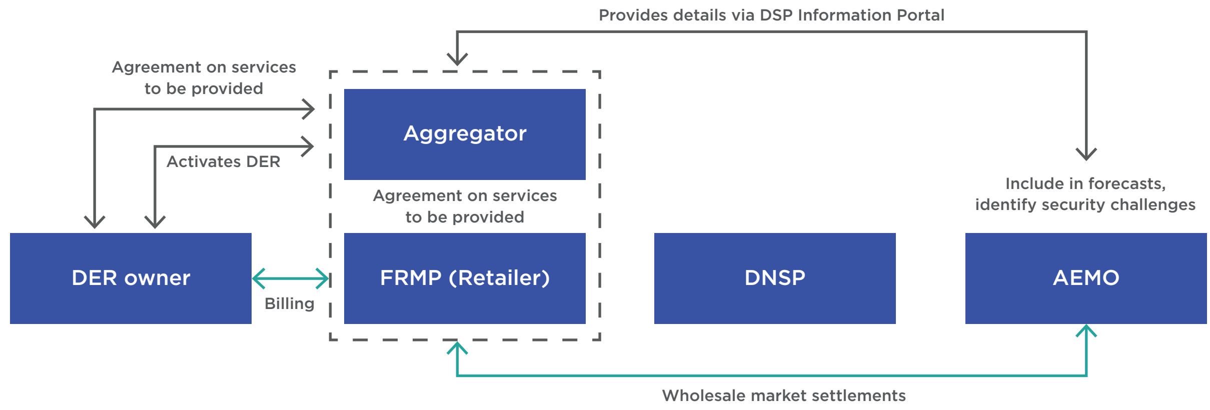
Before discussing possible long-term frameworks for DER dispatch and optimisation, it's useful to describe the present system architecture for this functionality.

Currently, DER has limited desire or opportunity to participate directly in the market. The current market arrangements have been designed around traditional sources of supply and the transmission system (within transmission limits), which was where the electricity generating units were, with retailers representing the customer base in an environment of one way flow from the large generating system to the customer site.

The key features of the current market arrangements include:

» **Economic dispatch:** In the current market framework, market customers (i.e. transmission connected loads or retailers) or generating units above 30MW operate directly in the market. There is the concept of a small generator aggregators, which allows small generating units to participate in the market, but on a non-scheduled basis. Units below 5MW are exempt from registering or participating in the market. Third parties, like aggregators, cannot directly participate in the market without becoming, or affiliated with a retailer. During real-time dispatch, the retailer will moderate the operation of the customer's DER (within the terms of their agreement with the customer), to maximise value to the retailer's portfolio in the wholesale market. Alternatively, the customer may elect to establish a new connection point and NMI for a component of their load (such as an electric vehicle charging point), and could allocate a new retailer for that component of their load, to act as the aggregator. Wholesale market settlements are managed between AEMO and the retailer, with the retailer undertaking billing arrangements with the customer (incorporating network fees and other charges). The retailer's billing may incorporate additional customer rewards for the activation of DER contracts, or this may be settled separately between the customer and aggregator.

Figure 12: the present framework for DER dispatch in the market.



- **Ancillary services:** generating units (not a small generator aggregator) together with loads (direct transmission connection, retailers, or aggregator DR provider (market ancillary service provider)) can offer ancillary services. In mid-2017, AEMO implemented rule changes that enabled unbundling the provision of frequency services from retail, and the concept of an aggregator was introduced. The AEMC is currently reviewing how best to integrate DER into the ancillary services market.
- **Network support:** support agreements can be negotiated between the relevant network service provider and aggregator/retailer/customer for the provision of services to manage their networks. These agreements are largely bespoke. With the growth of DER, there will be a greater need for network business to look at network support services from DER to manage voltage/network issues or deter network investment. There are restrictions on a network's ability to directly participate in the market noting it is earning a regulated return on its monopoly assets.
- **Emergency reserve:** the current mechanism for the provision emergency reserve, RERT, is technology and resource neutral. DER can offer emergency reserve. It was designed to be used rarely and therefore the contract arrangements are largely bespoke in natures. Processes are in train to develop standardised products.

While the aggregate size of DER remains small, and while AEMO has the ability to adequately forecast DER behaviour, DER operation can be unscheduled with no need to participate in the central dispatch process. When the quantity becomes large, and it is deemed necessary for adequate power system operation and system security, AEMO can require more participation in the central dispatch process. This may include providing bids and receiving dispatch targets, providing real-time telemetry, and inclusion in constraint equations.

Notably, in all of these existing frameworks, the DNSP has no formal involvement in the process, outside of possible engagement in the original connection of the DER device. This means that there are no formal arrangements in place at present to manage distribution level constraints, and ensure that DER dispatch remains within distribution network technical limits. This important gap needs to be addressed in future frameworks.

5.2 Functions required in future frameworks

High level functions required for distributed level optimisation are summarised in the figure below.

Both Figure 13 and Table 1 indicate the potential allocation of responsibilities for each of these functions, and the majority of the functions appear to align well with existing parties.

More detailed analysis and consideration is required to assess who could deliver two of the key functions most effectively for consumers, the distribution level optimisation and dispatch, and the forecasting systems. Section 5.3 explores the allocation of responsibility for the distribution level optimisation and dispatch function specifically.

In addition to viable long-term frameworks for managing distribution network constraints in the real-time dispatch of DER, the successful integration of DER will also require a wide range of other developments, including in relation to market frameworks.

Figure 13: High level overview of key functions for distribution level optimisation

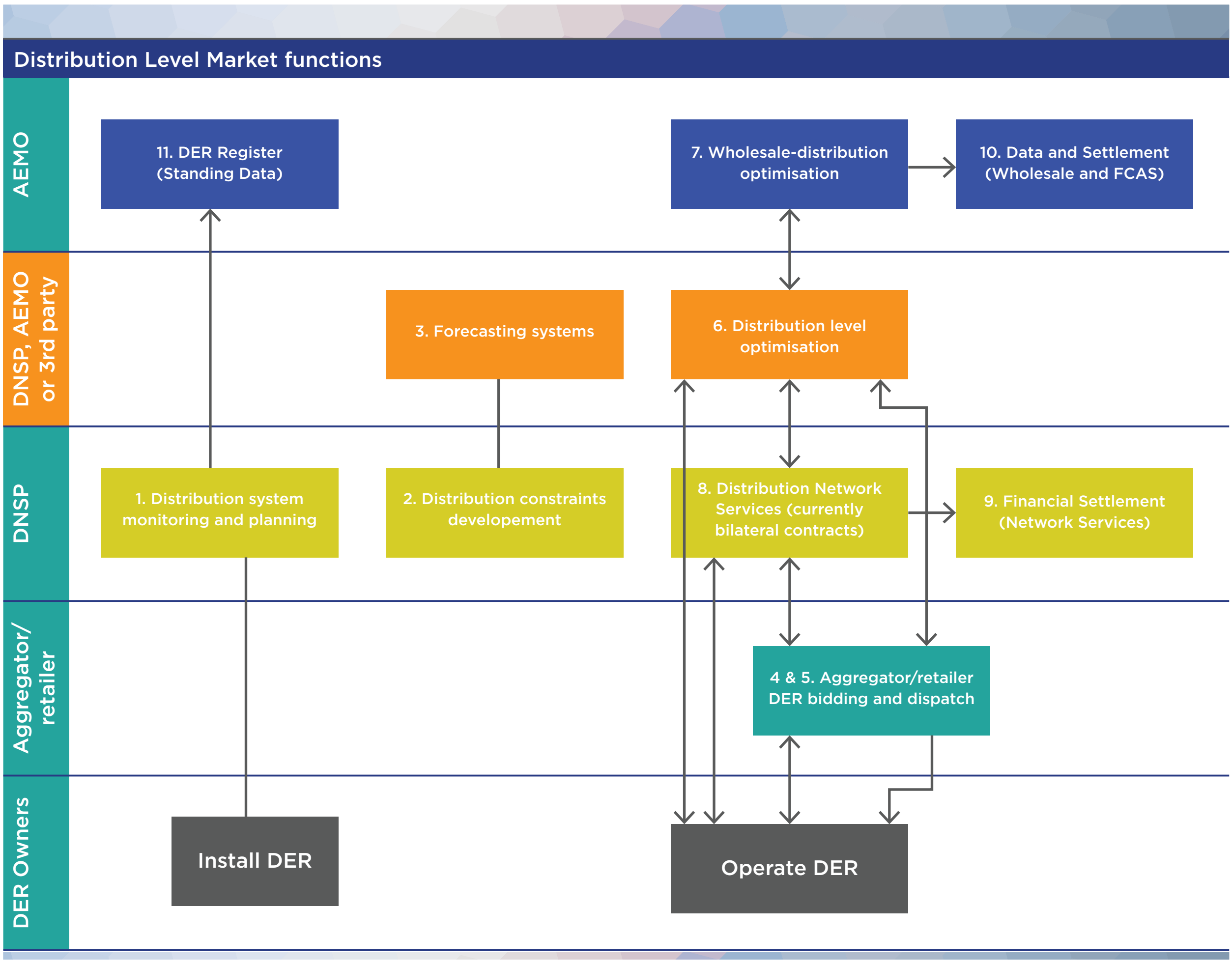


Table 1: Summary of key functions in DER optimisation

Function	Description	Owner
1. Distribution system monitoring and planning	Enhanced function: distribution network monitoring to inform distribution network constraint development	DNSP
2. Distribution constraints development	New function: to develop distribution network constraints that will be a key input into the distribution level optimisation.	DNSP
3. Forecasting systems	New function: provide key forecasting information to allow for distribution level optimisation – may be available to market participants	DNSP, AEMO, or new third-Party
4. Aggregator DER bid and dispatch	New function: Aggregates local DER installations to provide bids into the energy, FCAS and Network Markets (through distributed level optimisation)	Third- Party: New Participant category
5. Retailer DER bid and dispatch	Enhanced function: Retailer aggregates customer DER installations to provide bids into the Wholesale Market for scheduled generation, scheduled load, FCAS and Network Markets	Retailer
6. Distribution level optimisation	New function: optimise distributed level resource dispatch within distribution network constraints, to establish an aggregated bid stack for DER per area that can feed into wholesale optimisation. Dispatch DER once aggregated dispatch signal received.	DNSP, AEMO, or new third-Party
7. Wholesale - distributed optimisation	Integrate distributed level optimisation results into existing wholesale market optimisation.w	AEMO and operator of distribution level optimisation
8. Distribution Network Services	Enhanced function: Distribution network services, such as power quality/voltage control, which can be provided by aggregated DER, either through bilateral contracts or potential through an optimization	DNSP
9. Financial Settlements (Network Services)	Enhanced function: financial settlement of distributed network services dispatched Network Market	DNSP, aggregator/ retailer
10. Data & Settlement (Wholesale and FCAS)	Enhanced function: AEMO settles wholesale and distributed level transaction. AEMO already settles the existing market to the NMI	AEMO
11. DER Register	New function: AEMO to provide DER register based on AEMC rule requirements.	AEMO

5.3 Principles for framework design

1. Simplicity, transparency and adaptability of the system to new technologies
2. Supporting affordability whilst maintaining security and reliability of the energy system
3. Ensuring the optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER
4. Minimising duplication of functionality where possible and utilising existing governance structures without limiting innovation
5. Promoting competition in the provision and aggregation of DER, technology neutrality and reducing barriers to entry across the NEM and WEM
6. Promoting information transparency and price signals that encourage efficient investment and operational decisions
7. Lowest cost.

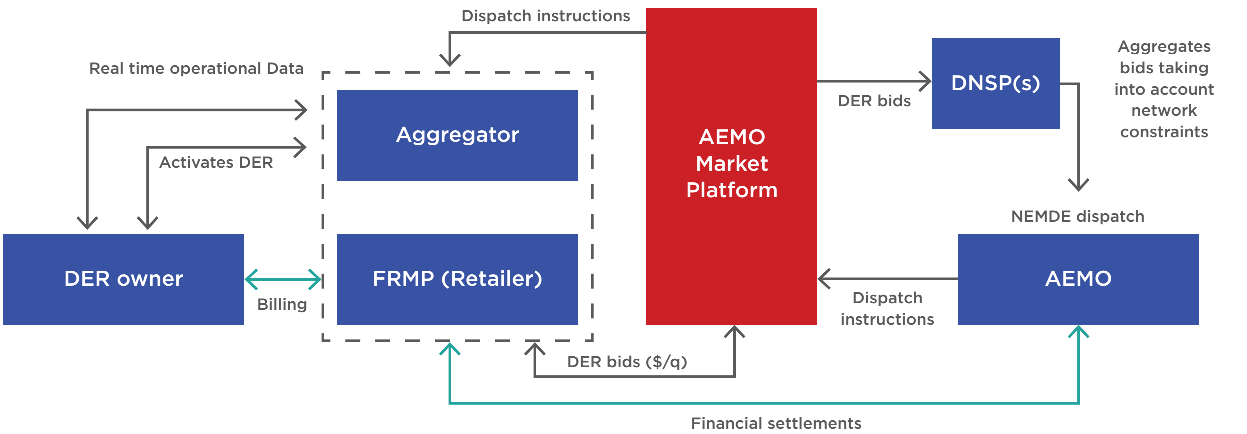
5.4 Responsibility for distribution level optimisation and dispatch

When DER penetrations reach very high levels, improved frameworks for system dispatch are required that allow DER dispatch to be optimised within distribution network technical limits, as well as transmission and system limits. As outlined above, this is a new functionality which no organisation is performing at present. The options are presented in the following section.

5.4.1 Single Integrated Platform; AEMO central platform and optimising dispatch taking into account transmission and distribution network constraints

Under this model, AEMO provides a central platform that interfaces with aggregators for the provision of DER services – therefore providing direct access to the market. Aggregators would provide bids and offers directly to AEMO via this platform. Each distribution network business would also be connected to the central platform.

Figure 14: AEMO central platform



To consider local network constraints, AEMO would optimise the resources taking into account local network constraints provided by the distribution network business. AEMO would then optimise the dispatch of DER based upon those bids, as a part of the overall system optimisation in the NEM Dispatch Engine (NEMDE).

In real time, aggregators would provide bids to AEMO representing their dispatch preferences. AEMO would optimise the dispatch of DER based upon those bids, as a part of the overall system optimisation in the NEM Dispatch Engine (NEMDE). AEMO would provide dispatch schedules to aggregators, who would then activate their customer's DER. Settlements would remain between AEMO and retailers, as in the present framework.

The advantage to this model is that it allows aggregators operating in multiple regions to interact with a single entity (AEMO) during the real-time dispatch process. It means that functions for dispatch of DER would need only be maintained by one organisation as opposed to multiple organisations. AEMO is independent and unbiased in facilitating the dispatch process.

The optimisation of distribution level dispatch may be extremely complex, and the interface between DNSPs and AEMO around the communication of real-time network status and real-time distribution network constraints will be equally complex. This model represents an expanded role for AEMO, which will require expanded resources. AEMO's funding model may need to be adapted to fit this expanded role.

AEMO would provide dispatch schedules to aggregators, who would then activate their customer's DER. Settlements would remain between AEMO and market participants. The distribution network business could also use the central platform to seek network support services from aggregators.

The advantages of this model are:

» It allows aggregators operating in multiple regions to interact with a single entity (AEMO) via a central platform.

» It allows DNSPs to take responsibility for management of DER in their own networks. DNSPs are best placed to understand, quantify and manage the limits of their own network, and this model potentially limits duplication of resources at other organisations to attempt to fulfil this role.

» It requires a lot of the dispatch process to be coordinated between distribution business and AEMO – seamless for the interfacing aggregator.

» AEMO is independent and unbiased in facilitating the dispatch process.

However, some important disadvantages are also apparent:

» A multi-stage optimisation will likely be required, first dealing with components of the distribution system, aggregating to a single distribution network, then being aggregated to the NEMDE process at a system level.

» The interface between distribution network service providers and AEMO around the communication of real-time network status and real-time distribution network constraints will be complex and difficult to manage.

» This would represent an expanded role for AEMO, which will require expanded resources. AEMO's funding model may need to be adapted to fit this expanded role.

5.4.2 Two Step Tiered Platform; DNSPs optimising distribution level dispatch

The straw man model for consideration involves DNSPs taking responsibility for optimisation of DER dispatch within their own networks. A possible process is illustrated in Figure 15. In this model, aggregators would provide bids to the DNSP, representing their dispatch preferences. The DNSP would aggregate these bids, taking into account any distribution network constraints that may prevent DER operation. For example, if two aggregators offer 1MW each behind a 1.5MW network constraint, with one offering at $5/MWh, and the second offering at $6/MWh, the aggregated bid would show availability of 1MW at $5/MWh, and 0.5MW at $6/MWh. The remaining 0.5MW (offered at the higher price of $6/MWh) cannot be delivered, and so would not feature in the aggregated bid.

The DNSPs would aggregate bids from all active DER in their networks, the pass these aggregated bids to AEMO associated with each transmission connection point. AEMO would then include these aggregated bids in the NEMDE dispatch optimisation.

The aggregated distributed resources would appear to NEMDE as a single virtual generator or scheduled load located at the transmission connection point.

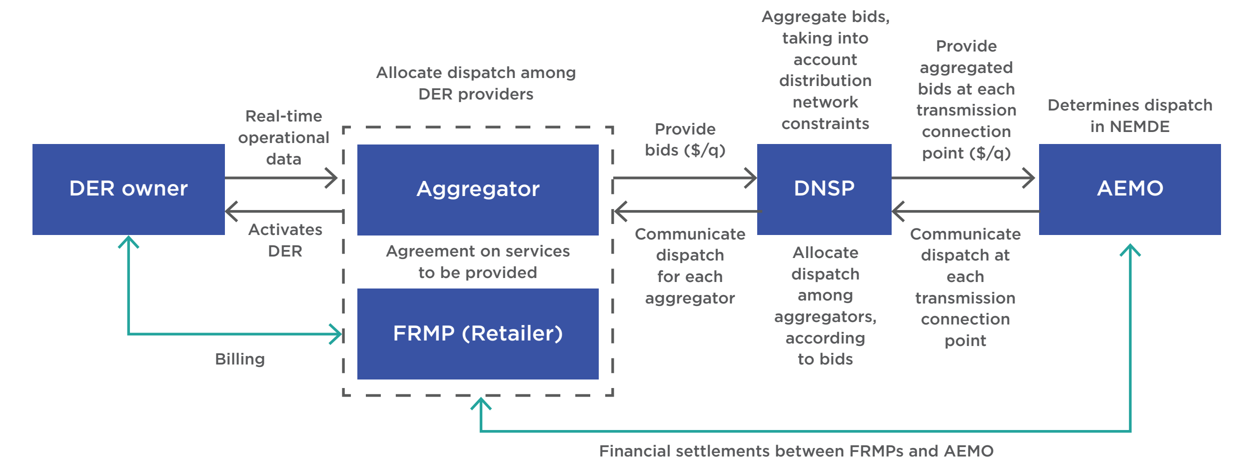
AEMO would calculate dispatch targets at each transmission connection point, and communicate these to the DNSP. The DNSP would disaggregate these dispatch targets to each aggregator, based upon their respective bids (with the lowest priced offers having the most access to network capacity). Aggregators would then activate their customer's DER to meet the required dispatch targets.

Settlements would remain between AEMO and the retailer, as per the present system. Settlements are already calculated at an individual NMI level, and the existing revenue metering system would incorporate the moderated operation of DER behind each customer's meter.

The advantages of this model are:

» It allows DNSPs to take responsibility for management of DER in their own networks. DNSPs are best placed to understand, quantify and manage the limits of their own network, and this model potentially limits duplication of resources at other organisations to attempt to fulfil this role.

Figure 15: Two Step Tiered Platform; DNSPs optimising distribution level dispatch



» It may facilitate a more decentralised operation of distribution networks, allowing operational strategies that manage "fringe of grid" operations without the need for constant centralised control. This may assist with managing the extreme degree of complexity involved.

The disadvantages are:

» DNSPs do not have any existing experience with real-time dispatch processes, and have limited requirements for real-time management of their networks with respect to non-network assets. DNSPs would need to establish this capability.

» The interface between DNSPs and AEMO around the communication of aggregated bids in real-time will need be carefully designed to minimise complexity. This model may cause challenges in integrating NEMDE optimisation with distribution network optimisation, since they will be separate processes operated by separate entities.

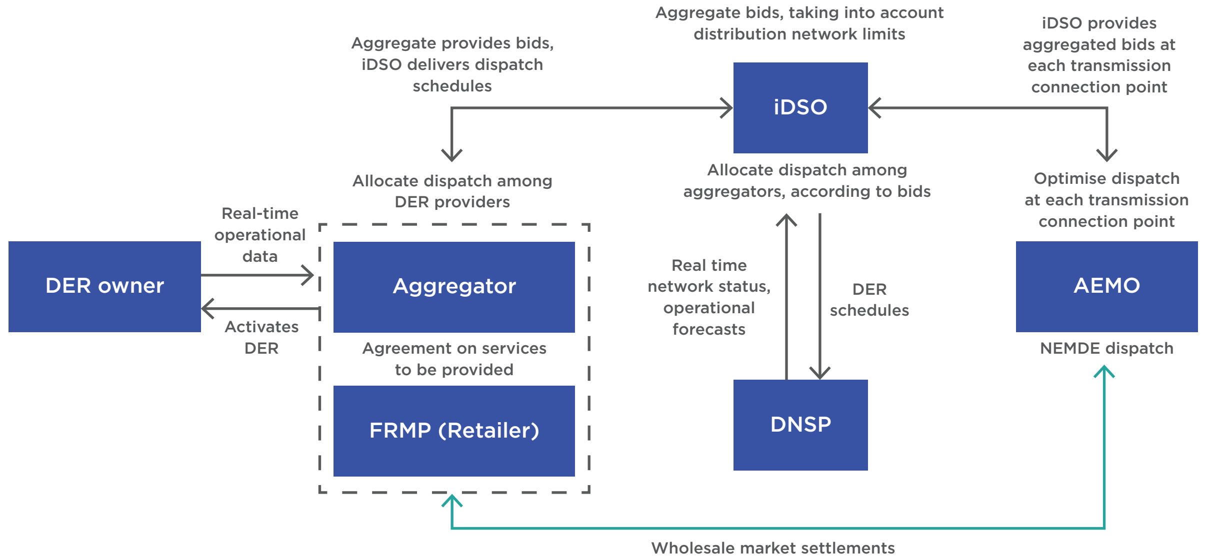
» DNSPs may not be perceived as adequately independent and unbiased to fulfil this role. Models for managing any potential conflicts of interest with ring-fencing could be considered.

This would represent an expansion of the role of DNSPs, which will require an expansion of resources, and change the way in which DNSPs are currently funded.

5.4.3 Independent DSO or AEMO optimising distribution level dispatch

The third straw-man option is illustrated in Figure 16. In this model, an independent distribution system operators (iDSOs) is required to take on the responsibility of optimising DER dispatch within distribution network technical limits. This requires establishing a separate iDSO for each distribution network, or a single iDSO for the NEM.

Figure 16: iDSO optimises distribution level dispatch



The independent DSO model would operate similarly to DNSP optimisation process described above, but with aggregators providing bids to the iDSO, and the iDSO aggregating those bids to each transmission connection point, taking into account distribution network limits. The iDSO would pass these aggregated bids to AEMO to include in the NEMDE central dispatch process.

This model provides an alternative to the previous options in that it allows some degree of decentralisation. As an independent party, the iDSO is a single entity taking entire responsibility for the complex dispatch task at a Transmission and Distribution level, but without the concerns around conflicts of interest inherent in the previous options. However, this is the most complex of the models described, involving interfaces between the iDSO and DNSP (to share real-time network status and distribution network constraints), and complex interfaces between the iDSO and AEMO (attempting to co-optimise resources in a multi-stage process across two different organisations).

For the iDSO to operate, new independent organisations would need to be established in each distribution network area, with associated approaches developed for funding those organisations. They would need extensive capabilities in the interpretation of network limit advice and the development of constraint equations, potentially duplicating these capabilities at DNSPs and AEMO.

Complex and crucial information flows would need to be established in real-time between DNSPs and the iDSOs (to communicate operational forecasts, network status, and so on), as well as between iDSOs and AEMO (to communicate DER bids and schedules). It is unclear whether introducing this level of complexity and associated costs to customers to establish would be warranted.

Consultation Questions:

1. How do aggregators best see themselves interfacing with the market?
2. Have the advantages and disadvantages of each model been appropriately described?
3. Are there other reasons why any of these (or alternative) models should be preferred?

6. Immediate actions to improve DER coordination

This consultation paper presents options for long term frameworks for management of DER optimisation and dispatch, and the evolution of new DER markets. These frameworks represent a potentially considerable change to the present, and are likely to require extensive consultation and lengthy implementation times. However, more immediate actions are required to mitigate emerging challenges related to large DER projects and localised issues associated with growing residential scale DER populations. The following measures are suggested as "no regrets" actions which can streamline the DER transition, and provide a stepping stone to future frameworks, regardless of which is eventually implemented.

The actions suggested here are consistent with the stage approach outlined in the Electricity Network Transformation Roadmap, which explored the need for a transition from relatively simple processes, to development of new functionality over time.

The suggested "no regrets" actions that should be explored and implemented in parallel with consideration of the above described longer term frameworks are as follows:

- **Review of registration frameworks** - The frameworks for registration of aggregated DER need review. At present, there is no category suitable for the registration of a large aggregated DER provider which would facilitate participation in the central dispatch process. Clearly defined criteria for participation are required, with clearly defined obligations that apply in that case.
- **AEMO to develop criteria for participation of VPP in central dispatch** - Capacity thresholds (MW) may not adequately define the point at which system security and operation necessitates scheduling, particularly where multiple smaller aggregated groups of DER are behaving in synchrony.
- **Expanding information exchange between DNSPs and AEMO** - A key requirement of enhanced operating arrangements is that they facilitate the effective exchange of information between transmission and distribution including both providing the best possible information from the distribution networks in all planning horizons including real-time operation to assist AEMO carry out its functions, and the coordination of services including demand control and response that will allow dynamic control to be effectively utilised for the entire system benefit.

The provision of accurate data will rely on the development of more sophisticated forecasting approaches.

- **Piloting and testing** - Piloting and testing aggregation, market and mediation platforms before they begin to impact operating frameworks. It is possible to develop initial arrangements that can achieve much of the early value from effective optimisation and coordination operation of DER where it is most valuable, but does not compromise the subsequent development of an operating framework that fits into a potentially different market structure. This may include the piloting of more active demand response mechanisms.
- **Sharing information relating to bilaterally provided DER services** - The nature of the services to be provided should be negotiated between the aggregator and the relevant parties (within the aggregator's agreements with their DER customers).

  These agreements could be communicated to AEMO using the DSP information portal allowing Aggregators, DNSPs and TNSPs to share information with AEMO on contracted DER. AEMO and the DNSP could then liaise to identify and address any potential system security challenges at the distribution or system level, and implement any required measures (such as defining constraint equations that maintain the DER dispatch within secure thresholds).

- **Building understanding of network constraints** - Currently many distribution businesses have only limited understanding as to how much DER can be connected to their networks whilst still maintaining the performance of the network and quality of supply based on quantifiable factors including thermal, voltage control, power quality and relay protection limits.

  In order to inform and execute optimal strategies to maximise DER value release, network hosting limits must be well understood. Although a number of approaches are possible, this is likely to require expansion of current network modelling and monitoring capabilities into low voltage (LV) networks. It may also require more active management of LV networks than DSNPs have traditionally undertaken. Development of this capability will however enable:

  - More accurate indications to be provided to prospective DER providers and customers as to where they can most readily connect to the network
  - More efficient connection processes
  - Development and execution of the most economic short-term strategies to increase hosting capacity
  - Ultimately, near-real time constraint assessment, enabling the more sophisticated value release strategies as discussed in this paper.

  A relatively simple analysis approach may be used initially, but with additional sophistication being applied over time as experience is gained.

- **Standards for DER monitoring and management** - DERs are emerging that are becoming smarter and able to change their profiles or consumption patterns in response to some form of remote signaling or control. As the numbers of smart DERs grows, it is essential that technical standards and protocols are developed to encourage interoperability and standardised communication protocols are developed. This is important to ensure that fleets of DERs can be coordinated and orchestrated as outlined earlier in this paper. Failure to standardise the connection, operation and interoperability will likely result in the failed opportunity to maximise the capability of growing DER capability but in the worst case could result in low visibility of and reduced capability to orchestrate growing ranges and numbers of DERs - leaving the potential for further DER value release unable to be tapped.

Consultation Questions:

1. Are these the right actions for the AEMO and Energy Networks Australia to consider to improve the coordination of DER?
2. Are there other immediate actions that could be undertaken to aid the coordination of DER?

7. Next Steps

7.1 Collaboration

At a time of unprecedented change across Australia's electricity sector, industry wide collaboration is essential to deliver the most efficient pathway to facilitate this transition.

Informing these considerations are the key principles:

1. Simplicity, transparency and adaptability of the system to new technologies
2. Supporting affordability whilst maintaining security and reliability of the energy system
3. Ensuring the optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER
4. Minimising duplication of functionality where possible and utilising existing governance structures without limiting innovation
5. Promoting competition in the provision and aggregation of DER, technology neutrality and reducing barriers to entry across the NEM and WEM
6. Promoting information transparency and price signals that encourage efficient investment and operational decisions
7. Lowest cost.

With this in mind, we are seeking to engage with stakeholders throughout this consultation process to develop two key deliverables:

1. A First Steps – No-regrets actions report in late 2018
2. A comprehensive DSO White paper in 2019.