Consultation paper

Assessing DER integration expenditure

November 2019

AUSTRALIAN
ENERGY
REGULATOR

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Request for submissions

The Australian Energy Regulator (AER) invites interested parties to make submissions on this consultation paper by 20 January 2020.

We prefer that all submissions are in Microsoft Word or another text readable document format. Submissions on our draft decision paper should be sent to AERinquiry@aer.gov.au.

Alternatively, submissions can be sent to:

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We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

We will place all non-confidential submissions on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014), which is available on our website.

Please direct enquires about this paper, or about lodging submissions to AERinquiry@aer.gov.au or to the distribution branch of the AER on (03) 9290 1470.

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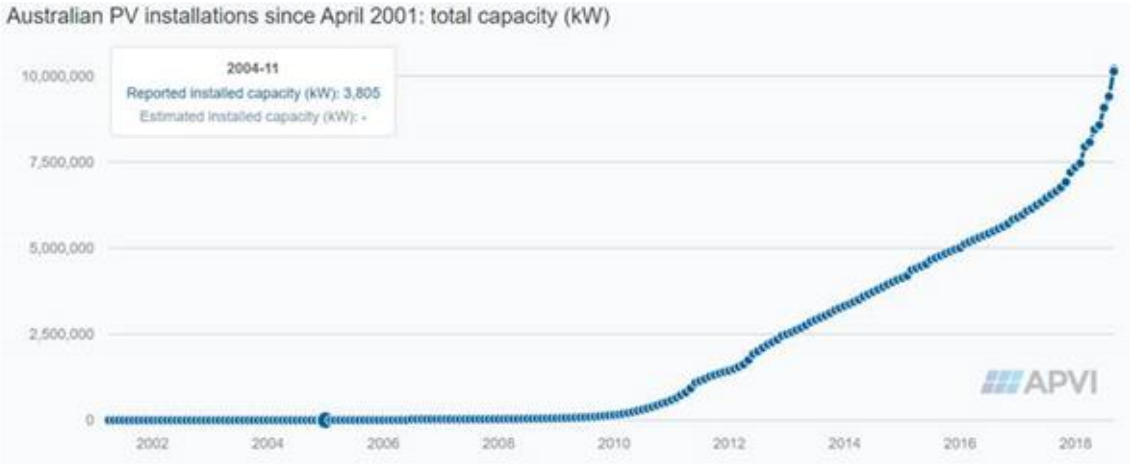
1 Overview

Distributed Energy Resources (DER) including solar photo-voltaic (PV), energy storage and electric vehicles (EVs)[1] represent a fundamental change to the system of electricity delivery that has been in place for over a hundred years. Figure 1 shows the uptake of solar PV installations since April 2001.

Figure 1 – Australian Solar PV installations



Source: Australian PV Institute - http://pv-map.apvi.org.au/analyses

As shown, solar PV has grown from being a relatively immaterial amount in 2010 to over 10 million kW of installed capacity in 2018. The pace of change in the energy sector is significant and Australia is at the forefront of this change. Recently, we have observed these other changes to the energy market:

- electricity generation is moving from large centralised generation that is far away from load centres to smaller, decentralised generation that is close to load centres;
- the rise of the prosumer – consumers are moving from passive participants to active participants who generate some of their own power and can respond to pricing signals;
- electricity has traditionally been difficult or expensive to store, but is increasingly being stored to help balance supply and demand. While many new energy sources are now less dispatchable (e.g. wind, solar), consumer demand is increasingly becoming more flexible to meet the available supply.

[1] DER is defined in more detail in section 3. Appendix A of this report provides an overview of the different types of DER.

More broadly, there are ongoing policy reviews and structural changes that are occurring in relation to this energy transformation. We anticipate that this pace of change will continue. This environment of rapid change creates additional risk to consumers both from action that is premature, and action that is overly late.

As part of our regulatory determination process, a Distributor Network Service Provider (DNSP) will provide us with a five year forecast of its required revenue that it seeks to recover from its customers. Capital and operating expenditures are a significant component of this. We assess expenditure forecasts to determine if they reasonably reflect the expenditure criteria. In doing so, we must have regard to each of the expenditure factors specified in the National Electricity Rules (NER).[2]

Given that DER is a relatively new driver of network, we consider that additional guidance on our approach to the assessment of DER driven network investment may be warranted. This paper seeks input from consumers and industry on how best to provide guidance to DNSPs on the kind of considerations they should draw on in demonstrating that expenditures relating to greater DER penetration are prudent and efficient. This is intended to improve customer outcomes by promoting efficient and prudent DER-related investment and helping us in our assessment of proposed DER-related expenditures. This approach should also support better outcomes for DNSPs through improved consistency, transparency and predictability in the regulatory process.

The objective of this consultation is not to define preferred models or outcomes, or to promote one technology or approach over another. Instead, we intend that this consultation process will define a framework for identifying options, assessing consumer benefits and considering appropriate project timing. This framework would take the form of a guidance paper that would supplement the existing Expenditure Forecast Assessment Guideline (EFA Guideline).[3]

External policy and structural changes will continue and may need to be accommodated within this process. As with other tools that we use to asses DNSP forecast expenditures, this process will also need to be flexible and continue to adapt over time.

Throughout this paper we have posed a series of questions. We welcome stakeholders' views on these questions as well as any other feedback stakeholders may have (see page 2 for details on how to make a submission).

Table 1 sets out the steps in the process and indicative timing.

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[2] NER, clauses 6.5.6(c) and 6.5.7(c)

[3] AER, Expenditure Forecast Assessment Guideline – Distribution, November 2013.

Table 1 indicative consultation timeframes

Key steps	Indicative dates
Submissions on consultation paper due	20 January 2020
Publish draft guidance	March 2020
Submissions on draft guidance due	April 2020
Publish final guidance (and apply to open resets)	June 2020

Once we have considered all submissions, we will publish our draft position on our approach to assessing DER expenditure proposals. We expect to publish this in March 2020. We will also seek stakeholder views on the draft position prior to publishing the final guidance paper.

We intend to apply the DER expenditure assessment approach we arrive at through this consultation process to the electricity distribution decisions we will publish after July 2020. As noted above, the DER expenditure guidance paper will be integrated into the existing AER guidelines and expenditure assessment processes. As part of the reset process, we will provide the relevant DNSPs and other stakeholders an opportunity to submit their views on how we should apply our decisions to their specific circumstances. We will take those submissions into account in our draft regulatory determinations for those DNSPs.

2 Purpose and objectives of the consultation paper

The purpose of this paper is to seek feedback on:

- the general framework around the development and assessment of DER integration network investment, in particular, where it differs from conventional network investment that has been covered by our EFA Guideline
- the level of clarity we should provide on the way we consider forecast expenditures relating to DER
- the opportunities, challenges, benefits and risks that need to be considered in formulating a DER driven investment proposal
- how to coordinate the assessment of expenditures with the broader policy, technical and social changes that are also occurring; and
- how DER integration expenditure fits into the broader expenditure assessment framework.

The reason we are seeking this feedback is to ensure that a future DER integration expenditure guidance paper:

- supports better outcomes for consumers by improving the way forecast DER integration expenditures are developed and assessed; and
- balances stakeholders concerns on the DER costs, benefits and risks that must be considered now and into the future.

The paper does not propose specific potential changes to our expenditure assessment processes. This will be the subject of the draft guidance paper due to be published in 2020, but this will be informed by feedback on the issues raised in this paper. We have highlighted possible areas for consideration – such as how customer benefits can be measured – and pointed to examples of how this has been considered elsewhere.

Relationship to other initiatives

Australia is considered to be at the forefront of DER deployment and, as noted in Appendix A, this is posing various challenges to the way the electricity supply system is operating. As a result, a range of broader policy projects and initiatives being pursued by the Energy Security Board (ESB), Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO), the AER and other agencies and organisations that will effect some of the challenges we identify in this paper. This work is intended to ensure the regulatory regime is able to effectively facilitate the efficient integration and use of DER for the benefit of consumers.

There are multiple projects and reform processes examining the best way to integrate DER. These include the AEMC's Electricity Networks Economic Regulation Frameworks Review 2019 (ENERF). The 2019 ENERF noted that we are already reviewing DER integration expenditure in current regulatory proposals and the AEMC considers the incentive-based regulatory frameworks provides DNSPs the ability to undertake such expenditure, if it is prudent and efficient. As a key recommendation, the 2019 ENERF also foreshadowed and supported our work in developing further guidance on how it considers DNSP DER integration expenditure in revenue proposals and what we consider as prudent approaches to integrating DER.[4]

Other related initiatives include the following:

- The Post 2025 Market Design Review being undertaken by the Energy Security Board
- The AEMC's Demand Response Mechanism that allows third parties to aggregate DER – as a building block for aggregation of DER and aggregators participation in the wholesale market
- The Open Energy Networks project – to develop a model for distribution markets – jointly being undertaken by AEMO and the Energy Networks Association (ENA)
- Technical standards development (for devices, information sharing and protocols (APIs) - underway through the Australian National University, AEMO and other bodies
- The Distributed Energy Integration Program (DEIP), an initiative of the Australian Renewable Energy Agency, that brings together energy peak bodies, market authorities, industry associations and consumer associations to maximise the value of customers' distributed energy resources for all energy users
- AEMC review of regulations for Stand Alone Power Systems and microgrids, as well as the separate development of a framework for regulatory sandboxes
- Multiple Virtual Power Plant (VPP) trials – to facilitate aggregation of DER, other trials are being developed through the Australian Renewable Energy Agency (ARENA) and our Demand Management Incentive Allowance
- AER consideration of network tariff structure statements, which are aimed at promoting more cost reflective pricing that enables efficient decisions to be made about the deployment of DER by customers as well as investments by network businesses. We are also promoting this through round-tables on tariff reform.

These important reforms will address many of the challenges that the NEM currently faces in integrating DER. In doing so, these initiatives may influence the development of a DER integration expenditure guidance paper.

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4 Australian Energy Market Commission, Electricity Networks Economic Regulation Frameworks Review 2019, pp. 24-25.

3 What is DER?

DER commonly refers to solar PV, storage, EVs, and other consumer appliances that are capable of responding to demand or pricing signals. The definitions of DER can be quite varied, and new devices and appliances are appearing at a rapid rate. This paper focusses mainly on PV, but also considers storage and EV.

DER, for the purposes of this paper, are flexible resources connected to the low voltage networks which produce electricity or manage demand. This is inclusive of, but not limited to:

- rooftop solar
- battery storage
- EV's and vehicle to grid services
- solar hot water
- other generators
- smart appliances (e.g. air conditioning, pool pumps)
- small diesel
- building electrification (e.g. heat pumps)
- energy management systems (e.g. microgrid controllers).

PV generation has been growing at the residential level for 20 years. Distributed storage (i.e. batteries) are reducing in cost and, although not cost effective in most residential applications, represent a growing market. EV availability is increasing and prices are forecast to be at parity with conventional vehicles around 2025.

A common feature of DER is that the cost of the devices are continuing to decrease:

- Solar PV costs have fallen 73 per cent[5] between 2010 and 2017
- Battery storage costs have fallen 73 per cent[6] between 2010 and 2016
- EV costs are also decreasing rapidly as battery storage costs reduce and production volumes increase.

Coupled with government subsidies, this has resulted in the deployment of significant volumes of PV, and similar profiles for storage and EV deployment growth are forecasted. Further information on the various types of DER and trends of use is provided in Appendix A.

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5 Renewable Power Generation Costs in 2017, IRENA, 2017.

6 Bloomberg New Energy Finance Survey, 2017.

4 Network response to DER

To date, DNSPs are managing electricity flows from consumer DER at penetration rates of over 30 per cent.[7] These are among the highest levels of DER penetration in the world. Even at the higher end of these penetration levels, annual DNSP costs to meet these levels of DER penetration through augmentation appears to have been small in comparison to overall expenditures, though not explicitly quantified. DNSPs have also implemented processes to limit the risk to the network from exceeding DER hosting capacities. These processes include limiting the allowable export from connecting DER. High volumes of export restrictions are likely to limit how a consumer may participate in energy markets more broadly, constraining consumer choice in energy services, and may lead to inefficient outcomes. In some cases, networks are not allowing any additional PV export for new connecting systems due to local network constraints.

The offer of zero-export or significant augmentation do not represent a long-term sustainable solution to the continuing deployment of consumer DER. Recent discussions with DNSPs suggest substantial increases in DER integration expenditures are forecast over the coming years. Some of these DNSPs have identified PVs as contributing to voltage increases. The challenge is to determine the efficient use of existing network capacity and the efficient levels of additional investment.

In addition, differing levels of DER deployment mean that its effect on the networks varies considerably between jurisdictions. This is an important factor when considering the timing of investment to manage DER integration on the networks. This suggests that customers in some states will benefit from a smarter grid before others. Some states and territories will have the opportunity to observe the trials and investments of others before making investments of their own. Socialisation of these early trials and investments should provide the opportunity for other businesses to avoid some of the learning costs of the early adopters. This would also support the development of a set of common standards and platforms.

More detail on network responses to increasing levels of DER is provided in Appendix C.

[7] Australian Photo Voltaic Institute – Analysis. https://pv-map.apvi.org.au/historical#4/-26.67/134.12

5 The assessment framework

5.1 National Electricity Rules

Our role is to make decisions on whether a business' forecast of total capex and opex reasonably reflect the capex and opex criteria.[8] In doing so, we must have regard to each of the capex and opex factors specified in the National Electricity Rules (NER).[9]

If we are satisfied that the DNSP's forecast reasonably reflects the criteria, we accept the forecast.[10] If we are not satisfied, we substitute an alternative estimate that we are satisfied reasonably reflects the criteria for the DNSP's forecast.[11] To date, we have assessed DNSPs' forecast DER integration expenditure in accordance with the capex and opex criteria.

Every five years, the DNSPs prepare a forecast of expenditures for the next (five year) regulatory period.[12] We are required to review these forecast expenditures in line with the obligations contained in the NER.

Over time, we have established a consistent approach to the expenditure review process with multiple tools and methods being used for different expenditure classes (the "toolkit"). The assessment framework, approach, techniques and information requirement are set out in our EFA Guideline – Distribution.

Within the current assessment toolkit, we employ a number of different techniques to assess forecast expenditures including benchmarking, trending, modelling and engineering reviews. These tools are applied at each of the stages of the expenditure assessment process depending on the type of expenditure that is being proposed.

5.2 Additional framework guidance

5.2.1 Investment tests

We have developed a test and guideline for networks when considering large capital intensive projects. The distribution version of this test is referred to as the Regulatory Investment Test – Distribution (RIT-D).

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8 NER, 6.5.6(c) and 6.5.7(c)

9 NER, 6.5.6(a) and 6.5.7(a)

10 NER, 6.5.6(c) and 6.5.7(c)(1)

11 NER, 6.5.6(d), 6.5.7(d) and 6.12.1(3)(4).

12 The current Victorian regulatory control period has been extended by 6 month to 5.5 years to align reporting periods.

The RIT-D establishes the processes and criteria for DNSPs to apply before investment decisions are made. The purpose of the RIT-D is to ensure DNSPs consider all credible options (which may include both network and non-network options) when choosing how to address identified network needs.[13] The preferred option is that option which maximises the economic benefit to all those who produce, consume and transport electricity in the national electricity market (NEM).[14]

The RIT-D must also consider several classes of market benefits.[15] Our RIT-D Guideline also provides guidance on the methodology for valuing market benefits.[16] We consider, where relevant, the benefits considered as part of DER-related capex should include the same benefit consideration as the RIT-D. This approach is comprehensive and consistent with our capex criteria.

The identification and quantification of market benefits as part of the RIT-D process was also designed to be predictable, transparent and consistent.[17]

5.2.2 Tariff Reform

Network tariff reform is key to making energy markets work better for energy consumers. We have an ongoing program of work to make network pricing more cost reflective. Cost reflective prices may lower electricity costs as, in the long term, reductions in peak demand result in lower overall network expenditure, with benefits passed through to all consumers.

Tariff reform is also important to unlock value from DER. The development of improved price signals will help consumers with DER improve the value that this investment delivers to them as well as the broader energy community. Tariff reform and the more cost-reflective signals that come with it will be increasingly important as we see more flexible loads and generation connect to the system. The AEMC also strongly supports our continued effort to implement network pricing reforms.[18]

The effect of tariff reform will remain a key consideration when developing forecast DER integration expenditures and this should be factored into a network business' case for DER-related investment.

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13 NER, cl. 5.15.2(a).

14 NER, cl. 5.17.1(b).

15 NER, cl. 5.17.1(c).

16 AER, Application guidelines regulatory investment test for distribution, December 2018, p. 35.

17 NER, cl. 5.17(c)(3).

18 AEMC, Economic regulatory framework review integrating distributed energy resources for the grid of the future, September 2019, xii.

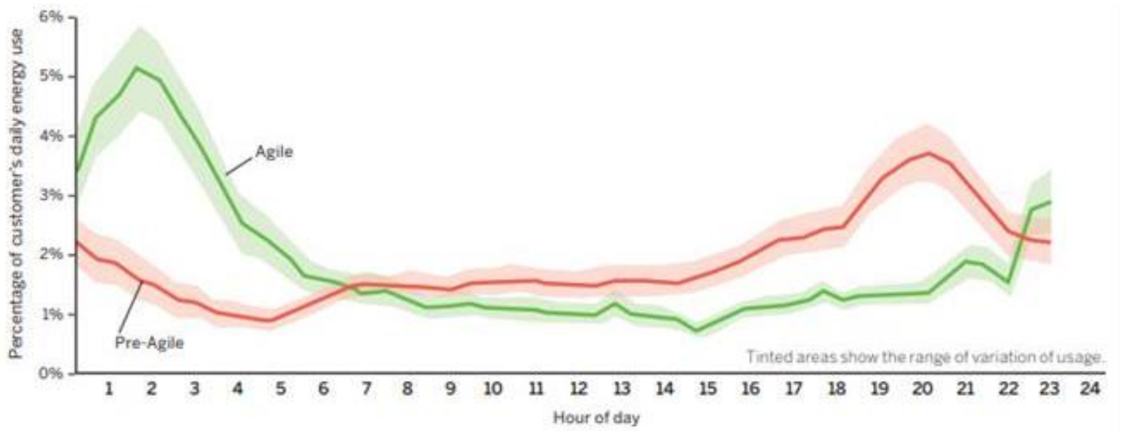
Example 1: Impact of tariff reform

The home charging of EVs provides a very important driver for the deployment of more cost reflective tariffs.

Under a flat tariff structure, the EV consumer is provided with no signal or incentive on when to charge their car. As such, it is logical for them to simply plug in the vehicle when they arrive home. Unfortunately, this will often coincide with the local network peak which typically occurs between 6pm and 9pm on a weekday evening.

Figure E-1 shows that Trials in the UK of time-based electricity tariffs demonstrated that more than half of EV consumers will defer charging of their vehicle if provided with a pricing signal to do so (Agile time-of-use tariff). This approach has the benefit of greatly reducing the impact on the system peak and therefore reducing network expenditures. Under this approach all network customers would be better off, not just the EV consumer.

Figure E-1 Electric vehicle owners' charging habits change on time-of-use tariff



Source: Octopus Energy, (2018). Agile Octopus: A consumer-lead shift to a low carbon future.

5.2.3 What we considered in assessing a recent DER integration expenditure proposal

Our assessment framework is not yet formally defined in respect of DER integration expenditure, however we have recently assessed DNSPs' proposals for these expenditures. Our assessment of one proposal, and the factors we had regard to, are highlighted below:

- *Is there evidence of a problem that needs to be addressed?*

  Evidence demonstrated that the growth in customer high-voltage complaints corresponded with the growth in solar PV where PV penetration rates are high relative to the base load on LV feeders. That is, there was evidence of a growing voltage non-compliance problems that is likely to be caused by growth in installed PV.

- *Has the DNSP considered a range of reasonable and practical options to address the need?*

  The DNSP had considered a range of options that included limiting PV exports, undertaking traditional augmentation, implementing dynamic PV export limits, and other solutions with limited application such as adjusting tap settings. However it was not clear the extent to which the DNSP had considered combinations of options in determining its proposed solution.

- *Are the costs and benefits of the options reasonable and realistic evaluations?*

  The proposed program was based on new technology, which created difficulties for the DNSP to demonstrate efficiency in proposed costs. This also made it difficult for us in developing an alternative estimate without a measure of similar works upon which to compare the proposed costs. We considered the proposed costs to be reasonable, on the basis that the cost estimates did not appear to contain any unnecessary components and were based on the best information at the time.

  We investigated alternative studies of PV export values, which were used in the benefit calculation. As part of this process, we attempted to estimate our own value, however we did not have confidence in other sources of information at the time.

- *Are there any other relevant factors that might influence the costs or benefits of the options that might reasonably alter the choice of the most efficient and prudent option (e.g. other benefits – market benefits, risks, etc.)?*

  We considered that the program may facilitate additional market benefits from PV export that other options may not facilitate or would likely cost more to achieve (e.g. network augmentation). In our view the program may also facilitate the development of consumer involvement in energy markets, or the operation of VPPs that may not be readily implemented under other options without further capital investments.

5.3 Why we consider a DER integration expenditure guidance paper is required

Distributed energy resources represent a change in the way that consumers interact with electricity networks and the demands that they place on network services. These changes are exogenous to the network and may create the need for DNSP's to invest in new technologies or make other changes to their networks.

Determining the incremental network costs associated with new DER installations can be difficult due to the existing categorisation frameworks. DER effects are hard to assess as they potentially cross a number of cost categories. For example:

- assessing the hosting capacity[19] of network components may incur additional operating expenditure when considering applications for new DER network connections.

- addressing quality of supply issues caused by DER could fall in the opex cost category, or in the augmentation (capital) expenditure group depending on the most appropriate solution.

- increasing DER has resulted in material reductions in demand and related augmentation expenditure.[20] However, it can also create the need for additional augmentation expenditure when reverse flows exceed the capacity of the existing system.

Although there is uncertainty about the way consumers will adopt new technologies, higher levels of PV penetration, energy storage and EVs, are likely to affect network expenditures in unique ways. For instance, networks may experience voltage fluctuations as a result of increased PV export leading to increased investment to address these issues; while energy storage may be operated in a manner that contributes to a reduction of network investment. The effects and complementary nature of the various forms of DER need to be considered and it is important the approach used to assess these factors is effective.

These uncertainties present a risk to consumers if investments are made that may prove unnecessary. The need for future expenditures will depend, in part, on how these risks are managed and on the adoption of more efficient price signals. These uncertainties also include the future development of DNSPs to adopt a Distribution System Operator (DSO) model whereby the DSO operates to manage the flows and optimise generation across the distribution network.[21] In combination, these uncertainties would suggest that DNSPs need to adequately consider all available options and the optimal timing of each option. The main purpose of providing greater guidance is to promote this approach to DER integration expenditure.

It is important to have transparency over the investment being proposed and to have a clear view of its implications across the investment lifecycle. With current uncertainties, it is difficult to assess the long-term network service and cost implications for customers. In particular, future asset stranding risks will need to be appropriately assessed as this risk is ultimately borne by consumers. As such, the investment timeframe is key because a short investment recovery timeframe may be less risky than a long investment timeframe (e.g. 50 years or more) due to the stranding risk uncertainty.

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[19] The capacity of the network to safely and reliably connect additional generation or load resources. This may be impacted by limited visibility of those parts of the network.

[20] Quarterly Energy Dynamics Q2 2019, Market insights and WA market operations, AEMO, page 6.

[21] See Appendix A.

Given the growth in consumer adoption of DER, the scale and scope of future DER integration expenditures that are being considered by network businesses, there is a strong argument for:

- refinement in the methodology used to assess the prudency and efficiency of forecast DER integration expenditure;
- clear direction and a level of certainty to DNSPs on how their proposed expenditure will be assessed, including what information and supporting evidence should be submitted with their forecast proposals.

Foundational questions –

Question i – Are our assessment techniques outlined in our Expenditure Forecast Assessment Guideline (the EFA Guideline) sufficient to assess DER integration expenditure?

Question ii – What form of guidance should we include to clarify how our assessment techniques apply to DER integration expenditure? For example, should we update the EFA Guideline to be more prescriptive, or only include principles to allow for greater flexibility in our assessment and information requirements as DER integration matures?

6 Good practice model development

In developing any future guidance related to DER integration expenditure, we are aware of the need to balance prescription and compliance costs with the overall benefit to consumers. As such, we will seek to align guideline requirements with good practice approaches that are already in place within the industry.

The following section considers aspects of good practice that have been drawn from existing AER guidelines and application notes as well as the recent work in assessing DER expenditure proposals. These documents include the EFA Guideline (2013), the Regulatory Investment Test – Distribution (2013) and associated applications notes (2018). We consider that the practices identified in these documents remain valuable when assessing forecast DER expenditures.

Through this consultation process we are seeking feedback on these 'good practices' and how they may support the assessment of forecast DER expenditures. We envisage that our assessment approach will be consistent with the RIT-D guideline, but recognise the differences in benefits and beneficiaries. The following approach is drawn from our RIT-D guideline and application notes:

- Identifying and defining the need – identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services should be the starting point for any investment proposal.
- Recognising technology risk – the rate of technological change and the uncertainty in how the technology will develop in the energy sector is higher than it has been since the times of Edison and Tesla. In this context, the risks of stranding associated with both traditional network assets and new technologies associated with managing DER may increase. It is therefore important to test any proposed network strategies and associated investments against a reasonable range of scenarios, and to use options analysis and sensitivity analysis within each scenario context.
- Defining a reasonable counterfactual as the basis of options analysis is important in demonstrating a prudent and efficient investment. The counterfactual should consider all relevant costs associated with the business as usual maintenance of the quality, reliability or security of supply of standard control services. Comparison of the costs and benefits of each credible option against the counterfactual forms the basis of the cost benefit analysis for each credible option.
- Scenario analysis and options analysis are important complementary tools in managing network investment risk in a changing environment and in demonstrating the prudency and efficiency of proposed investments. Scenario analysis would indicate a reasonable range of possible future operating environments that will impact on the maintenance of network services. Options analysis would indicate how the identified need would be addressed in the context of each scenario. Credible options would include:

- Network options – traditional network options as well as connection standards and technical standards[22] can greatly impact the way DER operates on the network and the impacts it can have. In considering network options consideration should be given to sampling approaches. Networks have used sampling and modelling techniques in forecasting for many years and these methods have proven effective in the management of the network. In managing DER, similar sampling and modelling methods could be more efficient than deployment of expensive capital equipment.
- Non-network options – distributed energy resources are, by definition, located at the end of the electricity network. Typically networks have less visibility of this part of the network. There is opportunity for DNSPs to purchase information from metering or DER data providers rather than building their own assets and systems. Network tariff reform and the demand management incentive scheme (DMIS) also provide options to utilise price signals or demand management techniques in managing any network impacts from DER. We consider it important to see a coherent and coordinated approach across the expenditure strategy, tariff strategy and demand management strategy in future regulatory proposals. Example 1 (above) provides an indication of the ability to defer or reduce network expenditures through the deployment of more cost-reflective pricing structures.
- Short-term options that facilitate risk mitigation – in a changing and uncertain environment, risks associated with uncertainty (i.e. a lack of information) can be managed by considering options that defer investment until better information is available. Options that maintain the widest range of future courses of action, and options that involve small incremental investments rather than large single commitments.

- Cost-benefit analysis is needed to show the prudence and efficiency of a proposed network investment. Project justifications require analysis of the costs and benefits relevant to each credible option, within each scenario, relative to the counterfactual. Fundamental to any changes in network expenditures is the requirement to demonstrate alignment to the capital expenditure objectives and as appropriate demonstrate the customer benefits. Many of these benefits may be

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[22] For example; the 2015 update to the Australian Standard inverter AS4777 has increased the baseline DER hosting capacity of electrical networks by approximately 30% according to SAPN analysis. In other words, by changing the operating characteristics of home inverter systems, the standards have enabled approximately 30% more systems to be connected for the same level of network impact.

market benefits and the RIT-D may provide an appropriate starting point for this analysis.

- Determining a consistent value (or methodology) for new or additional PV generation will be a critical input when examining the benefit of future DER expenditures. In some states, feed-in tariff benchmarks are set based on methods to value PV export.[23] The New York State Public Service Commission has also developed a standardised approach for valuing the system impact of PV.[24] It may be possible to extend an approach for valuing solar PV to other forms of DER to support standardised analysis of customer benefit.[25]

- Avoiding duplication and "rail-gauge" problems – it is important for the industry to work together to provide customer outcomes that are consistent across the NEM in order to be efficient. Where possible international standards should also be considered. Shared learning and the development of common platforms, communication standards, and systems will reduce the overall cost and complexity of facilitating DER. In contrast, DNSP specific communication protocols, interfaces, connection standards, etc. will lead to increased cost and complexity for consumers and industry providers. We recognise relevant differences in networks when assessing investment proposals. However, it will be important for networks seeking to develop bespoke solutions to make a strong case for any such proposals. For example, specific relevant differences may include smart metering in Victoria, or relevant jurisdictional regulations.

- Ring fencing considerations – DNSPs should have regard to our ring fencing guidelines and any implications the proposed DER investment may have in regards to ring fencing.

Question 1 – Information provision – What information is reasonable and necessary in identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services?

Question 2 – Options analysis – What range of options should DNSPs consider for DER related investments? Does the Regulatory Investment Test – Distribution provide the appropriate starting point for this analysis?

23 For example, in NSW, the benchmark rate excludes subsidies, while in Victoria, values inclusive and exclusive of subsidies are calculated. https://www.ipart.nsw.gov.au/Home/Industries/Energy/Reviews/Electricity/Solar-feed-in-tariffs-201920; https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff

24 https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources

25 The distribution of benefits between owners of DER and other consumers may also need to be considered more broadly (e.g. whether and how allowing charging for exports would better share these benefits and more efficiently align incentives). This is a matter outside the scope of this process, but would require a review of the existing NER provision 6.1.4 by the AEMC.

Question 3 – Sampling and modelling – Electricity networks have utilised sampling and modelling techniques to forecast energy demand and consumption for decades. These processes have proven affective for large cohorts of consumers where diversified behaviours can be predicted with sufficient accuracy. Is it reasonable to assume that sampling and modelling techniques will play a part in developing dynamic models of the electricity networks?

Question 4 – Non-network options – Distributed energy resources are, by definition, located at the end of the electricity network. Typically networks have less visibility of this part of the network. What approaches or information is reasonable to assess whether DNSPs have considered purchasing the necessary information from metering or DER data providers rather than building their own assets and systems?

Question 5 – Policy and standards – The optimisation of DER can be improved through many different approaches. Factors such as tariff reform, connection standards, technical standards, energy efficiency standards, etc. can greatly impact the way that DER operates on the network and impact on network performance. How should these options be integrated with the development of network DER proposals?

Question 6 - Cost benefit analysis – Project justifications will require detailed analysis on the costs and benefits of each option. Many of these benefits may be external to the DNSP's cost base, and may accrue directly to DER users. What level of analysis is required?

Question 7 – Customer Benefit – With DER being able to provide services across the electricity supply chain, how should DNSPs identify and value customer benefits? These benefits can include reliability outcomes, increased export potential, greater access to energy markets, access to network support services, etc. Should a common approach to valuing consumer exported electricity be established?

Question 8 – Options value – Noting the technological rate of change and the typical asset life of 65 years of many network assets, it is important to test whether current research could provide a more efficient option in the near future. Should an assessment of emerging alternative approaches be a requirement for DER forecast expenditure? Should there be an 'options value' placed on this?

Question 9 – Shared learning and systems – The development of common platforms, communication standards and shared systems may reduce the overall cost and complexity of facilitating DER. Should DNSPs need to show how they have considered options that leverage shared learning, common standards and common systems to provide efficient solutions, and that they have consulted and implemented learnings from prior works and trials across the NEM?

Question 10 – Rail gauge outcomes – as a corollary to the above question, it will be increasingly important for the industry to work together to provide customer outcomes that are consistent across the NEM (or with international standards if applicable). What approaches or information is reasonable to show that any DNSP-specific communication protocols, interfaces, connection standards, etc. will not lead to increased cost and complexity for consumers and industry providers?

7 Implementation

We propose to use the DER integration expenditure assessment approach decided in this review process in our determinations for each electricity DNSP, and we intend to apply the guidance paper to reset decisions after June 2020.

We will provide the relevant DNSPs and stakeholders an opportunity to submit their views concerning how we should apply the DER expenditure guidance paper in these determinations. We will take those submissions into account in our regulatory determinations for those DNSPs.

8 Questions

Throughout this paper we have posed a series of questions. We welcome stakeholders' answers to these questions as well as any other feedback stakeholders may have (see page three for details on how to make a submission). We have listed them here for your convenience.

Question i – Are our assessment techniques outlined in our Expenditure Forecast Assessment Guideline (the EFA Guideline) sufficient to assess DER integration expenditure?

Question ii – What form of guidance should we include to clarify how our assessment techniques apply to DER integration expenditure? For example, should we update the EFA Guideline to be more prescriptive, or only include principles to allow for greater flexibility in our assessment and information requirements as DER integration matures?

Question 1 – Information provision – What information is reasonable and necessary in identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services?

Question 2 – Options analysis – What range of options should DNSPs consider for DER related investments? Does the Regulatory Investment Test – Distribution provide the appropriate starting point for this analysis?

Question 3 – Sampling and modelling – Electricity networks have utilised sampling and modelling techniques to forecast energy demand and consumption for decades. These processes have proven affective for large cohorts of consumers where diversified behaviours can be predicted with sufficient accuracy. Is it reasonable to assume that sampling and modelling techniques will play a part in developing dynamic models of the electricity networks?

Question 4 – Non-network options – Distributed energy resources are, by definition, located at the end of the electricity network. Typically networks have less visibility of this part of the network. What approaches or information is reasonable to assess whether DNSPs have considered purchasing the necessary information from metering or DER data providers rather than building their own assets and systems?

Question 5 – Policy and standards – The optimisation of DER can be improved through many different approaches. Factors such as tariff reform, connection standards, technical standards, energy efficiency standards, etc. can greatly impact the way that DER operates on the network and impact on network performance. How should these options be integrated with the development of network DER proposals?

Question 6 - Cost benefit analysis – Project justifications will require detailed analysis on the costs and benefits of each option. Many of these benefits may be external to the DNSP's cost base, and may accrue directly to DER users. What level of analysis is required?

Question 7 – Customer Benefit – With DER being able to provide services across the electricity supply chain, how should DNSPs identify and value customer benefits? These benefits can include reliability outcomes, increased export potential, greater access to energy markets, access to network support services, etc. Should a common approach to valuing consumer exported electricity be established?

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Appendix A - What is DER?

DER commonly refers to solar PV, storage, EVs, and other consumer appliances that are capable of responding to demand or pricing signals. The definitions of DER can be quite varied, and new devices and appliances are appearing at a rapid rate. This paper focusses mainly on PV, but also considers storage and EV.

PV solar generation has been growing at the residential level for 20 years. Distributed storage (i.e. batteries) are reducing in costs and, although not cost effective in most residential applications, represent a growing market. EV availability is increasing and prices are forecast to be at parity with conventional vehicles around 2025.

A common feature of DER is that the cost of the appliances are continuing to decrease:

- Solar PV costs have fallen 73 per cent[26] between 2010 and 2017;
- Battery storage costs have fallen 73 per cent[27] between 2010 and 2016;
- EV costs are also decreasing rapidly as battery storage costs reduce and production volumes increase.

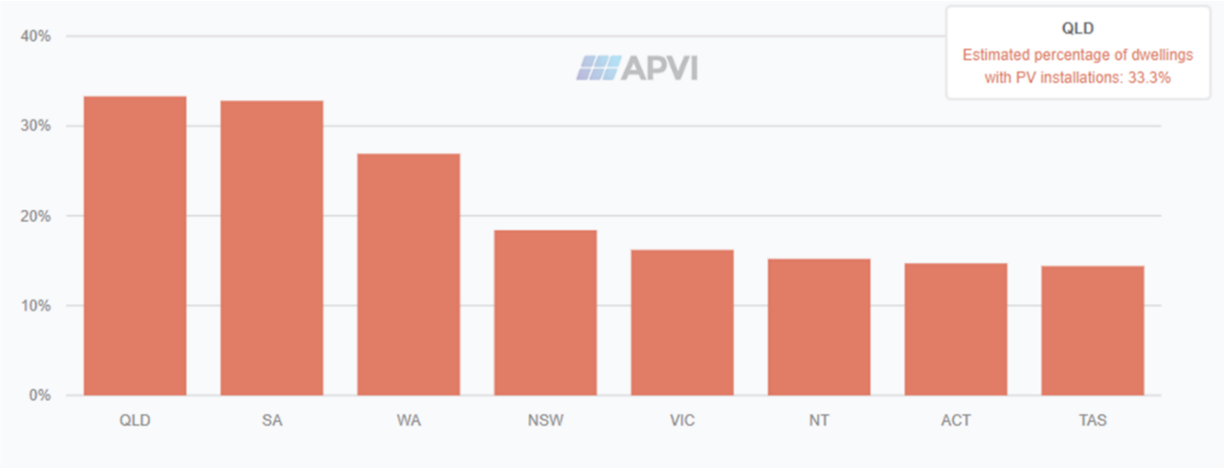
In conjunction with government subsidies, this has resulted in the deployment of significant volumes of PV, and similar forecast profiles for storage and EV deployment.

Figure 2 shows that the deployment of residential PV has varied considerably between jurisdictions.

[26] Renewable Power Generation Costs in 2017, IRENA, 2017.

[27] Bloomberg New Energy Finance Survey, 2017.

Figure 2 Percentage of dwellings with a PV system by state/territory

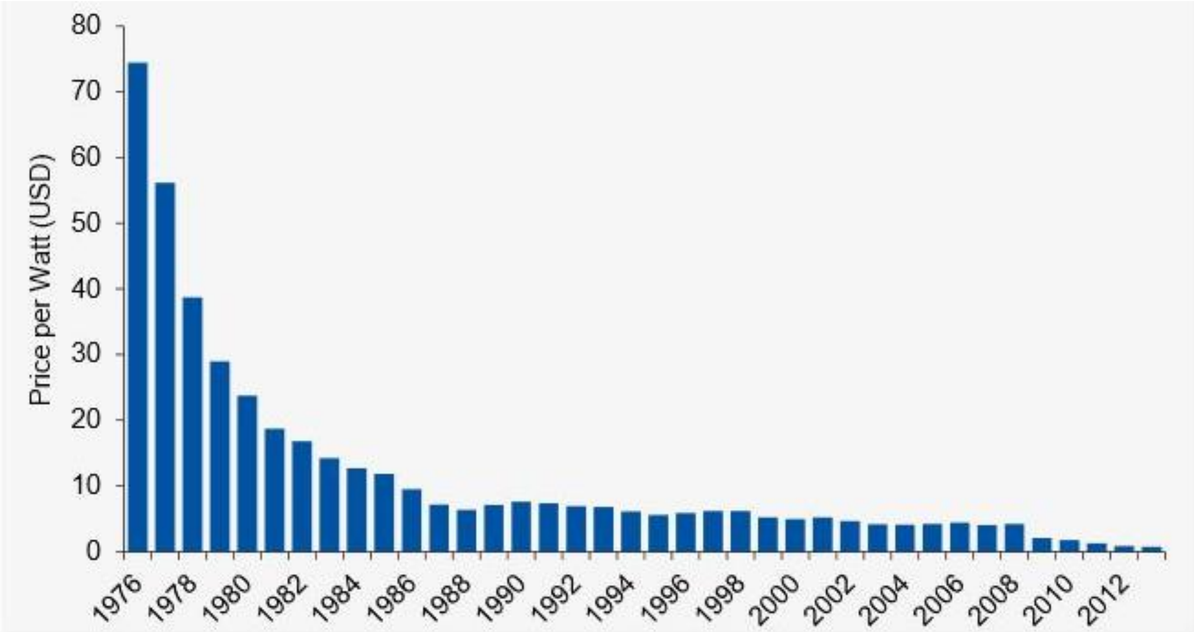


Source: Australian Photo Voltaic Institute, March 2019.

The differing levels of PV deployment is an important factor when considering the timing of investment to manage PV impacts on each distribution network. This suggests that customers in some states will benefit from a smarter grid before others. Some states and territories will have the opportunity to observe the trials and investments of others before making investments of their own. These learnings should provide the opportunity to avoid some of the learning costs of the early adopters, as well as allowing for an emerging set of common standards and platforms.

Adoption of PV, storage and EVs is forecast to continue across the NEM customer base. Figure 3 shows that the cost of PV generation has decreased by 99 per cent since 1976 and is currently reducing at a rate of 7 per cent per annum.

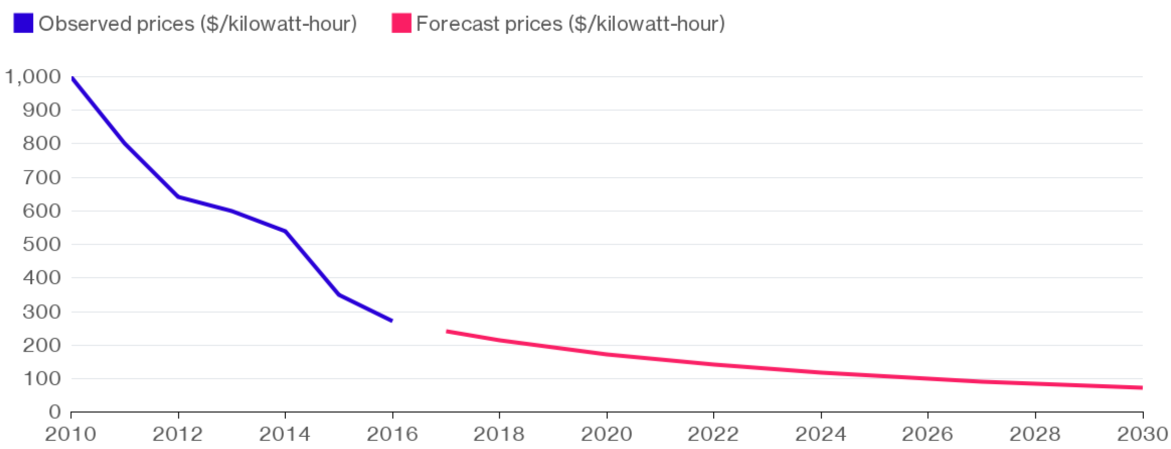
Figure 3 Price of crystalline silicon photo-voltaic cells



Source: Bloomberg New Energy Finance

Storage can be provided by a number of different technologies. The main consumer storage products are based on Lithium Ion (Li-ion) technology, which Figure 4 shows is reducing in cost by approximately 15 per cent per annum.

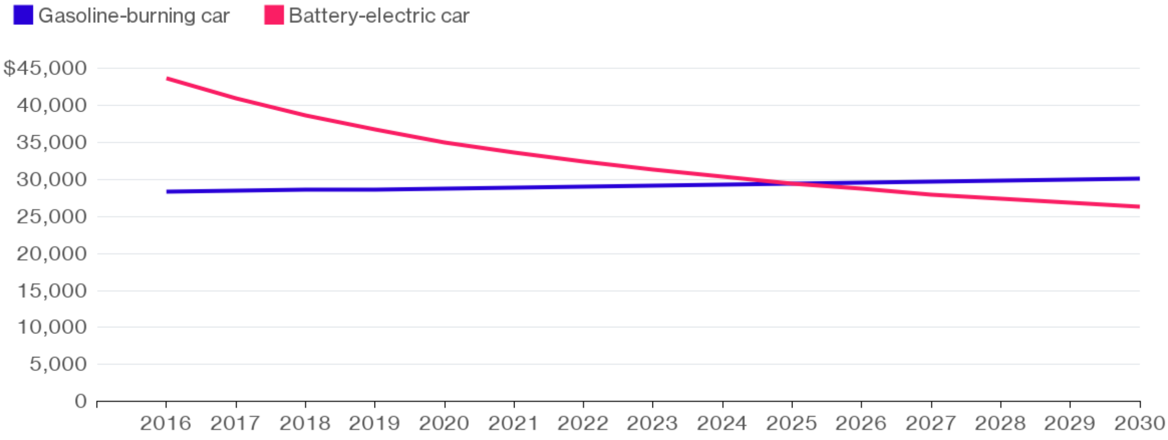
Figure 4 Observed and forecast prices of lithium-ion batteries



Source: Bloomberg New Energy Finance

EVs are also reducing in price, mainly due to the falling costs of Li-ion storage. Figure 5 shows that in the absence of direct subsidies or other incentives, EVs are forecast to reach pricing parity with Internal Combustion Engine (ICE) vehicles by 2025.

Figure 5 Forecast prices of electric and ICE vehicles ($USD)



Source: Bloomberg New Energy Finance

In summary, the general trend of increasing levels of DER penetration within electricity networks is forecast to continue.

Appendix B - What are the effects of DER on networks?

The following three sections discuss the current and possible future impacts of the three main types of DER (PVs, battery storage and EVs) on distribution networks.

Photo-voltaic

The generation of electricity at the consumer's premises can have positive and negative impacts on the operation of the distribution network, and potentially at the transmission level.

Electricity demand growth in Australia had been steadily growing since the formation of a national grid.[28] Since 2008-09, this trend has been halted and partly reversed with demand remaining relatively flat. The primary drivers for the change in demand growth are energy efficiency, reduced consumption and PV.[29]

These factors, but particularly PV, have resulted in the network peak demand being reduced and moving later in the evening.[30] This has led to a significant reduction in network augmentation expenditure across the NEM.

PV can also have adverse impacts on networks. The two primary impacts[31] are voltage rise and overload:

1. Voltages on electricity networks can rise as PV systems inject their energy into the system. The PV system has to inject at a higher voltage than that of the network to be able to export the energy that is being generated. When large numbers of PV systems are all doing this, the voltage impact can be material.

2. Electricity assets can be overloaded in the reverse direction if the volume of locally produced energy is greater than the capacity of the network assets.

At present, the capacity of residential PV generation across the NEM is less than 11 per cent of the total distribution transformer capacity.[32] There are pockets of PV penetration where the generation capacity is greater than the installed network capacity, but this is currently very uncommon and is a risk that DNSPs are actively managing, including through deterministic limits on export. In the short to medium term, the primary PV impact that needs to be considered is that of voltage rise.

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28 Five Years of Declining Annual Consumption of Grid-Supplied Electricity in Eastern Australia: Causes and Consequences, Sandiford, Forcey, Pears and McConnell, The Electricity Journal, 2015.

29 AEMO, Electricity Statement of Opportunities, August 2018.

30 Here Comes the Sun - ARENA Project, Moreland Energy Foundation, 2017.

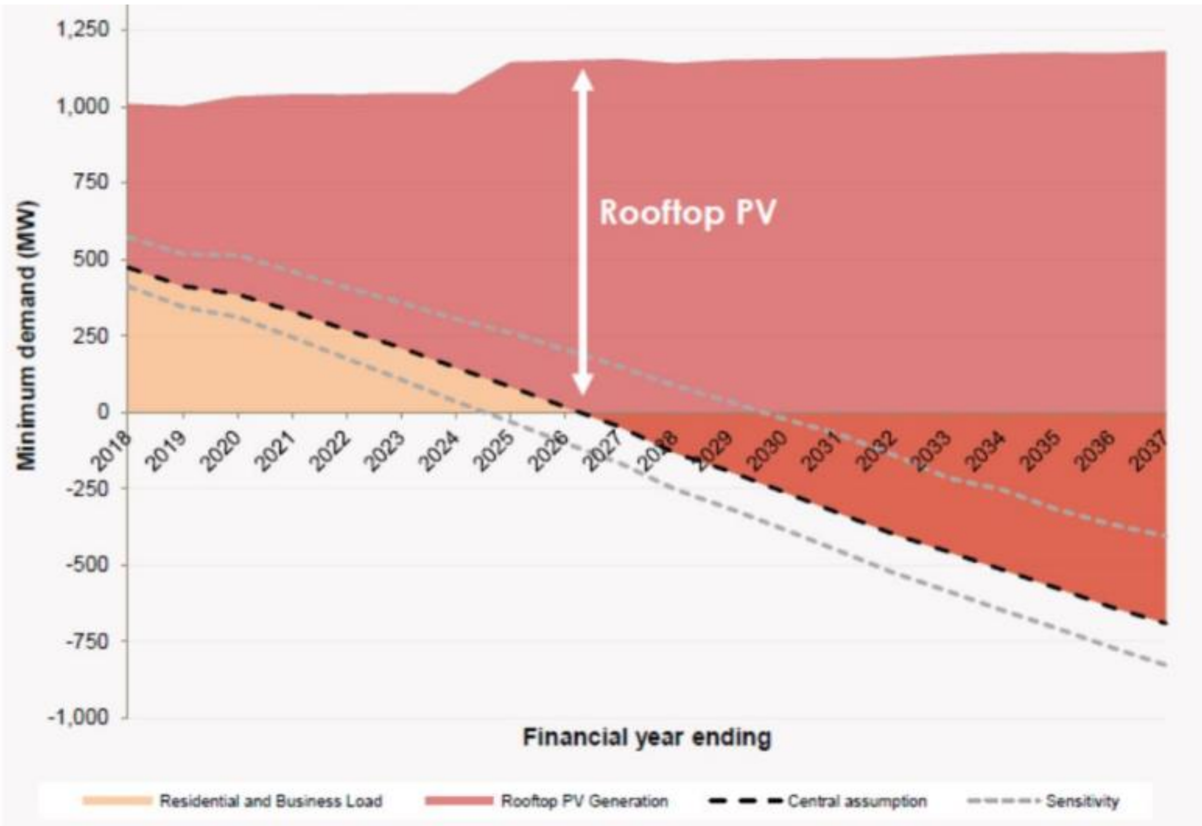
31 PV systems (including inverters) can also insert harmonic disturbances into electricity networks.

32 RIN category analysis summary 2018 – internal.

In addition to the local network impacts of PV, there are potential security risks for transmission systems from high levels of PV penetration. Figure 6 shows that AEMO has identified a possible future risk when the generation from PV could possibly exceed the state-wide demand. In this case, there is a risk to system control of frequency in the event of a separation event (e.g. disconnection of the Heywood interconnector).

There are many aspects of AEMO's modelling that reduce the impact of PV on the minimum demand forecast. However, some mechanism to limit or curtail solar PV export may be necessary in the future.

Figure 6 AEMO forecast of minimum demand in South Australia



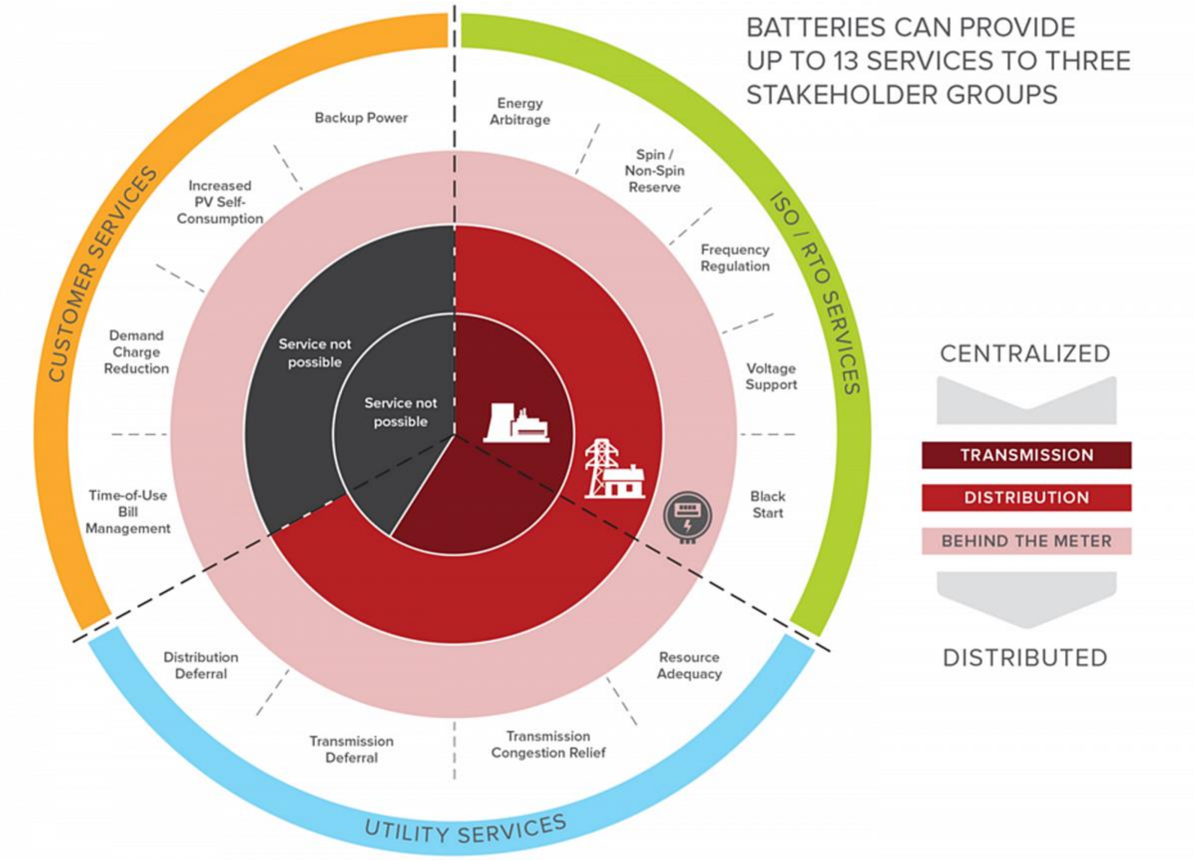
Source: AEMO Forecast Minimum Demand in South Australia

Storage

There are many trials of energy storage already located within the NEM.

Energy storage can provide many services to the network, and thereby can work to reduce overall network costs. However, energy storage can also provide many other services to consumers and to the energy system. Figure 7 highlights the range of services that are possible from home energy storage appliances.

Figure 7 Service applications of household batteries



Source: Rocky Mountain Institute, 2015.

The relative value of these services will drive consumer behaviour. For example; consumers that are seeking to derive maximum benefit from energy arbitrage may impose additional demand on the network and therefore increase network costs. On the other hand, consumers that are responding to network pricing signals should act to reduce or defer network investment. It is the balance of the services that consumers seek from their energy storage that will ultimately determine the overall impact on the network.

Noting that network costs represent between 25 and 50 per cent of the average consumer bill, it is likely that the overall impact on the network from energy storage will be to increase demand to some degree, otherwise the optimal value from the storage could not be achieved.

As an example of this, the AGL VPP trial in South Australia recently directed their cohort of storage devices to enter charging mode in anticipation of an approaching weather event. The “precautionary charging” was to provide the consumers with the maximum possible storage charge in the event of a reliability event (i.e. a backup service). The impact of this co-ordinated charging behaviour was to increase demand on the network above the typical maximum demand level. If this were to occur regularly or on a widespread basis, additional network capacity would be required.

Electric vehicles

The future impact of EVs on networks is not well known at this time. A residential EV would consume approximately half the annual load of the average residential home.[33] If this additional load were to be drawn coincident with high network loads, significant additional infrastructure would be required. Conversely, there is already sufficient network capacity to support a high level of EV penetration if these loads are timed to coincide with lower overall demand.

The public charging of EVs is developing as charging stations are being rolled out across major highways and in commercial centres. Public EV charging is currently designed to be quick; super-charger stations have an extremely high peak demand to support fast charging. Managing these local demands may require additional network infrastructure, although the use of "second life" batteries[34] is also being considered as a means of buffering the system peaks.

Home charging is currently designed to a different paradigm with slow charging taking 6-12 hours. Homes with EVs are also more likely to have PV installed, which will also impact the charging schedule and network impact. The timing of residential charging and the subsequent network impact are likely to be completely different from the fast-charging infrastructure. Current estimates are that fast-charging could account for 20-25 per cent of total EV charging. The balance of these two forms of EV charging will drive different needs in terms of network infrastructure.

Another variable in the future roll-out of EV fleets is the potential for the vehicle to deliver services back into the grid. This is referred to as Vehicle-to-Grid (V2G). The early generations of EVs that are currently on the road are not equipped with the ability to generate back into the grid. However, significant work if being undertaken to develop this facility.

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33 This is a rough approximation and will vary by location and consumer.

34 EV batteries are resource-intensive. They are generally warrantied to power an EV for eight to 10 years, but they can retain between 60 to 70 percent of their original capacity by the time they retire from the road. The re-use of transportation batteries is estimated to be a multi-billion dollar market with many uses for second-life batteries in applications where the energy density (weight) of the battery is not a material concern.

Appendix C - Network response

Network responses to increasing levels of PV and other DER vary. Some recent reset proposals have identified PVs as contributing to voltage rise, and have identified projects to manage PV and move the networks towards a future operating model. The current approach to managing increasing levels of DER penetration involves a range of traditional network activities including;

- Moving customer connections between different phases (phase balancing)
- Moving the open point on LV interconnected systems to rebalance loads
- LV conductor upgrades
- Transformer tap changes
- Transformer upgrades
- Zone substation and regulator tapping changes.

To date, these approaches have enabled DNSPs to meet consumer DER connections penetration rates of around 30 per cent. Annual DNSP costs to meet the current levels of DER penetration have not been explicitly quantified but appear to have been relatively small. To date, no pass-through applications have been received in relation to DER hosting capacity or related voltage compliance.

DNSPs have also implemented processes to reduce the risk to the network from exceeding DER hosting capacities. These processes include limiting the allowable export from connecting DER, which are applied when the customer (or their representative) seek connection of the new DER. The most common limit on DER export is 5kW, but is reduced to 2.5kW or even zero (0 kW) in some cases. These export limits represent a consumer loss. While it is challenging to determine the value that a consumer would attribute to an export limit, there is a volume of electricity generation that is being lost through the export limit process. Determining a consistent value (or methodology) for lost PV generation will be a critical part of developing a pathway for future DER expenditures.

There are social, economic and political considerations associated with applying export limits to customer DER. As network penetration of DER increases, the networks are likely to impose greater export restrictions. High volumes of export limitation may lead to outcomes that are not in the long term interests of consumers. While it is not likely to be economic to provide unconstrained access for all consumer DER, some degree of improved capacity hosting may be beneficial.

Export limits and operating envelopes

Export limits represent the maximum amount of energy that the individual consumer is allowed to push back into the grid. This is typically measured in kW or kVA.

The export limit is usually agreed when the consumer is seeking to connect a DER asset. Customers without an agreed export limit are assumed to have a default export limit of zero (0kW).

The Operating Envelope is an emerging term to describe the connection limits on both import and export. This terminology will become increasingly important in describing the operation of home storage appliances such as batteries and EVs.

At present, DNSP hosting capacity (and subsequent export limits) are determined on a static basis. The worst-case scenario[35] is identified and the hosting capacity is set based on that scenario. Customers who seek to connect once the hosting capacity limit is reached are typically offered a zero-export connection agreement, or an offer to augment the network. The network augmentation costs will typically be disproportionate to the volume of energy that the consumer is seeking to export as these costs are not socialised with all DER consumers.

Neither the offer of zero-export, nor the augmentation costs represent a long-term sustainable solution to the continuing deployment of consumer DER.

[35] The degree of analysis varies by DNSP. Some hosting capacity checks are undertaken at individual locations. In other cases, generic modelling or assumptions are applied.