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19 January 2017

John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

Distribution Market Models Approach Paper

AEMO welcomes the opportunity to comment on the Distribution Market Models approach paper. This review is timely given the profound changes affecting electricity markets.

As the generation mix changes, the traditional model of supply following load is being displaced by a model where load is able to follow supply. As smart embedded generation and demand management becomes more prevalent, market structures will need to evolve to allow distributed energy resources to be deployed efficiently.

The energy market transformation is an opportunity to improve customer outcomes and shift towards a low carbon power system. However, it also brings new technical challenges that must not be overlooked. We need to ensure that the technical consequences of decisions are understood, and robust solutions are identified, tested and implemented in a timeframe that keeps pace with changing market conditions.

A key issue for AEMO is accessing the information that we require to be able to fulfil our statutory obligations to manage a secure and reliable electricity system and prepare forecasts of electricity demand. These issues are discussed in AEMO's report for COAG on Visibility of Distributed Energy Resources (attached).

AEMO would like to work with the AEMC and other stakeholders to develop a distribution market model that best serves the long term interests of customers. If you would like to discuss any of the issues raised, please contact Jess Hunt on 08 8201 7315.

Yours sincerely,

David Swift
Executive General Manager, Corporate Development

Attachments: AEMO response to Distribution Market Models Approach Paper
AEMO, Visibility of Distributed Energy Resources, January 2017

Attachment 1 AEMO response to Distribution Market Models Approach Paper

1. Do stakeholders agree with these definitions, or have any views on the project scope as a result of these definitions?
2. Do stakeholders support this project scope? Is there anything that has not been flagged for consideration that should be? Is there anything that should be excluded from the project scope?

The consultation paper defines “distributed energy resources” as an integrated system of smart energy equipment co-located with consumer load (such as a battery or a smart air conditioner). The definition explicitly excludes passive equipment such as a rooftop solar PV system that generates and feeds power into the grid when the sun shines.

AEMO agrees that there is an important distinction to be made between these different resources. However, excluding consideration of passive energy resources could result in a missed opportunity to explore the technical issues associated with rooftop PV and the development of an efficient, non-discriminatory regulatory frameworks to address these issues. For instance, some DNSPs prevent consumers from adding new rooftop PV once uptake on the local network reaches a certain threshold. There may be more flexible alternatives, such as requiring prospective PV owners to install smart equipment that can be remotely controlled, or establishing a framework to shift load to periods of high PV output. Local network issues arising as a result of passive energy resources may also drive new grid support services that could be provided by DER.

Accordingly, AEMO supports the proposed definitions, subject to either:

- the inclusion of certain issues associated with passive energy resources within the project scope, or
- a separate (but related) process to explore issues associated with passive energy resources.

In addition to the matters included in the project scope, the Commission should explore the underlying case for distributed markets. Historically, high transaction costs have precluded the development of distribution level markets. Technological developments are reducing these transaction costs to the extent that such markets are now feasible.

Distribution markets bring significant potential benefits in terms of empowering consumers and promoting more efficient outcomes and behaviour. However there are still barriers to achieving these benefits in practice. If distribution markets are implemented in the presence of inefficient network tariff structures, the markets could act to exacerbate distortions and increase costs from a system-wide perspective.

AEMO would not want these issues to become an excuse for inaction. However, it is important to have a robust understanding of the relevant costs and benefits in order to ensure that any reform package includes the full suite of measures to deliver benefits in practice as well as in theory.

3. Are there any other elements of a DNSP's role or current responsibilities that should be considered?

The consultation paper identifies the regulatory investment test, incentives schemes, service classification, ring fencing, and network pricing reform as relevant matters.

We suggest that there may also be merit in considering the rules and process applying to DER connections, to ensure that DNSPs' requirements and processes do not inhibit the efficient uptake of DER. The connections rules applied by DNSPs are diverse and they have the potential to strongly influence the development of DER markets.

As outlined in the consultation paper, there are many mechanisms in the NER that promote efficient non-network solutions as an alternative to network investment. In practice, these mechanisms attempt to counterbalance the incentive for networks to favour network investments that arise under the building blocks regulatory model. We note that the AEMC proposes to examine this issue as part of the Electricity Network Economic Regulatory Framework Review.

4. Are there any aspects of the regulatory framework that are not set out in sections 2.3 or 2.4 but which should be considered through this project?

The consultation paper notes that AEMO is responsible for maintaining power system security. The detailed arrangements are more complex. In practice, AEMO, DNSPs and TNSPs work together to maintain power system security.

Under the current framework set out in Chapter 4 of the National Electricity Rules (Rules), AEMO has overarching responsibility for security of the power system, including the distribution system. Among other things, AEMO must maintain effective communications and coordinate activities with transmission system operators and distribution system operators (DSOs).[1]

At the same time, network service providers and must meet the Rules system standards and network performance requirements.[2] Further, registered participants have obligations to meet their performance standards. These requirements are a key element of the overall framework for maintaining system security.

The Rules also confer on AEMO the power to delegate its power system security functions to network service powers.[3] AEMO has entered into an instrument of delegation with TNSPs in order to delegate a number functions, including the function of liaising with DSOs. This framework has the advantage of flexibility as it is relatively straightforward to reallocate roles and responsibilities between AEMO, TNSPs and DNSPs.

Given the changing technical characteristics of the power system, new challenges may emerge that are not contemplated by the existing Rules framework. In these cases it may be beneficial to amend the instruments of delegation, or potentially the Rules, to ensure that accountability lies with the party best able to manage the risk.

There may be benefits in undertaking a review of the Rules system standards and network performance requirements to ensure that they remain fit for purpose.

[1] NER 4.10.
[2] NER Schedule 5.1a and Schedule 5.1.
[3] NER 4.3.3.

5. Should the coordination of distribution systems with distributed energy resources be centralised under the direct control of one body? Or should it be devolved and performed in a tiered manner?

There is a distinction to be made between power system operations and managing distribution level markets. As the role of distribution system operator becomes more complex, it is worthwhile to consider whether the current Rules framework remains optimal. DNSPs currently manage a wide range of issues on their networks including voltage, thermal loading and power quality. AEMO's overarching responsibility for system security in electricity can be contrasted with the arrangements that apply gas, where our responsibility for managing the gas system ends at the bulk supply points.

The question of who should be responsible for managing the market platforms that support the provision of grid support services by DER involves a number of difficult trade-offs. A centralised approach maximises opportunities to optimise between different DER services, however it runs the risk of being cumbersome and slow. A devolved approach that relies on commercial platforms may permit superior products to evolve through competition rather than picking winners, but it also involves duplication and the risk of incompatibility between competing services. A well designed central platform may enable new technologies by providing low cost access to market. Alternatively, a central platform could form a barrier to entry if it becomes bound up in red tape.

In some cases, DER services may be subject to competing priorities. For example, the DNSP may seek generation to support the local network at a time when there is an oversupply of generation at the grid level, with AEMO curtailing other generators and consumers seeking to charge their batteries. Consideration should be given as to how competing priorities are managed.

AEMO also notes that with a high penetration of DER, new challenges arise in efficiently managing scheduled generators. Overall system costs could be reduced by co-optimising between DER and scheduled generators. This would likely require some form of centralised platform to coordinate efficient dispatch of all providers and services.

AEMO supports incremental reforms that keep pace with changing circumstances without locking in a particular solution. For instance, we note that the AEMC's recent decision in relation to ancillary services unbundling creates an opportunity for DER to provide ancillary services. Further incremental measures could involve:

- Enhanced monitoring and controls to promote the active management of distribution networks
- More sophisticated and transparent network planning tools to better support DER solutions
- Industry wide interoperability standards and
- Uptake of DER-based grid support services, for instance via network support contracts.

Ultimately, we support the solution that promotes the long term interests of consumers, regardless of whether it involves an expansion or contraction of AEMO's role.

6. Do stakeholders agree with the Commission's framework and these principles of good market design? Is there anything that the Commission has missed, or is unnecessary?
7. Are there any other issues the Commission should have regard to in considering possible market design options?

AEMO supports the principles of good market design set out in Box 3.2. We agree that market-based solutions are often the most efficient. However, we believe that the principles should give greater emphasis to the maintaining the security, reliability and efficiency of the power system.

The energy market transformation involves many players and is likely to involve a series of step changes. Often these step changes are driven by commercial factors rather than power system security, for instance when a large generator makes a decision to exit the market. Customers and policy makers expect power system security and reliability to be maintained throughout the transition.

The design of the electricity market needs to accommodate the laws of physics. In practice, policy makers and market designers face difficult choices given the complexity of the issues and multiple competing interests. Going forward, there would be benefits associated with a decision making framework that explicitly takes into account:

- the technical consequences of different market design options; and
- the costs and benefits of potential solutions to any technical problems.

The decision making framework should be designed to ensure that policy choices are made with a full understanding of the technical consequences of the chosen option. In many cases, an iterative process may be required.

8. Do stakeholders agree with the Commission's assessment of the technical impacts of distributed energy resources set out above in sections 4.1 to 4.8?

We agree with the technical impacts identified by the Commission, however, we would also add technical impacts associated with:

- loss of visibility,
- loss of dispatchability, and
- load volatility.

As noted in our response to questions 1 and 2, we consider that these matters should be within scope even though they are associated with both passive and smart DER.

Loss of visibility

As DER is installed behind the meter, it is often invisible to AEMO and network operators. This lack of visibility affects AEMO's ability to understand the operational impacts of DER on the power system. These issues are discussed in AEMO's report for COAG on Visibility of Distributed Energy Resources (attached).

A framework should be established to ensure that relevant data is collected and made available to AEMO and network operators. The framework should be flexible and take into account which party is best placed to collect the required information and efficiently make it available to those who require it on an as-needs basis (taking into account confidentiality issues). A transparent process should be established to assess what information should be collected and who has access to it.

Load volatility

The technical characteristics of key types of DER (including solar PV) allow it to ramp up and down quickly, for instance, when the sun goes behind a cloud. Solar PV output within a neighbourhood is highly correlated. Further, more active customer participation means that blocks of load may suddenly shift in a coordinated fashion due to demand side management.

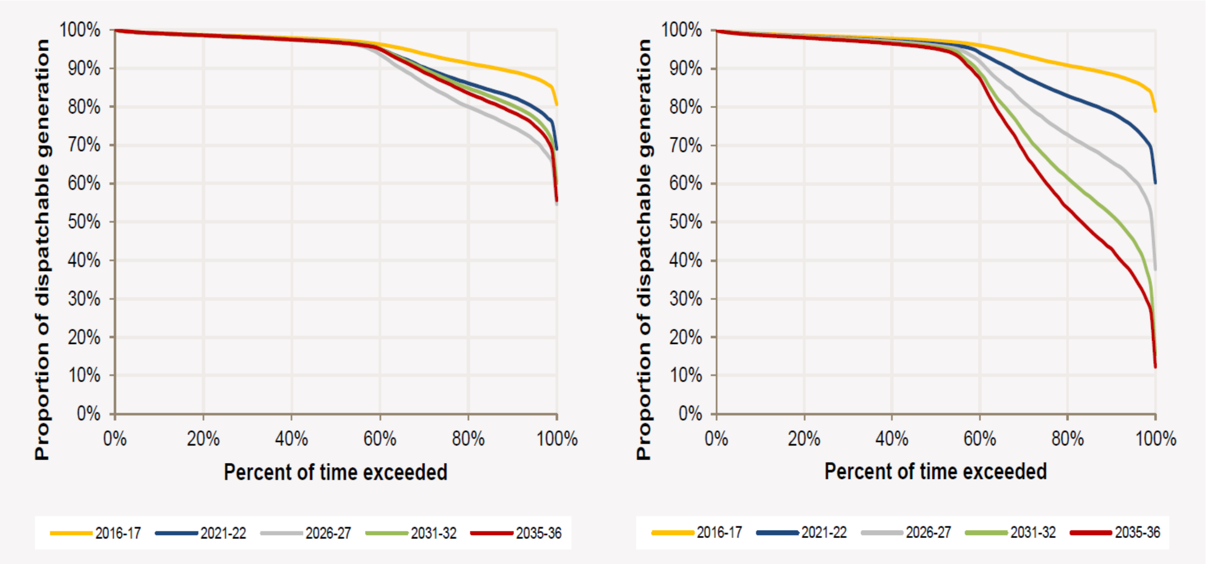
As a result, DER increases increasing volatility in load profiles can reduce the accuracy of network models and dispatch forecasts, leading to less efficient market operations (such as increased FCAS costs).

Loss of dispatchability

We note that the Commission's position is that imbalances between supply and demand is a driver of the technical issues listed in Chapter 4 rather than a technical issue in itself. We regard loss of dispatchability as an issue in its own right.

As non-dispatchable, inverter-connected generation comprises a greater proportion of total generation over the next 20 years, the visibility and control of the power system is expected to reduce (see Figure 1). In particular, if current trends continue we anticipate that rooftop PV output will exceed minimum demand in South Australia by the mid 2020s. This change in the generation mix leaves AEMO with fewer tools to manage the supply-demand balance. As the proportion of generation that can be dispatched falls, it becomes increasingly necessary to activate the demand side in order to maintain power system security.

Figure 1 Proportion of dispatchable generation in the NEM, Neutral (left) and Low Grid Demand (right)



Source: AEMO, 2016 National Transmission Network Development Plan.

If embedded generators and/or loads are price sensitive and capable of exerting a significant influence on wholesale market outcomes, then eventually some form of arrangements are required to ensure that the supply-demand balance is maintained, either by AEMO or via devolved means. If these parties are to be dispatched, then the system operator will need to understand the relevant distribution network limitations and constraints.

9. Do stakeholders agree with the Commission's preliminary assessment of these opportunities, and possible solutions to address the technical impacts of distributed energy resources?

The Commission has identified a broad range of high level solutions; network based solutions, technical solutions, operational solutions, market based solutions and price signals.

We agree that a combination of these solutions are likely to be required. We support incremental reforms that provides flexibility for the market design to evolve in line with technological developments and consumer preferences.

10. Do stakeholders have any initial views on who should be responsible for managing these opportunities, or implementing possible solutions to the technical impacts?

AEMO has not yet formed a position with respect to this question. However, we anticipate that responsibility for implementing solutions will vary depending on the issue. For instance, responsibility for managing local voltage issues is likely to continue to lie with DNSPs whereas frequency should continue to be managed at a grid wide level.

As the new model emerges, it would be worthwhile to consider whether today's DNSPs are appropriately structured to take on new grid management and market functions.

The term distribution system operator (DSO) refers to the entity that is responsible for maintaining the distribution system and making investment decisions. The DSO function currently resides with DNSPs, however it could be undertaken independently of the entity responsible for owning and maintaining distribution network assets (the DNO). This structure could help to ensure that DER based solutions are given equal weight to network solutions in network planning decisions. Similarly, there may be questions relating to competitive neutrality if the DNSP has a role in dispatching DER and/or load management.

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.[4] A recent UK Parliamentary review of low carbon network infrastructure concluded that policy makers should keep the governance of distribution networks under review, and 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.[5]

4 See, for instance, Wellinghoff, J. Tong, J. and Hu, J. (2015) The 51st state of Welhuton, 27 February 2015. The 51st State. Available at: http://www.sepa51.org/phaseII/Welhuton_51stState_Addendum.pdf and Rahimi, F. and Mokhtari, S., 2014. From ISO to DSO: imagining new construct--an independent system operator for the distribution network. *Public Util. Fortn*, *152*(6), pp.42-50.

5 House of Commons Energy and Climate Change Committee Low carbon network infrastructure First Report of Session 2016–17, June 2016.

VISIBILITY OF DISTRIBUTED ENERGY RESOURCES

FUTURE POWER SYSTEM SECURITY PROGRAM

Published: **January 2017**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to explain the need for visibility of distributed energy resources located behind the meter, using information as at the date of publication.

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EXECUTIVE SUMMARY

The energy market has been undergoing a transformational change which has seen an increase in distributed energy resources (DER) such as rooftop photovoltaics (PV). These systems provide opportunities to manage the power system in new ways, particularly with advanced metering and digital technologies. However, if their uptake is not holistically managed, these systems, in aggregate, can have a material and unpredictable impact on the power system and its dynamics due to their cumulative size and changing characteristics.

As technology changes, AEMO's responsibilities to maintain a secure and reliable power system remain unchanged. If the opportunities presented by DER are not taken up in a coordinated way, large penetrations of DER that are being installed "behind the meter" (BTM, meaning on customers' premises) are likely to be "invisible" to AEMO. This lack of visibility affects AEMO's ability to quantify and manage the operational impacts of DER on the power system. In the Future Power System Security (FPSS) program, industry and government stakeholders have also identified the need for visibility of DER as a high priority challenge.

Two of AEMO's core responsibilities in managing the National Electricity Market (NEM) are to maintain power system security and reliability and to deliver information to support efficient market outcomes.

Maintaining power system security

AEMO operates the power system through a security constrained, optimised dispatch process. In doing so, AEMO continuously quantifies the limitations on the system to determine an operating envelope, taking into account the prevailing power system and plant conditions, and predicting the impacts of unexpected events. This requires sufficient information and data about the power system and its components to effectively quantify how the power system might respond to a range of system events, and thus the operational measures required to maintain the power system within applicable standards such as the frequency operating standards (FOS).

Large penetrations of DER installed BTM, if not visible and predictable, will progressively decrease AEMO's ability to:

- Quantify how the power system is likely to behave and manage operations within the boundaries of the *technical envelope*.
- Manage the power system using the usual operational levers, because DER is managed by consumers or their agents.
- Develop, calibrate, and validate its technical or business models, meaning AEMO needs to assume how future trends will deviate from past trends.
- Predict variability in load due to DER, increasing regulation frequency control ancillary services (FCAS) requirements and costs.
- Predict load and its response to disturbances as accurately in the past.
- Have certainty in the effectiveness of emergency control schemes to manage power system frequency, if DER affected, for example, the volume of load available to be shed.

Furthermore, with the dynamics of the power system changing, a lack of visibility of DER will affect the operational management of extreme power system conditions, and may make parts of the grid more prone to failure. This may have implications for the management of any contingent events which may require certain mitigation measures to satisfy the FOS[1].

[1] This may in part be alleviated by the introduction of a special class of contingency events called "protected events" that would give AEMO authority to put in place pre-emptive measures to manage these extreme conditions. This is being explored as part of the AEMC's System Security Markets Framework Review.

Delivering market efficiency

Information is key to delivering an efficient market which achieves the National Electricity Objective (NEO), AEMO is responsible for providing accurate information to the market. This information supports participants in making a range of operating and investment decisions. The information provided is optimised across the entire energy portfolio, across timeframes from pre-dispatch out to 10-20 year planning horizons.

If AEMO is unable to accurately predict how the system is going to perform across all these time periods, then it will not be able to provide information needed to support market efficiency or reliability. This includes for example:

- Quantitative positions for generators and other participants to make short-term decisions on unit availability, unit commitment, maintenance scheduling, future fuel contracts as well as trading.
- Sending efficient signals to the market in relation to future investments such as generation to meet potential shortfalls in supply, or network needs.

A lack of visibility of DER will impact AEMO's ability to perform both these functions effectively, resulting in the power system being operated increasingly inefficiently, with asset under-utilisation, less informed investment decisions, and ultimately increased costs borne by consumers.

How load is changing

Changes in the energy market and technology development are giving more power to consumers to choose how their electricity demand is met. This has resulted in a large uptake of rooftop PV, and it is anticipated that other DER, such as energy storage, will become more cost-effective for consumers in the near future. Frameworks to capture this uptake require implementation now to make sure they are in place for any DER entering the market. Once installations have been made, the information becomes very difficult to collect.

These DER technologies have common drivers underlying their operation, which impact both the prediction and response of load:

- **Load forecasting** has relied on the underlying diversity in consumer behaviour which means not all appliances are used at the same time in the same ways. For those that are used widely at the same time, such as air-conditioners, use is correlated to weather patterns and so has some predictability. Some DER, on the other hand, are either undiversified, such as rooftop PV, or currently less predictable in how they operate, like batteries. The undiversified operation of DER can, in aggregate, offset the underlying diversity in consumer demand and change the daily load profile. This makes load forecasting more challenging, with an increased dependence on locational drivers which can in turn further increase the variability and ramping behaviour of DER.

  Specific DER technologies can also be expected to change their technical characteristics over time as technologies mature and become more efficient, or existing installations degrade in their performance.
- **Load response** to system disturbances is important to the ability to manage power system security, as AEMO needs to understand how load, in aggregate, will respond to these events. Many DER are connected to the network via power electronic inverters which are programmed to disconnect from the network if voltage or frequency reaches certain thresholds. Without visibility of how these DER are pre-set to respond, AEMO cannot plan efficiently for contingency events, and will not know whether large penetrations of DER will present challenges to preventing blackouts, or in the worst case, a black system following non-credible or multiple credible contingency events. In the near future, AEMO will specifically need to quantitatively assess the ability of the system to withstand "protected events" and to maintain frequency within standards.

International system operators have estimated the benefits of having visibility of DER for operational load forecasting. These studies found that these benefits outweighed the costs of establishing the data collection processes.

DER also represent an opportunity to provide solutions to some emerging system security challenges if their capability is leveraged. Some DER have the capability to be controllable, which means they could potentially provide ancillary services and load shifting to manage power system dynamics. This would create benefits at both the distribution and transmission network levels.

The need to enable visibility

The National Electricity Rules (NER) provide mechanisms that allow AEMO to access information it requires to fulfil its obligations. In particular, Network Service Providers and Generators have a number of obligations to give information to AEMO to ensure power system security and reliability requirements are met.

AEMO has very few powers to obtain similar information about unregistered generation. In the case of DER, their relative proportion has until recently been low, so issues related to the collection of information about their technical properties was not a significant concern.

If the uptake of DER is coordinated so as to harness their full capability to provide power system benefits, then these systems and how they behave will be visible to the market. However, there are gaps in the consistent collection and storage of data related to DER installed BTM that do not participate in any registered service. While there are systems in place (or in development) that enable AEMO to access information from distribution network service providers (DNSPs), there is no mandate for the DNSPs to collect all the required future information for AEMO to perform its system operation and planning functions.

Currently, the information collected on DER varies for each DNSP, and often only concerns the localised needs of their networks. Importantly, DNSPs often require different information about the system and its components depending on their operational obligations.

The data framework for rooftop PV only exists because the Clean Energy Regulator (CER) requires the information for the purposes of compliance with the small-scale renewable energy scheme. The data collected therefore reflects only what is required by the CER, and is not sufficient for AEMO’s operational needs. For example, AEMO does not have any information about the historical generation of PV, but rather relies on samples provided voluntarily by individual households to derive the best currently available estimate.

The current mechanisms for AEMO to access information (from registered participants or other institutions) are only effective if the required information has been collected in the first place. This is where the gaps are.

Data needs for power system operation

AEMO has completed a comprehensive stocktake of the current operational processes it performs to manage power system security, as well as identifying any future developments that may be required, such as incorporating new technologies in forecasting and planning functions.

The specific data requirements will vary for each technology, and each component within the DER system. Broadly, AEMO requires:

- Static data on location, capacity, and the technical characteristics of the systems, in particular the inverters interfaced to the network.
- Real time, or at least five-minute, DER output data, aggregated at the connection point level for operational forecasts.

These information gaps affect all AEMO’s operational processes, from real-time dispatch to longer-term planning. Broadly, the range of impacts will be:

- To mitigate potential system security risks, AEMO would need to apply more conservative limits on the *technical envelope* than the limits that would be applied if there were more certainty around load behaviour. This would result in more stringent constraints in the dispatch process, creating market inefficiencies that would end up having economic consequences for both consumers and participants. It will also make it more challenging to plan short-term outages and network augmentation needs.
- The inability to accurately forecast the increased variability in load will create greater requirements for FCAS.
- The efficacy of emergency frequency control schemes such as under frequency load shedding (UFLS) will be unknown without knowledge of the DER inverter trip settings. This undermines AEMO's ability to operate the power system within the FOS.
- Inaccuracies in medium- and long-term planning processes will distort the signals sent to the market on future power system needs, creating the risk of either under- or over-investment in infrastructure.

These impacts will result in an inefficient market and increased costs to consumers.

Enabling visibility

It is necessary to establish a broad, flexible, and technology-neutral framework to facilitate visibility of DER installed BTM. This framework should leverage existing mechanisms and frameworks so far as possible.

There are three key considerations associated with a data collection framework: collection, storage, and access/communication. It would be necessary to establish a regulatory obligation to collect the data, a regulatory obligation to host the data, and a sharing protocol.

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. There are both technical and regulatory options for data collection, each with their own pros and cons.

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1. INTRODUCTION

Purpose of this report

The purpose of this document is to outline, and invite comment from stakeholders on:

- The need for visibility to efficiently accommodate increasing penetrations of distributed energy resources (DER) in the power system while maintaining power system security.
- The potential impact of DER on market efficiency and reliability if their existence and behaviour is not visible or predictable.
- Potential regulatory changes that may be required to address information gaps.
- Initial options for the collection of data, recognising the need for further consideration and consultation on these.

DER can refer to small generation or load shifting systems that are located at customers' premises[2]. Examples include either rooftop or commercial installations of photovoltaics (PV), energy storage, demand management, electric vehicles (EVs), combustion motors, and cogeneration units. They can vary in size, and are typically considered to be anything from around 1 kilowatt (kW) up to tens of megawatts (MW). Although generally small individually, DER are becoming increasingly important in the power system. They have capabilities that, if unlocked and managed appropriately, can provide benefits to the power system as well as the consumer. If not, their aggregated behaviour has the potential to adversely impact the power system in a number of ways. In this case, without appropriate visibility of these systems, AEMO may not be able to operate the power system securely or efficiently.

The National Electricity Rules (NER) facilitate access to information about some DER, however, there are gaps in the data collection and storage frameworks, particularly for DER that are small and located 'behind the meter' (BTM), such as rooftop PV.

As a result of not only the adverse impact, unmonitored, aggregated DER has on the power system but also the relative proliferation of DER installed BTM, a mechanism to collect, store, and make available information about the location, type and performance of DER installed BTM is needed as soon as practicable.

Context

This work is part of AEMO's Future Power System Security (FPSS) program[3]. The program takes a strategic approach to studying future power system security requirements, and will evolve to accommodate new challenges and changing context as new products and services enter the market.

The FPSS program progress report released in August 2016[4] outlined the potential technical challenges being investigated. Of these, the need for visibility of DER was identified as a high priority challenge as stated in Section 6.1 of the progress report:

> **Challenge:** The customer-driven trend for DER and technologies that can integrate the control of devices to manage load is not directly visible to AEMO. In aggregate, these can have a material impact on the power system, and a lack of visibility affects AEMO's ability to accurately assess the operational limits of the power system.

[2] In most instances, DER also refers to those systems that are controllable. Here, those that are not form the critical information gap.
[3] http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability
[4] AEMO. *Future Power System Security Program: progress report*, August 2016. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis.

Through the FPSS program, AEMO has also been identifying whether updating existing processes or introducing new processes under the current regulatory framework would adequately address the challenges identified. This work complements the broader program of the Australian Energy Market Commission (AEMC) through its System Security Market Frameworks Review.[5] Where changes to regulatory or market frameworks may be required, AEMO is working to determine the technical specifications of possible solutions, and informing the AEMC on what implementing them operationally may entail.

AEMO's work on the visibility of DER also has some intersection with a consultation on energy storage registration by the Energy Market Transformation Project Team (EMTPT), a working group of the Senior Committee of Officials of the COAG Energy Council. The EMTPT has been consulting on the need to establish a battery storage registry for, amongst other purposes, power system operations and planning. AEMO's submission discussed the work of the FPSS program, and the need to consider DER more broadly.[6] The EMTPT also received several submissions from stakeholders who expressed concern over the need for AEMO to have visibility of DER. This report aims to address those concerns.

Structure of report

This report outlines AEMO's assessment of its operational processes, and the DER-related data considered critical to the future operational management of the power system:

- Chapter 2 describes how DER are changing the daily load profile and the ability to forecast load accurately. It also explains how load in aggregate responds differently to system disturbances due to the different characteristics of DER.
- Chapter 3 outlines the current mechanisms for accessing information about DER, highlighting the gaps.
- Chapter 4 describes the operational processes AEMO implements to provide an indication of where large penetrations of DER will have an impact, and the technical and market consequences of not having adequate visibility. In describing these operational processes, the information about DER that is required by AEMO is outlined, with emphasis on the fact that data requirements will be different for different technologies.
- Chapter 5 then proposes a broad change to regulatory frameworks to address the need for visibility of DER, with the framework having appropriate flexibility to be adaptive to new technologies.

While this report focuses on the National Electricity Market (NEM), the need for visibility of DER is equally pertinent to the South-West interconnected system (SWIS) in Western Australia.

Inviting stakeholder comment

AEMO invites stakeholder feedback on the need for visibility of DER installed BTM and how this can be achieved. Stakeholders wanting to provide input can:

- Email submissions to StakeholderRelations@aemo.com.au by 28 February 2017.

[5] More information about this review, including the consultation paper and submissions, is available at http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review.

[6] More information on this consultation, announced in August 2016, is available at http://www.coagenergycouncil.gov.au/publications/energy-market-transformation-%E2%80%93-consultation-processes. AEMO"s submission is available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/EMTPT-Energy-storage-registry---AEMO-submission.pdf.

2. THE EVOLUTION OF THE DEMAND SIDE

Key considerations

- Changes in the energy market and technology development are increasingly empowering consumers to choose how their electricity demand is met, and as a result more DER are being installed.
- In the case of some individual DER technologies, there is a common underlying driver that influences how devices based on that technology operate. For example, rooftop PV generates when the sun is shining, so there will be a relationship between co-located devices using PV technology. The undiversified operation of DER, can in aggregate, offset the underlying diversity in consumer demand and change the daily load profile. This makes load forecasting more challenging, with an increased dependence on locational drivers.
- It will become increasingly challenging to produce accurate regional forecasts if they cannot capture the underlying locational drivers of DER. This will lead to an increased need for complementary energy services, such as frequency control ancillary services (FCAS), to manage increased variability and ramping of some DER.
- The ability to predict load is one aspect that affects the ability to manage power system security and manage market reliability. Another is understanding how load, in aggregate, will respond to power system disturbances.
- In response to system disturbances, DER connected to the network via power electronic inverters behave differently to direct connected load or generation. One example is that they are usually programmed to disconnect from the network if voltage or frequency reach certain thresholds. Without visibility of how they are pre-set to respond, AEMO cannot plan efficiently for contingency events, and will not know whether large penetrations of DER will present challenges to preventing a black system or how they will participate in recovery from a black system following non-credible or multiple credible contingency events[7].
- While DER can present challenges for power system operations, they also represent an opportunity to be part of the solution to emerging operational challenges. DER have the capability to be controllable, which means they could potentially support the provision of ancillary services and load shifting services to manage power system dynamics, or defer network investment.
- International system operators have estimated the benefits of having visibility of DER for operational load forecasting. These studies found that these benefits outweighed the costs of establishing the data collection processes.

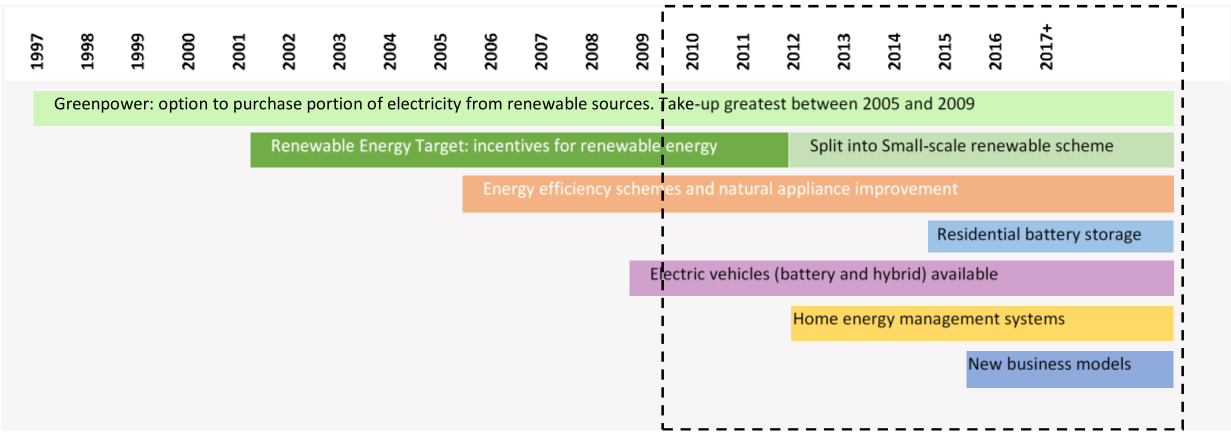
2.1 Increasing consumer choice

AEMO has traditionally been concerned primarily with power system data at the transmission level. Operations have relied upon supervisory control and data acquisition (SCADA) systems for oversight of the transport of generation to the distribution network, and to relay information about power system conditions. These SCADA systems typically are only embedded down to the substation level, with the AEMO system operator not requiring detailed data beyond the transmission connection point. Distribution system operators have a range of means of acquiring data and exercising control over their distribution systems, but these are varied in nature and not uniformly interfaced with transmission system operators or AEMO control systems.

[7] Contingency events are defined in the National Electricity Rules. Credible contingency events refer to unexpected but reasonably possible events which the power system is required to be secure against, whereas non-credible contingency events broadly refer to events that are very rare and large unexpected events against which the power system may not be secure.

However, the energy market is changing, with new small-scale technologies, technology and IT systems, and business models[8] providing consumers with more options to actively manage how their demand is met. Figure 1 shows the evolution of some of these changes. The pace of these changes has quickened over the last few years with the introduction of incentives, lower technology costs, and greater consumer engagement. This increases the urgency for a framework to capture information about the location and technical characteristics of future installations before this information is lost.

Figure 1 Some of the ways consumer behaviour has changed



Consumers have had the option of purchasing a portion of their electricity from renewable sources through their retailer via the GreenPower scheme since 1997. The Renewable Energy Target (RET) was initiated in 2001, but gained the most traction with consumers when it was officially split into the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) in January 2011. The SRES scheme provided subsidies for rooftop PV systems and solar hot water. As of May 2016, there were 5,353 MW of rooftop PV installed across Australia, increasing from 569 MW in January 2011.[9]

New products that can affect load and supply, such as energy storage, EVs, and home energy management schemes, have also recently emerged. This has been driven by a general rise in energy prices while at the same time technology costs are decreasing, and the technologies themselves are becoming more capable. Many new business models are also emerging that involve participation in traditional services facilitated by third-party aggregators, modules that allow the user to set and forget based on the household needs, or technology leasing arrangements.

Although these changes are within the distribution network, and are small individually, sufficient penetration will mean in aggregate they will have a material impact on the power system. As an example, there are 4.7 gigawatts (GW) of installed rooftop PV in the NEM[10], in comparison with the largest power station, Eraring in New South Wales, which has a capacity of 2.9 GW.

This impact in turn affects AEMO's ability to manage the power system securely and reliably, which is discussed in detail in Chapter 4.

2.2 Impacts of DER on power system operations

There are two broad areas where a lack of visibility of DER *directly* impacts power system operations:

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[8] The new business models represent new ways of owning or operating technology for commercial gain. For example, retailers are providing rooftop PV and battery systems to customers on a contractual or leasing basis, third-party aggregators are working with consumers to utilise their systems, and various other technologies are available that allow consumers to choose how to operate their systems.

[9] Data from Clean Energy Regulator, available at: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

[10] http://pv-map.apvi.org.au/historical#4/-26.67/134.12, accessed 16 August 2016

- **Prediction** of load.
- **Response** of load.

These are discussed in greater details in the following sections. It is important to remember that while many DER generate energy, if they are located BTM, then they are “seen” via a change in load characteristics.

The overall consequences of not addressing these impacts is included Chapter 4, which also discusses the more *indirect* impacts of DER on operations.

DER can also present positive opportunities for power system operation, as outlined in section 2.3.

2.2.1 Prediction of load

In the past, load could be predicted with sufficient accuracy by analysing historical data to determine the relationship with variables such as weather, time of day, day of week, electricity prices, and (for longer term forecasting) broader economic factors such as gross state product.

These correlations for load in aggregate could be created in the past because there is an underlying diversity in the behaviour of consumers. That is, on the average day, consumers use their appliances at different times and in different ways. This creates a spreading of load across the day rather than being concentrated at the same time, and allows the preparation of sufficiently accurate forecasts of load, based on the above broad parameters, on a regional level.

Figure 2 Example of diversity of household loads

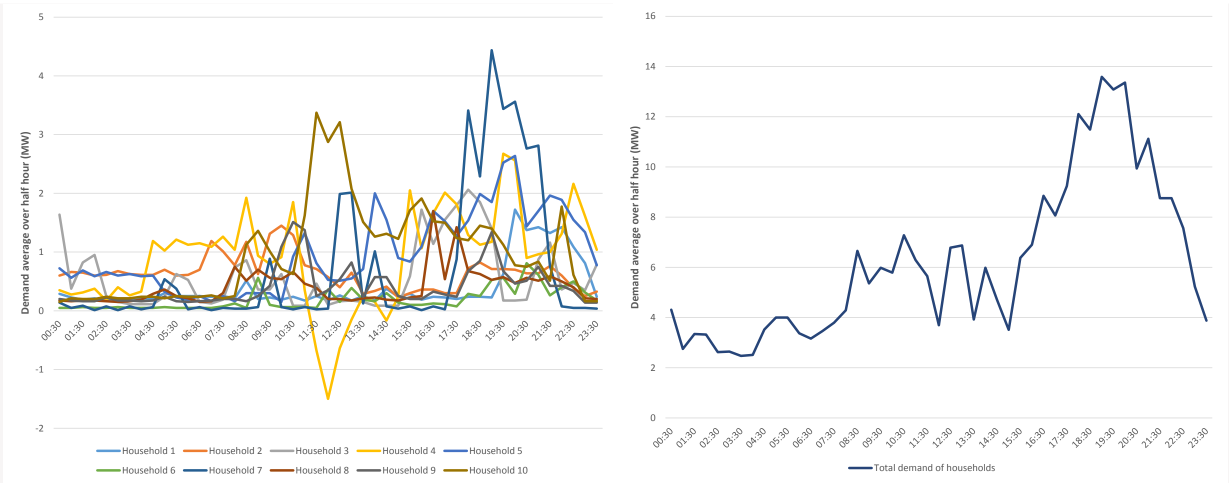


Figure 2 (left) shows a simplified example of load diversity across ten Victorian households on 13 June 2016.[11] Even across these ten households, there are differences in the load supplied by electricity from the grid. Household 4 has a rooftop PV system installed, and in the middle of the day, the generation exceeds the household load, and the excess is exported to the grid. Household 10, on the other hand, has its peak load in the middle of the day. The figure on the right depicts the total demand of these households, which shows the overall trend, with peak demand occurring in the evening (typical for a winter day in most NEM regions).

In instances when consumers behave similarly, such as the utilisation of air-conditioners on a very hot day, the material increase in demand can be anticipated through weather patterns, and AEMO puts in place operational measures to manage these instances. This can be done without the need to know explicitly about the number of air-conditioners, due to the predictable dependence on weather. Another

[11] AEMO National Meter Identity (NMI) data.

example is the hot water peak in South Australia which occurs at 11.30 pm (market time) every night as some 300,000 hot water systems (approximately 250 MW) switch on.

These events have been operationally managed to date without direct knowledge of the underlying appliances, as they are examples of regular and predictable behaviour (although they generally result in higher market prices). The aggregated behaviour of DER generally does not occur in an apparently regular manner. DER in general will have locational (and potentially commercial) drivers, rather than all being correlated to a particularly underlying variable, making it more challenging for outcomes to be predicted by AEMO's current forecasting processes.

The presence of diversity in the "passive" demand side has to date given AEMO the ability to forecast aggregate demand with sufficient accuracy to operate the power system securely. Additional benefits of this diversity have included:

- As the demand profiles of each NEM region are not coincident, the system maximum demand is much less than the sum of maximum demand of each NEM region, reducing overall supply side investment.
- Differences in demand profiles across different regions and sub-regions means generation can be transferred across different parts of the network, assisting in the reliability of supply.

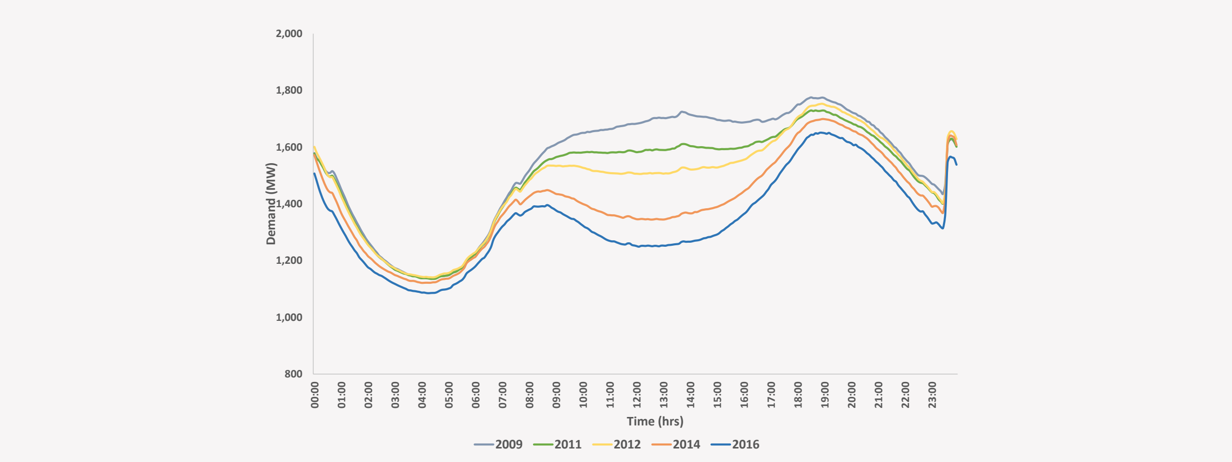
Accurate load forecasting is important for day to day operations of the power system as well as short-term reserve assessment, and for infrastructure assessment and planning over the medium and longer term. What is important in these assessments is the daily load profile, how quickly the demand changes, and the relationships between the minimum and maximum demand.

Currently, AEMO forecasts load at the transmission connection point and on a regional basis.

How are demand patterns changing?

The significant uptake of DER changes the load behaviour and the ability to predict it in a number of ways, as the underlying drivers of DER operation are fundamentally different from the demand drivers. Consider for example the increased installed capacity of rooftop PV. The output of these devices is dependent on factors such as panel quality, location, orientation, solar irradiation, and temperature. So while they can be correlated with weather, PV systems will generate at the same time in each location and so are not diverse in when they operate. This changes the daily load profile as seen by the network. More importantly, each additional PV system changes the load profile in exactly the same way. A commonly referenced example of this is the "duck curve" of Figure 3 which shows how the average daily load profile has changed over the years due to rooftop PV in South Australia.

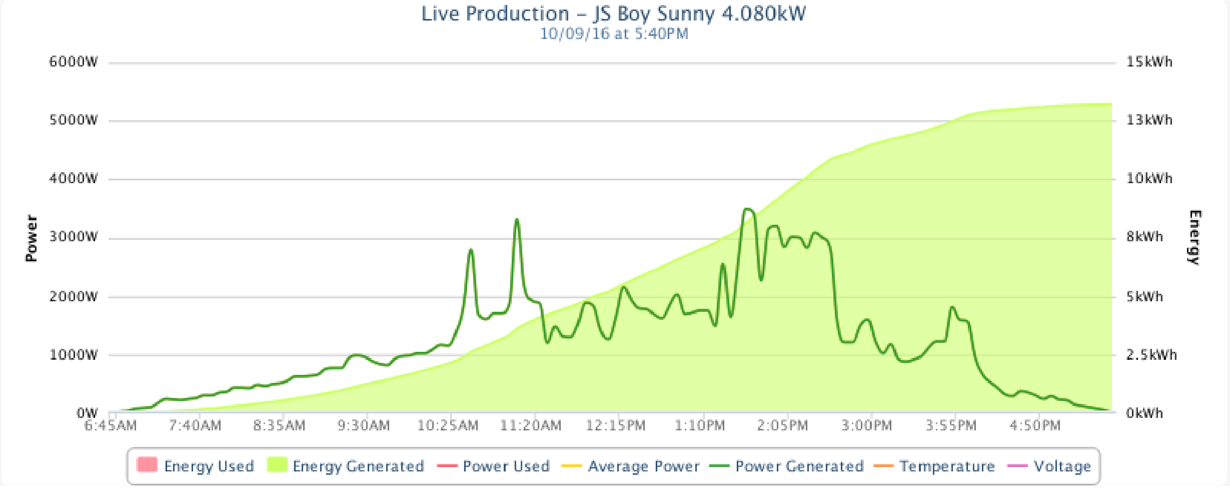
Figure 3 South Australian daily demand for grid electricity



The figure shows the daily load profile based on averaged five minute data across selected calendar years between 2009 and 2016. As the capacity of rooftop PV has increased over the years, its impact on the load profile during the day is evident, with a large dip in demand followed by large ramping up in demand once the solar generation subsides.

An additional challenge with rooftop PV and most DER is the variability in output they display. Preliminary analysis by AEMO suggests that rooftop PV within a distance of 10 km has variability that is correlated.[12] This means PV systems within this proximity are all affected in a similar way by changing weather patterns such as cloud cover.

Figure 4 Output of a single rooftop PV system on a slightly cloudy day*



* Obtained from www.pvoutput.org.

Figure 4 shows the real-time output of a single rooftop PV system on a cloudy day. The spikes correspond to when the clouds moved away from the panels, and during the middle of the day the generation is quite low, indicating that cloud cover remained over the panels. Each solar system within the vicinity of this installation would have a similar profile of peaks and troughs. If there are a large number of these systems, the aggregate effect of these peaks and troughs can be sizeable. These effects would be locational, so the impact across a region would be stochastic, meaning locational peaks would sometimes correlate, giving “super-peaks” or “super-troughs”. This challenges operations, as the system needs to meet these peaks and troughs as well as the average of them. This has implications for voltage control and line flow management in distribution systems. In this way, the underlying diversity of demand can be offset by the undiversified operation of rooftop PV in a less predictable yet material way. AEMO has had to develop its forecasting processes to account for PV (discussed in section 4.1.1).

A further consideration is how each DER technology can change in its characteristics relative to each other. For example, as standards develop, new installations will have different technical characteristics to the existing fleet.

Not all DER generate energy. Some DER have the effect of shifting load depending on how they are programmed to operate, such as energy storage. How these are operated, however, could be quite different for each device. Residential battery storage systems, for example, could operate based on a retail tariff, and so could in aggregate change the load profile based on how the tariff changes throughout the day. Alternatively, the device could be part of an aggregated service where the devices are operated remotely by a third party.

[12] AEMO, *Projection of regulation FCAS requirements*, to be published.

Similarly, EVs will draw large amounts of demand from the grid, depending on how they are used and charged. In particular, the time of day that they are charged can vary depending on factors independent of the energy market, such as traffic congestion, so is much harder to predict.

Although the underlying diversity of human behaviour will still be there, it will be offset by the undiversified operation of DER. This makes load forecasting increasingly difficult, and it is likely that forecasts will need to become more frequent and more granular; that is, load forecasting on a regional level may no longer provide adequate accuracy, as the aggregate drivers of demand become more locational with greater uptake of DER. How granular will depend on how the market evolves, as the net effect of DER on load profiles will depend on the number, location, type, performance, and operation of the devices. Whether these load forecasts are performed by AEMO or others is discussed in Section 5.2.

Further specific examples of how DER impact load forecasting are summarised in Table 1.

Table 1 Summary of impacts on load forecasts

	Description	Implications
Variability and uncertainty	Many DER have an underlying variability and uncertainty that produces a forecast error. For example, the generation from PV depends on the individual panel performance as well as shading and orientation on a system basis, and with cloud cover as a whole. Battery storage and EVs have an uncertainty in how they are used (for example, when EVs are charged).	Greater forecast error may increase regulation FCAS requirements. Each DER technology will contribute differently to FCAS requirements as they have different underlying drivers.
Ramping	A large concentration of DER in a localised area can ramp up or down quickly because of their variability. For example, rooftop PV will reduce or stop generating if there is cloud cover. If this cloud cover moves quickly, the cumulative impact of all affected rooftop PV systems can be material. Also, ramping capability will be required as solar generation reduces towards the evening and other generation will have to ramp up (as evident in Figure 3).	Preliminary analysis by AEMO of rooftop PV has found that within the five-minute dispatch period, systems within a 10 km radius had variability that was closely correlated. This will have an impact on the regulation FCAS requirements due to ramping events. The Californian Independent System Operator (CaISO) estimated that in 2020, it would require 13,000 MW of ramping capability within three hours[13].
Performance characteristics	As with any product, each type of DER will vary in its performance characteristics. Some PV panels will be more efficient than others, generating more energy relative to its capacity.	Forecasts of the impact on load profiles will need to be calibrated against real performance data to more accurately reflect the properties of the system.
Price decoupled	DER have different drivers of uptake and rely on external factors such as household economics and behaviour, and the retail price they pay. DER can also change the price elasticity of demand through either responding to prices decoupled from the wholesale price (e.g. retail tariff), or by self-optimising behaviour based on prices, acting as a demand response that is not visible to system operators.	AEMO needs to forecast the behavioural investment decisions of consumers. Without visibility, it will be difficult to predict aggregate behaviour. International consultants DNV GL worked with the New York Independent System Operator (NYISO) to assess the impact of this behaviour. It found that demand response that was not visible to the operator resulted in cascading fluctuations in price, supply and demand[14].

[13] CaISO, *Distribution Resource Integration,* Presentation to Electric Advisory Committee Meeting, March 2014. Available at: http://energy.gov/sites/prod/files/2014/03/f13/Mar2014EAC-Loutan.pdf

[14] DNV GL, *A Review of Distributed Energy Resources,* September 2014. Available at: http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf

	Description	Implications
Measurement and telemetry	Generation that participates in the dispatch process is equipped with telemetry or metering equipment to measure and control the generation output for both operational and market transaction purposes. DER do not generally have associated metering or remote control so AEMO has to estimate the difference between the underlying demand that is consumed and the demand that is required to be met from grid-supplied generation.	Without measurement of the actual output of DER, AEMO has no ability to calibrate and validate its forecasting models. Currently, AEMO uses the PV installation data, and historical load and weather data to estimate the generation output of rooftop PV. That is, AEMO needs to "backcast" this. This then affects the accuracy of the load forecast, as the historical data on which they are based may be poor indicators of future usage patterns.

2.2.2 Response of load

The ability to predict load is one factor that affects AEMO's ability to manage power system security. Another is understanding at the technical level how load, in aggregate, will respond to power system disturbances.

The power system is:

- In a satisfactory operating state, if different electrical characteristics such as frequency and voltage are within technical limits.
- Secure, if it will remain in a satisfactory operating state following a credible disturbance.

Frequency, for example, is maintained within a narrow band around 50 Hertz (Hz). Frequency deviations occur when there is a misbalance between supply and demand. The larger the imbalance, the larger the frequency fluctuation.

AEMO puts measures in place to manage any deviations, including FCAS, and placing constraints on power flows in the system if there is a risk of separation events.

For AEMO to manage power system security, it must also operate with enough mechanisms in place that should a single disruption (a credible contingency event[15]) occur, AEMO can return the power system to a secure state within a short time period.

AEMO constantly revises the operating bounds of the power system, referred to as the *technical envelope*[16], to fulfil this obligation.

Part of defining the *technical envelope* involves understanding how the load will respond to these disturbances. AEMO determines a set of "load relief" indices for each load sector (residential, commercial, and small and large industrial), at each connection point, through real-time measurement and data analysis.

Electronic appliances, such as fridges, washing machines, and dishwashers, have generally been powered by AC induction motors. This provides a stable response to disturbances that permeates across the network and dampens the effect of the disturbance. So, in determining the potential outcome of a power system event, AEMO has traditionally considered the contribution from load to be a stabilising or "relieving" influence. It incorporates this into operational processes by assuming that a percentage change in load will result from a percentage change in frequency.

How has load response changed?

DER are viewed by AEMO as a change in load even if, like rooftop PV, they are generators. This means their response to power system disturbances needs to be considered as part of the load relief.

[15] A credible contingency event is defined in clause 4.2.3 of the NER, and broadly refers to an unexpected but reasonably possible event which the power system is required to be secure against.

[16] The *technical envelope* is defined in clause 4.2.5 of the NER, available at: http://www.aemc.gov.au/getattachment/fe2c99ec-5a79-4143-97e0-f498f94a1451/National-Electricity-Rules-Version-83.aspx

In response to power system disturbances, DER have a different behaviour to traditional appliances. Technologies such as PV and energy storage are connected to the network via power electronic inverters.[17] They are programmed to disconnect from the network if voltage or frequency reaches certain thresholds. So, unlike traditional appliances, their reaction to a system disturbance is a controlled outcome, rather than a technical or mechanical characteristic. Their programmed response can also vary between manufacturers, or based on the different preferences of installers and owners.

Without visibility of how the DER are pre-set to respond, the prudent course of action is for AEMO to take a conservative approach. This affects the bounds of the *technical envelope* on a day to day basis if the penetration of DER is large.

It also means that AEMO does not know how these devices will respond to extreme power system conditions, and whether they will present challenges to preventing a black system following non-credible or multiple credible contingency events.

This information is also important in considering restoration following a black system.

GE Energy Consulting has been performing a study for the Hawaii Natural Energy Institute to investigate the impacts of large penetrations of rooftop PV on grid stability. [18] Analysis has focused on the island of Oahu which has the largest penetration of DER. Work to date has considered the impact of rooftop PV on the Oahu power grid's dynamic performance following contingency events of both loss of a generator or loss of a load. The studies found that the level of DER considered did not erode grid stability to a loss of generator event, but increasing penetrations of DER significantly eroded grid stability to loss of load events. The asymmetrical results arises as the PV systems have different responses to under and over frequency events, with the majority of the inverters having been upgraded to include frequency ride-through capability, while none have control systems to provide over-frequency droop[19] response.

Given the volume of inverter-connected small-scale PV generation in the NEM, and the lack of information on how it will respond to frequency disturbances, in 2015 AEMO initiated a stocktake of the then current fleet of inverters and their frequency trip settings.[20] The key objective was to ascertain whether they would respond simultaneously to frequency disturbances by disconnecting at a set frequency. The data collected indicated a low probability of inverters tripping in unison due to frequency disturbances within the required frequency operating ranges. Limitations in the data obtained, however, mean concern remains over what conclusions can be drawn.

Data about inverters came from the database of the Clean Energy Regulator (CER), which contains details of the installations under 100 kW that registered to create Small-scale Technology Certificates (STCs). The CER data showed that, as of May 2015, 3.69 GW of small-scale PV had been installed across the NEM.

Up to March 2016, AEMO had acquired the frequency trip settings for 1.64 GW (44%) of this installed capacity. Efforts to acquire additional trip settings were limited by:

- The CER information only including details about inverters for installations after 2010.
- After 2010, the CER recorded 180 different inverter manufacturers. Eleven manufacturers were surveyed, as they covered 82% of the installed capacity in the CER's records.
- As manufacturers were not obliged to provide their settings to AEMO, not all of them provided the requested frequency trip settings. Some manufacturers had also gone out of business, so it was not possible to gather information about their systems.

While the simultaneous tripping of the current fleet of inverters appears unlikely under normal operating conditions, the study did suggest that, under rare events, the disconnection of PV inverters at extreme

[17] Inverters convert direct current (DC) to alternating current (AC).
[18] GE Energy Consulting. Oahu distributed PV grid stability study Part 1 (March 2016) and Part 2 (May 2016). Available at: http://www.hnei.hawaii.edu/projects/oahu-distributed-pv-grid-stability-study
[19] Droop response refers to the percentage of speed or frequency change as a function of power or gate position change.
[20] AEMO. *Response of existing PV inverters to frequency disturbances,* April 2016. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/43BE01476E2D4992A3BDA2DA2E1A14A4.ashx

frequencies may reduce the effectiveness of the UFLS schemes in regions with large penetrations of rooftop PV. AEMO has since performed studies as part of the re-design of the South Australian UFLS scheme in late 2016, which suggest that the majority of inverters disconnect at frequencies below where UFLS operates.

AEMO's inverter study revealed a number of critical observations with respect to DER data collection:

- It is difficult to collect information on DER after installation to an adequate level of confidence.
- As the level of PV uptake in the NEM was not expected, the industry did not fully understand what information it needed and why. This indicates the need to be flexible in the future approach to data collection.
- Information about DER is critical, and the industry cannot rely on data collection from other agencies. Given the penetration of rooftop PV, AEMO was very lucky that the CER collected and could make available basic information about these installations. This enabled AEMO to side-step some of the challenges of not having data for its operational processes. This opportunity is unlikely to be there again, however, as the CER doesn't collect the full range of data required, and no one is currently collecting information on battery storage or replacement and upgrades of rooftop PV.

2.3 The opportunities of DER for power system operations

While DER can present challenges for power system operations, they also represent an opportunity to be part of the solution to emerging operational challenges.

DER have the capability to be controllable, which means they could potentially provide ancillary services and load shifting to support the management of power system operations, including during disturbances. This has benefits for operations of both the distribution and transmission systems:

- At the transmission level, DER have the potential to provide a range of frequency control services.
- AEMO's operational levers for managing the power system currently rely on the central dispatch of utility-scale generation. Increasing penetrations of DER will impact power system operations by reducing these operational levers (see Section 4.1.1). The implications of this would likely be ameliorated if arrangements were in place that incentivised or required the controllability of DER.
- At the distribution level, DER could be leveraged to provide network support such as voltage control or managing local peak demand. These non-network alternatives at the distribution level could potentially reduce the need for network augmentations.

A number of studies, such as GE's Oahu grid stability study, highlight the grid support services that can be provided by DER.

To capitalise on the opportunity to extract the full efficient capability of DER devices in the NEM, regulatory frameworks need to be adapted to provide the appropriate level of visibility and controllability of these devices. In particular, performance standards of inverters will have a role to play in the integration of larger penetrations of DER. For example, standards may require smart inverter functions that support grid stability locally through voltage support, or provide system support through frequency control capabilities.

2.4 The need for visibility of DER for prediction and response of load

AEMO is not the only system operator to have identified the need for access to additional data relating to DER. Around the world, operators such as the New York Independent System Operator (NYISO) and California Independent System Operator (CaISO) also have large penetrations of DER and have studied the impact that a lack of information will have on their ability to meet their respective obligations.

These international bodies found that the greater the visibility the system operator has of DER, the more operational flexibility the power system operator has in efficiently managing the balance of supply and demand, and in planning against contingency events.[21]

Visibility enables system operators to develop and validate forecasting models to more accurately reflect the effects of emerging DER across all operational and planning timeframes. This would also enable greater quantification of the underlying drivers of variability for some of these technologies, particularly those that are more behavioural.

Ultimately, more accurate load forecasts mean:

- The *technical envelope* can be better quantified, as can the specification of the measures required to be taken to prevent the power system from exceeding this *technical envelope* for credible contingency events.
- FCAS requirements may be less.
- Forecast reserve requirements may be less.
- Investment decisions would be better informed.

For example, a further study initiated by CaISO[22] found that:

- Improving the load forecasts by having visibility of DER would provide net benefits in the range of US$90–US$309 million per year in 2020, depending on the exact penetration.
- For the high DER penetration scenario, visibility of DER would deliver a projected saving of US$391 million in reduced load following ancillary services (equivalent to regulation FCAS in the NEM). The impact of visibility of individual types of DER were assessed, and it was found that:
  - Visibility of rooftop PV was projected to provide the greatest net benefits (US$176 million per year).
  - Visibility of demand response that is not registered was projected to provide net benefits of approximately US$149 million per year
  - Visibility of distributed energy storage was projected to provide net benefits of up to US$63 million per year.
- The study also found that visibility of DER led to more efficient voltage management.

The cost of implementing the measurement equipment required was estimated to be:

- US$65 million upfront expenditure on equipment for data collection.
- US$2 million ongoing operational costs.

The next chapter outlines the need for visibility specific to AEMO's operational processes in the NEM.

[21] KEMA, *Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources for CAISO*, June 2012. Available at: https://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf
Future Electric Utility Regulation. *Distribution systems in a high distributed energy resources future*. October 2015
DNV GL. *A review of distributed energy resources*. September 2014

[22] KEMA, *Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources for CAISO*, June 2012. Available at: https://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

3. VISIBILITY OF THE NEM POWER SYSTEM

Key considerations

AEMO has limited access to data about DER, particularly DER that are installed BTM:

- AEMO currently exempts generating systems below 5 MW from registration as the cost of complying with the NER would be prohibitive. This means there is no set framework to collect information about their performance.
- There is inconsistency in what is collected across the NEM by distribution network service providers (DNSPs).
- While systems are in place that enable AEMO to access information from DNSPs, there is no mandate for any party to collect and store of all the required information. The current development of demand side participation (DSP) guidelines by AEMO will only partially meet this gap.

The effective, efficient planning and operation of the NEM relies on the ability of AEMO and network service providers (NSPs) to:

- Accurately forecast demand and intermittent generation.
- Model economically efficient solutions to power system congestion.
- Quantify the behaviour of the power system when it is subjected to disturbances with the potential to affect system security and place limitations on network transfer capability.
- Determine efficient performance standards for generation intending to connect to the network.

The modelling AEMO conducts also provides the market with information that influences commercial decisions, and ranges from real-time analysis to longer-term horizons (10–20 years).

Information describing power system elements is critical to the accuracy of these models. See AEMO's Factsheet – *Visibility of the Power System*[23] for further details.

3.1 Sources of information

A range of mechanisms in the NER allow AEMO to access the information it requires to fulfil its obligations. Chapter 2 of the NER requires that any person who owns, controls, or operates a generating system connected to a transmission or distribution network register as a generator, except where they meet the exemption criteria. The exemption criteria are set by AEMO and may apply for certain generating systems under 5 MW, or under 30 MW with annual exports below 20 gigawatt hours (GWh).[24]

3.1.1 Generating systems above 5 MW

Through the registration process, the information required by AEMO has been readily available from relatively large network-connected plant. Conversely, control of that relatively large network-connected plant has been sufficient to meet statutory power system security obligations.

Generators operating a generating system greater than 5 MW in nameplate capacity must be registered with AEMO, and the NER generally requires systems greater than 30 MW to be scheduled. As part of the registration process and the ongoing requirements applicable to registered generators, AEMO and

[23] http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/0DE87F5ADD5D42F7B225D7D0799568A8.ashx.
[24] http://www.aemo.com.au/About-the-Industry/Registration/How-to-Register/~/media/Files/Other/Registration%202014/Registration%20NEW%20PAGE/ATTACHMENT%208%20%20Generator%20Classification%20and%20Exemptions%20Guide.ashx.

NSPs are provided with the information they need. In particular, generation participating in the central dispatch process has SCADA systems that provide real-time information on generation output.[25]

Through the generation connection and registration process, technical performance requirements for registered generating units are set in accordance with Schedule 5.2 of the NER.

3.1.2 Generating systems below 5 MW

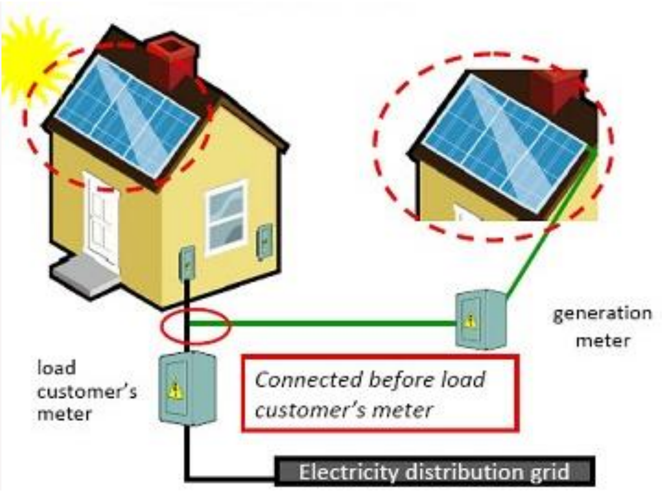
AEMO automatically exempts non-market generating systems below 5 MW from registration, because compliance with the connection process in Schedule 5.2 of the NER historically was considered negligible, the registration would be a significant cost and likely to render small generating systems unviable. These generating systems instead negotiate connection requirements with the relevant NSP on a case by case basis.

As these generating systems are exempt from registration, there is no set framework to collect information about their performance. These systems can be visible to the network, or can be located BTM and thus not be directly visible as they are not metered separately (see Figure 5). This means that, even if appropriate metering was installed, AEMO would only see the net demand from the consumer, and not have any understanding of how DER devices are operating.

For BTM systems, there is no co-ordinated or central mechanism to allow AEMO or NSPs to directly influence the technical design of plant being installed, or even to have access to information on the technical design of the plant.

Technical standards of the devices interfaced with the network are set by Standards Australia, and while AEMO can input into these, they have very long lead times to develop and/or revise. Furthermore, these connections are treated on an individual basis, rather than on a systemic basis where in aggregate they can have a material impact on the power system. This has historically been acceptable, but with a shift to greater proportions of DER, it is unlikely to continue to be an appropriate consideration in the near term.

Figure 5 Diagram of a BTM system



The current mechanisms available to AEMO to access information BTM are outlined below.

[25] A lot of other plant also has the data acquisition part of SCADA, while dispatchable generators also have the control part of SCADA.

The Clean Energy Regulator

Currently, information about BTM installations of rooftop PV is obtained from the CER. It is fortuitous that the CER has frameworks in place to collect PV data, and it is mandatory to register PV systems with the CER to receive incentives under the SRES.

However, the data collected by the CER is limited in that:

- It represents installations registering for SRES only, when only systems less than 100 kW are required to register. This is of particular concern, as the market is seeing a greater uptake of systems greater than 100 kW.
- Data will not be collected or maintained once the SRES scheme ends in 2030.
- The deeming period for STCs decreases each year meaning there will be less financial imperative to register under the scheme closer to 2030. This means that many new installations may not be captured.
- There is no mechanism to capture any PV upgrades or retrofits.
- Only basic (and static) data is collected, which does not meet all the technical needs of AEMO.

When the SRES was initiated as a separate scheme, there had been little uptake of rooftop PV. Also, the generous feed-in-tariff schemes had not yet been established by the state governments. It was not anticipated that the confluence of these policies would drive such a broad and rapid uptake of rooftop PV across the NEM. As such, AEMO had not identified the data it would require from these systems into the future, such as the inverter information discussed in section 2.2.2.

Distribution Network Service Providers

There are a number of processes through which AEMO can access information from DNSPs, for example:

- Metering data is obtained via Market Settlement and Transfer Solutions (MSATS).
- AEMO surveys DNSPs to inform longer-term forecasts and details at each transmission connection point.
- General information gathering powers can be used if necessary for certain AEMO planning obligations.

However, there is currently no mandate for DNSPs to collect and store BTM information under the NER. Specifically some of the mechanisms for data collection available to AEMO allow access to information the DNSPs have, but do not provide a right or obligation for DNSPs to collect specific new data as the technology within their networks changes.

AEMO has sought data on rooftop PV and energy storage in the past from DNSPs, with varying levels of success.

While information about DER below 5 MW can be visible to DNSPs during their connection to the network, currently any data collected by DNSPs:

- Is based on DNSP needs at the distribution level, not the needs at the transmission level at which AEMO operates.
- Varies in the level and type of data collected, depending on the aspects of each DNSP's local network.
- Varies in the measuring and monitoring devices on different DER technologies.
- Varies in the digital format it is stored and utilised, creating inconsistencies across the NEM.

The variability in the information about DER is evident in the submissions made by the DNSPs to the EMTPT's consultation on establishing a storage registration process, as shown in Table 2.

Table 2 Summary of responses of DNSPs and representatives to EMTPT consultation[26]

Respondent	Comment
Australian National University (ANU)	ANU has consulted with eight distribution network service providers and has found that the majority of these providers currently have no mechanism for collecting installation data for energy storage devices, nor are they being directly informed by installers of the presence of these devices within their networks.
Ausgrid	Ausgrid note that AEMO annually requests small scale embedded generation data from Ausgrid for transmission connection point forecasts. Because Ausgrid have historically collected small embedded generator information to fulfil several obligations, they have been able to provide this information to a level of accuracy useful to AEMO for these purposes. However, Ausgrid's ability to collect data and information on embedded generation and energy storage in the future will be affected by recent reforms at the state and national level. Note, the information collected here for AEMO only fulfils a small subset of its needs for all future operational processes.
Energy Networks Association (ENA)	ENA recommends that further consideration be given to the adequacy of existing information collection powers or incentives for owners or installers of energy storage systems to register new or upgraded systems with a formal registry. Existing data collection powers, such as those available under connection agreements, are not providing sufficient clarity as to the DER connected to distribution networks.
Energex	Energex will continue to monitor the presence of solar PVs as part of the connection agreement process to support ongoing operational and safety requirements.

Demand side participation guidelines

Systems below 5 MW can interact with the power system in several ways, including being active in demand side participation (DSP). AEMO is currently undertaking consultation to formulate its requirements for electricity demand forecasting through the development of DSP information guidelines which will enable AEMO to obtain information on DSP from registered participants.[27]

As these guidelines give AEMO access only to registered participants, not all DER installed BTM will be captured. Some of these may be registered if they participate in service provision (that is, are controllable), most likely through a retailer or third-party aggregator, in which case AEMO will have visibility through these registered entities. However, a large subset of DER installed BTM is expected to be operated solely by the consumer, and so have no obligations to be registered.

A further restriction of this information mechanism is that it only allows AEMO to access information for load forecasting. There is no ability to collect information for understanding the load response to system disturbances, or power system security studies more generally.

In addressing these gaps, AEMO is cognisant of the need to ensure mechanisms are not duplicated.

3.2 Where are the gaps?

While mechanisms (and systems) do exist to provide AEMO with access to information, they are only effective if the required information is collected in the first place.

Under the current mechanisms, there are clear gaps in the collection of BTM data, and a lack of a nationally consistent requirement on DNSPs in terms of what information they collect and store.

Where smart metering is in place at a sufficient concentration, modelling can be applied to determine aspects of DER operation. This still, however, requires some knowledge of what is installed and where for validation and calibration, because the metering data still represents the net load only as the DER are installed BTM. There is also inconsistency in metering across the NEM, and while contestable metering will be progressively rolled out, there is unlikely to be national consistency on what data will be collected and where unless explicit frameworks are established.

[26] Available at: http://www.coagenergycouncil.gov.au/publications/energy-market-transformation-%E2%80%93-consultation-processes.
[27] https://www.aemo.com.au/Stakeholder-Consultation/Consultations/NEM-Demand-Side-Participation-Information-Guidelines-Consultation.

At present, the primary gap in visibility is for DER that are installed BTM and not controllable, and this is the focus of the rest of this report.

3.3 What has changed to make visibility so important now?

AEMO has been able to operate the power system in a secure and reliable manner without visibility of DER below 5 MW because these have, until recently, constituted a small component of the whole power system. Furthermore, these facilities didn't materially change the load profile through either their aggregated size or interaction with the market.

However, the energy market in Australia has been undergoing a rapid transformation, and consumers are becoming much more active in determining how their demand is met. Changes in the supply mix at the utility scale are also changing the dynamics of the power system. The increased consumer choice (see section 2.1) has seen the traditionally passive demand side become more active through a significant uptake in DER, which is expected to continue. This is why the need for visibility of DER was identified as a high priority challenge in the FPSS program.

Currently, AEMO lacks the ability to directly influence the technical standards of DER facilities, and there are no frameworks that allow AEMO to even know about the presence of these devices on a consistent or reliable basis.

With a material proportion of generation connections now being less than 5 MW in size and located BTM, AEMO's operational functions will become more challenging if the information gaps are not addressed. In particular, periods of minimum demand will become progressively more challenging to operationally manage.

Not only does the shift to more decentralised generation change the prediction and response of load as outlined in the previous chapter, a lack of visibility has broader implications on operational processes. For example, at times of high DER generation, there is less dispatched generation, which reduces the ancillary services available to AEMO to regulate frequency and voltage.[28] (While there are opportunities for DER to provide such services, this has not happened to date.)

As the power system becomes more decentralised, the ability to access data about DER facilities and their components will become increasingly important, and, if not addressed, will affect AEMO's ability to maintain power system security.

3.4 Why is this urgent?

National frameworks, that have consistency in the need for data collection, management and accessibility for DER, need to be enacted as soon as possible. These also need to be broadly scoped to capture any emerging technologies that may develop in the future.

The urgency is because any delays in establishing frameworks are likely to have permanent consequences, even if a technology is viewed to be in its infancy:

- These frameworks can have long lead times to implement, so it is important to start the process now.
- Frameworks cannot be effectively established after a technology has entered the market. If any BTM plant is installed before information gathering arrangements are in place, then data on that plant will be lost.

This view is supported by the Public Interest Advocacy Centre, which stated in its submission to EMTPT that "*the establishment of a register is time-critical if it is to be effective and avoids the complexity that*

[28] There are also challenges related to reduced system strength and reduced inertia at these times.

would ensue from the retrospective collection of the required information in the context of a rapidly evolving market."[29]

The lack of visibility of DER, and the legacy issues created by frameworks not being established prior to market uptake, are important for both normal operation and planning for contingency events, as highlighted in the following section.

[29] Available at: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Public%20Interest%20Advocacy%20Centre%20-%20Response%20to%20consultation%20paper%20on%20battery%20registration.pdf

4. IMPORTANCE OF VISIBILITY IN AEMO'S OPERATIONAL PROCESSES

Key considerations

No or limited visibility of DER that are BTM will affect:

- Maintaining power system security as it will progressively decrease AEMO's ability to:
  - Quantify how the power system is likely to behave and manage operations within the boundaries of the *technical envelope*.
  - Manage the power system using the usual operational levers, because DER are managed by consumers or their agents.
  - Develop, calibrate, and validate its technical or business models, meaning it will need to assume how future trends will deviate from past trends.
  - Predict variability in load due to DER, increasing regulation FCAS requirements, and costs.
  - Predict load and its response to disturbances as accurately in the past.
  - Have certainty in the effectiveness of emergency control schemes in preventing a black system if, for example, DER affects the volume of load available to be shed.
- Market efficiency and reliability as AEMO will have decreased ability to send the most efficient signals to the market in relation to future investments including generating unit commitments, and long-term generation and network investment.

All these impacts will lead to an increasingly inefficient power system, with asset under-utilisation, less-formed investments, and ultimately increased costs borne by consumers.

Specific data requirements will vary for each technology, and each component within the DER system. Broadly, AEMO will require:

- Standing data on the location, capacity, and technical characteristics of the systems, in particular the inverters interfaced to the network.
- Real-time (or at least five-minute) operational data from DER, aggregated at the connection point level, for operational forecasts.

4.1 AEMO operational processes requiring visibility of DER

To understand the consequences of lack of visibility of DER, it is important to first understand the operational functions AEMO performs to maintain power system security and reliability. A simplified overview is shown in Figure 6.

These are grouped in terms of the broad operational functions:

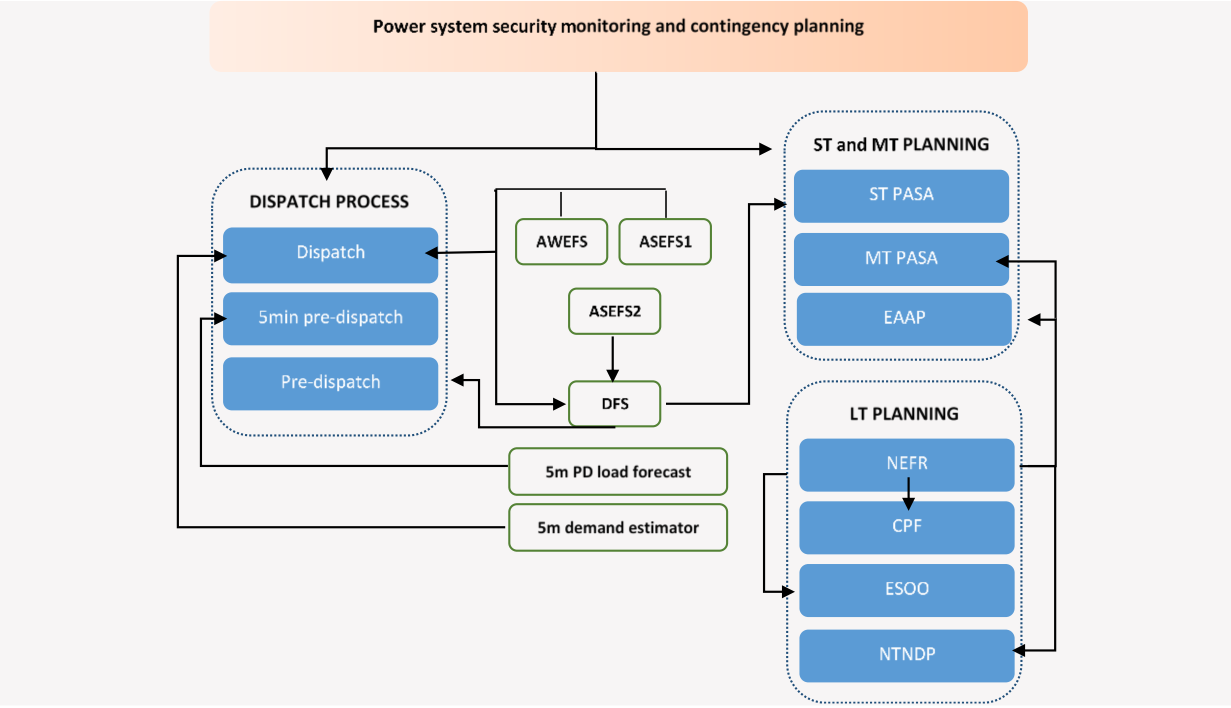
- The central dispatch process.
- Short-term and medium-term planning.
- Long-term planning.
- Power system security monitoring and contingency planning (a range of studies that AEMO performs from real-time stability analyses to longer term network planning decisions).

The solid blue boxes represent the processes that are visible to the market, while the green boxes are modelling processes AEMO performs that feed into these visible studies.

Underpinning these processes is external information that is crucial to their accuracy, such as:

- Participant information, including offers for dispatch, generating unit availability, generating unit commitment and real-time generation.
- Power system conditions obtained from SCADA, such as voltage, current, power, and network loading.
- Weather data that can affect generation and demand.

Figure 6 Overview of operational processes that contribute to power system security management



AWEFS: Australian Wind Energy Forecasting System
ASEFS1: Australian Solar Energy Forecasting System (utility-scale)
ASEFS2: Australian Solar Energy Forecasting System (rooftop PV)
DFS: Demand Forecasting System
PD: pre-dispatch
ST PASA: Short-term Projected Assessment of System Adequacy
MT PASA: Medium-term Projected Assessment of System Adequacy
EAAP: Energy Adequacy Assessment Projection
NEFR: *National Electricity Forecasting Report*
CPF: *Connection Point Forecast*
ESOO: *Electricity Statement of Opportunities*
NTNDP: *National Transmission Network Development Plan*

These operational processes cover multiple timeframes, from providing real-time system analysis, to short-term market signals, to planning studies that cover 10–20 year horizons. The frequency at which these are updated ranges from every five minutes to annually for the longer-term models.

As the timescales over which AEMO seeks to manage system security vary, so does the type, resolution, and frequency of the data and information it requires. As the data varies depending on purpose, it is generally grouped as either standing data, dynamic data, or real-time data:

- Standing data refers to properties that remain unchanged (or change infrequently), such as location, capacity, electricity characteristics, or equipment settings.
- Dynamic data refers to data that changes over time but is not used in real time, such as weather data that may be updated hourly.
- Real-time data refers to the properties that change within each dispatch interval or a similar timeframe. For example, the output of every large-scale generation source in a given dispatch interval or system conditions at a given point in time can be considered as real-time data.

The operational processes in Figure 6 depend on a combination of each group of data.

A lack of visibility of DER will impact nearly all of AEMO's processes highlighted in Figure 6, because it decreases AEMO's ability to accurately quantify load and its response to system disturbances. Only the accuracy of AWEFS and ASEFS1 are not affected by DER as these forecast intermittent generation above 30 MW which are registered with AEMO.

There are implications on the real-time through to the longer-term management of power system security. For some processes, the risk flows through the operational chain, while for other processes, such as the central dispatch, the risks are compounded due to the types of information required.

In some cases, visibility of DER is required to operationally manage the system, and lack of visibility will have operational consequences and implications for the central dispatch process.

This section will provide a high level overview of AEMO's operational processes to provide an understanding of the implications a lack of visibility of DER can have on power system security. Operational procedures for these processes are available from AEMO's website.[30]

4.1.1 Central dispatch process

AEMO is responsible for matching supply and demand through a centrally-coordinated dispatch process. The dispatch process operates on a five-minute cycle, and includes AEMO forecasts of non-scheduled generation and semi-scheduled generation (utility-scale intermittent generation), to achieve the supply-demand balance.

The central dispatch process aims to efficiently match electricity supply to demand while ensuring the power system remains in a secure operating state. The dispatch process also co-optimises the procurement of FCAS.

There are three main market outputs of the dispatch process:

- The dispatch process provides a **load estimate** that is fed into the NEM dispatch engine (NEMDE) which dispatches generation to meet load at least cost each five-minute dispatch interval. The load estimate will be affected by the changing load profile through the demand estimator which provides a forecast. The dispatch also includes power flow constraints that are imposed to maintain the *technical envelope*. These are discussed in Section 4.1.2 below.
- The five-minute pre-dispatch provides a **short-term load estimate** for market participants to adjust generation operational strategy and bidding structure. It utilises a load forecast determined by the five-minute demand estimator and recent load input.
  - As a result of the load inputs, it may not be accurately reflecting the changing demand profile due to DER, in particular if there are future price-sensitive aggregated loads.
- The pre-dispatch process[31] provides a **weekly load estimate** for market participants to plan generation and bidding strategies. The pre-dispatch process relies, among other things, on the demand forecasting system (DFS) which provides region-level load forecasts over the timeframes of half-hour pre-dispatch up to the Short-term Projected Assessment of System Adequacy (ST PASA).[32] It is a real-time system that requires SCADA inputs of system conditions to give an accurate forecast for each half-hour of the pre-dispatch. It integrates the pre-dispatch outputs of non-scheduled generation in AWEFS and ASEFS1, and ASEFS2, while also looking at recent load data.
  - This can be impacted by DER through the DFS, which currently incorporates forecasts of rooftop PV generation produced by ASEFS2. Issues related to DER and ASEFS2 are outlined on the following page.

[30] http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Dispatch-information/Policy-and-process-documentation
[31] The pre-dispatch system procedures are available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/2016/SO_OP_3704---Predispatch.pdf
[32] The operating procedures for this process are available at http://aemo.com.au/media/Files/Other/electricityops1/SO_OP_3710_Load_Forecasting_June_14.pdf

- Importantly, at this stage, rooftop PV is the only DER that is included in the DFS. Any other emerging or new DER would need to be incorporated, and, depending on the technology, the information needs could be quite different.
- AEMO is currently scoping a proposal to develop a residential battery storage forecasting system that would integrate in the same fashion as ASEFS2.

Example: The need for DER visibility in ASEFS2

Used in pre-dispatch, AEMO's Australian Solar Energy Forecasting System 2 (ASEFS2) provides a clear example of the need for DER visibility, and the challenges faced when appropriate frameworks are not in place. Given the large penetration of rooftop PV in the NEM, and its projected increase, the importance of accurate and sufficient data for ASEFS2 is critical, but sourcing this data is challenging:

- PV installation by capacity and postcode is sourced from the CER with the limitations as outlined in section 3.1.2.
- Rooftop PV generation output is obtained from www.pvoutput.org on a daily basis, and is of a resolution of 30 minutes. This website provides a sample of around 5,500 PV systems that have the data resolution and reliability that AEMO needs – so out of the 1.36 million systems currently installed in the NEM, AEMO has access to generation data of only 0.4% of the fleet, and needs to upscale these to the installed capacity per postcode from the CER. The locations of these 5,500 systems are not evenly distributed across the NEM, so AEMO may not have a statistically reliable sample – it is arguably highly unlikely that this sample is representative of the fleet of systems, as consumers who voluntarily provide data on www.pvoutput.org are likely to be "enthusiasts", proactive about optimising their systems (panel quality, orientation, shading etc.).
  - ASEFS2's reliance on www.pvoutput.org for producing estimated actuals of rooftop PV generation is a crucial single-point-of-failure. If the website was taken offline, AEMO would have no way of producing estimated actuals of rooftop PV generation and, over time, no way to re-calibrate ASEFS2.
- Weather forecasts are currently updated every six hours.
- The generation output of rooftop PV depends on factors including the type of panel, its age, orientation, surrounding temperature, and shading. This makes estimating the output of a rooftop PV system much more complicated than considering its capacity and the number of daylight hours. The type and age of the panels in particular mean two systems of the same capacity can vary in their output.
- Some larger inverter manufacturers offer their customers online portals via which they can view real-time data from their rooftop systems. This could provide an alternative data source for AEMO but has been cost-prohibitive to date, and also only captures part of the market.

AEMO is currently working on:

- A system to provide redundancy to www.pvoutput.org by allowing the system to produce estimated actuals of rooftop PV generation using satellite data including cloud vector motion tracking, in addition to that produced from the www.pvoutput.org upscaling method. AEMO would still rely on the CER to provide the relevant upscaling per postcode.
- Reviewing the approach of other system operators such as CaISO[33], who have deployed automatic weather stations in substations linked to SCADA to provide real-time irradiance measures. This is then used together with a theoretical model (assuming horizontal panel inclination) and up-scaled to installed capacity to produce an estimate of small-scale rooftop PV.
- Options to update weather more frequently.

[33] ISO PIRP Solar Technical Requirements. Available at: https://www.caiso.com/Documents/ISOPIRPSolarTechnicalRequirements-Revision5.doc

DER requirements here are:

- Standing data on installation details and location will remain a high priority.
- Real-time data of generation output is a high priority, unless the combination of satellite tracking and real-time localised irradiance measurements is developed and is demonstrated as a suitable substitute. In any case, real-time or near real-time (five minutes) output from the systems, suitably aggregated, would be required to maximise efficiency in a forecasting process that is growing in importance as the penetration of DER increases.

Consequences for central dispatch if there is no data on DER

The central dispatch process is AEMO's primary means of maintaining the power system in a secure operating state. Large amounts of DER contribute to:

- Decreased ability to effectively forecast operational demand. This will result in greater imbalances between supply and demand in the dispatch period, requiring greater amounts of regulation FCAS, increasing costs. The example on the next page shows some of the current impacts on demand forecasting observed in Queensland.
- DER displacing generation which is currently used to manage power system flows within network operating limits, if DER constitute a large proportion of generation at particular times. This will make it progressively more difficult to manage network flows within operating limits, and frameworks may need to be developed to encourage DER to become part of the solution to this challenge. This is particularly true in NEM regions such as South Australia which already have high penetrations of rooftop PV.
- Increased potential for DER generation to be in excess of regional demand during periods of minimum demand. This has implications for the management of network flows and power system frequency, particularly as there is no current mechanism or ability to constrain down generation from DER.
- The progressive displacement of synchronous plant by inverter-connected plant. This has the following effects on the power system:
  - Inertia is being removed from the power system, leading to increasing rate of change of frequency (RoCoF) for given contingencies, reducing the effectiveness of current frequency control techniques. Through the FPSS program, AEMO is currently exploring alternative mechanisms for frequency control, and there is potential for DER to be part of the solution to this emerging issue.
  - Regulation and contingency FCAS will become increasingly scarce.[34]
  - DER can displace generation that currently provides voltage control.
- The distribution network can become a source rather than sink of reactive power in regions of high DER penetration. As well as the dispatch of energy, it is AEMO's responsibility to dispatch sufficient reactive power plant to maintain the voltage profile across the transmission grid, including upon the occurrence of contingency events. Without visibility of the contribution of DER, it will be challenging to maintain voltage within the technical limits.

As well as the implications of inaccurate load forecasts on regulation FCAS requirements, reduction of the amount of dispatched generation reduces the operational levers that AEMO has to manage power system security.

As a consequence of this, without knowing how the DER would behave, AEMO would need to factor in broader margins in the *technical envelope,* which are closely linked to the power system security monitoring that is performed.

34 Although inverter-connected BTM plant has the potential to challenge power system operation, it may also be capable of providing some of the services that that have been provided by synchronous plant to date.

The pre-dispatch process provides information to market participants about the expected level of demand for the week ahead. This is used as a basis to make decisions on unit commitment and any associated operational costs such as fuel. Inaccuracies in these projections will have a direct impact on market efficiency and potentially reliability.

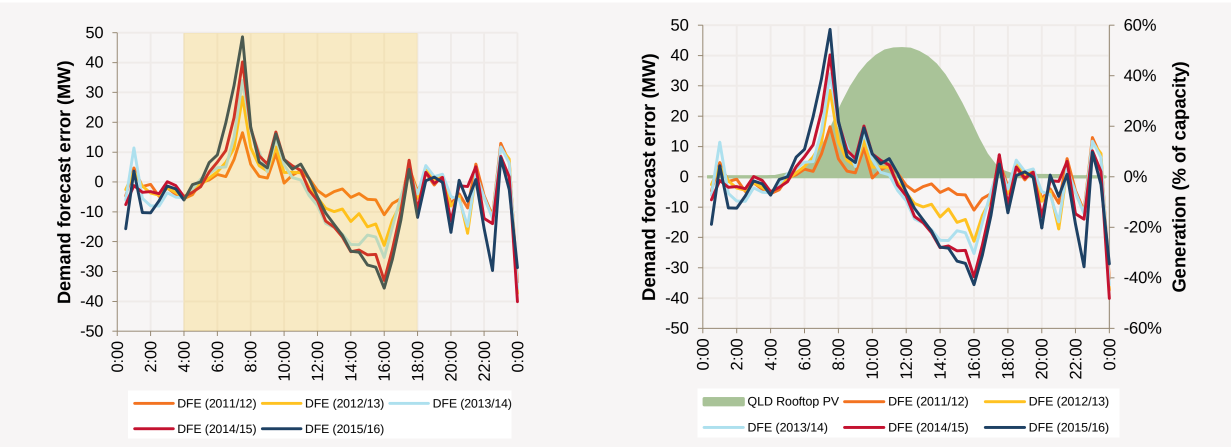
Example of load forecasting error due to no visibility

The five minute dispatch process currently does not explicitly account for rooftop PV, with ASEFS2 only feeding into the pre-dispatch forecasts. For each five-minute dispatch interval, AEMO calculates the demand forecast error (DFE) for the period, that is, the percentage difference in the actual demand compared with forecast demand.

AEMO has observed increases in the DFE in some regions at the times when solar generation is ramping up (increasing as the sun rises) and ramping down (decreasing as the sun sets).

Figure 7 (left) shows how the DFE in Queensland has changed over the last four years, with increasing deviation between 4:00 am and 18:00 pm[35] (shaded area). Comparing DFE to a sample of rooftop PV generation during the same period shows that DFE deviation occurs at the same time as rooftop PV is operating, as shown on the right hand side.

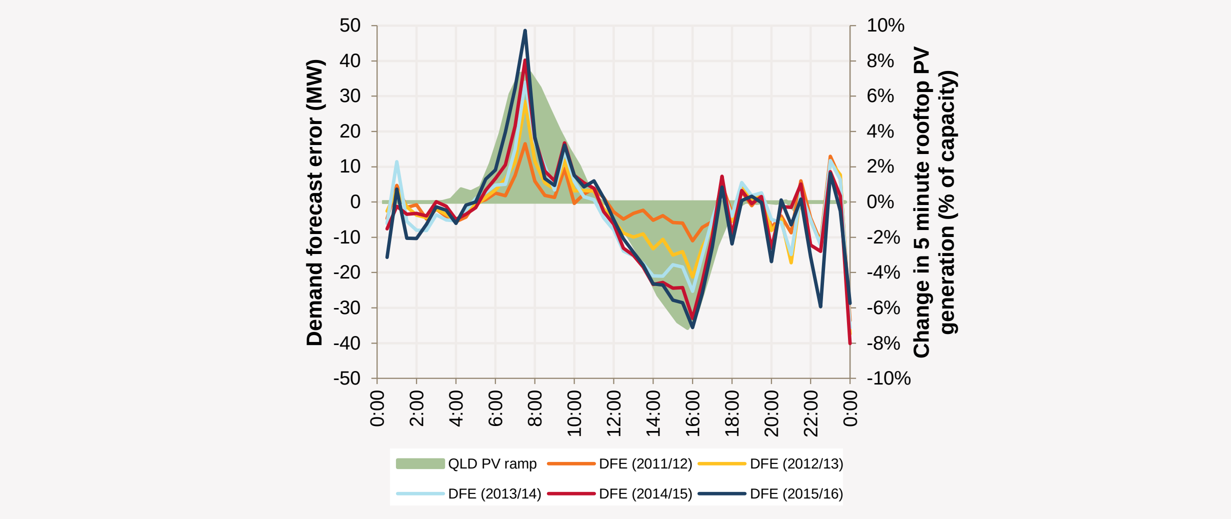
Figure 7 Queensland DFE and rooftop PV output



To investigate whether this is simply a coincidence, it can be compared to the change or ramping of rooftop PV generation rather than the generation output, as shown in Figure 8. This shows that the DFE is increasing proportionate to the change in solar generation.

[35] All times are presented in market time, which is Australian Eastern Standard Time.

Figure 8 Comparison of DFE and changes in rooftop PV generation in Queensland



4.1.2 Power system security monitoring and contingency planning

AEMO seeks to ensure the power flows through the network remain within technical limits by constraining generation in the market. AEMO can only do this with dispatchable (scheduled and semi-scheduled) generation. AEMO also coordinates the voltage profile across the main transmission grid to remain within technical limits.

These processes involve continuous power system security monitoring and contingency planning at the real-time operational level and to short-term and medium-term horizons. The analyses performed feed into most operational processes, most notably the central dispatch process through power flow constraints, or by dispatching reactive plant. They are also important considerations in performing network outage and augmentation assessments.

Understanding whether DER can behave *en masse* in response to system disturbances, as highlighted in the AEMO's Inverter Study[36], has implications for all these studies.

The additional information needs of these processes can be categorised by their outlook horizons, as outlined below.

Real-time assessments used to verify power system performance

AEMO performs a number of processes to:

- Manage transient stability – ensure the continued synchronism of all synchronous generation to reach a state of equilibrium on the power system following a credible contingency event.
- Manage transmission voltages so that they remain at acceptable levels after a credible contingency event.
- Manage transmission voltage stability after a credible contingency event.
- Ensure the damping of power system oscillations is adequate during normal operation and following a credible contingency.
- Provide limit advices specifying interconnector power transfer based on oscillatory stability of the power system for system normal and outage conditions.

These studies involve the continued analysis of potential contingencies that can occur.

[36] Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/43BE01476E2D4992A3BDA2DA2E1A14A4.ashx.

DER affect the accuracy of these studies, because they can change the characteristics of the generation fleet as a whole, and of load profile in response to system disturbances.

The analyses have implicit load relief indices that describe how the load in aggregate will respond to system events such as voltage and frequency deviations. As the penetration of DER increases, these load relief assumptions may no longer reflect the actual behaviour of load under contingency events. This is because load is less predictable than historically, and also because most DER are inverter-connected and thus can have different responses than assumed.

The changing load profile due to the proportion of DER generating can also indirectly affect the network flows in the power system, including the flows that AEMO is expected to control.

Furthermore, the presence of more non-synchronous generation, whether at the utility or distributed scale, reduces system strength[37], and this can also mean that the behaviour under fault conditions of plant connected to the power system can be different from what has been expected in the past.

Information for these studies also relies on the limit advices provided to AEMO by TNSPs on load models, and information provide to AEMO by generators such as computer models of their overall generation system. These will also obviously be affected by the changing characteristics of the load, so the NSP will also have some additional data needs. These all affect the information that is fed into the central dispatch process.

Near real-time, short-term, and medium-term studies

AEMO performs:

- Operational incident reviews to assess whether a prospective operational incident can pose a future risk to power system security under some circumstances.
- The stability analyses noted above to revise constraints on power system flows.
- Load flow, contingency, and voltage stability studies to assess whether short-term outages pose a risk to power system security.
- Analyses of the impact of transmission network augmentation on power system security.

These studies feed into the dispatch process if necessary, but are also used in short-term reliability and operational assessments such as pre-dispatch and ST PASA.

The impact of limited visibility of DER on these studies is similar to the real-time analysis risk of inaccurate dynamic load models, but also relates to the operational demand forecasting. The outage assessment, for example, relies on the demand forecast from DFS, which in turn depends on the projected level and output of DER in the power system.

Non-credible contingency events and emergency control schemes

AEMO also needs information about DER to determine the efficacy of emergency control schemes designed to safeguard the power system against extreme over or under frequency events.

Under frequency events, for example, rely on under frequency load shedding (UFLS) in which a distributed control system with relays in substations trips local load blocks if frequency falls below a given level for a set period of time.

The increase in DER means parts of some distribution networks are now operating with reduced power flows at some times, and potentially in reverse flow. These are the same parts of the power system UFLS has relied on to supress frequency excursions.

This means that, during periods of high output from DER, distribution network feeders that are selected to be tripped by UFLS could have a lower impact on an under frequency condition if they have high PV penetration. If these feeders are tripped in the daytime following UFLS action, the effectiveness of the

[37] For more information about system strength, see the *Factsheet – System Strength*, available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-Fact-Sheet_System-Strength---Final.pdf.

scheme will be reduced, resulting in UFLS shedding more distribution feeders to arrest the frequency deviation. This means that, ultimately, more customer load would be disconnected.

<u>Example: contingency planning relies on visibility of DER</u>

An example of the need for visibility and information about DER to plan for uncontrolled events was on 20 March 2015, when Europe experienced a near-total solar eclipse. Knowing both that a disruptive event was going to occur, and the location and capacity of DER across continental Europe, system operators across 23 countries spent the preceding six months extensively planning together for the event and putting in place measures to maintain system security throughout the eclipse.

The eclipse occurred on a sunny weekday morning, and affected an area that had around 89 GW of PV installed.[38] Preliminary forecasts estimated that if the day remained clear, the PV output would decrease by around 20 GW within the first hour of the eclipse, and increase by almost 40 GW after maximum impact of the eclipse. That is the equivalent of the entire NEM system coming online.

The system operators procured enough ancillary services, among other measures, to provide the support that was projected to be required to keep the system operating. There was more cloud cover over Western Europe than had been forecast so the impact was slightly subdued. Nevertheless, the large, fast decrease in PV output is evident, and, more significant, so is the ramp-up in PV generation as the eclipse passed.

As they could forecast and plan ahead, power system operators were able to maintain the interconnected system within relevant frequency operating standards. One of their main lessons was the importance of understanding the technical characteristics of PV generation, specifically[39]:

- *A clear description of the installed PV capacity and their capabilities is needed for the accuracy of forecast studies (technical data, retrofitting campaign, disconnection/reconnection settings and logics, etc.).*
- *Real time measurement of the dispersed PV generation is the key for adapting the operational strategy in real-time.*

Because regions in the NEM have high proportions of rooftop PV, which are forecast to increase much further, there is equal merit in these lessons in the NEM, as AEMO plans ahead to maintain power system security against large, uncontrolled events.

Consequences for power system security and monitoring

If data on DER is not obtained, it will decrease AEMO's ability to both:

- Perform stability analyses of the power system.
- Plan effectively for contingency events, and also scheduling generation and network outages.

At present, AEMO has identified the following risks:

- AEMO would not be able to accurately provide limit advices specifying interconnector power transfer based on oscillatory stability of the power system for system normal and outage conditions. AEMO would then have to apply conservative safety margins in constraining flows in the dispatch process.
- AEMO would also need to apply larger reactive reserve margins in the dispatch of reactive plant to manage transmission voltages.
- Operational incident reviews may not uncover the full root cause of incidents if they are masked by inaccurate assumptions made about DER, posing a risk to ongoing power system security.

[38] Some countries, such as Italy, have mostly utility-scale PV while others, such as Germany, have predominately rooftop PV.

[39] ENTSOE, *Solar Eclipse: The successful stress test of Europe's power grid*, 2015. Available at: https://www.entsoe.eu/Documents/Publications/ENTSO-E%20general%20publications/entsoe_spe_pp_solar_eclipse_2015_web.pdf.

- AEMO would not be able to efficiently assess planned network or generation outages and their risk to power system security.
- If inverter characteristics such as voltage and frequency trip settings are common across a very large number of inverters, they will respond in concert to system disturbances, affecting AEMO's ability to maintain system security.
- The disconnection of inverter-connected DER during non-credible contingencies will potentially exacerbate the frequency deviations, and reduce the effectiveness of current emergency control mechanisms. This could make it challenging for AEMO to prevent cascade into a black system.
- An increase in inverter-connected plant such as DER reduces power system strength by decreasing network fault levels. This can compromise protection operations and reduce the ability of some inverter-connected plant to ride through faults. This risk will be compounded if there is no visibility of how DER will respond to faults.
- Lack of visibility of DER will make it difficult to coordinate transmission and distribution connected resources during a system restart, should an outage occur.
- AEMO would not be able to plan for contingency events, such as a solar eclipse, that would affect particular technologies.[40]

If left to evolve under current operational arrangements, the above circumstances will result in AEMO having increasing difficulty in meeting its obligations to maintaining a secure power system. Some could be managed through the margins of the *technical envelope*, while others could not. A trade-off would be made in determining the operational limits to increase market costs to prevent losing the system.

4.1.3 Short-term and medium-term planning studies

Shorter-term reliability assessments are performed to provide market participants with information about potential shortfalls in the power system over timeframes up to two years. The objective is that, from these signals, the market will provide the necessary resources to meet the reliability standard, and hence reduce the risk of power system security and reliability issues. Examples include the ST PASA and Medium-term Projected Assessment of System Adequacy (MT PASA).

These studies rely on the expected uptake of DER as these affect the level of shortfall in reserves that are projected – in particular, how DER changes the daily load profile affects reserve assessment. This means the projected reserve requirements may be quite different to the actual requirements depending on DER, and this will have consequences for decisions such as the scheduling of maintenance, fuel contracts, and unit commitment.

This in turn can pose a risk to power system security and reliability if the incorrect market signals create under-investment in future requirements. Conversely, over-investment in infrastructure due to inaccurate forecasts will increase costs to consumers.

As AEMO does not have the actual historical generation of rooftop PV across the NEM, it relies on historical weather data and load data to provide an estimate of the generation patterns. This in itself creates inaccuracies in how generation is projected forwards.

The ST PASA and short-term assessments incorporate DER through the DFS, the limitations of which were discussed in Section 4.1.1.

The demand forecasts utilised in the MT PASA and Energy Adequacy Assessment Projection (EAAP) rely on the DER demand traces that are developed in the *National Electricity Forecasting Report* (NEFR) and discussed below.

[40] The next solar eclipse affecting Australia will occur on 22 July 2028 and will become visible to the NEM market from 10:57am until 3:23pm, with the maximum impact occurring at 12:57pm. The 2016 NEFR forecast approximately 15 GW of installed residential and commercial PV in the NEM by this date, an increase from 4.9 GW currently installed in the NEM.

4.1.4 Long-term planning

Long-term planning studies provide projected demand forecasts and supply gaps over a 10–20 year horizon, and provide critical long-term signals for required power system investment to maintain system security and reliability.

The NEFR and Connection Point Forecasting (CPF) reports are demand forecasting studies that provide an indication of the expected trends in demand, including the uptake and operation of DER. These provide vital information about what the daily load profile is expected to be, and how it could change. For example, they are important in determining key load shifts such as that shown in Figure 3. CPF studies are also used in marginal loss factor (MLF) calculations, which have an impact on dispatch outcomes.

AEMO uses these demand profiles in the planning studies of the Electricity Statement of Opportunities (ESOO) and National Transmission Network Development Plan (NTNDP) to create the expected demand traces, which are important for managing power system flows and identifying any network congestion due to the increasing penetration of DER. These studies also provide investment signals to the market about supply adequacy, and more recently, potential FCAS needs.

The planning studies rely heavily on DER in accounting for their uptake and future impact on the power system, particularly in terms of system strength, power flows, and network loadings. This will impact long-term planning investment decisions. The demand forecasts are used by some NSPs to benchmark their forecasts, and can influence their planning and investment decisions.

Without accurate forecasts, there is a risk that generation and network investments will be inefficient, with the potential for both over-investment and under-investment. This can be exacerbated by the conflict in the planning horizons of DER and network investments. NSPs are required to plan over a long-term horizon, and capital expenditure is recovered over a number of decades. DER, on the other hand, have a different investment lifecycle because of their size and location at the customer. This means they can enter and exit the market quickly.

Ultimately, a lack of visibility of DER will affect the efficiency of long-term planning and investment decisions, with the costs borne by consumers.

4.2 Overview of AEMO’s needs

As DER grows in penetration, the operational importance of accurate information about them increases, because AEMO’s processes will rely more heavily on understanding their behaviour.

In particular, as AEMO’s studies feed into each other (as shown in Figure 6), the risks associated with inaccuracy can compound.

The specific data requirements will vary for each technology, and each component within the DER.

For example, a residential battery storage system will have three main components – the rooftop PV panels, the battery, and an inverter that interfaces with the network – and AEMO will have specific data needs related to each of these components.

Broadly, AEMO will require standing data about the following characteristics of DER installations:

- **Location:** AEMO will require information about each installation at the National Meter Identity (NMI) level.
  - This is because each installation will have unique properties that need to be considered when aggregated to the transmission connection point.
  - NMI information is preferred, as every postcode does not map to the single connection point.
  - It provides a way to identify those DER participating in providing services and will be captured in the DSP guidelines. Providing services will change how they operate, and hence how they need to be forecast.

  - Disaggregated data also allows AEMO to determine the locational drivers that couldn't otherwise be considered.
- **Capacity:** The capacity of DER is important to forecast generation and load shifting.
- **Technical characteristics:** Technical characteristics are most important for the inverters interfacing with the network, because these will determine the response to system disturbances.
  - Technical characteristics include the electronic settings such as frequency and voltage trip settings, as well as other modes that may be enabled.
  - These cannot be aggregated as they will be unique to each individual DER, and these characteristics are vital inputs into power system stability studies.

Modelling daily load profiles requires data with resolution of at least less than five minutes or better for operational forecasts to 30 minutes for longer-term forecasts. This data is aggregated at the transmission connection point, and for operational purposes the frequency of update needs to be five minutes or better.

How these needs may change

As the penetration of DER increases, it may no longer be appropriate to forecast at the connection point or regional levels, as the drivers of the load forecasts will potentially be locational. This will require more granular information, with a greater reliance on real-time data feeds, so the relevant system services can be optimised.

Specific needs for rooftop PV and residential battery systems

Real-time data requirements

Modelling daily load profiles requires near real-time data with resolution of at least five minutes for operational forecasts, to 30 minutes for longer-term forecasts. This data is aggregated at the transmission connection point, and for operational purposes the frequency of update needs to be five minutes or better.

The importance of this data for DER will increase as its penetration increases. Real-time data will assist in the accuracy of load forecasts and minimise the level of regulation FCAS required due to the variability of DER within the dispatch period, and in adapting operational strategy in response to system events. The aggregated real-time output data is also required to develop, calibrate and validate load forecasts on a continual basis.

For rooftop PV and residential battery systems, the near real-time data AEMO requires, aggregated at the transmission connection point, is:

- For stand-alone PV systems, the generation.
- For systems integrated with storage, separate measures for PV generation and battery inflow to feed into separate modelling.

Standing data requirements

Table 3 Standing data requirements for PV and battery storage systems

Data Category	Processes affected	PV	Battery	Inverter	Resolution	Update frequency
Location of installation						
National Meter Identity (NMI) **(critical)**	Dispatch Power system security monitoring and contingency planning Forecasting and planning – all timeframes	Required to understand load behaviour at the transmission connection points for most studies, but also to design and calibrate how emergency control schemes will work at the distribution level. Installation data at the NMI level improves the accuracy and efficiency of operational forecasts, and hence planning. This is because: Not all postcodes correspond to the same transmission connection point. Generally there will only be one NMI per installation (covering load, generation and storage) but there may be the case when there are several NMIs. This may increase as more DER are installed. NMI can be linked to underlying drivers of the operation of DER. NMI will help AEMO identify if these DER are participating in other schemes and so can take account of this in the operational processes.			Disaggregated standing data	Monthly
Installation date (critical)	Dispatch Power system security monitoring and contingency planning Forecasting and planning – all timeframes	Month and year of installation Important to accurately model the fleet as they age.			Disaggregated standing data	Monthly
Decommission date (critical)	Dispatch Power system security monitoring and contingency planning Forecasting and planning – all timeframes	Month and year of decommission Important to modify forecasts.			Disaggregated standing data	Monthly
Technical specifications						
Size **(critical)**	Dispatch Power system security monitoring and contingency planning Forecasting and planning – all timeframes	Capacity kW	Capacity kWh	Capacity kW	Standing data disaggregated, as each system will perform differently depending on a number of factors	Monthly
	Capacity of DER is vital to forecast expected generation and/or load shifting. This is impacts all aspects of the operational processes as evidenced above from DFS, to the long-term planning information.					
Manufacturer, make and model number **(critical)**	Dispatch Power system security monitoring and contingency planning	Critical to accurately model the predicted response of the generation/load, as individual models will behave differently. As shown by the inverter report, this information may also be needed to gather further information not previously thought required as the power system changes.			Standing data, disaggregated as the technical settings of each model will vary.	Once at installation and if settings change

Data Category	Processes affected	PV	Battery	Inverter	Resolution	Update frequency
Performance derating (highly desirable)	Dispatch Power system security monitoring and contingency planning Forecasting and planning – all timeframes	% p.a and %/degree Celsius Orientation/tilt	% p.a	N/A	Standing data, disaggregated	Once at installation
	Rooftop PV reduces in efficiency of output once the ambient temperature increases. For example, a common PV cell in Australian reduces in generation by 0.5% for every degree above 25ºC. Similarly, battery storage systems degrade over time depending on the number of charging/discharging cycles. This degradation doesn't affect properties such as the charging/discharging ramping but the volume of energy that can be stored. This means that the effective capacity decreases over time from the nameplate capacity. This affects the generation output of DER and is particularly important for PV in modelling summer peak demand loads. This is given a medium priority rating only because this data may be able to be derived from the manufacture, make, and model information if that is obtained. The data itself is critical.					
Operation						
Device part of aggregated control (critical)	Power system security monitoring and contingency planning	Yes/No	Yes/No	Yes/No	Standing data, disaggregated	Once at installation then if settings change
	It is important to know that large aggregators may become significant from the point of view of planning supply point responses, coordinating protection setting in the distribution network, and under-frequency load shedding schemes. Rated as medium because data requirements could be imposed on the aggregator, provided they register with AEMO.					

Table 4 Inverter specific standing data requirements

Data Category	Processes affected	Requirements	Resolution	Update frequency
Trip settings (critical)	Dispatch Power system security monitoring and contingency planning Short-term Planning	Over and under frequency Over and under voltage	Standing data, disaggregated as the technical settings of each model will vary.	Once at installation and if settings change
	Critical to accurately model the predicted response of this generation/load as individual models will behave differently. This will assist to determine the technical envelope more efficiently and plan for contingencies.			
Enabled modes of operation (critical)	Dispatch Power system security monitoring and contingency planning Short-term Planning Long-term Planning	Frequency control mode Voltage control mode Reactive power control mode Power factor control mode	Standing data disaggregated.	Once at installation and if settings change
	For devices connected with inverters from October 2016, there is a requirement that they be equipped with frequency response capability, not that they need to be enabled. Knowing whether they are enabled or not will increase the accuracy of the frequency response models that feed into network constraints. Similarly, other modes of operation that affect power system stability can be enabled, and are relevant for AEMO to perform the power system stability models and understand how the system will behave if there are large penetrations of DER.			

4.3 Needs of other stakeholders

AEMO is not alone in needing more visibility of DER to fulfil its regulatory functions. NSPs will have their own challenges and processes that need to accommodate DER. There are many examples, including potential challenges with plant protection coordination due to current flow reversal, coordinating the return of supply to customers following disconnections, and voltage control.

5. ENABLING VISIBILITY

Key considerations

- It is necessary to establish a broad, flexible, and technology-neutral framework to facilitate visibility of DER installed BTM. This framework should leverage existing mechanisms and frameworks so far as possible.
- A data collection framework would have three main elements: collection, storage, and access/communication. It would be necessary to establish a regulatory obligation to collect the data, a regulatory obligation to host the data, and a sharing protocol.
- 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. There are both technical and regulatory options for data collection, each with their own pros and cons.
- Other solutions could exist in the emergence of alternate business models and evolving market structures, such as a focus on distribution system operators (DSOs).

5.1 Guiding principles

A framework should be established to ensure that relevant data is collected and made available to AEMO and network operators. The framework should be flexible and take into account which party is best placed to collect the required information and efficiently make it available to those who require it on an as-needs basis (taking into account confidentiality issues). A transparent process should be established to assess what information should be collected and who has access to it.

AEMO suggests changes should address the following principles:

- **Adaptability** – any necessary regulatory changes should be designed to be as readily adaptable as possible to the evolution of the power system, as information needs are likely to change over time. This is particularly important given that any changes to legislation or licence conditions are likely to be significant and time-consuming, with limited opportunity for fine-tuning in the period immediately following their completion.

  For example, adaptability might be supported by having a broad formal obligation set by regulation to collect and make data available. Data requirements for specific technologies can then be determined and modified on a continual basis by application to an appropriate administering authority, who imposes the obligation. Then the administrative body would assess the need, costs and benefits, and hence the reach of the framework. In particular, it addresses the objective noted in the consultation paper that the data registry should assist those who require the data in it to fulfil their regulatory functions.
- **Technology neutrality** – the principle of adaptability should be complemented by technology neutrality, so it could be applied to new technologies, including load-related technology, with minimal effort. This is particularly important with respect to the legislation and governing NER, as any definition of technology could inadvertently exclude emerging systems.

  A framework that addresses only one technology would be inefficient. For example, battery storage is anticipated to be the next technology that will have mass market uptake. It has specific data needs, so creating a specific framework around storage would provide shortfalls in other areas.

  In AEMO's view, the industry should use the current attention to creating a battery storage registry (including in the EMTPT consultation) as an opportunity to develop a broader, more encompassing strategy that can accommodate any future DER. AEMO's submission to the EMTPT consultation highlighted the need for a broader registry that was technology neutral.[41] AEMO will continue to work with the EMTPT on their consultation.

- **Accessibility** – the framework should allow a pathway to evaluate access to data for different parties based on each entity having different needs, objectives and relative priorities. This would also need to be designed with data security in mind.
- **Efficiency** – A cost benefit assessment of the data registry would need to be balanced, and to apportion costs to the parties that value the data most. It also needs to be efficient in avoiding duplication of existing mechanisms, and not placing onerous burdens on collection.
- **National application** – the framework should apply across Australia, rather than having variations across states or regions. This should be the case even if each state has a different dominant technology.
- **Co-ordination within and across jurisdictions** – the framework needs to be co-ordinated if matching changes are required to legislation, state-based licensing conditions, and the National Electricity Law (NEL), because each of those instruments has different decision-makers.
- **Compliance** – there needs to be confidence that the framework will achieve the desired outcomes at each step and ensure data quality.

The industry needs to ensure that, at a minimum, the status quo collection of rooftop PV data continues.

5.2 Considerations for a data collection framework

A data collection framework would have three main elements: collection, storage, and access/communication. It would be necessary to establish:

- **A regulatory obligation to collect the data:** The approach to data collection can be considered in terms of the type of data that AEMO requires to manage power system security:
  - Standing data will need to consider the technical specifications of all components of the DER, particularly any electronic settings of inverters, and take into account whether the manufacturer's settings are reconfigured in accordance with advice from the DNSP during connection;
  - Real-time data is required on an aggregated basis at the transmission connection point level.
- **A regulatory obligation to host the data:** The entity or entities responsible for the storage of data would need the capability to keep the data secure, and to process requests responsibly and efficiently. There would also need to be confidence that they will continue to have that capability on an ongoing basis.
- **A sharing protocol:** Communication standards need to be developed to ensure the quality and standardisation of data between multiple parties, and common communication and access standards. An example is the shared market protocol currently being implemented by AEMO. These communication standards will also establish cost efficiencies over the longer term.

The required data collection 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. This type of data would typically only be collected at the time of installation (and potentially if the installation or settings of the installation change). Real-time data can be aggregated but needs to be collected continuously.

Given the parties involved, the real-time data collection framework is likely to be most easily implemented via obligations in the NER. Alternatively, , there may be a role for the COAG Energy Council to liaise with the state authorities to establish an appropriate framework for standing data.

[41] AEMO's submission is available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/63648643DA4E4D609791CF50A2C3680A.ashx.

A collection mechanism for standing data could be given effect by a regulatory and/or technical solution. Examples of potential DER standing data collection mechanisms include:

- Jurisdictional electrical safety licensing requirements, which could be amended to introduce an obligation to register DER installations;
- DNSPs' standard connection agreements could include a requirement to provide additional DER data;
- Technical standards on inverters;
- Monitoring devices on inverters; or
- Requiring BTM DER systems to register with AEMO.

Various pros and cons apply to each option. Technical solutions are automatically consistent nationally if they are implemented via an Australian Standard. Changes to electricians' licences would require collaboration between jurisdictions to ensure consistency and ongoing compliance.

5.3 A new role for DNSPs?

The approach of Chapter 5 assumed that current roles for power system operation continue. Given the shift towards more DER, and the emergence of new business models, there has been a focus on the concept of distribution system operators (DSOs) and evolving market structures to allow new players to participate in multiple distribution trading platforms.

These concepts see the traditional model of supply following load, being superseded by a model where load follows supply. This would require AEMO to rethink how it interfaces with distribution networks.

Under these roles, the DSOs would actively manage the upstream as well as downstream flow of electricity. In this capacity, the DNSPs would be able to provide the load forecasts required by AEMO for each of the operational time periods from pre-dispatch for each transmission connection point, which AEMO could aggregate into its processes.

It is likely to need a longer lead time than the options above to develop the appropriate capability to ensure the national consistency and accuracy of the forecasts. The provision of this information would need to be clearly stipulated in the obligations of the DSO, and compliance monitored by the Australian Energy Regulator.

The data collection and hosting arrangements need to evolve in line with market structures.

5.4 Next steps

AEMO will collaborate with the EMTPT, where possible, to leverage mutual opportunities and avoid any duplication. We will also establish a process to consult with stakeholders regarding our detailed data requirements and to explore potential data collection mechanisms.

Stakeholders who wish to be part of the consultation may register their interest via email to StakeholderRelations@aemo.com.au by 28 February 2017.

LIST OF ABBREVATIONS

AEMC	Australian Energy Market Commission
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
BTM	Behind the meter
CASIO	California Independent System Operator
CER	Clean Energy Regulator
CPF	Connection Point Forecasting
DER	Distributed Energy Resources
DFS	Demand Forecasting System
DSP	Demand Side Participation
EAAP	Energy Adequacy Assessment Projection
EMTPT	Energy Market Transformation Project Team
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicle
FCAS	Frequency control ancillary services
GW	Gigawatt
Hz	Hertz
kW	Kilowatt
MSATS	Market Settlement and Transfer Service
MT PASA	Medium-term Projected Assessment of System Adequacy
MW	Megawatt
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Metering Identifier
NSPs	Network Service Providers
NTNDP	National Transmission Network Development Plan
NYISO	New York Independent System Operator
PD	Pre-dispatch
PV	Photovoltaic
SCADA	Supervisory control and data acquisition
SRES	Small-scale renewable energy scheme
ST PASA	Short-term Projected Assessment of System Adequacy
UFLS	Under frequency load shedding