



Executive Summary

AEMO has a role to ensure energy security for all Australians. The Australian energy industry is continuing its paradigm shift from a centralised power system to a decentralised one that is influenced largely by innovation in technology, greater consumer choice in energy supply and usage, coupled with state and federal government policies incentivising growth in renewable generation and a reduction in carbon emissions.

The market and regulatory frameworks need to change to maintain the security and reliability of the power system and ensure electricity networks are able to efficiently integrate distributed energy resources and support more active customer participation. There are a number of measures which can be taken to successfully make the transition the energy industry is undergoing and to minimise the cost to consumers:

- **Integrate and manage distributed energy resources (DER):** Networks that integrate and utilise DER can reduce electricity prices. The appropriate platforms to accommodate these resources must exist to capture their full potential. If managed effectively, DER not only boosts local energy supply but can also provide network support services that subsequently assist in maintaining reliability and security of supply at a lower cost.
- **Future system services and network development:** The national grid and wholesale market needs to adapt to future needs and a changing generation mix. The market and regulatory frameworks must encourage innovation and incentivise economic delivery of the system services and network development required to ensure customers receive secure, low-cost energy in the future. That will require the current ancillary services to be substantially changed and augmented with additional services including inertia and fast frequency response. Services in the future will come from a wider range of sources including distributed resources.
- **National planning and system operation:** The power system needs to be viewed as a whole and its development coordinated through effective national planning. Effective planning and system operation would ensure the efficient development and operation of the transmission grid and utility scale supply at a national level and couple this with innovative and cost-effective distributed energy solutions at the local level. This would seek to realise the most efficient overall outcome, meeting customers' needs at the lowest overall cost. National planning also needs to extend beyond a limited definition of security and consider the resilience of the system to a wider range of risks and meet society's evolving need for reliable supply.
- **Allow regulatory decision-making to promote proactive management of emerging issues:** The process of regulatory change is not sufficiently forward-looking to meet the needs of the paradigm shifts the NEM is undergoing. Clearly defined roles and policy principles for agencies such as AEMO, the AER and network service providers with broad expression rather than detailed definition will allow forward risk assessments on a continuous basis. A process where Ministers can agree on a longer-term strategic plan which integrates the necessary market and regulatory changes with the network developments required will be beneficial. These initiatives will allow emerging issues to be addressed and then progressed to take advantage of the opportunities and minimise adverse effects of change.



Introduction

The House of Representatives Standing Committee on the Environment and Energy is conducting an inquiry into modernising Australia's electricity grid with focus on ensuring power system security is delivered to customers at low cost. This is a result of the evolving electricity generation mix, increasing adoption of new technologies and changing, less predictable patterns of demand from NEM consumers.

The current energy market has evolved (and continues to evolve) since NEM commencement. However the pace of change in the industry has accelerated and the market and regulatory regimes need to adapt.

There are a number of reviews attempting to address the impacts and opportunities that the changing market environment is presenting, including (and not limited to) the AEMC's System Security Market Frameworks Review, Distribution Market Model Review, Review of regulatory arrangements for embedded networks, the AER's Demand Management Incentive Scheme and the Demand Management Incentive Allowance review. The Independent Review into the Future Security of the NEM being led by Dr Alan Finkel is an important initiative that is working to deliver a blueprint for the overall development of the market.

Today's power system displays very different characteristics to the power system of the previous decades and under which the current National Electricity Rules (NER) were established. The adaptation of such governing frameworks to the rising penetration levels of distributed energy resources and change in consumer behaviour in energy usage has been slow. Changes in technology have profoundly changed the options available to customers to meet their energy needs and the explosion in communications and computing allow opportunity to aggregate responses in real time. The network needs to change for the full value of these diverse resources and other changes to be realised and delivered in the long-term interests of NEM consumers in adherence with the National Electricity Objective (NEO).

AEMO's submission presents its views on addressing this deficiency through the context of technical information and policy initiatives that will allow our electricity grid to effectively accommodate the changes the energy industry is experiencing, and to adapt for future needs so that low-cost, secure and reliable energy is delivered to consumers.

Further, as AEMO has a key role in ensuring that the unprecedented challenges arising as a result of the energy transition are not overlooked, our submission also provides information on work AEMO has already commenced in our capacity as the national electricity transmission planner and NEM system operator to maintain power system reliability and security in the face of a changing generation mix and demand patterns.

1. Integrating and managing DER

1.1. The changing characteristics of the power system

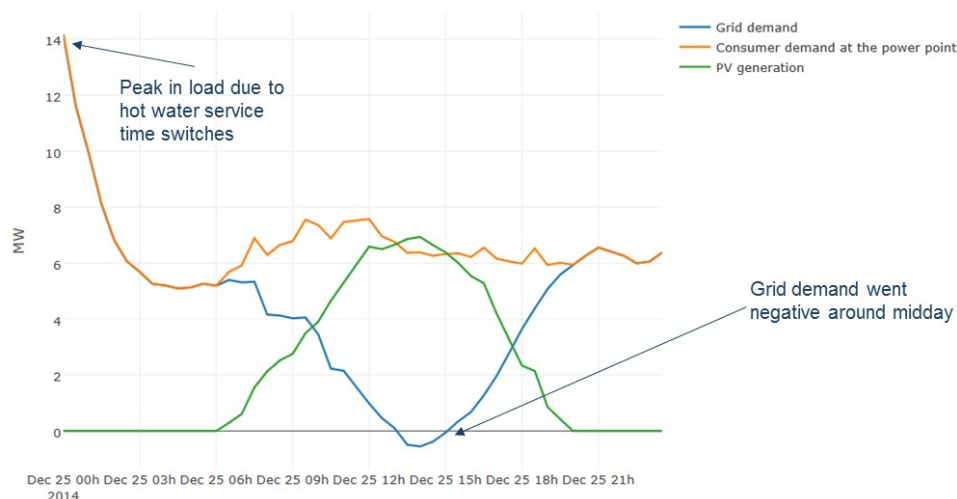
Historically, electricity has flowed in one direction from large generators through the transmission and distribution networks to consumers. More recently, electricity is starting to flow upstream as well as downstream due to an increasing amount of distributed energy resources and active consumer participation. Effective utilisation of distributed energy resources including:

- Embedded generation,
- Battery storage, and
- Controlled load and load shifting services

offers opportunities to deliver energy services to customers at the lowest overall cost and increase the productivity across the energy infrastructure chain. It is possible that in the future, the traditional model of supply following load will be replaced by a more dynamic model where load and demand are co-optimised.

This alters the characteristics of the power system, as shown in Figure 1 below which shows how a South Australian transmission connection point has experienced reverse flows during a low demand period due to high levels of DER penetration that already exist in some areas of the NEM.

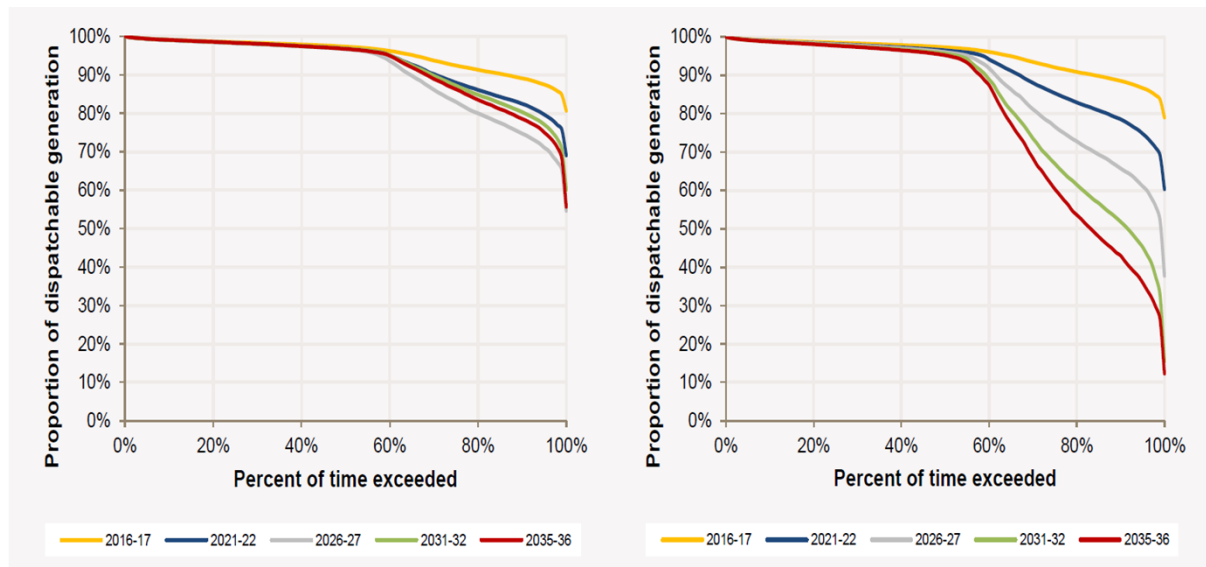
Kadina East transmission connection point, Christmas Day 2014



AEMO's 2016 National Electricity Forecasting Report (NEFR) showed that minimum demand for electricity is forecast to remain flat for five years, with the potential for a rapid reduction in the remaining forecast period (out to 2035-36) driven by projected increases in rooftop PV. In particular, the forecasts suggest that if the uptake of non-dispatchable, inverter-connected

generation continues at the current rate, then by the mid 2020s South Australian rooftop PV output will at times exceed minimum demand in (see Figure 2 below).

Figure 2 Proportion of dispatchable generation in the NEM, Neutral (left) and Low Grid Demand (right)



Source: AEMO, 2016 National Transmission Network Development Plan.

The change in the generation mix leaves AEMO with fewer tools to manage the supply-demand balance and requires more active power system management. This in turn changes the traditional approaches of power system design and operation to ensure power system security and reliable electricity supply.

1.2. DER and power system security

1.2.1. Data availability of DER

To manage power system security, observability of all components is required. As DER is installed behind the meter, it is often invisible to AEMO and network operators. Therefore increased penetration of DER affects the ability to understand the network, particularly the operational impacts on the power system as well as the benefits that can be provided from DER.

Currently, information disclosure obligations do not yet adequately cover new and emerging technologies such as inverter connected plant, and smaller scale distributed energy resources that can in aggregate, have a material impact on the performance of the power system as a whole.

The shortfalls in data availability fall into two categories:

- Static data relating to the technical characteristics (such as potential to relieve load as well as frequency and voltage dependency) of installed facilities at customer



premises such as rooftop PV installations, battery installations, and the associated inverter equipment.

- Real-time, or near real-time operational data to monitor the impact of distributed energy resources on the power system, and support operational management of issues as they arise. This effectively involves providing visibility of how devices are used in real-time, to support forecasting and operational planning functions including contingency planning.

AEMO believes that the availability of the right data will allow the relevant parties to understand the performance of DER. This will then allow the full benefit of these resources to be realised for power system management and ultimately consumers.

Attachment A provides more detail on work AEMO is undertaking to improve visibility of DER.

1.2.2. Challenges of DER

Parts of the NEM, particularly South Australia and Queensland, have very high levels of DER by global standards. We are continuing to learn about the intrinsic challenges associated with managing a dynamic interconnected power system. Table 1 below summarises AEMO's understanding of the distribution network impacts of increasing levels of DER.

Table 1 – Challenges of distributed energy resources

Network impact	Summary of challenges
Supply-demand management	<ul style="list-style-type: none"> • Excess embedded generation within distribution networks when generation (typically solar PV) exceeds local demand • Under supply of electricity during peak demand periods • Less predictable timing of peak periods due to intermittent solar generation or EV charging shifting peak periods • Intermittency of embedded generation (both short and long term).
Thermal loading	<ul style="list-style-type: none"> • Traditional network design based on unidirectional power flows • DER embedded in networks result in a change in power flows and cause overloading of equipment (thermal) due to exported energy (e.g. rooftop solar PV) • Inability to assess overloading of network elements • Uptake of electric vehicles could result in increased load during periods of charging
Voltage stability	<ul style="list-style-type: none"> • Some DER do not currently provide voltage or reactive support, leading to voltage instability • DER displacing traditional synchronous plant may not have the same level of reactive power capability and impact the ability to provide network voltage support • Increased penetration of DER exporting energy will cause a voltage rise on the distribution network • Increased uptake of electric vehicles (load) could result in voltage drops • Many DER are single phase which can lead to voltage imbalance.
Frequency stability	<ul style="list-style-type: none"> • Increased penetration of DER such as solar PV and energy efficiency can displace synchronous generation and lower the grid inertia and frequency response • Reduced level of frequency support available to the distribution network which effects system stability • Not necessarily a challenge on the distribution network which is connected to the transmission network

Network impact	Summary of challenges
System strength	<ul style="list-style-type: none"> • The presence of DER and the displacement of synchronous generators could result in reduced fault levels • The bi-directional flow introduced by distributed generation may result in a lack of coordination between protection devices.
Power quality	<ul style="list-style-type: none"> • Inverter connected DER produce harmonic currents • Increased penetration of DER can increase harmonic distortion on the network • Increased penetration of DER fuelled by intermittent sources will increase voltage flicker
Power factor	<ul style="list-style-type: none"> • Increased penetration of distributed generation with no reactive power support will result in a low power factor for the grid
Islanding & reclosing	<ul style="list-style-type: none"> • Networks (in particular distribution networks) not designed to detect embedded DER • Restoration of the network supply onto an islanded system (unsynchronised closure of a switching device) could have catastrophic results to all consumer devices • Existing education and work practices may not reflect increased risk of islanding due to embedded DER.
Load volatility	<ul style="list-style-type: none"> • Technical characteristics of DER (in particular solar PV) allow it to ramp up and down very quickly, for instance, when the sun goes behind a cloud. Solar PV output within a neighbourhood is highly correlated. • More active customer participation means that blocks of load may suddenly shift in a coordinated fashion due to demand side management • Increasing volatility in load profiles can reduce the accuracy of network models and dispatch forecasts, leading to less efficient market operations (such as increased FCAS costs).
Loss of visibility	<ul style="list-style-type: none"> • Loss of visibility undermines the system operator's ability to: • Send the most efficient signals to the market in relation to future investments. • Predict variability in load due to DER, increasing regulation FCAS requirements, and costs • Predict load and its response to disturbances as accurately as in the past • Manage operations within the boundaries of the technical envelope • Have certainty in the effectiveness of emergency control schemes in preventing a black system if, for example, DER affect the volume of load available to be shed.

1.2.3. Benefits of DER

Although DER can create technical challenges if not effectively integrated into the power system and market, it can provide real benefits driving increased utilisation of the grid and through the supply of a range of grid support services. Verified grid support services are outlined in Table 2 below.

Table 2 – Examples of grid support services that can be provided by DER

Network impact	DER based solution
Peak demand management	<ul style="list-style-type: none"> DER can be used to reduce network investment requirements by offsetting demand during peak periods. For instance, customers could receive a payment for temporarily switching off their air-conditioners when the system is under stress, or batteries can store excess rooftop PV output for use during the evening peak.
Emergency Reserves	<ul style="list-style-type: none"> A number of international markets have schemes which access DER to provide an emergency response to avoid involuntary load shedding in case of extreme conditions or unlikely events.
Thermal loading	<ul style="list-style-type: none"> DER can be used to prevent thermal overloads. For instance, if excess PV generation is leading to upstream power flows, hot water systems can be set to come on during the middle of the day in order to act as a "solar soak". Alternatively, solar PV could simply be curtailed.
Voltage stability	<ul style="list-style-type: none"> DER can help with voltage stability if the inverter has reactive power capability and/or low voltage ride through capability. There is scope to use storage to manage DER output variations.
Frequency stability	<ul style="list-style-type: none"> DER, especially storage, can help to maintain frequency stability. For instance, Reposit Power's GridCredits technology is designed to enable residential batteries to provide frequency control ancillary services (FCAS).
Reactive power capability	<ul style="list-style-type: none"> New inverters have the capability (as per AS 4777) to provide reactive power by being set to either voltage control mode or power factor mode – improving grid power factor and therefore minimising transmission losses.

DER also has the opportunity to provide benefits on a larger scale once optimised on the distribution system as an aggregated load or generator and part of a centralised dispatch system. As an aggregated and controllable load or generator, the dynamic behaviour of DER will allow it to be a more reliable source to assist in system security purposes.

For any of the benefits of DER grid support services to be realised however, new communication platforms need to be established. This is discussed in further detail below in Section 1.3.1.

1.3. Effectively managing DER

1.3.1. Grid architecture

There are a range of complex factors to consider when deciding how the framework could best enable and incentivise the efficient orchestration of distributed energy resources. Figure 3 below considers some of the relevant factors associated with different grid architecture models.

Figure 3 – Discussion of different approaches to grid architecture for managing DER

Shared platform	Distribution management systems	Commercial platforms
DER controlled using a central platform <ul style="list-style-type: none"> Facilitates optimisation between different DER services DER service providers interact with a single common platform Level playing field for new entrant DER service providers Control remains with system operator Risk that central platform is cumbersome & slow AEMO could control centrally or NSPs could be enabled to dispatch DER for local grid support <ul style="list-style-type: none"> If former, require systems for DNSPs to advise AEMO of DN needs Commercial platforms are likely to be deployed outside shared platform 	DNSPs control local DER using enhanced DMS <ul style="list-style-type: none"> Evolution of existing DNSP systems DER service providers interact with multiple DMS platforms <ul style="list-style-type: none"> Scope for a common protocol DNSPs could dispatch DER on behalf of AEMO <ul style="list-style-type: none"> Require systems for AEMO to advise DNSPs of FCAS needs AEMO could delegate SO responsibilities to DNSP Fits well with independent DSO model Price/service risks arising from monopoly service provision Commercial platforms are likely to be deployed in addition to DMS (eg for retail hedge) 	DER controlled by DER service providers <ul style="list-style-type: none"> Permits superior products to emerge through competition rather than picking winners Costs associated with multiple competing platforms <ul style="list-style-type: none"> Risk of redundancy No regulatory action required; organic development DER service providers responsible for co-ordinating multiple DER services Less scope for co-optimising different DER services AEMO/NSPs reliant on commercial players to dispatch DER on their behalf Needs to integrate with SO at some level

If DER in the future is able to meet a significant portion of the load and is coordinated by independent bilateral agreements, the wholesale markets managed by AEMO would increasingly play a “balancing role” in the system. This could lead to less transparency in market operation and potentially have impacts on the hedging strategies of existing generators and future loads. Coordination between providers would still be required to ensure stable operation of the grids.

In this scenario, consumers and DER providers would have maximum flexibility in setting terms and contracting arrangements for providing DER. However, sufficient competition and transparency would be required to ensure that consumers were able to receive the full value of any provided DER.

In these early stages of DER market development, it is difficult to know what the optimal grid architecture should look like. This dynamic environment suggests that we should exercise caution before adopting any model that requires a large investment in inflexible grid architecture. Given the uncertainty surrounding the best way forward, there may be merit in promoting an incremental approach to the development of grid architecture to support DER markets.

1.3.2. Data management of detailed power system information

There are three key features to a data collection framework – collection, storage, and access/communication, each having their own technical and regulatory components that would need to be considered. As our power system evolves towards a more distributed structure, it is necessary to establish a framework to ensure that relevant data is collected, at the appropriate network level, and made available to system and network operators.

The required framework is likely to be different for standing and real-time data. Standing data is required on a disaggregated basis at the level of installation. Real-time data can be aggregated but needs to be collected continuously.

The framework would need to be flexible and transparent with clear roles and responsibilities on parties to collect the required information as well outlining efficient and appropriate accessibility to that information.

It would therefore be necessary to establish regulatory obligations, including roles and responsibilities, to collect the data, host the data and a sharing protocol. In addition, it would be worthwhile considering in the process the consolidation of data requirements and management across the board to avoid any redundant aspects and to reduce any unnecessary regulatory burden.

AEMO notes that provisions are likely to require the support of State and Commonwealth governments to establish a policy response to this issue.

1.3.3. Roles and responsibilities to manage DER

Responsibility for distribution system security

Under the current framework set out in Chapter 4 of the NER, AEMO has overarching responsibility for security of the power system, including the distribution system. AEMO must maintain effective communications and coordinate activities with transmission system operators and distribution system operators.¹

The Rules also confer on AEMO the power to delegate its power system security functions to network service providers.² AEMO has entered into an instrument of delegation with TNSPs in order to delegate a number of functions, including the function of liaising with DSOs. We also hold regular meetings with TNSPs and DNSPs to discuss power system operations and resolve any issues as they emerge.

Given the limited role of DSOs under the traditional model of power system operation, this arrangement has worked well to date. Network service providers must meet the system standards in the Rules and network performance requirements,³ and these standards have been sufficient to enable AEMO to manage power system security to date, without entering into additional arrangements with DSOs.

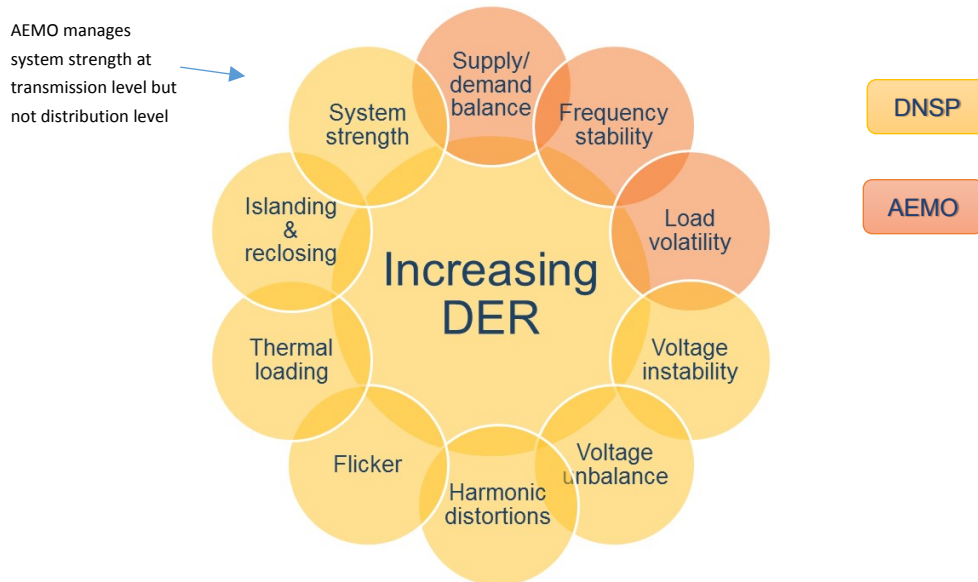
Therefore AEMO's focus is currently on system-wide challenges, namely maintaining the supply-demand balance, frequency control and forecasting in the presence of load volatility. The other technical challenges that arise as a result of increased DER are managed by DNSPs (see Figure 4).

¹ NER 4.10.

² NER 4.3.3.

³ NER Schedule 5.1a and Schedule 5.1.

Figure 4 – AEMO’s role in managing the technical challenges associated with DER at distribution level



As the technical characteristics of the grid become more complex and the importance of DER increases, the importance of effectively managing the distribution network and the scope of the DSO need to grow. It will also become necessary to review the division of responsibilities for power system security to ensure that they remain relevant and reside with the party best able to manage the risk.

The management of the transmission system and provision of energy and system services to distribution system will remain important and the DSO will need access to data on the potential impacts on their distribution network in both a planning and real time context. As larger amounts of DER are integrated on the distribution network, their impact may also start to be observed on the transmission network. It will therefore be important to ensure system security on the transmission level is not compromised by system security at the distribution level. Examples where technical issues that occur at the distribution network, arising from high penetration of DER, emerge onto the transmission network and potentially impact security of the wider system include:

- Voltage fluctuations
- Load volatility
- Impact on minimum demand (particularly in South Australia)
- Effectiveness of the under frequency load shedding scheme (UFLS) in South Australia
- Inertia and system strength

Subsequently, having clear definitions of roles and responsibilities will ensure that the network impacts of DER are addressed appropriately but it will also assist to realise the



system-wide benefits that can result from high levels of DER, such as a more resilient and faster-responding system, to be provided to consumers.

Coordination of services

When DER is able to provide multiple services within the market, coordination will be required to maximise the potential benefits. For example, storage systems which are contracted to provide grid support (responding to local peak demands) may not be able to participate in energy markets (responding to price signals) if guaranteed availability is required. Similarly, the dispatch of DER to address localised grid constraints can potentially work against price signals in the market, or vice versa.

Allowing decentralised dispatch of DER at the distribution level is likely to maximise consumer flexibility without interfering with price signals in the market. This ultimately enables more customised solutions for the consumer depending on the local consumption patterns, distribution network constraints and consumer preferences. It will be important to ensure coordinated provision of multiple distinct services at lower overall cost to maximise the potential benefits of the resource across the market.

Models for the role of distribution system operator

The term distribution system operator (DSO) refers to the entity that is responsible for managing the distribution system, supporting DER and maintaining the integrity of the network. The current limited DSO function is integrated with DNSPs.

The Energy Networks Association (ENA) has developed a view in their Network Transformation Roadmap where future DSOs would share responsibility for some of the functions currently performed by AEMO. This is broadly consistent with the current arrangements whereby AEMO has overarching responsibility for power system security and DNSPs have obligations to meet the system standards in the Rules.

As the new model is being considered, it is evident that the capability of the distribution network to assist with maintaining security of the wider power system is growing. Non-network options are increasingly emerging as credible alternatives to network upgrades. More active distribution system management can help to decrease the total costs compared to the traditional “fit-and-forget approach” of simply connecting new loads to the network. Research released by the Energy Networks Association (ENA) suggests that if networks buy grid services from DER, this ‘orchestration’ could replace the need for \$16.2 billion in network investment and lower average network bills by around 30% compared to today.⁴

Government and policy makers have indicated that they prefer market frameworks that support competition wherever possible, and therefore these services should be provided on arm’s length terms from any regulated monopoly business. This position reduces the risk that emerging markets will be controlled by incumbent players. It however also raises questions about what incentives network businesses have to deploy but not own efficient new

⁴ Energy Networks Association, Unlocking Value for Customers - Enabling New Services, Better Incentives, Fairer Rewards, 4 October 2016.



technologies under the current regulatory framework that arguably offers greater rewards for network businesses that adopt capital intensive network solutions over DER solutions.

AEMO is open to consider the actual model adopted. The strengths and weaknesses of the various models are being considered around the world. In New York and other United States jurisdictions the DNSP is the DSO. Under this model the DSO operates as an independent platform operator and is incented to support third party owned DER that allow more efficient network operations. A market structure that features an independent DSO is still in its formative stages. The idea has been proposed, but not adopted, in the United States. A recent UK Parliamentary review of low carbon network infrastructure concluded that policy makers should keep the governance of distribution networks under review. It further stated that policy makers should be prepared to separate distribution networks' operation from their ownership if the joint provision of DSO and DNO functions proves to have a negative impact on consumers.

Regardless of the model adopted, the role of distribution networks in maintaining overall system security is increasing. As such AEMO, transmission network operators and DSOs will need to collaborate and communicate in a greater capacity to ensure the system services required to maintain security will be provided in the most cost-effective manner.



2. Future system services and network development

2.1. The current frameworks for system security and network development

We must have market and regulatory frameworks that are relevant and adaptable to changes in the market environment so that the National Electricity Objective continues to be upheld.

At market start in 1998, the design of the market and regulatory frameworks within the NER were developed based on principles that would nationally optimise the power systems that existed within each of the eastern and southern Australian states. Such arrangements were established to allow development of a NEM that was based on centralised dispatch of generation so that customers received the most cost-effective supply of electricity no matter where they were in the NEM. The frameworks were also established under a concept where there was emphasis on having sufficient supply, predominantly sourced from large coal-fired plants, that was transported via the networks to meet peak demand to ensure security of supply to customers and also to provide a locational signal for network development or investment.

For a period of time these original principles have sufficed, however we are now entering a period where the market environment is changing due to policy direction, technology advancements and increased consumer participation in their energy usage and supply. For example, the penetration level of renewable generation has increased which in turn impacts the economic dispatchability of the older fossil-fuel plants and requires a different approach to acquire system services needed to deliver secure and reliable energy to consumers via the networks.

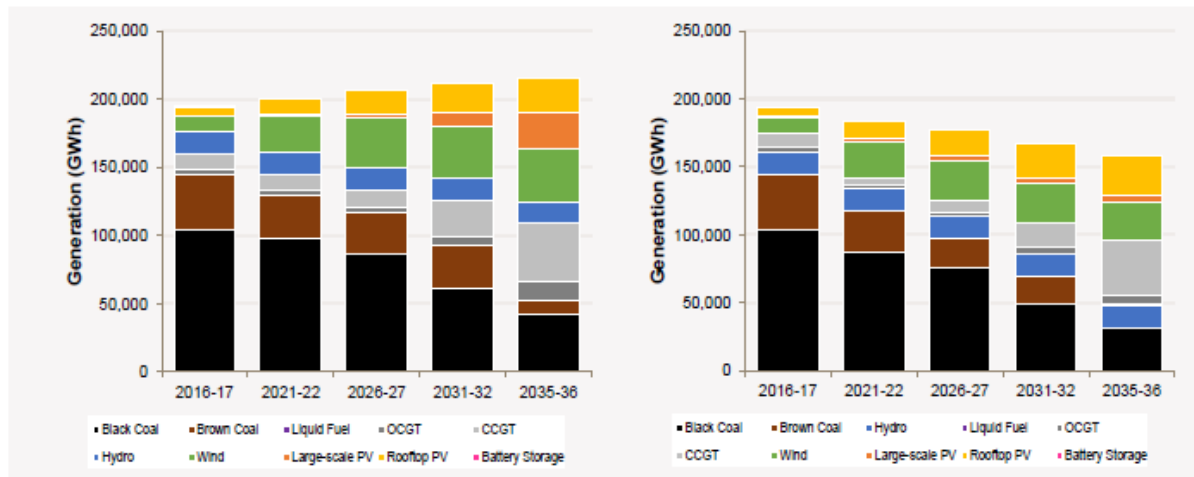
2.2. The impact of changes in the market environment

2.2.1. System security with growth in renewable generation and a lower carbon future

The growth in renewable generation in the NEM supply mix must be efficiently integrated to deliver reliable and secure energy supply.

As shown in Figure 5 below the levels of renewable generation are continuing to play a major role in the future generation mix. It also shows that as the mix of renewable generation increases, coal-fired generation is expected to decrease significantly from 74% of the NEM's generation mix in 2016-17 to 24% by 2035-36.

Figure 5 – Projected NEM generation (GWh), Neutral (left) and Low Grid Demand (right) scenarios



Source: AEMO, 2016 National Transmission Network Development Plan

In conjunction with the displacement of the availability of coal-fired generation is the loss of reliance on these plant's ability to inherently provide system services that assist in maintaining power system security. These services, traditionally referred to as ancillary services, include:

- System strength,
- Inertia (which affects the rate of change of frequency following a disturbance),
- Voltage support,
- Dispatchability, as well as
- Frequency regulation requirements.

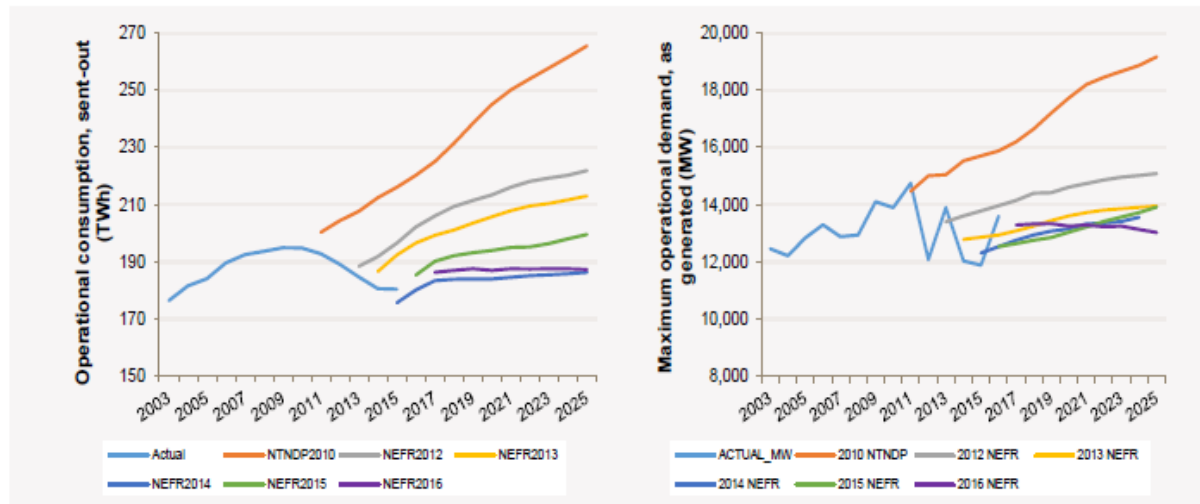
Therefore in an environment with high renewable penetration levels the system services required to deliver reliable and secure energy to customers must be acquired through other mechanisms if not from the resource themselves.

2.2.2. Network development drivers

The role and development of transmission networks is changing. Networks were originally designed for transporting energy from coal generation centres to customers to meet peak demand. However this is no longer the main driver for network development.

Since 2010, expectations for growth in both annual consumption of grid electricity (operational consumption) and maximum demand have changed. Figure 6 below shows this change through the New South Wales forecast as an example. The 2016 NEFR forecasts for the next 10 years project annual consumption to remain flat and maximum demand to decrease across the NEM due to factors including energy efficiency initiatives and changing consumer behaviour.

Figure 6 – Changing expectations for NEM operational demand (left) and NSW maximum demand (right)



Source: AEMO, 2016 National Electricity Forecasting Report

As such, network development is now primarily required to support large-scale generation development in new areas as well as facilitating system support services outlined above in Section 2.2.1.

In order for the benefits of network developments required for these reasons to be fully delivered and cost-effective to the market, different strategies to achieve this must be considered.

2.3. Delivering system services and networks in a cost-effective manner

2.3.1. 'Proof of concept' mechanisms

The emergence of new technologies and increased consumer participation in energy choices can serve to drive innovation in the NEM to deliver the services required at a lower cost.

'Proof of concept' mechanisms used to support innovation in these matters is potentially useful for the purpose of demonstrating emerging technologies and facilitating their integration into the network or the competitive market. While testing novel technologies it also shares cost and risk between appropriate parties for a period of time which makes it more attractive for potential investors.

AEMO and ARENA have developed a Memorandum of Understanding, undertaking to work together to establish collaborative programs. The shared work program to be established and managed under the MoU will support both utility or grid scale projects and projects which seek to utilise DER.

'Proof of concept' mechanisms for some distributed energy resources including customer load control, embedded generation and battery storage would be beneficial. These non-

network options also have the capability to provide power system services such as frequency control services and load balancing services. For example, households who offer to vary their consumption or output in response to real-time market signals (potentially through an aggregator) will be able to reduce their individual energy costs while also reducing the overall cost of energy production. This helps all participants better express their preferences for electricity consumption and pricing.

In addition, it also paves the way for alternative and lower-cost approaches to provide system services required and subsequently to manage power system issues if required. Therefore 'proof of concept' mechanisms to support technological innovation at all scales increases opportunity to find the most reliable and cost-effective solution in the longer-term.

2.3.2. Efficient integration

Small-scale and large-scale renewable technologies are no longer just fringe players of the NEM's power system, they are now core elements. It is therefore necessary for the market and regulatory frameworks to adapt to deliver efficient operation and development of a national grid and wholesale market.

There are some principles of the current market and regulatory framework design that should remain similar, such as technology-neutrality and encouraging the most efficient development option in the long-term interests of consumers. However the extent of the changing technical and operational characteristics of the power system and network development requirements means change is needed to deliver the best outcomes for consumers.

It is critical to ensure the ongoing provision of system security services with higher levels of renewable technologies in the supply mix. Although there are short-term operational solutions, including reducing interconnector flow or operating synchronous generators more frequently, it is the longer-term solutions of network development which are more cost-effective for consumers. These network and non-network solutions can provide more opportunities by resolving multiple power system requirements and can therefore be utilised more efficiently. Some of these include:

- New AC or DC interconnectors that allows for better access to geographically diverse resources across the NEM.
- Special protection schemes to act very rapidly to counteract a contingency event.
- Installation of synchronous condensers (including high inertia synchronous condensers and retrofitting retiring synchronous units as synchronous condensers) to provide system services.
- Installing new synchronous generation that can operate as synchronous condensers to allow significant flexibility to provide system services, without displacing inverter-connected generation.
- Leveraging the capability of demand response and DER (such as batteries) as discussed in Section 1.2.3.



A timely decision on the arrangements required to encourage the market to consider such options, and then deliver the most cost-effective solution is needed to enable efficient integration. While AEMO acknowledges that specific mechanisms are currently being considered in industry-wide reviews, AEMO believes the following principles are required to deliver efficient integration:

- Encouragement of the economic delivery of required system services through markets.
- Provision of additional system services from new plant through revised technical standards.
- Provision of additional system services by changing Australian standards for appliances, embedded generation and storage rather than through market design.
- Provision of additional system services and network development requirements through 'proof-of-concept' mechanisms.

To complement the changes to the market and regulatory frameworks required, responsibility and accountability must also be assigned in the process. This will allow opportunities from a low-carbon future to be integrated in a holistic manner to ensure that the full benefits are delivered to the consumers. This is best achieved with a national or NEM-wide perspective.

3. National planning and system operation

3.1. The revenue setting and planning framework

The current 'building block' approach for setting network revenues rewards the network businesses for building assets. It consequently does not support investment in high value services.

Under the building block approach a TNSP is rewarded for delivering transmission assets with an ongoing payment stream for the life of the asset. Decisions to increase the network capability to minimise the impact on the market are not rewarded to anywhere near the same degree.

There are some incentive programs designed to encourage certain positive service outcomes such as the Service Targets Performance Incentive Scheme but these represent only a small percentage of the total revenue allowance. In some cases there is no revenue at risk for failure to deliver the desired outcome on the market impact component of the scheme. Therefore the power of the incentive is low compared with the incentive of the business to over-invest in its asset base or drive down the unit cost of investment.

Reliability in majority of the states in the NEM is met through deterministic or redundancy planning standards. Planning requirements that consider the level of redundancy to be provided on the network are key drivers of capital expenditure. This framework does not encourage appropriate mechanisms for the network businesses to meet their investment requirement through non-network options as a rate-of-return would not be received on that option. This means that reliability is not met economically and consumers wear the cost.

For these reasons, the revenue setting framework that is complemented by states planning to redundancy standards must change or have the appropriate incentives in place so that consumers are not exposed to higher electricity prices.

3.2. National planning to deliver cost-effective results

A more efficient arrangement would reward businesses for delivering outcomes or services not assets. This would enable innovative and cost effective solutions to be deployed, such as sophisticated digital control schemes, demand side and generation support options.

An outcomes service-focused approach to transmission development will result in significantly higher transmission utilisation and lower transmission prices which ultimately means lower electricity costs for consumers.

A framework which encourages more optimised planning NEM-wide is likely to promote greater innovation to address network needs in the most cost-effective way for all NEM consumers.

3.2.1. Effective national planning



A more national strategic approach to transmission planning is required. This will effectively allow the opportunities from a low-carbon future to be delivered to consumers across the NEM at low-cost.

As discussed in Section 2, changes to the market environment have necessitated change in network development that was previously driven by the need to meet peak demand. This means that network planning in its entirety requires change – the change in network development needs affects the type of options or solutions to be considered to provide low-cost, reliable and secure energy to consumers.

To move to a lower-carbon future where the energy supply mix consists of higher levels of renewable generation across the NEM, increasing interconnection capacity can provide more benefits NEM-wide than only increasing intra-regional network capacity.

Modelling results from AEMO's 2016 National Transmission Network Development Plan (NTNDP) showed that:

- The potential interconnection options AEMO studied were found to deliver fuel cost savings by improving utilisation of renewable generation and reducing reliance on higher-cost generation.
- A combination of the potential interconnector developments was found to deliver positive net benefits in every NTNDP scenario assessed which indicates that these potential projects are likely to remain beneficial under a broad range of policy and grid demand uncertainties.

To determine if greater net benefits can be delivered to the market either through alternative (including non-network) options or through co-optimisation of various options, each potential development should be economically assessed from a NEM-wide perspective.

This will ensure a national strategic approach is conducted by evaluating the required network development holistically by including opportunities to strengthen NEM interconnection and thereby providing consumers with the most cost-effective solution.

3.2.2. Changes to the Regulatory Investment Test for Transmission (RIT-T)

Efficient investment through the RIT-T

The regulatory investment test for transmission is a transmission planning mechanism based on cost-benefit principles to determine optimal investment options and timing.

The regulatory test ensures that investments that are uneconomic are not developed. Effectiveness depends on a commitment to the economic foundation of the test and a well-informed market and regulator.

The application of the RIT-T is an obligation on the TNSPs that has a value through its role as a consultative mechanism and one which provides some transparency on the TNSP's decision making capabilities. However while it is true that a TNSP must satisfy the RIT-T in order to build a project above a certain monetary threshold, it receives equivalent revenue whether the investment proceeds or not as its revenue is approved by the AER at the commencement of the regulatory control period. These arrangements mean broader



consideration of economic benefits of all potential options is unlikely to occur and it is unlikely to prevent inefficient TNSP investment.

Subsequently, the regulatory test needs to improve so that it truly delivers efficient transmission investment. The RIT-T framework must deliver impartial decisions that take into account the changing environment that can result in uncertainty and therefore allow for more non-network options (such as battery storage) to provide the flexibility required to address uncertainty.

Administration of the RIT-T

A national planner will provide the credibility in the market in regards to a transparent process for transmission investment NEM-wide. Additionally, a national planner will have the necessary information across the NEM for the regulatory test to deliver more efficient results as intended.

AEMO already conducts the RIT-T in Victoria as the state's independent transmission planner and therefore has the required expertise in assessing a range of options to deliver the most economical solution for the customers. Accordingly, there is merit in formal arrangements that extends this role to oversee key strategic investments across the NEM. Our role as system operator would further benefit this extended role as it would allow our operational knowledge and expertise to be considered in the national planning process.

This highlights that there are synergies in network development and maintaining power system security so that opportunities within the evolving market can be delivered to consumers in the most cost-effective and secure manner.

3.3. Benefits of a combined national planner and system operator

Continued investment in transmission is essential to the efficient operation and success of the NEM. However, the manner in which assessments for such investment are undertaken, the analysis, public consultation and transparency of decisions is questionable.

With the market evolving due to a wide-range of reasons including technological, consumer-driven and also political in nature, there are benefits of a single entity having responsibility and accountability of certain aspects of power system development.

Under the current framework, AEMO as the NEM system operator is able to monitor the system's behaviour holistically based on operational information provided to us by TNSPs. This information would assist in reliability planning on a national basis as it would integrate the system security requirements in the development of the network which would optimise delivery of energy to consumers through the most cost-effective means.

A combined national planner and system operator further benefits the market as there is currently a lack of incentives on the state-based planners to consider inter-regional supply capability to address intra-regional issues which may be more cost-beneficial to consumers. Clear accountability for this to a body without having financial vested interests in the outcomes would address this problem.

Sections 1, 2 and 3 above have highlighted that in order to ensure energy security to customers is delivered through cost-effective measures in the future, many regulatory



changes will be required. Although any change to frameworks can take time, the following section provides improvements to the regulatory decision-making process to better enable the industry to be adaptive and keep pace with the changing environment going forward.

4. Allow regulatory decision-making to promote proactive management of emerging issues

4.1. Speed of regulatory decision-making

To effect regulatory change from proposal to delivery through the existing process can take many years.

The NEM governance framework has a hierarchy of regulatory instruments including:

- Legislation managed by the COAG Energy Council
- The NER managed by the AEMC
- Technical standards and/or guidelines are managed by the AEMC's NEM Reliability Panel
- Detailed industry procedures are developed by AEMO, and
- Processes and operational systems developed by AEMO and industry participants.

Industry consultation is included at each level, taking upwards of 6-months in each case. Once decisions are made, at least one year might then be required to implement changes, and transition periods are also required in some cases.

The trade-off inherent in this arrangement is that involving more regulatory bodies or agencies can provide additional checks and balances against vesting too much authority in a single body or agency, but at the cost of efficiency and speed of change.

However industry change is taking place at an increasing pace, with technology and business models far less predictable than they were at NEM commencement.

4.2. Clarity of roles and responsibilities

Accountabilities and obligations of market agencies must be clearly identified and acknowledged to effectively manage change.

Some NEM frameworks are more aligned with this principle than others, for example, consider AEMO's power system security responsibilities.

In the current framework, AEMO is able to make changes to a range of operational practices, including procedures for intervention, management of system restart, specifications for participation in existing frequency control ancillary services (FCAS), procurement arrangements and settlement mechanisms for FCAS.

However, other important elements of the power system security framework do not have clear roles defined in legislation or the NER, specifically:

- AEMO suggests there is a need for a clear responsibility for monitoring the adequacy of current access standards, and driving changes to them through a process of constant review and adaptation at a detailed technical level.



- Responsibility is not assigned for monitoring the adequacy of technical network access standards as currently set down in Schedules 5.2, 5.3 and 5.3a of the NER (for generators, customers, and market network services respectively).
- Access standards for some equipment, such as distributed generation, are not currently covered by the NER, and responsibilities are uncertain. The current process has not delivered any change to the NER based technical performance standards since 2007.
- AEMO recommends detailed technical specifications should be moved from the NER into a sub-ordinate instrument.
- No agency has been assigned responsibility for tracking emerging operational risks in relation to the power system, and promoting adaptation to the overall system security framework.

Work of the above type is closely aligned with other responsibilities of AEMO and NSPs, and it is often argued that there is nothing to stop these parties from pursuing them autonomously. However, the work requires allocation of expert resources, funding, and often the ability to access information from other businesses. Therefore in practice, in the absence of a clear obligation assigned to an appropriate body on a continuous basis, there is no certainty that forward risk assessments can be progressed with the necessary focus.

4.3. Changes to the decision-making process

The pathway that allows the efficient integration of market changes currently occurring and to ensure consumers still receive low-cost and secure energy supply requires strategic planning.

The regulatory framework has to pre-empt investment change. An effective response to rapid industry evolution requires innovation in the management of regulatory reform that keeps pace with changing market conditions.

It also requires the development of a longer-term plan, rather than a piece-meal or incremental approach, that encompasses a broader consideration of factors for a more proactive approach to market and regulatory framework change. That is, a process that integrates network development planning issues with their required market and regulatory changes from identification of the problem or need that requires resolution to the assessment of benefits that will be delivered to consumers and to the development of an implementation plan for that solution.

AEMO also believes that policy and Rules settings should more clearly assign forward-looking risk assessment and management roles to agencies with a view to identifying emerging technical issues early enough for them to be addressed proactively rather than reactively.

AEMO suggests that changes are required to the regulatory framework so that the higher regulatory instruments, including the Rules, are used to define roles and policy principles with broad expression rather than detailed definition. The responsibility of the detailed



adaptation of processes or settings within that broad policy space could then be managed transparently and regularly through one of the lower regulatory instruments by agencies such as AEMO and the AER in collaboration with NSPs.

If well designed, the proposed approach would:

- Save time in the regulatory decision-making process as changes would be aimed at the appropriate regulatory instrument for direct consultation with industry, rather than requiring a series of changes to be made in each of the individual regulatory instruments.
- Provide increased confidence within industry that issues are being addressed by an agency with clear responsibility for that issue, in contrast to the current relatively passive process that relies on lodgement of a Rule change without any agency having a responsibility to track risks and changes.
- Result in a transparent and clear process of risk assessment and management of an issue in its entirety, rather than making incremental step changes following occasional investigations triggered in response to incompletely addressing the issue.



ATTACHMENT A – AEMO’S WORK PROGRAMS

AEMO has established a major internal work program – the Future Power System Security (FPSS). Through this we have been consulting closely with the local and international energy community to understand the implications of the changes and to adapt power system management so that security can be maintained.

The FPSS currently has four key areas of focus, each with individual workstreams as relevant:

- Frequency management
 - High rates of change of frequency (RoCoF)
 - Insufficient amount of available frequency control ancillary services FCAS)
- System strength
- Information, models and tools (Visibility of the power system)
 - Visibility of DER
 - Tools and capabilities
- Managing extreme power system conditions
 - Emergency under frequency control schemes (UFLS)
 - Emergency over frequency control schemes

Other areas that AEMO has also progressed work on to understand the emerging challenges and opportunities under rapidly changing market conditions (which are not directly part of the FPSS work program) include:

- System security
 - Operational readiness plan for 2017-18 summer
 - Inaugural Power System Frequency Risk Review including declaration of potential Protected Events: assessing arrangements for managing non-credible contingency events which may result in cascading outages and major supply disruptions
 - Assessment of medium term Network Support and Control Ancillary Services issues
 - Review of Frequency operating standards
- System reliability
 - Medium Term Projected Assessment of System Adequacy process development
 - Extension of Reliability and Energy Reserve Trader reliability intervention mechanism



- Engagement with demand aggregators for emergency reserve
- DER and the future of distribution services
 - Amend Market Ancillary Service Specification to accommodate provision of ancillary services from DER and demand response.
 - Five minute settlement in the wholesale energy market
 - Implementation of Power of Choice rule changes – metering contestability, embedded networks and B2B frameworks.
 - Developing NEM Demand Side Participation Information Guidelines
- Network planning frameworks
 - Interconnector upgrade assessments
 - Engagement with non-network service providers.