Embedded Generation Project - Final Report

Energy Networks Association

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Table of Contents

Executive Summary

One of the most significant technical, regulatory and commercial challenges faced by the electricity industry to date is the continued uptake of embedded generation (EG)[1]. This has involved integrating EG into Australian electricity distribution networks, while maintaining the required levels of quality, safety, reliability and security of supply.

The Energy Networks Association (ENA) has launched the Electricity Network Transformation Roadmap (NTR) project to identify the preferred transition which the electricity network industry must make in the next decade, to be ready to support better customer outcomes under a diverse range of long-term energy scenarios. This includes investigating and assessing the impacts of continued EG growth on Australian electricity network service providers (NSPs) and determining how EG integration can be undertaken in a way that is beneficial for both customers and NSPs.

This report is a foundational piece for the NTR project, and is scoped to provide an overview of the key technical, commercial and regulatory impacts of EG. It looks at the opportunities EG presents for NSPs, how regulatory and policy options can be pursued to address the impacts, and how customers can receive greater value as either consumers, producers or prosumers[2] of electricity.

The report takes a proactive approach to new technologies and services. It has been prepared with the overarching principle that networks should actively develop industry-wide solutions, including integrating new technologies, to serve the long-term interest of their customers.

Audience

This report is intended to be released as a public document. It has been prepared on behalf of the ENA and its members in a process that has included extensive stakeholder consultation, input and review. Its public release is intended to help advance the customer’s ability to benefit from efficient and effective network operation through economic integration of EG, and seamless service offerings in EG related markets.

Objectives

The objectives of this report are to:

- investigate and assess the technical, regulatory and commercial impacts of continued growth in EG on Australian distribution and transmission networks

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[1] An embedded generating unit is defined as ‘a unit that generates electricity at a customer’s premises and is connected to a distribution system’. It includes, but is not limited to, micro-embedded generation units, electrical energy storage and electric vehicles.

[2] A prosumer is defined as a customer who both produces electricity (via an embedded generator, which can be supplied to the grid) and consumes electricity from the grid. A consumer is a customer who only consumes electricity from the grid.

- identify potential policy and regulatory options that the ENA and its members should consider in response to these impacts, to ensure the safe, reliable, affordable and efficient operation of the electricity network in the long-term interests of customers
- develop a high-level commercial framework to value EG and assess the commercial opportunities for NSPs.

Approach

In preparing this report, Marchment Hill Consulting (MHC) and the CSIRO undertook a desktop review of relevant literature, a survey of ENA members to gather views regarding the impact of EG on their network, and in-depth interviews to gather further insights. Workshops were held with the ENA and its members to test initial hypotheses, generate additional ideas, and review and refine the report's findings and recommendations. Draft sections of the report were also distributed to the ENA and its members for review and feedback prior to completion of the final report.

Authorship

The authorship of this report was shared between CSIRO and MHC. CSIRO focused on the technical impacts of EG, while MHC focused on the commercial and regulatory impacts. All policy and regulatory options and recommendations have been developed by MHC and represent their views only.

Limitations

The report has the following key limitations:

- It is necessarily broad in scope. Its intention was to set out the broad landscape as a background to further work by the ENA and its members, and it therefore addresses a range of topics and highlights areas for further work for which there were neither time nor resources to investigate further.
- ENA member views were gathered through a survey and a selection of interviews, however, the results do not necessarily represent the views of ENA or all relevant NSP stakeholders.
- The impact of EG often varies considerably between NSPs, which could be due to factors such as different EG penetration levels, network asset conditions and peak demand levels. Wherever possible, we have attempted to highlight the variability of key findings between networks, but note that not all findings and recommendations will be of similar relevance to all NSPs.

Key Findings

This report reviews the technical, commercial and regulatory impacts of EG on the Australian electricity network and builds on previous work such as the *Impacts and Benefits of Embedded*

Generation (IBEG) report[3]. We have found that increasing levels of EG on the network presents both opportunities and challenges for NSPs and customers – and that given appropriate conditions and incentives, EG can deliver significant benefits to NSPs and their customers alike. The challenge for industry is to ensure that the policy, regulatory and commercial environment, as well as relevant safety and technical standards, support the efficient deployment and use of EG in the long-term interests of all customers.

The sections below present the key technical, regulatory and commercial findings identified in this report. For highly complex findings, additional points of clarification or context are also provided.

Key Technical Findings

The findings in this section address the technical issues and options relating to increasing penetration of EG. *Technical Constraints and Network Impacts* will describe the key challenges associated with the network impacts of EG. Following on from this, *Options for Mitigating Network Impacts and Risks* will itemise ways in which networks can address these issues. *Options for Maximising Network Benefits* will demonstrate several in which EG can act to provide significant benefit to NSPs, industry stakeholders and customers (both directly and indirectly through reduced pricing). Finally the *Australian Standards Gap Analysis* itemises a number of key gaps in existing standards relating to EG.

Technical Constraints and Network Impacts

The findings identified in this section represent the ways in which EG can have negative impacts on the function, operation and maintenance of networks, or where EG can apply a new network constraint (or impinge upon an existing network constraint). These findings relate to the current state of networks as well as future business-as-usual operation; they may be manageable through deployment of techniques such as those included in *Options for Mitigating Network Impacts and Risks* below. Within the context of traditional network operation, we conclude that EG has benefits, albeit with an increase in the complexity of network operation.

1. Increasing penetration of EG, including greater uptake of rooftop solar and other EG, is changing load profiles on Australian electricity networks and making network load prediction more challenging. Appropriate planning and management of network load demand across different timeframes is essential to ensure both adequate power quality and a reliable supply of electricity of the network.
    - High penetration of EG increases the gap between the maximum and minimum network load. In addition to peak demand forecasts, accurate minimum demand and energy consumption predictions are required. These will assist in network planning relating to managing voltage and potential reverse power flow issues.
    - Accurate prediction of network load demand is essential for effective utilisation and management of EG sources on the network, and to establish sustainable load management systems for the smart grid.
2. Reverse power flow has been observed at the medium-voltage and high-voltage network levels. In radial networks designed for unidirectional power flow, this can affect the

[3] Energy Networks Association, *The Impacts and Benefits of Embedded Generation,* 2011

operation of protection and voltage regulation devices. In islanded networks, such as some remote communities, it can also have a detrimental effect on generator control and stability.

3. EG has the potential to contribute current to any fault in the vicinity. Protection system design and settings must be considered in rural and off-grid systems to ensure faults are cleared quickly. In urban areas, the added fault level (the maximum current that can flow in the network segment as a result of a fault) may restrict the amount of EG that can be connected due to system design fault levels.

Options for Mitigating Network Impacts and Risks

This section highlights the options available to networks for minimising — and if possible, eliminating — the negative impacts and constraints of EG identified in Section 3.2, to realise the benefits of EG while reducing the associated risks. The options discussed focus primarily on technical considerations; cost of implementation is discussed under the commercial impacts in Section 5.

4. Grid-scale storage has the potential to provide a range of network benefits relating to EG, including voltage management, energy balancing, and improving network stability. These benefits can increase the flexibility, reliability and efficiency of power delivery to consumers.
    - Currently, grid-scale storage is limited due to a combination of system cost and market maturity, and as such is generally only deployed in specific applications and locations as noted in Section 3.3.2.1. However, considering the market for energy storage devices has been estimated to reach 3000 MW by 2030, as well as expected improvements in related technologies, the deployment of grid-scale energy storage is predicted to see increasing uptake in the coming years.
5. Distributed storage can provide numerous benefits to networks, including improved management of voltage and power flows, peak load and generation management, and reactive power support. Customer-owned storage has the capacity to provide these benefits alongside direct benefits to the customer, despite not being network-owned.
    - For customer-owned storage, appropriate dispatch management is key. Unlocking its network benefits requires appropriate incentives to ensure that it is dispatched at times that are beneficial to networks. If incentives are not well-designed, customers may utilise storage in ways that are detrimental to the network. If direct control of non-network storage is desired, the deployment of operating systems (e.g. through demand response systems such as AS/NZS 4755 Part 3.5) and relevant communications platforms will enable controlled dispatch via consistent protocols.
6. Power electronics solutions, such as STATCOMs and smart inverters, have the capability to mitigate power quality issues relating to EG, including managing voltage ramp-rates and excursions. In some cases, they can also reduce harmonic content.
    - Smart inverters in particular can use a pre-existing generation resource to self-manage their own generation. As this functionality is not currently mandated, the penetration of these devices in networks is low. Retrofitting existing fleets of inverters would require a large capital investment.

- The current revision of AS/NZS 4777 part 2 includes some smart inverter functions to self-manage voltage issues where possible. However, this functionality is not currently mandatory within the standard, which may continue to limit market penetration even once the updated standard is published.

7. Improved prediction of renewable generation, informed through dedicated metering, can improve EG integration by increasing the utilisation of assets such as storage and solar photovoltaic (PV)-controlled air conditioning. It can also inform decisions on power system unit commitment and network planning. These benefits can be broadened beyond EG to medium and large-scale generation.

8. Improved network load prediction techniques that incorporate increased penetration levels of EG are necessary to retain the current benefits of short, medium and long-term prediction of net load in a high-penetration EG environment. The prediction techniques also need to incorporate any other factors that may be contributing to changing utilisation patterns of electricity networks.

Options for Maximising Network Benefits

The findings described below summarise the key benefits of EG for networks and network operators: reduced operating and maintenance costs, and increased lifespan of network assets.

9. Utilising EG for power and voltage profile levelling reduces the operation of expensive peaking plants. It can also ease voltage management requirements, improve power system reliability and provide frequency support.
10. Insecure[4], non-dispatchable energy source types of EG alone (predominantly PV and wind) provide only limited power and voltage levelling and frequency support. Adding storage to these offsets the insecure, intermittent nature of PV and wind, and allows such EG to provide these services effectively.
11. EG can contribute to peak load reduction. This alleviates congestion, reduces line losses and results in deferral of equipment capacity upgrades where capacity is constrained.
12. Evidence from the literature and distribution network service providers suggests that the reduction in cumulative net load due to EG can extend the life of both substation and distribution transformers.

Australian Standards Gap Analysis

An analysis of the state of Australian Standards relating to EG identified the following key gaps:

13. Australian standards do not well cover the functionality and performance requirements of protection relays used to prevent islanding and reverse power flow relating to embedded generators. This reduces the consistency with which DNSPs can implement these devices, with significant flow-on effects for the market and other industry stakeholders. These effects include increased cost of development, implementation and

[4] 'Insecure' relates to the operational security of the generation unit: i.e., a diesel generator can be considered secure because it is generally dispatchable, while a solar PV system without storage is uncontrolled, and is hence insecure.

commissioning; increased cost and reduced consistency of type-testing; and potentially reduced performance and reliability in-situ.

14. There is a significant lack of standards relating to the integration and operation of electric vehicles (EVs), including vehicle-to-grid-enabled EVs. This may increase the risks and reduce the potential benefits associated with EVs by limiting the uptake of EV demand response and vehicle-to-grid systems, as well as reducing consistency of approach and increasing implementation costs.
15. Grid-connected stationary energy storage systems utilising emerging technologies including lithium-chemistry and zinc-bromine flow batteries, are not well standardised in Australia particularly in the areas of safe installation, operation and disposal. This will likely have an impact on consistency of approach between jurisdictions, with significant implications for the market and industry; it may also increase the likelihood of incidents relating to the improper use of these systems.

Key Regulatory and Commercial Findings

This section reviews the current regulatory framework as it relates to connecting EG to the network, the commercial impacts of EG, and the development of a commercial framework to value these impacts. It also assesses the commercial opportunities of EG available to NSPs.

The key findings are categorised below as either regulatory or commercial.

Key Regulatory Findings

The below findings include impacts that need addressing through a regulatory focus.

16. Although recent reforms to Chapter 5 and 5A of the National Energy Rules (NER) have improved the connection process related to EG, the lack of a consistent national framework means that these have not been adopted uniformly across all jurisdictions.
17. Where augmentation costs may occur because of high levels of small scale solar PV penetration on a network (i.e. basic connections), the NER does not allow for these costs to be recovered directly from the EG owners in a cost-reflective approach. Instead, these costs are recovered from the entire customer base which introduces an element of cross-subsidisation between customers.
18. Within the Demand Management Incentive Scheme (DMIS), Demand Management Innovation Allowance (DMIA), RIT-D and RIT-T processes networks have opportunities to consider and implement non-network solutions including EG to resolve network constraints in the most cost effective manner, however there are areas for improvement and potential for change as part of current regulatory reform initiatives.
19. Currently, there is no universally applicable and agreed regulatory model to value the impact of EG on networks. Networks require an appropriate valuation approach if they are to identify the costs and benefits of EG and to signal the efficient sizing, location and operation of EG. In addition, there is a gap in the current understanding of the impact of EG on network reliability, safety and quality of supply and an appropriate valuation approach is also needed to allow NSPs to identify these impacts.
20. Ring-fencing requirements for NSPs currently differ by jurisdiction and are generally seen as inadequate for the purposes of emerging markets and technologies. In particular

it is unclear how storage technologies are to be treated under the current ring-fencing requirements and how NSPs might support the efficient creation of microgrids[5] or standalone systems as an option for the most efficient approach to energy supply.

Key Commercial Findings

The below findings include impacts that need addressing through a commercial focus.

21. Current volume-based network pricing structures includes a cross-subsidy from non-EG owners to EG owners. The recent changes to the National Electricity Rules require networks to set prices that reflect the costs of providing electricity to consumers with different patterns of consumption. These tariffs are cost reflective and are not specific to the technology choices of customers (i.e. are 'technology neutral'). There is opportunity within these new rules to support the efficient uptake and use of EG that reduces future costs to customers to below the level they might reach under volume-based pricing structures.
22. Several of the potential commercial opportunities for networks to offer new products and services based on EG depend on the networks having cost-effective access to customer data and/or a direct channel to the customer. (e.g. in home EG and demand optimisation, residential storage). The proposed new metering rules present opportunities for NSP related entities to participate in new customer–oriented markets for metering and related services but they also create risks associated with potential new costs for data access and the loss of a traditional DNSP service.
23. Active involvement in the EG and energy services markets on the part of NSPs or their related entities as either a market participant or to simply incentivise the efficient use of EG for the benefit of all customers, will require developing partnerships with other stakeholders including technology service providers and retailers.
24. The NSP business model needs to evolve to facilitate the integration of multiple distributed energy resources, including EG. This could provide greater network capacity and energy diversity to optimise grid performance for both supply and demand.

Recommendations

These recommendations have been prepared for the consideration of the ENA and its members to act upon, particularly in future stages of the Network Transformation Roadmap initiative. They have also been prepared with the overarching principle of the National Electricity Objective in mind. That is, that investment in and operation of the network should maximise the efficiency of the electricity supply chain, allowing consumers to enjoy the quality, safety, reliability and security of supply that reflects their long-term interests, at the lowest cost. This should result in the efficient deployment and use of EG at times, locations and scales that reflect its value to the customer, community and network.

[5] A microgrid is defined as 'a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid-connected or "island" mode.' For the purposes of this report, this definition is extended to also include permanent island networks.

EG may benefit customers by delivering new energy services and supporting more efficient use of existing network infrastructure. However, increasing levels of EG on the network presents challenges for NSPs which would ultimately have cost or risk consequences for network customers if not managed appropriately. The challenge for networks, retailers, regulators, technology proponents and customer representatives alike is how to work together to develop business models and pricing structures that fairly apportion value and costs.

The recommendations presented here recognise the often diverse responsibilities and interests of stakeholder groups, and aim to align their actions for the benefit of customers.

The recommendations have been grouped into three key main categories:

- Enabling Technologies and Pricing — what are the key technologies likely to deliver future value, and how could they be incentivised?
- Enabling Business Models — how could the network of the future operate, and what regulatory changes should be implemented to promote this transition?
- Enabling Partnerships — what partnerships are likely to be required for network service providers to actively participate in the EG market?

Policy and regulatory options that support the recommendations are also provided below, as appropriate. Policy options relate to approaches that involve a change to existing government policy or to the general operational policies or approaches adopted by NSPs.

Enabling Technologies and Pricing

An appropriate valuation approach to capture all the costs and benefits of EG to networks should be developed and implemented in close consultation with stakeholders to enable effective signalling of the network value of EG to customers.

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG.
- Developing appropriate price signals to encourage efficient uptake of EG, reducing future network costs to below the level they might reach in the absence of EG uptake and thereby benefiting all customers. This could include:
    - discounting connection charges, network charges or providing direct payment, reflecting the costs and benefits available to the NSP, or
    - implementing price signals or incentives for customers to undertake efficient investment in storage, retrofit distributed inverters and to be appropriately rewarded for demand management.
- Using the valuation framework to manage the voltage regulation, power quality, reliability and safety impacts of EG on the network. This could, for example, support the

strategic deployment of medium-scale power electronics solutions, such as STATCOMS, at locations where they may be the least-cost solution to help manage power quality issues.

***Support the implementation of cost-reflective network price signals that promote uptake of EG in ways that are beneficial to all customers*.**

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Supporting a national approach to cost-reflective pricing that removes inconsistent jurisdictional obligations on tariff structures and assignment.
- Supporting the implementation of a balanced framework for the uptake of smart meters for the fastest economic roll out to benefit all customers.
- Encouraging adoption of technologies that support efficient pricing and customers' ability to access data and manage their demand (e.g. in-home displays, apps, data portals).
- Working closely with retailers, technology proponents and metering service providers to bundle products and tariffs to optimise value for customers and simplify product offerings while supporting efficient network outcomes.

***Support incentives and policies that promote innovation and commercialisation in relation to energy storage technologies in ways that enhance the efficient use of the network for the benefit of all customers*.**

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Identifying and supporting opportunities to restructure current incentives and subsidies so that they can support technologies and services that result in more efficient use of the network for the benefit of all customers (for example, restructuring premium feed-in-tariffs to enable customer to choose to use these subsidies to install storage solutions which support lower peak demand and reduced network expenditure).
- Working with the industry and regulators to build on the principles of the Demand Management Innovation Allowance to enhance the industry's ability to support research and development activities that support innovation and integration of new technologies, and ultimately create a more efficient network for the benefit of customers.
- Investigating opportunities for the development of cost-effective policies and incentives (such as model availability requirements and fuel standards) supporting EV uptake, where it promotes efficient use of the network for the benefit of customers.

***Support the development of appropriate standards that facilitate the safe integration of EG on the network*.**

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Supporting the development of a new Australian Standard to manage the functionality of protection relays for inverter energy systems.

- Revisiting the development of standards such as AS/NZS 4755 Part 3.4, or facilitating the local acceptance of a similar international standard for managing EV charging and discharging.
- Supporting the development of standards relating to the safety of small-scale and large/grid-scale energy storage systems. Focus should be directed to those addressing safe installation/operation and fire protection. In addition, lithium chemistry may require particular attention, because its standards are immature.

Enabling Business Models

There should be no inherent advantage or disadvantage for network service providers in competing to provide services and pursuing commercial opportunities related to EG.

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Supporting changes to current state-based ring-fencing rules to create a national framework with the overarching principle to ensure no market participant is unnecessarily constrained in a competitive environment with regard to providing services to customers.
- Supporting the removal of state-based rules barring or limiting network providers' ability to own and operate EG (for the purpose of network support).
- Ensuring that they are free to enter into direct commercially based trading relationships with customers and that NSP's related entities should not be restricted from providing energy selling services to customers, where they meet appropriate ring-fencing requirements.
- Supporting a review of relevant rules to ensure no barriers exist to the creation, operation and maintenance of microgrids or standalone systems by networks as an option for the most efficient approach to energy supply.

There should be no inherent advantage or disadvantage for network service providers to utilise EG for network purposes compared with network upgrades.

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Working with the industry and regulators to identify where there may still be a disadvantage for network providers to utilise EG for network purposes compared with network upgrades. NSPs could then build on the recent reforms to the Demand Management Incentive Scheme to ensure that any disadvantages for NSPs using EG in this way is addressed.

Support the evolution of the network provider business model to include that of the grid integrator — efficiently and effectively integrating multiple distributed energy resources, including EG.

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Propose that in future market arrangements, the NSP can coordinate the day-to-day operation of multiple sources and types of EG and other distributed energy resources, where this provides the most cost-effective option for the customer.

Enabling Partnerships

Network providers should work towards developing partnerships with relevant energy service providers to promote sustainable and efficient uptake and operation of EG.

Policy and regulatory options that could be considered in future stages of the Network Transformation Roadmap to support this recommendation include NSPs:

- Removing knowledge and organisational barriers to cooperation between NSPs, technology providers and retailers to offer bundled products.
- Reviewing the current regulatory framework to determine its suitability for a more customer-oriented electricity market. This should include assessing its flexibility to adapt to an increasingly complex market as a result of the adoption of new technologies and the changing priorities of customers.

Critical Further Work

This report has proposed elements of a high-level framework to value the impact of EG on the network. Integrating the valuation framework into the regulatory framework would require the Australian Energy Market Commission to initiate a rule change proposal, and further work should include initiating or supporting this process. Such work would include improving and solidifying the valuation framework put forward in this report, with the ultimate goal of capturing all the costs and benefits relating to EG.

Once a robust valuation framework is implemented, it could be used to develop appropriate price signals to encourage the efficient uptake of EG and minimise future network costs for customers. It could also be used to determine where current subsidies and incentives could be restructured and redirected towards technologies and services that support efficient use of the network. A single solution is unlikely to be suitable for all jurisdictions. Further work should therefore focus on research and modelling to understand appropriate approaches for each jurisdiction’s circumstances.

We have also identified a lack of relevant Australian Standards for certain types of EG. Given the potential benefits to customers and NSPs alike from small-scale energy storage, further work should support the development of standards for the safe installation, operation and control of such EG systems.

Abbreviations used in this report

AC	alternating current
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	automatic generation control
AEP	American Electric Power
BES	battery energy storage
BESS	battery energy storage system
BEV	battery electric vehicle
CAES	compressed air energy storage
CAIDI	Customer Average Interruption Duration Index
CBD	central business district
CEC	Clean Energy Council
CES	community energy storage
CHP	combined heat and power units
CSO	community service obligation
CSP	concentrating solar power
CST	concentrating solar thermal
DC	direct current
DER	distributed energy resources
DFIG	doubly fed induction generator
DG	distributed generation
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	distribution network service provider
DR	demand response
DRED	demand response enabling device
DRM	demand response mode
DSTATCOM	distributed static synchronous compensator
DTx	distribution transformer
DUOS	distribution use of system
EG	embedded generation
EHV	extra high voltage
ENA	Energy Networks Association
ENSTO-E	The European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FFT	fast Fourier transform

GW	gigawatt
HESS	hybrid energy storage system
HV	high voltage
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
kVA	kilo-volt ampere
LOL	loss-of-life
LSCPV	large-scale centralised photovoltaic
LV	low voltage
MAIFI	Momentary Average Interruption Frequency Index
MHC	Marchment Hill Consulting
MT	microturbine
MV	medium voltage
MVA	mega-volt ampere
MW	megawatt
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
NPV	net present value
NSP	network service provider
OAF	overambient flicker
OLTC	on-load tap changer
OpenADR	Open Automated Demand Response
PCC	point of common coupling
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PHS	pumped hydroelectric storage
pu	per unit
PV	photovoltaic
RAB	regulatory asset base
RIIO	Regulation = Incentives + Innovation + Outputs
RIT-D	Regulatory Investment Test for Distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCB	supercapacitor bank
SMES	superconducting magnetic energy storage
STATCOM	static synchronous compensator
SVC	static VAR compensator
SVR	step voltage regulator
SWER	single-wire earth return
SWIS	South West Interconnected System
THD	total harmonic distortion
UPS	uninterruptible power supplies
US	United States
V2G	vehicle-to-grid
VAR	volt-amps reactive
VCR	value of customer reliability

VRB	vanadium redox battery
XP-DPR	Xtreme Power-Dynamic Power Resource
X/R ratio	ratio of reactance to resistance

1 Background

Over the last five years, solar photovoltaic (PV) systems have emerged as a viable alternative source for household energy supply. This has been driven by government incentives and a sharp increase in manufacturing capacity to reduce costs.

The historical uptake of solar PV in Australia is presented in Figure 1.

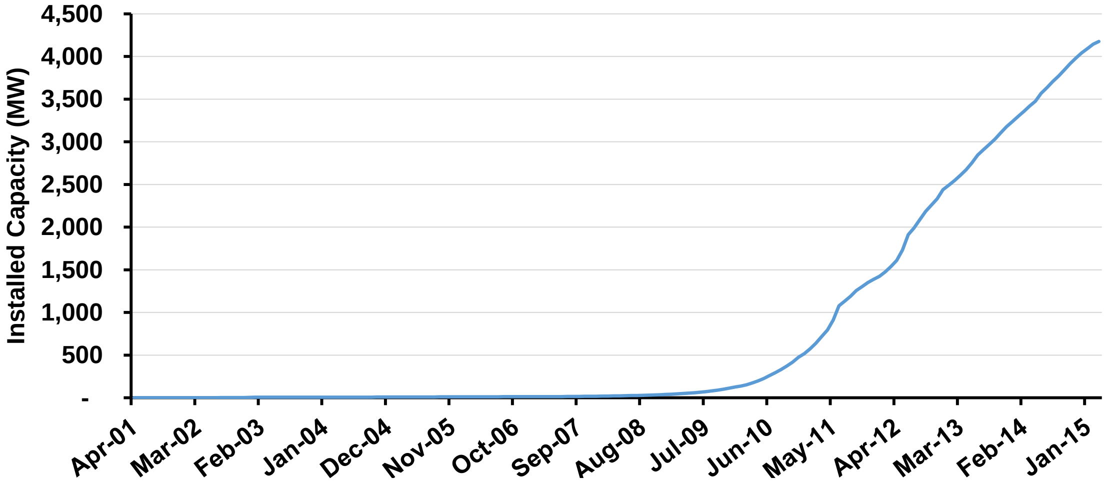

Figure 1 – Australia's historical solar photovoltaic uptake, April 2001 to January 2015

Source: Australian PV Institute

The relatively generous, state-based feed-in tariffs (FiTs) that were offered in the past have now been reduced to below $0.10/kWh in all states. Nevertheless, solar PV uptake has remained strong and is generally forecast to grow at a steady pace. This is at least partially driven by the emergence of new solar PV business models that focus on making solar PV more accessible to consumers, such as solar financing with no upfront costs or residential solar power purchase agreements via alternate energy sellers.

The increasing penetration of solar PV is starting to pose several challenges for Australian network service providers (NSPs). One is maintaining a reliable and safe electricity supply while managing high levels of embedded generation (EG) penetration on their network. Another is an erosion of NSP customer grid-supplied electricity consumption, and subsequent cross-subsidisation from non-solar PV customers to solar PV owners. Recent reforms to introduce cost-reflective network pricing could partly address the impacts on cross-subsidisation, but may take some time to implement effectively.

EG connection and operation is regulated under the National Energy Rules, as well as different state-specific legislation and guidelines. The cost and duration of the connection process affects the investment decisions of EG proponents and their expected return on investment. It also poses challenges for NSPs in providing timely information and connection services while managing their networks in a safe, secure and reliable manner. Recent regulatory reforms[6,7] have been introduced to make the connection process more transparent and streamlined.

Despite these challenges, EG provides NSPs with commercial opportunities. For example, certain EG technologies, if managed properly, could be used to reduce stress on the network during peak times, which would defer augmentation investments and improve network reliability and quality of supply.

This report will review the current technical, regulatory and commercial impacts of EG to provide an overview of the commercial opportunities available to NSPs. It also proposes a valuation framework that can be used to gain a better understanding of the true impacts of EG on the network. This will enable the design of appropriate pricing and incentive mechanisms to promote future, efficient EG uptake.

[6] Australia Energy Market Commission, *Rule Determination [ERC0147] – National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014

[7] Australian Energy Market Commission, *Rule Determination [ERC0158] - National Electricity Amendment (Connecting Embedded Generators Under Chapter 5A) Rule 2014*, 13 November 2014

2 Scope and approach

2.1 Scope

The scope of this report includes:

- Investigating and assessing the impacts of the continued growth in embedded generation (EG) for Australian distribution and transmission[8] networks. This includes the
    - technical impacts of connection, including planning, design, operation and maintenance of networks
    - technical issues for customers to establish and manage a connection to the distribution network
    - regulatory impacts of connection, including the robustness of current regulatory instruments in meeting distribution network and customer needs in facilitating safe connection of EG
    - cost of facilitating connection, and how these costs should be recovered
    - commercial impacts of connection, including the development of a high-level commercial framework to value EG and an assessment of commercial opportunities for network service providers (NSPs) arising from EG.
- Identifying policy and regulatory options that the Energy Networks Association (ENA) should consider in response to these impacts, to ensure the safe, reliable and efficient operation of the electricity network in the long-term interests of customers.

2.2 Approach

In preparing this report, Marchment Hill Consulting and CSIRO have:

- reviewed the relevant literature
- surveyed ENA member organisations
- interviewed key stakeholders from ENA member organisations
- held workshops with ENA members, and incorporated their feedback in document reviews.

For the technical section, the literature review targeted the existing state of play of EG in Australian networks, and was also informed by the international context. This was then expanded to look at the likely development of the EG space over the next 5, 10 and 20-year timeframes, referencing relevant literature as well as real-world trials, and reflecting ongoing modelling and technology development.

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[8] As the definition of an embedded generating unit is 'a unit that generates electricity at a customer's premises and is connected to a distribution system', we understand that impact assessment will primarily focus on impacts relating to low-voltage and medium-voltage distribution networks. The exception to this is in relation to the upstream impacts on the transmission network caused by EG connected to the distribution network.

For the regulatory and commercial sections, the literature review was designed to inform the picture of the current regulatory framework in Australia relating to EG connection. Further research formed the international and Australian context for commercial frameworks to value the impact of EG and the commercial opportunities for NSPs.

The literature review further guided the development of the survey distributed to ENA members. The survey gathered views of ENA members about their experience of the technical, regulatory and commercial impacts of EG on the network. Details of the survey respondents and interviewees are in Appendix A – Survey responses.Following the survey, five interviews were undertaken with ENA members to gather more in-depth insights into the impact of EG.

A workshop was also held with ENA members to test initial hypotheses and project findings and to generate additional ideas for further work. All sections of the report were distributed to the ENA and its member organisations for review and feedback. A second workshop was held with ENA members to discuss the findings and recommendations of the draft report and to collect final feedback before completing the final report.

2.3 Document maps

Given the breadth and complexity of the report's findings, each section includes a concise document map to highlight their significance and relevance to different network types. A brief introduction to the icons used throughout is provided on the following page.

Document map key

The impact, constraint, mitigation option or opportunity applies at the customer premises.

The impact, constraint, mitigation option or opportunity is relevant for the low-voltage distribution network.

The impact, constraint, mitigation option or opportunity is relevant for the medium-voltage distribution network.

The impact, constraint, mitigation option or opportunity is relevant for the high-voltage transmission network.

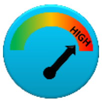
The impact, constraint, mitigation option or opportunity is relevant for networks with typically high impedance and limited interconnection. These networks are most often rural.

The impact, constraint, mitigation option or opportunity is relevant for networks with typically low impedance and greater interconnection. These networks are most often urban.

The impact, constraint, mitigation option or opportunity is relevant for microgrids, where there is no connection to the wider grid or there is capacity for sustained, independent, islanded operation.

The impact, constraint, mitigation option or opportunity is of low significance given its probable effect on network performance or business operation.

The impact, constraint, mitigation option or opportunity is of moderate significance given its probable effect on network performance or business operation.



The impact, constraint, mitigation option or opportunity is of high significance given its probable effect on network performance or business operation.

The impact, constraint, mitigation option or opportunity is likely to be highly relevant to networks in the near term, probably within the next few years.

The impact, constraint, mitigation option or opportunity is likely to be highly relevant to networks in the medium term, probably within the next 5—10 years.

The impact, constraint, mitigation option or opportunity is unlikely to be relevant to networks in the near or medium term.

3 Technical impact assessment

Note on authorship

This section was written by CSIRO and reviewed by Marchment Hill Consulting to highlight links to the commercial and regulatory implications that relate to the findings of this chapter.

3.1 Introduction

The role of embedded generation (EG) in the Australian electricity sector has grown dramatically over the last decade, driven by falling technology costs and rising electricity prices. With aggressive storage price projections, and Australia's probable move towards more cost-reflective pricing in the future, the value proposition for EG looks set to grow further in coming years.

This presents both an opportunity and a challenge for Australia's network providers. The system is moving ever more rapidly from a predominantly one-way bulk energy transport system to one of distributed generation and bidirectional power flows, including intermittent renewable generation. The demand-side also represents an increasingly strong participant.

This chapter explores both sides of this potentially dramatic shift. It catalogues the key technical constraints and issues that may dampen enthusiasm for the change, but also captures the very real benefits that may be delivered if suitable mitigation strategies are embraced and appropriate standards deployed. The work draws extensively on more than 200 references to unify and summarise findings from academic studies, industrial trials and Australian standards. The result may not always deliver clean answers for a still-emerging field, but it does provide the rich context and contemporary insight necessary for considered decision making.

The chapter has four main sections, each summarising key technical findings drawn from the literature:

- The Technical Constraints and Network Impacts section highlights the prevailing and impending issues that may limit the value proposition of EG for Australian networks.
- The Options for Mitigating Network Impacts and Risks section explores the relevant strategies for addressing such issues, drawing on theoretical and practical studies to assess the early strides that have been made.
- The Options for Maximising Network Benefits section underlines the potential for EG to deliver meaningful value in the Australian context, illustrating that effectively managed systems should be viewed as a genuine opportunity.
- The Australian Standards Gap Analysis highlights the rich suite of standards relevant to EG and identifies where further refinement, modification or addition may aid in the delivery of optimal EG performance.

While we consider the implementation cost of EG options in broad terms, this is not a focus of this chapter. The commercial impacts of EG (both positive and negative) are covered in greater detail in Chapter 5.

3.2 Technical constraints and network impacts

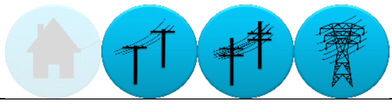
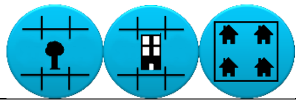
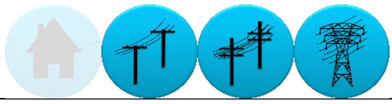
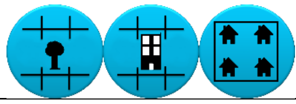
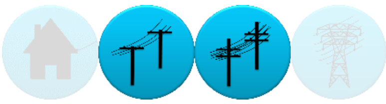
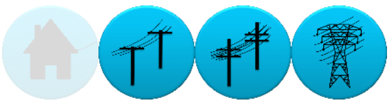
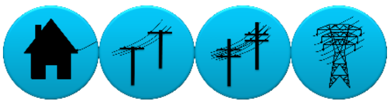
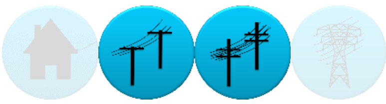
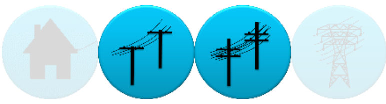
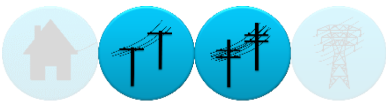
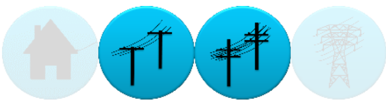
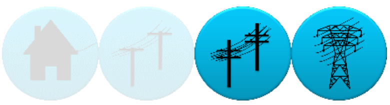
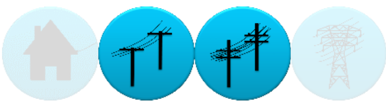
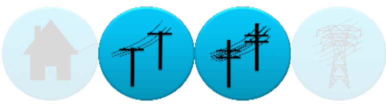
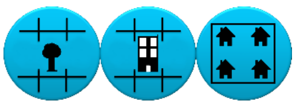
3.2.1 Introduction

Though EG presents an exciting opportunity for network and consumers alike, it also promises a new set of constraints, challenges and issues that must be better understood and proactively addressed.

This chapter reviews academic literature and trial findings to highlight the hurdles that may inhibit the potential of EG for the Australian energy sector, with a focus on power quality, protection, network stability and power regulation impacts.

The document map presented across the following two pages provides a précis of the key issues identified within this chapter and summarises where, when and how significantly the impact may be felt. Taken together, the impact and timing indicators provide a preliminary assessment of risk. For readers interested in only those constraints and impacts that apply for particular network types, or only those issues that are considered most pressing, the map will guide you to the most relevant sections of this chapter.

Document map

Technical constraint or issue	Network level	Network type	Impact	Timing	Chapter section
Power regulation (energy balance)			MEDIUM	MED TERM	3.2.2.1
Power regulation (ramp rates)			MEDIUM	MED TERM	3.2.2.2
Power regulation (thermal loading)			MEDIUM	MED TERM	3.2.2.3
Power regulation (losses)			LOW	MED TERM	3.2.2.4
Power regulation (load prediction)			MEDIUM	NEAR TERM	3.2.2.5
Power regulation (bidirectional power flow)			MEDIUM	NEAR TERM	3.2.2.6
Protection (network fault currents)			MEDIUM	NEAR TERM	3.2.3.1
Protection (network fault level)			MEDIUM	NEAR TERM	3.2.3.1
Protection (fault current limits for microgrids)			MEDIUM	MED TERM	3.2.3.1
Protection (fault detection in self-islanding microgrids)			MEDIUM	LONG TERM	3.2.3.1
Protection (bidirectional power flow)			MEDIUM	MED TERM	3.2.3.2
Protection (unintentional islanding)			MEDIUM	MED TERM	3.2.3.3
Protection (impedance relay operation)			LOW	NEAR TERM	3.2.3.4

Technical constraint or issue	Network level	Network type	Impact	Timing	Chapter section
Network stability (power station voltage stability)			MEDIUM	MED TERM	3.2.4.1
Network stability (power station frequency and rotor angle stability)			MEDIUM	MED TERM	3.2.4.1
Network stability (circulating reactive power)			LOW	MED TERM	3.2.4.2
Power quality (voltage intermittency and voltage rise)			MEDIUM	MED TERM	3.2.5.1
Power quality (voltage imbalance)			LOW	NEAR TERM	3.2.5.2
Power quality (voltage flicker)			LOW	MED TERM	3.2.5.3
Power quality (harmonics)			LOW	NEAR TERM	3.2.5.4
Power quality (voltage regulation)			MEDIUM	MED TERM	3.2.5.5

3.2.2 Power regulation

What is it?

Power system regulation is a collection of services that adapt in real or near real time to unanticipated system changes. Such services include automatic generation control, frequency droop and voltage regulation.

What role does embedded generation have?

The need for generation to occur at the time of use — coupled with constant and often unpredictable changes in demand — makes electricity supply systems large, dynamic and complex, and their regulation a challenging task. Historically, distribution networks have been regarded as a passive termination of the transmission network, having the goal of supplying end users reliably and efficiently. The mix of a greater penetration of EG in electricity networks will likely result in a gradual, but inevitable, change of distribution networks towards a new kind of active network. The requirement for power regulation is increasing, due to a larger proportion of the electricity supply consisting of variable and unpredictable EG.

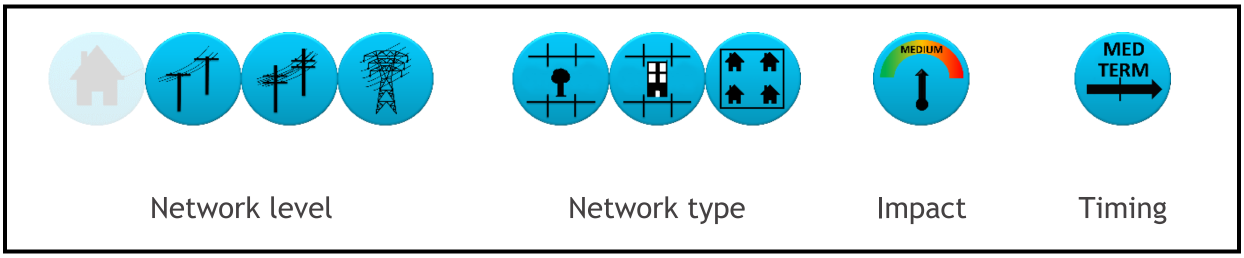
Why does it matter to Australian network operators?

Australia has seen a significant increase in the capacity of EG in the last few years. This is a continuing trend, driven by factors such as government incentives, increased electricity costs and reduced manufacturing costs of EG systems. An example of this can be seen for the increased rate of solar photovoltaic (PV) capacity in Australia, as shown earlier in Figure 1.

When assessing the impacts of increased EG penetration, the key aspects requiring consideration include voltage profiles, regulation, electrical losses, power factor, capacity planning, power quality, system operations and protection. A core operational and market function of electricity network operators is to forecast system load, and then to ensure that sufficient generation and non-generation resources are committed such that intra-hourly deviations can be accommodated by those resources. These deviations can take place in the upward or downward direction, and are currently largely caused by changes in load. With increased penetration levels of variable EG sources, the net load-following requirement could increase substantially in certain hours, due to the variability and forecast uncertainty of wind and solar production.

The remainder of this section provides background information about the impacts of increased EG on regulation aspects of energy balance, ramp rates, thermal loading, losses, load prediction and bidirectional power flow: all of which are becoming more dynamic, instead of being limited to a single, peak-demand-driven constraint.

3.2.2.1 Energy balance



In any power system, there has to be a reliable continuous balance between production and consumption, and enough resources must be available to counterbalance changes in production and consumption (i.e. load demand). This balance of energy production and consumption is known as the energy balance.

Historically, conventional generation sources, such as coal or gas-fired power stations, have been controllable, dispatchable and large-scale, with a dynamic wholesale market driving least-cost and reliable supply of electricity. Each generation unit is dispatched and scheduled according to its heat rate, fuel cost and availability, associated transmission losses and output ramp rate, with the goal of reliably satisfying electricity demand at the lowest possible cost [21] .

The availability and quantity of electricity produced by conventional generation sources can be controlled by system operators, together with the generators' governors and electricity system-wide automatic generator control (AGC) system or similar. This stands in sharp contrast to solar and wind outputs, in which weather variations may lead to highly intermittent generation. The inclusion of such technologies means that conventional generators must follow not only the usual demand variations, but also account for the output variations caused by intermittent generation.

Five normal functions of generation operations that could be impacted are: load-frequency control, load following, ramping rate, unloadable generation and operating reserve.

Load-frequency control

The amount of load and generation at any given time needs to be matched to maintain the system frequency at the desired level (50 Hz in Australia). When load exceeds generation, the system frequency will drop. When a change in the system frequency is detected, power system operators and AGC/governor interactions will increase or decrease the output of conventional generators to match the load.

Intermittent renewable generation technologies generally cannot participate in these system frequency regulations, because their output is already maximised based on available renewable resource. Output control is therefore typically limited to curtailment. Thus, as the penetration of renewable EG systems increase, the capacity to efficiently manage system frequency decreases. The current draft of AS/NZS 4777 Part 2 supports this in compliant inverters.

Load following

If an increase in solar or wind power is not coincident with the system load increase, other generating units in the system will have to be offloaded to absorb all the solar or wind power. When solar or wind power production falls, the output from other units will have to increase to take up the generation slack. Utilities normally use intermediate plants to follow the load. The integration of high-penetration, intermittent EG may therefore increase load-following duties for the conventional generators assigned for system regulation.

Ramping rate

Ramping rate represents the generator's ability to change its output over time. The ramping rate of online generators may need to be increased to follow the sharper system load changes brought about by increased intermittent generation. Some conventional generators may not be used if they cannot operate at higher ramp rates; for those can, the increased ramp-rate requirement may reduce equipment life or decrease operation efficiency. The increased ramp rate requirement may necessitate more online peaking plants, which could raise wholesale electricity prices.

Unloadable generation

The down-ramping rate of a generator may differ from its up-ramping rate, both of which are important to meet the normal system load-following requirement. The amount of generation that can be offloaded (down-ramped) is called unloadable generation. To accommodate the maximum output from intermittent generating technologies, system operators have to make certain that online conventional generators can be backed down quickly enough: particularly when simultaneously facing a sudden increase of intermittent generation output and a system load increase. Such an accommodation to absorb energy from intermittent generation cannot be made by tripping off a unit, because it may be needed again shortly after being taken offline [22] . Note that this can be readily achieved by curtailing the intermittent generator.

Operating reserve

The impact on the electric system operating reserve is also related to the intermittency of solar and wind generation technologies. Utilities carry operating reserve to guard against sudden loss of generation and unexpected load fluctuations. Any load and generation variations that cannot be forecast have to be considered when determining the amount of operating reserve. If utilities cannot predict the short-term fluctuations of intermittent renewable generation sources, more operating reserves must be scheduled to adequately regulate the system. This requirement will increase the cost of integrating intermittent EG sources such as solar and wind [22] .

Together, the above five impacts imply that more units may need to be brought online or put on regulating duty, which may increase system operating costs. Conventional generators may be forced to be more flexible, with their output resulting in a higher per unit cost. Adequate system flexibility is a key requirement for managing increased levels of EG on the electricity network.

Several studies have looked at the likely impacts of increased levels of intermittent, renewables-based EG. A study that modelled net load (total load minus EG output) for different penetration levels of solar PV in the California Independent System Operator network showed significant impact on minimum net load [23] . The load duration curve shown in Figure 2 shows original (without solar PV) net load and the predicted impact of incorporating solar PV at 10, 30 and 50% penetration levels. Some reduction in peak demand is seen (far left), and the 30 and 50% penetration scenarios have a large impact on minimum net load. This may affect the generation portfolio by either driving down generation loading or reducing generation run-times. Both of these affect plant efficiencies and equipment lifetimes, and ultimately, economic viability. Potential mothballing of systems here would fundamentally affect the capacity and flexibility of the generation mix.

As an example, the standard United States fuel mix has a large proportion of coal-fired generation. The rate of power change of coal-fired generation is largely limited by thermal inertia and unit-specific, fuel-system limitations. This makes them less flexible than gas-fired generation, for example. If the 30% solar PV penetration load duration curve is used for the United States fuel mix, an incursion into coal-fired generation occurs as shown in Figure 3. This then raises questions of generation flexibility, and how coal-fired generation will manage requirements to reduce output and allow further integration of EG. One potential response is to replace cheaper, less flexible plants with expensive, more flexible plants [23] . The Australian fuel mix for electricity generation in Figure 4 [25] shows that about 70% of all electricity generated comes from coal-fired generation. Therefore, the same requirements for the United States fuel mix scenario may apply in Australia. Note that the Australian fuel mix for electricity generation in Figure 4 does not include EG or non-grid private generation, but includes generation from semi-scheduled and large, non-scheduled intermittent generators.

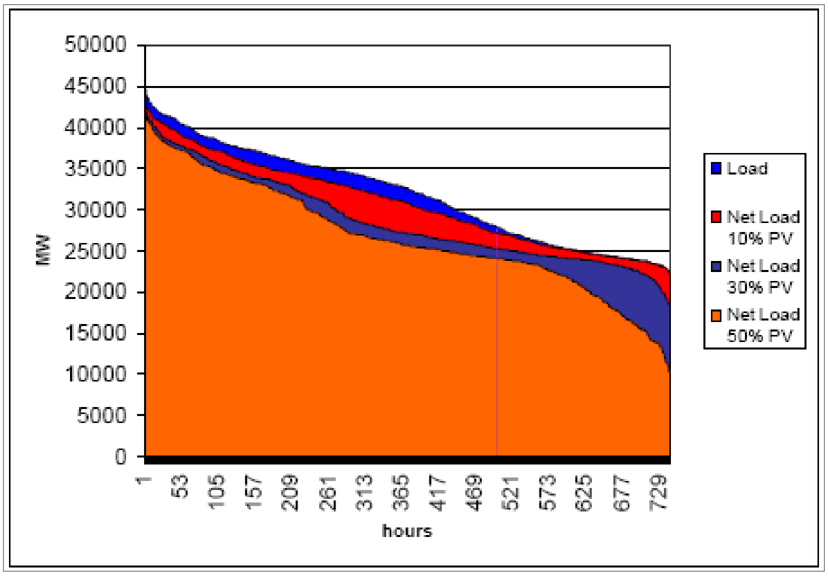


Figure 2 – Predicted load duration curve, California Independent System Operator July 2007, with 10, 30 and 50% solar photovoltaic penetration [23]

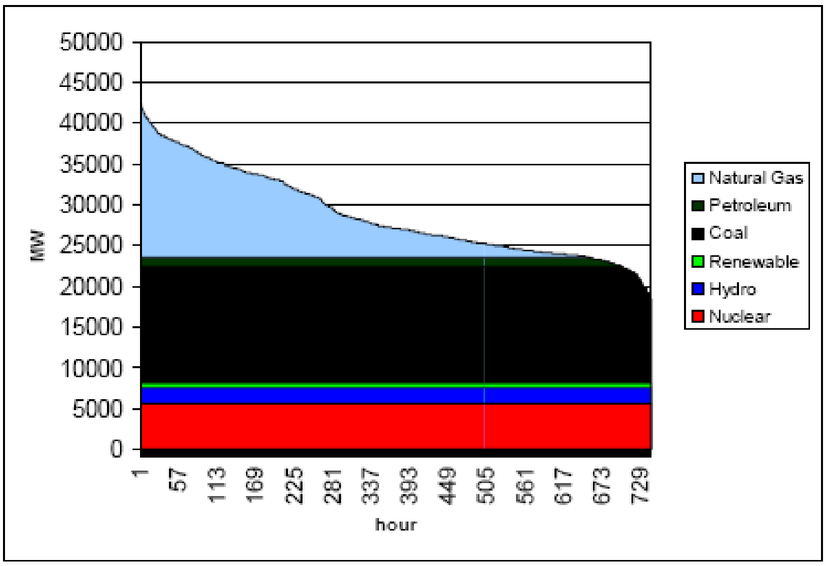


Figure 3 – Dispatch order for United States fuel mix with 30% solar photovoltaic penetration [23]

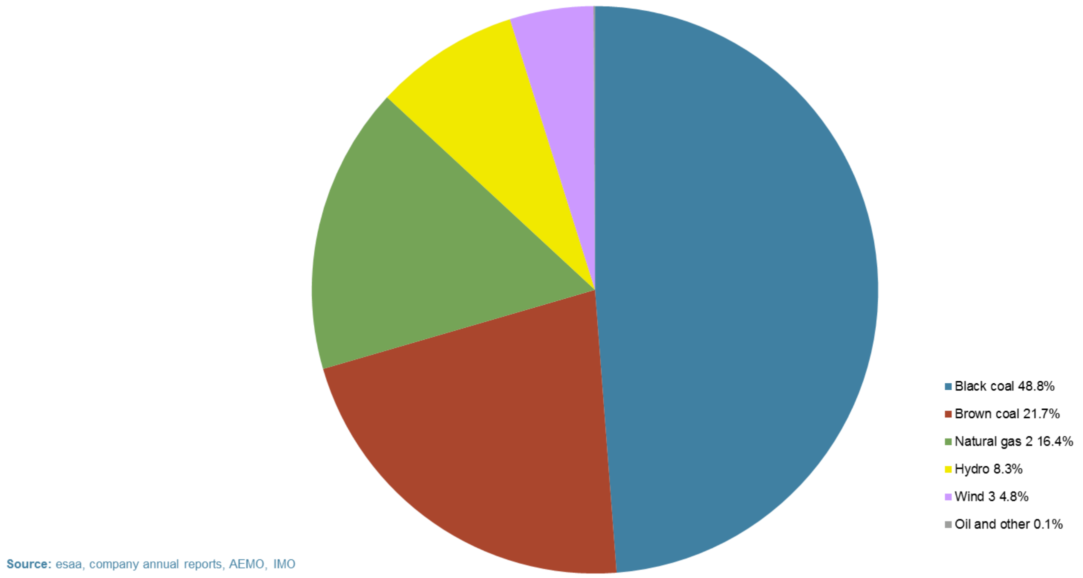
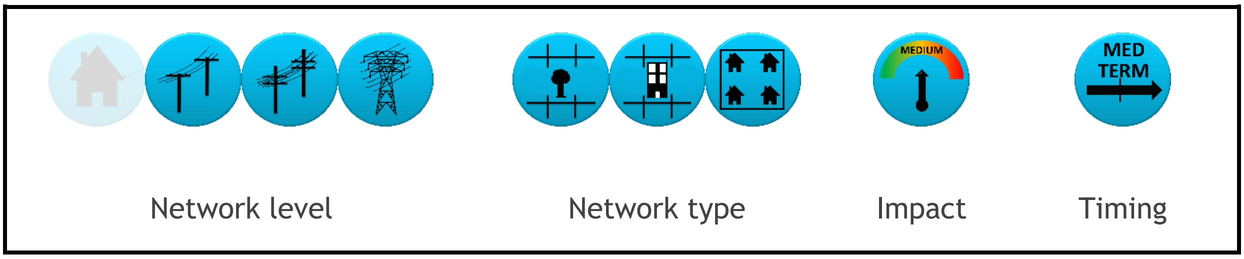


Figure 4 – Principal electricity generation in Australia by fuel type, 2013—2014 [25] (Reproduced courtesy of the Energy Supply Association of Australia)

3.2.2.2 Ramp-rates compared with conventional generation



Ramp rates of conventional generation, which are a potential impact caused by increased levels of EG, were briefly discussed in Section 3.2.2.1. They are covered in more detail in this section, including discussion of increased variability in load when intermittent, renewable-based EG is integrated.

At a high penetration level, the ramp rate of intermittent EG output can cause adverse impacts on an electricity network. One of the main challenges to the power system is correlated to the instantaneous penetration of intermittent EG: that is, the fraction of total system load provided by the EG source at a given instant in time [22] . Several studies have looked into net load with varying penetration levels of intermittent EG [22] and investigated net load variability due to solar generation. Solar generation is viewed as negative load. When it is combined with the system load, it yields a net load corresponding to the power that must be supplied by other sources in the system. When load demand and solar power are both increasing or decreasing coincidentally, the need for other generation sources to vary their output will decrease. However, when load and solar power move in opposite directions at the same time (e.g. when load is decreasing, while solar power output is increasing), the large variation in output level required may significantly affect the operation and performance of traditional generation plants.

The existing electricity system already incorporates significant variability in load demand. This is managed through generator dispatch and ancillary service mechanisms. However, as the penetration levels of intermittent EG increase, further measures may be required (e.g. additional ancillary services). A study on the net load variability in the Californian grid was reported in [24] . In this study, hourly change in total load (delta) for load-only and net load (i.e. load minus renewable generation) was analysed for a model of the Californian grid assuming 33% penetration of renewable energy: in this case, wind and solar. Figure 5 illustrates the hourly change for different loading conditions, with the data split into deciles. The first decile is a measurement of delta when load is between 90 and 100% of peak load (top 10% of peak-load hours), while the 10th decile is a measurement of delta for loads up to 10% of peak load. The thin lines above and below the bars represent the standard deviation of the positive and negative deltas, respectively. Incorporation of renewables increases the hourly net load variability across the majority of deciles. For example, the standard deviation of net load variability in the 10th decile increases by 47% with the integration of 33% renewable energy.

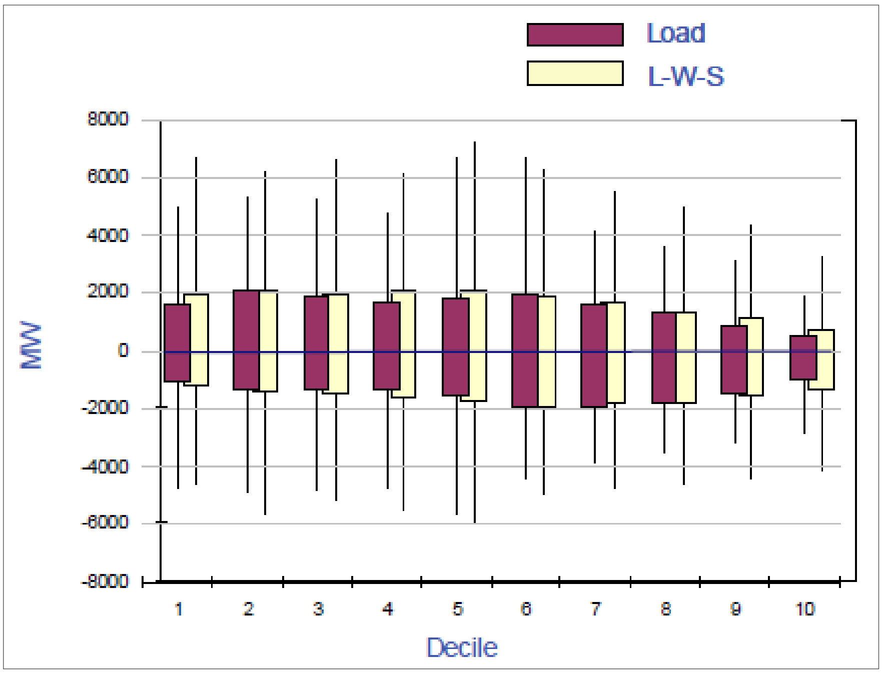


Figure 5 – Predicted hourly net load variability in the Californian grid with 33% renewable penetration. (L-W-S = load minus wind minus solar) [24] (Reproduced courtesy of the California Energy Commission)

This analysis was taken further to examine the net load variability for each hour of the day, the distribution of which is shown in Figure 6. At 6:00 am, the maximum and minimum deltas are similar, but the average hourly variation increases from 2000 to 2500 MW when incorporating 33% penetration of renewables. During the afternoon peak hours, the averages are similar, but the maximum and minimum deltas are significantly larger for net load with solar and wind energy integrated. The standard deviation is also noticeably larger for net load, increasing from approximately 1300 to 1600 MW (about 23%).

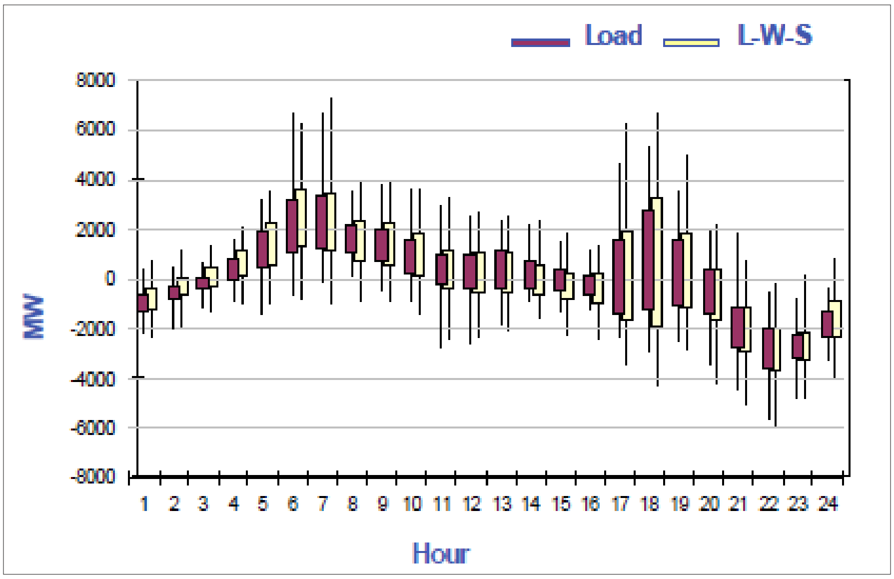


Figure 6 – Hourly net load variability by hour of day. (L-W-S = load minus wind minus solar) [24] (Reproduced courtesy of the California Energy Commission)

A recent study [26] investigated the impacts of solar radiation variability on PV power output in the existing Alice Springs electricity network. The aim was to obtain an estimate for the maximum penetration of grid-connected solar power generation that could be integrated without energy storage. The study took into account existing power stations, both conventional and renewables-based, and aggregate load on the Alice Springs network.

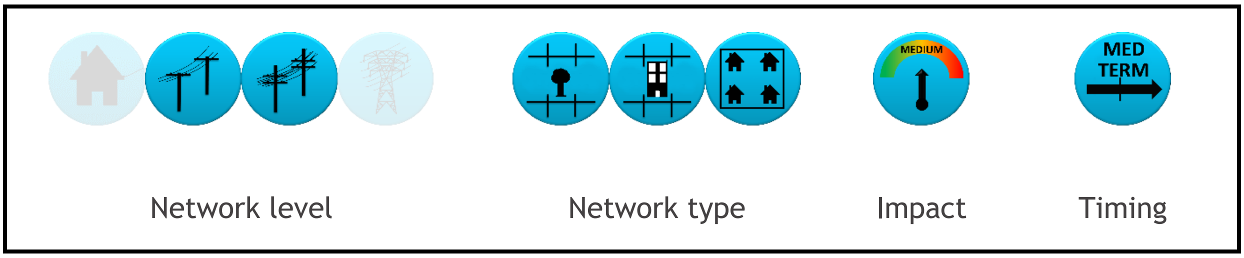
The load demand in Alice Springs varies substantially across the year, with daytime maxima ranging from 27 MW (winter peak) to 51.5 MW (summer peak), and the minima ranging from 18 MW (winter low point) to 23.2 MW (summer low point). Alice Springs has three main centralised power stations, incorporating 19 dual-fuel gas/diesel generators with a combined generation capacity of approximately 100 MW. Existing installed solar PV capacity is around 4 MW, and consists of residential and commercial systems as well as a 1-MW PV plant. The net load variability for the whole Alice Springs network was modelled for three different scenarios:

- existing load demand with 10-MW single PV array
- existing load demand with three sets of 3.3-MW PV arrays
- existing load demand with nine units of 1.1-MW PV arrays.

The net load variability was the highest for the single 10-MW PV array scenario, which was significantly reduced for the nine units of 1.1-MW PV arrays scenario, due to the geographical dispersion of the PV arrays. The study found that the level of variance for the single 10-MW plant was more than four times that of nine units of 1.1-MW plants separated geographically around Alice Springs, and that the ratio was very similar for January (maximum load) and September 2014 (minimum load). The study was carried out in the context of the entire Alice Springs network, and localised network impacts of EG due to other grid constraints, voltage rise and frequency stability were not investigated. Another study [27] reported observations of close to 1-MW net load variability in Alice Springs (installed solar PV capacity of 2.1 MW) over periods of minutes due to cloud-movement-induced solar PV fluctuations.

To avoid any adverse impact on network operation, we conclude that the increased net load variability caused by higher penetration of intermittent EG must be taken into consideration and investigated further for network planning and design.

3.2.2.3 Thermal loading



Most equipment in an electric power system has a thermal limit. The thermal limit can be defined as a limit on the power carried by an electric power system that results from the heating effects of the power carried by the devices.

Ageing network assets, along with increased accommodation of intermittent EG, can potentially increase system stresses in active distribution networks. Traditional security assessment incorporates deterministic (static) thermal limits of assets, which limit the extraction of hidden impacts of variations in thermal capacities. Because dynamic thermal limits and variations in weather conditions are aperiodic (irregular) events, their detailed modelling is beneficial for determining the latent capacity of an active distribution network.

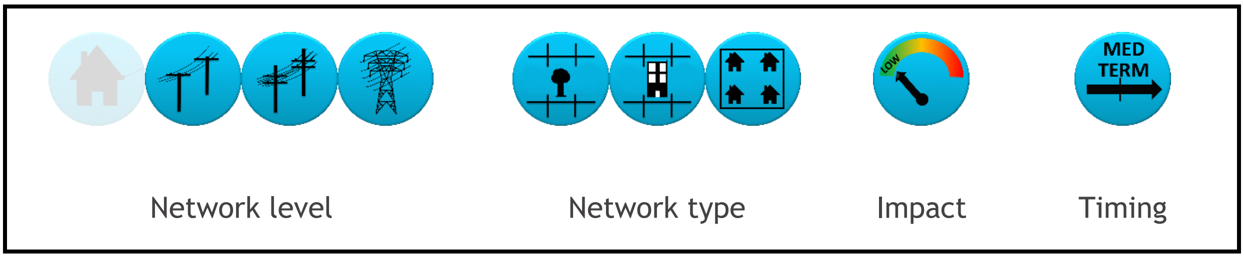
New stochastic (random) models are proposed in [28] to capture dynamic thermal limits of assets, change in weather conditions, and their aperiodic patterns. The results suggest that stochastic variations in weather patterns can affect the security of supply to customers considerably more than can the effects of dynamic thermal limits. The study also mentions that the change in weather patterns can considerably increase the costs of outages. Determining the actual latent capacity of assets due to dynamic effects and its utilisation does not necessarily reduce the impacts on security of supply in an active distribution network. The effectiveness of modelling dynamic thermal limits to determine impacts is more beneficial and necessary in stressed networks than in moderately loaded networks.

As an example, the United Kingdom generation profile is expected to change significantly in the future; an increased penetration of wind power is anticipated to increase the share of renewable energy sources to 20% by 2020. This will result in the need to transfer large amounts of renewable energy from the north of Scotland to the mainland demand centres in the south. The transmission capacity in the existing network cannot accommodate the increased power transfer. The United Kingdom system operator and owners must therefore maximise the use of existing transmission lines closer to their thermal limits to avoid constraining some generation plants and to improve the stability limit. To enable this, a hierarchical framework for the future stability control system has been proposed to improve stability and push the stability limit beyond the static thermal limits [29] .

An interesting example of a customer asset that can cause thermal loading issues is a plug-in electric vehicle (PEV). While not typically considered EG, electric vehicles (EVs) are highly correlated loads that can also discharge to the grid through vehicle-to-grid (V2G) capability. A study in the United States has identified the local distribution network as a likely area to be adversely affected by unregulated PEV and EV charging, due to the characteristics of their electric power generation [30] . The study looked at the impact of PEV charging on a local distribution transformer insulation life, which is mostly affected by the hot-spot winding temperature. A transformer model developed in the study was used to estimate the hot-spot temperature, given the knowledge of load ratio and ambient temperature. Additionally, different penetrations of PEVs were studied from the transformer insulation life aspect. The results indicated that a high penetration of PEVs can significantly affect the power grid, including potentially reducing the lifespan of transformers: particularly in the case of poor coordination of charging times. Conversely, low penetration of PEVs is not detrimental to transformer life, especially if charging is coordinated to some extent.

The integration of distributed EG in low-voltage (LV) networks was studied in [31] , which studied the thermal loading impacts of both the transformer and the line connecting the substation busbar to the first terminal along the feeder. Deterministic analysis of two limit cases (units located at the furthest or nearest households to the substation bus) indicated that the thermal loading of the transformer reached 100% of its rated value with an EV penetration level of approximately 25%. The individual phases exceeded their rated loading capacity for EV network penetrations of approximately 23—30%. This indicates that the thermal loading of network components must also be considered as a barrier to the number of EVs that can charge simultaneously on a particular network. However, the stochastic analysis (random location of EVs, weather uncertainty and time-varying load profiles) revealed that the cable exceeded its maximum rated loading less than 2% of the time with loading levels of 127% for 50% EV penetration. This suggests that the distribution of EVs and associated charging profile in distribution networks can have a profound impact on thermal loading, although the specific impact in a given case will be heavily influenced by the network design and other contextual considerations. The probability was the same for both winter and summer. The thermal loading of transformers due to high penetrations of EV may be kept low by using off-peak or controlled load charging mechanisms.

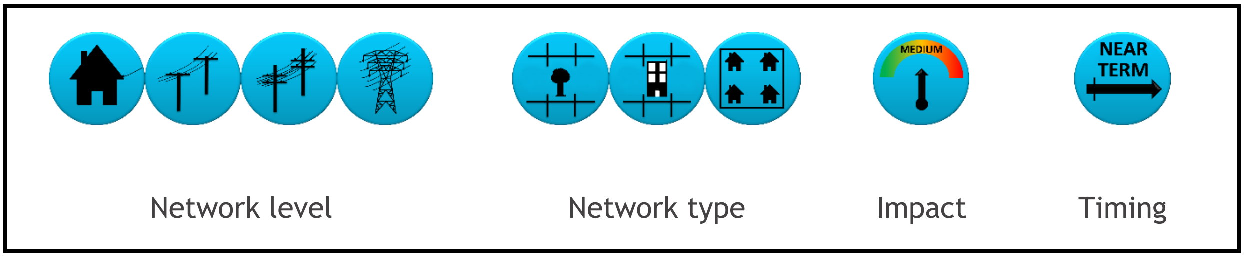
3.2.2.4 Losses



The transmission of electrical energy from power generation plants to consumers or end users via the transmission and distribution networks is usually accompanied by voltage drop and power losses. Power losses in electricity networks are caused by active and reactive power flows through line resistances and transformer impedances. The magnitude of active power loss depends on the amount of current flow and the line resistance, while reactive power losses can be defined as the reactive power that is absorbed by network components such as line inductance or transformers. Hence, reactive power must be supplied by generation in addition to the reactive power consumed by network loads. These losses are inherent in the utility grid system and can be minimised by controlling volt-amps reactive (VAR) sources, such as capacitor banks and EG. One of the challenges in using EG to reduce or minimise losses in the electricity network is the optimal sizing and placement of the generators in the electricity distribution network.

Several algorithms have been developed [32] [33] for optimal allocation and sizing of EG in the distribution network. While EG can introduce problems to the electricity network, it also has benefits that need to be explored further.

3.2.2.5 Load prediction



When a significant amount of intermittent renewables-based EG is incorporated into a power system, appropriate planning and management of load demand is essential to ensure adequate power quality and reliable electricity supply. As seen throughout this report, the potential mismatch between intermittent generation output and load may lead to inefficient operation of conventional power systems, or otherwise necessitate renewable generation curtailment. Accurate forecasting and prediction of load demand is essential for effective use and management of EG sources on the network, and also to establish sustainable load management systems for the smart grid.

Load prediction is broadly classified in the context of the following timeframes [59] :

- long-term forecasting (1—20 years), for applications in capacity expansion and long-term capital investment return studies
- medium-term forecasting (1—12 months), used to prepare maintenance scheduling and to plan for outages and major works in the power system
- short-term forecasting (1—4 weeks ahead), required for operation planning, unit commitment and economic dispatching
- very short-term prediction (1—7 days ahead), used for load exchange and contracting with neighbouring networks and to maintain a secure power system.

In Australia, operational generator dispatch and frequency control requires very short-term to short-term load forecasts (next five minutes, 1—2 hours, day-ahead and week-ahead). Long-term forecasts (year to years-ahead) are required for network planning and bulk generation (centralised or distributed) planning. Accurate load prediction across all timeframes is very important for appropriate investments, and hence the changing and challenging aspects of load prediction stated earlier in this section would need to be considered.

For most of the eastern states of Australia, the National Electricity Market (NEM) provides a central dispatch mechanism that adjusts power supply to meet load demand through the dispatch of generation every five minutes. Shorter-term to instantaneous generator output is regulated by the generator governors under AGC or similar systems, with some generators assigned load-following duty to maintain system frequency.

In the Australian NEM, the Australian Energy Market Operator (AEMO) measures electricity demand by metering supply to the network, rather than metering consumption. The advantage to this method is its inclusion of electricity used by customers, network losses and the energy used to generate the electricity (i.e. auxiliary loads). A high-level topology of the Australian electricity transmission network that connects supply (generation) and demand (customers) is shown in Figure 7. This figure also shows the different points at which various types of generation are connected, and the points at which supply and demand are measured. As seen in Figure 7, small-scale EG are attached to both transmission and distribution customers, which reduces the amount of electricity that needs to be supplied by large-scale generation. For example, a large increase in residential rooftop solar PV systems would reduce load demand. Similarly, energy efficiency and load control initiatives would also reduce load. On the other hand, an increased uptake of EVs or PEVs may increase the demand at customers' locations, with the potential of new peak demand created if EV charging times are not appropriately coordinated. An increase in the uptake of battery storage systems and customers controlling their loads at times of high prices would also contribute to the challenge of predicting customer load demand, with the difficulty increasing when these activities are more widespread. However, the growing use of smart meters may improve the ability to forecast the level of customer load demand.

Power systems operate by ensuring the amount of load and generation at any given time is matched in order to maintain the system frequency at the desired level. In scenarios with high penetration of small-scale EG, the energy supplied by these generation sources would need to be subtracted when calculating the energy supplied by generation controlled through the NEM dispatch process (i.e. the scheduled and semi-scheduled generation sources). Reliable operation of any power system and minimisation of impacts on the normal functions of the generation operations (see Section 3.2.2.1), relies on accurate prediction of load demand. This is essential to minimise operating spinning reserve and load-following generation capacity in excess of the load. Forecasts would need to take into account small-scale EG as negative load, as well as all other initiatives that are likely to change the load demand profile (e.g. battery storage systems, time-of-use electricity tariffs, demand-side participation).

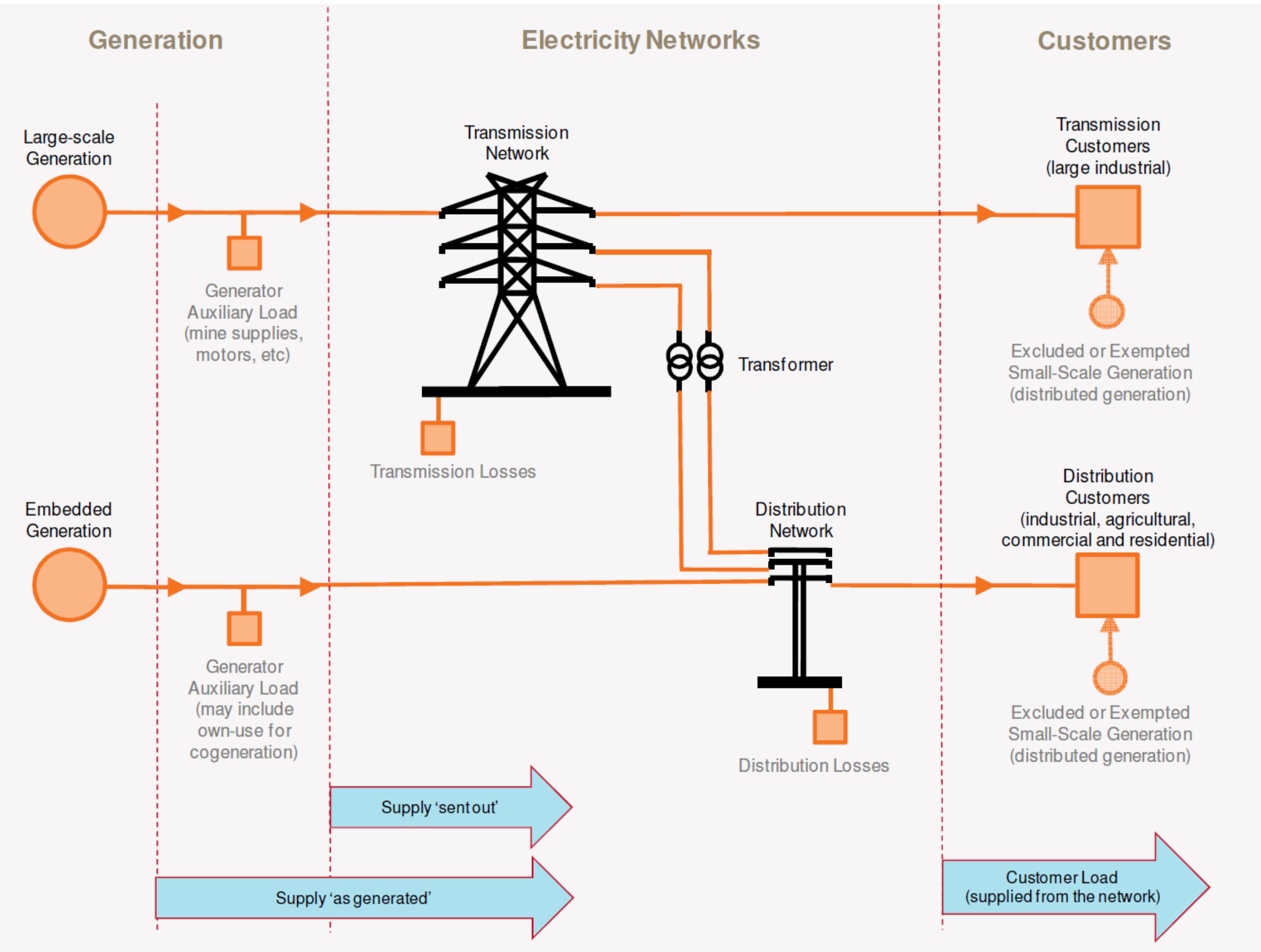


Figure 7 – Electricity network topology [37]

Internationally, the International Council on Large Electric Systems Working Group C1-24 state that the increasing installation of EG in distribution networks, along with the changing characteristics of that generation (particularly rooftop solar PV), are changing the utilisation patterns of electricity networks. This is now becoming a global issue [38] .

Changes required to load prediction include:

- producing accurate minimum demand and energy consumption forecasts, in addition to traditional peak demand forecasts
- making long-term forecasts more granular (on at least an hourly basis, possibly shorter)
- understanding the price elasticity of demand as it relates to demand-side response
- differentiating the energy consumed by customers from the electricity generated by their own EG
- understanding the relationship between energy tariffs and customer behaviour and the impact on network revenues.

Issues that make accurate load prediction challenging include the:

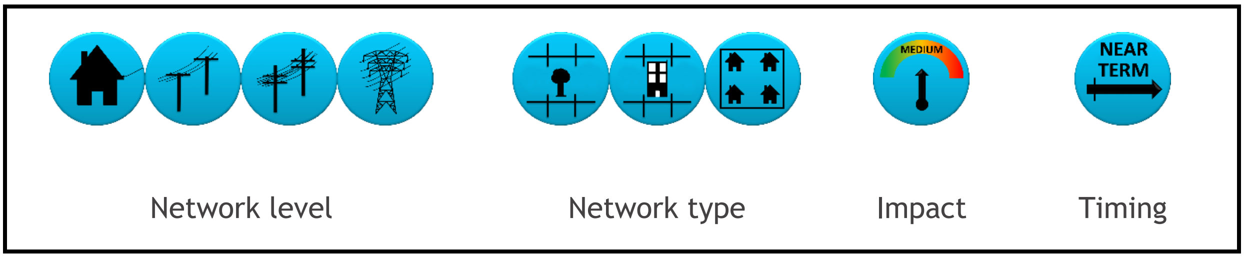
- changes to customer behaviour in response to electricity prices, and the availability of low-cost EG systems such as rooftop solar PV arrays
- limited information available to system operators from beyond customer meters
- impact of government policies that encourage energy efficiency
- government and regulatory policies on tariffs, including FiTs
- government policies facilitating EG in distribution networks
- uncertainty in the economy.

The capital expenditure (capex) required to augment the capacity of the network depends heavily on peak demand forecasts. Such forecasts are a large part of the capex programs in the current regulatory control period of network service providers (NSPs).

As a percentage of total capex, demand-related capex is around 25% for distribution network Ergon, but can be much larger for transmission networks: approximately 60% in one case [60] . If demand growth exceeds the forecasts reflected in the regulatory determination, NSPs may need to incur additional capex. Otherwise, if actual demand turns out to be less than that forecast, expenditure might be set too high. A large proportion of capital outlay is related to asset replacement and customer connections (distribution network service providers; DNSPs), rather than to meet increases in peak demand [60] . If there is a significant growth in demand-side participation, energy efficiency, individual onsite EG and uptake of cost-reflective pricing (e.g. time-of-use tariffs), the proportion of capex for demand-driven augmentation could decline. An increased addition of EG and time-of-use tariffs could potentially change customer demand profiles significantly. This would need to be taken into consideration when forecasting load demand.

Key Finding: *Increasing penetration of EG, including greater uptake of rooftop solar and other EG, is changing load profiles on Australian electricity networks and making network load prediction more challenging. Appropriate planning and management of network load demand across different timeframes is essential to ensure both adequate power quality and a reliable supply of electricity of the network.*

3.2.2.6 Bidirectional power flow



With the recent rise of EG — and in particular, residential rooftop solar — in many parts of Australia's energy networks, bidirectional power flow has moved from being a topic of research curiosity to drawing the attention of Australian distributors. For example, Ergon noted in 2012 the 'potential for reverse flows into the high voltage network as penetrations increase' [14] Energex has gone a step further, indicating that this has already occurred within their network during times of peak solar generation [15] .

Several issues relate to bidirectional power flow in a radial distribution (and potentially transmission) network. Of these, the highest immediate impact is likely to be the effect of reverse power flow on voltage regulators such as step voltage regulators (SVRs), which are more prevalent in rural networks than in urban networks. SVRs maintain voltage on a network segment within specified tolerances. The specific operating modes of SVRs and the inherent limitations of each are described in [16] and summarised below:

- Normal bidirectional mode
    - this simplistic control strategy can include a flaw wherein reverse power flow can cause the transformer to sense a high-voltage (HV) condition on the supply side
    - this causes it to tap in the wrong direction, resulting in the opposite outcome than intended and likely a major over-voltage on the LV side
- Co-generation mode
    - supports reverse power flow without critical impacts
    - any generation on a regulated line will cause the SVR to operate suboptimally due to incorrect estimation of the regulated voltage point
- Reactive bidirectional mode
    - can address most issues of reverse active power flow, but may be susceptible to the same issues as normal directional mode when reactive power flows in the reverse direction
    - currently of limited concern, except on network segments with high capacitive loads (e.g. shunt capacitor banks for power factor regulation), but may become more significant as smart inverters or static VAR compensators (SVCs) perform more volt-VAR control.

In addition to the issues relating to control strategy, the ability of SVRs to regulate voltage correctly can also be affected by reverse power flow. To maintain voltage within the specified range, an SVR must estimate the voltage along the length of line it is managing. This estimation is typically formed through line drop compensation, and is based on the current at the SVR and the known per-unit-length resistance and reactance of the line. The current through the line is assumed to be proportional to the current at the SVR and the line length between the SVR and the voltage regulation point. Significant generation in the line can invalidate this assumption, causing the SVR to incorrectly detect a light-load condition. This can lead to poor voltage regulation and deviations from the intended voltage range at the load connection point.

Some Australian DNSPs have provided anecdotal evidence stating that in rare circumstances on some extreme network segments, the current peak is no longer caused by maximum demand, but rather by maximum generation. This is due to the high penetration of strongly correlated rooftop solar PV, in particular.

Beyond this, in smaller remote-area or off-grid networks, reverse power flow that is not managed before reaching the generator can significantly affect the control and operation of the generation unit, including over-excitation, over-voltage and frequency destabilisation [19] . Other concerns relating to bidirectional power flow include the need to upgrade supervisory control and data acquisition and other load-monitoring equipment to account for it where it was not originally included in system planning.

Historically, electricity networks were designed for unidirectional flow of power from source to load. However, EG can also result in power flow from load to source. This can adversely affect network voltage and protection systems [34] . For example:

- In the presence of EG on the network, fault current is supplied both from the power system and the EG(s). This can increase the short-circuit current, which can exceed breaker capacity.
- Based on the location of the EG and fault, the power flow from the EG(s) can reduce feeder current from the substation, which may decrease relay sensitivity to operate during fault conditions.
- Non-optimal voltage control might reduce the voltage profile along the medium-voltage (MV) feeder.

The protection-related issues of reverse power flow are detailed in the following section.

To integrate and accommodate high penetration levels of EG on distribution networks, protection coordination is required that can sustain bidirectional power flows. At present, some local supply authorities are limiting the maximum power of PV systems, which is one way of reducing the possibility of net reverse power flow. Local DNSPs have observed reverse power flow in their networks, some of which have resulted in voltage rise.

Some modern grids are designed to accommodate reverse power flow. For example, reverse power flow is limited to 60% of the transformer nominal rating in Ontario, but is more typically limited to 30% [35] . In a study of three Swedish distribution networks, the duration of reverse power flow ranged from 0.1—3.5 hours a day through the MV/LV transformer substation when all properties had a 1-kWp solar PV system installed [36] . When larger, 3-kWp systems were installed on each property, the daily reverse power flow duration ranged from 1.1—8.9 hours.

In the next 20 years, the increasing prevalence of embedded solar generation may exacerbate the above problems. This is noted in the Future Grid Forum's scenario modelling [20] , which indicates that by 2050 between 18 and 45% of energy may be supplied by onsite generation: including a significant portion of distributed solar. Even the high end of this range may be considered a conservative forecast for some networks' for example, Energex already has 1 GW of connected PV on a network with a combined peak of 5 GW, and government policy could see this double by 2020. In such scenarios, the NEM, which is dominated by networks that operate on near-identical time-zones and hence sunlight patterns (cloud cover notwithstanding), could be expected to have a highly correlated solar resource. Such a time-correlated and intermittent source may cause significant reverse power flow into upstream and HV networks unless carefully managed.

Key Finding: *Reverse power flow has been observed at the medium-voltage and high-voltage network levels. In radial networks designed for unidirectional power flow, this can affect the operation of protection and voltage regulation devices. In islanded networks, such as some remote communities, it can also have a detrimental effect on generator control and stability.*

3.2.3 Protection

What is it?

Network protection is the switchgear and other equipment installed and operated to protect the electrical system from faults and the plant from damage. It ensures the safety of workers and the public while maximising the reliability of the network.

What role does embedded generation have?

EG can affect several aspects of protection, from production of excess supply leading to reverse power flow through protection elements to inadvertently supplying voltage in the absence of a grid connection, which has significant safety implications.

Why does it matter to Australian network operators?

Australian DNSPs have already seen some issues with protection schemes from existing EG. This is only expected to increase as EG continues to penetrate networks.

Traditional radial networks were generally designed to facilitate unidirectional power flow under normal system conditions. The increasing penetration of EG in distribution networks adds complexity to the power flows within a network, by introducing issues such as bidirectional power flow and variations in the scale of fault currents. In turn, these issues can complicate the protection requirements for these systems.

As detailed below, several investigations in recent years have identified issues related to increasing EG penetration. These include:

- current flowing in a network experiencing a fault condition, which may necessitate review of protection settings
- reverse power flow in some networks, which can affect the operation of existing protection schemes
- poorly controlled or mutually supporting local generation, which can retain a voltage during a grid failure, leading to an islanded grid with potential safety concerns
- downstream generation affecting the operation of impedance relays, which rely on accurate knowledge of local network impedances.

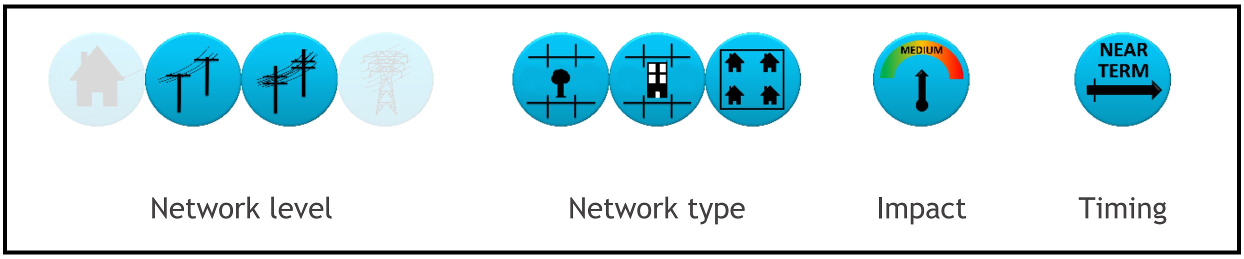
3.2.3.1 Fault detection in high-embedded generation systems

In a typical network based on centralised generation, fault detection is performed predominantly through the use of either fuses (typical on LV networks), or over-current protection relays, which trip circuit breakers. These trigger quickly on a high-current event, and more slowly for lower current faults, to protect the cabling on that network segment.

When a short-circuit fault occurs, the impedance between the active and the neutral, or between two actives, is reduced by several orders of magnitude. This greatly increases the current flowing through the active. A low-impedance fault will generate a current that far exceeds the standard load current of the network; when this occurs, the protection device will activate and interrupt the current flow before any significant damage is caused. Various schemes, such as sensitive earth fault and distance protection, can detect faults of magnitudes less than load current and initiate trips after a longer time, which is required to ensure that a fault exists.

EG can detrimentally affect the currents flowing in a network under fault conditions in several ways, as detailed below.

Contribution of embedded generation to network fault currents



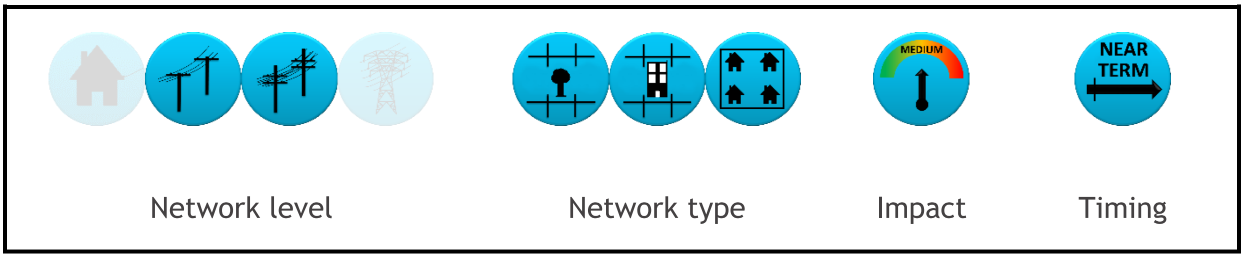
Low-impedance faults in distribution networks have traditionally been detected and eliminated through the use of over-current relays and similar protection systems. Some concern has been noted by industry [1] and in academic literature [2] about the capacity for EG to provide additional fault current, such that the embedded generator effectively masks the fault from the protection system, leading to the protection system failing to operate. However, there is limited evidence of this occurring in actual network systems.

Reference [3] proposes that faults that draw current from both a grid supply and EG should not cause protection devices to fail. They claim that the impedance seen between the fault and the wider grid is not changed by the EG, and so the fault current through the grid-side protection device should not change significantly. This is true for over-current protection. However, distance protection must be set to take account of the remote end of EG, as it will hold up the voltage and effect distance relay operation.

Reference [5] indicates that inverter-coupled systems are generally only able to supply relatively small currents, even under short-circuit conditions. The authors found that these currents are typically around two to four times the rated current of the inverter. In strong urban or central business district (CBD) MV networks, this is relatively small in comparison to a typical fault current. However, in weaker networks (e.g. long rural or single-wire earth return (SWER) grids), network impedances may be high enough that protection systems need to be designed to account for the more significant input from EG. In these cases, it is possible that inverter-coupled EG may supply enough fault current such that current at the fault is high, but protection devices do not trigger. In particular, the devices should not trigger within the time limits required by AS/NZS 3000 and related standards for fault currents at the fault that would normally cause a trip.

Synchronous and induction machines and transformer-connected systems can also contribute fault currents significantly higher than inverter-connected systems ([5] [6]). This is because the fault current that can be supplied by these generators is limited only by the generator or transformer impedance, and so may be sufficient to compromise some fault-detection schemes if settings are not adjusted.

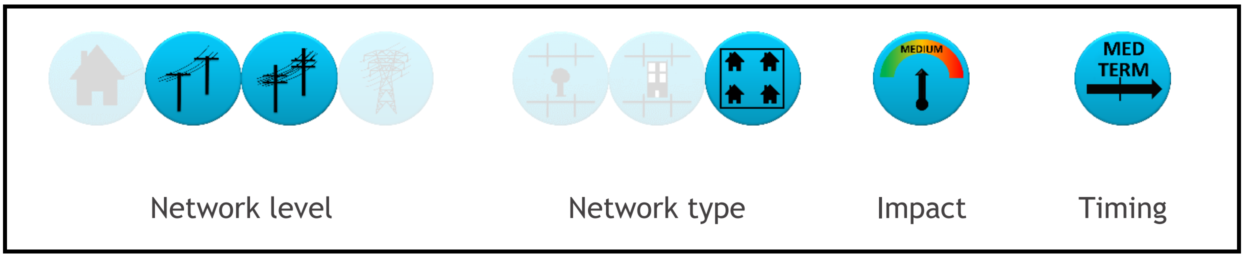
Network fault level



Many fault-detection schemes will also have a maximum fault current that can be interrupted without the protection device (typically a circuit breaker) failing. This is sometimes termed the maximum or ultimate short-circuit current. The maximum short-circuit current rating of devices on a network is collectively known as the network design fault current for that segment of network. This has been identified as an issue for a number of Australian networks; in particular, Victorian DNSPs have identified this as a barrier to incorporating EG in CBD and commercial networks.

If one or more EG units are connected within a network, the fault current will be the combined currents of both the grid inertia and the EG. In the case of high fault current generation, such as synchronous or induction machines and transformer-coupled inverter systems, the protection device may exceed its maximum operating current and fail to operate correctly. This is why embedded generators may not be allowed to connect to a network that is already approaching its maximum design fault current.

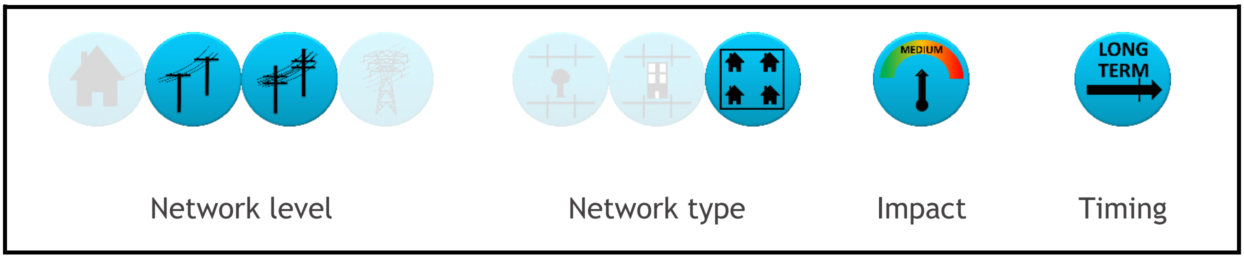
Fault current limits on off-grid and microgrid systems



In the case of both off-grid and grid-connected microgrid systems, a protection system must still interrupt faults, regardless of the presence of grid inertia to supply large fault currents. This has proven challenging in the case of purely inverter-based systems [7] .

Solutions that have been proposed to this problem include incorporating energy storage elements, such as flywheels, purely for the purpose of supplying large fault currents [9] , and using machine intelligence techniques, such as artificial neural networks, to detect electrical faults by performing pattern recognition on system states [10] . Such techniques also show promise in differentiating between short-circuit faults and inrush currents on motors and transformers [11] . This is still very much an open area of research.

Fault detection in self-islanding microgrids

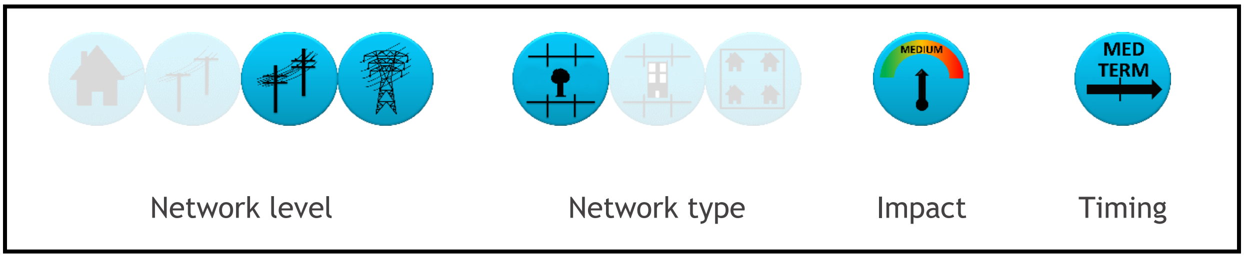


Assessment of fault detection thus far has assumed that subnetworks including EG are essentially of static design, and can be either grid-connected or islanded, but not both. However, there is an emerging trend [12] of grid-connected microgrids that can change to isolated operation in the presence of grid outages, increasing the continuity of supply.

In these 'self-islanding' microgrids, any internal protection mechanisms must be able to detect and isolate faults reliably in both grid-connected and islanded modes of operation. When grid-connected, the traditional methods of fault detection as described above should suffice, typically through identification of low-impedance faults with over-current devices. However, the limitations on the supply of fault current in off-grid microgrids will equally apply when the microgrid is islanded. An ideal protection system could operate correctly in both situations. While some work [13] has been undertaken in this area (in this case, using phase imbalance and the thermal properties of the protected conductors to help identify faults), it remains an open area of research.

Note that most Australian DNSPs put strict requirements on the operation of temporary islands in or connected to their networks, and many do not allow temporary islands to operate at all.

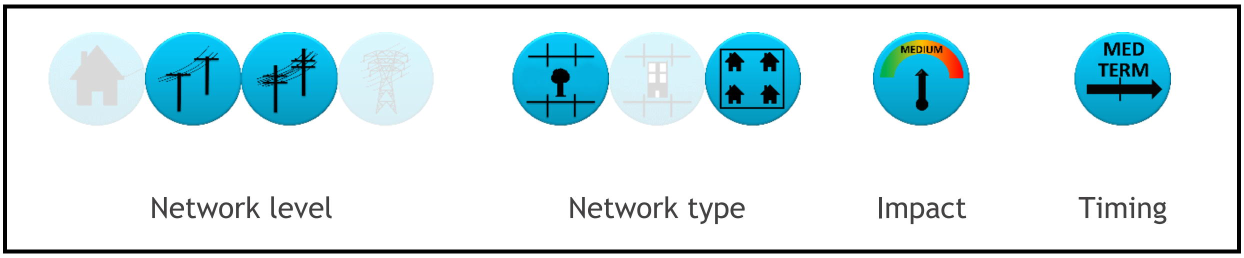
3.2.3.2 Impacts of bidirectional power flow on protection systems



The degree to which bidirectional power flow affects network operations — and in particular, protection mechanisms — is strongly tied to the type of network experiencing the effects. During the *Smart Grid Smart City* project, Ausgrid trialled a significant penetration of EG on an urban feeder in Newington. They did not identify any significant events relating to the feeder protection. On the other hand, they noted that high-penetration EG could lead to reverse power flow, which could significantly affect rural networks [18] : particularly in the area of reclosing circuit breakers without having extinguished the fault, as described in Section 3.2.2.6.

Reverse power flow in a radial network can also trip some types of protection devices that are specifically designed to protect unidirectional generators from upstream power flow [17] . However, this only relates to types of relays that are rarely used in Australian networks, and as such may not be a significant issue here.

3.2.3.3 Unintentional islanding



A concern with high-penetration EG, and particularly grid-connected microgrid systems, is their potential to remain in operation in the event of a grid failure, and thus provide a voltage signal for load (and other generation) equipment to connect to. This is a critical issue for DNSPs, because the equipment may continue to energise the network while being worked on by personnel, greatly increasing the risk of electric shock and arc-flash. There are two instances of working on the power system: either ‘live line’ or ‘dead’ under a permit system. The potential problem occurs in the latter, when a worker may assume the local power system is ‘dead’, because they have undertaken isolation from the feeder supply points, but EG may still be back-feeding. This risk can be addressed through standard operating procedures (e.g. testing dead, applying earths, wearing personal protective equipment).

These situations are typically avoided by ensuring that EG is coupled to the network via a grid protection device. This will detect when the main supply is de-energised, and disconnect the generation (and potentially the entire microgrid, in the case of self-islanding systems) from the grid. For example, the strict disconnect requirements in AS 4777.3-2005 require that inverter-coupled systems cease energising their AC output within two seconds, and remain offline until a stable grid supply has been detected for at least one minute. In addition, inverter-coupled systems must also include at least one form of active islanding detection, whereby an inverter will attempt to force a change in grid parameters; the degree to which this succeeds will identify whether the system is grid-connected or off-grid. This reduces the possibility of closely-coupled inverter systems reinforcing the supply seen by each other, leading to the formation of an unintentional island. Note that these limits remain broadly similar in the current draft of the upcoming AS/NZS4777.2-2015, although the field of application has been extended from inverters rated up to 30 kilo-volt ampere (kVA) to any inverter connected to the LV network.

Even noting this requirement for active anti-islanding detection, there is some concern in the literature [2] that closely-connected inverter systems at a high enough penetration may still produce a stable supply beyond the restrictions described in AS(/NZS) 4777. This is usually related to the requirement for inverters to provide some level of fault ride-through and grid support. A potential scenario may involve a fault that is incorrectly identified by an inverter as a voltage excursion; the inverter then attempts to ride through the LV by maintaining its own output, creating a temporary islanded network. This can be exacerbated when multiple inverters are co-located, such that they support one another, reducing each inverter’s ability to detect the fault or off-grid condition and further extending the duration of the island.

If this type of islanding lasts long enough, it could cause safety concerns as described above. It also poses a potential issue to automated recloser systems (see Section 3.2.2.6).

Summary of anti-islanding detection methods

Mechanisms for detecting an islanded electrical system have traditionally relied on passively monitoring electrical parameters for deviations that indicate the network segment has been isolated, and then commanding the inverter to stop exporting power. More recently, significant effort has been made into researching active methods for identifying grid disconnections, typically by attempting to vary the grid parameters.

Reference [3] identifies the following passive and active islanding detection mechanisms, along with a review of the benefits and drawbacks of each specifically for the case of PV inverters.

Passive techniques

- Over/under-voltage and over/under-frequency detection
- Phase jump detection
- Direct monitoring of voltage and current harmonics
- Rate of change of frequency
- Rate of change of power output

Active techniques

- Impedance measurement
- Sliding mode frequency shift (active phase shift)
- Sandia frequency shift (active frequency shift with positive feedback)
- Reactive power export error detection

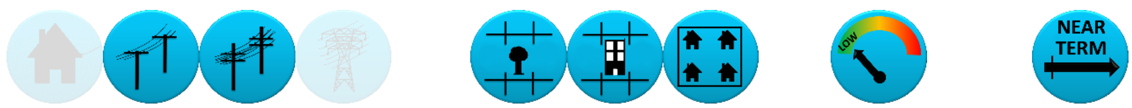
Reference [3] also describes a number of 'remote techniques', where a grid failure is detected by the grid operator rather than by the inverter or its grid protection device. This is then communicated to the inverter to force it to shut down. As these types of techniques rely on communication with the inverter, they may be limited in applicability. However, the upcoming update of AS/NZS 4777 Part 2 includes a demand reponse (DR)-type interface including a DRM0 command to isolate from the grid, which may encourage future adoption of these techniques.

No single technique was shown to demonstrate a superior set of functionality [3] . Rather, they all trade off desirable and non-desirable aspects, including complexity of implementation, non-detection zone, speed of detection and isolation, and rate of false positives/false negatives.

Automatic re-closing of non-synchronised network segments

When a fault is detected on a piece of network, a circuit breaker can be opened to isolate the network segment in which the fault has occurred. In the case of overhead breakers with reclosers, these faults are often quickly cleared, and the breaker is closed to once again provide supply to the network segment. However, if an island has formed during the power disruption, there may no longer be direct synchronisation of the voltages on either side of the breaker. When the connection is made and the unsynchronised voltages clash, this can cause unpredictable current flows. It can also potentially damage the EG, as well as customer loads and appliances.

3.2.3.4 Impedance relay operation



Network level | Network type | Impact | Timing

Impedance relays can be used to only operate on specific regions within a feeder. These units rely on knowledge of the impedance characteristics of the local network to estimate where faults are occurring, based on fault current and voltage profiles. By varying the voltage profile seen at a relay, EG may compromise the reliability of these systems.

> ***Key Finding:*** *EG has the potential to contribute current to any fault in the vicinity. Protection system design and settings must be considered in rural and off-grid systems to ensure faults are cleared quickly. In urban areas, the added fault level (the maximum current that can flow in the network segment as a result of a fault) may restrict the amount of EG that can be connected due to system design fault levels.*

3.2.4 Network stability

What is it?

According to AEMO, 'power system stability is the ability of the electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical or electrical disturbance, with system variables bounded so that practically the entire power system remains intact' [61] .

What role does embedded generation have?

By varying the typical operating constraints under which a conventionally designed power system operates, EG can have a detrimental effect on the voltage and frequency stability profiles of a generating unit. In addition, circulating reactive power in islanded microgrids or off-grid power systems can cause oscillatory effects in voltage at various points on the network.

Why does it matter to Australian network operators?

Stability is of significant issue to all network entities, but in particular to those that own generation assets. While most Australian DNSPs do not currently own significant generation assets, this is becoming increasingly attractive in managing fringe-of-grid networks, as detailed below.

The impact of EG on power system stability has been a concern for some distribution networks for many years [61] . Until recently, this has typically been considered a primary concern for LV and MV distribution networks. However, the significant increase in distributed solar in recent years has affected the upstream HV network. With the uptake of EVs and battery storage expected to greatly increase in the next 10—20 years, there is a strong possibility that correlation of these new loads due to static tariff structures or consumer behaviour may increase this effect.

Power system stability can be broadly categorised into stability at centralised generation (i.e. power station stability), and stability within the transmission or distribution network. At a central generation, such as a power station, generator output voltage, rotor frequency, rotor angle and output phase angle are all critical to maintaining stability of power networks. Within distribution networks, frequency and its related variables are primarily controlled by the upstream generation, while voltage stability is of greater relevance.

3.2.4.1 Power station stability

In the traditional radial model of a power system, maintaining the stability of centralised generation is key to ensuring consistent, reliable power for consumers, as required by the Australian National Electricity Rules. Power station stability is strongly coupled to the load demand on power networks, as detailed below. Increasing penetration of EG may actually improve power system stability [63] . However, this is dependent on complex interactions between system dynamics, and the role of large amounts of EG in this is not yet clear.

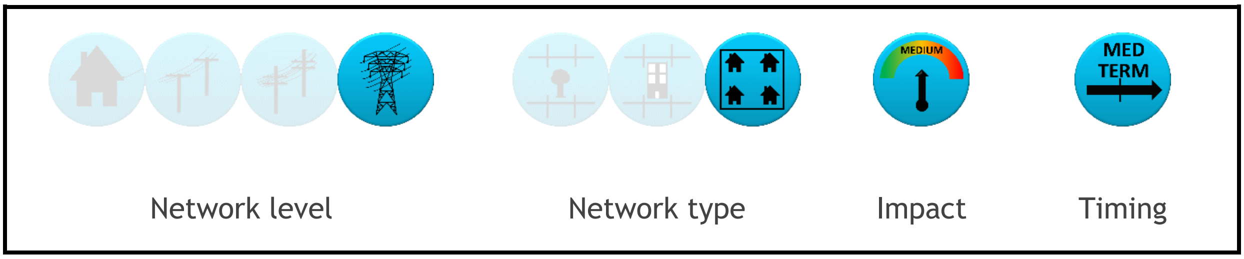
In a typical large-scale network power station, stability is the concern of the generator operator; the DNSP is shielded from these issues to a degree. In addition, given the relatively low penetration of EG when compared with the total load supplied by existing, large-scale, centralised generation, it is easy to assume that Australian utilities will not face these problems for some time — if ever. However, some Australian DNSPs (most notably Horizon Power) manage significantly smaller generators that have already been exposed to significant penetrations of EG. In addition, there is an increasing case being mounted for other DNSPs to be able to own and operate small generation assets in islanded microgrids as an alternative mechanism for supporting fringe-of-grid networks. In these situations, challenges such as those detailed below may become significantly more problematic than in the current, centrally dominated generation model.

At time scales of several cycles to several seconds, a balance is maintained between power demand by customers and power supplied by generators. This occurs via the interaction between the passive dynamics of the transmission and distribution networks, the primarily large electromechanical machines generating power, and the regulation and control mechanisms on the network designed to provide electrical power as drawn by customers. These system dynamics are maintained within safe operating limits of the electrical system infrastructure.

The interaction among all the components of the electrical system, including all associated regulatory mechanisms, should result in stable voltages and power flows — in the sense that small departures from an equilibrium operating point will decay at time scales faster than changes in load. At time scales of several cycles to several seconds, the stability of at least three parameters are of engineering design interest: voltage stability, power system frequency and synchronous generator rotor angle stability. Voltage stability, a primary concern for distribution networks, is strongly coupled to the regulation of reactive power flows. Power system frequency and synchronous generator rotor angle stability are both strongly coupled to the regulation of real power.

Phase angle stability is also a significant factor. However, given its relationship to frequency stability, as well as the limited relationship with EG (beyond EG acting as a negative load), this report does not address it in detail.

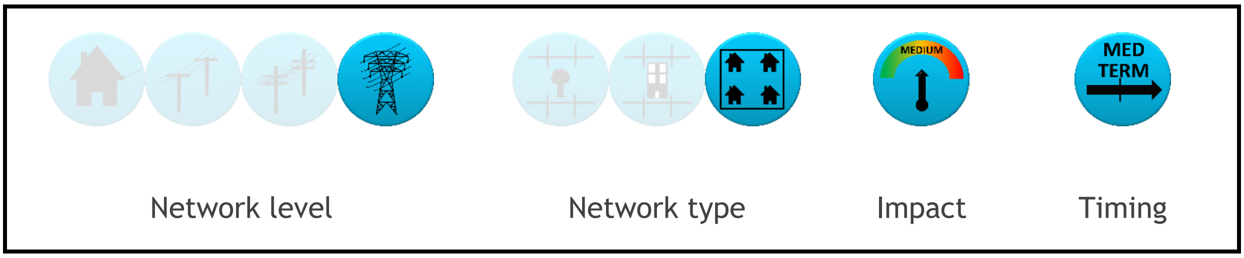
Voltage stability



Voltage stability on electrical networks is maintained by control mechanisms that are designed with the implicit assumption that the alternating current (AC) voltage at any given location in the network will increase with the injection of reactive power, rather than decrease. The transmission of too much real power across a transmission link — or the provision of insufficient reactive power at various points within a network — can violate this condition, resulting in voltage instability. Correspondingly, an insufficient quantity of generation providing voltage support via the production of reactive power in response to a fall in voltage (a service that is presently provided by synchronous machine generators) could lead to voltage instability.

The inclusion of EG will typically reduce the likelihood of voltage instability. This is due to demands to transmit too much real power across a link, which will typically reduce real power flows, rather than increase them, since it generates power closer to load. Inverter-based EG typically supplies little or no reactive power, either pushing centralised generation to increase reactive power outputs or risking voltage instability [64] .

Frequency and rotor angle stability



Frequency stability and rotor angle stability are both associated with the regulation of real power supply, and refer to the behaviour of large-scale mechanical generators. Rotor angle is the phase difference between voltage phases of the generator's rotor and that of the grid. The rotor angle increases with increasing power generation output requirements (up to a stability limit), and its stability is defined relative to the grid. The frequency is that of the grid (corresponding to that of the majority of the generators), and its stability is defined relative to an external set-point reference. Grid frequency and generator rotor angle are not strictly independent, in that frequency is the rate of change of phase. However, there is sufficient separation of time scales and set point to ignore this dependence in stability analysis and regulation design.

Frequency stability is achieved if the responsiveness of generators to rising and falling power demand requirements is sufficient to ensure that the resulting transient phase errors do not exceed the stability margin for any generator. Instantaneous net differences in power supplied by mechanical generators and that delivered to the grid are met by changes in energy stored in the generators in the form of rotational inertia, and hence rotor phase angle. Inverter-based generators have negligible inertia, and would be typically incapable of increasing power generation at the rates required to help maintain frequency stability. Embedded synchronous generation, on the other hand, will be associated with corresponding rotational inertia, and may help maintain grid frequency stability.

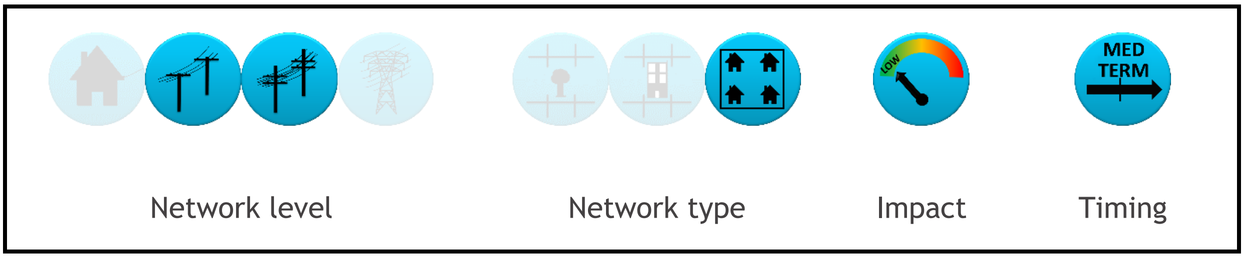
Different types of centralised generation plant have different power frequency dynamic characteristics. These are influenced by their power control scheme, and constrained by the inherent mechanical energetic dynamic characteristics of their physical mechanisms. Hydro-electric turbines, synchronous and asynchronous generators, steam turbines that provide mechanical power to synchronous generators, and generating devices with inverters all have their own particular dynamics. Different types of load and transmission links also have their own particular steady state and dynamic characteristics that relate real (and reactive) power consumption to grid frequency and voltage supply. The interaction among these dynamic responses determines whether the interacting electricity supply network is stable (on a local, small-signal scale).

The steady-state response of synchronous machines is typically characterised by a (closed loop) droop, with an approximately negatively proportional relationship between frequency and power generation. Maintaining frequency stability of the system would likely be easier if EG mimicked the dynamic power response to frequency deviations of centralised plant. Some inverter-based EG uses droop [65] , but truly replicating the frequency response of large-scale power generators would likely require significantly more inertia than is typical of EG.

Small-signal rotor angle stability refers to the stability characteristics of the regulated phase angle of electromechanical generators. It appears to depend [66] on the interaction between the torsional characteristics of a turbine generator (shaft) and the generator's own excitation controls (speed governors) with nearby direct current (DC) inverters. This type of stability seems to be associated primarily with self-regulation exciting resonant electrical modes. It does not appear to be strongly associated with interaction with other generators via the grid.

Large-scale rotor angle stability requires local stability of equilibrium stability. In addition, the magnitude of disturbances from all sources (including faults) must not produce a response that takes the rotor angle phase difference outside its stability region.

3.2.4.2 Circulating reactive power from embedded generation



The ability to export or import reactive power is a key benefit of embedded generators and can be used in many aspects of network control, from simple reactive power support to optimisation of local voltage through volt-VAR control.

Volt-VAR control, in particular, is a useful technique for ensuring that voltage deviations (e.g. due to high-penetration solar EG) do not lead to inverter disconnection and loss of generation. In this sense, integrated volt-VAR control in existing EG directly improves the stability of distribution networks. However, if not properly controlled, reactive power loading and injection can lead to a situation where VARs are supplied by local EG and absorbed by a nearby generator. This inflates network currents and increases I^2R losses, and can also lead to steady-state voltage instability due to the strong coupling of voltage and reactive power.

As noted in the previous section, droop control is a useful mechanism for allowing EG to react to frequency and voltage deviations in the same manner as traditional generation. This greatly simplifies the integration of droop-capable EG units. However, both local voltage variations within a network and increasing power output values can lead to poor reactive power sharing, and resultant steady-state voltage instability [67] . This is particularly prevalent in microgrids, where the ability to provide reactive power support is primarily or wholly the responsibility of local EG [68] .

3.2.5 Power quality

What is it?

Power quality refers to how close a single or multiphase supply voltage comes to the intended waveform. The properties that contribute to power quality include:

- waveform amplitude and variability
- phase imbalance
- voltage flicker
- voltage harmonics.

What role does embedded generation have?

EG can significantly affect power quality by exporting (or in some cases importing) power on one phase more than others, or at an inopportune time. It can also generate current harmonics, which can have detrimental effects on the local voltage waveform and hence on other electrical equipment.

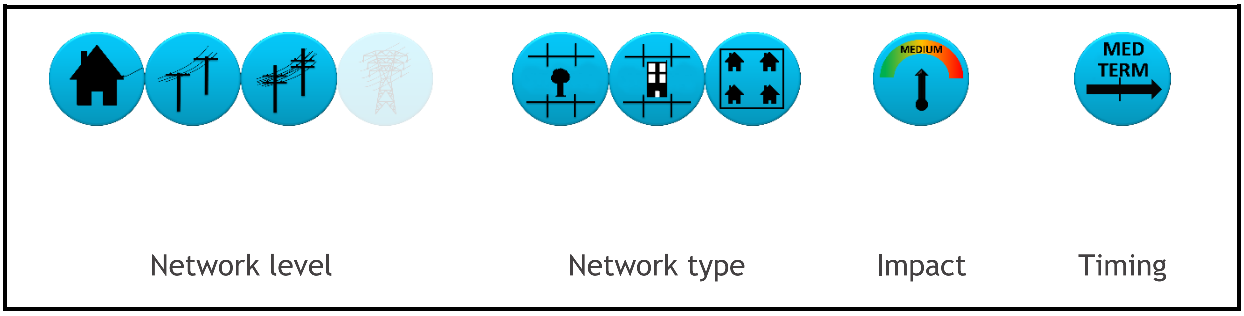
Why does it matter to Australian network operators?

Network operators in Australia are required to maintain the above aspects of power quality on their networks within strict tolerances, and EG can pose a challenge to their management.

This section considers the potential technical challenges that affect quality of power: specifically with regards to voltage fluctuation, harmonic distortion and reactive power compensation. The increased penetration of renewable energy in the grid has caused growing concern in distribution system planning regarding power quality issues, as observed by Australian DNSPs. Therefore, the impact of EG integration must be carefully investigated to ensure optimum system performance.

Common problems related to voltage fluctuations are over/under-voltage, voltage flicker and power outages. These can disturb sensitive electric and electronic equipment, reducing its lifespan and inconveniencing consumers. The variability of renewable generation over time is not the only reason for these problems; grid-connection issues, load dynamics, faults during operation and starting of load motors are also responsible. The following sections will address these technical impacts. Several of the power quality impacts of EG are also covered in detail in Section 5.2.3, where they relate to the commercial operations of networks.

3.2.5.1 Voltage intermittency and voltage rise



The integration of EG can result in over-voltage issues. This need not be a problem when EG is connected to a system facing an LV problem; but for weakly loaded systems, it may result in HV problems, thereby interfering with standard voltage regulation practices [39] . In a weak grid with low short-circuit capacity and high grid impedance, the voltage rise problem may be severe, the control capability of EG may need to be exploited [69] . DNSPs have had different experiences of voltage rise, due to different network strengths and settings. However, in general, the weak parts of a network are more likely to start experiencing such issues at relatively modest penetration levels. Accordingly, rural feeders are more likely to experience voltage rise problems because of their long span, which increases the feeder impedance values. Specifically, due to the Ferranti effect, the voltage at the receiving end of lightly loaded long transmission line becomes greater than the sending end because of the voltage drop across the line inductance.

Recently, Ausgrid conducted a real-world trial on the strong part of a network, using batteries to simulate different PV penetration levels [72] . No single threshold level of penetration was observed at which voltage problems arose. However, Ausgrid noted that while higher penetrations may cause no problem on a strong part of the network, it may on the weaker parts, or on networks with considerably different operating characteristics.

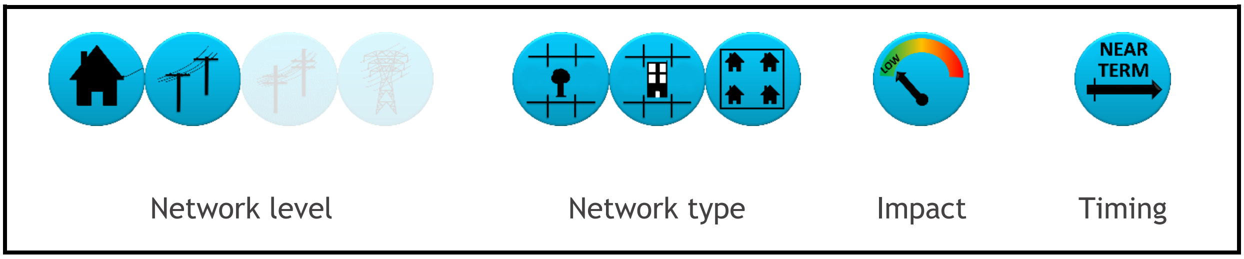
As with most network trials, Ausgrid's results are context dependent.For example, recent studies by Ergon Energy and Central Queensland University [43] have explored the issues involved in varying PV penetration levels on different SWER networks. If all customers (around 70) installed 5-kW PV systems, then the voltage rise would be around 8% on LV networks; if they all installed 10-kW PV systems, it would be around 15%. Increasing the penetration levels of rooftop PVs in residential networks of Perth Solar City could also cause a voltage rise above 6% of the nominal voltage [40] [41] .

The effect of EG on power quality and stability was also investigated on an island microgrid on Heron Island, Queensland [57] . The system has unique factors, such as small-inertia diesel generators, high R/X ratio cables, high PV penetration, and a complete lack of coordination of loads and power generation. The simulation results indicate approximately 10% increase temporarily over-voltage and about 6% of steady-state over-voltage, when PV begins to increases by 75% towards 98% of its operational 50-kW capacity. A wind turbine study observed a steady-state voltage rise in the network due to wind speed variation, and voltage sag due to the turbine's high start-up current [46] .

The impacts of voltage intermittency relating to EG, and in particular how they influence the commercial operations of networks, are discussed in Section 5.2.2.

Note that Queensland currently has a standard endpoint line-neutral voltage of 240 V +/–6%, compared with the rest of the NEM, which has standardised on 230 V +10/–6%. Better aligning both base voltage and voltage range would enable improved consistency of standards and solutions to address EG issues.

3.2.5.2 Voltage imbalance



Voltage imbalance in the three-phase system is a condition in which the three-phase voltages differ in amplitude, and/or do not have 120-degree phase difference. The voltage imbalance factor has been defined using several methods, but the Institute of Electrical and Electronics Engineers (IEEE) recommend $|V^{-}/V^{+}|*100$, where V^{-} and V^{+} are the negative and positive sequence voltage component, respectively [74] . This definition can be related to the maximum voltage deviation from the average phase (or line) voltage, divided by the average phase (or line) voltage. The allowable limit for voltage imbalance is 2% according to the IEEE standard [74] . The compatibility level for voltage imbalance in Australian Standard AS61000.2.2 is a negative-sequence component of 2% of the positive sequence component, but allows up to 3% where there is a high level of single-phase loads, as is typical in residential areas. Note that the standard does not refer to specific restriction on the zero sequence component.

Such voltage fluctuation, which can be caused by the intermittent nature of EG, is exacerbated in single-phase systems, because voltage increases can occur on the connected-phase only — hence contributing to phase imbalance in the network. This can be managed through phase-swapping, but this comes with an associated cost.

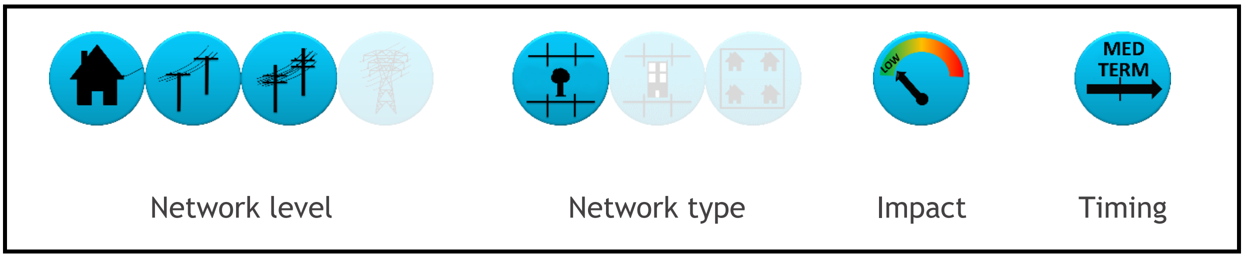
Additionally, the physical location of rooftop PV is still largely dictated by customer choice. For example, it is possible that 80% of customers on one of the three phases have installed PV, while only 50% and 10% of customers on the other two phases have installed PV. In such a condition, even if the voltage imbalance of the network was within the standard limits without any PV, it is not guaranteed to remain so. Therefore, the possible PV installation number or rating on such systems must be investigated in a way that retains the voltage imbalance within the standard limit.

For example, Ergon state that solar PV has produced power quality issues such as voltage rise and imbalance caused by single-phase connections [73] . Researchers at Queensland University of Technology have shown that rooftop PV (with a rating of less than 5 kW) can increase network voltage imbalance by 0.1% when installed at the beginning of the feeder, and by 0.25% when installed at the end: specifically when the feeder supplied up to a 1-MW load [47] . Therefore, rooftop PV installation will typically have a minor effect on the voltage imbalance at the beginning of an MV feeder (less than 1%). However, multiple PV units at the end of the feeder might increase to more than the 2% standard limit. The same study shows that depending on the load of the phase in which the PV is installed, the voltage imbalance will increase or decrease based on the location and rating of the PV. Also, if PV is installed on one low-voltage line, the voltage imbalance will be modified on all other LV lines of the network. Some minor improvement is suggested in [47] and completed in [48] .

In general, EG seems to pose little risk to the voltage imbalance on a system, according to probabilistic load flow experiments [44] . As penetration levels increase from 1 to 50%, the maximum imbalance remains unaffected, at around 3%. An exception is encountered if EG provides VAR support; in this case, the EG risks increasing the voltage imbalance if not properly controlled.

Another case of voltage imbalance of up to 5% occurs when wind energy farms are located in rural areas with a weak local network or relatively long transmission lines. Such a voltage imbalance can worsen the performance of doubly fed induction generators (DFIGs) by introducing unwanted torque harmonics and inaccuracy in the generation of commanded active/reactive power [46] . DFIGs are widely used in wind energy harvesting systems, due to their smaller power converter, flexibility in autonomous control of the active and reactive power, and relatively simple and rugged structure. The impacts of negative-sequence voltage on DFIG system performance were recently investigated, and a collaborative control strategy based on the reduced-order generalised integrator was developed to reduce such impacts during network imbalance [70] .

3.2.5.3 Voltage flicker



Periodic disturbances to the network voltage are defined as ‘flicker’. The level of flicker is quantified by the short-term flicker severity value, P_{st}, which is the perception of light flicker in a short-term (10 minutes) interval. According to IEEE standard 1453, the allowable limit for the flicker meter output is $P_{st}=1$. Also important is the flicker duration, which is the percentage of time that the bus’ P_{st} is above a given value. In particular, overambient flicker (OAF) is a measurement of the percentage of time that P_{st} is greater than or equal to 0.02. The concerns associated with flicker are also related to voltage variations. In most cases, voltage flicker consists of small, periodic voltage fluctuations with frequencies of less than about 30—35 Hz [46] .

Reference [44] indicates that increased flicker caused by EG can vary based on the presence of regulators in the system. On a feeder without regulators, the flicker manifests itself as direct flicker, occurring at low values of P_{st}. In contrast, on a feeder with regulators, the flicker manifests itself as indirect flicker, by increasing the length of time over which high flicker values occur. Indirect flicker occurs at higher values of P_{st} (because of tap changes); hence, it is the more concerning source of impact on network voltage. It is also the major driver for a large OAF, and signifies increased operation of the voltage regulator tap changers and capacitor switches. This opens the door to a centralised, intelligent control scheme for voltage-regulating devices on feeders with high penetrations, which would increase device life and reduce the most noticeable aspect of EG-induced flicker.

Since buses without voltage regulators are usually located at urban feeders and early parts of rural feeders, the results in [44] indicate that urban feeders are likely to see EG flicker impacts in the form of direct flicker with minor impact. Rural feeders are instead likely to see EG flicker impacts as indirect flicker, because the buses often have voltage regulators. As EG penetration levels increase from 1 to 50%, the average P_{st} value increases slightly from 0.008 to 0.009, while the average OAF and maximum OAF change dramatically from 4.2 to 9.7% and 13.8 to 25.4%, respectively [44] .These values approximately double in a weak network, showing the sensitivity of a weak network to voltage flicker. These results match intuition on EG impacts. The study also demonstrates that EG’s direct flicker is unlikely to have a major impact on network voltage, since it concentrates near lower P_{st} values. However, the magnitude and probability of the P_{st} value noticeably increase as EG penetration increases.

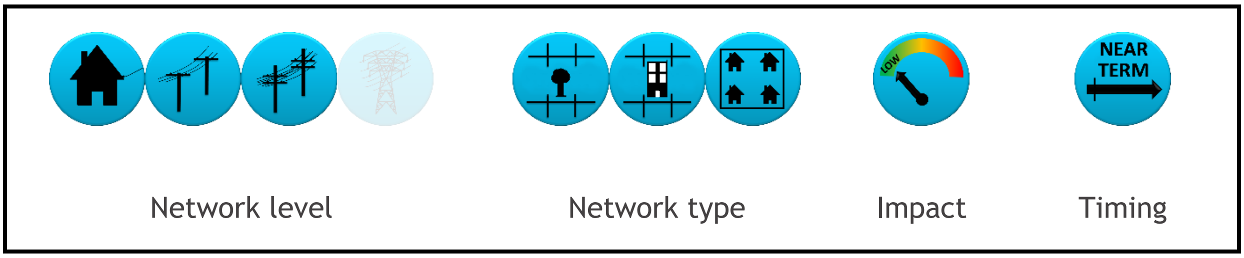
While an overambient flicker value is defined as any flicker greater than or equal to 0.02, a large OAF does not imply a flicker problem on the system. For there to be a detectable, harmful flicker problem, OAF would generally need to be greater than 1.0, which does not occur in any scenario in [44] . The largest P_{st} observed was 0.6053, which occurred during the most susceptible test with 50% EG penetration on a weak system. Based on these results, the impact of EG on flicker appears to be relatively minor. However, the flicker measured here is on the main feeder only; the flicker on the laterals and customer services is likely to be higher. Additionally, the weaker system tends to have higher flicker metrics. The result of weakening the system on OAF is dramatic, causing the weaker system to experience more than double the OAF of the strong system for equivalent EG penetrations [44] .

In wind turbines, flicker emissions are produced during switching and start-up, as well as during continuous operation (due to variations in wind speed, the tower shadow effect and mechanical properties of the wind turbine). Flicker emissions from variable-speed wind turbines, such as DFIG, are low (around 0.05) compared with those from fixed-speed wind turbines, such as squirrel-cage induction generators, which are around 0.16 [46] .

Flicker emissions increase in both fixed-speed and variable-speed wind turbines at higher wind speeds, due to higher turbulence intensity in the wind. However, there is a fundamental difference in flicker level between the two types of turbine; while it strictly increases at higher wind speeds for fixed-speed turbine, it first increases but then decreases at rated wind speed for the variable-speed turbine. As the wind turbine reaches rated power, the variable-speed system will smooth out the power fluctuations, and thereby limit the flicker [46] . The authors of [49] also studied flicker emissions in a DFIG-based wind farm. They found that wind generator control strategies, wind generator reactive power capability and the operating point of the power curve all affected flicker emissions.

Flicker may also occur in PV modules during fast alternations of clouds and sunshine, but reference [45] suggests this has no noticeable impact on voltage.

3.2.5.4 Harmonics



Harmonics are one of the most dominant attributes that need to be kept to a minimum to ensure good network power quality. Harmonic distortion can be minimised by good control algorithm design in the current control loop. According to IEEE standard 519, harmonics in the power system should be limited for both the harmonic current that a user can inject into the network at the point of common coupling (PCC), and the harmonic voltage that the utility can supply to any customer at the PCC. The limits of different harmonic orders for LV-connected inverters are specified in Australian Standard AS 4777.

Power electronic devices, together with operation of nonlinear loads, inject current harmonics into the grid, which may potentially create voltage distortion problems. These effects may increase power system heat losses and reduce the lifespan of nearby connected equipment. Harmonic current flowing through the impedances of a distribution network causes voltage distortion. Harmonic voltages also cause voltage distortion and zero-crossing noise in the network. The degree of distortion of an AC voltage or current is known as the total harmonic distortion (THD). It is defined as the ratio of the square root of the sum of the squares of the individual harmonics to the fundamental harmonics.

A comprehensive study analysed the harmonic impacts on both winter and summer seasons with 10-kW PV penetration on the distribution network [50] . The measured results provided basic guidelines that include the following for this case: THD of the PV current was low during high generation, and high in the period of low generation. Also, odd current harmonics affect the distribution network significantly more than do even harmonics.

Experiments at CSIRO's Renewable Energy Integration Facility in Newcastle, Australia showed that increasing PV penetration from 7.5 to 11.3 kW increases the harmonics injection into the network [75] . The fast Fourier transform (FFT) analysis found that current harmonic injections from all even harmonics are within the range stated in the AS4777 standard. However, the third and ninth harmonics exceeded the regulatory standard, while injections from the seventh and 15th harmonics just reached the threshold levels.

Although fixed-speed wind turbines do not employ any power electronic converters, they can cause harmonic distortion through the interaction of power factor correction capacitors and system impedances. A small amount of harmonics is also produced during the starting up of the turbines, while wind turbines with converters inject harmonics into the network during their operation. The design of power electronic converters and filters is the influencing factor of harmonics produced by wind turbines [46] .

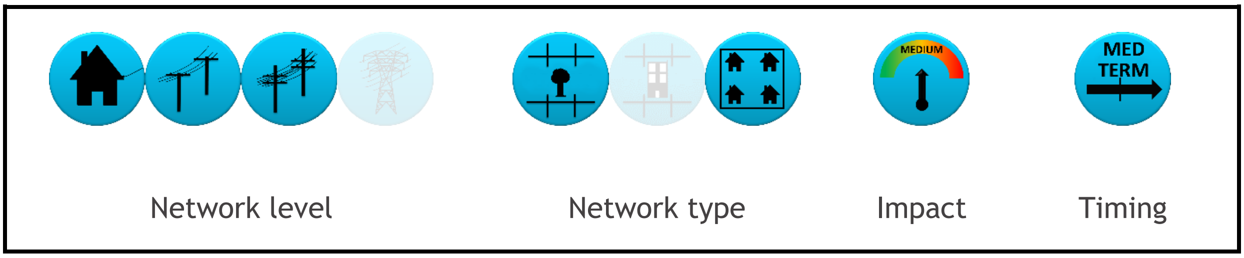
Characteristics of harmonics injected into a wind energy integrated power system were investigated with variety of configuration and operating conditions in [51] and [52] . Voltage distortion is expected to be observed in the distribution network due to the rotating machine characteristics [51] and the design of power electronic interface [52] in the wind energy systems, which lead to harmonics in the air-gap. As a result, the stator and rotor will contribute to current harmonics. Harmonics are also observed in the main field passing over the stator slot, due to the inherent characteristic of the machine; hence, these are in need of a different approach if they are to be managed [51] .

A recent study [53] investigated the problem of a frequency converter in a wind energy system causing harmonics in the line current, leading to harmonic voltages in the network. With the application and guidance of International Electrotechnical Commission (IEC) regulatory standards IEC 61000-3-6 and IEC 61000-4-21, this study integrates several appropriate harmonic load models representative of harmonic network elements and harmonic sources. Potential voltage distortion was observed, caused by coincidence of the first harmonic resonance frequency with the peak harmonic spectrum of the wind turbine current. The harmonic distortion of the voltage increased at minimum load, as well as being more pronounced closer to the wind farm. An HV distortion appeared at the MV busbars, which is concerning, while minimal distortion occurs at the HV side [53]

Reference [54] explored the characteristics of self excitation and harmonics generated by a fixed-speed induction generator used in wind turbine generation. The saturation of the magnetic circuit in the transformer and the resonance circuit between the capacitor compensation and the rest of the circuit causes harmonic injection, which makes the power system vulnerable. The tap changer, capacitor compensator, power factor and level of generation all influence the intensity of saturation, as well as the characteristics and amount of the harmonic source injection. Power quality behaviours — in particular, voltage sags and harmonics injection into the network — were investigated in a study on integrating wind energy into LV and MV networks [55] . The results showed low injection of voltage sags for all three case study scenarios. Observed THD was within the safety limit; however, it increased with greater wind energy penetration into the system.

The harmonic issues arising from PV systems coupled by multiple inverters have been investigated at CSIRO's Renewable Energy Integration Facility [56] . They showed that harmonic current emission is related to the output power level of the PV inverter. In addition, the current and voltage waveform distortion at the PCC to the grid can be significantly increased; however, this is most prevalent when the net power flow through the bus is small.

3.2.5.5 Voltage regulation



There has recently been much interest and concern in the industry regarding allowing EG to participate in VAR support, and therefore regulate the voltage at their bus, in the same way as a conventional generator.

For example, in wind turbines, the consumption of reactive power by an induction generator is a common problem affecting grid power quality. An induction generator requires an increasing amount of reactive power as the power factor improves at high loading, and the reactive power must be supplied locally as close as possible to the demand levels. Due to fluctuations in the active and reactive power, the voltage also fluctuates at PCCs.

A recent study [44] exemplifies why allowing EG to participate in VAR regulation requires careful consideration. The effect of using VAR-regulating EG to help shape the voltage profile of a feeder is profound, and the possible benefits are vast (see Section 3.3.4). However, it is clear that without careful management of VAR injections, unexpected, less-desirable results in voltage quality can easily occur. For example, the maximum regulated voltage limits would be expected to fall as more VAR capacity is available to the system. This is the case when comparing metrics at the same EG penetration level: which is, in this experiment, the installed capacity of EG on the system over the peak-load demand. For example, in [44] , at 25% EG penetration level, the maximum voltage falls from 1.069 per unit (pu) with 20% VAR support to 1.066 pu with 100% VAR support. At 50% EG penetration level, maximum voltage falls from 1.083 pu (20% VAR support) to 1.076 pu (100% VAR support). However, the maximum voltage limit increases over the cases without any VAR support (e.g. at 50% EG penetration level without any VAR support, it has a 1.073 pu voltage limit). These findings may be due to an inconsistent amount of VAR injection across the feeder.

Another important issue to address when considering EG reactive power participation is how much the inverter must be oversized. The authors of [47] found a substantial decrease in voltage imbalance with a modest 16% oversizing of the EG.

The capability diagram of grid-tied microgrids is defined in [58] as the import/export capability of active/reactive power. This research analysed the impacts of individual EG capability limits, load modelling, voltage regulation, EG outages, and plug-in hybrid EV operation on the limits of microgrid capability diagram. Due to time-varying load and generation patterns, the capability diagram of a microgrid will vary over time, and it is not practical for the microgrid central controller to derive capability diagrams for an entire day.

3.2.5.6 Power quality impact by technology

Table 1 and Table 2 summarise the power quality impacts identified in the literature for inverter technology and rotating machines.

Table 1 – Power quality impacts of inverter technology

	Consideration	Impact	Note
Voltage rise	Network configuration No. of feeders Voltage regulation method	May exceed the standard limit	As penetration level increases, the average voltage goes up, but minimum and maximum voltages are almost stable
Voltage imbalance	Geographical and electrical distribution of photovoltaic (PV) installation Intermittent nature of PV	1) Minor impact 2) May exceed the standard limit at the end of the feeder	1) Network phase imbalance worsens in single-phase systems due to inconsistent embedded generation (EG) distribution 2) Imbalance increases when EG installed at the end of the feeder
Flicker	Grid impedance	No noticeable impact	1) Weak network has higher flicker metrics 2) Direct flicker on a feeder without voltage regulator (urban feeders) has minor impact (low metric values) 3) Rural feeders (with regulator) are likely to see indirect flicker impact
Harmonics (total harmonic distortion)	Harmonic content of the grid voltage Series impedance of the grid PV inverter topology Current control loop technology	Normally below the standard limit, but may exceed the limit	1) Odd current harmonics generally have more impact than even harmonics 2) Total harmonic distortion increases with increasing EG penetration
Voltage regulation	Inconsistent volt-amps reactive (VAR) injection	Needs careful management	As VAR capacity increases, minimum voltage rises and maximum voltage falls

Table 2 – Power quality impacts of rotating machines

	Consideration	Impact	Note
Voltage rise/drop	Network configuration Number of feeders Voltage regulation method	May exceed the standard limit	
Voltage imbalance	Wind farm location Rural areas with weak networks Long transmission lines	May exceed the standard limit, depending on turbine location	Small wind turbines in suburban and downtown areas may help

Flicker	Wind speed variation Tower shadow effect Mechanical properties of wind turbines Start-up operation of generators	May exceed the standard limit	1) Flicker emission of variable-speed turbine (doubly fed induction generator) is lower than fixed-speed (squirrel-cage induction generator) 2) Flicker emission increases at higher wind speed
Harmonics (total harmonic distortion)	Power electronics Rotating machine characteristics	Normally bellow the standard limit, but may exceed the limit	Fixed-speed turbines have no power electronic converters, but may cause harmonic distortions due to power factor correction capacitor Turbines with converters (variable-speed turbines) inject harmonics Small amount of harmonics during start-up Harmonic distortion of the voltage is increased at minimum load and closer to wind farm
Voltage regulation	Inconsistent volt-amps reactive (VAR) injection	Needs careful management	As VAR capacity increases, minimum voltage rises and maximum voltage falls

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3.3 Options for mitigating network impacts and risks

3.3.1 Introduction

Though it is clear that embedded generation carries a set of real issues that may inhibit its capacity to play a meaningful and beneficial role in Australia's electricity networks, the solution set is rich. The range of mitigation options looks set to grow as storage technologies mature, forecasting improves, and inverters become smarter — and as systems emerge that can unify these elements to deliver highly responsive load and generation. This section explores such options, highlighting opportunities for maximising EG performance and the studies that have shown the real-world value of pursuing these opportunities. The document map on the following page summarises the resultant findings, indicating the types of network where benefit is likely to be seen, when uptake will likely deliver meaningful benefit to the network, and the significance of the opportunity.

Document map

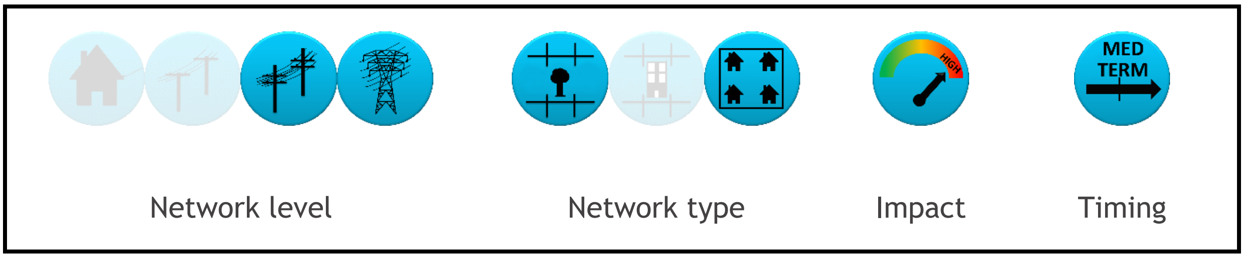
Mitigation option	Network level	Network type	Impact	Timing	Chapter section
Energy storage (grid-scale storage)			HIGH	MED TERM	3.3.2.1
Energy storage (distributed storage)			HIGH	MED TERM	3.3.2.2
Ancillary services			LOW	MED TERM	3.3.3
Intelligent networks (static compensators)			MEDIUM	NEAR TERM	3.3.4.1
Intelligent networks (passive static VAR compensators)			MEDIUM	NEAR TERM	3.3.4.1
Intelligent networks (smart inverters)			HIGH	NEAR TERM	3.3.4.1
Intelligent networks (demand response)			MEDIUM	MED TERM	3.3.4.2
Intelligent networks (ramp rate management)			MEDIUM	NEAR TERM	3.3.4.3
Enabling technologies (renewable energy prediction)			HIGH	NEAR TERM	3.3.5.1
Enabling technologies (voltage flicker identification and control)			MEDIUM	MED TERM	3.3.5.2
Enabling technologies (separate generation and load metering)			LOW	NEAR TERM	3.3.5.4
Enabling technologies (improved models for load prediction)			MEDIUM	NEAR TERM	3.3.5.5

3.3.2 Energy storage

Energy storage is often seen as a critical component in mitigating the effects of intermittency in some EG. It is also important for storing bulk energy to reduce the likelihood of reverse power flow in the transmission and distribution networks. This section highlights mechanisms by which grid-scale and distributed storage can offset key issues caused by EG.

The Australian Energy Market Commission (AEMC) and CSIRO have recently published a detailed report on the integration of energy storage into Australian networks [1] . The report describes types of electrical energy storage and existing Australian trials and deployments, and analyses technologies considered of particular interest for Australian network entities. It provides additional context for the information given below.

3.3.2.1 Grid-scale storage



Grid-scale storage encompasses several different technologies with a wide range of characteristics. These include pumped hydroelectric storage (PHS), compressed air energy storage (CAES), batteries, flywheels, superconducting magnetic energy storage (SMES) and supercapacitors.

It is not yet clear which type of energy storage will be the most cost-effective. Many people automatically think of batteries as the default form of electricity storage, but at an industrial scale, they require many improvements in the coming decades. PHS is at a mature stage of development, but locations where they can be built are limited. Other types of storage, such as flywheel and CAES, are promising technologies for particular applications and locations. For example, the remote towns of Marble Bar and Nullagine in Western Australia previously required the delivery of more than one million litres of diesel by truck each year to meet their energy needs. Through the combined use of solar power and two 500-kW flywheel storage by Horizon Power, this has been reduced by more than 400,000 litres [74] .

The potential market for energy storage devices could be 3000 MW by 2030, even without any specific government policies to support storage, but several barriers might restrict this growth [74] . The Australian Energy Storage Roadmap [75] outlines initiatives to better define and address the safety, environmental, technical, commercial and informational barriers to the deployment of both large and small-scale energy storage technologies.

The essential characteristics of typical grid-scale energy storage mediums can be described in terms of the metrics listed below [2] :

Metric	Unit	Description
Nominal energy storage capacity	kWh	Amount of energy that can be stored

Usable energy storage capacity (kWh):	kWh	Usable amount of energy that can be stored, allowing for limits on the practical depth of discharge without undesirably shortening the life of the storage facility
Typical power output	MW	Amount of power that can be discharged within the typical discharge duration
Energy density	Wh/L	Nominal storage energy per unit volume, i.e. the volumetric energy density
Power density	W/L	Maximum available power per unit volume
Charge/discharge duration	Time	Time needed for the storage to fully charge or discharge
Response time	Time	Time needed for the storage to start providing power output
Lifetime	Years or cycles	Number of years or cycles that a storage technology will continue to operate. The rating in terms of years versus cycles depends on the specific storage technology
Roundtrip efficiency	%	Ratio of energy discharged by the system to the energy required (including losses) to charge the system over each cycle
Capital cost	\$/kW or \$/kWh	Upfront investment costs of a storage technology per unit of power discharge (\$/kW) or energy storage capacity (\$/kWh)

Grid-scale energy storages can provide many grid services, which can be broadly classified based on their timescale as power (short-duration) or energy (long-duration) services. Common grid services are described below [2] :

- Power quality services
    - support use of electric energy without interference or interruption
    - generally refer to maintaining voltage levels within bounds
- Transient stability services
    - help maintain synchronous operation of the grid when the system is subject to sudden (potentially large) disturbances
- Regulation services
    - correct short-term power imbalances that might affect system stability
    - generally used for frequency synchronisation

- Spinning reserves
    - provide online reserve capacity that is ready to meet electric demand within 10 minutes
- Voltage control
    - provides the ability to produce or absorb reactive power
    - provides the ability to maintain a specific voltage level
- Energy arbitrage
    - using power that is produced during low-cost periods to serve load during high-cost periods
    - i.e., energy storage charges during off-peak times and discharges during peak times in order to provide load levelling/load shifting
- Load following (balancing)
    - adjusting power output as demand fluctuates to maintain power balance in the system
- Firm capacity services
    - provide energy capacity to meet peak power demand
- Congestion relief
    - reduces network flows in transmission constrained systems
    - done by either increasing the capacity of the lines or providing alternative pathways for the electricity [3] [4]
- Upgrade deferral
    - deferring either generation or transmission asset upgrades
    - e.g. by using energy storage to reduce peak loading on the system.

The commercial impacts and benefits associated with grid-scale storage are further explored in Section 5.4.5.

Table 3 summarises the advantages and disadvantages of several different storage technologies, while

Table 4 lists the general requirements of energy storage applications.

Table 3 – Advantages and disadvantages of storage technologies [10] . (Reproduced courtesy of Elsevier)

	Storage technology	Advantages	Disadvantage
1	Flywheel	Few environmental impact, long life, insensitive to depth of discharge, high peak power capacity, high efficiency, rapid response	Low energy density, high rate of discharge, high cost
2	PHS	Moderate efficiency, long storage duration, large capacity, long life, low cycle cost	Specific topological site, large land use, high capital cost and adverse effect on environment
3	CAES	High energy and power capacity, moderate capital cost, moderate long storage duration, quick start up, moderate efficiency, long life	Adverse environmental impact, requires burning of fossil fuels, difficult to site
4	NaS battery	High energy and power capacity, good response time, no self-discharge, high efficiency, long life time, minimum maintenance	High production cost, concerns for safety, operate with in specific temperature
	Ni–Cd battery	High energy density, long life, tolerant to temperature and deep discharge	Environmental concern, high capital cost, memory effect, need advance charging and discharging monitoring device
	Li-ion battery	Short access time, high energy density, high efficiency, long life, possible in small devices	High cost and technical issues, requires ideal charging condition
	Zn–Br battery	High energy and power capacity, long life	Low energy density, low efficiency, limited to small scale efficiency
5	SMES	High energy and power capacity, short response time, long life time and very high efficiency	Requires to be kept at low temperature, Low energy density, high capital cost, potential health issue, discharges quickly
6	Super capacitor	Moderate efficiency, long life	Low energy density, limited power system application, high discharge rate
7	V2G	Possible for distributed generation, user friendly, plug and play technology	Stills an immature technology, high cost and complex control system
8	Hydrogen	Storable, few environmental impact, transportable, moderate efficiency	Underdeveloped storage technology, risk of explosion

Table 4 - General energy storage application requirements[1], Electric Power Research Institute (EPRI) [13] .

Application	Description	Size	Duration	Cycles	Desired Lifetime
Wholesale Energy Services	Arbitrage	10-300 MW	2-10 hr	300-400/yr	15-20 yr
	Ancillary services [2]	See Note 2	See Note 2	See Note 2	See Note 2
	Frequency regulation	1-100 MW	15 min	>8000/yr	15 yr
	Spinning reserve	10-100 MW	1-5 hr		20 yr
Renewables Integration	Wind integration: ramp & voltage support	1-10 MW distributed 100-400 MW centralized	15 min	5000/yr 10,000 full energy cycles	20 yr
	Wind integration: off-peak storage	100-400 MW	5-10 hr	300-500/yr	20 yr
	Photovoltaic Integration: time shift, voltage sag, rapid demand support	1-2 MW	15 min-4 hr	>4000	15 yr
Stationary T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	10-100 MW	2-6 hr	300-500/yr	15-20 yr
Transportable T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	1-10 MW	2-6 hr	300-500/yr	15-20 yr
Distributed Energy Storage Systems (DESS)	Utility-sponsored; on utility side of meter, feeder line, substation. 75-85% ac-ac efficient.	25-200 kW 1-phase 25-75 kW 3-phase Small footprint	2-4 hr	100-150/yr	10-15 yr
C&I Power Quality	Provide solutions to avoid voltage sags and momentary outages.	50-500 kW	<15 min	<50/yr	10 yr
		1000 kW	>15 min		
C&I Power Reliability	Provide UPS bridge to backup power, outage ride-through.	50-1000 kW	4-10 hr	<50/yr	10 yr
C&I Energy Management	Reduce energy costs, increase reliability. Size varies by market segment.	50-1000 kW Small footprint	3-4 hr	400-1500/yr	15 yr
		1 MW	4-6 hr		
Home Energy Management	Efficiency, cost-savings	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr
Home Backup	Reliability	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr

1. Size, duration, and cycle assumptions are based on EPRI's generalized performance specifications and requirements for each application, and are for the purposes of broad comparison only. Data may vary greatly based on specific situations, applications, site selection, business environment, etc.
2. Ancillary services encompass many market functions, such as black start capability and ramping services, that have a wide range of characteristics and requirements.

The characteristics of different technologies and their appropriate grid services are listed in

Table 5, which highlights that characteristics and applications can vary drastically for different storage technologies. For example, the limited energy capacity of flywheels constrains these devices to provide power services, such as regulation. In contrast, technologies such as PHS and CAES have a high energy capacity; therefore, they have historically been used for services with longer time scales, such as energy arbitrage. However, recent improvements in the response time, cycle efficiency and power-to-energy ratios have expanded the potential applications of PHS and CAES technologies. For example, variable-speed pumps on a PHS system can provide frequency regulation [5] .

Table 5 also shows that different battery technologies have a wide range of energy capacity levels, charge/discharge durations, response times and efficiencies. This variety makes batteries suitable for many energy and power services. Details about the costs of different technologies are outlined in [14] .

Table 5 – Grid-scale storage technologies [2] . (Reproduced courtesy of Elsevier)

	L/A battery	Li-ion battery	NaS battery	VRB flow battery	Super capacitors	SMES	High-powered flywheels	Pumped hydro	CAES
Energy storage capacity (kW h)	$\leqslant$100	$\leqslant$10	$\leqslant$100	20–50	$\leqslant$10	$\leqslant$10	1–25	$\geqslant$150	$\geqslant$10
Typical power output (MW)	1–100	0.1–5	5	0.01–10	0.1–10	0.1–10	0.01–10	250–1000	100–300
Energy density (W h/L)	50–80	200–500	150–250	16–33	2–10	0.2–2.5	20–80	0.5–1.5	3–6
Power density (W/L)	10–400	0	0	0	100,000	1000–4000	1000–2000	0	0.5–2
Discharge duration	Hours	Minutes–hours	Hours	2–8 h	Seconds	Hours	Seconds–minutes	Several hours	Hours
Charge duration	Hours	Minutes–hours	Hours	2–8 h	Seconds	<Seconds	15 min	Several hours	Hours
Response time	<Seconds	Seconds	Milliseconds	<Seconds	Seconds	<Milliseconds	Seconds	Seconds–minutes	Minutes
Lifetime (years)	3–10	10–15	15	5–20+	5–20	5–20	20	25+	20+
Lifetime (cycles)	500–800	2000–3000	4000–40,000	1500–15,000	50,000	>50,000	>100,000	>50,000	>10,000
Roundtrip efficiency (%)	70–90%	85–95%	80–90%	70–85%	90%	>90%	85–95%	75–85%	45–60%
Capital cost per discharge ($/kW)	$300–$800	$400–$1000	$1000–$2000	$l200–$2000	$1500–$2500	$2000–$13,000	$2000–$4000	$1000–$4000	$800–$ 1000
Capital cost per capacity ($/kW h)	$150–$500	$500–$1500	$125–$250	$350–$800	$300–$2000	$1000–$10,000	$1500–$3000	$100–$250	$50–$150
Power quality			√	√	√	√	√	√	
Transient stability	√				√	√	√		
Ancillary services									
Regulation		√	√	√	√	√	√		
Spinning reserves	√	√	√	√				√	√
Voltage control		√	√	√	√		√		
Energy services									
Arbitrage			√	√				√	√
Load following	√	√	√	√		√	√	√	√
Firm capacity							√	√	
Congestion relief	√	√	√	√				√	√
Upgrade deferral	√	√	√	√	√	√	√	√	√
Advantages	Low cost, high recycled content	High efficiency, high energy density,	High energy density, quick response, efficient cycles	Higher depth of discharge, high cycling tolerance	Rapid response time, high power density	High efficiency	Rapid response time, low maintenance, high cycles	Rapid response time, large capacity	Rapid response time
Disadvantages	Low energy density, large footprint, limited discharge depth	Cost prohibitive, overheats, limited discharge depth	Safety issues	Low energy density, low efficiency	Cost prohibitive	Cost prohibitive, low energy density	Cost prohibitive, tensile strength limitations	Geographically constrained	Low efficiency, geographically constrained

In general, energy storage has the inherent flexibility to be used as a generation, transmission, or renewable energy integration asset, or a combination of these. In a power system with renewable energy resources, grid-scale storage can reduce effects of intermittent, uncertain and non-dispatchable power sources in several ways (see e.g. [6] [7] [8] [9] . As discussed throughout Section 3.2, the high penetration of intermittent renewable resource, together with demand variations, has introduced many challenges to distribution systems. These include power fluctuations, reverse power flow, voltage rise and LV stability. In such cases, large-scale storage can prevent loss-of-load by providing firm capacity. It can also suppress power output fluctuations by improving power quality or providing ancillary services such as regulation. When the availability of wind or solar power does not align with demand, storage can facilitate time shifting of loads.

For example, PV sources have been integrated with battery energy storage (BES) in a commercial distribution system to create a dispatchable PV-BES source [6] . Advances in dispatchable BES technologies provide an opportunity to make such non-dispatchable PV sources, such as conventional generators, dispatchable. Reference [7] developed a mitigation strategy for solar PV impacts by an effective use of distributed energy storage integrated with solar PV in the LV networks. The storage consumes surplus solar PV power during PV peaks, and uses the stored energy in the evening for the peak-load support. A charging/discharging control strategy considers the current state of charge of the storage and the intended discharge period. It can also reduce the impact of sudden changes in the PV output on the grid by absorbing generation fluctuations during peak output periods.

Another critical role of storage in renewable energy applications is in offsetting the types of voltage rise (or fall) caused by sharp renewable ramp rates (as seen in Section 3.2.5.1). This action is often accomplished by co-locating storage with the renewable power source [11] . Co-locating storage with wind farms can stabilise power output and regulate power levels in response to either market or operational conditions [10] .

Coupling power electronics with energy storage can improve basic storage system capabilities, power quality and grid stability [8] [9] . When power electronics include the capability to provide both real and reactive power (VAR), the integrated storage system can provide voltage support by both injecting or absorbing VAR to control voltage levels [12] . Compensating for large voltage surges or drops (referred to as HV and LV ride-through, respectively) helps maintain power quality and stability in the system [14] . Power electronics can also control storage behaviour in response to AGC signals to correct frequency deviations [10] .

Recent work has investigated coupling energy storage with flexible AC transmission system devices to provide a wider range of control options. For example, the importance of voltage-VAR instability is analysed in [6] . Figure 8 – highlights how storage and VAR injection can improve power quality and reduce the negative impacts of renewable energy. In this experiment, the PV size is 4.33 MW and 2.39 MVAR, the BES power rating is 1.8 MW and the BES energy capacity is 13.5 MWh.

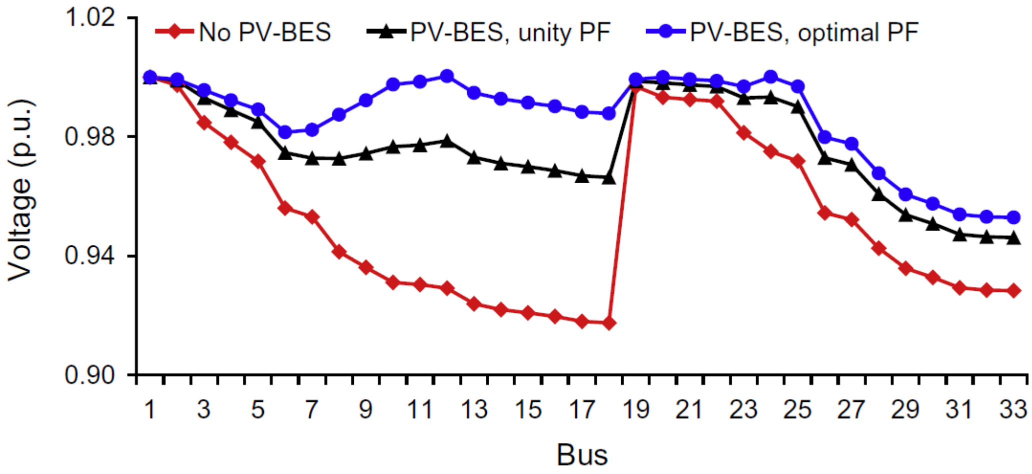


Figure 8 –Voltage profile of three different scenarios, without storage (No PV-BES), storage without VAR (PV-BES, unity PF) and storage with VAR (PV-BES, optimal PF) [6] . BES = battery energy storage; PF = power factor; PV = photovoltaic; VAR = volt-amps reactive

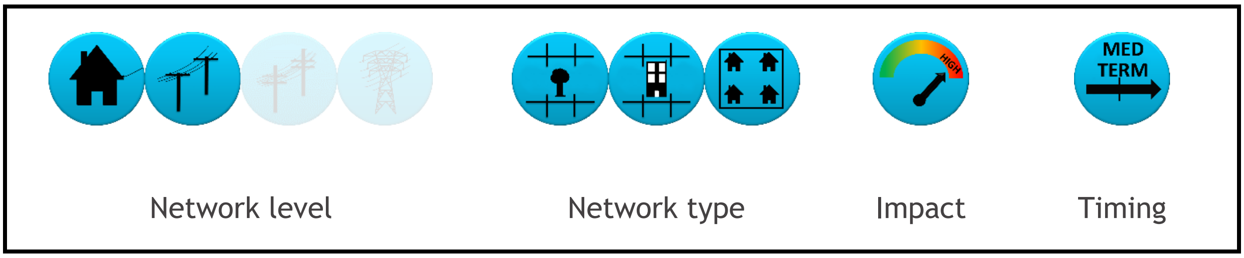
While energy storage systems can significantly contribute to planning and operation in power systems, their widespread use has been limited to date. This is due to:

- relatively high technology costs
- a lack of deployment experience
- barriers and uncertainties caused by the present electricity market and regulatory structures that were designed for conventional electricity systems
- technical limitations, such as the maximum limit of energy a given storage can hold.

For a recent international review of the implications of regulatory and electricity market structures on the emergence of grid-scale electricity storage, refer to [15] and Section 4.

Key Finding: *Grid-scale storage has the potential to provide a range of network benefits relating to EG, including voltage management, energy balancing, and improving network stability. These benefits can increase the flexibility, reliability and efficiency of power delivery to consumers.*

3.3.2.2 Distributed storage



Distributed storage is defined as an energy storage system that is connected deep within the distribution network (typically at LV and often behind the meter). It is often connected for the purpose of providing energy services to end customers, where the storage system can generate in parallel with the grid. Services can range from storing bulk energy from local generation (e.g. rooftop solar PV) and off-peak charging (energy arbitrage) to managing short-term intermittency of EG and improving voltage and power quality with inverter-based control techniques.

In this section, we address the technical benefits relating in particular to managing the negative impacts relating to EG. Section 5.4.3 details commercial and strategic benefits associated with residential storage, in particular.

Many of the mitigation strategies for grid-scale storage discussed in Section 3.3.2.1 are also valid for distributed storage. A strong case can be made for distributed storage to resolve EG-related issues, by storing energy from a local embedded generator for use at a later time. This can be broadly broken into two categories:

- fast storage, for smoothing intermittent local supply (both generation and load) and any resultant voltage variability
- bulk energy shifting, to better balance load and generation (particularly for peak-shifting).

As discussed in Section 3.2.2.6, anecdotal evidence from some DNSPs indicates that in certain parts of the LV network, extreme penetrations of rooftop solar have led to daytime generation causing peak reverse power flows, rather than the usual peak net load. In these cases, options for managing these peak flows without significant direct network investment include: curtailing the generation (either by using the energy in discretionary loads or simply dumping it), or using distributed storage to store the energy for later discharge.

Some Australian DNSPs place limits on the maximum charging and discharging current allowed to an energy storage system. This can restrict some undesired impacts of these systems, such as their contribution to peak load or generation if not properly managed. However, this may also limit the versatility and capability of the system, particularly in managing the intermittency (and accompanying voltage effects) of high-penetration renewable generation, such as solar PV.

Distributed storage is well placed to reduce the impacts of intermittent supply or peak power flow issues, due to its potential for co-location with the power flow to be balanced. This allows local constraints to drive the control strategy for the storage. This may be compared with the grid-scale case, in which the capability of storage to directly reduce impacts is restricted to those occurring at the level where the storage is connected (or higher). Grid-scale storage does have some capability to provide lower-network benefits; however, these are far more limited than that of distributed storage. For example, in the case of competing voltage and power factor impacts at different LV network points, a single MV-connected storage unit may not be able to support all of these functions, while targeted storage could.

When distributed storage is either directly or indirectly under the control of a customer, it could be expected to benefit the customer. In some cases, this might be expected to be to the detriment of the local NSP; however, economic drivers of the end-customer can align with those of the DNSP under many circumstances. In such cases, an energy storage system may provide significant value to the network at no infrastructure cost. To make the best use of distributed storage, utilities must provide incentives that will direct the customer towards controlling storage in a manner that does not conflict with, and ideally supports, the network and any issues it may be experiencing (EG-related or not). This can only occur when such incentives are permitted under the regulatory environment.

For residential battery systems to have discharge-to-grid capability, they require a grid-connected inverter (compliant to AS 4777) to convert the direct current supplied by the battery into 240/415 V AC power for the grid. As with the grid-scale storage described above, modern inverters have significant additional capability to improve network power quality through techniques such as power factor correction and volt-VAR support. Any bidirectional battery system should therefore be similarly able to assist with these functions. More information on the capability of inverters to improve network power quality can be found in Section 3.3.4.1.

Network management of distributed storage

Several options are available for allowing DNSPs to manage distributed, grid-connected storage assets for their own benefit. They are likely to receive the most direct benefit of an energy storage unit if they can direct its charging and discharging directly. Such a control strategy is used in [56] , where the power flows in and out of distributed energy storage systems are controlled by a DNSP in conjunction with tap-changing transformers to manage voltage rise due to high-penetration solar PV.

However, such central-control strategies — and distributed control strategies, which are managed solely by the DNSP or other central agency — are unlikely to encourage consumer uptake of these systems. This is key to enabling strong penetration of distributed storage without requiring massive investment from DNSPs. A more likely scenario would involve a network customer installing a battery system (perhaps coupled with a new or existing solar PV or other generation system) to manage their own energy use and maximise the economic gain from any EG they may own. A business case could be made to these customers whereby they may cede some level of control over their storage system to the DNSP, perhaps in exchange for off-peak charging tariffs for example. These systems can be used to provide network support as described above without requiring large capital investment.

Such a form of control requires an interface that enables a DNSP to take temporary control of a customer’s energy storage system. The AS/NZS 4755 suite of DR standards is currently developing Part 3.5 – Operational instructions and connections for grid-connected electrical energy storage (EES) Systems. This will expand the existing 4755 architecture to include distributed energy storage systems. Adding a 4755-compliant demand response enabling device (DRED) to a residential energy storage system will allow customers to use their system for their own benefit the majority of the time, as determined by their contract with their DNSP). At the same time, this allows the network to intervene to limit (or encourage) charging or discharging, or provide reactive power support, when it is beneficial to the network to do so. A draft issue of this standard for public comment may occur before the end of 2015. The current draft of AS/NZS 4777 Part 2 includes similar DR functionality, which will apply to all inverter energy systems and include battery-coupled inverters, This standard is expected to be published in late 2015.

Electric vehicle storage

Distributed storage can be considered to include charge/discharge-controllable EVs, with or without a bidirectional charging system. A residential EV charging station that supports vehicle-to-grid discharge of the car's internal battery can provide similar benefits to stationary distributed storage, in the context of ensuring that the EV's state of charge is sufficient when the owner intends to drive it.

The ability for EVs to provide energy storage services for network support through their participation in ancillary services markets is detailed in Section 3.3.3.2.

Storage devices as loads

Some types of energy storage devices do not (and in many cases, cannot) generally discharge to the grid. Examples of these include uninterruptible power supplies (UPS), consumer electronics such as laptops and mobile phones, and non-discharge-capable EVs. Such devices may have a significant effect on networks, particularly when taken as aggregated loads; however, they are generally similar to other power electronics systems, as detailed in Section 3.3.4.1. They may also provide benefits if properly network integrated and under some level of network control, by acting as discretionary load for the purposes of managing EG.

Some of these devices may develop into systems that overlap with the above definition of distributed storage in the future. Hybrid UPS/backup power systems already fulfil some of the role of distributed storage, as described above. As noted above and in Section 3.3.3.2, V2G-capable EVs have been developed for use in network support. However, these are currently struggling to find either manufacturer support or a market for their capabilities.

Australian trials of distributed storage

Very few trials of distributed storage have been conducted in Australia. Recently, Ergon deployed 10 residential energy storage systems alongside home energy management systems with alternative tariffs to investigate how these tools might affect consumer behaviour and reduce peak-load concerns. The trial is still in the preliminary stages, and no conclusive results have yet been published.

As part of their Smart Grid Smart City technology trial, Ausgrid deployed 60 10-kWh zinc bromine distributed energy storage systems through the Newington, Elermore Vale and Upper Gundy areas of eastern New South Wales. The results from this trial were mixed, and noted significant technical issues relating to the maturity of the battery technology that negatively affected the outcomes of the project. These issues included:

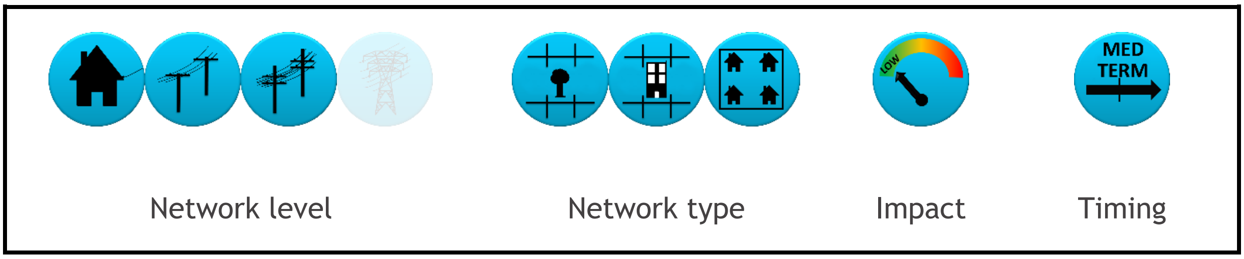
- high passive energy consumption
- difficulty matching peak load due to limited capacity, particularly for long-duration peaks
- poor battery performance at high ambient temperature
- reduced system performance after the first five months.

The trial identified that the systems deployed were smaller than would have been ideal for a residential system targeting peak-load shifting. Consequently, the results have better informed industry regarding appropriate sizing of the systems, as well as provided guidance about technology selection. While no negative power quality impacts were identified as part of this trial, the dominating factor was determined to be the strength of the Ausgrid network in the trial locations.

Although the trial's results imply significant limitations of the technology, these issues are in part due to the technology's immaturity. In particular, the reduced system performance after prolonged deployment and the significant reduction in capacity at high temperatures may have related to technical issues that could be improved upon or potentially solved by further development.

> ***Key Finding:*** *Distributed storage can provide numerous benefits to networks, including improved management of voltage and power flows, peak load and generation management, and reactive power support. Customer-owned storage has the capacity to provide these benefits alongside direct benefits to the customer, despite not being network-owned.*

3.3.3 Ancillary services



This section discusses how ancillary services can be implemented to address some of the network impacts outlined in Section 3.2. The impacts that may be mitigated by additional ancillary services include:

- energy balance
- ramp rates
- thermal loading
- losses
- demand (load) prediction
- bidirectional power flow
- phase imbalance.

Traditional ancillary services, such as fuel-powered operating reserves, are expensive to run. This section will explore contemporary alternatives, such as using EG or EV-distributed batteries for grid balancing, increasing spinning reserve capacity and load following.

3.3.3.1 Embedded generation

With increasing penetration of EG, particularly intermittent renewables such as solar and wild, system stability issues such as those discussed in Section 3.2.4 will become more likely, possibly causing power outages and damage to electronic devices [28] [29] . These issues may be addressed through additional ancillary services to ensure optimal grid operation.

A simulation study of a standard IEEE 13-bus network [30] investigated the feasibility of wind and solar-based EG to provide voltage and stability support ancillary services to a microgrid with 70% of total generation from renewables. The study found that for microgrids to operate safely (either independently or as part of a larger grid), each EG unit must contribute to ancillary services for frequency and damping support. The simulation showed that the voltage stability of the network improves during a disturbance or increase in load demand.

Reference [31] proposes that household rooftop PV systems could provide active power ancillary services. The study identified that even with the intermittency of PV generation and uncertainty related to household energy consumption patterns, there are potential economic benefits for households to provide active power support.

3.3.3.2 Electric vehicles

Several studies [32] [35] have explored customer charging behaviours and driving patterns, as well as the technical performance of EVs, to assess the ability of EV fleets to provide a range of ancillary services. They show that V2G-capable EVs may profitably provide power to the grid and can be more attractive than conventional ancillary services. They can reduce operating costs, as well as generate revenue for utilities. EVs can provide the following services:

- voltage and frequency regulation
- load balancing
- spinning reserve
- load following.

Traditionally, spinning reserve is supplied by the free generating capacity of committed units. Spinning reserves are online, synchronised generators that can rapidly increase their generation to respond immediately to unexpected power fluctuations (e.g. fast changes in load demand or a sudden loss of generation). The intermittent nature of renewable energy technologies means that more reserve may be required to maintain the stability and reliability of the power system. The expected uptake of EVs in the next 10—20 years promises the opportunity for distributed batteries in EVs to link to a smart grid, thereby increasing the power system spinning reserve capacity. This could be achieved by either dynamically reducing the EV charging load on the grid, or by increasing V2G generation.

EV-based reserves have several advantages over conventional fuel-powered reserves, including high ramp rates and negligible start-up costs. Because EVs can act as both a load (while charging) and a source (V2G), they could be used as load-following generators. If there is an increase in the power generated from renewables or a drop in demand, EVs can store the surplus energy through battery charging to minimise the mismatch between generation and loads. This flexibility of EVs may reduce many EG network impacts. As Australia’s EV uptake grows, they can facilitate and enable higher penetrations of EG (including but not limited to renewables). Significant environmental benefits would also result from using EVs (ideally powered from renewable sources) instead of traditional fuel-powered reserves.

One of the technical barriers to EV-based ancillary services is the accelerated degradation of batteries through charging and discharging. Consequently, most EV manufacturers do not significantly support V2G capability. However, although V2G may reduce the lifetime of batteries, this cost is outweighed by the value that EV-based ancillary services can bring to networks [33] . With coordinated and efficient charging/recharging strategies, EV-based ancillary services are overall more economical for both utilities and customers [33] , [35] .

There are several other barriers to increasing the penetration of V2G operations in Australia. For example, the charging and discharging current for EVs is typically limited by Australian DNSPs to 20 A for a single-phase charger, to minimise the likelihood and potential for peak-load effects, particularly in high-penetration areas. EVs with larger capacities (e.g. Tesla) can use significantly larger charging and discharging capacities, which may improve the economic case for these systems in Australia.

To export stored energy from EVs to the grid, an inverter compliant with AS 4777 is also required. This comes at substantial additional cost. While many houses will already have a compliant inverter on the premises due to rooftop solar PV, these are generally designed with a single supply point and no charging capability, indicating they are not able to be retrofitted to a V2G system. There are also significant challenges in metering and communications for control of the devices. Standards such as the now-paused AS/NZS 4755.3.4 (see Section 3.5.2.3) and the international Open Automated Demand Response (OpenADR) will hopefully assist in future development of these EV-based ancillary services.

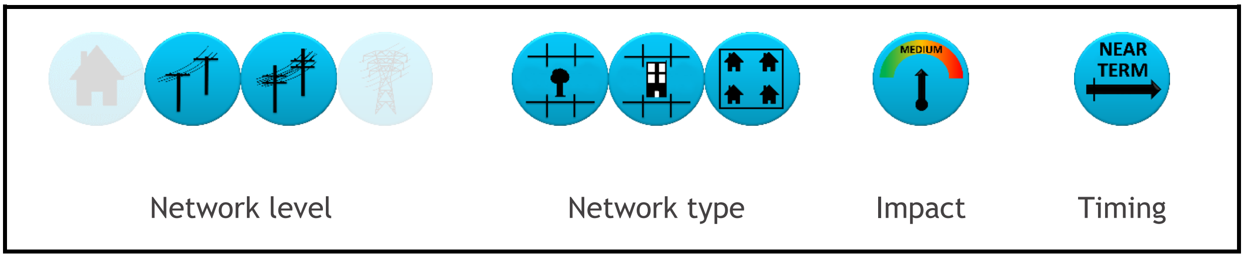
3.3.4 Intelligent networks

This section covers a broad range of topics that fall under the traditional area of the ‘smart grid’. Some of these techniques have previously been proposed to support the network in other ways. However, their relevance to the rising concern of reducing the impact of EG warrants their renewed attention.

3.3.4.1 Power electronics solutions

Power electronics solutions have been regularly touted as having the capacity to strongly control voltage variability and improve power quality at many points in the distribution network. Several power electronics devices may be able to help manage voltage and power quality issues in distribution networks. Of these, static synchronous compensators (STATCOMs), smart inverters and SVCs are particularly capable in this area, and are detailed below.

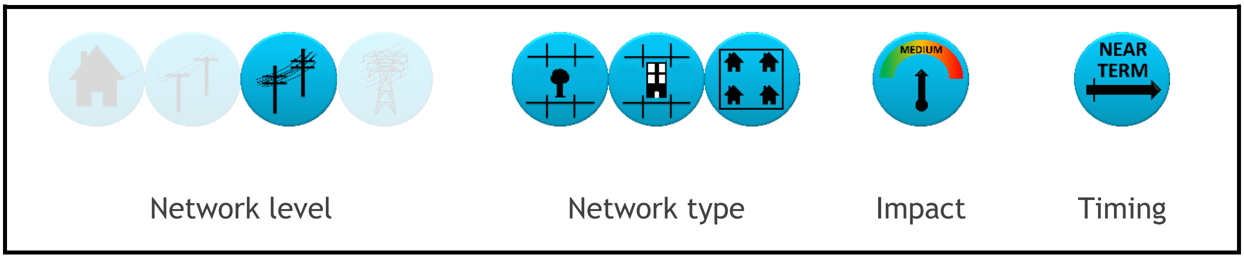
STATCOMs



STATCOMs are power electronics devices typically based on a voltage-source inverter, which is controlled in such a way as to provide one of a variety of power quality improvements in distribution networks. STATCOMs have been trialled numerous times in recent years in Australia and worldwide. Trials have ranged from relatively small deployments, in the order of tens of kVA [58] , to multi mega-volt ampere (MVA) systems connected at the substation level for feeder-level support [61] . An Australian trial [59] demonstrated significant benefits after installing a 20-kVA STATCOM in the LV network, including reduced voltage variation and reduced voltage imbalance.

STATCOMs can provide simple reactive power support, slow and fast-reactive voltage control and counter-harmonics, and also improve voltage balance between phases [62] . They can be configured to include (or be paired with) energy storage such as batteries, which allow the unit to provide real power support at peak-load times.

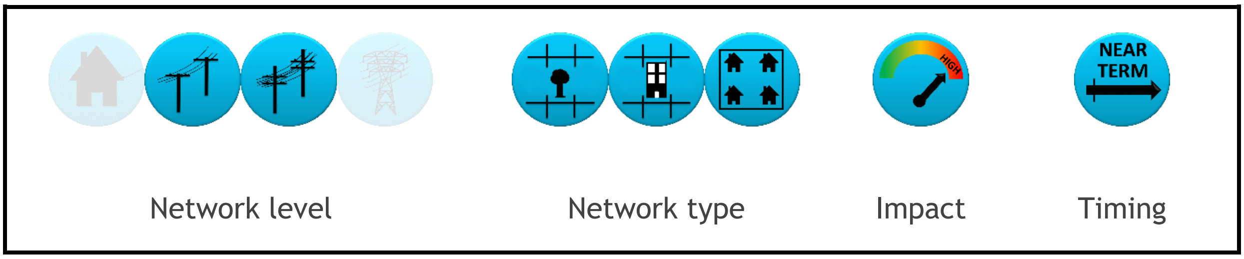
Passive static VAR compensators



While typically consisting of dynamically switched passive components, rather than active power electronics, passive SVCs can be applied in a manner that performs many of the benefits of STATCOMs and smart inverters described above. SVCs are well established and understood devices that are already being used in networks to provide both voltage support and power factor correction at transmission and distribution level. Many passive SVCs include limited capability for filtering harmonics. However, these filters are often sized to deal directly with the harmonics injected by the SVC itself, and therefore do not provide any real harmonic improvements to the wider network.

Unfortunately, the capital cost associated with passive SVCs may make them prohibitive at a small-scale distribution level. They are worth considering at larger scales, particularly when they can be co-located with intermittent embedded generators that cannot provide their own reactive power support. This may be due either to the function not being available, or because the inverters are already operating at rated power and so cannot expend any for VAR support.

Smart inverters



With the increasing penetration of inverter-coupled EG in distribution networks comes a host of grid-connected inverters. While these are often seen as causing significant issues for DNSPs, most inverters are able to perform many of the functions of a STATCOM, without the upfront infrastructure cost. In this way, intermittent or uncontrolled generation such as rooftop solar PV can be modified to facilitate its own high penetration. Inverters that can improve power factor and support voltage are often termed 'smart' inverters.

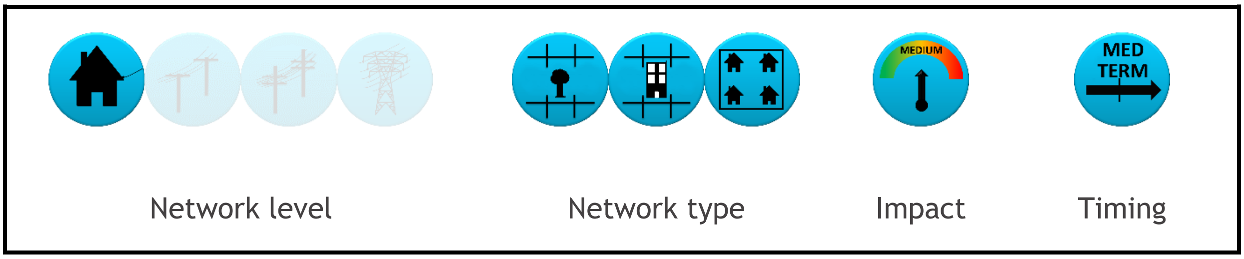
Most currently available inverters cannot act in this fashion, purely because their firmware does not support a control strategy to do so. To support this capability, a firmware upgrade is often required. We can learning from the German experience of attempting to simply retrofit the existing inverter fleet with a modified LV disconnection limit, wherein cost became a near-prohibitive issue. Instead, it may be simpler to encourage incoming embedded generators to include smart inverters as a baseline capability, and to replace failed existing inverters primarily with smart inverters.

The current revision of AS/NZS 4777 Part 2 includes the capability to offset voltage rise caused (at least in part) by the energy system the inverter is connected to. This is initially done by gradually increasing the amount of reactive power absorbed by the inverter until a nominal kVA threshold is reached. If voltage issues continue once this threshold is reached, the inverter can move to ramp down its power output, wasting potential supply energy. This is intended as a last resort, since foregone energy can represent a significant cost to the system owner.

One limitation of using distributed inverters in this manner is that voltage control is often most required at times of high export of energy, when inverters are likely to be exporting close to their rated apparent power output. This is particularly the case for high-penetration rooftop solar and the geographic correlation of power output. While this limits the capacity for smart inverters to improve power quality, it does not eliminate it. For example, a system of voltage-source PV inverters has been used overnight to control voltage fluctuations caused by the intermittency of a co-located wind farm [63] .

> ***Key Finding:*** *Power electronics solutions, such as STATCOMs and smart inverters, have the capability to mitigate power quality issues relating to EG, including managing voltage ramp-rates and excursions. In some cases, they can also reduce harmonic content.*

3.3.4.2 Demand response



DR provides an excellent resource for managing power flow issues within distribution networks. For example, the PeakSmart controlled air-conditioner trials by Energex and Ergon demonstrated that with appropriate incentives, end customers were often willing to allow DNSPs to take control of their air-conditioning systems for relatively short periods of high demand.

DR is at different levels of maturity across Australia; timing may be midterm for some jurisdictions, while others are current. Recent standards developed in Australia and internationally have provided significant guidance into how DR can be enabled technically. Hundreds of models of air conditioners from 15 manufacturers [64] can now support the AS/NZS 4755 DR architecture. Similar standards have been developed for pool pump controllers and electric hot water systems, with the prospect of battery storage and EV chargers also being investigated for inclusion. Note that the EV standard AS/NZS 4755.3.4 has been put on hold to review international development (see Section 3.5.2.3. In addition, some EV manufacturers indicate a preference for incentivised charging when beneficial for networks through appropriate tariffs or other price signals, rather than through direct charge control by DNSPs.

The primary opportunity for DR to address the impacts of EG is its ability to control discretionary loads at times when it is beneficial to the network. EG acting as a load (such as user-controlled storage charging) may otherwise cause peak-load conditions at times when this may not typically be the case. In this circumstance, being able to reduce load through DR could be a significant benefit.

A more likely case is significant excess energy in the distribution network due to oversupply of EG output, such as from rooftop solar PV. In these cases, the ability to take advantage of this oversupply by enabling discretionary loads to be switched on could benefit the network and the customer. The network could better manage issues such as voltage rise and reverse power flow, while the customer may be able to use the energy generated by their solar system in their own home.

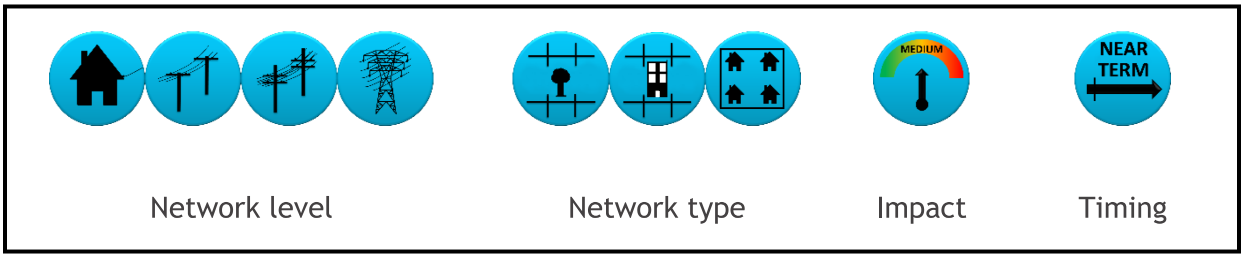
Currently, the only AS/NZS 4755-compliant systems that can turn on discretionary loads are electric hot water heaters and pool pumps. It is envisaged that this capability will also be included in the respective energy storage and EV standards, if and when they are published. Unfortunately, electric hot water and pool pump systems have yet to see significant uptake of the 4755-style control architecture, unlike air conditioners.

Reference [65] shows that air conditioners have significant capability to act as a discretionary load. They can pre-cool residences at times when energy may otherwise be dumped, as well as improve user comfort and reduce overall energy consumed. The current version of AS/NZS 4755 precludes the capability for air conditioners to push on load in this way. However, there may be scope to provide these capabilities to DR enabled air conditioners outside the AS/NZS 4755 architecture, or to modify the standard so that air conditioners that do support these capabilities are not deemed non-compliant. While the latter may appear to be a better solution from a market perspective, concerns have been raised about consumer issues, with DNSPs switching on air conditioners while the occupants are not home or do not require it. Such cases should be taken up to address these issues.

Other issues also affect the uptake and support of regulators in enabling DR for DNSPs, or that limit DNSPs' benefits relating to DR. For example, if not properly managed, the return of generation or load at the end of a peak event can induce a peak load of a similar magnitude (and conceptually higher) than if no demand event has been called.

DNSPs should use DR tools to address issues that are appropriate for the scale of the technology. A localised demand or generation peak at a distribution substation can be effectively managed by calling a targeted DR event, provided that sufficient penetration of DR-enabled loads or generators are available on the small network segment being managed. Managing a much broader peak (e.g. a zone substation) would require a similar proportional penetration on a much larger network segment, and may have unintended commercial consequences due to the impact on consumers. This highlights the need to critically analyse the requirements of a given peak, and the potential implications of managing it using DR.

3.3.4.3 Ramp-rate management



Methods to minimise or reduce the impacts of increased ramp rates of net load as a result of high penetration, intermittent EG include energy storage, advanced inverter control, active power curtailment, load control and spatial diversity of EG resources. Increasing system flexibility (or decreasing flexibility requirements) will also support increased levels of intermittent EG.

System flexibility

System flexibility can be described as the ability of an aggregated set of generators connected to a network to respond to the variation and uncertainty in net load [69] . Not including techniques such as energy storage and load shedding, measures of system flexibility [70] include:

- Minimum load
  - the lowest power output that conventional generation sources can manage without being forced to turn off
  - the lower the minimum load, the less likely generation will be forced to shut down during periods of light net load brought on by high penetration of EG
- Start/stop speed
  - the time required for generators to start-up and shut down
- Ramp rates
  - the rate at which generation can increase or decrease output
- Level of spinning reserve
  - the more spinning reserve, the greater the ability to accommodate short-term fluctuations in net load (generally at a higher cost)
- Load balancing area
  - the area over which generation output is matched to demand
  - for the Australian NEM, this is the entire east coast of Australia, including South Australia and Tasmania.

Ways to increase system flexibility include balancing the generation portfolio and introducing more flexible conventional generation. Power systems can also be redesigned to handle reverse power flow from distributed EG.

Reducing net load variability would reduce the need for increased flexibility of the system. Measures suggested in [23] include:

- energy storage
- load control
- increased control and communication
- ability to curtail intermittent EG
- spatial diversity of the resource.

Experience with systems containing large amounts of intermittent renewable generation have shown that flexibility of the portfolio balance is crucial for economic and stable operation [71] . It is predicted that generators that can vary their output as well as cycle on and off quickly will deliver high value in future energy systems, because they are best able to respond to the increasingly variable outputs caused by growing renewable penetration. Reference [70] that Californian grid operators should plan for a combination of flexible generation and import-export agreements to allow for a smaller minimum net load (load minus distributed EG) and greater net load variability. The report also suggested that the evaluation of the generation flexibility of a system should be done at the 'load-following' time scale in relation to the variability of the net load.

Curtailment

To manage the increased fluctuations in net load introduced by intermittent generation, curtailment of EG generation would be required if the generation portfolio is not sufficiently flexible, and other measures such as those mentioned above are insufficient.

A study into the degree of curtailment of variable generation required for different mixes of wind and solar generation for varying levels of system flexibility was performed on the Electric Reliability Council of Texas (ERCOT) system [69] . The curtailment requirements for varying levels of minimum load for penetration levels of up to 80% renewables were analysed. The simulation results of two scenarios are shown in Figure 9: one in which the minimum load capability is 21 GW (approximately 35% of annual peak load), and another in which minimum load capability is 13 W (approximately 22% of annual peak load). In the first case, 21% of generation from renewable energy sources had to be curtailed, due to the minimum generation constraints of inflexible wind and solar generation, which contributed only 20% of the energy demand. In the second case, less than 3% curtailment was required by increasing flexible generation, with renewables contributing 25% of the system's annual energy. For a wind penetration level of 50%, curtailment dropped from 50 to 20% for a 10% increase in system flexibility (i.e. reduced minimum loading capability). Inputs into the study would have included the load profile for ERCOT network, the local wind generation profile and the theoretical minimum load levels.

The effect of energy storage on increasing system flexibility was also investigated in the ERCOT study, the results of which can be seen in [22] . Insufficient transmission capacity can reduce flexibility, as shown by a real-world example in which insufficient transmission from west Texas to loads in the east resulted in 17% curtailment of wind generation in 2009.

The ERCOT study used theoretical values for system flexibility. For this study to be applicable in Australia, it would need to use the local generation mix and models of solar and wind generation based on local wind and irradiance data. Work of this type would be of great assistance in determining possible penetration levels of intermittent EG for local power system networks. A study could also investigate if, and to what extent, the introduction of energy storage would increase system flexibility compared with introducing more flexible generation.

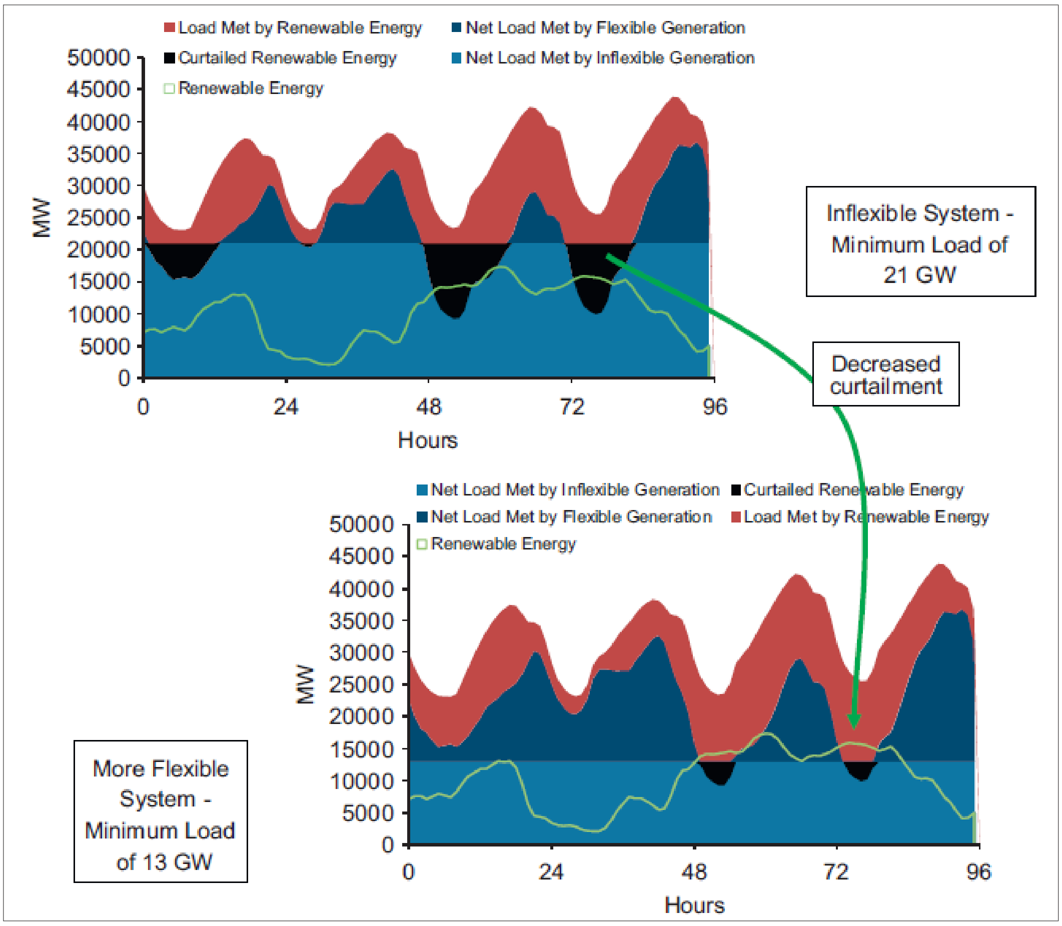
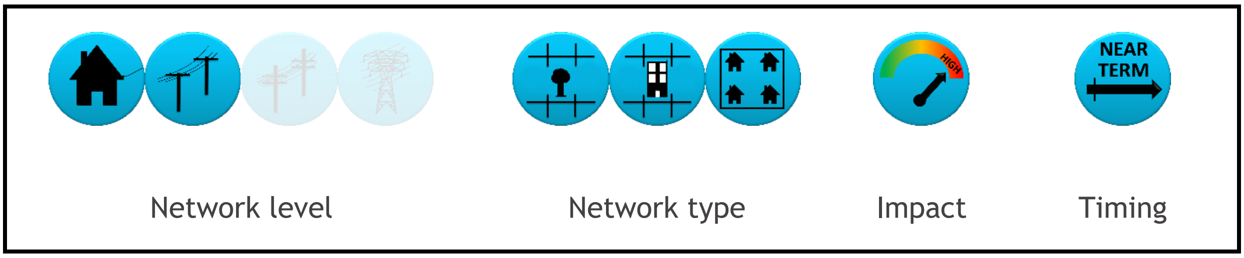


Figure 9 – Impact of system flexibility on curtailed energy, Electric Reliability Council of Texas [69]

3.3.5 Enabling technologies

Some mechanisms for reducing the impacts of EG require supporting techniques to function optimally (or in some cases, at all). This section details the technologies that could best enable the integration and uptake of the mechanisms covered in previous sections of this report.

3.3.5.1 Renewable energy prediction



Managing increased levels of intermittent renewable energy will require accurate prediction of solar and wind availability. Reliable forecasts are important for managing both the intermittency and uncertainty of renewable generation, and should be incorporated into network planning and grid and market operation, including accurate generator unit commitment scheduling.

Prediction models can be broadly categorised as either statistical and physical [19] . Statistical models apply statistical methods on existing time series of the resource, and do not involve any physical modelling. In contrast, physical models include a physical modelling of the atmosphere based on different types of atmospheric data. Hybrids of physical and statistical models are also common.

Figure 10 illustrates the recommended prediction methods for solar, wind and waves on different temporal and spatial domains; some of these are also listed in Table 6. As indicated, physical models are preferred to statistical models for long-term forecasts; however, there are some exceptions for solar. Total sky images are sometimes applied for short-term, high-resolution forecasting.

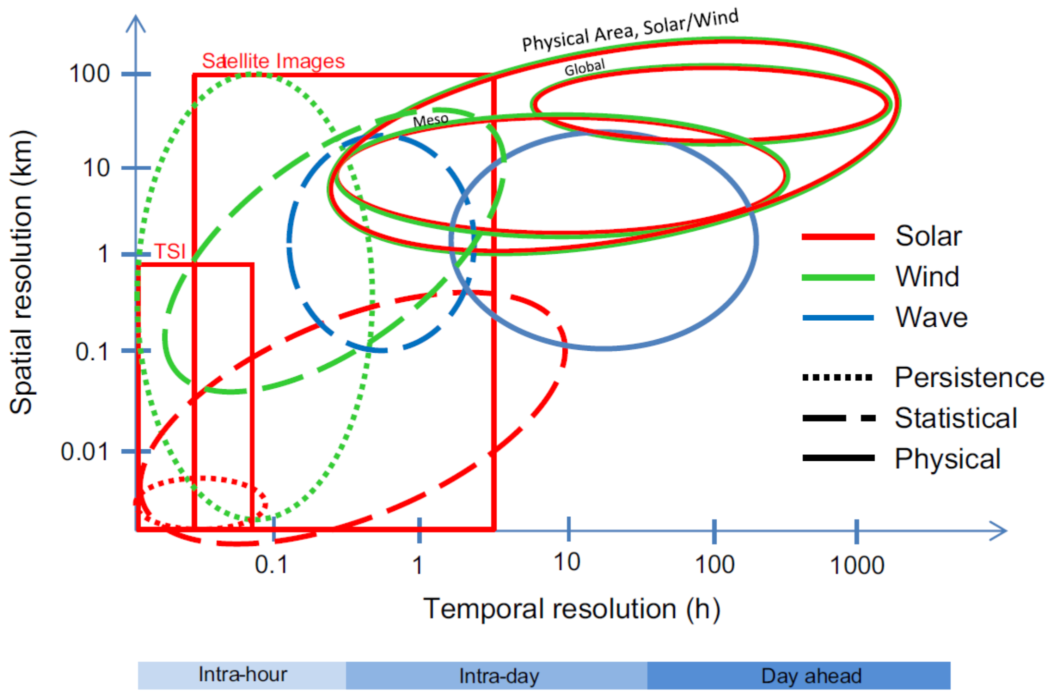


Figure 10 – Recommended prediction methods for solar, wind and wave resources in different temporal and spatial domains. [19] TSI = total sky images

Prediction at various timescales is also required. For example, improved day-ahead prediction of renewable resources is required for more accurate unit commitment, and accurate forecasts are needed to predict the rapid ramping of solar system output.

Table 6 – Some renewable resource prediction models reviewed in [19]

Resource	Method	Site	Metrics
Solar	Physical: satellite images (SI) and NWP, (NDFD)	Six sites across the United States	RMSE
Solar	Physical: NWP (WRF)	Andalusia, Spain	RMSE
Solar	Statistical: ANN	Ajaccio, France	RMSE
Solar	Statistical: ANN + GA	California	RMSE
Solar	Hybrid: ANN + SI + lagged GHI	Spain	RMSE
Wave	Physical: SWAN statistical: spectral model	Four different sites in Atlantic and one in Pacific Ocean	MAE
Wave	Statistical: mix of neural network and regressions. Two different time horizons analysed: short term and long term	Four different locations in the Pacific Ocean	Mean absolute percent error
Wind	Statistical: Markov-switching autoregressive model	Two different offshore parks in Denmark	RMSE
Wind	Physical: combined physical and statistical (Fuzzy-NN)	11 wind farms in Ireland	RMSE
Wind	Statistical: ARIMA-GARCH	64 wind farms in Ireland	RMSE

ANN = artificial neural network; GA = genetic algorithm; MAE = mean absolute error; NWP = numerical weather prediction; RMSE = root mean squared error; SI = solar irradiance;

In Australia, forecasts of solar generation would be required up to two years out, as is currently required for wind generation. Forecasts should include information about the expected output, such as the degree of uncertainty, to indicate particularly volatile periods. Since 2008, AEMO has used the Australian Wind Energy Forecasting System, which provides a wind forecast every five minutes. The system was developed in response to the growth in intermittent generation in the NEM, and to facilitate operation of the market.

In May 2014, the first phase of the Australian Solar Energy Forecasting System was installed and commissioned into the live market system at AEMO [18] , while the scientific program to design improvements was completed in June 2015. This first phase provided an operational system that uses basic forecasting based on weather forecast products and statistical techniques, to cover all of the AEMO-required prediction timeframes (from five minutes to two years). The system caters for large-scale PV and solar thermal plants, enabling the integration of solar energy generation at all scales into the national grid and allowing operators of larger systems to participate in the NEM.

The solar forecasting system is configured as an extension to the wind forecasting system, which has been successfully operating within AEMO market systems [18] . Without such forecasting systems, wind and solar renewable energy generation will be subject to increasing levels of curtailment. This will undermine both their viability and their significant contribution to greenhouse gas reduction. Note that extensions to forecasting systems to cover embedded renewable generation are likely to be more pressing as penetration levels increase.

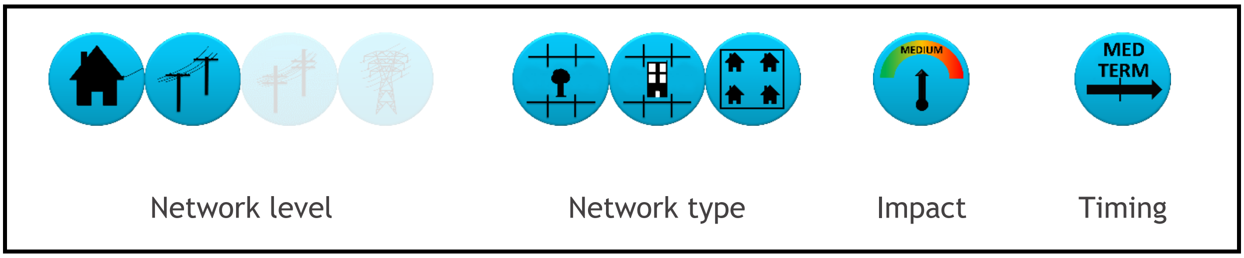
Solar intermittency is believed to be more predictable than wind intermittency, because it is affected by fewer climatic elements [16] . As discussed throughout this report, however, the ramp rates for solar (mainly PV) are potentially significantly higher than wind, due to the lack of system inertia. Solar output is more predictable in the very short term, because the movement of clouds is visible; however, accurate prediction of long-term solar output is needed to determine ways to effectively compensate for solar intermittency.

Key elements that may help to drive solar prediction across different time scales include [16] :

- temperature, irradiance and location
- correlation between weather patterns in nearby geographical locations
- ability to obtain samples at all required time intervals (i.e. seconds, minutes, hours, days)
- accuracy of data
- cross-checking of data with satellite data
- seasonal data to cater for seasonal variations
- sky-view cameras for large-scale solar farms to monitor cloud movement
- a large network of ground-based monitoring stations that correlate satellite data with their output, which should be maintained for several years.

***Key Finding**: Improved prediction of renewable generation, informed through dedicated metering, can improve EG integration by increasing the utilisation of assets such as storage and solar photovoltaic (PV)-controlled air conditioning. It can also inform decisions on power system unit commitment and network planning. These benefits can be broadened beyond EG to medium and large-scale generation.*

3.3.5.2 Voltage flicker identification and control



Typically, wind farms are connected to MV distribution feeders (e.g. 33 kV). A short-term flicker severity (P_{st}) of 0.35 is considered acceptable for wind farms installed in distribution networks, while for wind farms connected to transmission networks, the P_{st} at the PCC should be below 0.30 [20] . Refer to Section 3.2.5.3 for the definition of P_{st}.

Although this section summarises results only from wind farms, the general findings are applicable to other types of EG.

When flicker emissions are higher than the established limits, strategies for mitigation are required. Table 7 depicts strategies for reducing the flicker emission of wind farms, highlighting the main advantages and disadvantages of each. The first two strategies do not actively reduce the magnitude of voltage variations, although they do allow it to be reduced. However, these strategies are expensive and can generate environmental impact. Strategies that actively reduce the magnitude of voltage variations are more effective. These include using storage devices to smooth the net active power injected to the grid, and exchanging reactive power with the grid. The latter is preferred, because it does not need any further investment in additional equipment.

Table 7 – Strategies for flicker emission mitigation reviewed in [22]

Strategy	Advantage	Disadvantage
Strengthen the grid and increase the voltage level	Low losses	High cost and environmental impact
Increase the inertia of the wind turbines	Smoothing of the power generated	High cost
Energy storage in the DC link of back-to-back power converter of variable-speed turbines	Low cost	Low energy cpacity
Short-term storage devices in the wind farm	Fast response and active power regulation capability	The need of investments in additional equipment
Compensate voltage fluctuation by reactive power using FACTS devices	Fast response and active power regulation capability	The need of investments in additional equipment
Compensate voltage fluctuation by reactive power using wind turbine	Fast response and no need of additional equipment	Possible oversizing of the grid-side power converter of wind turbines

DC = direct current; FACTS = flexible alternating current transmission system

The authors of [21] and [22] studied flicker emissions in a DFIG-based wind farm, and found that wind generator control strategies, wind generator reactive power capability and the operating point of the power curve had large impacts on flicker emission. They propose a flicker mitigation strategy that injects compensating reactive power to the network; its value is affected by the transmission line ratio that connects the wind farm substation to the grid. This strategy can be implemented as an integrated control approach with the main control strategy, without significantly compromising the performance of the main control scheme.

The weighting between two strategies can be adjusted by varying the control parameters. Hence, a wind farm developer can adjust the mitigation level and performance requirement according to the utility's standards. The short-term flicker severity and average reactive power for a range of mean wind speeds for three main control strategies before and after implementing the flicker mitigation strategy are shown in Figure 11.

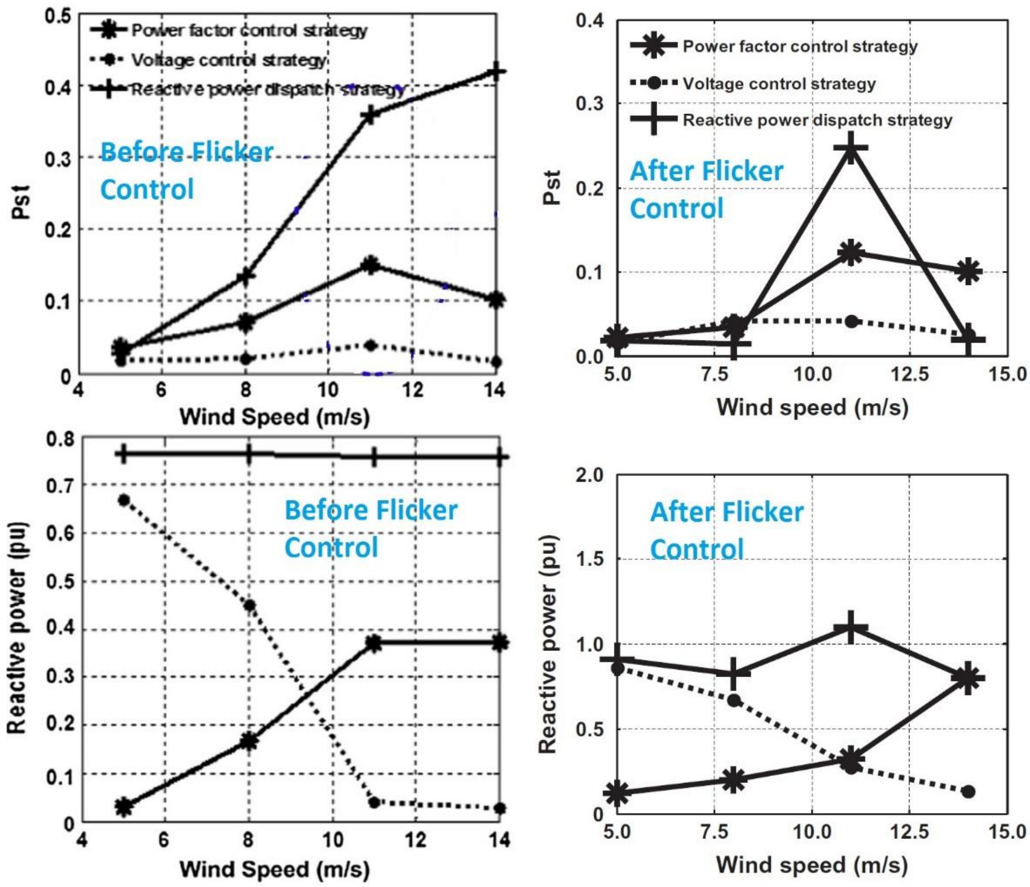


Figure 11 - Flicker emission comparison between wind generator main control strategies for different wind speeds, before (left) and after (right) implementing the flicker mitigation strategy [21]

In Figure 11, high short-term flicker severity can be seen for the reactive power dispatch strategy compared with the voltage and power factor control strategies before and after the flicker mitigation. As an example, at a mean wind speed of 14 m/s, the flicker severity (P_{st}) is 0.42 for the reactive power dispatch strategy before the flicker mitigation, while for the voltage and power factor control strategy, it is only 0.016 and 0.10, respectively. In the reactive power dispatch strategy, the DFIG reactive power capability is limited to 0.78 pu at full operating speed, hence the full active power output. This leads to reactive power deficit under certain wind conditions.

Figure 11 also shows that the reactive power requirement for the voltage control strategy has progressively decreased, since higher wind speeds imply higher active power output. However, the reactive power capability to maintain the voltage at a higher value (i.e. 1.05 pu) has also decreased. Furthermore, reactive power for power factor control strategy increases at higher wind speeds, due to the greater active power output of the wind generator. Flicker emissions substantially decrease after implementing the flicker mitigation strategy. In particular, for the reactive power dispatch strategy, short-term flicker severity (P_{st}) falls from 0.42 to 0.03.

References [23] and [24] propose individual pitch control and generation torque control methods, respectively, to mitigate the flicker emission at different wind speeds in DFIG wind turbines. The generator active power oscillation caused by turbulence, wind shear and tower shadow effects, which leads to flicker emission, is significantly damped by these control methods at both high and low wind speeds. The results that show the effectiveness of these control methods are given in Figure 12.

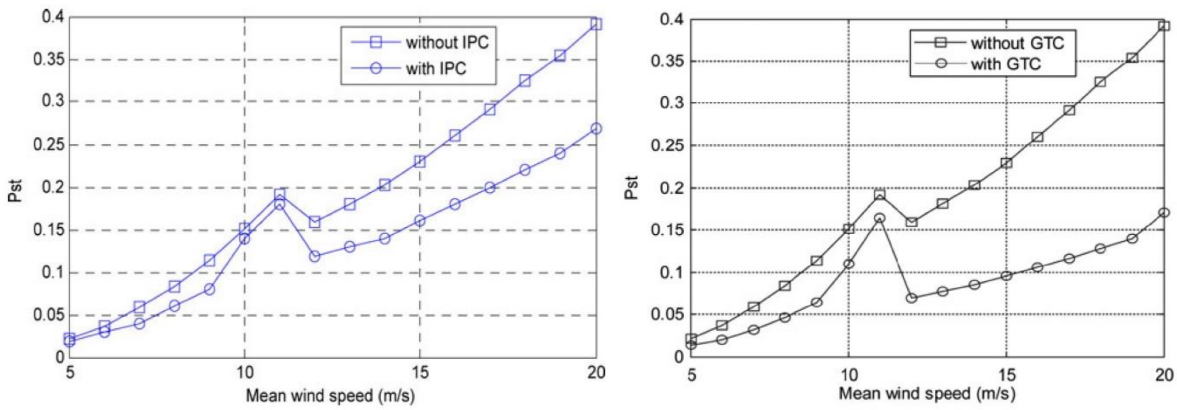


Figure 12 – Comparison of flicker values after individual pitch control (IPC) and generation torque control (GTC) with the original case (without flicker mitigation) [23] , [24] (Reproduced by permission of the Institution of Engineering & Technology)

Voltage flicker evaluation

Another aspect of flicker mitigation is usually hidden behind the flicker control strategies: effective flicker evaluation. According to the IEC standard 61000-4-15, the general functions of flicker meter can be divided into several blocks, as shown in Figure 13 [25] .

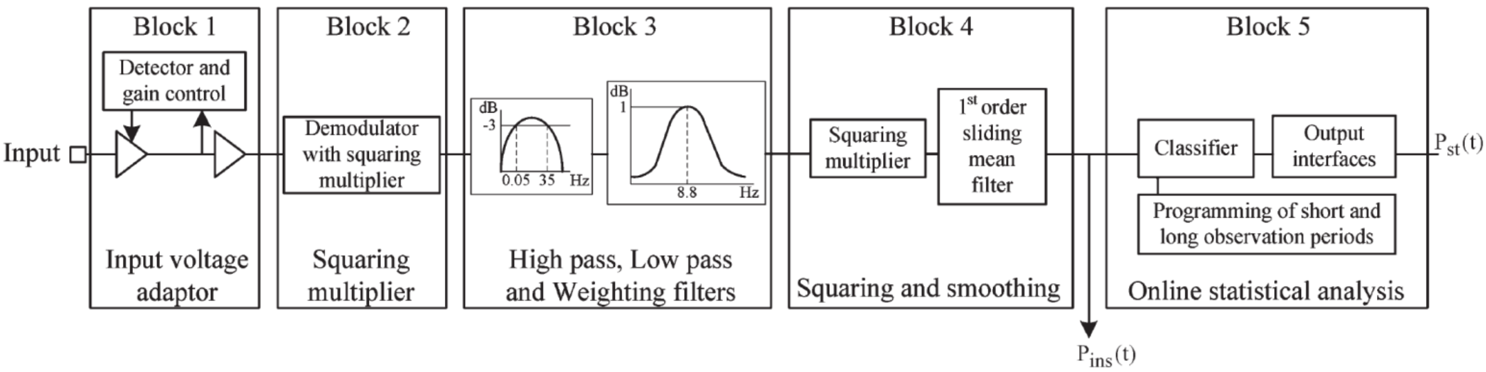


Figure 13 – Block diagram of flicker meter functions, as shown in [25] (Reproduced courtesy of IEEE)

The whole solution procedure shown in Figure 13 is complicated and successive. Some inaccurate estimation results may propagate measurement errors. An accurate solution procedure, based on conventional Prony's method, is proposed in [26] to deal with this problem. The main characteristics of the proposed mechanism are:

- The variation trajectory of flicker components can be accurately tracked.
- The calculation of the evaluation index is robust to the interferences of harmonics, interharmonics, fundamental frequency deviation and variations of flicker components.

- There is no need to tune parameters or compensate for the proposed mechanism.
- The computational burden associated with the conventional method is reduced.

The proposed solution procedure could perform an accurate calculation of flicker severity index to meet the requirements in IEC 61000-4-15, where the maximum acceptable relative error is 5%. The relative error of the new method for different case studies is within 0.5%, compared with around 8% and 11%, respectively, for conventional flicker meters and FFT methods.

Finally, a decrease in the power quality of renewable generation due to voltage fluctuations may be mitigated by foreknowledge of its occurrence. To relate the quality of power produced from small-scale renewable energy installations to the meteorological values that drive them, several neural network methods are used [27] . Data from an experimental, small-scale, residential installation that includes PV and wind power are used to build the models, and are then used to estimate the values of short and long-term flicker severity. The error of short-term flicker values is around 20% and 60% for 1 minute and 10 minute forecasts, respectively.

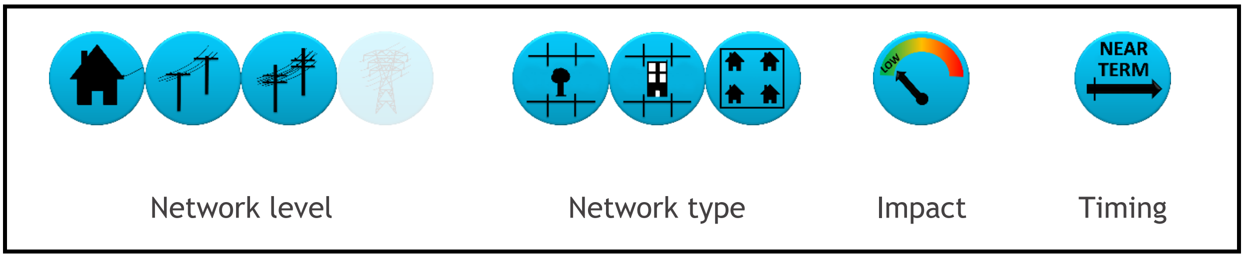
3.3.5.3 Smart meters

Smart meters are advanced interval-type metering devices that record customer energy consumption (typically reported in half-hour intervals). They provide more information than conventional meters and allow digital communications with electricity distributors.

The growing use of smart meters in Australia can enable the EG mitigation options discussed in this report, and therefore facilitate higher penetrations of EG. Applications for smart meters include:

- improved load prediction for residential and commercial customers, especially the accuracy of short-term prediction [36] [37] , which allows utilities to plan resources and improve the balance of energy throughout the grid
- DR to shift loads to times of peak renewable output, and thereby reduce reverse power flow. Smart meters assist with both:
    - DR programs for remote on/off control of loads; and
    - flexible pricing, including time-of-use tariff structures
- outage identification and confirmation, which reduces the overall duration of the interruption and damage to assets
- supply of data to manage voltage levels [28] [37] .

3.3.5.4 Separate metering for embedded generation and loads

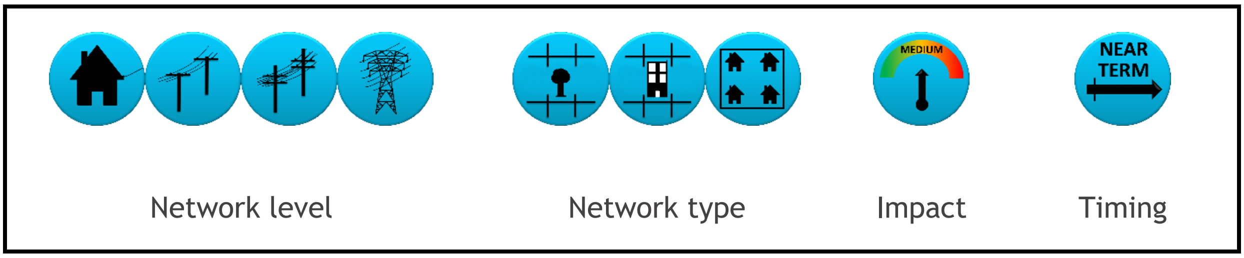


As discussed in Section 3.3.5.1, accurate prediction of loads ensures the reliability and stability of power systems, which is especially important under high penetrations of intermittent renewable EG. Separate metering of EG and loads can improve the ability to forecast loads, because the exact consumption can be measured instead of the net exports/imports.

Australia includes a significant penetration of both gross and net-metering systems. Separate metering of load and generation, as facilitated by gross metering, provides considerably greater insight into the makeup of network load and better facilitates independent prediction of load and EG production. Net metering does not support this. New load-plus-generation techniques would therefore need to be developed, as discussed in Section 3.3.5.5.

In 2001, the Australian Greenhouse Office published a document discussing different mechanisms for metering embedded generators in Australia [38] , and the benefits and drawbacks of each. While the advantages of gross metering (which allows direct measurement of EG) were discussed, the report was broadly supportive of a true net-metering scheme to simplify connection and reduce cost. As indicated above, such a scheme would not support the proposed separate prediction of load and generation. The report did not appear to include the potential benefit of separate metering in improving load prediction, most likely because it was published before the rise of household PV in Australia, when embedded generators had low levels of network impact.

3.3.5.5 Improving models for load prediction



An accurate estimation of net load is required to determine the necessary flexibility of generation for a given penetration level of EG. Models characterising net load need to clearly represent the expected variability during the timeframes of interest.

In the NEM, generators are scheduled and dispatched into production to match supply every five minutes [72] , as shown in Figure 14. Under increasing renewable EG, NEM planners must consider how much generation flexibility is required to manage intermittent renewable variability. To assist in this process, the amount or extent of variability in net load that the network might experience in a five-minute interval needs to be determined.

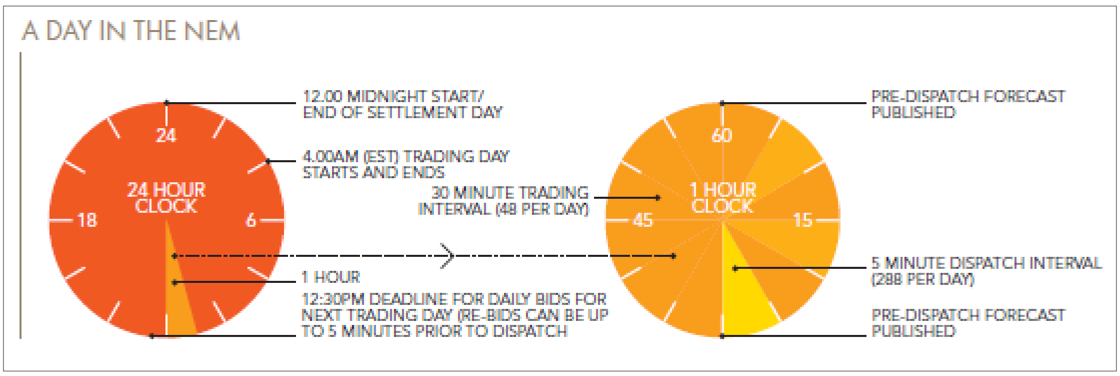


Figure 14 – A day in the National Electricity Market (NEM) [72]

For effective operation of the power system, and to ensure adequate power quality and reliable supply of electricity, generation output must match load demand at all times. This is managed in real time by the generator governors and AGC or similar systems, together with some online generators providing spinning reserve. Accurate prediction of load demand is essential to effectively manage and use both EG and conventional generation sources on the network, and to establish suitable load management systems for any smart grid. Many studies of load prediction consider EG as negative load, and defined net load as the system load minus the EG. The net load is the total load that needs to be met by conventional forms of generation.

Various models have been developed to predict load demand over different time intervals. These include neural network training using algorithms such as the steepest gradient descent algorithm, Newton algorithms and Levenberg-Marquardt algorithm for short-term load prediction for microgrids [73] . Alternatives to neural network approaches include statistically based multiple-regression models, which are more transparent and readily describable than black-box neural approaches.

Factors contributing to changing use patterns of electricity networks need to be taken into account for accurate prediction of load demand, irrespective of approach. These include:

- increased penetration of intermittent renewables-based EG
- changes to customer behaviour in response to electricity prices and new tariff structures (e.g. time-of-use tariffs)
- increased uptake of energy efficiency measures, partly encouraged by government policies
- potential increase in the uptake and use of EVs and energy storage.

Forecasts of generator dispatch long-term load demand need to be more granular: at least on an hourly basis, and possibly shorter. Better understanding of the factors listed above requires customer load statistics, detailed load profiles and EG output data for individual homes and buildings. These data also need to be more granular to be implemented in generator dispatch load prediction models, thereby allowing accurate forecasts of load demand at short time intervals.

Key Finding: *Improved network load prediction techniques that incorporate increased penetration levels of EG are necessary to retain the current benefits of short, medium and long-term prediction of net load in a high-penetration EG environment. The prediction techniques also need to incorporate any other factors that may be contributing to changing utilisation patterns of electricity networks.*

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3.4 Options for maximising network benefits

3.4.1 Introduction

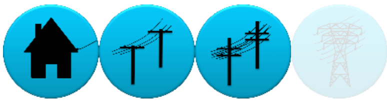
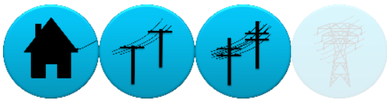
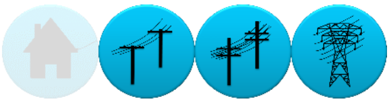
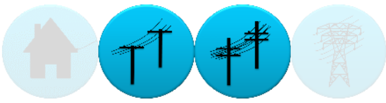
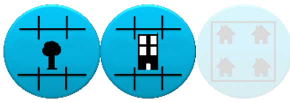
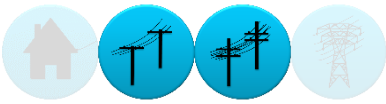
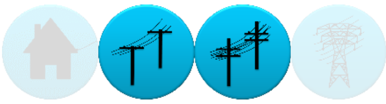
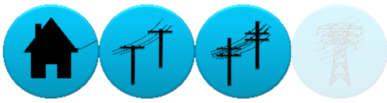
The previous sections of this chapter focus on the issues that EG may present to Australian networks, and the mechanisms available to alleviate these issues now and into the future. This could imply that EG is a problem to be solved, rather than an opportunity to be embraced.

As a reponse to this implication, this section underlines the many network benefits that well-managed EG will deliver. It draws extensively on real-world trials in both domestic and international markets to emphasise the direct benefits afforded by EG in:

- addressing peak load
- deferring network upgrades
- supporting frequency
- managing voltage
- delivering a high-reliability grid.

The document map on the following page summarises these benefits and many others, highlighting the significance of each and where and when they are most likely to deliver meaningful outcomes for Australian networks.

Document map

Benefit	Network level	Network type	Impact	Timing	Chapter section
PV and peak-load reduction			LOW	NEAR TERM	3.4.4
Power and voltage levelling			MEDIUM	NEAR TERM	3.4.5
Frequency support			MEDIUM	MED TERM	3.4.6
Dispatchability			MEDIUM	MED TERM	3.4.7
Electrical infrastructure life extension			MEDIUM	NEAR TERM	3.4.8
Reduced operating costs			MEDIUM	MED TERM	3.4.9.1
Investment deferral			MEDIUM	MED TERM	3.4.9.2
Power quality and network service provision			MEDIUM	NEAR TERM	3.4.9.3

3.4.2 Overview of relevant literature

Given the detailed nature of the literature associated with this section, we have written a brief summary of references to allow the reader to better understand the results therein. In the interests of brevity, this work is contained in Appendix C – Maximising network benefits: overview of relevant literature.

3.4.3 Embedded generation technologies

This report discusses many different types of EG technologies. These include 'secure' energy source types, such as diesel engines, gas and steam turbines, and combined heat and power (CHP) units, as well as 'insecure' intermittent energy sources, such as PV and wind. PV and/or wind combined with energy storage, which offsets their intermittent nature, is also considered an EG technology. Storage is not required for secure EG.

3.4.3.1 Storage

Forms of energy storage include batteries, pumped hydro, flywheels, supercapacitors and fuel cells. The majority of studies investigating storage as EG, including all those referred to in this report, focus on batteries.

Battery storage systems can be categorised as either a battery energy storage system (BESS) or hybrid energy storage system (HESS). A HESS combines battery storage with a more responsive technology, and in one case referred to here, also uses a STATCOM [11].

Battery energy storage systems

As noted in Section 3.3.2, BESSs can reduce the costs of peaking plants by reducing variable operation (ramping requirements) and minimising start and stop operations. This increases plant efficiency and reduces maintenance costs [10], and is a strategic benefit of energy storage that needs to be recognised. Properly deployed energy storage will allow utilities to participate in novel business opportunities, protecting them against inevitable challenges to their existing business models [14].

BESSs can absorb and deliver both real and reactive power with subsecond response times. With these capabilities, BESSs can mitigate solar power generation issues such as ramp rate, frequency and voltage issues [7].

A BESS typically consists of a:

- battery bank
- control system
- protective circuitry
- power electronics interface, for AC-DC power conversion
- transformer, to convert the BESS output to the distribution or transmission system voltage level.

The four-quadrant power electronic converter on a BESS can inject reactive power to maintain either a power factor or voltage set-point on the bus. The benefits of improved power factor are reduced power system losses and reduced line current upstream of the reactive power source [7].

BESS battery types are summarised in [11]. Lead-acid batteries are the most common type of BESS, because they are the cheapest. Their drawback is their lifespan, which is considered short at typically less than 1000 cycles and is shortened by deep cycling. Lithium-ion batteries are expensive, but have a longer lifespan than lead-acid batteries, and are not affected by deep cycling. They are also more efficient (the efficiency of a battery is the ratio of the possible energy output from a battery (discharging) for an amount of input energy (charging) [21]). Sodium sulfur batteries are also more efficient than lead-acid batteries, have a longer lifespan and are less affected by deep cycling (2500 cycles). They can also be scaled to the MW range, but pose a safety risk due to their high operating temperature.

The vanadium redox battery (VRB) has a long service life and is considered an excellent candidate for large-scale PV applications, although it is expensive. The power and energy ratings of VRBs are independent of each other, which increases the battery's scalability for PV systems of different power ratings. The one major drawback of the VRB is its low efficiency when operated at less than 20% of its rated power. Hence, one of the objectives of the VRB power management system is to avoid its operation at low power levels [11].

Hybrid energy storage system

The benefit of a HESS over a BESS is that the strengths of each technology are combined to improve system performance.

The challenge facing HESSs lies in the management of power sharing between the technologies. Power sharing is assigned according to the response time of each technology. A smaller storage device with a fast response time manages small, high-frequency power fluctuations, while a larger storage device with a slower response time manages large, low-frequency power fluctuations [11].

3.4.3.2 PV Combined with Storage

Figure 15 presents a simple one-line diagram depicting a BESS in parallel with a solar PV system. Power conversion can typically operate in all four power quadrants, able to inject real power and both inject and absorb reactive power. A BESS/PV system can also perform load shifting. This reduces congestion, line losses, and pollution from inefficient peaking power plants that only operate at times of peak demand [7].

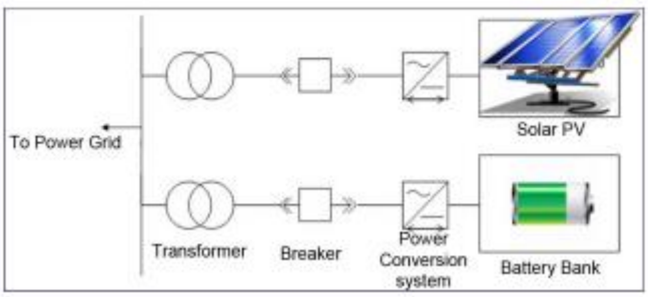


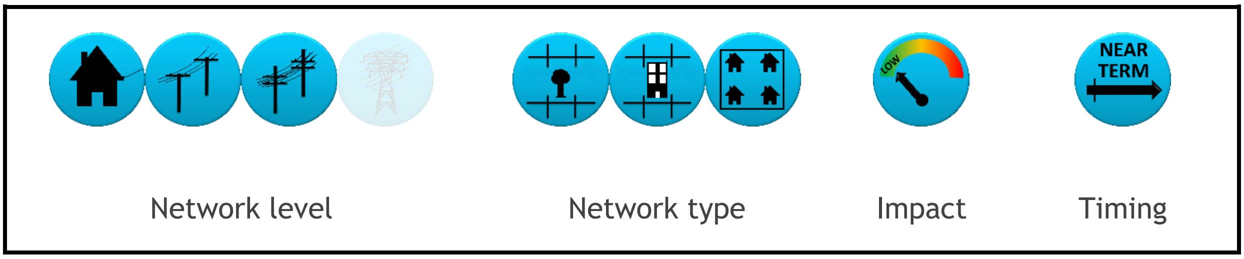
Figure 15 - One-line diagram of battery energy storage system and photovoltaic (PV) system [7] (Reproduced courtesy of IEEE)

The technical benefits of a PV/STATCOM/BESS system, summarised in [10], include:

- ancillary services

- voltage regulation support
- provision of MW and MVAR support during critical contingencies
- provision of LV ride-through by PV inverters during faults
- postponement of transmission upgrades in constrained circuits.

3.4.4 Photovoltaics and peak-load reduction



This section explores the extent to which PV generation coincides with peak load, and the subsequent ability of PV to contribute to peak load reduction.

The ability for PV generation to reduce peak load depends on the naturally occurring coincidence between the two. Load profiles vary according to load type; residential peak load tends to occur during late afternoon/early evening, while commercial peak load tends to occur near the middle of the day. Both load and generation profiles vary according to location and season. As a result, the coincidence between PV generation and peak load varies according to location and season.

Reference [4] shows how PV can reduce peak commercial loads. Figure 16 illustrates an approximate reduction in peak load of 500 kVA for a 10% PV penetration level, and a 1.5 MVA reduction for 20% PV penetration.

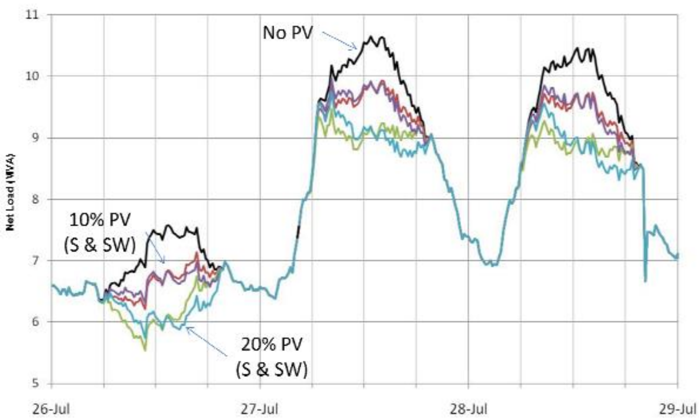


Figure 16 - Reduction in peak commercial load due to photovoltaic (PV) penetration [4] (Reproduced courtesy of IEEE)

AEMO has provided information about the contribution of rooftop PV data to reducing summer and winter maximum peak demand in different regions of the NEM [22]. The data produced for summer is analysed in Figure 17. No results for winter are shown, because the reduction of winter peak demand due to PV is negligible. The summer results show that reduction varies according to year and state. For example, in 2005—06, South Australia had the highest proportion of installed PV contributing to reducing maximum peak demand, at nearly 50% of the installed PV. This value dropped to less than 20% for 2012—13. New South Wales recorded the highest contribution, at nearly 30% in 2012—13. The variation in contribution is due to varying customer load demand; reduced contribution indicates that maximum peak demand is being pushed back in the day.

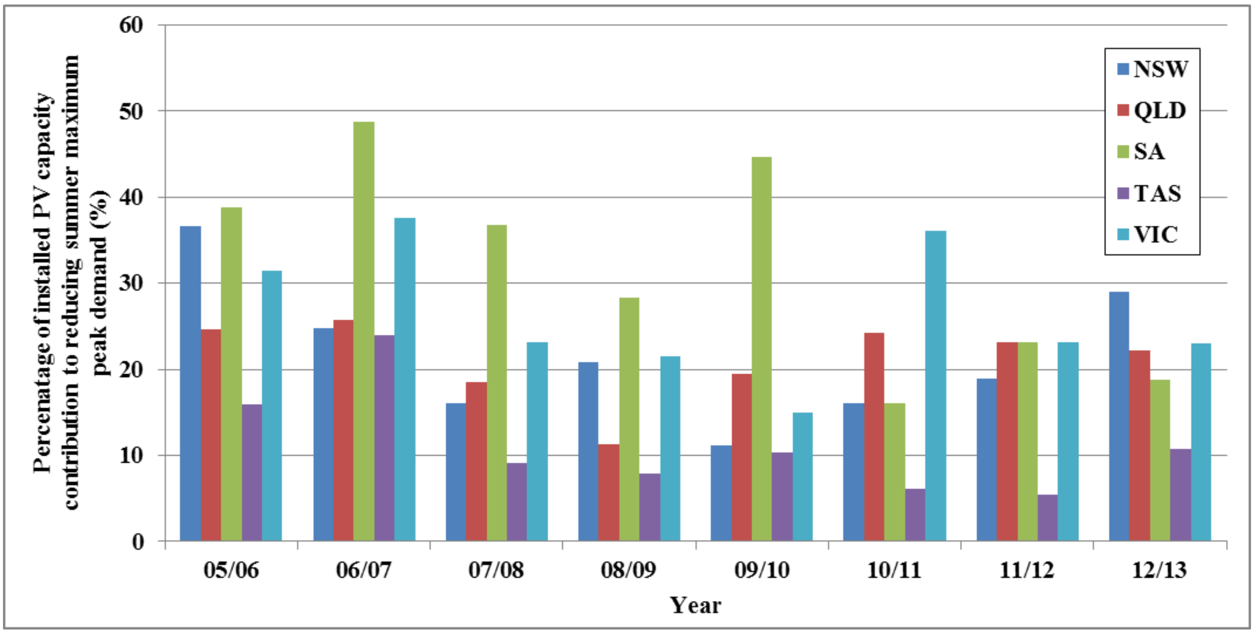


Figure 17 – Percentage of installed photovoltaic (PV) capacity contribution to summer maximum peak demand (%) [22]. NSW = New South Wales; QLD = Queensland; SA = South Australia; TAS = Tasmania; VIC = Victoria

The following sections review DNSP studies of the effects of PV generation on peak demand in their networks (including projections for higher PV penetration levels) and outline the extent to which PV can reduce peak load in geographically diverse jurisdictions. The studies provide evidence of reduction in peak load due to solar PV installations, with variation between DNSP jurisdictions. Observed and projected peak-load reductions range from 0.3—2.95% depending on geographical location and PV penetration level. Larger reductions (~2.95%) are seen for simulated networks running at 50% PV penetration.

3.4.4.1 Western Power

Western Power estimates that PV systems reduced the 2011 system peak load by 0.62% (24 MW) and the substation peak load by as much as 1.75% in some locations [23]. In 2012, a decrease in peak demand of 1.33—1.72% due to PV was observed.

Increasing uptake of PV systems across the network is expected to reduce the system peak even further. Western Power has undertaken various PV saturation trials and simulations, estimating a projected peak reduction of 2.95% (135 MW) by 2017 (Figure 18) under higher penetrations of PV. The peak load is reduced, and the new peak occurs slightly later in the day.

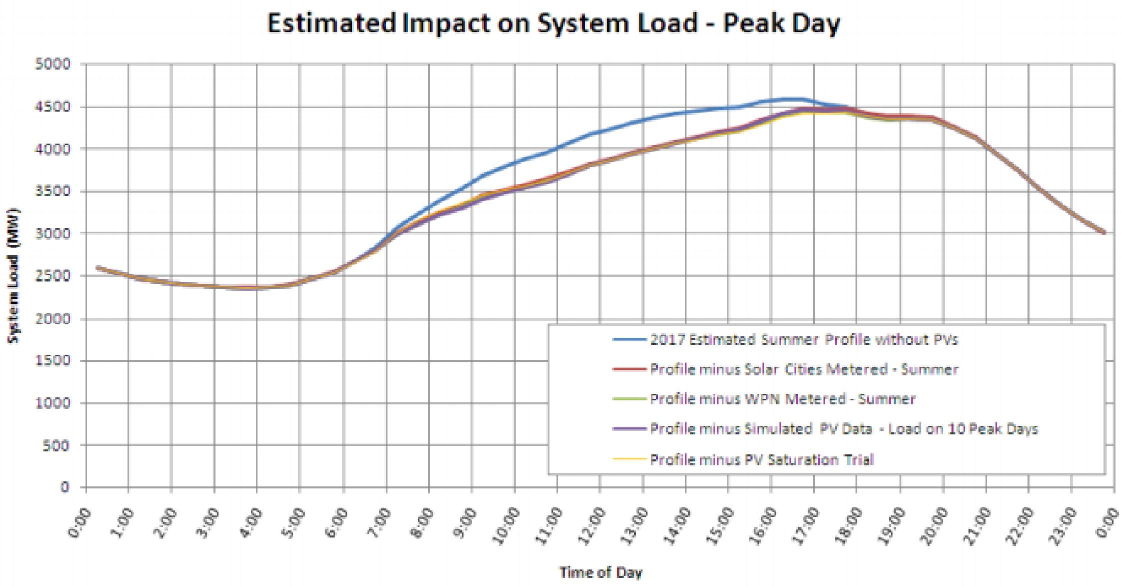


Figure 18 - Projections of peak load in 2017 [23]

Table 8 outlines Western Power's summary of average impacts and recommended adjustment to system peak forecasts. The ability of PV to reduce peak demand increases under higher forecasted penetrations out to 2017.

Table 8 - Summary of average impacts and recommended adjustment to system peak forecasts [23]

Year	Photovoltaic capacity (MW)	Forecast peak (MW)	Peak reduction (MW)	Peak reduction (%)
2013	243	4093.09	72.26	1.77
2014	299	4208.01	88.52	2.10
2015	357	4324.27	105.36	2.44
2016	414	4438.31	121.90	2.75
2017	472	4584.49	135.33	2.95

3.4.4.2 Ausgrid

Ausgrid [24] investigated reductions in peak demand resulting from the New South Wales Solar Bonus Scheme. They concluded that the reduction was not significant enough to warrant deferring investment in the electricity network. The greatest potential for network investment deferral was identified at Charmhaven Zone Substation on the Central Coast. However, the above average PV penetration was still estimated to be insufficient to offset the need for an additional zone substation transformer. Ausgrid found that if the uptake of PV on this substation were increased threefold, there could possibly be enough peak-load reduction to defer upgrading the transformer for one year. The value of this deferral was estimated as equivalent to a feed-in tariff of one cent per kWh over 10 years for only the PV customers supplied by Charmhaven Zone Substation.

Table 9 and Table 10 list the estimated impact of PV and associated percentage reduction in peak demand for different summer peak days and across the top five zone substations in 2011. The reduction is as much as 1.2% at Avoca Zone Substation.

Table 9 - Estimated solar impact on Ausgrid summer peaks for summer 2010—11 [24]

Summer peak day	Date	Day	Time of peak (Eastern standard time)	Actual system peak (MW)	Estimated solar impact (MW)	% reduction
1	3/02/2011	Thursday	4:00 pm	6072	18.0	0.30
2	1/02/2011	Tuesday	4:00 pm	5922	22.5	0.38
3	2/02/2011	Wednesday	4:00 pm	5802	21.6	0.37
4	4/02/2011	Friday	3:30 pm	5553	23.9	0.43
5	31/01/2011	Monday	4:00 pm	5423	22.9	0.42

Table 10 - Summary of solar impact on summer peak 2011 at top five zone substations [24]

Zone	Zone peak date and time	Zone peak (MVA)	Rated capacity of solar connected at time of summer peak 2010/11 (MW)	Estimated solar impact at time of summer peak 2010/11 (MW)	Estimated % peak reduction
Pennant Hills	5/02/2011 17:30	83.75	1.33	0.38	0.5
Pennant Hills	3/02/2011 17:30	79.84	1.33	0.33	0.4
Pennant Hills	2/02/2011 17:00	79.85	1.33	0.49	0.6
Pennant Hills	4/02/2011 17:00	75.64	1.33	0.54	0.7
Avoca	5/02/2011 16:00	43.27	0.93	0.50	1.2
Avoca	3/02/2011 18:00	40.50	0.93	0.18	0.4
Avoca	1/02/2011 18:30	39.71	0.93	0.11	0.3
Avoca	2/02/2011 18:30	36.70	0.93	0.11	0.3
Nelson Bay	3/02/2011 17:30	44.28	0.97	0.31	0.7
Nelson Bay	3/02/2011 18:00	42.64	0.97	0.26	0.6
Nelson Bay	5/02/2011 17:30	38.76	0.97	0.35	0.9
Nelson Bay	2/02/2011 17:30	37.73	0.97	0.34	0.9
Sefton	1/02/2011 17:00	76.06	0.68	0.27	0.4
Sefton	2/02/2011 16:30	72.95	0.68	0.33	0.5
Sefton	3/02/2011 17:00	72.40	0.68	0.27	0.4
Sefton	31/01/2011 16:30	70.39	0.68	0.33	0.5

Charmhaven	3/02/2011 16:30	44.24	0.93	0.24	0.5
Charmhaven	1/02/2011 17:30	43.73	0.93	0.31	0.7
Charmhaven	5/02/2011 17:30	43.50	0.93	0.31	0.7
Charmhaven	2/02/2011 18:00	39.77	0.93	0.24	0.6

Ausgrid has also shared half-hour electricity data for 300 homes with rooftop solar systems that are measured by a gross meter [25]. The meter measures and records the total amount of solar power generated every 30 minutes. Ausgrid examined the 2014/15 season and estimated a reduction in summer peak demand at the zone substation level of about 50 MW from the 240 MW of generation capacity. Each of the 187 substation zones were split into three categories (Table 11). The zone peak between 11:00 am and 4:00 pm is categorised as 'High', between 4:00 pm and 6:00 pm as 'Medium' and after 6:00 pm as 'Low'.

Table 11 – Reduction in peak demand for each zone substation category, 2014—15 [25]

Solar effectiveness	Year	Total system load (MVA)	Rated capacity of connected solar (MVA)	Estimated solar contribution at time of peak (MVA)	% solar effectiveness	No. of zones
High	2015	2483	59	32	54	66
Medium	2015	1943	110	18	17	63
Low	2015	633	72	0	1	58
Total	–	**5059**	**241**	**51**	**21**	**187**

A histogram of this analysis shows that the contribution from solar at the zone substation level averages about 1% and finds a maximum of 6% (Figure 19).

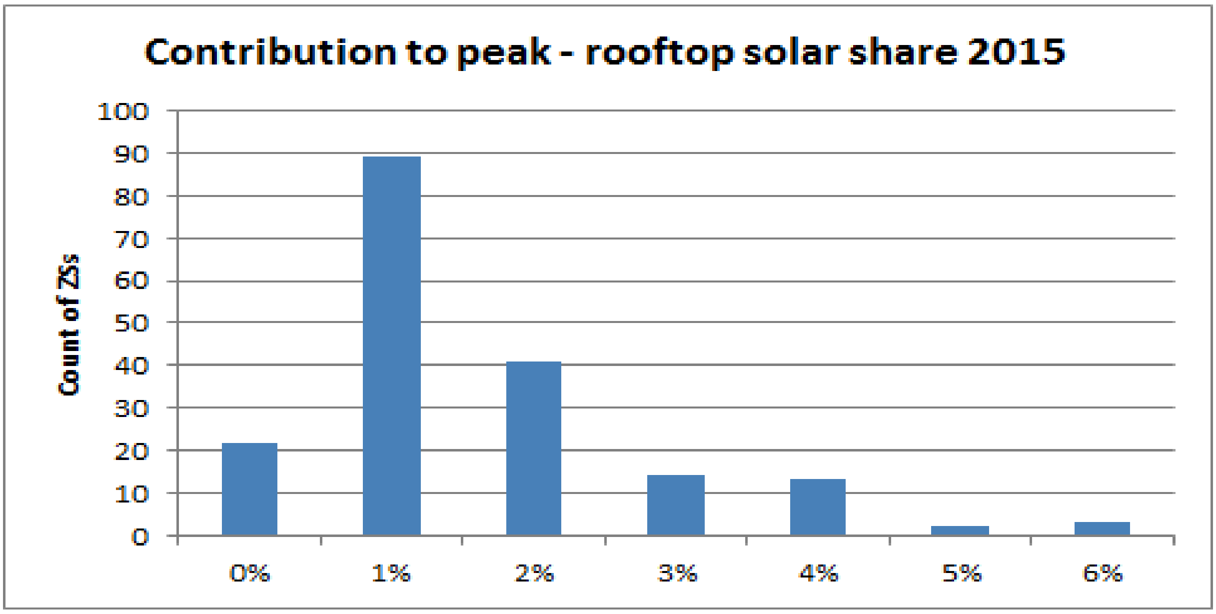


Figure 19 - Rooftop solar contribution to maximum peak reduction of analysis of 2014/15 [25]

Ausgrid notes that 2015 was generally mild, with no extreme temperatures. When there are higher temperatures and higher demand, peaks at zone substations are typically pushed back in the day while residential air-conditioning ramps up, with a resultant lower contribution from solar. A coarse estimate on the impact of very hot days on PV and maximum peak coincidence indicates that the solar effectiveness drops to 15—20%.

Analysis of the 2010/11 data from [25] is summarised in Figure 20 and Figure 21. The total load for 300 homes was combined, and the daily maximum peak demand (kW) identified (the blue curve in Figure 20). The total PV generation for all 300 homes was also combined; this value was subtracted from the total load. The reduction in the daily maximum peak demand due to PV was then identified (Figure 20, red line). Figure 21 gives the percentage decrease in the daily maximum load due to PV.

The figures show that maximum peak reduction only occurs during the summer months. Figure 20 indicates that on higher demand (hotter) days, the reduction in maximum peak demand due to PV is also higher. On the two days where the highest percentage reduction occurred (>20%), the maximum peak demand was 600 kW. Maximum peak demand occurred during early February, ranging between 600 and 840 kW. During this period, maximum peak reduction ranged between 3 and 20%.

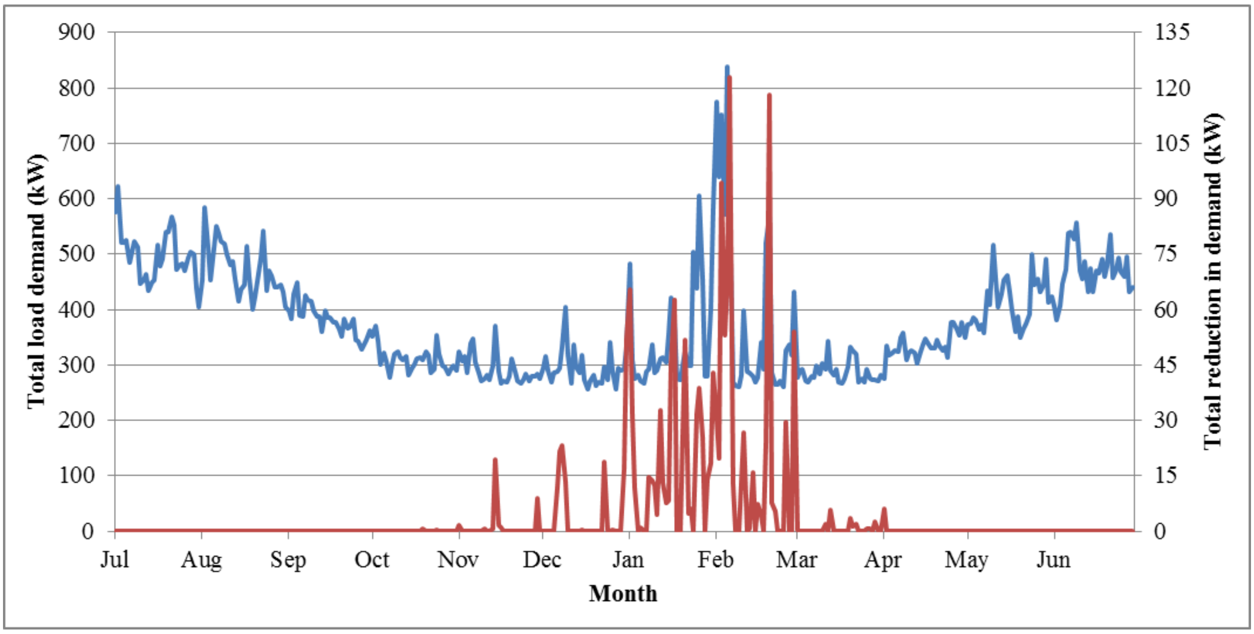


Figure 20 - Maximum peak demand (left y-axis, blue) and reduction in peak demand (right y-axis, red), 2010—11 [25]

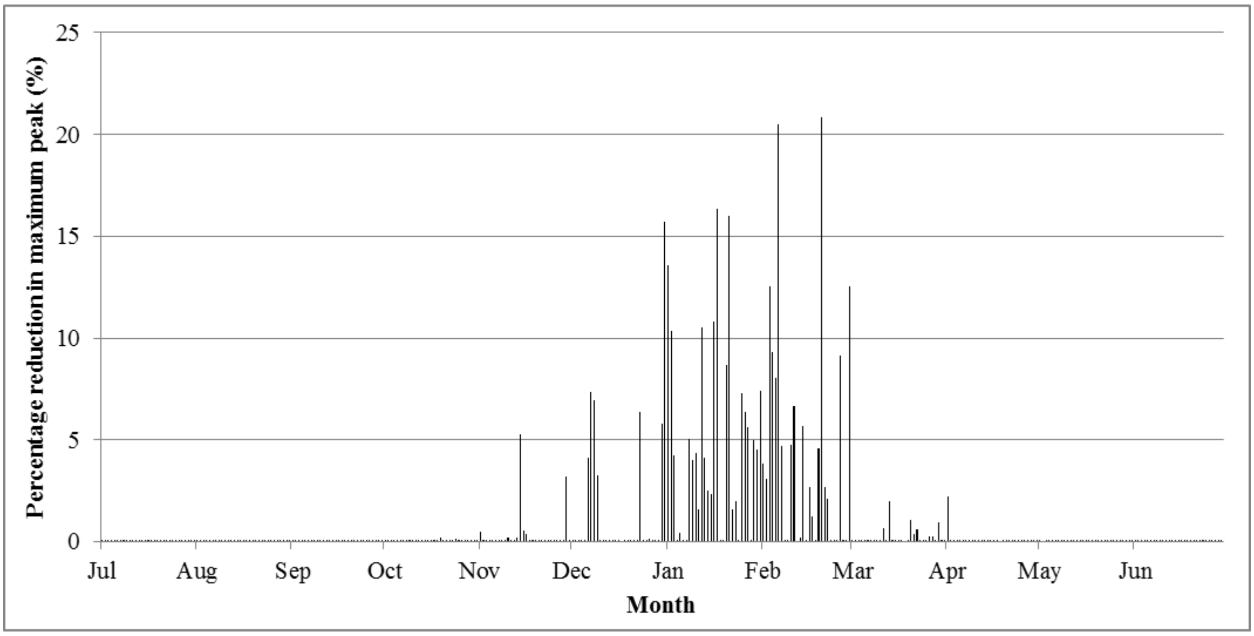


Figure 21 - Percentage reduction in maximum peak demand, 2010—11 [25]

3.4.4.3 Energex

Energex state that the impacts on domestic peak demand for upstream assets tend to be negligible across their network [2]. They acknowledge some benefit from a small number of solar PV installations on some commercial buildings attached to commercial and industrial day peaking substations and 11-kV feeders. On a typical day, these installations may reduce the overall network peak demand. Figure 22 shows the system peak occurring at around 2:00 pm for the load, not including solar PV generation. On this day, Energex estimated a peak reduction of more than 335 MW and peak-load shift to 3:00 pm. However, they acknowledge that factors contributing to this reduction may include temperature, humidity and degree of cloud cover. In different circumstances, PV may have no impact on peak demand, particularly at local levels.

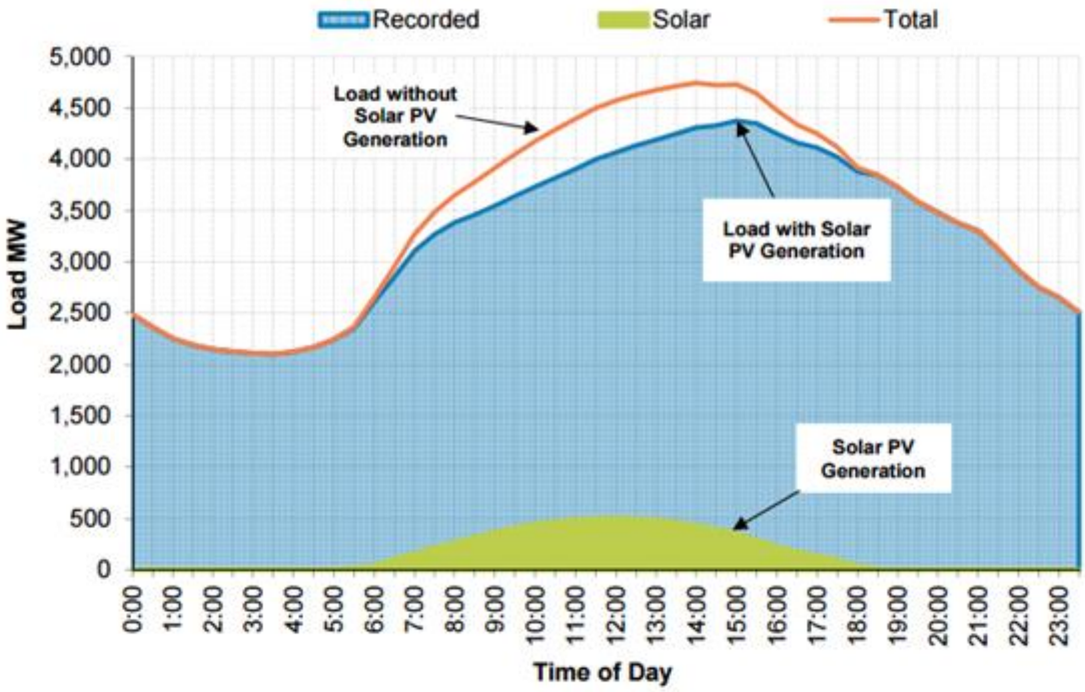


Figure 22 - Energex system demand, solar photovoltaic (PV) impact, 22 January 2014 [2]

3.4.4.4 Endeavour Energy

Endeavour Energy identified a negligible effect of PV on peak demand, even at 50% penetration of 1.5-kW systems [26]. Figure 23 was included in Endeavour Energy's submission to the New South Wales Independent Pricing and Regulatory Tribunal in 2010. It compares the theoretical 50% penetration PV output with the 2010 summer peak demand at a major zone substation in Glenmore Park. The figure shows only a very slight overlap between PV generation and peak demand.

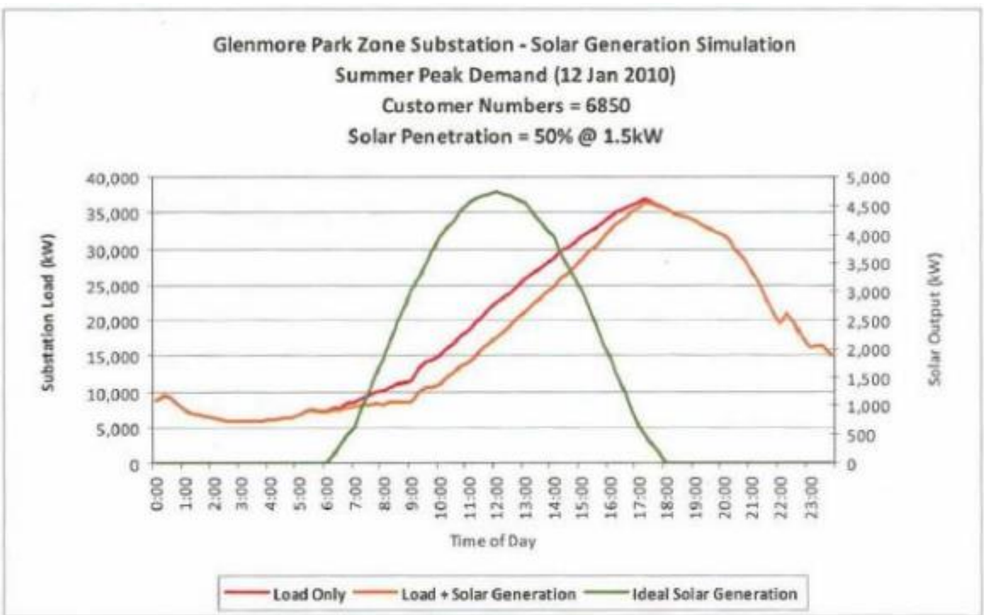
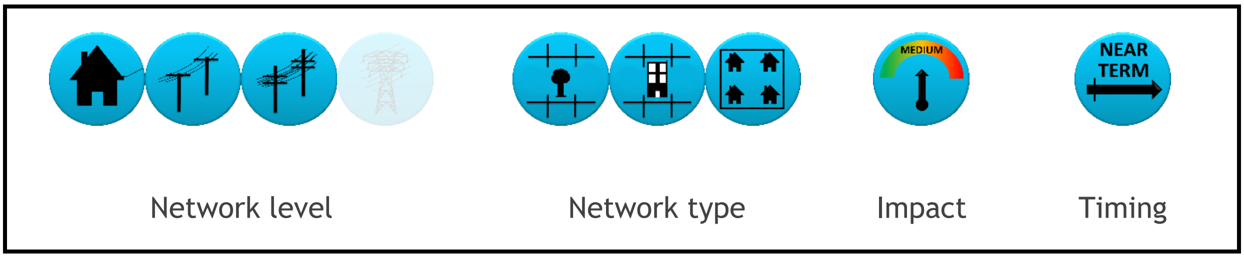


Figure 23 - Theoretical solar output compared to substation demand, 2010 [26]

3.4.4.5 Panel orientation

Peak load may be reduced further by orienting solar panels to the west. This would reduce the mismatch between PV generation and load profiles by increasing late afternoon PV generation, thereby increasing the chance of overlap with peak network load. The extent to which panel orientation may influence peak load was not found in published literature. However, it may be worth exploring further. If the reduction were significant enough, it may be worthwhile offering incentives to customers installing west-facing panels.

3.4.5 Power and voltage levelling



Power and voltage profile levelling involves minimising both high-frequency (seconds) and low-frequency (hours) fluctuation in voltage and power. Levelling reduces peak load and alleviates congestion, reduces line losses and increases the life of electrical equipment. This enables the deferral of equipment capacity upgrades where capacity is constrained. It also reduces the operation of expensive peaking plants, eases voltage management requirements and improves electrical system reliability.

Levelling in microgrids significantly reduces wear and tear on the diesel generators supplying the rest of the grid, and helps the thermal units maintain power balance and the system electrical frequency [7].

An illustrative Australian LV distribution network was used to test the effectiveness of a PV/storage system at reducing peak load [5] (see Figure 24). The circuit length was 350 m; pole-to-pole distance, 30—40 m; conductor type, 7/3 AAC; transformer size, 160 kVA; PV size, 2—4 kW; and battery size was 250 Ah.

Figure 24(a) shows how redirecting PV real power to charge the battery reduces voltage rise. The algorithm is also designed to minimise voltage fluctuation due to PV; the effectiveness of this control is also illustrated in Figure 24(a). Figure 24 (b) shows how reverse power flow is reduced. In Figure 24(a), the rise in voltage around the peak-load period is an indication of peak-load support from battery discharging.

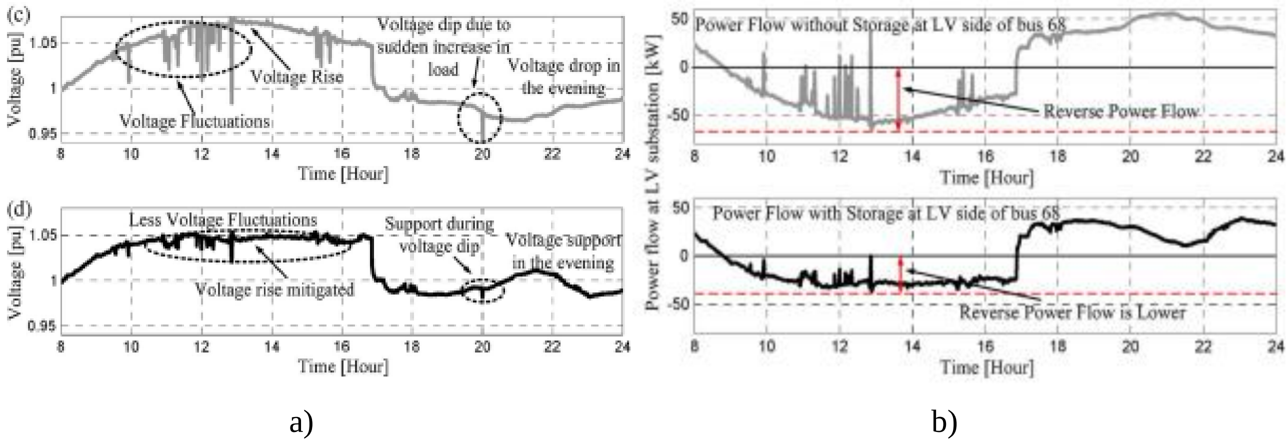


Figure 24 - Performance of battery energy storage system. Top row, no storage; bottom row, with storage [5] (Reproduced courtesy of IEEE)

In reference [6], a BESS is integrated into each PV bus of the General Electric distribution power system model [27] (see Figure 25). Each BESS is modelled as a lithium iron phosphate battery and incorporates ageing effects to take account of battery lifetime. On-load tap changer (OLTC)/SVR operation positions, peak-load reduction and peaking power generation are recorded over the life of the BESS system. The BESS usage, lifetime and system performance, in terms of battery size, are then analysed on every bus. Actual annual load information, PV power profile and temperature data is used for the analysis.

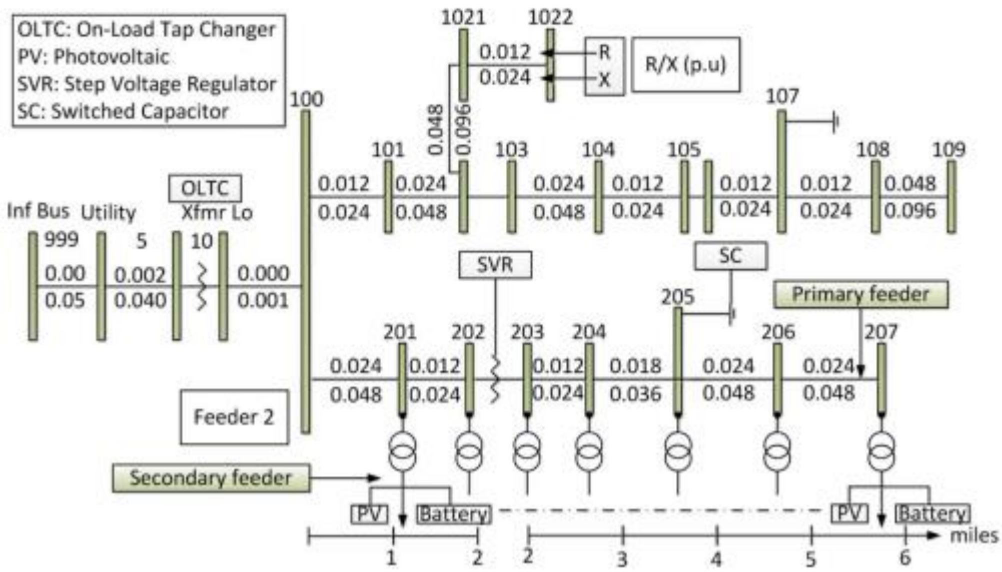
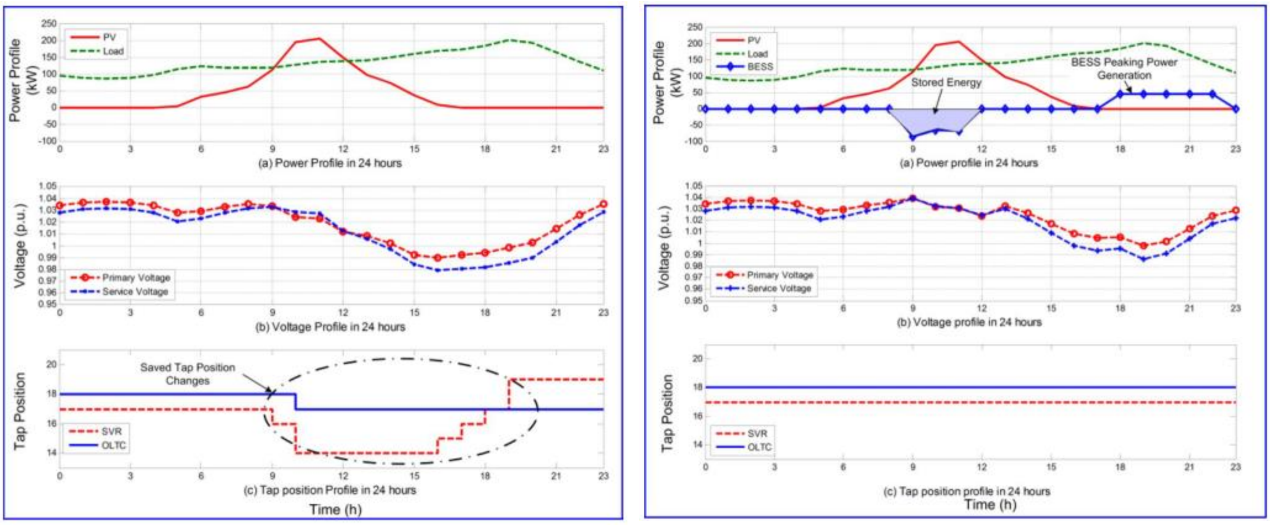


Figure 25 - General Electric feeder model [6]

The study in [6] focuses on feeder 2. The peak load is 11 MVA; the seven loads range between 0.3 and 0.5 MW, with a 0.92 power factor; primary voltage is 12.5 kV, and secondary is 240 V. Although load power factors in Australia are typically higher than 0.92, the findings of the paper are still relevant to Australian electrical networks. Using rules-based control, a central unit is used to manage the actions of the BESS for voltage regulation and peak-load reduction.

Figure 26 presents the benefits provided by BESS operation over a 24 hour period. The results illustrate a smoother voltage profile and reduction in both peak load and SVR/OLTC operation. Figure 27(a) shows the annual reduction in SVR/OLTC operations, while Figure 27(b) gives the annual reduction in peaking power generation for a given PV penetration and BESS size in the study. PV penetration is the ratio of PV generation to peak load and BESS size is measured in peak-load hours. The reduction in OLTC and SVR operation, as well as peaking power generation, is clear.



a) b)

Figure 26 - Power and voltage profile, step voltage regulator (SVR) and on-load tap changer (OLTC) operation. a) Without a battery energy storage system (BESS); b) with BESS [6]

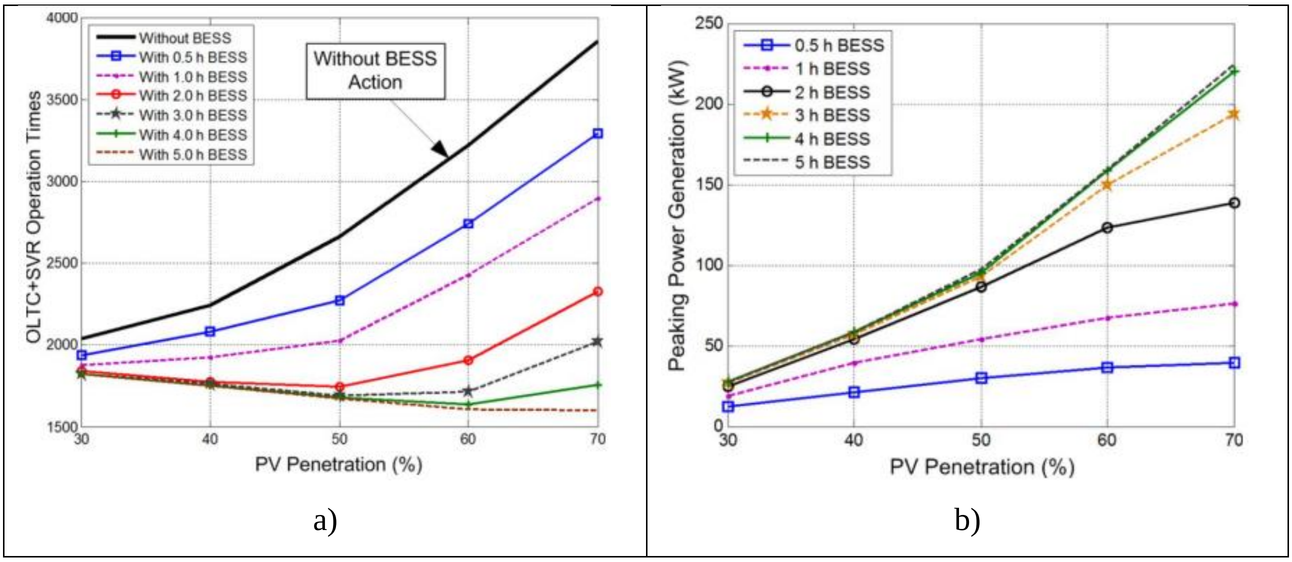


Figure 27 - (a) Reduction in step voltage regulator (SVR) and on-load tap changer (OLTC) operations; (b) reduction in peaking power generation [6] BESS = battery energy storage system

For networks with sufficient levels of wind penetration, power generation from wind at night — when load is much lower than during the day — may reverse power flow at the PCC and cause voltage rise. STATCOMs or SVCs would normally be used to manage this voltage rise, but large voltage-source inverters, normally used to interface PV solar farms to the grid, could be used instead [28]. The capacitor of the voltage-source inverter is operated in ‘self-supporting’ mode, and therefore doesn’t require an external DC power source. Instead, the reverse power from the wind turbines provides the required power. Simulation testing shows that the voltage-source inverter helps maintain voltage levels within regulation limits.

A PV-coupled BESS using the Xtreme Power-Dynamic Power Resource (XP-DPR) has been developed for renewable energy applications [7]. The MW-scale system, manufactured by Xtreme Power in Texas, is currently operating in a solar-coupled mode on 12.47 kV power systems in the Hawaiian Islands, as well as at a solar technology testing facility in Colorado under the auspices of Xcel Energy and the National Renewable Energy Laboratory. Most BESS control systems can be operated via AGC signals, much like a conventional utility generation asset, or in a solar-coupled mode. In the latter, real and reactive power commands for the converter are generated many times per second based on real-time PV output and power system data. Control algorithms implemented in the XP-DPR provide control of ramp rates, frequency support and voltage/reactive power support, as well as services designed to optimise the financial returns of the PV installation, including peak-shifting and levelling.

Figure 28 depicts the operation of an XP-DPR BESS smoothing the volatile power output of a 1-MW solar farm. Note that the system ramp rate is maintained at less than 50 kW/min, whereas the solar resource alone had a maximum second-to-second ramp rate of more than 4 MW/min.

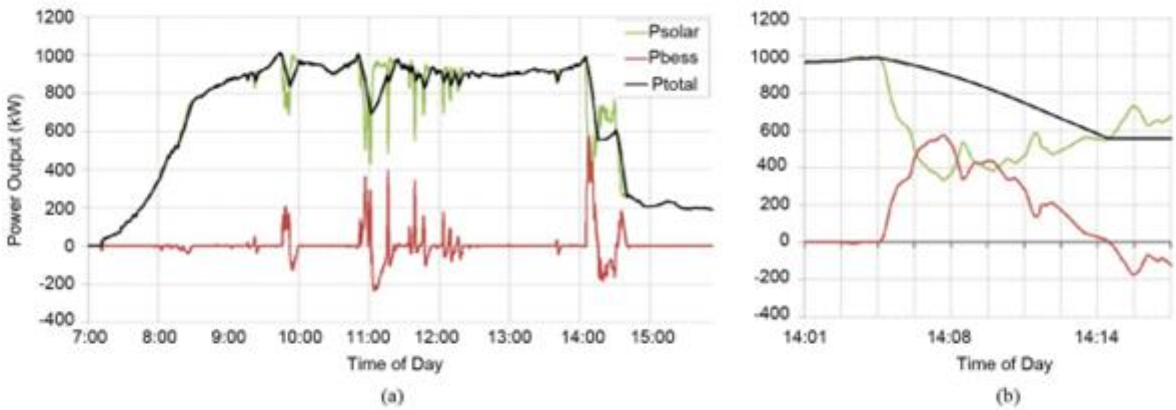
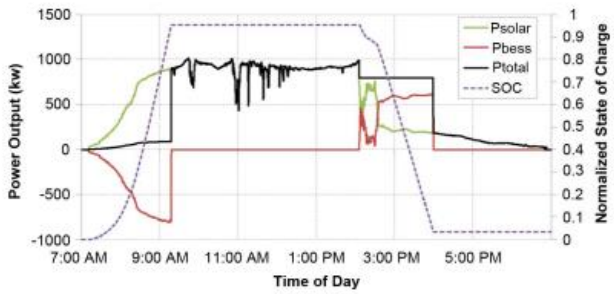
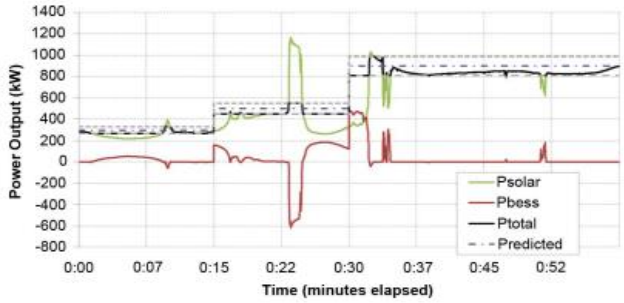


Figure 28 - Ramp-rate control to 50 kW/min for a 1-MW PV installation and a 1.5-MW/1-MWh battery energy storage system. (a) Full day; (b) details of largest event [7] (Reproduced courtesy of IEEE)

BESS units can also apply a time-shift algorithm optimised for a given set of solar generation and load forecasts. The algorithm can charge the BESS from the grid at night, or from some percentage of the solar generation during the day. The BESS can then be discharged in the afternoon hours, coincident with the evening peak. Figure 29 shows the morning PV generation being used to charge the BESS for one day and for one hour; the BESS is then discharged to a consistent 750 kW output from 2:00—4:00 pm.





a) b)

Figure 29 - (a) Full day operation of time-shift algorithm; (b) 1-hour of time-shift algorithm [7] (Reproduced courtesy of IEEE)

3.4.5.1 Storage – Australian trials currently in progress

Three DNSPs are currently participating in battery storage trials: Ausgrid, Ausnet and Ergon Energy.

i) Ausgrid has trialled a 60-kW battery storage system in Newington, Sydney, to test how battery storage can help manage summer peak demand events. As part of the Smart Grid, Smart City program, Ausgrid also completed a trial of 60 5-kW battery storage systems installed in homes in suburban Newcastle. The aim was to understand the technical impacts of adding battery storage to the grid, and the potential of batteries to power local areas during maintenance or outages.

ii) AusNet is currently trialling a 1-MW battery to support the electricity grid during peak demand periods. Named the Grid Energy Storage System, the battery is located at Thomastown industrial estate. The system also includes a 1-MW diesel generator. It provides active and reactive power support, and can also enter islanding mode when isolated from the grid.

iii) Ergon energy is currently trialling their Grid Utility Support System. Figure 30 shows that the system reduces LV excursion over 48 hours, covering two morning and two afternoon peak periods.

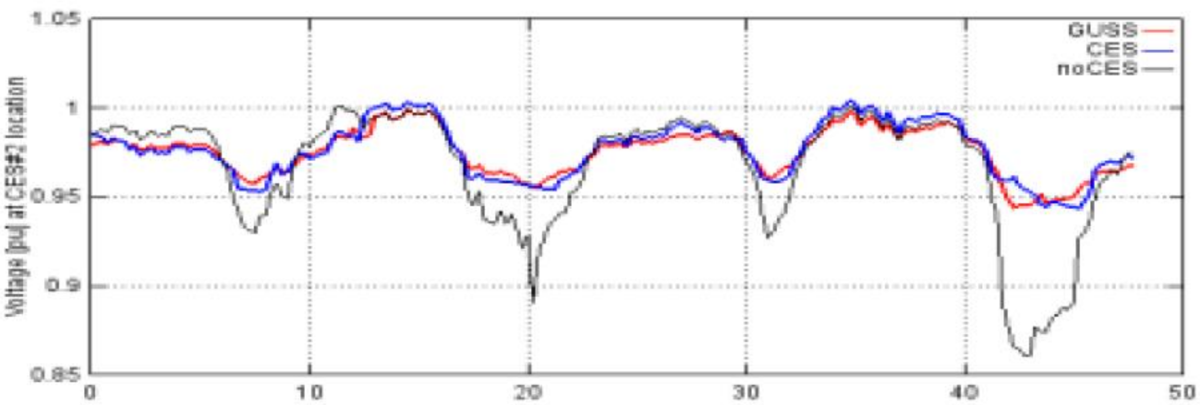


Figure 30 - Voltage profile or Ergon Energy trial, with and without Grid Utility Support System (GUSS). CES = centralised energy storage

3.4.5.2 Virtual power plant

This section discusses work that considers the power of several small-scale, distributed EG devices in aggregate. The power generated from all devices, when considered in aggregate, may be controlled to replicate large-scale dispatchable generation: a 'virtual power plant'. The virtual power plant systems discussed in this section are PV combined with storage, and standalone storage.

In a virtual power plant, groups of EG have system visibility, controllability and impact similar to a transmission-connected generator, with similar parameters (e.g. scheduled output, ramp rates, voltage regulation capability, reserve) [29]. The aggregate power generated from the EG is controlled and dispatchable.

In 2005, American Electric Power (AEP) pushed energy storage to the distribution level in the form of sodium sulfur batteries located at distribution substations. The storage sizes are 1, 2 and 4 MW, with 7-hour discharge capability. AEP is developing and installing smaller, more broadly distributed energy storage units at the edge of its grid, at customer sites. Termed community energy storage (CES), the units are 25-kW operated as fleets to provide aggregate benefits at the MW scale using existing communication and control technologies [14].

AEP found that power system reliability was improved when storage is pushed further out on the system. Each battery installation is equipped with 'dynamic islanding', a feature that allowed AEP to serve hundreds of customers during a power outage.

AEP list numerous advantages for the CES system, including the capacity to:

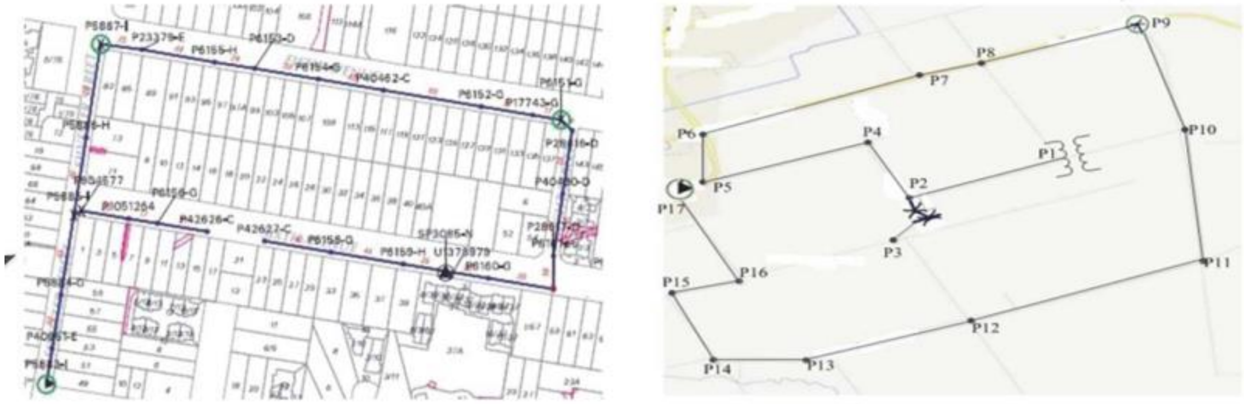
- provide buffering of customer-owned renewable generation
- improve power quality
- enable load levelling for capital deferral and optimised grid operation
- enable frequency regulation and other ancillary services.

To install and operate a fleet of hundreds of CES units, standardisation and battery cost reduction are critical. Through an effort sponsored by the Electric Power Research Institute (EPRI), with collaboration of more than 20 utilities, vendors and manufacturers, AEP has developed detailed functional specifications for CES. The specifications are open source and publically available [30].

AEP terms CES as a 'virtual substation battery', but claims it has distinct advantages over an actual substation battery. These include:

- more reliable backup power to customers
- more effective voltage and VAR support
- more scalable, flexible implementation
- likelier to be a standardised commodity
- more efficient buffering of customer renewable sources
- more synergy with EV batteries
- easier installation and maintenance
- less critical effect of unit outage on the grid
- lower resistive loss in wires
- better fit into smart grids.

The potential for PV combined with storage to improve the voltage profile of residential LV circuits is examined in [8]. The aim is to mitigate both voltage rise due to PV and voltage drop during peak demand periods. All EG devices are in communication, and control is coordinated. A potential deficiency of using reactive power absorption (for voltage rise) and reactive power injection (for voltage drop) for rural Australian feeders due to the cables’ low X/R ratio (ratio of reactance to resistance) is also pointed out in [8]. For rural areas, the authors propose using storage integrated with PV as well as reactive power controls to manage voltage levels. Battery charging and discharging is managed through voltage-dependent droop control, while constant and variable droop control is considered. The proposed control method was tested on urban and rural distribution feeders located in Brisbane, Queensland (see Figure 31).

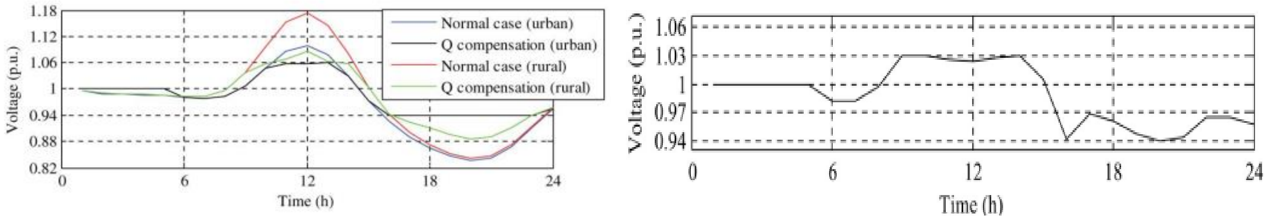


a) b)

Figure 31 - (a) Urban feeder; (b) rural feeder [8]

For the urban case shown in Figure 31, the houses are 10—35 m apart and cable X/R ratios vary between 0.8 and 1.1. For the rural feeder, houses are 80—200 m apart and cable X/R ratios are around 0.17. Load data is taken from the distribution network operator. The average peak load is 3 kW and PV size is assumed to be twice this to simulate severe over-voltage conditions. The voltage for the house at the end of the feeder is examined. The PV inverters are capable of providing 3.6 kVA during the day and 6 kVA during the evenings, running on battery power.

Figure 32(a) shows the change in voltage profile for urban and rural cases when only reactive power support is provided; breaches of the lower voltage limit still occur in the rural case. Figure 32(b) shows the rural feeder voltage when real power from the battery is also injected into the feeder. In this case, voltage levels remain above the lower voltage limit.



a) b)

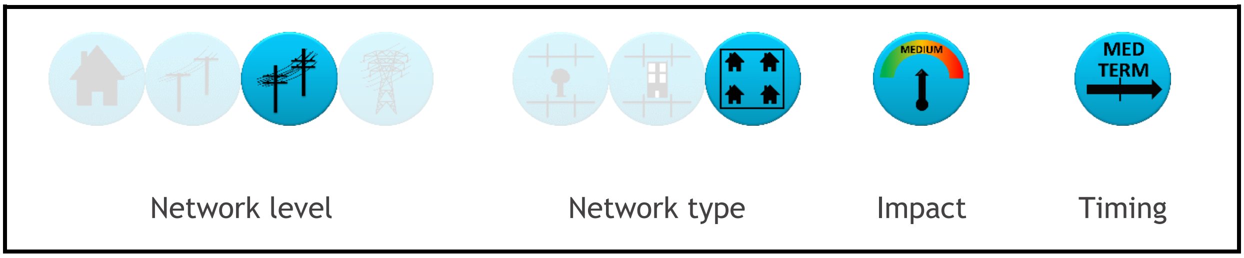
Figure 32 - (a) Voltage profile for urban and rural feeders, with and without Q compensation; (b) rural feeder voltage when real power is also supplied from the battery [8]

The study found that variable droop control is as effective as constant droop control, while at the same time reducing the required storage capacity for the house at the end of the feeder [8]. With variable droop control, houses towards the end of the feeder have a lower power response to a voltage change than those closer to the head of a feeder. Storage at these locations can therefore be reduced.

__Key Finding__: Utilising EG for power and voltage profile levelling reduces the operation of expensive peaking plants. It can also ease voltage management requirements, improve power system reliability and provide frequency support.

__Key Finding__: Insecure, non-dispatchable energy source types of EG (predominantly PV and wind) alone provide only limited power and voltage levelling and frequency support. Including storage offsets the insecure, intermittent nature of PV and wind, allowing EG to provide these services effectively.

3.4.6 Frequency support



This section examines the contribution of EG to frequency control. It refers to PV technology combined with energy storage, in which the PV + storage system is controlled to replicate the frequency support response of a synchronous generator. The same support could also be provided by wind combined with storage and actual synchronous generators such as diesel engines or gas turbines.

Reference [31] describes the design of a ‘grid-friendly’ PV plant. The plant includes a controller that manages real and reactive power flow and allows it to contribute to the reliability and stability of the electrical transmission and distribution system. The PV plant’s features include:

- dynamic voltage and/or power factor regulation of the solar plant at the point of interconnection
- real power output curtailment to ensure upper voltage is not breached
- ramp-rate controls to ensure that the plant output does not ramp up or down faster than a specified ramp-rate limit
- frequency control to lower plant output in the case of an over-frequency event, or increase plant output (if possible) in the case of under frequency
- start-up and shut down control.

Generator emulation controls are discussed in [32]. In these systems, the inverter of the grid-connected PV system is controlled to mimic the behaviour and dynamics of a synchronous machine. The generator emulation control allows the inverter to supply reactive power and current harmonics to local loads, provide voltage support through volt/VAR control, and perform frequency regulation through hertz/watts control.

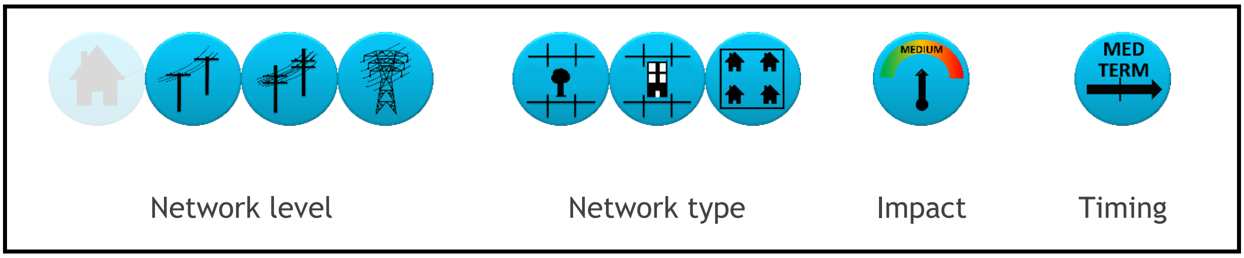
The XP-DPR BESS [7] provides frequency support using proportional control to deliver or absorb power in support of grid frequency stabilisation. This control is equivalent to conventional generator governors equipped with a speed-droop or regulation characteristic. The droop response of the XP-DPR is a function of the mechanical inertia of the conventional generation (rotating machines) in the network. The smaller the inertia (installed capacity of conventional generation), the more the frequency is affected by a step change in load or generation, and the greater the required change in real power generated by the BESS for a given change in frequency. *R* is defined by equation 1, where *1/R* is the gain of the proportional controller:

$$\%R = \frac{percent\ frequency\ change}{percent\ power\ output\ change} \times 100 \qquad (1)$$

The concept of large-scale, centralised PV (LSCPV) plant providing frequency support functionality, frequency-sensitive mode and inertial response was tested in [9]. A LSCPV plant was integrated into a standard IEEE 12-bus system with penetration levels of 5% and 20%. Frequency-sensitive mode and inertial response were primarily provided though the control of active and reactive power. Sufficient active power reserve was required to ensure the LSCPV plant can operate in frequency-sensitive mode and provide inertial response. Active power reserve was realised by setting the maximum power point set-point below its maximum, and the reserve was released during transients.

The performance of the LSCPV was tested by initiating a frequency event (major loss of generation) on the IEEE system. For the two test scenarios, with the LSCPV plant providing frequency-sensitive mode and inertial response support, the system recovered more quickly. A daily load profile was also applied to the system and the frequency deviation across the day recorded. The load profile was divided among all the loads present, and the generators acted together to compensate for any power mismatches, while AGC was managed by the largest generator in the system. The frequency distribution was shown to have less deviation when LSCPV plant frequency support was present [9].

3.4.7 Dispatchability



Many papers that discuss the potential of EG to provide power, voltage levelling and frequency support also discuss dispatchability. Dispatchable EG increases the pool of generation that can be called on to meet load demand, increasing generator portfolio flexibility.

Individually, EG is relatively small in scale, but may be large when considered in aggregate. It is also likely to have a fast response time, enabling rapid response to both local and network load changes. This section refers to PV combined with storage, and wind combined with storage, as dispatchable systems.

Reference [11] proposes combining a supercapacitor bank (SCB) and a VRB to smooth out the power fluctuation of a 1-MW grid-connected PV plant. The power management of the HESS was designed to reduce the power requirement of the SCB to one-fifth of the VRB rating, and also to avoid operating the VRB at reduced power levels. SCBs experience cell voltage unbalancing issues above the MW level; minimising the required size of the SCB (relative to the VRB) avoids this issue.

The power management system controls the HESS such that it meets the Australian 5-minute semi-scheduled dispatch requirements [33], and maintains operation of the VRB and SCB with rating constraints. A test case was simulated using a 250-kWh VRB and 50-kW SCB (the capacity of the VRB was not specified). High-speed (~1 second) insolation measurements taken from the St. Lucia campus of the University of Queensland were used for PV production modelling. A 30-min window of solar insolation and a power cap was carefully selected to ensure that all operating modes (normal, deficit and excess power mode) of the HESS were triggered. Figure 33 shows that the operating constraints were breached on only three occasions (200, 400 and 900 seconds) [11].

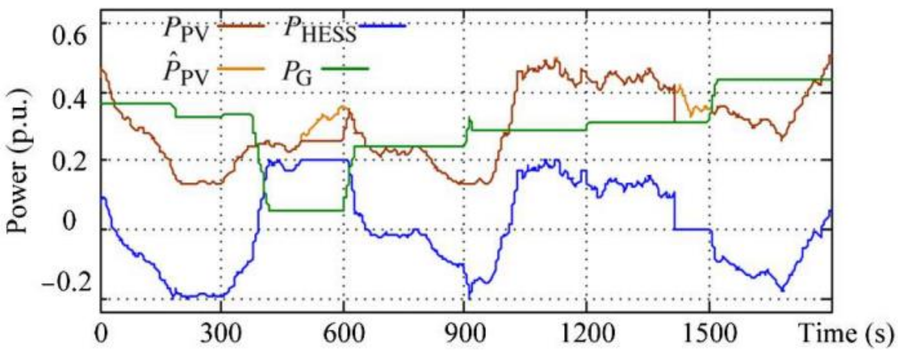


Figure 33 - Hybrid energy storage system (HESS) operation [11]

The HESS was also tested using a week’s worth of worst-case insolation data, believed to have been during a period of high variability in insolation [11]. The average PV power generated for each 5-min period was selected as the power cap. The results show that the HESS does operate outside of constraints on occasions, but that the power management system quickly returns power to within constraints. The test case shows that the proposed HESS and power management system can control the power generated from a 1-MW PV such that its operation meets Australian grid code requirements. The SCB was also kept at one-fifth the size the VRB, and VRB operation at low levels is avoided.

The work presented on rule-based control in reference [12] is similar to [11], with a focus on BESS in place of HESS. A control strategy was designed to minimise the power fluctuations of variable renewable EG (wind or solar) and make its power dispatchable. The effectiveness of this control strategy and BESS was tested using an actual PV system and wind farm data. As in [11], the results show that the normally variable power generation is smoothed considerably, making dispatch possible [12].

The BESS was connected at the system’s PCC, and charged/discharged through a power converter to smooth the net power injected to the system. The performance of the BESS and control system was tested at hourly intervals (consistent with United States dispatch windows). Maintaining constant power for 1 hour is more difficult than maintaining power for 5 min, as is required in Australia [11].

Prediction is not mentioned in [11], and is unlikely to be useful. For solar, at 5-min intervals, cloud transients are the source of unexpected variability in insolation, and prediction of either a break in the clouds on an overcast day or random passing cloud on a sunny day is not possible using standard regression methods. Reference [12] assumes that prediction would be used to determine the target power generation for the upcoming hour. When testing the system, the target power selected was the average of the upcoming hour wind or solar generation. A random error with zero mean and 0.1 standard deviation was introduced to represent prediction error.

A simple rule-based system was used to control the BESS [12]. The battery's state of charge must remain within 30 and 100%, and current flow in and out of the battery must not exceed maximum charge or discharge rates for the battery. The BESS and control system will fail to meet the target power when any of these operational constraints are reached.

The system was tested with 1.5 MW solar and 50 MW of wind. For the solar case, the battery is sized at 300 kWh, while for wind, the battery is sized at 10 MWh. Looking at the HESS system in [11], the relative battery size for the solar case in [12] is smaller: 20% of PV capacity compared with 25%. It might be expected that the battery size should be larger, because power is to be maintained over 1 hour, instead of 5 min. The authors of [11] may have oversized the VRB to ensure performance. An iterative process is used to select the size of the battery in [12]; the process is not explained, but may optimise battery size selection.

For the 1.5-MW solar case, the effectiveness of the BESS at meeting the target power is best illustrated by histograms of the difference in actual power and target power before and after the BESS. Figure 34 shows that the BESS greatly reduces deviation from the target power; undesirable deviation is considered anything greater than 100 kW, positive or negative. The percentage of these occurrences reduces from 16 to 4% with the BESS [12].

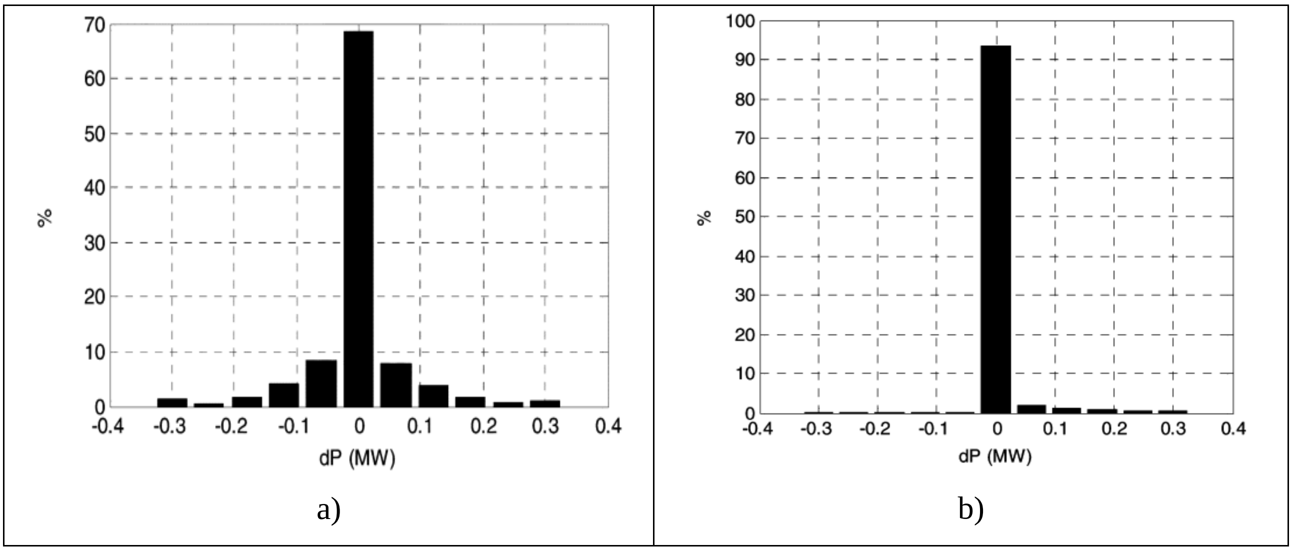
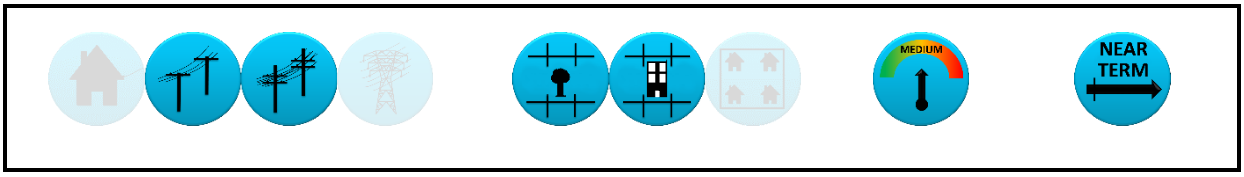


Figure 34 - Histogram of difference in actual power and target power for a 1.5 MW solar photovoltaic system. (a) Without a battery energy storage system (BESS); (b) with BESS [12]

3.4.8 Electrical infrastructure – life extension and investment deferral



Network level	Network type	Impact	Timing

This section considers how the installation of EG affects the life of electrical infrastructure and contributes to investment deferral.

It is apparent that any asset life extension is economically beneficial to DNSPs, although there is no consensus about the extent of these benefits in monetary terms [15].

The growth of EG and a growing realisation that investment here may defer network augmentation means that 'non-wire solutions' are now considered a realistic alternative to traditional network upgrades. The benefit of EG in this context is straightforward: it will take more time for the current on-load transformers or feeders to reach their technical limits if EG can be effectively deployed and controlled to manage current flows. Therefore, the first step towards quantifying the benefit of transformer or feeder investment deferral is to measure the impact of the EG output on the currents across the distribution network [34].

Transformer life is dependent upon insulation life. The main factors determining insulation life of an oil-immersed transformer are:

- load
- ambient temperature
- the number and magnitude of faults it has endured
- moisture and oxygen content of the oil.

The rate of ageing of transformer insulation is primarily temperature dependent (references [3, 35] detail a transformer heating model). The thermal response is a function of the transformer constants and load. The loss-of-life (LOL) calculation is based on the transformer insulation condition, which is a function of insulation temperature.

PV reduces daytime load, and as a result, limits the temperature rise of the transformer. However, the transformer temperature reached at peak demand is the key concern. For the midday peak, PV can directly reduce maximum transformer temperatures. For the typical late afternoon/early evening peaks seen in Australia, the transformer temperature at the start of the peak demand period will often be reduced by afternoon PV output, as discussed in Section 3.4.4. As a result, the transformer temperature reached at peak demand is also reduced. This leads to the conclusion that PV can extend transformer life (at least from the perspective of temperature stress).

Energex claims that PV has contributed to a rating increase of 10% for their substation transformers [2]. As of March 2014, 49 substations had been uprated, with a total capacity increase of 309.5 MVA. Following a review of the 2013—14 summer load profiles on all mixed and industrial substations, a further 19 substations were uprated by an additional 148.5 MVA. Energex expects further upratings beyond July 2014, dependent on the rate of future solar PV system connections.

In reference [4], for a commercial load, the number of hours a substation transformer experiences overload conditions is calculated each year using an assumed load growth rate of 4%. The number of overload hours is again calculated with PV penetration levels of 10% and 20%. For a projected 2016 load, the number of hours that a substation transformer is overloaded decreases from 510 to 179 for 10% penetration and to 35 for 20% penetration. This defers the transformer upgrade by two and four years, respectively.

Reference [13] analyses transformers in a 102-node, 400/230-V distribution network connected to the South West Interconnected System (SWIS). These transformers are non-thermally upgraded paper, with a life of 30 years. The distribution transformer (DTx) used for the analysis is unbalanced [13]. Out of 77 connected residential consumers, 13 are connected to phase-A, 17 connected to phase-B and 21 to phase-C; 26 of the premises have a three-phase connection. A total of 64 kW of PV is connected to the DTx. In Australia, it is standard practice to load a transformer up to 1.4 times its rating for a short period of time in a given year [36]. The LOL of a DTx is therefore investigated for loading up to 1.4 times its rated power (280 kVA, in this case). Figure 35 gives the temperature difference in hot-spot temperature, loading and reduction in LOL as a result of PV generation. The saving in LOL is 0.2, 14, and 160 days for phases A, B and C respectively. Table 12 shows the increase in LOL reduction with increasing PV penetration.

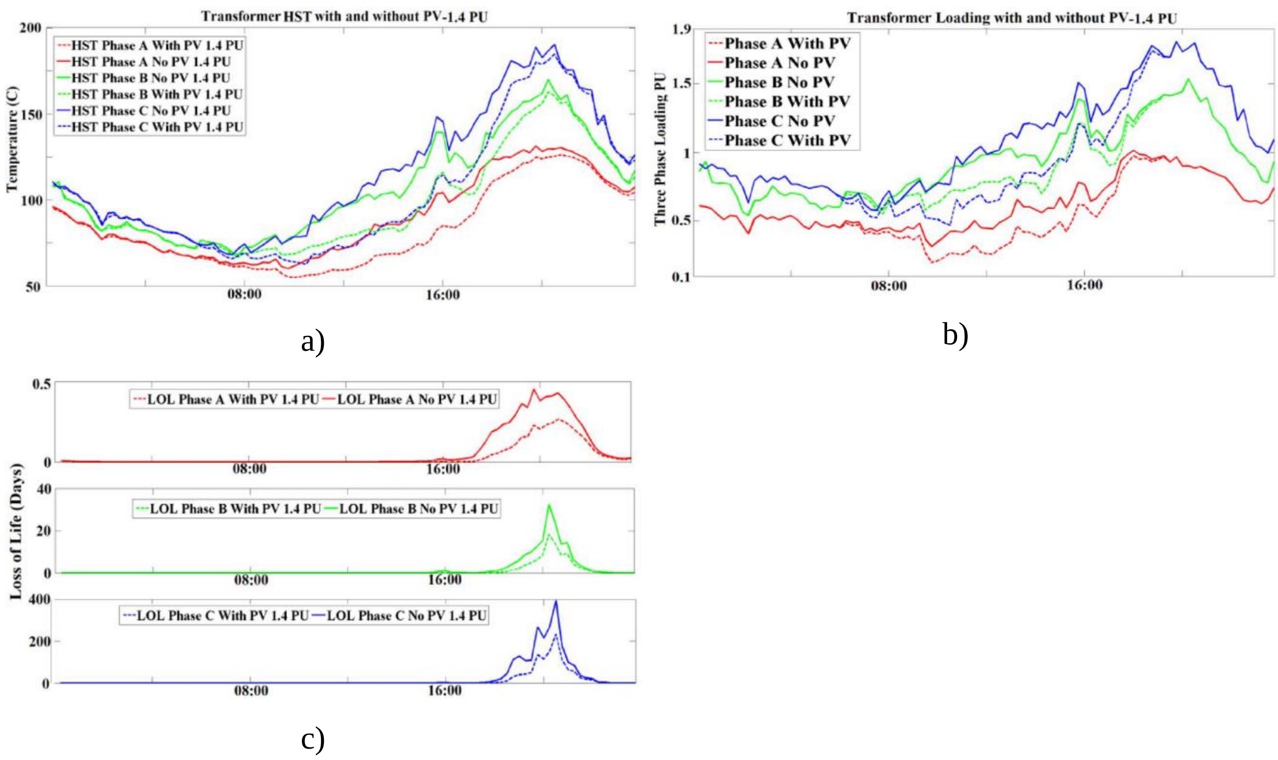


Figure 35 - At a loading of 1.4, (a) distribution transformer (DTx) hot-spot temperature (HST) with and without photovoltaics (PV); (b) DTx loading with and without PV; (c) DTx loss-of-life (LOL) with and without PV [13]

Table 12 - Loss-of-life improvement with photovoltaic (PV) growth [13]

Transformer loading/phase C PV installation	Total (max) (°C)	Hot-spot temperature (max) (°C)	Loss-of-life (days)
1.1 PU-26 kW PV	79.5	137.9	22
1.1 PU-35 kW PV	77.1	130.6	14
1.2 PU-26 kW PV	85	151.7	85
1.2 PU-40 kW PV	82.1	141.9	40

Reference [15] explores a method for quantifying the economic benefits of DTx life extension through EG, applied to actual DTx installed in five sample cities in Iran to provide realistic estimates. A DTx exhibits time-varying profiles of load and ambient temperature over the days of its operation history. To remove the time dependence in the profiles of these two variables, an approach was adopted from a previous work by the authors [17] to classify the operation history of any analysed DTx into eight typical days corresponding to seasons, weekdays and weekends. Each typical day was thought of as a sequence of 15-minute intervals during which transformer load and ambient temperature were kept near-constant.

The study calculated the DTx LOL for each of the eight typical days. DTx load profiles were generated through stochastic models of customer load and EG production, taking into account atmospheric conditions (e.g. temperature, insolation, wind).Figure 36 is a schematic diagram of the modelling process. The EG units considered include PV, wind, CHP units and microturbine (MT) units. Load data consists of characteristics adopted from [37] (historical Iranian load data with a noise input of 15%).

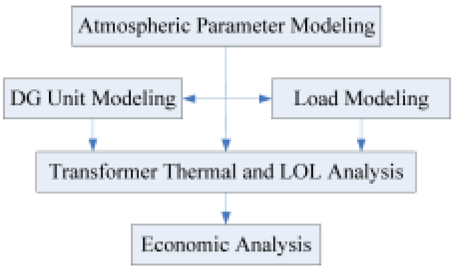


Figure 36 - Distribution transformer loss-of-life (LOL) modelling process [15]. DG = distributed generation (Reproduced courtesy of IEEE)

Ageing formulas for oil-immersed transformers in [3] were used in the analysis. Table 13 gives the parameters of cities examined for the analysis.

Table 13 - Parameters of cities examined for the analysis of distribution transformer loss-of-life [15]. (Reproduced courtesy of IEEE)

CCN [(a)]	City	Ambient Temp. (°C)			Solar Irradiance (kW/m^2)			Wind Speed (m/s)			Capacity Factor			
		Mean	Std. [(b)]	Skewness	Mean	Std.	Skewness	Mean	Std.	Skewness	PV	WT	CHP	MT
1	Divandareh	8.3	10.2	0.2	218.4	310.3	1.3	2.9	2.3	1.2	0.1352	0.1632	0.5715	1.0
2	Moalleman	19.8	11.5	-0.1	239.3	323.3	1.0	4.9	3.1	0.8	0.1846	0.2747	0.4673	1.0
3	Fadashk	18.6	10.4	-0.2	282.7	378.0	1.0	5.1	3.1	0.5	0.2018	0.2994	0.5111	1.0
4	Eghlid	17.4	12.3	0.5	270.5	356.0	1.0	3.2	2.6	1.8	0.2062	0.1595	0.4484	1.0
5	Kish Island	22.0	12.1	0.1	209.5	285.5	1.1	4.4	2.9	1.3	0.1678	0.2138	0.4215	1.0

[(a)] CCN=City Code Number, [(b)] Std.=Standard Deviation

CHP = combined heat and power; MT = microturbine; PV = photovoltaic; WT = wind turbine

The analysed transformers were rated at 315 kVA (20/0.4 kV) and were equipped with an oil-natural air-natural cooling system. Their thermal parameters, as shown in Table 14, were derived from data provided by manufacturer.

Table 14 - Thermal parameters of transformers analysed in reference [15]. (Reproduced courtesy of IEEE)

THERMAL PARAMETERS OF THE SAMPLE TRANSFORMERS

$\Delta\Theta_{TO,R}$	$\Delta\Theta_{H,R}$	m	n	R	τ_{TO}	τ_{H}
55°C	25°C	1.6	1.0	8	3hr	0.08hr

The following assumptions were used in the analysis:

- All EG units operate at unity power factor.
- A maximum aggregated capacity limit of 50% is assumed to be applied by the DNSP to the installed EG units. This means that total installed capacity of EG units under each proposed scenario should be kept lower than 50% of the DTx-rated capacity.
- All customers in the sample cities are subjected to the same patterns of wind speed and solar irradiance.
- The analysed transformers are assumed to have a design life of 20.55 years when they are well-dried, oxygen free and operating continuously at a hot-spot temperature of 110 °C.

Table 15 gives the life extension and estimated economic value (US$/year) for each city for each EG type.

Table 15 - (a) Transformer life extension; (b) estimated economic value (US$) of distributed generation technologies [15]. (Reproduced courtesy of IEEE)

TRANSFORMER-LIFE EXTENSION (YEARS)

CCN	Scenarios			
	PV	WT	CHP	MT
1	30.6	33.1	6.4	22.0
2	5.0	11.7	2.1	10.1
3	4.5	24.5	4.5	15.8
4	6.6	19.0	5.8	19.0
5	1.7	3.7	1.3	8.0

a)

ESTIMATED ECONOMIC VALUE OF DG TECHNOLOGIES IN THE TRANSFORMER-LIFE EXTENSION, PER YEAR (IN U.S.$)

CCN	Scenarios			
	PV	WT	CHP	MT
1	366.0	378.9	130.3	309.7
2	241.4	447.3	118.3	405.5
3	133.5	443.3	133.5	343.5
4	146.4	310.5	131.9	310.5
5	143.2	274.3	112.6	485.1

b)

CCN = city code number; CHP = combined heat and power; MT = microturbine; PV = photovoltaic; WT = wind turbine

Reference [17] calculates the reduction in LOL in a DTx due to EG for a combination of technologies. The method was applied to an actual distribution system in Iran (an urban section in the city of Sirjan) with 10 km of 20-kV feeder and 44 DTx's supplying 52 km of LV (400/230 V) feeders. Three typical DTx's were selected for analysis. For an EG penetration level of 10%, the LOL rate is presented for a typical winter and summer weekday. Penetration level is the ratio of EG to DTx rating. Eight scenarios were tested: no EG, PV, wind, CHP, MT, half PV/wind, PV/CHP and wind/MT. The results in Figure 37 show that the LOL rate decreases for all scenarios. In summer, PV provides the most reduction, followed by PV/wind. In winter, CHP provides the most reduction, followed by PV/wind, MT, PV/CHP and wind/MT, which all provide similar reductions.

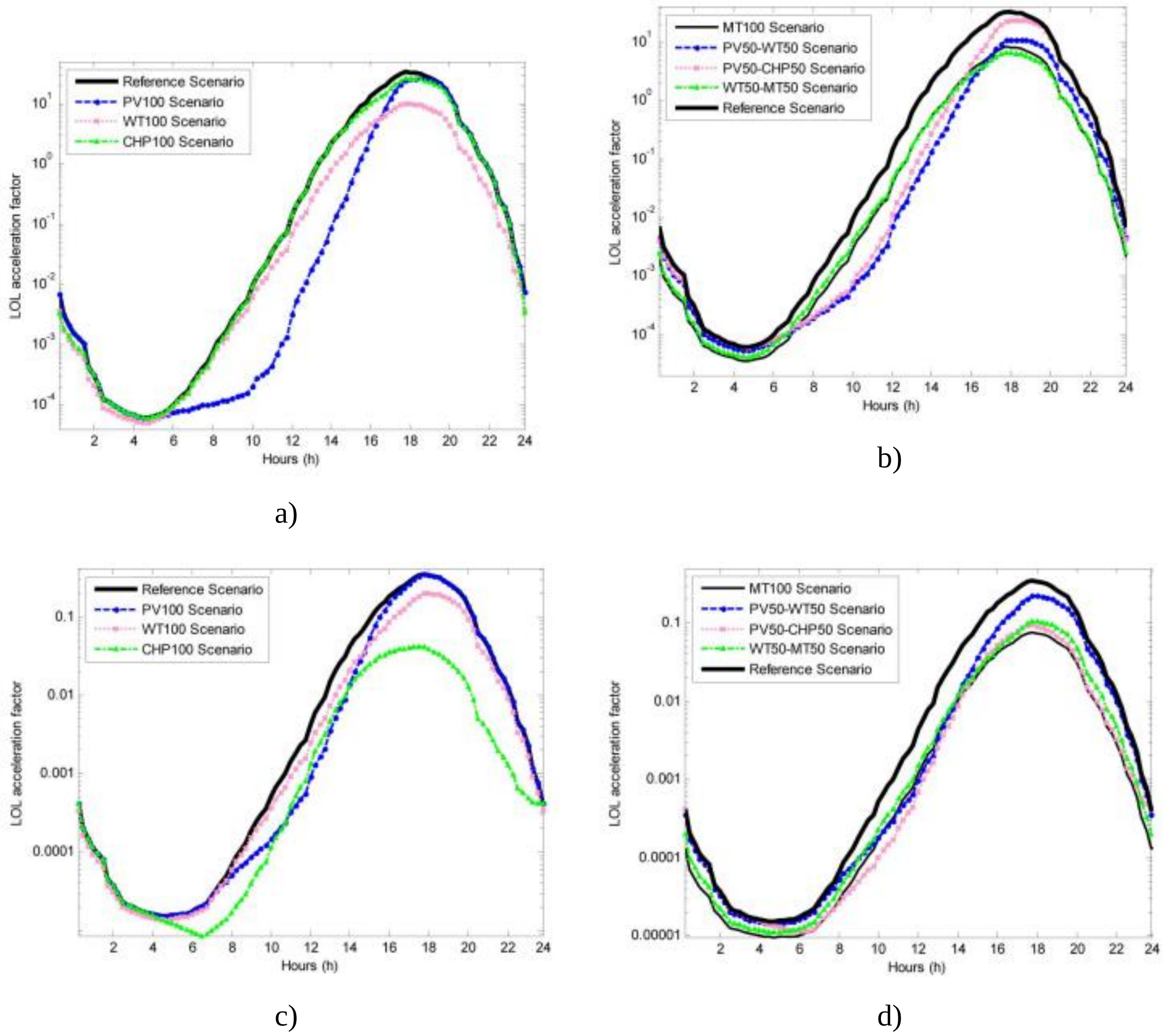


Figure 37 - Reduction in loss-of-life (LOL) acceleration rate in (a, b) summer and (c,d) winter for different combinations of photovoltaic (PV), wind turbine (WT) combined heat and power (CHP) and microturbine (MT) sources of embedded generation (EG) compared to reference scenario without EG [17]

Figure 38 provides an insight into the reduction in LOL rate over the life of the DTx. The annual LOL rate for each technology and combination of technologies is plotted against penetration level. Relative to the reference LOL rate, the best result is achieved through the MT, at 15% penetration. The LOL rate is reduced from 1.2 to 0.15 (87.5% reduction).

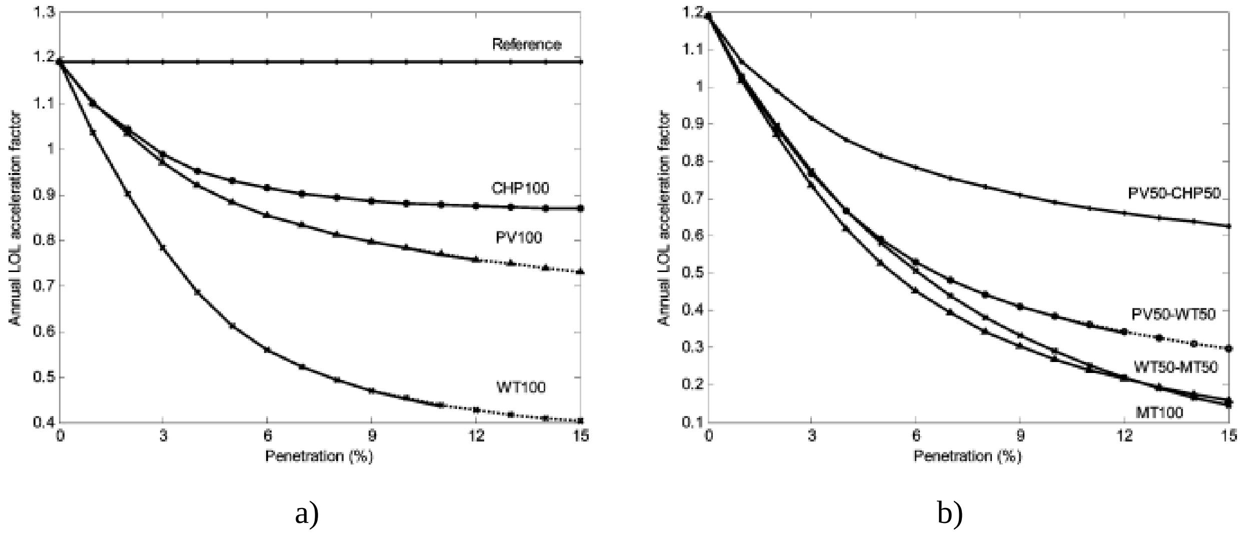


Figure 38 - Annual loss-of-life (LOL) reduction for different combinations of photovoltaic (PV), wind turbine (WT) combined heat and power (CHP) and microturbine (MT) sources of embedded generation (EG). (a) CHP, PV and WT compared to reference scenario with no EG; (b) PV/CHP, PV/WT, WT/MT and MT [17]

The impact of EG on distribution networks' investment deferral in the long-term is assessed in [16]. Due to the randomness of the variables that affect this (e.g. load demand patterns, EG hourly energy production, EG availability), a probabilistic approach using a Monte Carlo simulation was adopted. Several scenarios characterised by different EG penetration and concentration levels and EG technology mixes were analysed. The study aimed to estimate the admissible load growth in distribution networks with and without EG. Inhibitors to load growth, which are incorporated into the modelling process, include: power flow capacity of transformers and cabling, maximum voltage drop and ohmic losses. EG penetration is defined as the ratio of EG capacity and peak-load demand.

The model was tested using a semi-rural MV network (Figure 39). The maximum transfer capacity of the network (the maximum power that can be supplied through the distribution network in normal operating conditions) is approximately 7 MW.

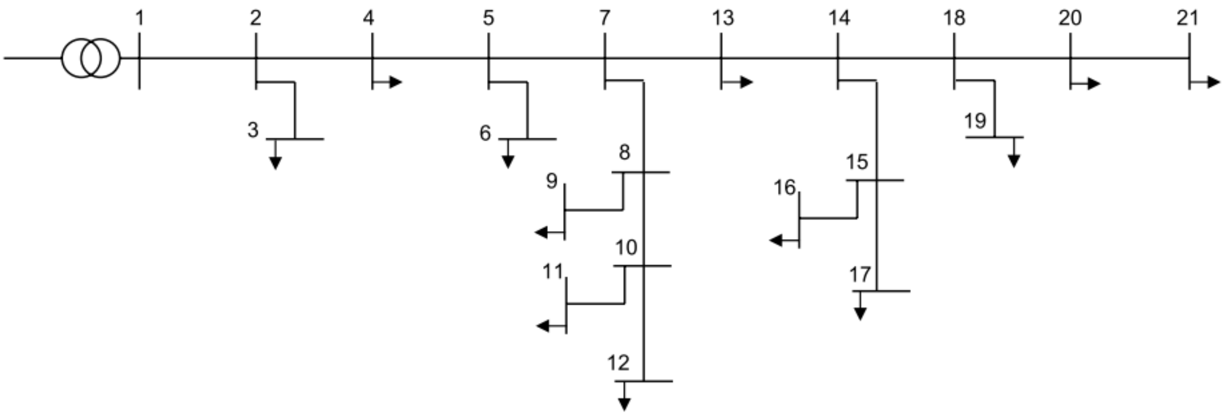


Figure 39 - Semi-rural network used for the probabilistic model tested in reference [16]

The technologies used in the model were CHP, wind and PV. CHP generation data was based on actual historical data. For wind, at each hour a random number was generated with a Rayleigh's probability density function, with mean equal to the average speed of the wind farm's location. The power produced was then estimated using manufacturers' power vs speed wind curves. PV output profiles were generated using theoretical irradiance values, and production then calculated using data from the manufacturers. Variability due to cloud was then incorporated.

The availability of the EG units is incorporated into the model. Table 16 specifies the failures/year and the mean time to repair.

Table 16 - Embedded generation units failure rates [16]

Embedded generation type	Failures/year	Mean time to repair (days)
Wind turbines	5	3
Photovoltaic	0.2	1
Combined heat and power	1	3

Each load node in [16] is considered to have a specific combination of consumer types. Each type of consumer is characterised by a load pattern using real historical hourly data. To include short-term demand uncertainty, a ±10% uniformly distributed band noise was added to the hourly demand of each node. Each test scenario was characterised by different EG penetration levels, EG concentration levels and EG mix parameters. The percentage chance of overload occurring with and without EG was then calculated using a Monte Carlo method (Figure 40). The overload probability is the likelihood that the power flow exceeds the maximum transfer capacity.

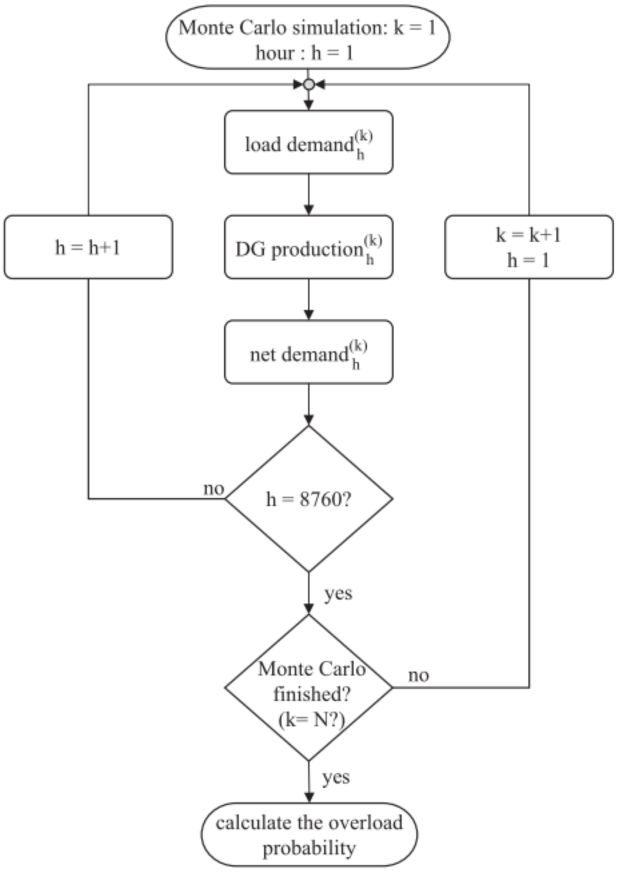


Fig. 4. Algorithm flow chart for overload probability computations.

Figure 40 - Monte Carlo algorithm flow chart used in reference [16]. DG = distributed generation

The calculated increase in admissible load growth is given in Figure 41. Figure 41(a) is for CHP at node 12, (b) is for wind at node 12, and (c) is for PV at node 12. CHP provides the biggest increase in admissible load growth: more than 275% at 100% penetration. Wind is the worst, at just more than 225% at 100% penetration. Figure 41d) shows the increase in admissible load growth when either wind, PV, CHP or CHP/wind is installed at nodes 11, 16 and 21. Again, wind is the worst performer, with the other technologies performing equally well to provide an increase in admissible load growth of nearly 250% at 100% penetration.

The financial benefits of EG are not discussed in reference [16]. However, an investment deferral time could be calculated as the increase in admissible load growth over an assumed load growth percentage. The savings from investment deferral could then be calculated as in [34].

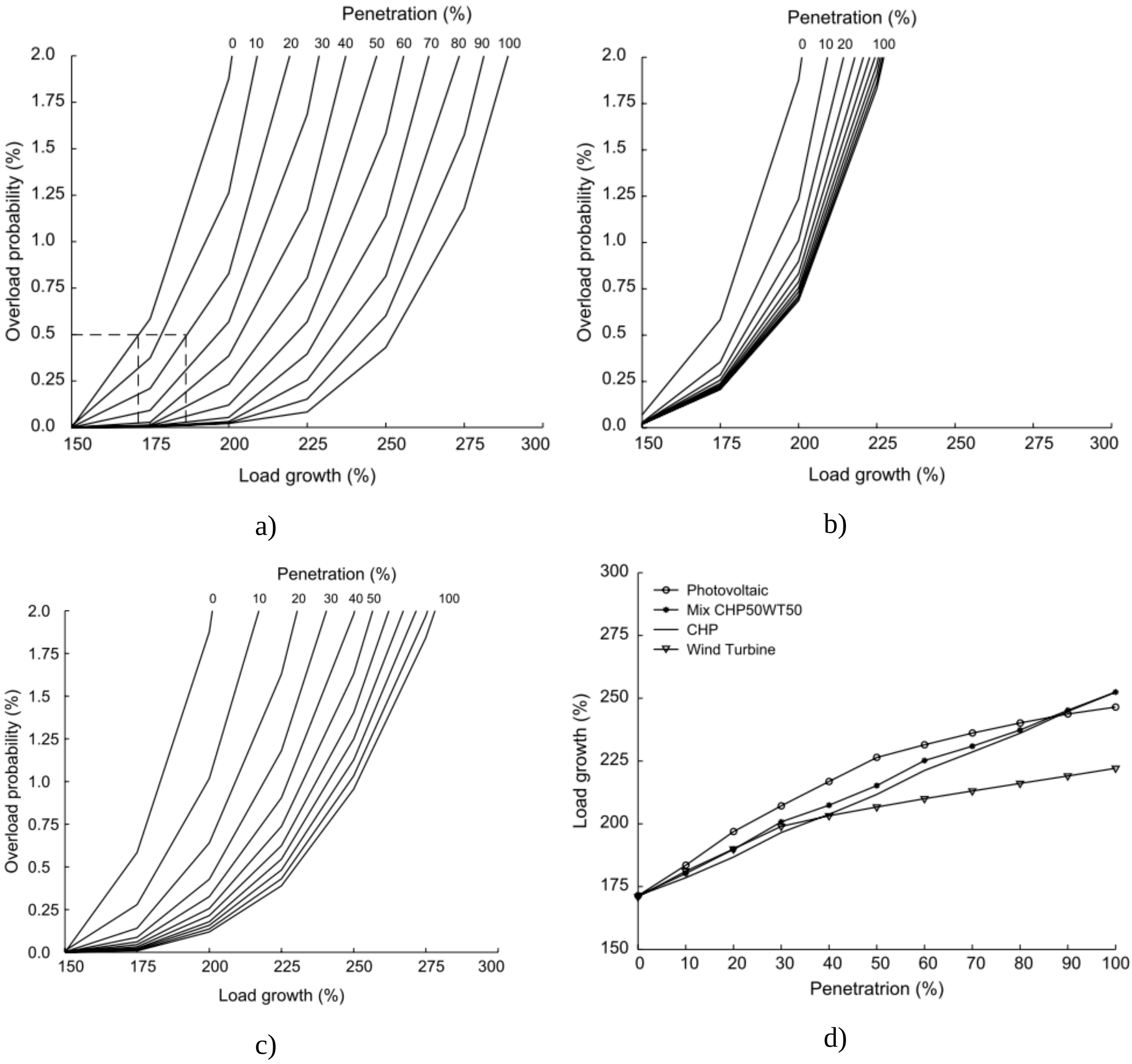


Figure 41 - Increase in admissible load growth for (a) combined heat and power (CHP); (b) wind turbine (WT); (c) photovoltaic (PV); and (d) load growth v penetration for WT, CHP, PV and CHP/WT [16]

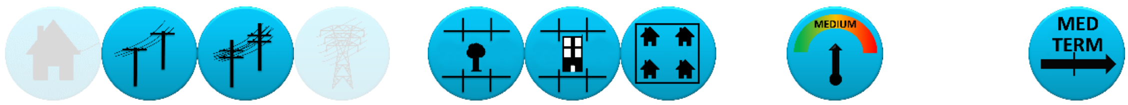
> ***Key Finding:** EG can contribute to peak load reduction. This alleviates congestion, reduces line losses and results in deferral of equipment capacity upgrades where capacity is constrained.*

> ***Key Finding:** Evidence from the literature and distribution network service providers suggests that the reduction in cumulative net load due to EG can extend the life of both substation and distribution transformers.*

3.4.9 Cost—benefit analysis

This section discusses studies that present cost—benefit analyses of EG.

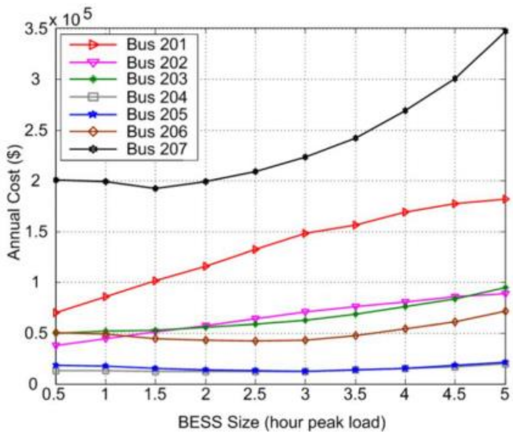
3.4.9.1 Savings though reduction in operation costs



Network level | Network type | Impact | Timing

The following papers consider the cost benefits of installing EG to reduce network operating costs.

Reference [6] conducts a cost—benefit analysis of BESS for a PV penetration level of 70%. Figure 42(a) shows that no BESS installation is profitable for the scenarios analysed, and that the savings from the reduction in OLTC and SVR operation, peak-load shifting and peaking power generation do not offset the investment cost. Figure 42(a) presents the best identified cost-benefit scenario; 70% is the highest penetration level simulated, and lower penetrations of PV give poorer returns. Figure 42(b) lists the inputs used in the analysis. The savings due to reduced OLTC and SVR operation are calculated as the reduction in operation and maintenance costs. Savings from peak-load shifting are calculated as the difference in the cost of energy supplied at peak-load rates compared to off-peak load rates, while savings due to a reduction in peaking power generation are self-explanatory.



a)

Parameters	Symbol	Value	Remark
Discount rate	d	0.03~0.04	NREL [30]
Unit PCS cost	C_{PCS}	400$/kW	SANDIA [21]
Installation cost factor	$CF_{install}$	5%	EPRI [22]
LiFPO4 battery cost	C_W	300$/kWh	Balqon Corporation [31]
Unit levelized annual cost of gas combustion turbine	LC_{CT}	120$/kW-y	PJM Interconncetion [23]
Electricity rate at peak load	EP_{on_peak}	21.715 c/kWh	Tallahassee Utility[32]
Electricity rate at off-peak load	EP_{off_peak}	7.536 c/kWh	Tallahassee Utility[32]

b)

Figure 42 - (a) Results of cost-benefit analysis of battery energy storage systems (BESS); (b) Inputs into cost—benefit analysis [6]. EPRI = Electric Power Research Institute; LiFePO$_4$ = lithium iron phosphate; NREL = National Renewable Energy Laboratory; PCS = power conversion system; PJM = Pennsylvania-Jersey-Maryland; SANDIA = Sandia National Laboratories

Although this work found that no BESS installation is profitable under the tested scenarios, varying the inputs to the cost—benefit analysis (Figure 42 (b)) could result in a positive outcome. The power conversion system cost is set to US$400/kW, taken from a 2003 report [38]. A price of US$300/kWh is used for the battery cost; reference [39] suggests that $250/kWh is the required price for battery storage to be cost competitive. Peak load and off-peak load electricity rates can also differ; peak rates >22 c/kWh and off-peak rates <7.5 c/kWh are certainly possible (values in US$).

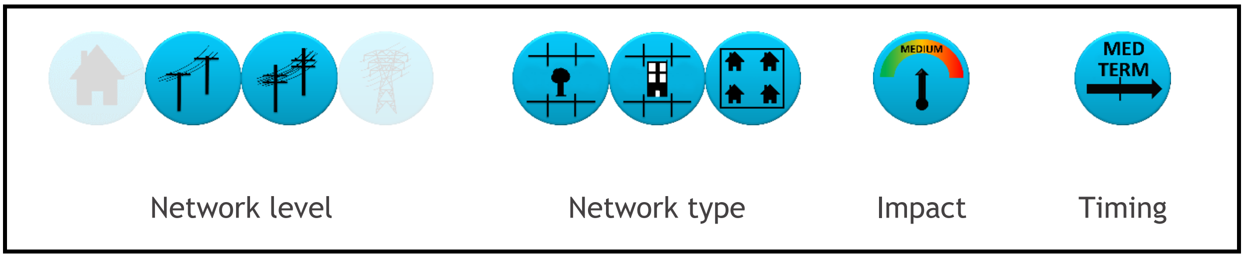
The economic benefits of a distributed STATCOM (DSTATCOM) in combination with a large solar farm are considered in [40]. The following rules govern the operation of the solar farm and DSTATCOM:

- If voltage levels are within regulation limits, then the DSTATCOM does not operate, and generation from the solar farm is uncurtailed.
- If the upper voltage limit is breached, then the DSTATCOM is operated to reduce voltage.
- If voltage cannot be sufficiently reduced by the DSTATCOM, then generation from the solar farm is curtailed until the voltage is within regulation limits.

Revenue from the installation was calculated as the sum of solar farm generation revenue and savings from the reduction in conventional generation. The savings from reduced conventional generation are the product of the reduction in energy demand (due to the solar farm) and conventional generation operational cost ($/kWh). The installation was located at the end of a Taipower 11.4-kV distribution feeder, which is 12.1 km long. A typical hourly daily load curve for the feeder was taken for each season. After the rules of operation were applied, the solar farm output was calculated to derive the reduction in conventional generation. Insolation measurements from the Taiwan Weather Bureau were used to estimate hourly solar farm generation for the year for a range of solar farm capacities. For DSTATCOM sizes of 0, 50, 200, 350 and 500 kVA, the optimum sized solar farm was determined to maximise the net present value (NPV).

The study found that a 4.5-MWp solar farm in combination with a 500-kVA DSTATCOM is the most profitable [40]. This set-up gives an NPV of $9.47 million, with a payback period of 9.87 years; the life of the equipment is 25 years. The study does not take into account potential savings from the voltage management, such as increased life of other assets (e.g. transformers). It also assumes no clean energy credits for the clean power generation from the solar farm, and does not monetise the auxiliary services that such a set-up could provide.

3.4.9.2 Savings through investment deferral



The mechanism by which EG may be considered as an alternative to network investment is discussed in Section 5.3.3.1. Here, we investigate cost—benefit analyses to help identify the viability of EG in these non-network solutions. The following papers consider the cost benefits of installing EG to defer network investment.

Reference [18] deployed CHP EG at different locations and penetration levels to assess the deferral in investment for a practical United Kingdom extra-high-voltage (EHV) network (33–132 kV. The calculation used to evaluate investment deferral is given in equation (2):

$$\Delta PV = \sum_{i=1}^{M}(PV_i - PV_{inew}) = \sum_{i=1}^{M}\left(\frac{Asset_i}{(1+d)^{n_i}} - \frac{Asset_i}{(1+d)^{n_{inew}}}\right) \tag{2}$$

where:

PV_i	NPV of future investment without EG installation (current condition)
PV_{inew}	new NPV of the future investment with EG installation
ΔPV	change in NPV, which could be regarded as either investment deferral or acceleration, dependent on the direction of the change
M	total number of assets in the network
d	discount rate
$Asset_i$	modern equivalent assets cost
n_i	time to reinforce a network asset if no EG is installed
n_{inew}	new time to reinforce a network asset if EG is installed.

Investment deferral savings are therefore associated with the amount of time before an asset needs to be upgraded. The time required before an asset requires upgrading is a function of load growth. Where EG decreases load growth, more time is required before an upgrade is needed. Load growth rate, r, is assumed to be 1.6%, the projected load growth rate in the United Kingdom. The discount rate is set to 6.9%. n_i can be calculated through equations (3) and (4):

$$C_i = D_i \times (1+r)^{n_i} \tag{3}$$

$$n_i = \frac{log C_i - log D_i}{log(1+r)} \tag{4}$$

where:

C_i	asset load capacity
D_i	current load
r	load growth rate.

In equation (4), a network asset (*asset*$_i$), such as a circuit, has a capacity of C_i, and supports a power flow of D_i. The time to reinforce the network asset is the number of years that it takes for the circuit to grow from D_i to C_i for a given load growth rate r. Reference [18] assumes that reinforcement occurs when the circuit is fully loaded. The test system is a 33-kV network with a peak demand of 81 MW. EG units are 1.2-kW CHP gensets.

Table 17 shows the reduction in investment as a percentage of the required investment if no EG units were installed. Savings are calculated for EG evenly distributed and allocated in proportion to load for four penetration levels, while penetration percentage is the installed EG capacity as a percentage of the total load [18].

Table 17 - Investment savings presented as a percentage of the required investment if no embedded generation (EG) unit were installed [18]

Penetration level	1.5%	11%	28%	32%
	Reduction in investment (%)			
EGs evenly distributed	4.75	32	65	70
EGs allocated in proportion to load	7	42	77	82

Table 17 reveals that large savings can be made in investment deferral when EG is installed throughout the network, especially when EG units are allocated according to load demand: up to an 82% reduction for a 32% penetration level. Despite the investment savings calculation in equation (2) not taking the cost of the EG unit into account, the formulation is at least sufficient to underline the potential benefits of EG.

In reference [34], a test distribution network was broken up into separate feeder groups to test the reduction in current due to EG (Figure 43). At each bus, EG was installed with a gradually increasing capacity from 10 to 100 kVA. For each incremental increase, load flow and feeder currents were calculated. A load growth of 3% was assumed for all buses. The time taken for currents to reach levels where a cable upgrade is required was then calculated from when the EG is installed. The savings were calculated by NPV, equivalent to the interest on the investment cost of the cable upgrade for the deferral time. The NPV calculation does not take into account the investment cost of the EG, assuming instead that it is owned by a third party, not the DNSP.

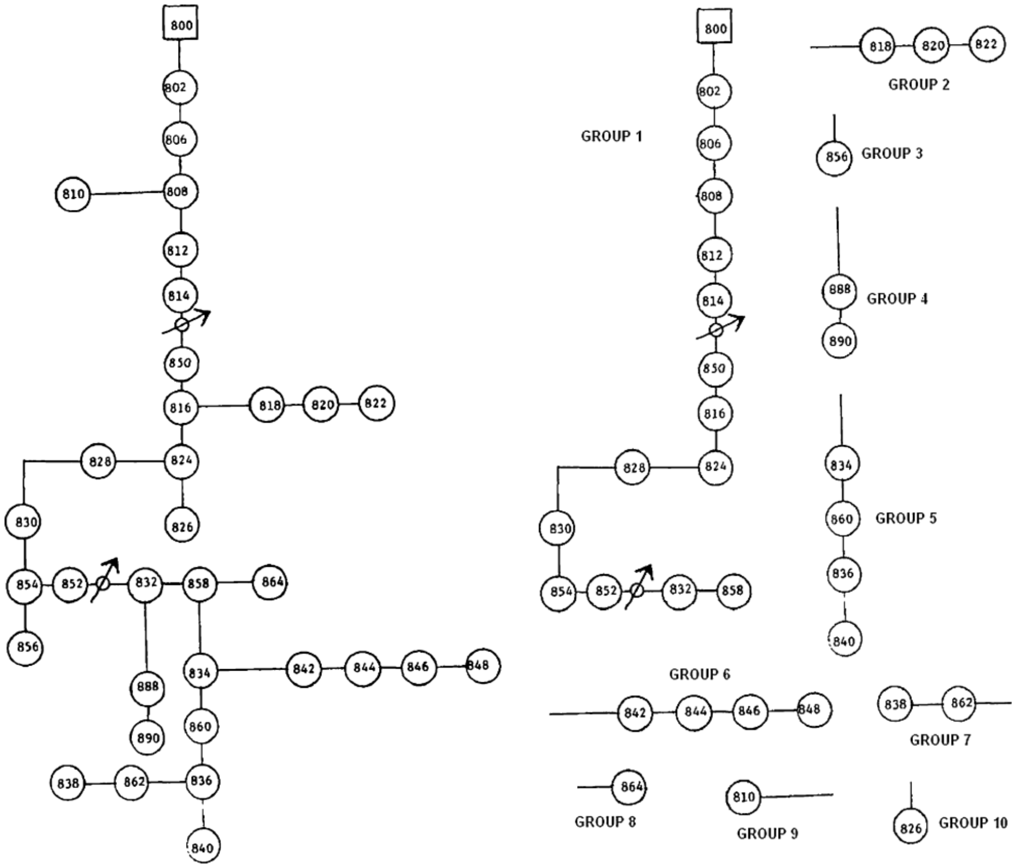


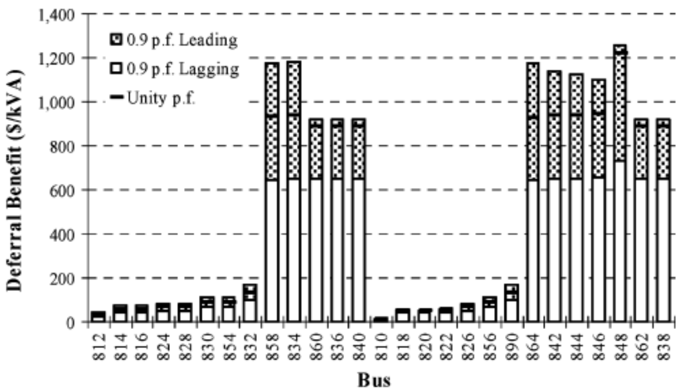
Figure 43 - Test distribution network used in reference [34]

The cost to upgrade each feeder group is given in Figure 44(a). Figure 44(b) gives the financial benefit for 100-kVA EG installed at their respective buses, and the equivalent current reduction due to an EG installation of 100 kVA at bus 830. At bus 858, its deferral benefit of nearly \$1200/kVA equates to more than 15 years' upgrade deferral.

TABLE I
GROUP CONDUCTORS, AMPACITY LEVELS AND UPGRADE COSTS

Feeder Group	Existing Wires		Wires for Upgrade		Length (m)	Upgrade Cost ($)
	AWG	Amps	AWG	Amps		
1	2	94	1/0	150	14,326	278,525
2	2	60	1/0	94	6,401	127,281
3	2	60	1/0	94	2,164	104,921
4	1/0	150	2/0	190	975	116,056
5	2	94	1/0	150	1,067	163,273
6	2	94	1/0	150	549	158,769
7	2	94	1/0	150	488	158,239
8	4	60	2	94	152	94,304
9	4	60	2	94	549	96,395
10	4	94	2	94	914	98,326

a)



b)

Figure 44 - Feeder upgrade costs used in reference [34]

Reference [20] calculates the return on investment for DNSPs installing EG technologies (gas and diesel generators). The return on investment was calculated for three different operating systems that run only at:

i. maximum, normal, and medium load (5820 hours per year)
ii. maximum and normal load (weekdays from 8:00 am to 8:00 pm, 2880 hours per year)
iii. maximum load (80 hours per year).

The load bands (maximum, normal, medium) are given in Table 18(a). The calculated PV for the investment is given by equation (5):

$$f_1 = \sum_{y=1}^{N} \frac{R_y + LI_y - OM_y}{(1+d)^y} + ND - CDG \quad (5)$$

where *d* is the discount rate, *ND* is the network deferral benefit, R_y is the annual sales in energy, OM_y is the annual operations cost, *CDG* is the capital cost of the EG and LI_y is an annual loss incentive payment for reduction in losses.

A case study using an 83-bus, 11.4-kV radial distribution network was used to examine the potential economic benefits (Figure 45).

Table 18 - (a) Load bands; (b) group conductors, amp capacity and upgrade cost used in reference [20]

(a)						(b)				
Load band	Duration (h)	Active power (MW)	Reactive power (MVAR)	Losses		Existing wires		Wires for upgrades		Upgrade cost (£)
Minimum	2940	5.670	4.140	0.0199		AWG	Amps	AWG	Amps	–
Medium	2940	8.505	6.210	0.0450		2	60	1/0	94	64,913.31
Normal	2800	11.340	8.280	0.0807		2	94	1/0	150	142,047.75
Maximum	80	14.175	10.350	0.1272		1/0	150	2/0	190	59,188.56

AWG = American wire gauge

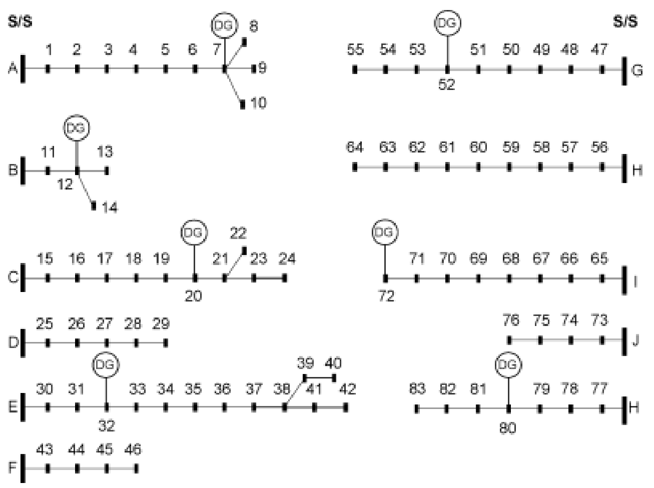


Figure 45 – The 83-bus, 11.4-kV radial distribution network used in reference [20]

EG was installed at buses 7, 12, 20, 32, 52, 72 and 80, and network deferral benefit was calculated assuming load growth of 1%, 2% and 3% [20]. EG units were assumed to operate at a fixed power factor of 0.9 leading. The study focuses on deferment of cable upgrades; the cost of this was derived from the average marginal investments on feeders per growth in system peak calculated for 124 utilities in the United States. The values used are given in Table 18(b).

The study showed that gas engines have an investment cost of £600/kW, with operation costs at £28/MWh. The diesel generators have low installation costs of around £100/kW, but much higher operational costs of around £150/MWh. The price of energy was assumed to be £60/MWh. Results of the analysis for 3% load growth and 20-year planning horizon are given in Table 19.

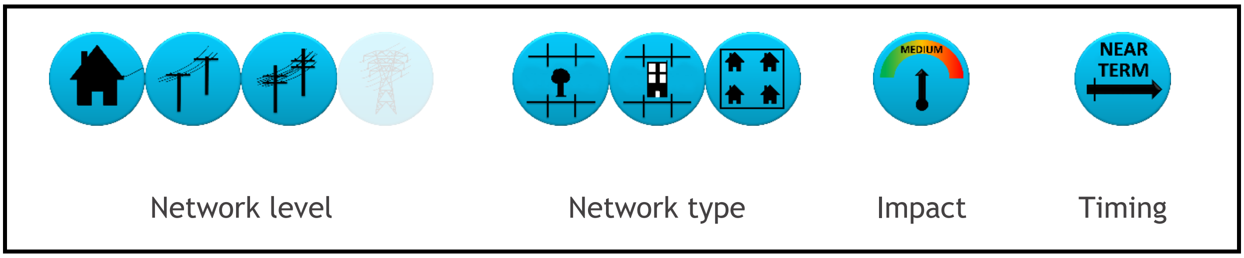
Table 19 - Return on investment at 3% load growth and 20 year planning horizon for distributed generation (DG) [20]

DG location		Gas			Diesel		
		DG operating scenario					
		A	B	C	A	B	C
Capacity (MW)	7	4.3340	4.5901	–	–	–	–
	12	3.5590	3.8523	–	–	–	–
	20	2.3766	2.6006	0.5016	0.5016	0.5016	0.5016
	32	3.8787	4.2642	0.5906	0.5906	0.5906	0.5906
	52	3.5263	3.7904	–	–	–	–
	72	2.4286	2.6646	0.3380	0.3380	0.3380	0.3380
	80	3.7559	4.0955	0.5400	0.5400	0.5400	0.5400
	Total DG	**23.8591**	**25.8576**	**1.9702**	**1.9702**	**1.9702**	**1.9702**
Objective function breakdown							
£ 000s	ND	597	597	597	597	597	597
	LI	-243	-94	2	77	45	2
	R	103,830	55,684	118	8,574	4,234	118
	OM	48,454	25,986	55	21,435	10,607	295
	CDG Pg	14,315	15,515	1,182	197	197	197
	Objective function	**41,415**	**14,686**	**-520**	**-12,385**	**-5,919**	**224**

CDG Pg = Capital ost of DG; LI = Loss Incentive; ND = Network Deferral benefit; OM = annual Operation and Maintenance costs; R = annual energy sales

It is not specified in [20] how the sizing of the EG is selected. The results show that the proposed gas installations are profitable for the first two operating schedules, but not the third; the gas generators do not run long enough to generate the revenue to offset their high capital cost. The opposite is true for diesel, but the low capital cost and high running costs fit well when operating during peak demand periods only.

3.4.9.3 Embedded generation as an alternative option

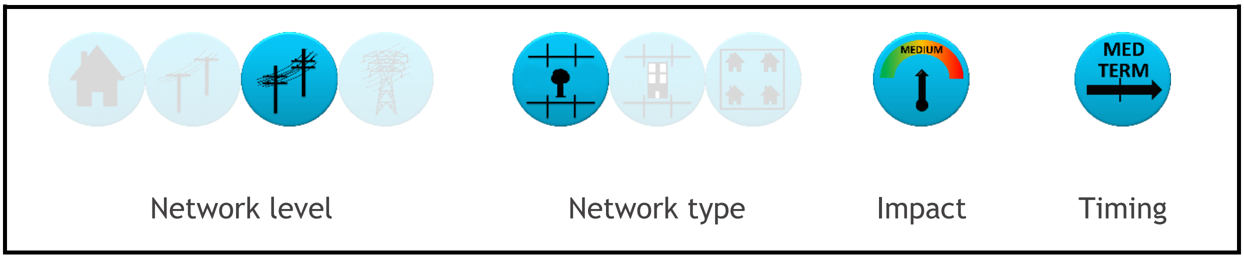


This section presents work that uses EG to deliver outcomes in power quality and network services.

Reference [10] performs an NPV calculation for adding STATCOM/BESS to a PV system, calculating a 13% return on investment for the scenario considered. The services/benefits provided by a combined PV/STATCOM/BESS, such as MW and MVAR support, ancillary services, voltage regulation and investment deferral provide a revenue stream and payback on investment.

Reference [8] examined the use of PV and storage to manage voltage profiles on a rural feeder, comparing the cost in storage to that of purchasing a DSTATCOM. The required capacity of the DSTATCOM provides the same voltage profile results as the proposed PV storage control system. The study found that 60 kVAR of DSTATCOM is required, costing US$3600, while the cost of the batteries (ZnBr) was US$9600. They note that the DSTATCOM cannot provide peak shaving: only reactive power support.

3.4.10 Stability and reliability



This section discusses the findings of reference [19], which calculates the increase in network reliability delivered by the installation of EG in rural Brazil.

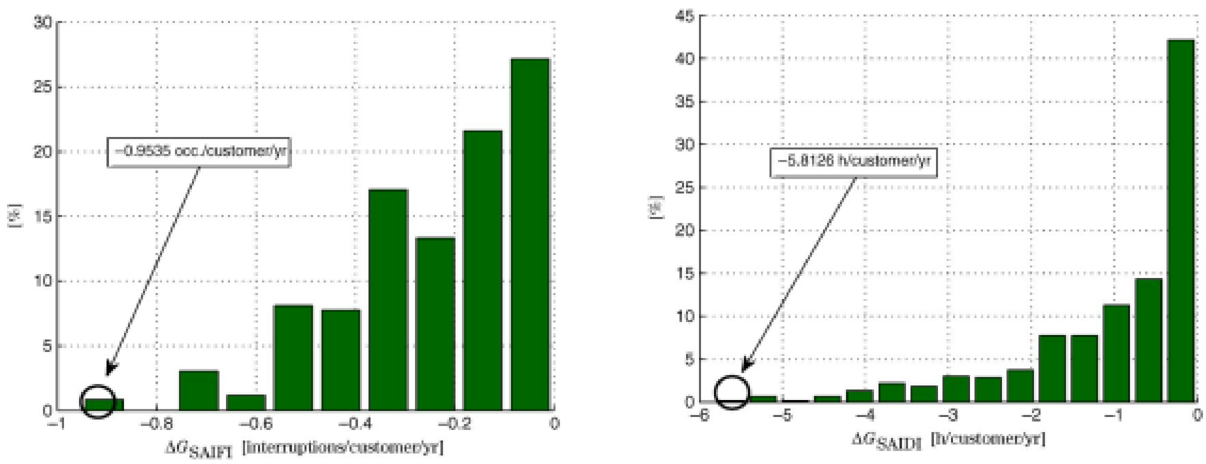
The rural network consists of conventional generation with EG distributed among subsystems. The study investigates how effectively EG can maintain subsystem voltage and frequency after either a:

i. change in state of the EG within the subsystem
ii. load state transition
iii. protection device event (termed islanding).

The effectiveness of the EG system was measured by comparing the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), with EG and without.

The test feeder covers 166 km^2, providing electricity to 1865 customers with a total peak load of 1.03 +j0.34 MVA. The rural feeder is weak and characterised by poor supply at certain times of the year. The rural network consists of 10 sectionalisers (and their 10 respective reclosers) and 41 fuses. Load is stochastically assigned as a percentage of the peak; EG is stochastically assigned a capacity. If islanding occurs, it is assumed that the EG is able to perform load following perfectly, up to its capacity. EG systems are individually ramped up or down following a merit order. The state of the system is determined every hour over a period of 593 simulated years. In the event of subsystem islanding, the capability of the EG within the subsystem to meet load demand is calculated and reliability metrics recorded.

The study found that EG does improve reliability within the rural network, as illustrated by Figure 46. The frequency and duration of inadequate services for the whole system dropped from 3.6 occurrences per year and 2 hours/year to 0.18 occurrences per year and 0.0978 hours/year, respectively. There were an average of 1.4 islanding events a year, of which 92% were successful.



a) b)

Figure 46 - Impact of embedded generation on (a) System Average Interruption Frequency Index (SAIFI); (b) System Average Interruption Duration Index (SAIDI) [19]

3.4.11 Stocktake

Reference [41] provides detailed information on 176 projects, including 116 studies, trials and demonstration projects from across Australia and 60 key projects from Europe, the United States, Korea and Japan, among others). The projects discussed in this section examine the benefits EG provides to the electrical networks. The majority of the relevant projects in [41] are either ongoing, with no results to date, or otherwise commercial in confidence; those covered here are complete with results or findings that are publicly available.

3.4.11.1 Breaking the solar gridlock – potential benefits of installing concentrating solar thermal power at constrained locations in the National Electricity Market

Reference [1] examines the potential for concentrating solar power (CSP) to defer network augmentation.

The methodology of this project consisted of four tasks (see Figure 47):

- Task 1 — identify avoidable network investment
- Task 2 — identify the likelihood of CSP being able to generate during peak-load periods at the identified locations
- Task 3 — identify the locations where CSP can provide cost-effective network support, and also determine appropriate plant capacity and configuration
- Task 4 — undertake case studies at constrained locations in Queensland, New South Wales, Victoria and South Australia.

CSP is defined as being able to meet a network constraint when the indicative firm capacity at the location for the time and season is above 80%, and a CSP plant of capacity equal to the maximum projected network constraint could be physically connected at the appropriate connection point.

The cost effectiveness of CSP replacing network augmentation was assessed by comparing the CSP plant's levelised cost of electricity to potential revenue, including a calculated network support payment. Different CSP plant configurations were assessed, ranging from the minimum size plant to alleviate the constraint to the maximum size able to be connected without requiring network augmentation to export energy. The configurations included the assessment of varying amounts of thermal energy storage.

A reduction of 4% per year was included in the modelling for CSP capital costs to allow for the projected CSP learning curve: a midrange among estimates for likely cost reduction. The proposed network investment was reduced by 20% prior to calculating the network support payment, reflecting the fact that electricity generation (of any type) cannot replicate the certainty offered by wires and poles. This also means the total societal cost of meeting network constraints is reduced by 20%. However, the comparison of CSP installation to other non-network solutions is not considered in this study [1].

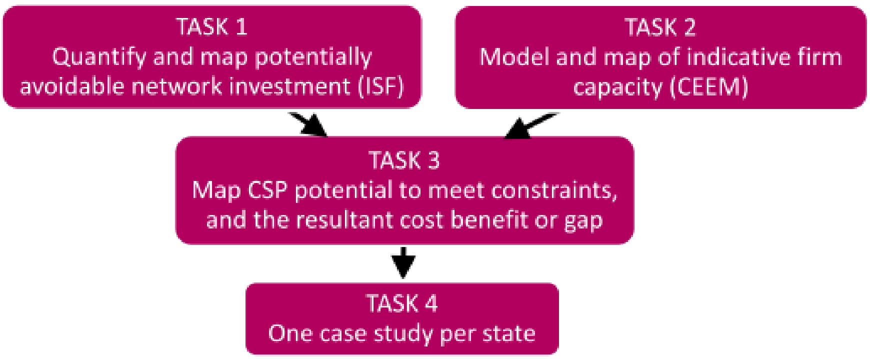


Figure 47 - Methodology for identifying concentrating solar power (CSP) potential to defer network augmentation [1]

A total of 92 constraints, or constrained areas, were identified in non-metropolitan areas in the NEM [1]. Approximately $0.8 billion of potentially avoidable network augmentation was identified across the NEM in areas with suitable solar irradiance for installation of CSP (defined here as average direct normal irradiance, which is more than 21 MJ/m^2/day); Figure 48 breaks this down by time period and state. A further $0.5 billion of potentially avoidable network expenditure was identified in areas with direct normal irradiance below 21 MJ/m^2/day. Most of the investment occurs from 2016 onwards. This reflects the fact that maximum demand forecasts were reduced significantly during 2012, deferring many cases of proposed growth-related augmentation.

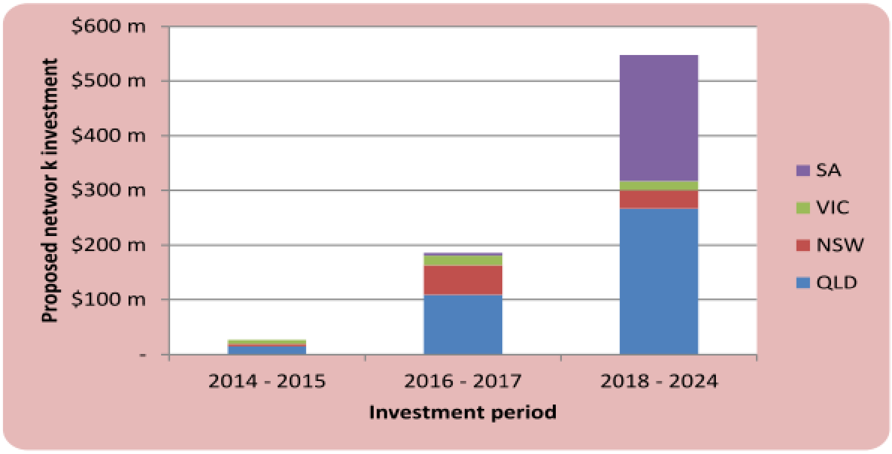


Figure 48 - Potential network augmentation projects ($) arranged by state [1]. NSW = New South Wales; QLD = Queensland; SA = South Australia; VIC = Victoria

Table 20 gives the proportion of grid-constrained locations where CSP could indicatively avoid the need for further network augmentation. Table 21 summarises the cost benefit of CSP installed at grid-constrained locations, while Table 22 provides an overview of the results for each case study.

Table 20 - Proportion of grid-constrained locations where concentrating solar power (CSP) could indicatively avoid the need for further network augmentation [1]

	Queensland	New South Wales	Victoria	South Australia	All states
Number of locations where CSP could indicatively avoid the need for network augmentation	20	7	17	4	**48**
Proportion of all locations (%)	87	88	53	100	**72**
Proportion of location with DNI > 21 MJ/m^2/day (%)	90	100	100	100	**94**

DNI = direct normal irradiance

Table 21 - Cost benefit of concentrating solar power (CSP) installed at grid-constrained locations [1]

	Queensland	New South Wales	Victoria	South Australia	All states
Proportion of cost-effective sites (%)	30	0	14	67	**25**
Proportion of sites with cost-benefit > -$20/MWh (%)	45	17	14	67	**39**

Table 22 - Overview of the results for each case study [1]

Location	Network operator	Optimum plant (MW/TES)	Proposed augmentation year	Proposed augmentation cost ($ million)	Network payment ($/MWh)	Net benefit ($/MWh)
The Riverland, South Australia (line replacement)	ElectraNet	40 MW, 5 hrs	2022	226	110	144
The Riverland, South Australia (line upgrade)	ElectraNet	130 MW, 5 hrs	2022	10	1	60
Charleville, Queensland	Ergon	20 MW, 5 hrs	2022	70	6	16
Wemen, Victoria	Powercor	77 MW, 5 hrs	2021	12	3	23
Gunnedah supply, New South Wales (CSP at Moree)	Transgrid	50 MW, 5 hrs	2019	24	9	-13
Millchester, Queensland	Ergon	40 MW, 15 hrs	2017	46	16	-29
Gunnedah supply, New South Wales (CSP at Gunnedah)	Transgrid	50 MW, 5 hrs	2019	30	13	-39

CSP = concentrating solar power; TES = thermal energy storage

3.4.11.2 Effect of small solar photovoltaic systems on network peak demand

Ausgrid examined the impact of distributed PV on peak demand [24]. The estimated peak reduction was between 0.3 and 1.2%, while the capacity of the installed PV contributing towards peak reduction ranged between 16 and 86% (averaging approximately 32%). The orientation of the PV panels is not stated in the report, but it is likely that the majority are north-facing. If panels were oriented towards the west, then the impact on peak reduction would be larger.

Figure 49 shows the potential afternoon gain in generation if panels were oriented towards the west. The figure compares typical generation of a north-facing system and a tracking system, but the generation of a tracking system and a west-facing system will be closer towards the end of the day. The observed peak period here was around 5:00 pm; at this time, generation of a west-facing system could potentially be double that of a north-facing system.

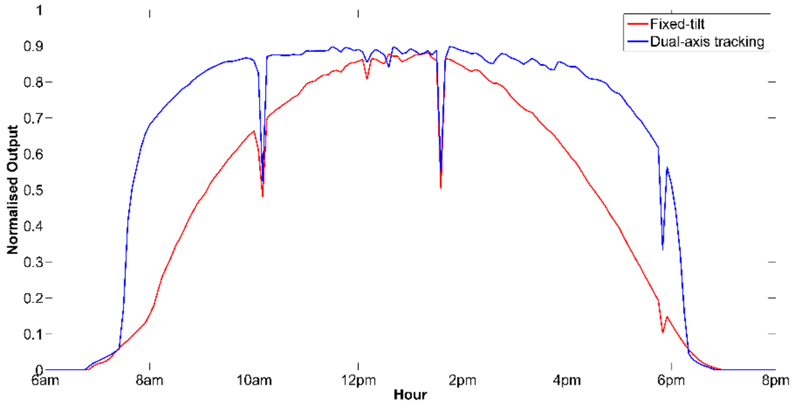


Figure 49 - Generation comparison between dual-axis tracking and fixed tilt [42]

3.4.11.3 Maximising the benefit of photovoltaic utility scale storage at PNM Prosperity project

The PNM Prosperity Energy Storage Project [43] is a smart grid demonstration project in New Mexico, United States. The 500-kW PV system has two advanced lead-acid batteries: one is 500 kW and provides fast response for power smoothing, and the other is 990 kWh for peak-load shifting. The system control algorithm's optimisation objectives are peak-load reduction, avoided generation and arbitrage. Figure 50 shows the measured output for the system for a single day and reveals the effectiveness of the algorithm at shifting output.

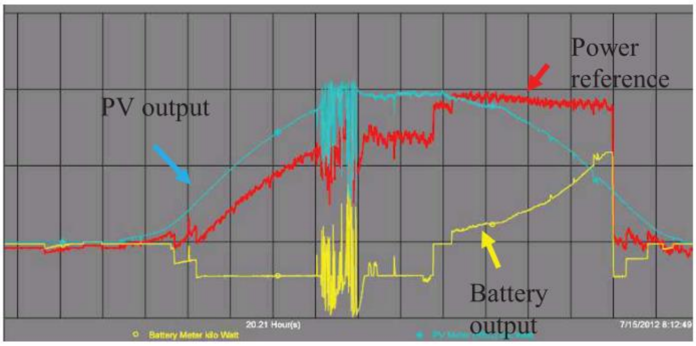


Figure 50 - PNM Prosperity Energy Storage system output for a particular day [43]

3.4.12 Summary

While significant focus has been given to the costs associated with the rise of EG, little public attention has been drawn to the potential for networks to derive significant benefit, both from existing EG and from targeted incentives or deployment of new systems. The uptake of rooftop solar PV over the last five years — combined with incentivising appropriate EG storage systems, and strategic deployment of targeted EG assets, such as network-owned batteries — has demonstrated potential for significant gains, both economically and in terms of network power quality and reliability.

Some of these benefits rely on an increasing peak load to enable network investment deferral, which will make EG economically viable. In several networks, the general trend in recent years is towards a reduction in peak load. However, this is by no means universal. The above techniques are often applicable at numerous network levels; even on an unconstrained feeder, existing distribution substations could benefit from these techniques.

Several of the methods discussed in this section have benefits that go beyond those for the transmission NSP or DNSP. Reduced line losses, lower costs of operating generation assets, such as peaking plants, and increasing renewable generation are all of benefit to disparate network entities as well as consumers.

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3.5 Australian Standards gap analysis

Considerable work has been done to address the technical challenges associated with integrating large volumes of EG in distribution networks. Although there are solutions to these challenges are available, it is unclear whether current technical standards and regulations can safely and efficiently support them. In addition, new load types and electricity usage patterns are changing the requirements for the electricity system. Recent consultations with industry stakeholders by MHC reveal concerns regarding current standards and connection processes for EG [1].

The aim of this analysis is to establish whether current Australian standards and regulations reflect and can facilitate the abovementioned changes. Key gaps are identified and recommendations made for areas where new or revised Australian standards may be considered. The scope is limited to gaps of a technical nature in the context of EG, with priority given to standards for the following areas:

- grid-connection requirements, including standards to resolve power quality and voltage issues caused by high-penetration solar PV
- remote management, as both a load and source (particularly with energy storage and EVs), including integration of V2G-enabled EVs
- remote DR, including upstream communications and shifting essential loads to match peak generation from EG (particularly solar PV)
- safety considerations, including battery installations, off-grid systems and protection systems (fault ride-through and stability).

3.5.1 Summary of standards

This section provides an overview of the Australian standards that are referred to in this report. The standards outlined in Table 23 are considered relevant in the context of EG. They primarily cover inverter grid connection, DR enabling equipment, and safety of storage and EVs.

Table 23 - Summary of standards relevant to embedded generation

Standard	Description	Published	Reference
AS 4777.1 AS 4777.2 AS 4777.3 DR AS/NZS 4777.2	Grid connections of energy systems via inverters • Part 1: Installation requirements • Part 2: Inverter requirements • Part 3: Grid protection requirements • Part 2 (DRAFT) : Inverter requirements	Parts 1—3: 20/05/2005 Part 2 draft: 31/03/2015	[2]-[5]
AS/NZS 4755.3.1 AS/NZS 4755.3.2 AS/NZS 4755.3.3 DR AS/NZS 4755.3.4 DR AS/NZS 4755.3.5	Framework for demand response capabilities and supporting technologies for electrical products • Part 3.1: Interaction of demand response enabling devices and electrical products — Operational instructions and connections for air conditioners • Part 3.2: Interaction of demand response enabling devices and electrical products — Operational instructions and connections for devices controlling swimming pool pump units • Part 3.3: Interaction of demand response enabling devices and electrical products — Operational instructions and connections for electric storage and electric-boosted storage water heaters • Part 3.4 (DRAFT): Interaction of demand response enabling devices and electrical products — Operational instructions and connections for grid-connected charge/discharge controllers for electric vehicles • Part 3.5 (DRAFT): Interaction of demand response enabling devices and electrical products — Operational instructions and connections for grid-connected electrical energy storage (EES) Systems	Parts 3.1—3.3: 20/11/2014 Part 3.4 draft: 18/07/2013 Part 3.5 draft: 30/04/2015	[6]-[10]
AS 4086	Secondary batteries for use with stand-alone power systems	05/10/1997	[11]

AS/NZS 4509.1	Stand-alone power systems — Safety and installation	20/12/2009	[12]
AS ISO 6469.1	Electrically propelled road vehicles — safety specifications • Part 1: On-board rechargeable energy storage system (RESS)	30/06/2014	[13]
AS/NZS 3000	Australian/New Zealand Wiring Rules	12/11/2007	[14]
AS/NZS 3010	Electrical installations — generating sets	27/06/2005	[15]

3.5.2 Gaps in standards

3.5.2.1 Network connection requirements for embedded generation

This section discusses gaps in standards relating to grid-connection requirements for EG. These connection requirements cover:

- protection and control
- power quality
- voltage
- fault current
- remote monitoring.

The key gaps identified in the analysis include:

1. A lack of technical standards for the grid connection of EG less than 5 MW and not connected at the LV level.
2. A uniform approach needed to address voltage rise, which should be reflected in AS/NZS 4777.
3. Standards are required for protection relays for inverter energy systems.

Embedded generation less than 5 MW

The current version of AS 4777 specifies the electrical installation requirements for inverters and grid protection devices. It currently applies only to 'micro' EG: single-phase units with a generating capacity less than 10 kVA and three-phase units less than 30 kVA. Residential systems (e.g. rooftop solar PV) would generally fall into this category.

The grid-connection requirements for EG rated between 30 kVA and 5 MW are currently determined by DNSPs. These requirements are not clear in general and can vary significantly between jurisdictions. Connection requirements for systems above 5 MW are well covered under chapters 5 and 5A of the NER [16], [17]. Recent revisions to chapters 5 and 5A of the NER (effective 1 March 2015) provide connection processes for EG below 5 MW. However, these processes are largely non-technical and include items such as connection timeframes and contract negotiation. Additionally, Chapters 5 and 5A do not currently apply in Queensland or Victoria. The Queensland and Victorian governments announced plans to implement the National Energy Customer Framework (NECF), which will take effect on 1 July 2015 (Queensland) and 31 Dec 2015 (Victoria). Chapter 5A and its recent amendments, along with the implications of these, are explored in further detail in Section 4.2.1.2.

Revisions to AS/NZS 4777.2 (inverter requirements) are currently being drafted and will supersede AS 4777.2 and AS 4777.3 (grid protection requirements) [9]. The draft proposes extending the coverage of the standard to include all inverters connected at an LV level. This excludes MV-connected EG; consequently, there may still be a desire for technical connection standards to be extended for EG that is less than 5 MW and not connected at the LV level.

Gap 1

A lack of technical standards for the grid connection of EG less than 5 MW and not connected at the LV level.

Restrictions due to high-penetration solar photovoltaics

Increasing solar PV uptake has caused concerns among DNSPs about the cumulative effect that grid-connected systems may have on distribution networks. Perhaps the most commonly reported issue regarding high volumes of PV is the reversal of power flow, causing voltage rise. This happens when the power generated from PV is higher than the load demand (typically in the middle of the day), which can drive node voltages above specified limits.

To address the issues surrounding increased PV uptake, several DNSPs have introduced PV system capacity limits and other solutions in constrained areas. For example, Ergon Energy and Energex require that all newly installed AS 4777 compliant inverters must be able to limit power exports (either built-in or by separate relay) [18]. Since 2012, Horizon Power require some solar PV installations (depending on tariff, system size and network hosting capacity) to have generation management (storage) to control ramp rates [19]. This requirement was complicated by a lack of compatible inverters, and it took approximately 12 months for the market to respond.

MHC recently consulted with industry stakeholders, including representatives from the AEMC, AEMO and Australian Energy Regulator (AER) as well as various utilities. The stakeholders proposed that, for example, instead of DNSP-imposed generation management at the customer level (as with Horizon Power), feed-in tariffs (FiTs) could be reduced and the funds used to implement centralised storage at the network level [1].

The approaches taken by DNSPs responding to the technical challenges of PV are diverse across Australia. Typical measures to limit the impacts of PV include:

- OLTC (at MV/LV transformer) to reduce voltage levels at times of high PV generation

- power-limiting relays
- SVCs
- network reconfiguration
- energy storage at the customer level – prosumer storage
- reactive power control by PV inverters
- DR through price signalling to shift loads to times of high PV generation
- direct load control by DNSPs (remote demand management).

Developing a more consistent approach that allows for diverse network characteristics may be beneficial. The technical means to achieve this could be standardised and handled under inverter connection standards such as AS 4777; some of this is being addressed in the ongoing review of AS/NZS 4777 Part 2. A collaborative approach with DNSPs to develop standards would be appropriate to ensure the solutions are viable.

Gap 2

DNSP's diverse solutions to voltage rise and other EG issues are inconsistent, and complicate development and manufacturing of inverter systems. A more uniform approach, which is reflected in AS 4777, should be explored.

3.5.2.2 Protection

AS 4777 and most DNSPs require backup or central protection; however, no technical standards exist for protection relays. These standards are needed because locally developed limited export products are entering the market with additional protection functions.

Gap 3

No current standards exist or are under development in Australia governing the functionality of protection relays for inverter energy systems.

3.5.2.3 Remote management of embedded generation (energy storage and electric vehicles)

This section discusses gaps in standards relating to the remote management of EG that can be both a load and source (particularly energy storage and EVs). The key gaps identified in the analysis include:

4. A lack of standards in general governing the integration of EVs, including V2G-enabled EVs.
5. A lack of a standardised, well-defined communications protocol for smart meters, whether a backend meter protocol or a shared-market protocol managed by the 'gate keeper', as proposed by the AEMC.

Electric vehicles

EVs with V2G capability allow excess energy stored in batteries to be exported to the grid. Standards and regulations must facilitate the integration of such vehicles safely and efficiently. EG in the form of EVs is not well covered in general by Australian standards.

There is an opportunity for AS 4777 and AS/NZS 4755 to be extended to include EVs in the following areas:

- DR — operational instructions and connections for grid-connected EVs (a draft for this was published in 2013, but is currently on hold)
- connection requirements for V2G power feedback
- EV supply equipment and associated bidirectional communications protocols — e.g. charging stations, plugs, other fittings.

Some DNSPs, as well as the Standards working group, have noted that the lack of standards is unlikely to be an issue in the short term, given the reasonably slow uptake of EVs in Australia. However, the gap remains, and a proactive approach would ensure the industry is well positioned in case EVs are adopted faster than expected. Several relevant international standards in this area could be adopted or modified for adoption in the Australian market.

Gap 4

There is a lack of standards in general governing the integration of EVs, including V2G-enabled EVs.

Metering energy storage and electric vehicles

This section reviews metering infrastructure in the context of EG. Specifically, it looks at issues surrounding the metering of energy storage and EV imports/exports that may be hindering EG uptake.

First, net load metering can be problematic if we consider a customer that, for example, may be importing on one phase and exporting on another. How should customers be billed in these scenarios? How is the asymmetry between import and export price models dealt with? These questions are complicated by smart meter and interval meter recordings being taken only at half-hourly intervals. These complex issues are not currently reflected in Australian standards. We recognise, however, that this may be more of a market rules issue than a gap in standards.

Second, there is a lack of consistency between DNSPs across Australia relating to upstream communications. Smart meters communicate interval data back to DNSPs over secure, private ‘mesh radio’ networks. A backend protocol system (defining communications from the smart meter to the DNSP) is currently not specified in Australian standards. Additionally, different jurisdictions may have different communications requirements. In Victoria, mesh radio networks provided by SilverSpring or Wimax are used, as well as the well-established, special-purpose wireless ‘Zigbee’ protocol for home area networks [20].

The Australian Energy Market Commission (AEMC) has published support for a shared-market protocol, rather than a common backend protocol between smart meters [21] (Figure 51). Their reason for rejecting a common smart-meter protocol is that allowing proprietary protocols would reduce initial investment costs and increase the flexibility of new services, allowing them to be introduced more quickly. They make the point that if a shared-market protocol were specified, there would be no need for a standardised meter protocol, because all authorised parties (such as electricity retailers) would communicate via the market protocol. They recommend that the market protocol be built by extending the current arrangements in place for business-to-business communications managed by AEMO.

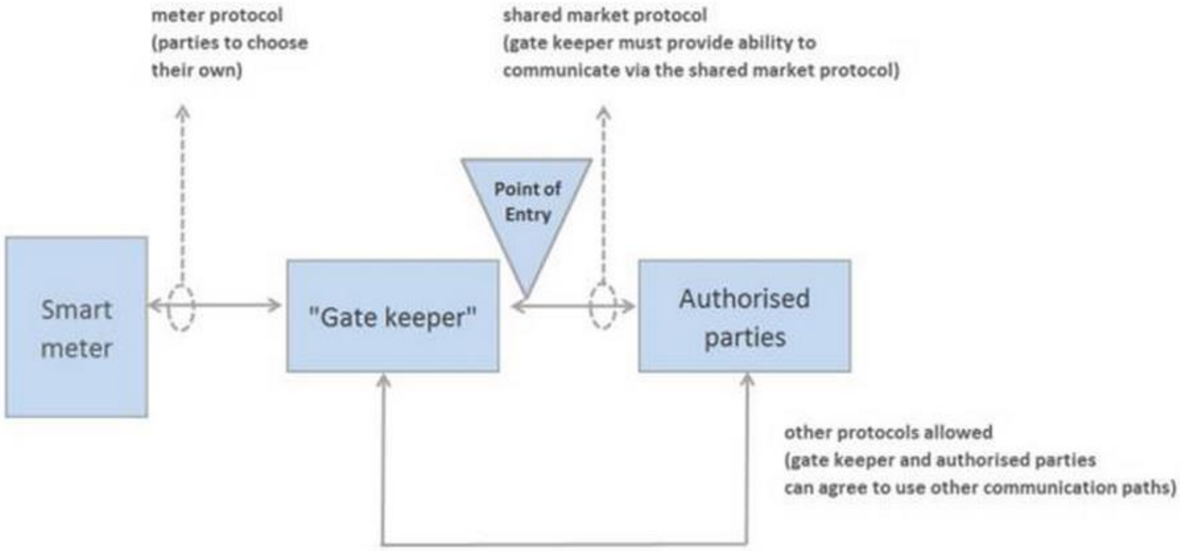

Figure 51 – Australian Energy Market Commission vision of shared-market protocol [21]

The AEMC suggest that shared meter protocol would specify a protocol for different functions known as 'agreed metering services' while maintaining provision for alternative functions and new services through alternative market protocols (Figure 52). An example of an agreed service might be the remote control of an appliance that is facilitated by the smart meter. The alternative market protocols would provide a means for accessing agreed metering services as well as other services. This would allow the benefits of alternative communications to be captured. The AEMC recommends further work to define the scope of the agreed metering services [21].

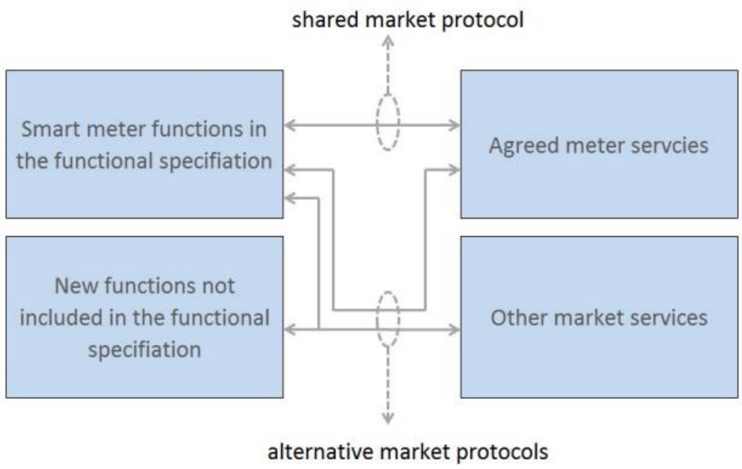

Figure 52 – Access to agreed market services and other services, as suggested by the Australian Energy Market Commission [21]

A standardised protocol of some kind (whether meter or market shared) would therefore be beneficial. It would need to be developed with collaborative input from DNSPs to ensure existing protocols are incorporated smoothly.

Gap 5

A lack of a standardised and well-defined communications protocol for smart meters, whether a backend meter protocol or a shared-market protocol managed by the 'gate keeper', as proposed by the AEMC.

3.5.2.4 Remote demand management

Remote demand management refers to the ability of DNSPs to shift certain customer loads to reduce peak demand, thereby increasing grid efficiency and infrastructure savings. Loads can be brought forward to match periods of peak renewable generation, such as the middle of the day for solar PV. This section reviews the standards for remote demand management and the role it plays in facilitating EG.

AS/NZ 4755 specifies a framework for DR capabilities and supporting technologies for electrical products including air conditioners, swimming pool pump units and electric water heaters. The aim of the standard is to ensure that these types of appliances are manufactured with interfaces and communications protocols that allow them to be controlled remotely.

The key gaps identified in the analysis include:

6. Demand-response mode (DRM) 4 is not defined in current demand-response frameworks for air conditioners.

7. A lack of standards for a feature-rich, bidirectional communications protocol to facilitate DR.

Air conditioners

Air-conditioning systems are one of the main drivers of summer peak demand in Australia [22]. These systems have the potential to facilitate EG through DR. Research by CSIRO and others have demonstrated the advantage of pre-cooling residential houses during the middle of the day when there is a surplus of EG (primarily solar PV), to offset evening peak demand. While there are arguments for and against this type of DR, the idea is gaining more recognition. There are gaps in the treatment of air conditioners under AS/NZS 4755.3.1 that preclude this capability from the DR market.

AS/NZS 4755 defines the following DRMs:

- DRM 1 — turn appliance off or operate at minimal load (this is the only mode required for an appliance to be AS/NZS 4755 compliant)
- DRM 2 — operate appliance at no more than 50% load
- DRM 3 — operate appliance at no more than 75% load
- DRM 4 — turn on appliance by bringing the load forward (but not extending daily running hours).

DRM 4 is currently actively excluded from the air-conditioner interface in AS/NZS 4755.3.1, effectively prohibiting the shifting of air-conditioning loads for pre-cooling. Reasons for not wanting air-conditioner control are valid, including concerns about how to charge customers for the usage; however, with appropriate controls, these issues could be addressed. The gap in the current AS/NZS 4755.3.1 is that it specifically precludes the option for manufacturers to implement DRM 4 and for customers to enter into demand-management agreements (which may well have the appropriate controls to respond to the issues raised).

While the ability to turn on load using DRM 4 in AS/NZS 4755 does exist for other appliances, including pool pumps and water heaters, uptake of this standard suite by manufacturers of these appliance types has been extremely limited. For this reason, it would be beneficial to have DRM 4 defined, because it would encourage the manufacture of DRM 4-compatible air conditioners and take advantage of pre-cooling.

Gap 6

There is currently no standardised method of bringing forward air-conditioning load (pre-cooling) to manage local issues caused by excess EG.

Upstream communications protocols

DR communications protocols in Australia are currently relay based and one directional. The DR standards AS/NZS 4755 series may benefit from the inclusion of a standard for a more advanced protocol that supports:

- detection of the type of appliance (e.g. air conditioner vs EV)

- validation that the DR instruction has been received
- communication about the operating status of the appliance and the types of DRMs that it supports.

AS/NZ 4755 describes a DRED interface to which a common upstream communication protocol can be built. No standardised upstream communication protocol is in place for DREDs. As such, there is no means for manufacturers to standardise a common protocol.

Bidirectional communications protocols have been implemented overseas with success. An example is the OpenADR specification that has been trialled in the United States [23]. The OpenADR specifications describe a standards-based model for communications between DNSPs and end consumers. In 2014, the IEC approved the OpenADR 2.0 specification as a publically available specification (IEC/PAS 62746-10-1) and announced that it would form the basis for the commission of a new standard to be developed. OpenADR has since been adopted in other countries, such as India and parts of Asia.

These international resources could be adapted to develop more comprehensive standards that are appropriate in an Australian setting.

Gap 7

A lack of standards for a feature-rich, bidirectional communications protocol to facilitate demand response.

3.5.2.5 Safety

This section reviews standards for safety in the context of EG. It covers battery installations, protection systems (fault ride-through) and off-grid systems.

The key gaps identified in the analysis include:

8. A lack of standards in general for energy storage, particularly with regards to safety.
9. A lack of standards governing fault ride-through for non-inverter EG.
10. A lack of standards for off-grid EG, particularly with regards to safety.

Energy storage

As a result of increasing EG penetration and decreasing energy storage costs, the uptake of emerging energy storage technologies in the future is expected to be widespread. Standards need to be sufficient to facilitate the growth in this emerging industry, particularly with regards to safety.

Australian standards for energy storage are currently fairly limited, in particular with regards to safety and network connection requirements. This deficiency poses safety risks and may delay the uptake of emerging energy storage technologies in Australia. The standards that do exist are largely focused on mature battery technologies and do not extend to the whole energy storage system connection to the grid. For example, AS 4086 deals with secondary batteries for use with stand-alone power systems, which are not designed to inject power to the grid. AS/NZS 4509 covers the safety and installation requirements for these. Standards for the grid connection of energy systems via inverters also exist in the AS 4777 series, and the upcoming AS/NZS 5139 addresses some safety aspects of energy storage systems with inverter energy systems. However, these standards are limited at a commercial scale, as discussed in Section 3.5.2.1. Some EV standards cover safety requirements for EV batteries (e.g. electrical isolation testing in AS ISO 6469.1), but not in great detail. AS/NZS 3000 and AS/NZS 3010 include earthing and neutral connection requirements.

Additionally, while there is generally an obligation for customers to advise DNSPs when they have installed systems such as energy storage, this is not always adhered to. There is a concern that this could have implications for safety. It must also be recognised within standards that energy storage can be both a load and an EG (via an inverter).

Standards for energy storage are being developed internationally. A review of relevant battery standards is available from http://batterystandards.vito.be/. It would be beneficial to review how these standards may be relevant and applied in an Australian setting.

There is consequently a need for safety standards to support the growth of emerging energy storage technologies. They should comprehensively cover a range of new technologies (e.g. lithium and flow batteries, flywheels). The Clean Energy Council is currently reviewing this area.

Gap 8

A lack of standards in general for energy storage, particularly with regards to safety, although work is currently ongoing in this area.

Protection systems (fault ride-through and stability)

With high penetrations of solar PV, disturbances such as sudden cloud cover or sudden load coming online can significantly increase net load, resulting in large power swings (real and reactive power oscillations) and voltage dips in the network. These issues are of particular concern on high-impedance networks, as noted in Section 3.2.5.1.

Because these oscillations are often low in magnitude and well-damped, a system will usually return to a steady state quite quickly. It may be preferable for EG devices to 'ride through' the LV event to avoid a possible chain reaction of generators going offline. There is potential for EG to stay operational during a fault or other LV event and support the grid with reactive power, if necessary.

Section 5.2.5.8 of the NER specifies fault ride-through requirements for large-scale generators. It may be beneficial to outline similar requirements relating to LV ride-through for EG, particularly in the future with respect to DNSP-operated microgrids. LV ride-through is currently not dealt with in AS 4777, and systems must disconnect from the grid in the event that these conditions are met. The current revision of AS/NZS 4777.2 includes a trip delay of one second for low-level under/over-voltage and under-frequency events to improve fault and LV ride-through capability. However, it will take some time for this to filter through to deployed inverters. Note that this restriction applies only to LV-connected inverters, and not to other inverters or non-inverter generation.

Gap 9

A lack of standards governing LV ride-through for non-inverter EG.

Off-grid systems

AS 4777 is currently not mandatory, although most DNSPs and renewable energy certificates require it. As such, there is no obligation for off-grid systems to comply with the standard. Parts of the standard are relevant to safety whether grid-connected or not, such as the requirement for isolation switches, which isolate the inverter energy system for people working on other parts of the electrical installation. Inverter signage and labelling requirements may also present a safety concern for off-grid systems that are not obligated to comply.

Since off-grid systems are not covered by other standards, there is a recognised gap here with regards to safety. International standards such as IEC 62109-2 *Safety of power converters for use in photovoltaic power systems – Part 2: Particular requirements for inverters* may be adopted for standalone PV systems.

Gap 10

A lack of standards for off-grid EG, particularly with regards to safety.

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4 Regulatory impact assessment

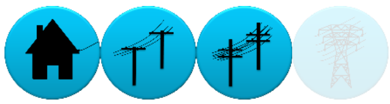
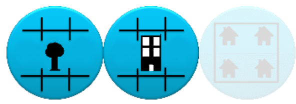
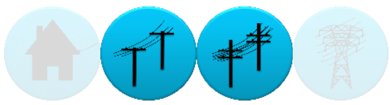
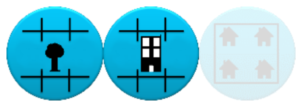
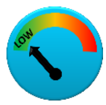
Note on authorship

This section was written by Marchment Hill Consulting (MHC) and reviewed by CSIRO. It highlights links to the technical impacts relating to the findings of this chapter.

4.1 Introduction

This section provides an overview of the current regulatory framework as it relates to connecting embedded generation (EG) in Australia, and considers its suitability in light of the rise in EG connections over the past five years. It also considers the cost of facilitating connection and how these costs should be recovered.

Document map

Regulatory impact key findings	Network level	Network type	Impact	Timing	Chapter section
EG connection regulations					4.2 and 4.3
Costs of connection					4.4

4.2 The National Electricity Customer Framework

The National Electricity Customer Framework (NECF) is a set of national laws, rules and regulations that govern the sale and supply of energy to consumers. The NECF has been adopted in the Australian Capital Territory, New South Wales, South Australia and Tasmania. Queensland is set to introduce the framework on 1 July 2015[9], with Victoria to follow suit from 31 December 2015.

The NECF includes the National Energy Retail Law, National Energy Retail Rules, and amendments to existing national regulation, including the introduction of Chapter 5A into the National Electricity Rules (NER).

Under the NER, network service providers (NSPs) are obligated to facilitate connection services for EG, which is regulated under chapters 5 and 5A:

[9] The Queensland Government announced in April 2015 that it would hold off on implementing part of the NECF known as the 'market monitoring regime', although this is not expected to affect Chapter 5 or 5A.

- Chapter 5 regulates registered market participants; i.e., connections in excess of 5 MW.
- Chapter 5A regulates connections not exceeding 5 MW, including small-scale solar photovoltaics (PV).

Chapter 5A sets out the connection arrangements for non-registered participants and micro-embedded generators (connections considered under Australian Standard 4777). It includes the processes for:

- basic connection services
    - connections related to a certain defined customer type
    - e.g. residential solar PV and micro-EG (less than 30 kW)
- standard connection services
    - connection services that are not basic (i.e. 30 kW — 5 MW) but where the Australian Energy Regulator (AER) has approved a model standing offer (as detailed under NER 5A)
- negotiated connection services
    - connections that do not fall under either of the above categories
    - participants may elect to exercise this option even if they are entitled to a basic or standard connection.

Basic and standard connection arrangements have been put in place to allow for a more cost-effective, streamlined connection process. However, given the complexities involved and varying network characteristics, distribution network service providers (DNSPs) may determine whether the connecting party must opt for a negotiated connection on a case-by-case basis.

Negotiated connections provide a framework to ensure that parties have sufficient information to negotiate effectively and in good faith.

4.2.1 Reforms

Recent reforms have been undertaken to amend chapters 5 and 5A of the NER to clarify and simplify the EG connection process. These are described below.

4.2.1.1 Chapter 5

Chapter 5 was significantly amended in 2014[10] to simplify the connection process and ensure transparency about connection costs and technical requirements. Key provisions of the final rule include:

[10] Australian Energy Market Commission, *Rule Determination [ERC0147] - National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014.

- publication of a connection process information pack by the DNSP, including application requirements and cost estimates
- a new two-stage connection enquiry process and application process, including clearly stated information requirements
- a register of all EG connected to the DNSP's network over the past five years
- a dispute resolution process that allows parties to use the Wholesale Energy Markets Dispute Resolution Adviser in accordance with Chapter 8 of the NER
- allowing DNSPs to charge a fee to recover the costs of preparing detailed enquiry responses.

This rule change came into effect on 1 October 2014.

4.2.1.2 Chapter 5A

The key change to Chapter 5A of the NER[11] involves allowing EG proponents to choose their preferred connection process. It applies to EG less than 5 MW that is not provided with a standard connection offer and that is not a micro-embedded generator.

EG proponents can now choose between the connection process set out in Chapter 5 or the negotiated connection service detailed in 5A.[12] This added flexibility allows them to choose the process most suitable to their specific circumstances, which in turn should result in a more efficient connection process.

This rule change came into force on 1 March 2015.

4.3 Non-National Electricity Customer Framework states

In addition to the NER, Australian states have certain state-specific legislation relating to connecting EG. This is particularly important in states that have not yet adopted the NECF, where the local service rules guide the connection process (e.g. the Victorian Essential Service Guideline 14 and 15 in Victoria. Further non-National Electricity Market (NEM) jurisdictional arrangements are detailed below.

4.3.1 South West Interconnected System

Western Australia operates its own network system: the South West Interconnected System (SWIS). This is not governed by the same rules and regulations that apply to the NEM; instead, network access is regulated and guided by the DNSP's determination process. Three separate arrangements are available, based on the capacity of the connection:

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[11] Australian Energy Market Commission, *Rule Determination [ERC0158] - National Electricity Amendment (Connecting Embedded Generators Under Chapter 5A) Rule 2014*, 13 November 2014.

[12] The adoption of appropriate standards should also be considered in this context. Please see Section 3.5.2 for more information.

- Small-scale solar PV (<30 kVA) follows a three-step process in which an application is first approved by the retailer before being submitted to the relevant DNSP.
- Connections with a capacity of 30—150 kVA are approved under a two-step process in which an enquiry is submitted to the DNSP, followed by an enquiry consultation. The application can then be submitted.
- Connections with a capacity >150 kVA follow a two-step process similar to the above.

Unlike the NEM, EG owners must also pay an additional ongoing distribution use of system (DUOS) charge.

Stakeholders in the SWIS have reported issues relating to the connection process for 150 kVA and larger EG. Applications may be bundled into a competing access group, in which the cost of augmenting the network to facilitate connection of all applicants is spread across each applicant based on their required connection capacity. These costs are then offered to all members of the group. If any members withdraw their application, the costs are then recalculated and offered to the remaining members, unless the total required generation connection capacity still exceeds the capacity being offered as the group's (network augmentation) solution. In this case, the offers will be made based on the order in which the applications were received.

Anecdotal evidence collected by MHC suggests this is a time-consuming process that may cause uncertainty for investors regarding the costs and timeframes for connection.

4.3.2 Horizon Power

Horizon Power supplies electricity to rural and remote customers in Western Australia outside the SWIS. The connection process on Horizon's network follows a three-step process of application, assessment and installation.

As part of the technical assessment of a proposed solar PV connection, Horizon may insist that storage is included as part of the installation to provide smoothing and prevent network instability. This sets their connection process apart from the rest of Australia's DNSPs. Horizon's potential requirement for storage applies to all installations >5 kW and to installations of <5 kW where the hosting capacity of the customer's town has been reached.

4.3.3 Northern Territory

Power and Water introduced changes to its connection process in 2014. The customer and its installer must still submit the required documentation, including a connection agreement, wiring diagram and certificate of compliance. However, residential installations (not exceeding 4.5 kW on single-phase and 6 kW on three-phase) are automatically pre-approved without the need for additional inspections or an engineering assessment.

4.3.4 Reforms

In addition to Victoria and Queensland potentially joining NECF over the coming year, Western Australia is currently undertaking a significant review of its regulatory framework. Launched in March 2014, the Electricity Market Review covers the structures of the electricity generation, wholesale and retail markets within the SWIS. It also investigates incentive options that would help industry participants to improve their investment decisions, and thereby realise efficiencies and minimise costs.The current connection and access arrangements are being reviewed under the Network Regulation work stream. The reforms will transition the current arrangements to chapters 5 and 5A of the NER. They are currently in the scoping stage, with a decision on the reforms to be implemented expected to occur progressively over 2015—17.

The Northern Territory government is also introducing the National Electricity Law and NER in its jurisdiction, and plans to complete this by 1 July 2015. Once completed, this would introduce the relevant chapters of the NER to guide EG connections and transfer the regulatory oversight obligations to the AER.[13]

4.3.5 Survey responses

The survey indicated that in general, NSPs find the current regulatory framework adequate in meeting both NSP and customer needs to facilitate safe, effective and efficient connection of EG.[14] However, further refinements are likely be required when different types of EG become prevalent in the market and new value streams and business models emerge.

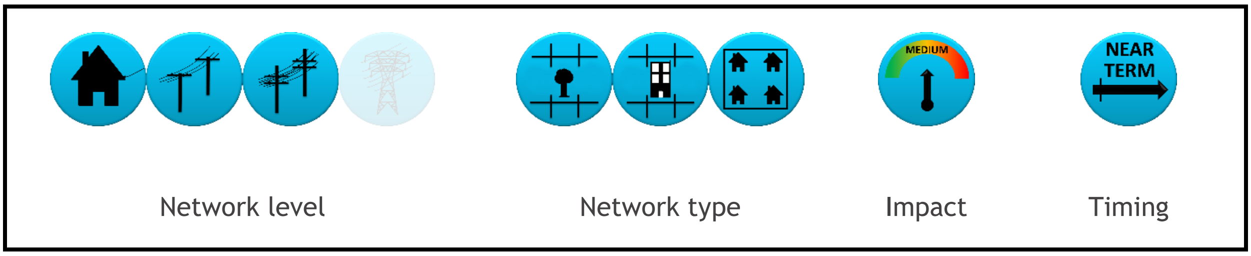
Concerns were raised about the yet unknown effect of the recently introduced reforms on NSP operations and costs. This should be closely monitored to gain a better understanding of the potential impacts.

> ***Key Finding:*** *Although recent reforms to Chapter 5 and 5A of the National Energy Rules (NER) have improved the connection process related to EG, the lack of a consistent national framework means that these have not been adopted uniformly across all jurisdictions.*

A high-level assessment of the characteristics of this finding against the document map key is shown below.

[13] Department of Treasury and Finance, *Northern Territory Electricity Market Reform - Information Paper,* February 2014

[14] For more details regarding the survey, please see Appendix A



Note: the impact is largely dependent upon the jurisdiction. Medium impact refers primarily to jurisdictions that have not adopted reforms relating to EG connection.

4.4 Cost of connection

The price charged to EG owners for connection services is based on the costs incurred by the DNSP in facilitating the connection. It takes into consideration the DNSP's obligation to maintain network reliability, safety and quality of supply.

The connection charges are regulated by the AER[15], which sets out a guideline for DNSPs to determine the allowable connection cost. DNSPs must further submit a 'model standing offer' for basic and standard connection services to the AER for approval. The offer sets out the connection process and contractual arrangements between the DNSP and the connection applicant.

The fees and charges payable to the DNSP under the model standing offer are generally made up of:

- network charges
  - as determined by the AER, payable by the customer's retailer
- site inspection
  - the DNSP may determine that a site inspection is required to determine the nature of the connection, payable by the connection applicant
- ancillary services
  - fees related to site establishment (e.g. updating load data, issuing meters, assigning a National Metering Identifier) and inspection of service work.

Under a negotiated connection service, the DNSP is allowed to charge a fee to cover expenses directly and reasonably incurred from assessing the application and preparing a connection offer.

According to NER 5A, DNSPs are not allowed to charge EG owners for network augmentations if the application is for a basic connection service (as defined in Section 4.2 above), or if a relevant threshold set in the DNSP's Connection Policy is not exceeded.

The Connection Policy is guided by the AER's *Connection Charge Guidelines for Electricity Retail Customers*, and sets out various guiding principles to determine an appropriate

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[15] Australian Energy Regulator, *Connection charge guidelines for electricity retail customers*, Version 1.0, June 2012.

threshold. The AER also provides the following recommended thresholds that fulfil the guidelines:

- 25 kVA on single-wire earth return (SWER) lines
- the maximum capacity of a 100-Ampere three-phase low-voltage supply elsewhere on the network.

4.4.1 Connection cost recovery

DNSPs are not allowed to charge EG owners of small residential solar PV systems (basic connections) for augmentation work, as a result of high levels of solar PV penetration on their network. This has caused issues relating to how these costs may be recovered by the DNSP.

Ergon and Energex determined the costs forecasted to be incurred due to additional administrative work (e.g. call centre costs, billing) and infrastructure required as a result of high levels of solar PV on their network[16]. The estimated infrastructure cost is shown in Figure 53.

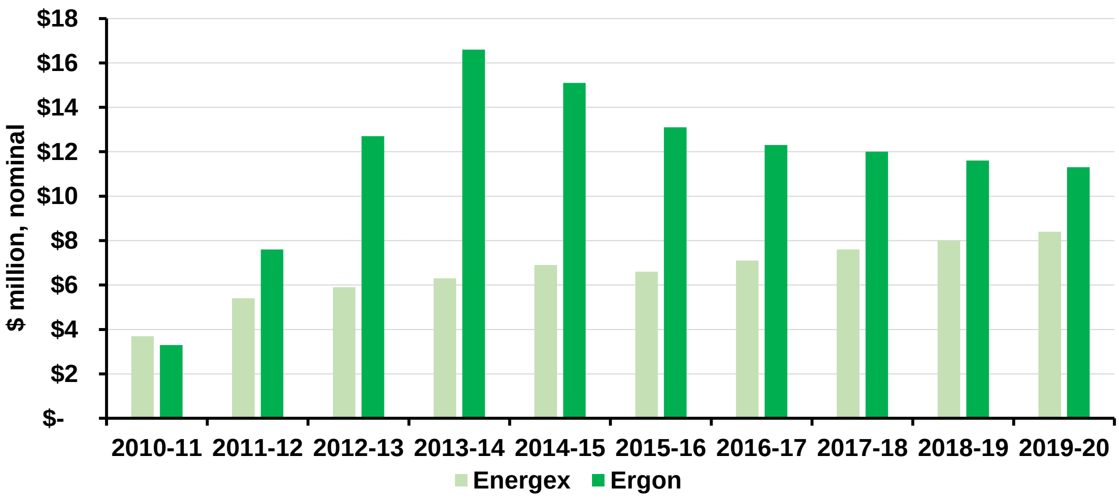


Figure 53 – Solar photovoltaic-related administrative and infrastructure costs

Source: Queensland Competition Authority

As not all of these costs could be recovered under the revenue allowance determined by the AER, the Queensland Competition Authority indicates that Ergon and Energex likely had to defer other capital and operating expenditure work to fund the necessary investments resulting from solar PV.

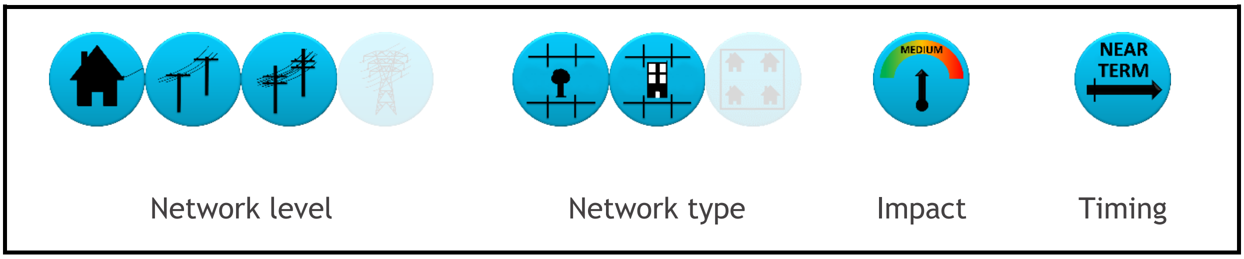
Additionally, DNSPs may charge connection applicants for augmentation from standard and negotiated connection services, but only up to ratio of the asset being used by the EG in

[16] Queensland Competition Authority, *Estimating a Fair and Reasonable Solar Feed-in Tariff for Queensland*, March 2013.

question. This means that the rest of the investment must be recovered from the DNSP’s customer base.

Key Finding: *Where augmentation costs may occur because of high levels of small scale solar PV penetration on a network (i.e. basic connections), the NER does not allow for these costs to be recovered directly from the EG owners in a cost-reflective approach. Instead, these costs are recovered from the entire customer base which introduces an element of cross-subsidisation between customers.*

A high-level assessment of the characteristics of this finding against the document map key is shown below.



Note: The impact and timing of this finding is largely dependent upon the jurisdiction and associated network capacity and EG penetration levels. The given ratings are based on evidence suggesting that this finding is of moderate significance to some jurisdictions in the near term.

5 Commercial impact assessment

Note on authorship

This section was authored by Marchment Hill Consulting (MHC) and reviewed by CSIRO. It highlights links to the technical impacts relating to the findings of this chapter.

5.1 Introduction

Growing levels of embedded generation (EG) are challenging network service providers (NSPs) to meet their responsibilities to maintain a safe, secure and reliable power supply. However, EG can also provide NSPs with new opportunities, such as addressing constraints on the network and deferring capital investments.

EG introduces new nuances and complexities to the calculation of market benefits for electricity network planners and managers. Benefits calculation is no longer as simple as increasing capacity on a single network element. With the introduction of EG, network planners and strategists must now understand and calculate:

- the potential impacts of an EG asset on adjacent network elements during emergency conditions
- how an EG asset can reduce energy at risk across the network element on which it is located as well as upstream elements
- how EG response times affect energy at risk and market benefits.

These and other considerations must be taken into account for electricity networks to determine the cost—benefit outcome of any EG solution for each network element.

This section puts the commercial impacts and opportunities of EG into context, and broadly covers three main areas:

i) key commercial impacts (positive and negative) of EG on the network

ii) a framework that places a value on relevant commercial impacts

iii) commercial opportunities that EG presents for NSPs.

Document map

Commercial impact key findings	Network level	Network type	Impact	Timing	Chapter section
Network Capacity			MEDIUM	NEAR TERM	5.2.1
Network Charges			HIGH	NEAR TERM	5.2.4
Valuation Framework			HIGH	NEAR TERM	5.3
Commercial Opportunities - price signals			MEDIUM	NEAR TERM	5.4
Commercial Opportunities - regulatory barriers			MEDIUM	NEAR TERM	5.4
Commercial Opportunities - metering reform			MEDIUM	NEAR TERM	5.4
Business Models - partnerships			HIGH	NEAR TERM	5.5
Business Models - EG integration			MEDIUM	MED TERM	5.5

5.2 Commercial impacts

The ongoing change in how electricity is produced, delivered and consumed is changing the role and management of the electricity system. The rise of solar photovoltaics (PV) and the increased consumer interest in gaining choice and control over their electricity consumption and expenditure are further changing the energy market.

The impacts of EG can broadly be grouped into the following categories:

- network impacts

- how increasing levels of EG on the network affect NSPs' ability to provide reliable and safe supply as economically as possible[17]
  - e.g. voltage regulation, power quality, network reliability

- customer impacts
  - the effect on customers investing in EG and the broader customer base
  - e.g. EG investment and cross-subsidisation

- generation and retail impacts
  - how EG affects centralised generation and the operating model of retailers
  - e.g. hedging and arbitrage opportunities

- societal impacts
  - the broader effects of EG on overall society
  - e.g. environment and public health.

A high-level overview of the commercial impacts is provided in Table 24.

Table 24 – Embedded generation (EG) commercial impacts

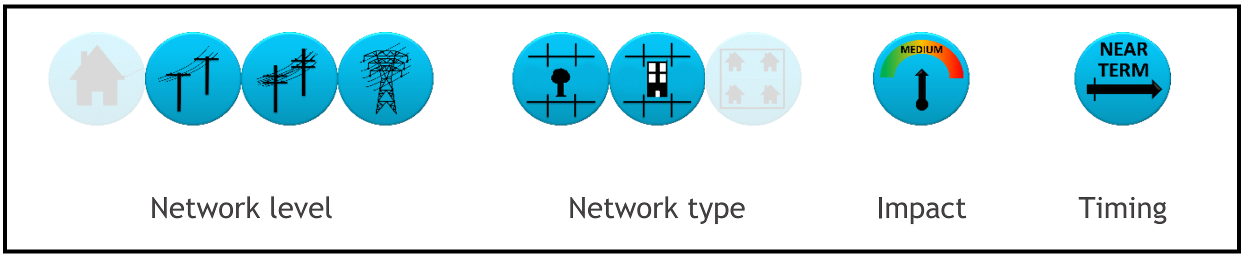
Stakeholder	Impact	Description/hypothesis
Network service providers (NSPs)	Network capacity	EG can reduce peak demand, defer capital investments and increase diversity in supply sources EG may also lead to network congestion or the need to change protection schemes or settings, leading to additional network augmentation
	Network reliability	EG could improve network reliability and backup supply reliability to individual customers, but may also reduce reliability through brownouts and low-voltage trips
	Voltage regulation	High levels of EG on networks can cause voltage issues and NSPs must actively manage it to meet prevailing standards EG could provide voltage support at the ends of long rural feeders
	Power quality	High levels of EG may cause power quality issues, which may result in network losses and appliance and equipment damage
	Distribution use of system (DUOS) and transmission use of system (TUOS)	Network charges collected by the service provider Current (kWh-based) charges result in a cross-subsidy from non-EG customers to EG customers
	Network losses	More localised EG may reduce overall losses on the network by reducing peak demand and the transmission and distribution distance of transported electricity
	Safety	Costs for NSPs to ensure a safe electricity network
Network customers	Installation	Cost of system, installation work, network augmentation charges and connection charges

[17] These impacts are further explored from a technical perspective in Section 3.2.

	Bill reduction and incentives	Reduced bill from onsite generation and added incentives for exporting energy, i.e. feed-in tariffs
Generators and retailers	Fuel costs	Renewable EG can reduce fuel hedging costs incurred by centralised fossil-fuel-based generation
	Wholesale prices	EG reduces grid-transported demand, depressing wholesale prices and hence gentailers' profitability
	Hedging costs/ arbitrage	EG can reduce network peaks and flatten load profiles, leading to lower hedging costs and potential market arbitrage
Society	Environmental	Reduced CO_2 emissions from greater penetration of renewable energy and generation efficiencies
	Public health and security	Improved public health and less reliance on fossil fuel imports through greater renewables penetration

This report focuses on the impacts of EG on NSPs and their customers. The following sections provide additional details on these impacts.

5.2.1 Network capacity



New investments in electricity network infrastructure are required to maintain network performance over time in the face of peak demand growth. Networks are incentivised to meet and manage demand at least cost.

EG can act as both a benefit and cost with respect to network capacity. For instance, high penetration of EG on the network may lead to additional network augmentation. As the level of EG on certain sections of network increases, the network may become congested (assets exceeding their nominal rating). An example of the additional costs created by high penetrations of EG was detailed in Section 4.4.1. However, EG output can also help defer network expenditure, if it is available at the right time and in sufficient amounts. For example, AusNet Services deferred $2.9 m of a planned transformer upgrade by contracting a local, downstream, 10-MW gas-fired power station operator to operate during times of network constraint[18,19].

[18] Grattan Institute, Sunrise, Sundown, May 2015.

[19] A simple cost-benefit analysis of this implementation is provided in Section 3.4.9.2.

Distribution network service providers (DNSPs) should be in a position to promote the use of EG in ways that result in the efficient use of the network – supporting them to meet their network performance standards at the lowest cost. To do this, DNSPs must be able to provide clear price signals to consumers that reflect the cost or benefits of EG on the network at a given time and in a given location. The introduction of more cost-reflective network pricing through recent changes to network pricing rules[20] should enable progress towards this (see sections 4.4.1 and 5.2.4). DNSPs must also be properly incentivised to seek non-traditional, lower-cost solutions to network constraints.

Several measures in the regulatory framework oblige and incentivise NSPs to adopt new technologies in the provision of network services, where this represents the most efficient alternative to traditional network expenditure. This includes the:

- ability of the AER to review and revise forecast expenditure on the basis of the efficient cost, taking into account the availability of new technologies
- ability of the AER to conduct an ex-post capital expenditure review and remove assets from the regulatory asset base (RAB) in instances of overspending
- incentives inherent in the Efficiency Benefit Sharing Scheme and the Capital Expenditure Sharing Scheme, which allow the NSPs to retain a portion of the benefit derived from using new technologies to reduce costs while still providing the required service.

Two recent key regulatory changes also incentivise DNSPs to explore the potential of EG to resolve network constraints, compared with traditional network augmentation:

- the Regulatory Investment Test for Distribution (RIT-D)
- the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS).

These are discussed further in the following sections.

5.2.1.1 Regulatory Investment Test for Distribution

Under the RIT-D process, DNSPs may consider non-network solutions to meet increasing demand on their network. For example, DNSPs could potentially use EG to reduce feeder loads, and hence defer upgrades to the distribution network.

The RIT-D process requires DNSPs to assess the costs — and, where appropriate, the benefits — of each credible investment option to address a specific network problem. They then need to identify which option maximises net market benefits (or minimises costs where the investment is required to meet reliability standards). The RIT-D applies to investments exceeding $5 million, and does not include investments to meet network refurbishment requirements.

[20] Australian Energy Market Commission, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9.*

The RIT-D rules have only recently been implemented[21], and very few RIT-Ds have actually been released to the market for competitive tendering.

MHC's own industry consultation on this topic as part of the Clean Energy Council (CEC)'s Future Proofing the Electricity Distribution Industry project found anecdotal evidence that the RIT-D was creating greater focus on the potential opportunities available via non-network solutions (incorporating EG)[22]. However, the consistency of standards and approaches to the RIT-D process across DNSPs varies; hence, this provides an opportunity to develop best-practice standards for the industry.

5.2.1.2 The Demand Management and Embedded Generation Connection Incentive Scheme

Chapter 6 of the National Electricity Rules (NER) provides the Australian Energy Regulator (AER) with the discretion to establish the DMEGCIS, which consists of an allowance for DNSPs to trial innovative demand management solutions, and a mechanism to allow DNSPs to recover foregone revenue resulting from the demand management implementation.

The stated purpose of the DMEGCIS is to:

- provide incentives for DNSPs to implement efficient non-network alternatives, or
- manage the expected demand for standard control services in some other way, or
- efficiently connect EG.

The Australian Energy Market Commission (AEMC) initiated a consultation process[23] in February 2015 to address two rule change requests. One was from the Total Environment Centre, and aimed to simplify the DMEGCIS process. The other, from the Council of Australian Governments, sought to strengthen the incentives for NSPs to undertake demand-management initiatives[24].

The AEMC have responded with a draft rule determination[25], which proposes the DMEGCIS is replaced with a:

- Demand Management Incentive Scheme (DMIS), which is
  - of the AER's own design
  - based on a set of defined principles aimed at providing distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management
- Demand Management Innovation Allowance (DMIA), which is

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[21] The Distribution Network Planning and Expansion Framework came into effect on 1 January 2013

[22] At the time of writing, this report had not yet been published by the CEC.

[23] Australian Energy Market Commission, CONSULTATION PAPER National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015.

[24] The two rule change requests have since been consolidated into one single request.

[25] AEMC, National Electricity Amendment (Demand management incentive scheme), 28 May 2015.

    - of the AER’s own design
    - based on a set of defined principles aimed at providing distribution businesses with funding for research and development in demand-management projects that have the potential to reduce long-term network costs.

The draft rule proposes that AER should have until 1 December 2016 to develop and publish the DMIS and DMIA.

In the United Kingdom, the Office of Gas and Electricity Markets has recently introduced[26] a new regulatory framework, known as RIIO (Regulation = Incentives + Innovation + Outputs). It includes an Innovation Stimulus Package, which explicitly encourages innovation that could result in better environmental and financial outcomes for the energy sector. The package has three main components:

- Network Innovation Allowance[27] — an annual allowance targeted at small-scale innovation or to fund the preparation of submissions to the Network Innovation Competition
- Network Innovation Competition[28] — targeted at large-scale projects, open to non-RIIO network licensees and awarded through an annual competition, with a maximum lifetime funding per project of £81 m
- Innovation Roll-out Mechanism[29] — aimed at supporting the deployment of fully developed technologies that provide environmental and customer benefits, but would not otherwise proceed, because the network
    - cannot fund the proposed roll-out using their existing price control allowance
    - cannot use an alternative price control mechanism to fund the roll-out
    - does not have a financial incentive to implement the roll-out.

Stakeholder submissions to the AEMC’s review of the DMEGCIS indicated that the relative size of the innovation allowance (a maximum of $1 m per year per DNSP) may have contributed to its lower uptake[30]. The final rule for the DMIA states that the level of the allowance ‘should be reasonable, considering the long-term benefit to retail customers’ [31]. There may be opportunity expand this allowance, in line with international initiatives.

[26] The RIIO applies to the revenue collection period commencing 1 April 2015.

[27] OFGEM, Electricity Network Innovation Allowance Governance Document, April 2015.

[28] OFGEM, Electricity Network Innovation Competition Governance Document, July 2015.

[29] OFGEM, Assessment of benefits from the rollout of proven innovations through the Innovation Roll-out Mechanism (IRM), April 2015.

[30] AEMC, Rule Determination National Electricity Amendment (Demand Management Incentive Scheme), August 2015, p 69.

[31] Ibid, p 73.

Key Findings: *Within the Demand Management Incentive Scheme (DMIS), Demand Management Innovation Allowance (DMIA), RIT-D and RIT-T processes networks have opportunities to consider and implement non-network solutions including EG to resolve network constraints in the most cost effective manner, however there are areas for improvement and potential for change as part of current regulatory reform initiatives.*

5.2.2 Network reliability

Australian NSPs are required to meet specific reliability standards. They are incentivised to maintain and improve network reliability through the Service Target Incentive Performance Scheme and Guaranteed Service Levels under the DNSP's licence agreements.

Network reliability is commonly measured by the:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- Momentary Average Interruption Frequency Index (MAIFI).

SAIDI, SAIFI and CAIDI relate to faults with a duration exceeding one minute, while MAIFI relates to faults with a duration of less than one minute.

The key input in determining the benefit of investments aimed at improving network reliability is the value of customer reliability (VCR). This is also used as an input under the Service Target Incentive Performance Scheme to calculate incentive rates. VCR is defined as the value different types of customers (residential, business or direct connection) place on reliable electricity supply, or conversely, the perceived incurred cost of a power outage in $/kWh terms.

Several studies have been conducted in Australia to determine the VCR, initiated with a study by Monash University in Victoria in 1997[32]. Most recently, the Australian Energy Market Operator (AEMO) updated the VCR numbers in November 2014 following a national survey[33].

Networks must ensure the most appropriate VCR is applied in the assessment of any network augmentation or replacement project. Locational VCRs are therefore essential in allowing network spend to align with market needs, and ensuring that network assets provide returns to network operators and avoid investment in underused assets.

High levels of EG on the network can reduce reliability through brownouts and low-voltage (LV) trips[34]. However, installing EG at strategic points on the network could improve network reliability by providing voltage and frequency support, as well as minimise the duration of

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[32] Monash University, *The Value of Lost Load: A Study for the Victorian Power Exchange,* Centre for Electrical Power Engineering, 1997

[33] Australian Energy Market Operator, *Value of Customer Reliability Review - Final Report,* November 2014

[34] Please see section 3.2.5.1 for more details regarding the technical aspects of this impact

unplanned and planned outages by allowing the switching of loads to adjacent network assets. This type of network support requires controllable EG (e.g. storage, diesel generators); hence, intermittent renewable generation is not suitable.

DNSPs could also use storage and other generation sources (e.g. solar PV, diesel generators) to form microgrids at strategic points on the network. This would allow sections of the network to island in the event of a fault, improving reliability for both the DNSP and its customers. However, this is currently just a concept, and not an existing or near-term solution.

Storage and other generation sources at customers' premises can also be used as uninterruptible power supplies (UPS) or standalone power systems in the event of a network outage. This would improve reliability for such customers, even if network reliability figures themselves are not improved. Fringe-of-grid customers that experience poor network reliability may value such backup supplies[35].

5.2.3 Voltage regulation and power quality

The NER sets out performance standards to which NSPs must adhere when operating and managing their network. In relation to voltage regulation and power quality, the key categories include[36]:

- power frequency voltage
- the NSP must keep supply voltage within a determined range
- voltage unbalance
    - the NSP must ensure that the average voltage unbalance measured at a connection point does not vary by more than 0.5—3.0% (depending on the voltage and averaging period)
- voltage fluctuations
    - the NSP must maintain voltage fluctuation (flicker) levels in accordance with applicable standards (AS 2279.4:1991)
- voltage harmonic distortion
    - the NSP must keep harmonic distortion below levels determined in AS/NZS 61000.3.6:2001.

High levels of solar PV penetration can result in voltage rise. DNSPs are required to operate their networks so that observed voltages do not exceed their allowable voltage range (230 V, +10%/—6%) according to AS 60038[37]. Additionally, according to AS 4777, solar PV inverters must shut down within two seconds of voltage or frequency moving outside of tolerance. If voltage moves outside the range, the inverter will trip, resulting in 'solar spillage'. There

[35] We note that AS4777 inverters are required to have anti-islanding protection, which would prevent the use of any connected EG in the event of a network outage.

[36] For more technical details regarding this impact, see Section 3.2.5.

[37] Allowable voltage range in Queensland and Western Australia is 240 V (+6%/—6%)

have also been reports of solar PV inverters' upper voltage limit having been set too high, resulting in the inverter not tripping and the HV current damaging household equipment.

Voltage fluctuation refers to momentary variations in voltage that can cause household lighting to flicker. This can be caused by intermittent supply from a power source (e.g. cloud cover varying the output from a solar PV unit), as well as by high EG penetration on a section of the network.

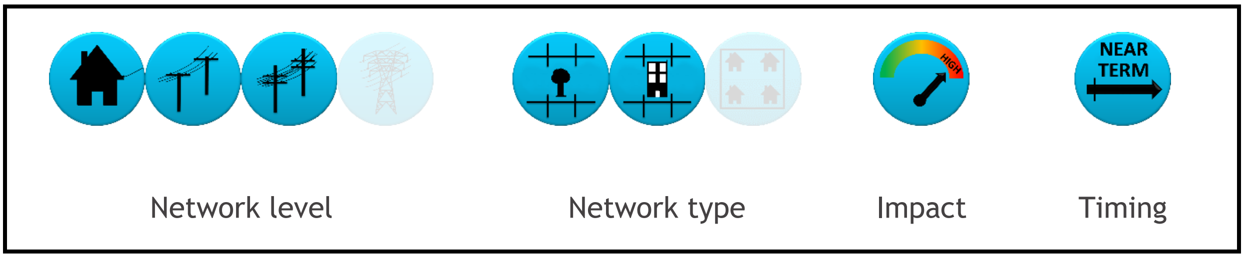
Harmonics distortion occurs when the current sinusoidal wavelength moves away from the ideal range of 50—60 Hz. It can result from nonlinear loads, such as air conditioners or personal computers, or from certain network equipment. It can also be caused by high levels of EG on a particular section of the network, because inverter switches may inject additional harmonics into the network. Harmonic distortion can contribute to network losses and damage household equipment and appliances.

High penetration of solar PV on a feeder (in excess of 40%, according to recent reports[38]) increases the risk of voltage issues. Furthermore, voltage issues are more likely during periods of light loading, and at locations further away from the substation, such as rural networks.

DNSPs generally control network voltage via volt-volt-amps reactive (VAR) control devices, such as switched capacitor banks and tap-changing transformers. These devices rely on localised measurement and tend to have simple control objectives (e.g. to maintain local voltage within a pre-determined range), and operate independently of similar devices deployed at other points in the network. This is a relatively static approach, and is not well suited to the increasingly dynamic network state resulting from increasing levels of EG.

As EG increases on the network, additional investments are required to manage emerging voltage and power quality issues. Increasing levels of EG will mean more costly and complex solutions to network issues. Forecasting this expenditure will therefore become increasingly difficult.

5.2.4 Network charges

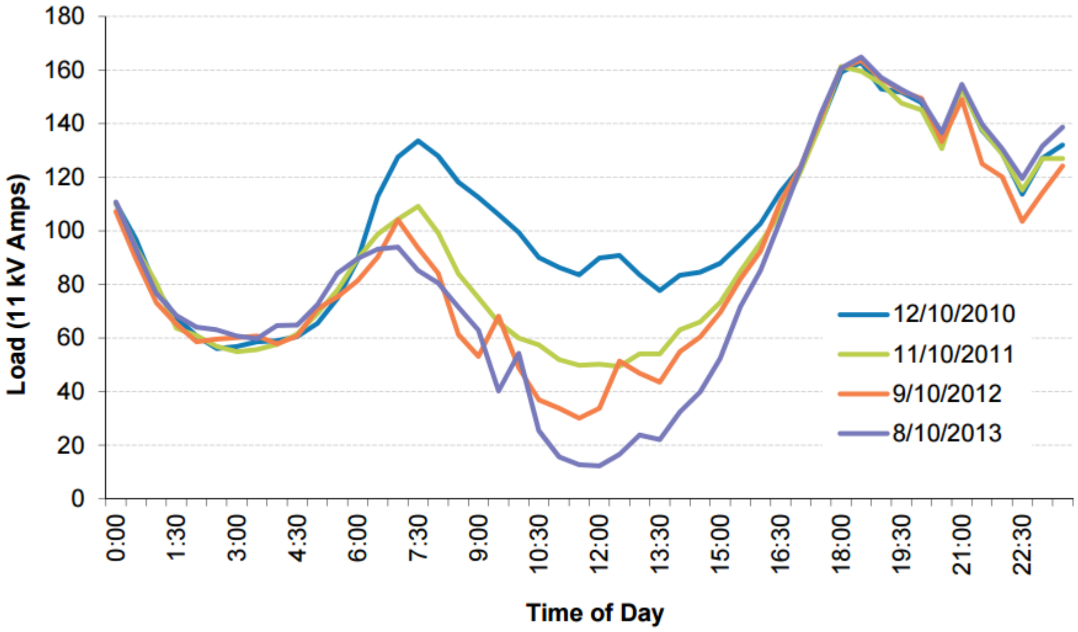


Australian NSPs recoup the costs associated with operating the network from their customers through the distribution use of system (DUOS) and transmission use of system (TUOS) charge.

[38] Energex, *Power Quality Strategic Plan 2015-20*, September 2014.

These are generally structured as a consumption-based component ($/kWh) and a fixed charge ($/day).

These tariff structures were designed for a network with one-directional power flow, where all customers consume energy in a similar manner. When customers install solar PV, they reduce their grid consumption. However, the solar PV generation profile is not well aligned to offset network peaks, as illustrated by Figure 54.



Source: Energex

Figure 54 - Solar photovoltaic impact on feeder load profile[39]

This means that while the NSP's revenue base is reduced, their overall cost structure and revenue targets remain unchanged. To recoup the cost of operating the network, the NSP will hence increase the (fixed and variable) network charge. As a result, customers who have not invested in solar PV — including customers that are excluded from the market, due to affordability or lack of appropriate installation space — pay more for their electricity because other customers have invested in EG[40].

In the survey undertaken for this report, DNSPs highlighted this cross-subsidisation as the key impact of EG. Several studies have sought to understand the size of this cross-subsidy, and the effect on electricity bills for both EG and non-EG owners under different tariff structures.

[39] Energex, *Distribution Annual Planning Report 2014/15 to 2018/19,* September 2014.

[40] A similar issue exists for air conditioners.

As part of the national business case for smart grid technologies developed for *Smart Grid, Smart City*, the forecasted effect on electricity bills was modelled under an inclining block tariff and a cost-reflective tariff. The modelling found that by 2034, an annual cross-subsidy of $420 would occur from non-solar PV to solar PV customers, while under cost-reflective tariffs it would amount to $47.[41]

In 2014, the Energy Networks Association (ENA) commissioned a report to further model the overall community cost of different tariff structures. The modelling used an inclining block tariff as the base case and compared it to a declining block tariff, seasonal time-of-use and a maximum demand tariff. Similar to *Smart Grid, Smart City*, the modelling was forecasted until 2034, and found that energy-based tariffs (inclining block, declining block and seasonal time-of-use tariffs) would result in an annual cross-subsidy of $500—700, while the maximum demand tariff would deliver only a marginal cross-subsidy.[42]

Most recently, the Grattan Institute analysed the costs and benefits of EG (particularly solar PV) under different tariffs, technology developments and subsidies. Like others, they found that a significant cross-subsidy exists, and that it would continue to grow under a business-as-usual scenario. The aggregate net cross-subsidy from consumers to prosumers would be $14 billion by 2030, $3.7 billion of which would be due to the current structure of network tariffs.[43]

Recent reforms[44] to the NER have introduced cost-reflective network pricing in Australia. Under the new rules, Australian NSPs will be required to design their network charges in a way that reflects the true cost of providing network services to customers with different consumption patterns. These tariffs are not specific to the technology choices of customers (i.e. are neutral). Draft proposals are to be submitted to the AER in late 2015 for new network prices that will take effect no later than 2017.

The implementation of new cost-reflective tariffs is not straightforward. Issues include:

- the reliance on interval or smart meter technology
    - this is particularly the case for demand-based tariffs, which are based on customer maximum demand in a period
- the impact of demand-based tariffs on customers with existing solar PV systems
    - this typically contributes to lowering a customer's overall usage, but not necessarily their maximum demand
- overcoming customer resistance to change
    - this includes their ability to understand and accept a new pricing regime, even when it may mean they are better off, or at least not worse off[45].

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[41] Ausgrid, *Smart Grid, Smart City: Shaping Australia's Energy Future*, July 2014.

[42] Energeia, *Network Pricing and Enabling Metering Analysis*, November 2014.

[43] Grattan Institute, *Sundown, Sunrise - How Australia can Finally get Solar Power Right*, May 2015.

[44] Australian Energy Market Commission, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9*.

[45] CSIRO, Australian Consumers' Likely Response to Cost-Reflective Electricity Pricing, June 2015.

The new network pricing rules require DNSPs to consult with customers and retailers while developing their new pricing approaches. However, ongoing effort will be required to manage implementation of the new tariffs and address existing cross-subsidy impacts to give customers the best possible outcome.

Key Finding: *Current volume-based network pricing structures includes a cross-subsidy from non-EG owners to EG owners. The recent changes to the National Electricity Rules require networks to set prices that reflect the costs of providing electricity to consumers with different patterns of consumption. These tariffs are cost reflective and are not specific to the technology choices of customers (i.e. are 'technology neutral'). There is opportunity within these new rules to support the efficient uptake and use of EG that reduces future costs to customers to below the level they might reach under volume-based pricing structures.*

5.2.5 Network losses

Line losses occur throughout the transmission and distribution network. In Australia, annual losses across networks between the generator and the customer are equal to roughly 10% of the electricity sent out[46]. Losses relate to the energy that heats up the network components. They are a factor of how close the asset is operating to its thermal capacity, and not strictly due to the distance between generation and consumption.

Network losses must be accounted for to ensure that enough electricity is generated to meet demand. The NER requires DNSPs to determine distribution loss factors for all levels of their network, which must then be approved by the AER. AEMO is tasked with ensuring that these are properly factored into spot prices.

Embedded generation (DG) installed at strategic points of the network or at customer premises is closer to the point of load. It can help reduce peak demand, which may reduce network losses.

The value of reduced network losses associated with EG should first be calculated. If this is significant, it could be leveraged for emerging commercial opportunities for NSPs arising from EG. This is discussed further in Section 5.4.

5.2.6 Network safety

NER chapters 5 and 5A stipulate that installations and connections must follow the relevant jurisdictional legislation as it relates to technical and safety requirements. These vary depending on the jurisdiction, but generally include:

- service and installation rules

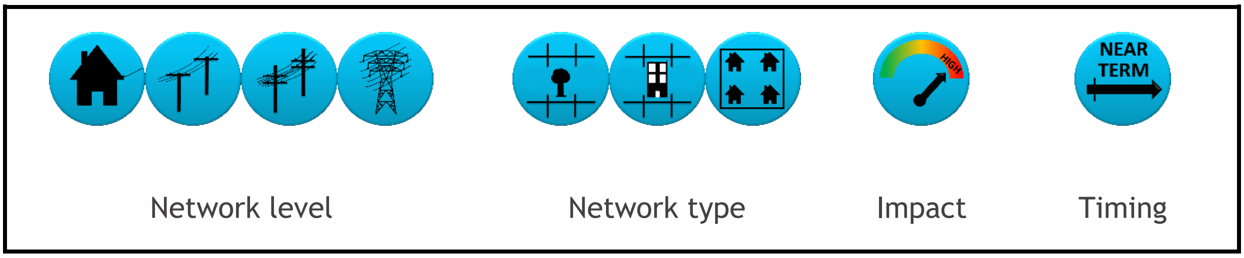
[46] For more technical details regarding this impact, see Section 3.2.2.4.

- electrical safety rules
- relevant network standards and connection policies.

The relevant safety and technical requirements must be included in the NSP's model standing offer for network connection. These generally spell out the rules to which the EG installer must adhere when facilitating the connection. However, it is ultimately the NSP's responsibility to ensure the safety of the customers connected to their network, and they must to routinely inspect and audit installation work[47]. In the survey undertaken for this report, DNSPs highlighted safety as one of the key considerations when facilitating connections to the network[48].

Australian NSPs are further required to meet specific reliability and quality of standards and are incentivised to maintain and improve network performance over time. High levels of EG on the network may impact fault level, asset loading and network stability and may hence lead to safety and reliability issues.

5.3 Valuation framework



The above assessment highlights that the commercial impacts from EG may be significant. To enable the design of appropriate pricing and incentive mechanisms to promote efficient uptake of EG, it is becoming increasingly important to understand its true impacts on the network.

The following sections provides an overview of key frameworks to value these impacts, put forward both internationally and in Australia, which have been used as the foundation for the commercial framework proposed in this report.

5.3.1 International context

To understand the value of EG and prepare utilities for the changing market state, several valuation frameworks have been developed internationally over the last decade. Some of these are described in more detail below.

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[47] AS 5577, released in 2013, provides nationally consistent requirements for the development of an Electricity Network Safety Management System and is an important first step towards national harmonisation of energy technical and safety regulation across Australia.

[48] For more details regarding the technical implications of this impact, see Section 3.2.3.

The main drivers for the development of these frameworks have generally been to allow for integration of high levels of EG on the network, and accurate pricing of incentive mechanisms, demand-response (DR) initiatives and electricity charges.

5.3.1.1 Advanced Energy Economy Institute

In a report[49] prepared for the Advanced Energy Economy Institute, Synapse Energy Economics put forward a framework to capture the costs and benefits attributed to EG. Table 25 shows the cost and benefit categories identified in the report.

Table 25 – Advanced Energy Economy Institute embedded generation cost and benefit categories (Synapse Energy Economics)

	Benefits		Costs	
	Category	**Examples**	**Category**	**Examples**
Impacts on all customers	Load Reduction and Avoided Energy Costs	Avoided energy generation and line losses, price, suppression	Program administration costs	Program marketing, administration, evaluation, incentives to customers
	Demand reduction and avoided capacity costs	Avoided transmission, distribution and generation capacity costs, price suppression	Utility system costs	Integration capital costs, increased ancillary service costs
	Avoided compliance costs	Avoided renewable energy compliance costs, avoided power plant retrofits	DSP costs	Transactional platform costs
	Ancillary services	Regulation, reserves energy imbalance		
	Utility operations	Reduced financial and accounting costs, lower customer service costs		
	Market efficiency	Reduction in market power, market animation, customer empowerment		
	Risk	Project risk, portfolio risk and resiliency		
Participant Impacts	Participant non-energy benefits	Health and safety, comfort, tax credits	Participant direct costs	Contribution to measure cost, transaction costs, O&M costs
	Participant resource benefits	Water, sewer, and other fuel savings	Other participant impacts	Increased heating or cooling costs, value of lost services, decreased comfort
Societal Impacts	Public benefits	Economic development, reduced tax burden	Public costs	Tax credits
	Environmental benefits	Avoided air emissions and reduced impacts on other natural resources	Environmental costs	Emissions and other environmental impacts

[49] Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources*, September 2014

The framework accounts for costs and benefits attributable to the impacts of EG for three main categories of stakeholders: utility customers, participants in distributed energy resources (DER) programs (essentially EG owners and operators), and society as a whole.

The report puts forward the following key approaches to assess the value of the impacts of different EG technologies on the three stakeholder groups:

- Direct monetisation
    - the preferred option, because it captures the costs and benefits directly attributable to EG
- Proxy valuation
    - the second best alternative, which involves applying a multiplier to the impact (e.g. avoided energy or capital)
- Alternative screening benchmark
    - a simplistic method that uses cost—benefit ratios for the EG program or implementation as a whole to determine its cost effectiveness
- Regulatory judgement
    - allows the regulator to determine if an implementation is cost-effective, based on the best available data (where the impacts cannot be monetised)
- Multi-attribute decision analysis
    - a method used to internally rank impacts using a decision matrix summarising the available data, and assigning a weighting to each impact based on its importance.

5.3.1.2 Princeton Roundtable

The Princeton Roundtable brings together economic and financial academia and professionals to discuss and develop new investment ideas and approaches for several areas and industries. The annual expert energy policy roundtable has been held since 2013. Part of the scope of work is to develop a new valuation framework for EG.

A report[50] published in preparation for the roundtable puts forward a proposed valuation approach based on two core principles. The valuation model must:

- consider both energy and capacity impacts from EG
- capture all costs and benefits attributable to EG.

With these high-level assumptions made, the report suggests the following approach to value DER:

$$Net\ Impact = E + C - Co + Be + Ext$$

where

[50] Travis Bradford and Anne Hoskins, *Valuing Distributed Energy: Economic and Regulatory Challenges - Working paper for Princeton Roundtable*, April 2013.

E = savings from offsetting wholesale energy purchases

C = savings from generation capacity investments

Co = costs associated with EG

Be = benefits associated with EG

Ext = environmental externalities (e.g. environment, job creation, security)

The first two categories are relatively self-explanatory, while the next two contain several subcategories:

- costs associated with EG
  - cross-subsidisation between EG and non-EG customers under an energy-based charge
  - administrative costs attributable to the NSP (e.g. for interconnection, changed billing process, system planning, integration, protection)
  - firming expenses incurred by the NSP to maintain network reliability as EG levels increase
  - asset lifetime and performance costs incurred by the NSP to maintain acceptable voltage levels and power quality as EG levels increase
- benefits associated with EG
  - transmission NSP and DNSP capacity investment offset — EG aligned with network peaks may defer otherwise required network augmentation
  - line losses and congestion — EG technologies that provide load reduction may reduce network line losses
  - merit order effect — reductions in load reduce energy and capacity clearing prices
  - fuel price hedge — relevant to renewable technologies only (fossil-fuel-based generation depends on a underlying fuel price volatility, which is borne by the customer).

The fifth category, environmental externalities, includes impacts that are not easily quantified but that may still materially affect society as a whole.

5.3.1.3 The Electric Power Research Institute

The Electric Power Research Institute (EPRI) published a report[51] in 2015 presenting an integrated approach for valuing EG on the network. The report focuses on the development of a universally applicable valuation framework, rather than a specific methodology that may only be applicable to a certain region or network type.

The EPRI framework uses a best-practice economic and engineering analytical tool to determine the extent of the impacts of EG. Similar to the frameworks described above, it provides an impact assessment across the entire energy supply.

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[51] The Electric Power Research Institute, *The Integrated Grid - a Benefit-Cost Framework,* February 2015.

The impacts as they relate to the distribution and transmission network and large-scale generation are shown in Table 26.

Table 26 – Electric Power Research Institute distributed energy resources impact assessment

	Impact	Benefit	Cost
Distribution	Loss reduction	✓	
	Capacity upgrade deferral	✓	
	Reconductoring		✓
	Line regulators/static synchronous compensators (STATCOMs)		✓
	Relaying/protection		✓
	Load tap changers accelerated wear		✓
	Voltage upgrade		✓
	Smart inverters	✓	✓
	Operation and maintenance		✓
Bulk power system (generation and transmission)	Generation mix changes	✓	✓
	Deferral of transmission upgrades	✓	
	Transmission losses	✓	
	Operation and maintenance	✓	✓
	Fuel savings	✓	
	Congestion	✓	
	System operation/uncertainty		✓

The framework also provides the impact assessment on the customer (which was determined to be only the EG investment) and society as a whole (e.g. environment, health, security).

EPRI's proposed framework highlights that geographical characteristics (e.g. voltage, topology) of the network must be taken into account. As a result, it also suggests that the impact analysis should be undertaken down to the feeder level.

As part of this analysis, EPRI introduces the concept of hosting capacity. This refers to determining the amount of EG that can be allowed on a certain feeder without adversely affecting supply quality and existing infrastructure. The analysis essentially involves incrementally adding EG to the feeder until a threshold is breached (defined as when services such as reliability or quality of supply fall below required standards). At this point, a mitigation strategy is developed and costed to restore the feeder to the required service level. Additional EG is then added until the next threshold is reached, which in theory would create a cost-curve for addressing increasing levels of EG on the network.

5.3.2 Draft Clean Energy Council valuation framework

Ernst and Young recently drafted a report[52] for the CEC as part of its Future Proofing the Electricity Distribution Industry program. The report reviews national and international valuation frameworks and puts forward a recommended, consolidated approach to value EG on the network.

The proposed framework has been designed to be scalable and applicable to any EG technology. As such, it has attempted to capture all value streams available from EG and put a value on the each specific cost and benefit to assess the total net present value (NPV) from EG on the network.

A high-level overview of the material value drivers and valuation approach put forward in the CEC report is provided in Table 27.

Table 27 – Clean Energy Council value drivers of embedded generation (EG) and valuation approach

Commercial impact	Description	Valuation approach
Network capacity upgrades	EG could reduce peak load on a feeder, deferring otherwise required network upgrades High levels of EG penetration may also lead to network congestion and additional network augmentation	A simplified version of the current Regulatory Investment Test for Distribution (RIT-D) approach with a half-hourly resolution
Network support	Altering the generating profile of network support generators or deferring generation investments using distributed EG	A simplified dispatch model using short-run marginal cost with half-hourly granularity to capture seasonal trends Parameters to consider include fuel costs, reliability statistics, maintenance, ramping capabilities and demand profiles
Voltage regulation	High penetration of EG on the network can lead to both over-voltage (during periods of low load and high EG output) and under-voltage (during periods of high load but low EG output) DNSPs must actively manage the voltage on the network to reduce this impact	Steady-state powerflow analysis to quantify the magnitude of the required reactive or voltage regulation support Potentially in-depth transient and fault analysis in networks where more sophisticated voltage management schemes may be required
Power quality issues	Harmonics (inverter switches injecting unwanted harmonics into the network) Flicker (variations in voltage, e.g. from momentary cloud cover) that change lighting levels	Transient analysis for different operational states and switching behaviour Unbalanced three-phase analysis

[52] Clean Energy Council, *Evaluation Methodology of the Value of Small Scale Embedded Generation and Storage to Networks*, April 2015

Commercial impact	Description	Valuation approach
Network reliability	Network service providers (NSPs) are incentivised to maintain and improve network reliability High levels of distributed energy resources (DER) penetration may reduce network reliability, but also improve it and offer other network support benefits	Statistical analysis (Monte Carlo) to estimate the expected unserved energy and number of outages with and without EG
Reassessment of fault level coordination, islanding and protection schemes	Legacy protection schemes are currently established (e.g. fault current detection and protection relays) Emerging capabilities (e.g. fault ride-through and islanding) may change the value proposition	Nothing proposed at this point
Dynamic control	Distribution NSPs can actively control EG to manage local network conditions Expected to be particularly valuable on rural networks with EG growth, where network augmentation can be deferred	Proposed to be assessed on a case-by-case basis

The CEC's proposed approach entails calculating the value of each impact on a feeder-by-feeder basis to reach an NPV for the EG in question. This could also be done a feeder category basis, using CSIRO's recent work[53] (e.g. urban 11 kV).

5.3.3 Proposed consolidated impact categorisation and valuation approach

A best-practice approach is starting to emerge from the international and Australian valuation frameworks assessed above. The approach:

- takes geographical and network specific conditions into consideration
- is applicable to all different types of EG
- is applicable to all stakeholders
    - customers, EG owners, NSPs, generators and regulators.

Limiting factors that explain why certain impacts may not be appropriate to include in the valuation framework include the following:

- The impact cannot be monetised (e.g. environmental, which in the absence of a carbon pricing mechanism, it is challenging to monetise).
- The impact is not material or not available under the current market state.

Table 28 presents our consolidated list of commercial EG impacts relating to NSPs and their customers, and the rationale for including an impact from the final proposed valuation framework.

[53] CSIRO, *National Feeder Taxonomy*, June 2013

Table 28 – Marchment Hill Consulting embedded generation (EG) valuation framework

Description	Included in framework?	Rationale
Network capacity	✓	One of the key potential impacts of EG is the ability to defer capital investments
Network reliability	✓	Certain types of EG can be used for network support and outage management
Voltage regulation	✓	Issues are already emerging on Australian networks, and network service providers must make investments to limit the impact
Power quality	✓	Similar to voltage regulation
Distribution use of system (DUOS)	✗	Estimated EG costs and benefits will form an input when determining DUOS
Network losses	✓	A split incentive exists to reduce network losses, which could be considered in a future framework EG can reduce marginal annual peak demand losses, freeing up additional capacity; it has been included as an impact consideration under 'network capacity' above

Following the review of the available frameworks and inputs from the stakeholder survey and interview process, we have identified the following key categories:

- network capacity upgrades
  - the impact of EG on peak demand (including peak demand line loss reduction) and associated capital investments
- network reliability
  - the impact of EG on the reliability and safety of the electricity network, and reliability of supply to customers to cover network outages (backup or UPS capability)
- power quality and voltage regulation
  - the impact of EG on the quality and safety of supply
- future considerations
  - impacts that may be monetised in the future resulting from technological or regulatory advances.

The suggested framework design and valuation approaches are described below[54].

[54] Although a brief description of the technical issues for each of these categories is necessarily included, further details can be found in the technical impacts sections of this report.

5.3.3.1 Network capacity upgrades

Network upgrades are often limited to one type of upgrade at a time (e.g. adding a transformer or line reconductoring). The process for determining the capital costs and market benefits of these upgrades is well established in Australia[55].

The process for determining whether EG is a viable alternative to network augmentation has been established under the RIT-D process. It uses a scenario-based approach that requires the NSP to assess credible options (including DER) to offset the otherwise required investment. When a network understands and accurately calculates the impact of DER solutions, the RIT-D is seen as an appropriate approach for larger investments given the risks and capital contribution involved.

However, RIT-D is only applicable to investments exceeding $5 million, which does not include the largest volume of projects (e.g. feeder upgrades and smaller substation projects). Furthermore, the RIT-D involves significant amounts of administration, time and effort on the part of both NSPs and EG proponents. Consequently, for smaller network projects in which EG (or equivalent DR technologies) can deliver superior market and financial benefits, a simplified version may be more appropriate. In such an approach, the valuation and calculation methodologies are the same as under RIT-D, but the NSP may deal directly with proponents in line with their internal contracting and governance arrangements.

5.3.3.2 Network reliability

Outage statistics on a feeder-level basis are captured by DNSPs as part of their regulatory investment notice, which can be used to determine network reliability with and without EG. This can be done through statistical analysis, either on a deterministic basis with all input parameters constant, or a probabilistic basis using Monte Carlo analysis to generate faults at random.

Further analysis could then determine the circumstances under which EG could improve network reliability (i.e. SAIDI, SAIFI and MAIFI savings). Such circumstances could include:

- applying fault events on different sections of the network to determine the types of faults for which EG can reduce the number of customers affected
    - e.g. by allowing a section of the network to island or providing voltage support
- avoiding faults by using EG to ensure that a network asset does not exceed its thermal rating
- avoiding outage time (SAIDI) after the event of a fault by allowing the NSP to undertake switching action
    - e.g. where EG is used to reduce load on a feeder adjacent to the faulted feeder to facilitate its additional load.

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[55] This is further explored in Section 3.4.9.2.

As mentioned in Section 5.2.2, VCR captures the perceived market benefits of avoiding a power outage to a customer. As such, it could be used to determine the potential reliability value available from EG. However, the value of reliability to NSPs (and as a result, to their customers) is currently captured through the Service Target Incentive Performance Scheme, which makes it a more appropriate approach to determine the reliability impact of EG. However, this scheme does not currently incorporate the full value of customer benefits of outage reduction and mitigation.

For EG to improve network reliability, additional remote or automatic control capabilities may be required, as well as possible changes to network topology (e.g. increased interconnection).

5.3.3.3 Voltage regulation and power quality

The key consideration for the valuation approach for voltage regulation and power quality is determining the potential deferral or addition of network support technologies for different network types under varying EG penetration levels.

Most NSPs can undertake this analysis (e.g. through steady-state powerflow, transient and fault analysis), although their ability to perform this analysis on the LV network is more limited.

5.3.3.4 Safety

It is ultimately the NSP's responsibility to ensure the safety of the customers connected to their network, as well as staff and contractors working on the network.

It is challenging to put a value on maintaining a safe network. Safety has been included as a category largely to highlight that it is the number one priority of NSPs, and that it comes at a cost.

At a minimum, the costs directly attributed to maintaining network safety when connecting and operating EG would need to be considered. Further work is needed to understand the magnitude of these and any additional costs incurred by the network relating to EG and network safety.

5.3.3.5 Future considerations

The items detailed below are impacts that may be monetised in the future, given technological or regulatory advances.

Fault level coordination, islanding and protection schemes

Several legacy protection schemes are currently established, but it is not well known how appropriate they are in the presence of higher levels of EG on the network[56]. Legacy protection schemes and equipment include:

- protection relays or reclosers
  - detect fault level currents on the network
  - order circuit breakers to open in the event of a fault
- anti-islanding protocols
  - switch off EG in the event of a fault to protect from continuing to feed the fault and damaging equipment
  - are meant to de-energise the network section so that field staff can work on it, but cannot (and should not) be relied on alone to ensure the safety of field staff.

Recent technology advances may require certain elements of these legacy schemes to be reassessed. Advanced inverters are able to support fault ride-through (i.e. additional tolerance for short-term deviations in frequency and voltage). This means that they may remain connected through a contingency and offer grid-stabilising services, such as injecting reactive power.

Fault ride-through and (intentional) islanding capabilities under higher penetration of EG may change the value proposition, allowing EG to support the network and improve reliability. However, this is still reasonably far from reality.

Dynamic control

Advanced inverters could allow NSPs to remotely control the output from EG. This means that output can be limited during periods of high EG output to limit the stress on the network. It may be particularly valuable on rural networks with EG growth, where network augmentation can be deferred. The addition of storage could reduce peaks and flatten the network load profile, and hence also potentially defer augmentation investments.

Network support

Several network support generator sets are distributed across the network, some of which are owned and operated by NSPs. Similar to the capacity benefits described above, distributed EG can alter the generating profile of network support generators, or defer generation investments or operational costs.

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[56] This is discussed in detail from a technical perspective in Section 3.2.3.

5.3.3.6 Framework design

This section provides an overview of the proposed framework design to value the impact of EG. It includes preparatory steps and an overall approach to determining the net impact of a particular EG. Each individual impact will require its own specific dataset and calculation approach.

The valuation process will follow three main steps:

i) gathering the relevant data and inputs
ii) determining the network classification
iii) calculating the net impact.

Gathering data and inputs is relatively straightforward, and is largely a function of the availability of data. We assume that the majority of inputs would be provided by the NSPs.

The following key network classifications should be considered:

- feeder type
  - based on reliability categorisation (central business district, urban, short rural or long rural)
  - will affect the level of redundancy and interconnectivity of the network
- geographical location
  - affects the generation profile of EG, particularly with solar PV, due to solar radiation and length of day
- customer mix
  - the load profile between residential and different type of commercial customers will affect the network load profile and hence the relative impact of EG
- network type
  - the loading and relative strength of the network will determine the extent of the impact of EG, as well as other equipment in the network that helps mitigate EG impacts (e.g. voltage regulators, automatic tap-changing transformers, static synchronous compensators)
- additional potential considerations
  - legacy issues (e.g. network design and topology)
  - health of the network
  - specific network assets and existing network at the connection point (e.g. single or multiphase, single-wire earth return).

Once the network classification has been determined, the costs and benefits of each impact category would be added together to calculate the net impact of the relevant EG.

An overview of the framework design is provided in Figure 55.

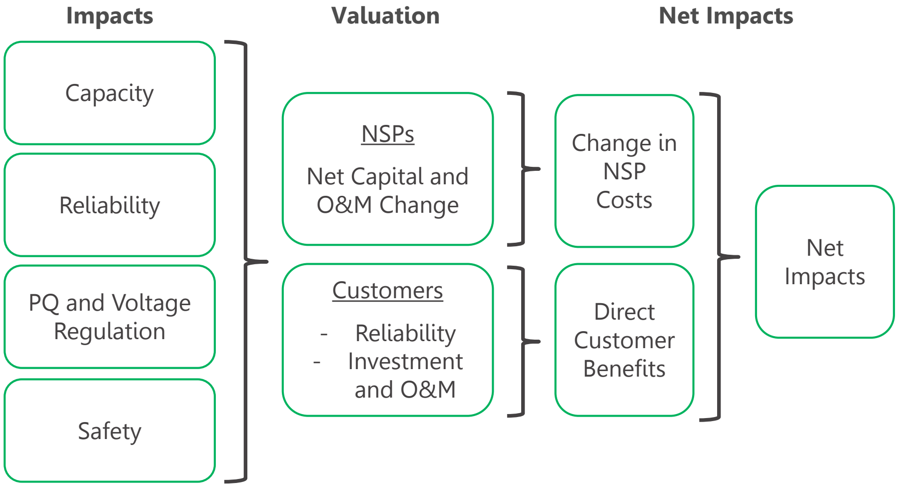

Figure 55 – Marchment Hill Consulting framework designed to value the net impacts of a specific type of embedded generation. NSP = network service provider; O&M = operation and maintenance; PQ = power quality

The net benefits to the network would be considered, as would the direct customer net benefits (e.g. the required EG investment and any reliability and cost improvements).

Key Finding: *Currently, there is no universally applicable and agreed regulatory model to value the impact of EG on networks. Networks require an appropriate valuation approach if they are to identify the costs and benefits of EG and to signal the efficient sizing, location and operation of EG. In addition, there is a gap in the current understanding of the impact of EG on network reliability, safety and quality of supply and an appropriate valuation approach is also needed to allow NSPs to identify these impacts.*

5.4 Commercial opportunities

As highlighted in the previous section, EG can disrupt electricity networks. However, it also gives NSPs the opportunity to make use of new technology, benefiting both themselves and their customers.

This section explores commercial opportunities for NSPs arising from EG, as well as the related strategic benefits and barriers to EG implementation. It is not intended to be a comprehensive review of the merits of these commercial opportunities. Rather, it provides a high-level overview and qualitative assessments to highlight opportunities for further work.

In this section, we focus on the following technologies:

- residential and commercial solar PV
- residential storage
- electric vehicles
- network storage
- microgrids
- demand response.

5.4.1 Strategic benefits and barriers

The strategic benefits of each of the technologies listed above include the ability to:

- improve network utilisation[57]
    - e.g. flattening the load profile and increasing grid-supplied consumption
    - this reduces the cost of the network for customers and improves the long-term viability of network assets
- incentivise customers to remain network customers
    - e.g. offering cost-effective services (either grid-connected or off-grid solutions)
    - this maintains the network's revenue base
- provide network support
    - e.g. power quality, voltage and outage management
    - this reduces the cost of running the network
- facilitate the introduction of cost-reflective network pricing
    - e.g. offering products and services that could managing the impact of time-of-use pricing for EG owners
    - this promotes improved use of the network
- use an existing core competency to offer a service in a competitive market
    - e.g. maintenance field services, asset management, network operations
    - this enable DNSPs to use their existing skills and experience to increase unregulated revenue.

[57] Network utilisation is defined as the average electricity flow through the grid over a period of time (e.g. one year) as a percentage of total capacity.

The commercial opportunities described below focus particularly on options that meet one or more of these strategic benefits. Opportunities where these benefits are not available will be provided as well, but in more general terms.

Barriers facing NSPs when pursuing commercial opportunities from EG include:

- competition
    - the market is mature, or a future market is expected to include a number of interested parties
- technology maturity
    - the technology solution is not mature enough to realise all available benefits, or NSPs lack experience offering and operating the technology
- standards and regulatory
    - lack of standards or regulatory guidance about the technology and related commercial opportunities
- data and customer access
    - the solution requires access to customer data
    - this could require additional customer consent or additional expense
    - the processes and costs are still emerging from market reforms.

The relationship between the barriers, strategic benefits and the relevant commercial opportunities of EG is provided in Table 29.

Table 29 – Embedded generation strategic benefits and barriers identified by Marchment Hill Consulting

Commercial Opportunities	Strategic Benefits					Barriers & Issues			
	Network Utilisation	Network Support	Maintaining Customer Base	Cost-reflective Pricing	Leveraging Capabilities	Competition	Technology Maturity	Standards & Regulatory	Data Access & Customer Acceptance
Solar PV									
Excess Solar PV Strategy	✓		✓	✓	✓			✗	✗
Residential Energy Storage									
With Solar PV		✓	✓	✓	✓	✗	✗	✗	
Without Solar PV	✓	✓	✓	✓	✓	✗	✗	✗	
Network Storage									
Network Support	✓	✓	✓		✓		✗		
Storage-as-a-Service	✓	✓	✓	✓	✓		✗	✗	✗
Electric Vehicles									
Installation and Maintenance					✓	✗			
Rollout Strategies					✓	✗			
Strategic Deployment					✓	✗			
Controlled Charging	✓	✓	✓	✓	✓		✗	✗	✗
Micrograms									
Fringe-of-grid / Off-grid		✓	✓		✓		✗		
Embedded. / Urban		✓	✓		✓		✗	✗	
Demand Response									
Expanding Current Capabilities	✓		✓	✓					
DR Trading Platform	✓		✓	✓			✗	✗	

DR = demand response; PV = photovoltaic

Table 29 reveals that the greatest strategic benefits of EG are generally accompanied by barriers (e.g. network storage). The strategic benefits and specific barriers to each commercial opportunity are discussed in the following sections.

5.4.2 Solar photovoltaics

The Australian solar PV market is relatively mature. As such, it offers limited opportunities for NSP market entry. However, NSPs can support their potential strategic objectives by offering products and services relating to the use of excess solar PV generation.

This is a promising commercial opportunity, because solar PV uptake is presumed to remain strong. Many network customers have installed oversized systems in relation to their in-house consumption, having been incentivised to do so through previously generous feed-in-tariffs (FiTs). NSPs could implement a conventional direct load control solution, similar to the water heating and pool pump schemes widely implemented in Queensland.

Suitable technologies include:

- heating and cooling (air conditioning)[58]
- water heating
- pool pumps
- electrical energy storage.

To pursue this opportunity, NSPs would need to target customers with solar PV installations, particularly those with oversized installations. This could be done directly, or via established retail channels such as electricity retailers or solar PV providers. Customers would need to be further incentivised to allow the NSP to access their data and to manage the EG and the demand-management technology installed at the premises. NSPs could implement this as part of cost-reflective network tariffs, since the use of such technologies would benefit solar PV customers under these new tariff arrangements.

The service could be marketed directly to existing solar PV customers. However, given the generous FiTs that many of these customers receive, they would need to be significantly incentivised to limit their exports during the day by using the excess generation to supply loads earlier, rather than those loads contributing to the evening network peak. A more realistic approach would be offer a bundled product (solar PV, storage unit, tariffs) to new customers. This would require the DNSP to work actively with the multiple parties, including technology providers, retailers and other service providers. Introduction of well-designed network and retail tariffs is fundamental to promoting desirable customer behaviour and protecting the commercial interests of NSPs.

Customers are generally likely to be reluctant to let NSPs turn on customer loads earlier in the day than they would otherwise choose. However, well-designed tariffs will encourage customers to respond more in accordance with the aim of the NSP’s direct load control.

Further opportunities may arise from restructuring premium FiTs to allow customers to divert this subsidy towards a discount on the cost of installing a storage solution.

[58] This is explored from a standards perspective in Section 3.5.2.

5.4.2.1 Grid-optimised smart solar

The Rocky Mountain Institute recently published a report analysing the economics of grid-defection and potential pathways and implications for the United States electricity markets[59]. The report highlights that increasing EG on the network means new opportunities for utilities, and puts forward some key options such as optimising new and existing solar PV on the network.

The majority of installed solar PV has a 'dumb' inverter: i.e. an inverter that cannot provide services such as voltage management and fault ride-through. These capabilities would benefit NSPs by enabling more active management of the distribution network. The Rocky Mountain Institute suggests that NSPs may incentivise the uptake of smarter inverters by reducing the connection charge or expediting the connection process.

5.4.2.2 Strategic benefits

Making use of excess solar PV generation represents a key strategic opportunity for NSPs. It would allow NSPs to:

- ease the overall impact of solar PV on the network by limiting exports
- improve network utilisation by increasing load during the day and freeing up network capacity during peak times through load shifting
- ease the introduction of cost-reflective pricing by offering a solution to limit the bill impact on EG owners
- incentivise network customers to remain customers by offering them additional benefits
- use existing capabilities such as direct load control to provide customers with an additional service.

5.4.2.3 Barriers and issues

Standards

AS/NZ 4755 specifies the framework for DR capabilities and supporting technologies for electrical products such as air conditioners, swimming pool pump units and electric water heaters. The current version of this standard does not support turning on air conditioners by bringing the load forward (e.g. for pre-cooling).

Data and customer access

It is not yet entirely clear under which arrangements NSPs may have full access to customer data under the new metering rules. Under the proposed rules, customer data would be the responsibility of the meter data provider. Home area networks-enabled smart meters could

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[59] The Rocky Mountain Institute, *The Economics of Grid Defection - How Grid-Connected Solar-Plus-Battery Systems Will Compete With Traditional Electric Service, Why it Matters, and Possible Paths Forward,* April 2015.

be used for this purpose. However, this is currently not included in the proposed minimum functionality requirements for smart meters. If implemented as a direct load control solution, NSPs will face a further barrier by having to visit every eligible site to reprogram the demand response enabling device (DRED).

Customers also lack options when engaging different service providers for different portions of their load. This would have to be negotiated via the customer's retailer. The possibility of customers changing to an alternative retailer adds further risk to the approach. AEMO recently submitted a rule change request[60] to the AEMC to initiate the process of establishing multiple trading relationships, which would enable different entities to provide different services at a single customer site.

The new metering reforms in the National Electricity Market (NEM) could provide opportunities for multiple parties to contract via the metering coordinator to gain access to meter data and functionality, and thereby provide services to customers. This could include using the meter's home area networks function to control devices in the home.

The metering rule also allows DNSPs to take on the roles of metering coordinator, metering provider and metering data provider. This would allow the DNSP to address the majority of challenges that may be raised by the rules. This would, however, require the DNSP to acquire appropriate accreditaion from AEMO, as well as adhere to any ring-fencing requirements.[61]

If the DNSP is not acting as the metering coordinator, it would be able to negotiate a commercial arrangement with the relevant metering coordinator for meter access. An alternative arrangement could also be made for the DNSP to partially fund, in whole or in part, the retailer's meter roll-out. In return, they would gain access to the metering services.

5.4.3 Residential storage

Residential storage is an emerging distributed energy service that represents both a technical and commercial opportunity for DNSPs[62]. Commercial opportunities include marketing residential storage solutions to:

- existing or new solar PV owners
    - this could include installation and operation and maintenance (O&M) services
- non-PV customers
    - this would take advantage of the difference between peak and off-peak prices.

NSPs may be able to market residential storage solutions directly to customers, similar to the product New Zealand NSP Vector launched in 2013. This involved a leasing arrangement for a

[60] Australian Energy Market Operator, *Rule Change Request - Multiple Trading Relationships,* December 2014.

[61] Australian Energy Market Commission, *Draft Rule Determination National Electricity Amendment - Expanding Competition in Metering and Related Services,* March 2015.

[62] Further information on the potential to leverage energy storage to mitigate the technical network impacts of EG is provided in Section 3.3.2.2.

combined solar PV and battery storage solution.[63] The program resulted in the installation of around 300 storage solutions across Auckland, but has now closed.[64]

Residential storage products could be structured either as a leasing arrangement or outright sale. Leasing is likely to be most attractive, allowing customers to avoid the substantial upfront cost. This would also require a strategic partnership with one or more technology providers. Storage services would predominantly be marketed to existing solar PV customers, or offered as a bundled solar PV and storage product to new customers.

As part of this offer, NSPs may also offer installation and O&M services to customers. It could also be linked to network cost-reflective prices to help manage customer bills.

DNSPs may also have an opportunity to obtain alternative energy seller status (as a separate, ring-fenced trading entity) for selling bundled solar PV and storage services to customers. Under such an arrangement, the DNSP would own, manage and control the PV and storage unit installed at the customer's premises, and sell energy generated by the solar PV to the customer as an exempt retailer. The storage unit would enable the customer to maximise the use of their generated power, and limit feedback into the grid (a common cause of technical issues). This added control of the storage unit would be especially attractive for DNSPs, because it would allow them to use it for other purposes such as network support. If such units were aggregated by, or for, the DNSP, it would potentially also allow NSPs to defer otherwise required network augmentation by discharging during times of network peak.

This combination of benefits, in which customers can provide support to networks in addition to meeting their own needs, will ultimately determine the cost effectiveness of distributed residential storage.

5.4.3.1 Strategic benefits

Strategic benefits for NSPs from implementing residential storage with controlled charging arrangements are relatively significant. It would allow the NSP to:

- use the storage for network support, e.g. for power quality and voltage management
- ease the introduction of cost-reflective pricing by offering a solution to limit the bills of EG owners
- use existing capabilities and asset management to provide an additional service to customers.

Additionally, if the storage is not bundled with solar PV, but is simply creating value for customers by enabling greater use of off-peak rates, network utilisation could be improved by increasing load during low load periods and freeing up network capacity during peak times through load shifting. Network customers could also be incentivised to remain so by offering them additional benefits.

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63 Vector, *Shareholder Review 2013*, August 2013.

64 Vector, *2014 Annual General Meeting*, October 2014.

5.4.3.2 Barriers and issues

Despite all of the attention being offered to residential storage and the number of solutions on offer in the market, its widespread uptake faces several barriers.

Competition

The main barrier for NSPs who wish to market storage solutions to customers is the likely presence of significant competition. The tier-1 retailers have been exploring opportunities in offering residential storage solutions, and are likely to be followed by specialised retailers and service providers.

Technology cost

Significant efforts are being made globally to reduce the manufacturing cost of energy storage technologies, and cost-effective solutions were generally expected to become available in the next 5—10 years. However, Tesla's launch of its Powerwall in April 2015 changed market expectations. Retailing at a starting price of US$3,500 for a 10-kWh system and US$3,000 for a 7-kWh version, Powerwall represents a step change in the price of residential storage and brings it one step closer to financial viability.

Regulatory barriers

To obtain alternative energy seller status, DNSPs need to apply for a retail exemption from the AER. As the National Electricity Customer Framework does not currently apply in all states (most notably Victoria and Queensland), DNSPs would have to apply for separate exemptions in those states under jurisdictional regulations. This creates a barrier to service providers competing across state lines.

Additionally, it is currently unclear whether chapters 5 and 5A of the NER sufficiently address the connection of storage solutions; there is uncertainty as to whether grid-connected energy storage batteries fall under the definition of 'generating plant'. This has implications for whether the requirements for a connection application and connection offer need to be fulfilled for storage solutions. Chapters 5 and 5A should hence be reviewed and amended (if applicable) to support the connection of energy storage.

The AEMC and CSIRO are currently undertaking a joint project aimed at understanding the regulatory impacts of storage solutions in the NEM. The final report, expected to be published in September 2015, should provide an informed view of any changes to the NER that will be required to facilitate storage technologies.[65]

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[65] Available at: <http://www.aemc.gov.au/News-Center/What-s-New/Announcements/AEMC-launches-project-on-integration-of-electricit>.

The required standards for installation and operation of storage technologies also need to be developed. The CEC has recently issued draft installation guidelines for storage[66] that could be used as a starting point to develop nationally consistent rules and guidelines.

Additionally, legacy premium FiTs are another potential barrier. Customers on these arrangements will have little incentive to invest in technologies that limit their electricity exports. These subsidies will stay in place across Australia for significant amount of time[67] and will be a sizeable expense for governments. As an example, a recent report by the Queensland Competition Authority forecasted that premium FiT payments made to Queensland prosumers until 2028 would equal $2.9 billion[68].

5.4.4 Electric vehicles

Electric vehicles (EVs) have been available on the international market for some time, but uptake in Australia has been slow. This is partly due to prohibitive costs, insufficient infrastructure and customer concerns such as limited driving range.

EVs represent a range of opportunities to NSPs. They will be a potential new source of load on the network as well as provide a new market in which NSPs can offer additional products and services.

The EV industry will require the expertise of the incumbent electricity industry players to safely and effectively develop, manage and maintain EV connection and charging infrastructure. The development of strategies to uncover these commercial opportunities will require focusing on customer solutions and empowerment as well as commercial relationships.

In addition to providing negotiated services relating to new connections (e.g. in car parks or business precincts) to cater to high levels of EV adoption, several strategic options are available to grow network business. These include:

- partnering with EV charging infrastructure providers for future roll-out plans, asset management and maintenance
- working with governments or EV manufacturers to develop and manage public charging infrastructure
- developing relationships with private companies (such as supermarket and fast food chains) for the roll-out of privately owned charging infrastructure
- partnering with EV sellers to promote connection and supply packages with innovative tariff structures and demand-management options to capture EV owners' charging needs

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[66] The Clean Energy Council, *Grid-connected Energy Systems with Battery Storage - Draft in Progress*, May 2015.

[67] In Queensland and South Australia until 2028, and in Victoria until 2024.

[68] Queensland Competition Authority, *Estimating a Fair and Reasonable Solar Feed-in Tariff for Queensland*, March 2013.

- making use of vehicle-to-grid (V2G) arrangements in which the storage capacity of the EV provides network support.

All of the above strategies will require the NSP to operate in a proactive manner and engage strongly with customers and industry.

5.4.4.1 Strategic benefits

Greater EV uptake will present NSPs with several strategic benefits. EVs:

- increase electricity usage
    - hence help drive prices down, provided they are charged at the right time
- rely on customers being connected to the grid
    - EG/storage sources are unlikely to be sufficient to service residential charging demands
- make use of existing NSP capabilities
    - e.g. engineering and technical expertise, asset management.

EVs therefore present a relatively unique EG value proposition for NSPs, because they increase grid consumption and promote grid dependence.

5.4.4.2 Barriers and issues

Regulatory and policy settings

Apart from the forecasted slow uptake of EVs, they present few barriers to NSPs engaging the market. Regulatory arrangements would need to be developed to allow for remote-controlled charging, as well as for appropriate cost recovery from charging infrastructure.

Supporting policies for EVs are currently lacking in Australia. These include direct funding for charging infrastructure, stringent emission standards and tax rebates. Such policies and incentives have driven increased uptake of EVs in other markets (e.g. California, Norway). Recent analysis by Energeia for the Energy Supply Association of Australia suggests that an additional 620,000 EVs could be added to Australia's vehicle fleet over 2023—2035 via cost-effective policy interventions[69].

Customer acceptance

As for residential storage, data access and customer acceptance will be required to allow NSPs to access controlled EV charging benefits.

Customers must also be incentivised (through a properly structured tariff or direct payment) to shift charging away from peak times themselves, or allow the NSPs to do so. This is critical. Otherwise, NSPs will have a new peak demand problem to manage with costly network augmentations: such as with the past boom in air-conditioner takeup, which customers are now reluctantly paying for through necessary tariff increases. The public, regulators and

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[69] Energia, Review of Alternative Fuel Vehicle Policy Targets and Settings for Australia, July 2015.

governments will be reluctant to fund augmentations for peak demand that will be poorly used and economically inefficient.

5.4.5 Network storage

Network embedded storage essentially refers to DNSPs installing storage on strategic points of their network to offer storage services to their customers and capturing additional value streams[70]. Such strategic points could include at or near the zone substation, or near distribution transformers scattered around subdivisions.

Storage services could include:

- wholesale market arbitrage
    - where storage is used to purchase electricity at cheap rates and sell back to the grid at high price periods
- network support
    - e.g. voltage management, peak shaving, islanding, outage management
- customer storage-as-a-service
    - e.g. enabling customers to store excess energy generated during the day (from their solar PV system) and use it at peak evening tariff times.

Network storage technologies are being extensively trialled and installed internationally. California in particular has establishing itself as the leading energy storage market, supported by the 1.3 GW of capacity mandated to be installed by 2020. Australian activity in network storage has been more limited, with AusNet Services' trial of a 1-MW Samsung lithium-ion battery on its network being one of the more significant examples.

In selling storage services, the DNSP could sell part of the storage capacity to retailers or demand aggregators, who in turn sell it on to customers. The storage used for network support could be part of the RAB, while a separate ring-fenced business could be set up for storage sold to end customers or demand aggregators: similar to how DNSPs currently sell pole space to telecommunication companies.

Opportunities for DNSPs in network storage include the following:

- DNSPs hold the potential real estate and know-how to facilitate network storage installations.
- Network storage could benefit from economies of scale.
- Network storage could be more practical for network purposes, because it involves fewer control points and subsequent integration issues.

One counter aspect is that the closer the storage is located to the loads, the more the network will benefit from it. For example, storage located at the zone substation will not benefit the downstream feeder(s), distribution transformers or LV network in terms of

[70] Further information is provided in Section 3.3.2.1.

levelling the load on them, or reducing their required capacity or backup capacity from adjacent sources.

Establishing storage-as-a-service would require certain foundational pricing arrangements, including virtual net metering. This allows EG owners to assign exports that otherwise would have fetched the grid FiT to other customers in the local area. Virtual refers to the metering arrangements, since electricity is not physically transferred between the sites, with transactions settled based on metered data. Networks would be ideally placed to develop these pricing arrangements as part of a storage and service product.

5.4.5.1 Strategic benefits

Depending on the approach of the NSPs, network storage could offer the following strategic benefits:

- Customers can use the grid to access storage capabilities, encouraging them to retain their relationship with their NSP.
- Network storage can provide network support services, such as power quality and voltage management.
- Storage capacity can provide peak support, flattening the network load profile and freeing up capacity.
- Offering a solution that will limit the impact of cost-reflective pricing on EG owners may make such pricing arrangements less contentious.
- The installation, maintenance and operation of network storage can make use of existing NSP competencies such as technical and engineering capabilities and asset management.

5.4.5.2 Barriers and issues

Barriers to network storage are described below.

Technology cost and maturity

As mentioned previously, storage technologies are currently generally too expensive to be financially viable at the residential scale, except where one installation can provide multiple benefits. However, recent installations by Australian DNSPs indicate that network storage could become a viable investment under certain circumstances.

Technology maturity is another current barrier. The majority of storage technologies have not been adequately tested to determine whether they can perform reliably for network purposes. Australian DNSPs are also in the early stages of trialling storage technologies, and are still familiarising themselves with its operational risks and capabilities.

The additional revenue streams described above under the ‘storage-as-a-service’ option make network storage an attractive option. However, this option would require the establishment of virtual net-metering services. As described above, these arrangements would require multiparty strategies, and they have not yet been sufficiently trialled in Australia[71].

Regulatory barriers

As noted above, the deployment of storage solutions may face regulatory issues. However, AEMC and CSIRO's joint project is expected to provide recommendations on any amendments required to the regulatory framework to facilitate storage technologies.[72]

There are also some regulatory restrictions on the ability of DNSPs to buy and sell electricity. AusNet Services has established a fit-for-purpose energy purchase agreement with EnergyAustralia. This is likely to be the most straightforward solution for similar future deployments, at least in the near term.

Ring-fencing arrangements would also need to be developed to facilitate a portion of the storage unit to form part of the NSP's RAB, and a separate portion to be used for commercial purposes.

5.4.6 Microgrids

Although several microgrids have been established in Australia, they are largely an emerging opportunity for most NSPs. The most viable option in the near term is likely to be at fringe-of-grid locations. Embedded microgrids installed at strategic points of the network, or for greenfield developments, may become attractive at a later stage.

Embedded microgrids, which are defined in this context as microgrids established in more urban areas of the network, hold a slightly different value proposition to fringe-of-grid microgrids. Because urban networks are designed with a higher degree of redundancy, network reliability is less of a driver to form a microgrid.

Urban microgrids represent an opportunity for DNSPs to offer premium reliability to targeted customers (e.g. data centres, hospitals, emergency services). Embedded microgrids could also be an option for greenfield developments, where they could establish a secondary revenue stream for the DNSP through O&M management fees. The embedded microgrid could also be established as a trading entity, which provides market access and subsequent arbitrage opportunities.

Fringe-of-grid microgrids involve DNSPs offering microgrid solutions where the cost to serve, on a per-customer basis, is greatest (i.e. in remote and rural communities). To ensure that customers across the state pays the same amount for electricity, state governments currently subsidise rural and remote customers through a payment to the local DNSP. This is called a

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[71] MHC notes the trial of local network charges and virtual net metering currently being undertaken by the Institute for Sustainable Futures and ARENA. The project involves trials in five different locations and is an important step towards better understanding of the impact and necessary technology and regulatory arrangements required to facilitate such a solution.

[72] Available at: <http://www.aemc.gov.au/News-Center/What-s-New/Announcements/AEMC-launches-project-on-integration-of-electricit>.

community service obligation (CSO) payment. The annual CSO payments made to DNSPs are significant; for example, Ergon Energy received close to $600 million in CSO payments from the Queensland government in 2013, up 20% from 2012[73].

Instead of maintaining connections to fringe-of-grid communities, DNSPs with significant amounts of long rural feeders (e.g. Ergon, which has 65,000 km of SWER lines) could use CSO payments to install DG (e.g. diesel, solar PV) and storage to establish off-grid microgrids in these rural communities.

The advantages this could bring to DNSPs include:

- enabling the use of energy storage where it is most economical
- establishing more sustainable electricity services to remote communities
- reducing maintenance and fault management costs
- improving reliability of supply to customers where network reliability is poor.

In the near term, the most attractive option for NSPs seems to be installing battery storage at strategic points on SWER lines to provide peak support and islanding capabilities, rather than establishing multi-EG microgrids. Ergon are currently trialling 20 batteries for these purposes on its network, with a view to expand the program over time.[74]

As technology options mature, DNSPs could take entire (particularly costly to serve) sections of the network completely off-grid, while maintaining ownership and control of the microgrid to generate revenue.

5.4.6.1 Strategic benefits

The strategic benefits available to NSPs from edge-of-grid microgrids include:

- providing network support
  - primarily voltage management, but also potentially increasing reliability
- reducing cost to serve
  - as such, incentivising rural customers to remain grid-connected (microgrid or main grid)
- using existing competencies to offer additional services
  - e.g. technical and engineering capabilities, asset management.

5.4.6.2 Barriers and issues

Barriers to cost-effective microgrids include technology maturity level of energy storage and control solutions, as well as regulations and standards required for safe operation in island mode. These are described further below.

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[73] Ergon Energy, *Annual Financial Statement*, 2013

[74] Available at: <https://www.ergon.com.au/about-us/news-hub/media-releases/regions/general/battery-technology-on-electricity-network-and-australian-first>.

Safety

A key concern of network operators is the potential implications of widespread, uncontrolled islanding on their grid. Uncontrolled islanding could lead to a safety issue for field staff, who may not know whether a line is energised; or a network stability issue, where significant ad-hoc synchronisation occurs.

The safety and stability implications of microgrids could be managed by developing and implementing appropriate procedures, management and staff training. This includes proper planning and design of microgrids.

Technology cost and maturity

Since storage is an important component of microgrid solutions, their deployment faces similar barriers to those of energy storage. Solar PV and generators (diesel or gas) are both mature technologies, while bespoke microgrid control solutions are also available in the market.

Regulations

The NER does not provide a regulatory mechanism for networks to consider the creation of microgrids or standalone systems as an option for the most efficient approach to energy supply. However, EG technology advancements may make such options the most cost-effective in the future.

In addition, rather than providing a payment directly to the DNSP to serve remote locations, the CSO regulations could be amended to allow DNSPs to pursue alternative options to service the rural network. The regulatory framework could be reformed to ensure DNSPs can receive dedicated funding, as long as they can prove that a microgrid is a more cost-effective option than the CSO payments. However, reforming the CSO payments would involve a great deal of political risk.

Standards

At the moment, there are no Australian industry standard protocols for a network operator to control a connection to allow it to island. The norm (both in Australian and internationally) has been to force EG, such as rooftop solar PV systems, to have some form of anti-islanding protection installed — i.e. they are required to disconnect from the network when the connected network loses power. This approach specifically prevents systems capable of operating in island mode from islanding while still connected to unintended part(s) of the (non-microgrid) network.

An international standard, IEEE guideline 1547.4, was approved in 2011 to specifically guide the design, operation and integration of microgrid systems with electric power systems. It includes current best practices for implementing the various ways in which microgrids can separate from a part of the main grid, including planned (or intentional) islanding, and reconnect while providing power to the islanded grid.

5.4.7 Demand response

Demand management, including DR, allows DNSPs to meet customer demand by shifting or reducing demand through non-network alternatives, rather than increasing supply through network augmentation[75]. Non-network alternatives can involve controlling certain customer loads (e.g. pumps, cooling, heating), or dispatching EG to offset demand or obtain capacity credits in the Wholesale Electricity Market[76].

These services are generally performed by some DNSPs (for residential customers), as well as by demand aggregators (for commercial and industrial customers). Demand aggregators contract capacity across the network to access arbitrage opportunities and support network augmentation deferral.

For NSPs, DR could provide the following commercial opportunities:

- expanding DR to increase network capacity and reliability
- providing a standardised commercial offer to potential DR proponents
- establishing and operating a trading platform for DR.

The first two points above represent what would be considered business as usual, and could be fairly easily implemented if the NSP sees sufficient value.

The trading platform is an emerging opportunity that could be owned and operated by the NSPs, allowing them to control the process and capture potential transaction fees. It would essentially allow:

25. NSPs to post their specific DR requirements on the platform
    - (e.g. xMW on a certain feeder)
26. DR proponents and demand aggregators to bid in to the market
    - (e.g. x$/MW) where they have capacity available or contracted
27. swift and transparent market clearing.

5.4.7.1 Strategic benefits

The strategic benefits available to NSPs from DR include improved network utilisation and capacity, and improved reliability through load shedding or support to enable switching in the event of a fault.

5.4.7.2 Barriers and issues

The most significant barrier for the DR opportunities outlined above relates to the trading platform, because it has not been trialled and tested in Australia. The required rules and

[75] Further information on the potential of demand management to mitigate network impacts is provided in Section 3.3.4.2.

[76] In the Wholesale Electricity Market, which has a peak demand of around 4000 MW, more than 500 MW of DR is already signed up by aggregators with commercial and industrial customers. It is an alternative to peaking generation capacity for the Independent Market Operator’s capacity market reserve capacity mechanism.

regulations would need to be established, as well as the technical requirements and platform design.

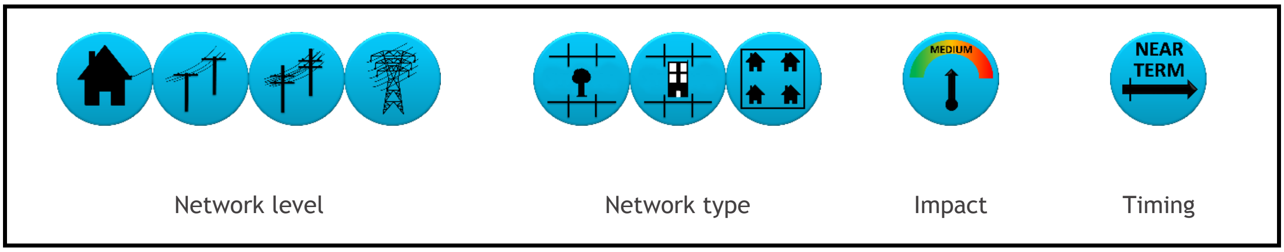
Valuation approaches to capture the capacity benefits of demand management are well established. However, approaches to capture the reliability impact of demand-management initiatives are less developed. The framework put forward in this report could be used as a starting point, but further work would be required to formalise such an approach.

5.4.8 Key findings

The key findings relating to all of the above commercial opportunities are listed below.

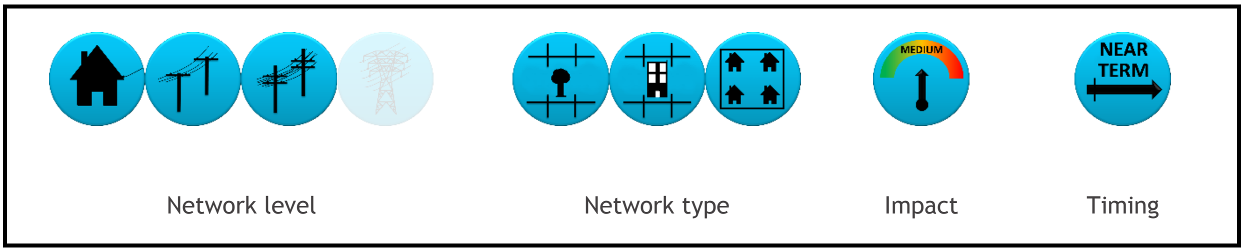
> ***Key finding***: *Ring-fencing requirements for NSPs currently differ by jurisdiction and are generally seen as inadequate for the purposes of emerging markets and technologies. In particular it is unclear how storage technologies are to be treated under the current ring-fencing requirements and how NSPs might support the efficient creation of microgrids or standalone systems as an option for the most efficient approach to energy supply.*

A high-level assessment of the characteristics of this finding against the document map key is shown below.



> ***Key finding:*** *Several of the potential commercial opportunities for networks to offer new products and services based on EG depend on the networks having cost-effective access to customer data and/or a direct channel to the customer. (e.g. in home EG and demand optimisation, residential storage). The proposed new metering rules present opportunities for NSP related entities to participate in new customer-oriented markets for metering and related services but they also create risks associated with potential new costs for data access and the loss of a traditional DNSP service.*

A high-level assessment of the characteristics of this finding against the document map key is shown below.



5.5 Implications for the network service provider business model

Under the current market structure, customers essentially make unilateral decisions regarding the type, size and location of their EG; third parties undertake sales and installation; and the NSP oversees the interconnection process to the network.

As EG technologies continue to decline in cost and different types of EG become prevalent in the market, new value streams will emerge. The business model of the NSP will likely have to evolve in turn.

This section discusses insights into how NSPs may need to change their business models and practices to capture the benefits and manage the challenges of increased levels of EG on the network.

5.5.1 Accenture – network business model evolution

Accenture recently published a report for the ENA exploring how NSPs' business models may adapt to a changing operating environment[77].

The report puts forward six main business model alternatives that are available to NSPs:

1. Information Services
2. Intelligent Grid Operator
3. Beyond the Meter Services
4. Distributed Platform Integrator
5. Distributed Platform Integrator and Trader
6. Distributed Energy Production Services.

Each proposed business model is described briefly below.

Information Services

This involves the NSP investing in advanced metering infrastructure to provide their customers with greater information about their energy usage. It would provide the foundation for improving data availability to establish a truly intelligent network.

Intelligent Grid Operator

[77] Accenture, *Network Business Model Evolution - An Investigation of the Current Trends on DNSP Business Model Planning*, January 2015.

This model would see the network operator invest in additional monitoring and communications technology (in addition to advanced metering infrastructure) to control both customer-sited EG and network equipment. This would enable the NSP to take further steps towards intelligent, dynamic operation of the network.

Beyond-the-Meter Services

In this model, the NSP would offer additional services to the customer extending beyond the metering point. These would include DR, home energy management systems, and installation and maintenance of equipment. The rationale behind this business model is that NSPs are relatively well positioned to provide these improved energy services to customers.

Distributed Platform Integrator

Similar to the better-known term of smart grids, the Distributed Platform Integrator business model would involve NSPs optimising grid services by improving their monitoring, control and automation capabilities. This involves real-time decision making, based on load and network state.

Distributed Platform Integrator & Trader

Similar to a virtual net-metering solution, this approach would involve NSPs facilitating transactions between distributed prosumers. It would allow customers to optimise their energy usage based on prevailing pricing and availability of EG.

Distributed Energy Production Services

This would involve the NSP marketing EG solutions to customers through leasing or technology partnership arrangements.

5.5.1.1 Strategic considerations

For all of the potential business models outlined above, Accenture suggests that a successful NSP would have to develop the following strategic capabilities:

1. intelligent network operations
    - invest in additional information and operational technology capabilities to increase the level of information available and improve subsequent decision making
2. industry and partnership management
    - identify suitable partners to provide capabilities, products and services lacking within the NSP and develop an appropriate regulatory strategy
3. market and commercial intelligence
    - gain a better understanding of customer choice to accurately price products and services, and improve market and competitor intelligence capabilities
4. performance management
    - develop and maintain performance metrics to quantify the impact of business decisions
5. customer interaction and marketing

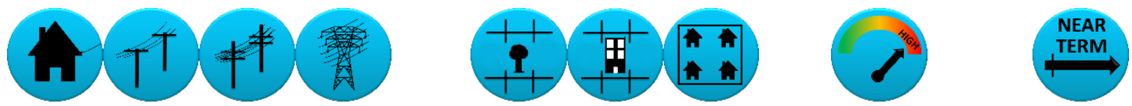
- develop marketing, branding and communication capabilities to attract and retain customers.

5.5.2 Key findings

Although not all of the above business models are directly related to the impact of EG on the network, they do hold some common themes that are important for NSPs to consider in developing a strategy to capture the benefits and tackle the challenges emerging from EG.

> ***Key Finding****: Active involvement in the EG and energy services markets on the part of NSPs or their related entities as either a market participant or to simply incentivise the efficient use of EG for the benefit of all customers, will require developing partnerships with other stakeholders including technology service providers and retailers.*

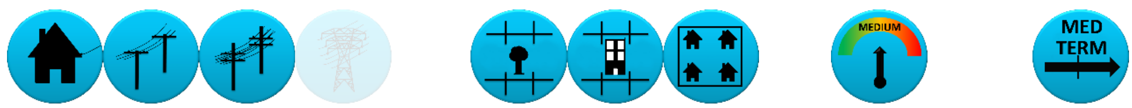
A high-level assessment of the characteristics of this finding against the document map key is shown below.



Network level	Network type	Impact	Timing

> ***Key Finding****: The NSP business model needs to evolve to facilitate the integration of multiple distributed energy resources, including EG. This could provide greater network capacity and energy diversity to optimise grid performance for both supply and demand.*

A high-level assessment of the characteristics of this finding against the document map key is shown below.



Network level	Network type	Impact	Timing

6 Policy and regulatory options

Note on authorship

This section was written by Marchment Hill Consulting (MHC) with contributions from CSIRO for the key technical findings. All policy and regulatory options in this section were developed by MHC.

6.1 Introduction

This report has reviewed the technical, commercial and regulatory impacts of embedded generation (EG) on the electricity network. Through this process, we have found that increasing levels of EG on the network present both challenges and opportunities for NSPs. However, given appropriate conditions and incentives, EG can deliver great benefits to NSPs and their customers alike. The challenge for the industry is to ensure that the policy, regulatory and commercial environment supports the efficient level of deployment of EG to serve the long-term interests of consumers.

The sections below present the key technical, regulatory and commercial findings identified in this report. It also gives policy and regulatory options to address these findings:

- A policy option relates to approaches that involve a change to existing government policy, or a change to the general operational policies or approaches adopted by NSPs as a whole.
- A regulatory option relates to potential approaches that require a change to existing industry regulations in order to be implemented.

Note that the policy and regulatory options identified in this section reflect some available options to pursue, rather than a recommended course of action, and many of them are not ultimately recommended to be pursued further. The policy and regulatory options that are carried forward for further consideration in support of the recommendations in Section 7 are highlighted in blue.

6.2 Key technical findings

Key findings from the technical review are described in the following sections.

6.2.1 Technical constraints and network impacts

1 Increasing penetration of EG, including greater uptake of rooftop solar and other EG, is changing load profiles on Australian electricity networks and making network load prediction more challenging. Appropriate planning and management of network load demand across different timeframes is essential to ensure both adequate power quality and a reliable supply of electricity of the network.

- High penetration of EG increases the gap between the maximum and minimum network load. In addition to peak demand forecasts, accurate minimum demand and energy consumption predictions are required. These will assist in network planning relating to managing voltage and potential reverse power flow issues.
- Accurate prediction of network load demand is essential for effective utilisation and management of EG sources on the network, and to establish sustainable load management systems for the smart grid.

2 Reverse power flow has been observed at the medium-voltage and high-voltage network levels. In radial networks designed for unidirectional power flow, this can affect the operation of protection and voltage regulation devices. In islanded networks, such as some remote communities, it can also have a detrimental effect on generator control and stability.

3 EG has the potential to contribute current to any fault in the vicinity. Protection system design and settings must be considered in rural and off-grid systems to ensure faults are cleared quickly. In urban areas, the added fault level (the maximum current that can flow in the network segment as a result of a fault) may restrict the amount of EG that can be connected due to system design fault levels.

Policy and regulatory options	Comment
Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG.	This will help distribution network service providers to perform a cost-benefit analysis on mitigation strategies, as well as provide an input to any future cost-reflective pricing regimes relating to EG. Efficient EG uptake refers to deployment and use of EG at times, in locations and at scales that reflect the value of EG to all customers.

6.2.2 Options for mitigating network impacts and risks

4 Grid-scale storage has the potential to provide a range of network benefits relating to EG, including voltage management, energy balancing, and improving network stability. These benefits can increase the flexibility, reliability and efficiency of power delivery to consumers.

- Currently, grid-scale storage is limited due to a combination of system cost and market maturity, and as such is generally only deployed in specific applications and locations as noted in Section 3.3.2.1. However, considering the market for energy storage devices has been estimated to reach 3000 MW by 2030, as well as expected improvements in related technologies, the deployment of grid-scale energy storage is predicted to see increasing uptake in the coming years.

5 Distributed storage can provide numerous benefits to networks, including improved management of voltage and power flows, peak load and generation management, and

reactive power support. Customer-owned storage has the capacity to provide these benefits alongside direct benefits to the customer, despite not being network-owned.

- For customer-owned storage, appropriate dispatch management is key. Unlocking its network benefits requires appropriate incentives to ensure that it is dispatched at times that are beneficial to networks. If incentives are not well-designed, customers may utilise storage in ways that are detrimental to the network. If direct control of non-network storage is desired, the deployment of operating systems (e.g. through demand response systems such as AS/NZS 4755 Part 3.5) and relevant communications platforms will enable controlled dispatch.

Policy and regulatory options	Comment
Create appropriate pricing mechanisms to incentivise the deployment of energy storage both on the network and behind the meter where cost-effective. This will help manage power flow and voltage issues, as well as make use of the capabilities of power electronics.	Storage holds significant potential for network support and should be implemented wherever it is cost effective.

6 Power electronics solutions, such as STATCOMs and smart inverters, have the capability to mitigate power quality issues relating to EG, including managing voltage ramp-rates and excursions. In some cases, they can also reduce harmonic content.

- Smart inverters in particular can use a pre-existing generation resource to self-manage their own generation. As this functionality is not currently mandated, the penetration of these devices in networks is low. Retrofitting existing fleets of inverters would require a large capital investment.
- The current revision of AS/NZS 4777 part 2 includes some smart inverter functions to self-manage voltage issues where possible. However, this functionality is not currently mandatory within the standard, which may continue to limit market penetration even once the updated standard is published.

Policy and regulatory options	Comment
Using the valuation framework to manage the voltage regulation, power quality, reliability and safety impacts of EG on the network. This could, for example, support the strategic deployment of medium-scale power electronics solutions, such as STATCOMS, at locations where they may be the least-cost solution to help manage power quality issues.	Efficient deployment of technologies could be promoted by determining the value of power quality support on different parts of the network.

Create incentives for customers to retrofit existing distributed inverters (e.g. on rooftop solar photovoltaics) to unlock STATCOM-like capabilities, such as managing local voltage issues and harmonics.	An EG valuation framework should be able to determine the benefit of retrofitting existing EG. This could be translated into an incentive for the customer to take action, possibly via reduced connection charges or cost-reflective network tariffs.

7 Improved prediction of renewable generation, informed through dedicated metering, can improve EG integration by increasing the utilisation of assets such as storage and solar photovoltaic (PV)-controlled air conditioning. It can also inform decisions on power system unit commitment and network planning. These benefits can be broadened beyond EG to medium and large-scale generation.

8 Improved network load prediction techniques that incorporate increased penetration levels of EG are necessary to retain the current benefits of short, medium and long-term prediction of net load in a high-penetration EG environment. The prediction techniques also need to incorporate any other factors that may be contributing to changing utilisation patterns of electricity networks.

Policy and regulatory options	Comment
Implement appropriate mechanisms that standardise the collection and exposure of household load and generation data.	Those options need to explicitly consider pathways for guaranteeing consumer privacy, while still delivering the data necessary for fine-grained residential models and forecasts. Gross metering will better enable the disaggregation of load and generation.

6.2.3 Options for maximising network benefits

9 Utilising EG for power and voltage profile levelling reduces the operation of expensive peaking plants. It can also ease voltage management requirements, improve power system reliability and provide frequency support.

10 Insecure, non-dispatchable energy source types of EG (predominantly PV and wind) alone provide only limited power and voltage levelling and frequency support. Including storage offsets the insecure, intermittent nature of PV and wind, allowing EG to provide these services effectively.

11 EG can contribute to peak load reduction. This alleviates congestion, reduces line losses and results in deferral of equipment capacity upgrades where capacity is constrained.

12 Evidence from the literature and distribution network service providers suggests that the reduction in cumulative net load due to EG can extend the life of both substation and distribution transformers.

Policy and regulatory options	Comment
Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG. The framework should take into account the critical network points where EG can provide a direct economic benefit by reducing operating costs and deferring network investment.	While some EG is already bringing a net-positive cost benefit, attention should be paid to technologies that are close to net-positive, such as energy storage, with the expectation that their position may improve soon.

6.2.4 Australian Standards gap analysis

13 Australian standards do not well cover the functionality and performance requirements of protection relays used to prevent islanding and reverse power flow relating to embedded generators. This reduces the consistency with which DNSPs can implement these devices, with significant flow-on effects for the market and other industry stakeholders. These effects include increased cost of development, implementation and commissioning; increased cost and reduced consistency of type-testing; and potentially reduced performance and reliability in-situ.

Policy and regulatory options	Comment
Supporting the development of a new Australian Standard to manage the functionality of protection relays for EG.	Standardising the performance of protection relays will reduce the risk of the application of these devices by utilities. It will also provide guidance to manufacturers about the core and additional functions of these systems.

14 There is a significant lack of standards relating to the integration and operation of electric vehicles (EVs), including vehicle-to-grid-enabled EVs. This may increase the risks and reduce the potential benefits associated with EVs by limiting the uptake of EV demand response and vehicle-to-grid systems, as well as reducing consistency of approach and increasing implementation costs.

Policy and regulatory options	Comment
Revisiting the development of standards such as AS/NZS 4755 Part 3.4, or facilitating the local acceptance of a similar international standard for managing EV charging and discharging.	Current industry projections indicate that significant EV uptake is unlikely for some time. However, near-term development of Australian standards or acceptance of international standards will ensure that local network operators will have tools ready to manage any issues that arise if needed.

15 Grid-connected stationary energy storage systems utilising emerging technologies including lithium-chemistry and zinc-bromine flow batteries, are not well standardised in Australia particularly in the areas of safe installation, operation and disposal. This will likely have an impact on consistency of approach between jurisdictions, with significant implications for the market and industry; it may also increase the likelihood of incidents relating to the improper use of these systems.

Policy and regulatory options	Comment
Supporting the development of standards relating to the safety of small-scale and large/grid-scale energy storage systems. Focus should be directed to those addressing safe installation/operation and fire protection. In addition, lithium chemistry may require particular attention, because its standards are immature.	Some standards relating to energy storage, such as AS/NZS 5139, are beginning to be developed. However, there is a significant risk that such systems will be deployed en masse before standards are in place to ensure systems can be deployed and operated safely.

6.3 Key regulatory and commercial findings

This report has reviewed the current regulatory framework relating to connecting EG to the network; the commercial impacts of EG; the development of a commercial framework to value these impacts; and the commercial opportunities available to network service providers (NSPs) from EG.

The key findings of the review have been categorised below as either regulatory or commercial.

6.3.1 Key regulatory findings

The below findings include impacts that require a regulatory focus in order to be addressed.

16 Although recent reforms to Chapter 5 and 5A of the National Energy Rules (NER) have improved the connection process related to EG, the lack of a consistent national framework means that these have not been adopted uniformly across all jurisdictions.

Policy and regulatory options	Comment
Ensure the adoption of the National Energy Rules chapters 5 and 5A (or equivalent) reforms in Victoria, Queensland, Western Australia and Northern Territory to introduce a consolidated regulatory framework across Australia.	Adoption of National Energy Customer Framework in Victoria and Queensland would have this effect, because Chapter 5A reforms are included in the Retail Law. However, alternate state-based derogations would also suffice. A uniform regulatory approach across Australia would provide EG proponents with greater certainty and ability to compete nationally.

17 Where augmentation costs may occur because of high levels of small scale solar PV penetration on a network (i.e. basic connections), the NER does not allow for these costs to be recovered directly from the EG owners in a cost-reflective approach. Instead, these costs are recovered from the entire customer base which introduces an element of cross-subsidisation between customers.

Policy and regulatory options	Comment
Introduce a cost-reflective connection charge, reflecting the fact that connections at certain sections of the network are more costly due to required augmentation work.	This would ensure that EG proponents pay for required augmentation. However, it would charge the last customer, and as such would not be equitable and create a barrier to future efficient uptake of EG. It is also inconsistent with the new requirement for networks to establish prices based on the long-run marginal cost to the network.
Charge even small-scale EG owners directly for required network augmentation.	Similar to the above point, this would create a barrier for future efficient uptake.
Forecast expected annual network investments required due to EG on the network that can currently not be recovered from the relevant EG owner. Forecast annual uptake of EG and add the expected required investment to the connection charge for EG customers. This could also be expanded to connections for heating and cooling devices that also affect network expenditure.	This may be the most straightforward option and would ensure EG-related costs are recovered from EG customers only. An appropriately designed EG valuation framework (see below) would address these impacts, as well as capture potential benefits.
Work closely with a range of industry stakeholders, including EG Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG.	A valuation framework would capture the augmentation cost as well as the benefits of EG to the network. The cost of augmentation could then be reflected in the connection charge or other pricing mechanism to the customer.

18 Within the Demand Management Incentive Scheme (DMIS), Demand Management Innovation Allowance (DMIA), RIT-D and RIT-T processes networks have opportunities to consider and implement non-network solutions including EG to resolve network constraints in the most cost effective manner, however there are areas for improvement and potential for change as part of current regulatory reform initiatives.

Policy and regulatory options	Comment
Working with the industry and regulators to identify where there may still be a disadvantage for network providers to utilise EG for network purposes compared with network upgrades. NSPs could then build on the recent reforms to the Demand Management Incentive Scheme to ensure that any disadvantages for NSPs using EG in this way is addressed.	The Australian Energy Market Commission recently published a determination on the DMIS, which includes provisions that the Australian Energy Regulator (AER), when designing the future DMIS scheme, should take into consideration the full value stream from demand-management initiatives when determining appropriate incentives. The determination makes no specific mention of increasing access to capital expenditure benefits, other than noting the final design of the incentives will be decided by the AER.
Develop a set of best-practice principles and a model process for planning network responses to constraints that distribution network service providers (DNSPs) could use to improve the quality and consistency of their approach.	This could be developed in conjunction with demand response, demand management and EG technology proponents.
Develop an incentive mechanism for DNSPs to use non-network solutions (which may include EG) based on appropriately benchmarked expenditure levels across the DNSPs (and relevant international comparators). A best-practice expectation could be set by the regulator for the use of non-network solutions, which the DNSPs could then be incentivised to outperform.	Benchmarking may not necessarily reflect the efficient deployment of EG. Care would be needed to take relevant local network and consumer characteristics into account (e.g. availability of load transfer opportunities). It is unclear whether this would support a goal of driving the efficient deployment of EG (i.e. at a time, location and scale that supports required network service delivery at lowest cost).

19 Currently, there is no universally applicable and agreed regulatory model to value the impact of EG on networks. Networks require an appropriate valuation approach if they are to identify the costs and benefits of EG and to signal the efficient sizing, location and operation of EG. In addition, there is a gap in the current understanding of the impact of EG on network reliability, safety and quality of supply and an appropriate valuation approach is also needed to allow NSPs to identify these impacts.

Policy and regulatory options	Comment
Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG.	A valuation framework to determine the impacts of different types of EG would allow customers to base investment decisions on the full value of the EG. The framework should consider geography, customer mix, and network and feeder type.

20 Ring-fencing requirements for NSPs currently differ by jurisdiction and are generally seen as inadequate for the purposes of emerging markets and technologies. In particular it is unclear how storage technologies are to be treated under the current ring-fencing requirements and how NSPs might support the efficient creation of microgrids[78] or standalone systems as an option for the most efficient approach to energy supply.

Policy and regulatory options	Comment
Supporting the removal of state-based rules barring or limiting network providers' ability to own and operate EG (for the purpose of network support).	Network service providers (NSPs) should be free to invest in EG when it is cost-efficient to do so.
Supporting changes to current state-based ring-fencing rules to create a national framework with the overarching principle to ensure no market participant is unnecessarily constrained in a competitive environment with regard to providing services to customers.	It will be difficult to define when a network would be best placed to provide the most efficient solution, or who would decide this.

[78] A microgrid is defined as 'a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid-connected or "island" mode.' For the purposes of this report, this definition is extended to also include permanent island networks.

Ensuring that they are free to enter into direct commercially based trading relationships with customers and that NSP's related entities should not be restricted from providing energy selling services to customers, where they meet appropriate ring-fencing requirements.	This would further enable NSPs to pursue commercial opportunities relating to customer-sited EG.
Supporting a review of relevant rules to ensure no barriers exist to the creation, operation and maintenance of microgrids or standalone systems by networks as an option for the most efficient approach to energy supply.	This could be supported by reforms to existing subsidies (e.g. community service obligation payments) where this opportunity proves to be a more efficient use of funds to serve remote customers.

6.3.2 Key commercial findings

The below findings include impacts that require a commercial focus in order to be addressed.

21 Current volume-based network pricing structures includes a cross-subsidy from non-EG owners to EG owners. The recent changes to the National Electricity Rules require networks to set prices that reflect the costs of providing electricity to consumers with different patterns of consumption. These tariffs are cost reflective and are not specific to the technology choices of customers (i.e. are 'technology neutral'). There is opportunity within these new rules to support the efficient uptake and use of EG that reduces future costs to customers to below the level they might reach under volume-based pricing structures.

Policy and regulatory options	Comment
Introduce a cost-reflective demand charge for all customers.	A demand charge would limit the cross-subsidy and signal costs of future expansions in network capacity.
Introduce a distribution use of system charge or negative demand charge for energy exported to the grid.	This would probably be more contentious than a demand charge, because it would only target embedded generation (EG) owners.
Increase the connection charge or introduce an additional fixed charge for EG owners.	A demand charge would reduce the cross-subsidy and ensure that all customers receive the same price signal, rather than specifically targeting EG owners.

Introduce cost-reflective network charges for EG output that take into account the relative value of EG as a generation source (e.g. reduced line losses, network support).	Reduced network charges could be applied to virtual net metering to reflect the reduced use of network infrastructure (and reduced line losses), as well as the potential value for network support (depending on the time and location of the EG output). This would support EG exports at times and in locations of most value to an efficient network, and support emerging business models (e.g. virtual net metering, community energy, storage-as-a-service) that promote efficient, ongoing use of the network.
Supporting a national approach to cost-reflective pricing that removes inconsistent jurisdictional obligations on tariff structures and assignment. Supporting the implementation of a balanced framework for the uptake of smart meters for the fastest economic roll out to benefit all customers. Encouraging adoption of technologies that support efficient pricing and customers' ability to access data and manage their demand (e.g. in-home displays, apps, data portals). Working closely with retailers, technology proponents and metering service providers to bundle products and tariffs to optimise value for customers and simplify product offerings while supporting efficient network outcomes.	The impact on consumers is a critical consideration for the implementation of more cost-reflective network pricing. Technology is available that can minimise this impact (e.g. automated demand-management devices, adding storage to solar, enabling network control of inverters) and simplify pricing messages for consumers. However, effective product bundling will require coordinated stakeholder input.
Developing appropriate price signals to encourage efficient uptake of EG, reducing future network costs to below the level they might reach in the absence of EG uptake and thereby benefiting all customers. This could include: • discounting connection charges, network charges or providing direct payment, reflecting the costs and benefits available to the NSP, or • implementing price signals or incentives for customers to undertake efficient investment in storage, retrofit distributed inverters and to be appropriately rewarded for demand management.	A valuation framework should be able to determine the benefit to the network from EG. This could then be translated into a customer incentive (e.g. cost-reflective network tariff arrangement) that would benefit the network.

Identifying and supporting opportunities to restructure current incentives and subsidies so that they can support technologies and services that result in more efficient use of the network for the benefit of all customers (for example, restructuring premium feed-in-tariffs to enable customer to choose to use these subsidies to install storage solutions which support lower peak demand and reduced network expenditure).	Historical subsidies have resulted in cross-subsidies between different customers. These subsidies are committed and long lasting (e.g. many premium FiTs do not expire until 2028). However, they do not promote uptake of new technologies, which can improve the efficiency of the network by reducing: • the technical impacts of high penetration of solar photovoltaics • peak demand, and hence the capital investment required to augment and maintain the network the need to augment and maintain long network connections to fringe-of-grid communities.
Working with the industry and regulators to build on the principles of the Demand Management Innovation Allowance to enhance the industry's ability to support research and development activities that support innovation and integration of new technologies, and ultimately create a more efficient network for the benefit of customers.	Innovation allowances allow network service providers to trial new technologies that will help shape the network of the future. A key international scheme is the United Kingdom's RIIO (Regulation = Incentives + Innovation + Output) program. Note that the Australian Energy Market Commission recently published a rule change to reform the Demand Management Incentive Scheme (DMIS), including the DMIA, which includes an innovation allowance for demand management and the connection of EG.
Investigating opportunities for the development of cost-effective policies and incentives (such as model availability requirements and fuel standards) supporting EV uptake, where it promotes efficient use of the network for the benefit of customers.	This would necessarily include more detailed cost —benefit analysis. It and would also rely on the availability of time -of -use pricing or similar demand- management incentives to ensure EV charging contributesd to efficient network usage.

22 Several of the potential commercial opportunities for networks to offer new products and services based on EG depend on the networks having cost-effective access to customer data and/or a direct channel to the customer. (e.g. in home EG and demand optimisation, residential storage). The proposed new metering rules present opportunities for NSP related entities to participate in new customer-oriented markets for metering and related services but they also create risks associated with potential new costs for data access and the loss of a traditional DNSP service.

Policy and regulatory options	Comment
Allow network service providers (NSPs) access to a certain amount of customer data required for network services for free, and access to additional data for network purposes at a reasonable cost, e.g. daily voltage alarms.	This would allow NSPs to use smart meters for certain network purposes and minimise the commercial impacts on the meter data provider.
Safeguard NSPs' access to the customer data required to safely manage the network.	For NSPs to proactively and dynamically respond to challenges from increasing levels of EG, increasingly granular real-time data would likely be required. Under the proposed new metering rules, customer data will be accessed via the metering coordinator. As such, NSPs may need to pay to gain access to some data. NSPs must work closely with stakeholders to determine the ideal level of customer data and how this access may be obtained. In the metering rule change process and Energy Market Reform Working Group review of new products and services, the details of how customer de-energisation and re-energisation and management of load switching to ensure customer and employee safety and network security remains under consideration.

23 Active involvement in the EG and energy services markets on the part of NSPs or their related entities as either a market participant or to simply incentivise the efficient use of EG for the benefit of all customers, will require developing partnerships with other stakeholders including technology service providers and retailers.

Policy and regulatory options	Comment
Removing knowledge and organisational barriers to cooperation between NSPs, technology providers and retailers to offer bundled products.	Partnerships and bundled products will be crucial to ensure that customers are presented with persuasive offers that promote mutually beneficial EG outcomes.

24 The NSP business model needs to evolve to facilitate the integration of multiple distributed energy resources, including EG. This could provide greater network capacity and energy diversity to optimise grid performance for both supply and demand.

Policy and regulatory options	Comment
Propose that in future market arrangements, the NSP can coordinate the day-to-day operation of multiple sources and types of EG and other distributed energy resources, where this provides the most cost-effective option for the customer.	Distribution network service providers will be ideally placed to provide these services.
Reviewing the current regulatory framework to determine its suitability for a more customer-oriented electricity market. This should include assessing its flexibility to adapt to an increasingly complex market as a result of the adoption of new technologies and the changing priorities of customers.	Leading the market transition to a network with increasing amounts of EG will require NSPs to identify international best practice.

7 Recommendations

Note on authorship

This section was written by Marchment Hill Consulting.

7.1 Introduction

The following recommendations have been prepared with the overarching principle of the National Electricity Objective in mind. That is, investment in and operation of the network should maximise the efficiency of the electricity supply chain, allowing consumers to enjoy the quality, safety, reliability and security of supply that reflects their long-term interests at the lowest cost. This should result in the efficient deployment and use of embedded generation (EG) in locations and at times and scales that reflect the value of EG to the customer, community and the network.

Increasing levels of EG on the network present challenges for network service providers (NSPs). However, they can also benefit customers through the delivery of new energy services and support more efficient use of existing network infrastructure. The challenge for networks, retailers, regulators, technology proponents and customer representatives alike is how they might work together to develop future business models and pricing structures that fairly apportion value and costs to all stakeholders and turns the challenges into opportunities.

These recommendations also attempt to recognise the often diverse responsibilities and interests of stakeholders, while aligning their actions to benefit customers.

The recommendations have been grouped into three key main categories:

- Enabling Technologies and Pricing
    - What are the key technologies to deliver future value?
    - How should they be incentivised?
- Enabling Business Models
    - How will the network of the future operate?
    - What regulatory changes would promote this transition?
- Enabling Partnerships
    - What partnerships are required for NSPs to actively participate in the EG market?

Policy and regulatory options that support the recommendations are also provided, where appropriate. Policy options relate to approaches that involve a change to existing government policy, or a change to the general operational policies or approaches adopted by NSPs as a whole.

7.2 Enabling technologies and pricing

An appropriate valuation approach to capture all the costs and benefits of EG to networks should be developed and implemented in close consultation with stakeholders to enable effective signalling of the network value of EG to customers.

Our review of the technical, regulatory and commercial impacts of EG has found that EG technologies — and storage technologies, in particular — may hold significant potential for NSPs, retailers and customers alike.

The challenge for the future consists of designing appropriate incentives and pricing structures to promote uptake and operation of EG technologies in a way that makes the network more efficient – as this is fundamentally in the best interests of customers.

As a first step in this process, the actual impact of different EG technologies on the network needs to be determined. This should include determining the capacity, reliability, safety and quality of supply impact of different types of EG, taking into consideration specific network topologies. The valuation framework developed for this report may be used as a starting point, with the ultimate objective of ensuring that customers' investment decisions reflect their impact on the network.

Within in this context, networks could also incentivise customers to allow NSPs access to their EG (e.g. their energy storage system) where network control of system can unlock additional benefits. The incentive could take the form of a discount on customer connection charges, tariffs or bills, or a direct payment reflecting the net benefits available to the network.

Policy and regulatory options and further work that support this recommendation are detailed in Table 30.

Table 30 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Working closely with a range of industry stakeholders (including EG proponents, the Australian Energy Market Operator and the Australian Energy Regulator) to develop an appropriate valuation framework that can be leveraged to develop pricing arrangements to promote efficient uptake of EG.	✓	✓	✓		✓	Review the National Feeder Taxonomy to determine its suitability for use in a valuation framework for EG and seek to update it where required.	WP6 - WPO 3/4	High
	✓	✓	✓		✓	Create a working group to finalise a valuation framework and begin testing with real NSP cost and benefit data.	WP6 - WPO 3/4	High
Developing appropriate price signals to encourage efficient uptake of EG, reducing future network costs to below the level they might reach in the	✓	✓	✓		✓	Based on the proposed valuation framework, undertake further modelling to develop appropriate incentive mechanisms that promote efficient uptake of EG.	WP6 - WPO 3/4	High

absence of EG uptake and thereby benefiting all customers. This could include: - discounting connection charges, network charges or providing direct payment, reflecting the costs and benefits available to the NSP, or - implementing price signals or incentives for customers to undertake efficient investment in storage, retrofit distributed inverters and to be appropriately rewarded for demand management.						Review and consider the implications of the recent rule change proposal regarding Local Generation Network Credits[79], keeping in mind the overarching principle that the impacts of bidirectional power flow and costs and benefits of EG should be taken into account when valuing the impact of EG.	WP6 – WPO 3/4	High
						Review and consider the current trial of virtual net-metering arrangements being funded by ARENA (http://arena.gov.au/project/investigating-local-network-charges-and-virtual-net-metering/), and investigate which lessons from this exercise can be applied by DNSPs to explore emerging business models that support efficient and sustained network usage.	WP6 – WPO 3/4	Low
Using the valuation framework to manage the voltage regulation, power quality, reliability and safety impacts of EG on the network. This could, for example, support the strategic deployment of medium-scale power electronics solutions, such as STATCOMS, at locations where they may be the least-cost solution to help manage power quality issues.						A comprehensive analysis should be undertaken to identify the impacts of reverse power flow at all stages of transmission and distribution networks, including the effect on network assets designed for one-way power flow and other associated protection issues.	WP6 – WPO 3/4	Medium
	✓		✓		✓	Capture high-fidelity (temporal and geographical) data on the intermittency and related impacts of high-penetration intermittency distributed generation, in particular rooftop solar photovoltaics, to help identify optimal mitigation strategies and associated control algorithms.	WP6 – WPO 3/4	Medium
						A coherent framework should be sought to help DNSPs identify mechanisms for dealing with high-ramp situations caused by high-penetration, intermittent EG.	WP8 – WPO 4	Medium

AEMO = Australian Energy Market Operator; AER = Australian Energy Regulator; ARENA = Australian Renewable Energy Agency; DNSP = distribution network service provider; NSP = network service provider; NTR = Network Transformation Roadmap; P&R = policy and regulatory; STATCOMs = static synchronous compensators; WP = Work Program; WPO = Work Program Objective

Support the implementation of cost-reflective network price signals that promote uptake of EG in ways that are beneficial to all customers.

Current energy-based tariffs have been found to create a cross-subsidy from non-EG owners to EG owners. Implementing appropriately designed demand tariffs would go some way towards addressing this impact and allow NSPs to accurately signal the costs to the customer of future expansions in network capacity. This is a crucial part of promoting uptake and operation of EG that contributes to the long-term objective of making the network more efficient.

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[79] Oakley Greenwood, *Local Generation Network Credit Rule Change Proposal – Proposed by City of Sydney, Total Environment Centre and Property Council of Australia*, July 2015.

Cost reflectivity should be an overarching principle for pricing across the network, capturing the impacts of EG depending on its location and the network type. Further initiatives for cost-reflective pricing could include cost-reflective feed-in tariffs (FiTs) or connection charges for EG owners.

Policy and regulatory options and further work that support this recommendation are detailed in Table 31.

Table 31 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Supporting a national approach to cost-reflective pricing that removes inconsistent jurisdictional obligations on tariff structures and assignment.	✓		✓	✓	✓	Model the impact of EG uptake (type and capacity) under different demand tariffs. This could be further expanded to model the impact of introducing a variable feed-in tariff for EG owners that reflects network value.	WP8 - WPO 5	High
Supporting the implementation of a balanced framework for the uptake of smart meters for the fastest economic roll out to benefit all customers.	✓		✓	✓	✓	Review the proposed metering reforms to highlight potential risks and opportunities for network service providers, and develop recommendations to manage risks and leverage opportunities. Highlight issues (where possible) through the remaining stakeholder consultation process for the reforms.	WP8 - WPO 3	Medium
Encouraging adoption of technologies that support efficient pricing and customers' ability to access data and manage their demand (e.g. in-home displays, apps, data portals).	✓		✓		✓	Undertake a review to determine the technologies that hold the most promise for customers to effectively manage their demand.	WP8 - WPO 3	Medium
Working closely with retailers, technology proponents and metering service providers to bundle products and tariffs to optimise value for customers and simplify product offerings while supporting efficient network outcomes.	✓		✓			Undertake modelling to understand how offers might be structured (e.g. storage + demand tariff offer for solar photovoltaic owners) to be attractive to customers.	WP8 - WPO 5	Medium

NTR = Network Transformation Roadmap; P&R = policy and regulatory; WP = Work Program; WPO = Work Program Objective

Support incentives and policies that promote innovation and commercialisation in relation to energy storage technologies in ways that enhance the efficient use of the network for the benefit of all customers.

Historical incentives for EG, including premium solar photovoltaic FiTs, have resulted in commercial imbalances such as cross-subsidisation, and present a major diluting impact to the intentions of cost-reflective network pricing.

Any future incentives should be designed to support efficient use of the network. This includes winding back or restructuring current, inefficient incentives and subsidies. One option may be for all customers to transfer all or part of the value of the premium FiT subsidy (which in some cases remains until 2028) towards a demand management solution that unlocks additional benefits to the networks and their customers. Subsidies currently provided to rural communities, such as the community service obligation payment in Queensland, could also be redirected to install microgrids in order to reduce reliance on costly long distance grid connections.

Policy and regulatory options and further work that support this recommendation are detailed in Table 32.

Table 32 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Identifying and supporting opportunities to restructure current incentives and subsidies so that they can support technologies and services that result in more efficient use of the network for the benefit of all customers (for example, restructuring premium feed-in-tariffs to enable customer to choose to use these subsidies to install storage solutions which support lower peak demand and reduced network expenditure).	✓		✓	✓	✓	Review the arrangement for community service obligation and other similar subsidies for opportunities to divert part of this subsidy to the installation of EG, where this provides the most cost-effective solution to the customer. Further model the cost—benefit impact to determine where on the network such EG installations are cost effective.	WP6-WPO 5	High
						Model the impacts of transferring the value of premium feed-in tariffs to demand-management technologies to understand how such a solution would be structured to be attractive to customers, networks and retailers, and avoid unintended consequences (e.g. impacts on environmental charges or wholesale energy prices).	WP6-WPO 5	High
Working with the industry and regulators to build on the principles of the Demand Management Innovation Allowance to enhance the industry's ability to support research and development activities that support innovation and integration of new technologies, and ultimately create a more efficient network for the benefit of customers.	✓		✓		✓	Review international innovation schemes (e.g. the United Kingdom's RIIO scheme) to identify learnings and best practice. Present the findings of the review to the Australian Energy Regulator to inform their development of the new DMIA.	WP6-WPO 5	Medium
Investigating opportunities for the development of cost-effective policies and incentives (such as model availability requirements and fuel standards) supporting EV uptake, where it promotes efficient use of the network for the benefit of customers.	✓	✓		✓	✓	Build on the work completed by Energia for the ESAA on cost-effective policy options to support the uptake of electric vehicles and assess the appropriate next steps.	WP6-WPO 5	Medium

DMIA = Demand Management Innovation Allowance; EG = embedded generation; ESAA = Energy Supply Association of Australia; NTR = Network Transformation Roadmap; P&R = policy and regulatory; RIIO = Regulation = Incentives + Innovation + Output; Work Program; WPO = Work Program Objective

Support the development of appropriate standards that facilitate the safe integration of EG on the network.

The standards gap analysis undertaken for this report found that standards need to be developed to support the integration of EG technologies and ensure safe operation of the network.

Energy storage is likely to be the next EG technology to be widely adopted by customers. The development of a standard to provide guidelines for the safe installation and operation of small-scale energy storage systems is therefore of particular importance.

Policy and regulatory options and further work that support this recommendation are detailed in Table 33.

Table 33 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Supporting the development of a new Australian Standard to manage the functionality of protection relays for inverter energy systems.	✓				✓	Consider proposing (or petitioning Standards Australia to commence) development of a standard to set out specific functionality and requirements for protection relays for inverter energy systems.	WP8 - WPO 4	High
Revisiting the development of standards such as AS/NZS 4755 Part 3.4, or facilitating the local acceptance of a similar international standard for managing EV charging and discharging.	✓				✓	Petition or propose to Standards Australia to recommence the development of AS/NZS 4755.3.4 standards.	WP8 - WPO 4	High
Supporting the development of standards relating to the safety of small-scale and large/grid-scale energy storage systems. Focus should be directed to those addressing safe installation/operation and fire protection. In addition, lithium chemistry may require particular attention, because its standards are immature.	✓	✓			✓	Encourage the development of Australian standards in energy storage that relate to the safe installation, operation and control of small-scale energy storage systems. Investigate the progress of the Clean Energy Council and build on these efforts.	WP8 - WPO 4	High

NTR = Network Transformation Roadmap; P&R = policy and regulatory; Work Program; WPO = Work Program Objective

7.3 Enabling business models

There should be no inherent advantage or disadvantage for network providers in competing to provide services and pursuing commercial opportunities related to EG.

This report has found a number of barriers that currently exist to network service providers engaging in the EG market, including restrictions on owning and operating generation units, cumbersome national ring-fencing regulations, and potential data access restrictions under the proposed new metering rules.

The regulatory framework should be reformed with the overarching principle that NSPs should be able to pursue opportunities and capture the full benefits available to them from investing in EG, within the reasonable limitations of the competitive environment.

Policy and regulatory options and further work that support this recommendation are detailed in Table 34.

Table 34 – Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Supporting changes to current state-based ring-fencing rules to create a national framework with the overarching principle to ensure no market participant is unnecessarily constrained in a competitive environment with regard to providing services to customers.	✓	✓		✓	✓	Review the current ring-fencing rules and other state-based rules to identify key shortcomings and prepare a submission to the Australian Energy Market Commission.	WP6 - WPO 4	Medium
Supporting the removal of state-based rules barring or limiting network providers' ability to own and operate EG (for the purpose of network support).	✓	✓		✓	✓			
Ensuring that NSPs are free to enter into direct commercially based trading relationships with customers and that NSP's related entities should not be restricted from providing energy selling services to customers, where they meet appropriate ring-fencing requirements.	✓	✓	✓		✓	Further investigate the potential for customers to enter into direct, commercially based trading relationships with NSPs, or for NSPs to offer services as an alternative energy seller.	WP6- WPO 5	Medium
Supporting a review of relevant rules to ensure no barriers exist to the creation, operation and maintenance of microgrids or standalone systems by networks as an option for the most efficient approach to energy supply	✓				✓	Review the current regulatory framework to identify barriers to NSPs establishing and operating microgrids where it is the most cost-efficient supply option.	WP6- WPO 5	Medium

NTR = Network Transformation Roadmap; P&R = policy and regulatory; RAB = regulatory asset base; WP = Work Program; WPO = Work Program Objective

There should be no inherent advantage or disadvantage for network providers to utilise EG for network purposes compared with network upgrades.

Current regulations for NSPs to use EG for network purposes do not provide sufficient incentives. NSPs are incentivised to increase capital expenditure through the regulated return they earn on the regulatory asset base. A similar incentive does not exist for non-network solutions, which means that NSPs would need to capture additional market benefits from the demand management initiative to make it worth their while.

Recent proposed reforms to the Demand Management Incentive Scheme have partly addressed this by stating several core principles for the Australian Energy Regulator to consider when designing a future scheme. This includes consideration of the full value stream from demand management initiatives. Overall, these principles are sound. However, more clarity will be required regarding the design of the scheme to ensure that NSPs can capture enough benefits to offset the forgone return on capital.

Policy and regulatory options and further work that support this recommendation are detailed in Table 35.

Table 35 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of Work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Working with the industry and regulators to identify where there may still be a disadvantage for network providers to utilise EG for network purposes compared with network upgrades. NSPs could then build on the recent reforms to the Demand Management Incentive Scheme to ensure that any disadvantages for NSPs using EG in this way is addressed.	✓		✓		✓	Undertake modelling to understand the level of benefits required to make demand-management initiatives more persuasive for network service providers to support the development of the revised DMIS.	WP6-WPO 5	Medium
						Further research is needed to improve net load forecasting methodologies incorporating EG and demand response. This will assist in network planning and scheduling of generation and storage assets.	WP6-WPO 5	Medium

DMIS = Demand Management Incentive Scheme; NTR = Network Transformation Roadmap; P&R = policy and regulatory; WP = Work Program; WPO = Work Program Objective

Support the evolution of the network provider business model to include that of the grid integrator — efficiently and effectively integrating multiple distributed energy resources, including EG.

As the levels of EG on the network increases, it will become more challenging to effectively manage the network. However, proactively managing the network under these conditions could provide NSPs with additional value. NSPs should therefore move towards becoming the provider of EG integration services, with the ultimate goal of reducing costs and improving grid performance.

This could be further expanded to facilitate a marketplace in which energy services, demand and supply from distributed and centralised sources may be traded, providing NSPs with an additional revenue stream. Under this scenario, it will be crucial to understand the EG value streams available to different stakeholders to enable efficient pricing and delivery of services.

Policy and regulatory options and further work that support this recommendation are detailed in Table 36.

Table 36 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Propose that in future market arrangements, the NSP can coordinate the day-to-day operation of multiple sources and types of EG and other distributed energy resources, where this provides the most cost-effective option for the customer.	✓		✓	✓	✓	Assess the impact of proposed metering reforms and other existing regulations on the ability of NSPs to perform this role.	WP6-WPO 5	Medium
						Review (including international case studies) how this role might evolve for DNSPs and the steps needed in the near term to support DNSPs' contribution to customer value.	WP6-WPO 5	Medium

DNSP = distribution network service provider; NTR = Network Transformation Roadmap; P&R = policy and regulatory; WP = Work Program; WPO = Work Program Objective

7.4 Enabling partnerships

Network providers should work towards developing partnerships with relevant energy service providers to promote sustainable and efficient uptake and operation of EG.

The active involvement of NSPs in the EG and energy services market relies on developing partnerships with technology and service providers and retailers.

Partnerships will be crucial to ensure that customer are presented with persuasive product offers that promote mutually beneficial EG outcomes. Bundling of product and pricing offers to minimise the impact on customers from the introduction of new tariff structures (e.g. maximum demand tariffs), while at the same time supporting efficient operation of EG to maximise its benefits, will be crucial under a future market state with high levels of EG.

Policy and regulatory options and further work that support this recommendation are detailed in Table 37.

Table 37 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Removing knowledge and organisational barriers to cooperation between NSPs, technology providers and retailers to offer bundled products.	✓	✓	✓		✓	Undertake modelling to understand how offers might be structured (e.g. storage + demand tariff offer for solar PV owners) to be attractive to customers.	WP8 - WPO 5	Medium
						Enable the Energy Networks Association to facilitate understanding and removal of current barriers to cooperation (e.g. organising workshops with technology providers and retailers).	WP8 - WPO 5	Medium

In response to a future electricity market that is likely to be much more customer-oriented, NSPs should optimise existing services around customer needs and expand organisational capacity to enable the provision of services that future electricity customers will value.

NSPs will require an increasingly commercial and customer-oriented mindset to actively engage in the emerging market for energy services. In addition to relevant marketing and communications abilities, NSPs may also need to improve performance management and customer insights capabilities.

This would represent a step change in the culture of many NSPs. Close cooperation with regulators will be key to ensure that his market transition is introduced in a way that provides NSPs with sufficient time to implement the required changes.

Policy and regulatory options and further work that support this recommendation are detailed in Table 38.

Table 38 - Policy and regulatory options

Policy and regulatory option	Network		P&R option type			Further work	NTR scope of work	Priority
	Distribution	Transmission	Organisation	Government	Regulatory			
Reviewing the current regulatory framework to determine its suitability for a more customer-oriented electricity market. This should include assessing its flexibility to adapt to an increasingly complex market as a result of the adoption of new technologies and the changing priorities of customers.	✓	✓	✓	✓	✓	Undertake a review to determine international best-practice regulatory and policy approaches.	WP8 - WPO 5	Medium

Appendix A – Survey responses

As part of this project, we surveyed members of the Energy Networks Association to understand their views on the impacts of embedded generation (EG) on the network. Nine responses were received. Figure 56 shows the number of respondents by state.

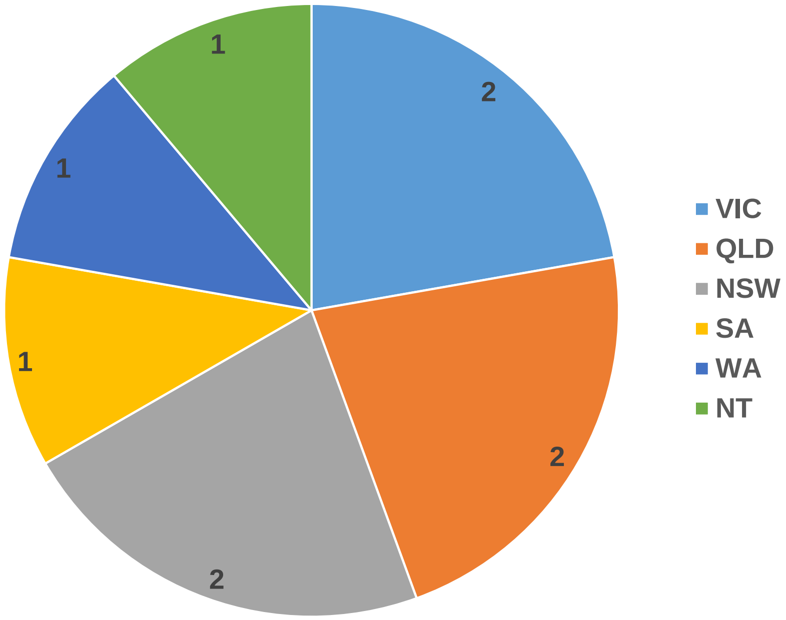

Figure 56 - Embedded generation survey responses by state

The survey questions are reproduced on the following pages.

Impacts of Embedded Generation on Distribution Networks - Survey

The survey covers Technical, Regulatory and Commercial impacts for Embedded Generation (EG). For the purposes of this survey, please consider EG as a unit that generates electricity at a customer's premises and is connected to a distribution system.

General Information

Organisation: ______________________

Respondents	Name	Role / Title	Sections / questions completed	Contact details (email/phone)
#1				
#2				
#3				
#4				

Technical Impacts

1. **Please indicate what issues you are starting to see in your networks because of embedded generation:**

☐ Voltage Rise ☐ Power Quality[80] ☐ Protection Problems ☐ Thermal Loading

☐ Stability / Unbalance ☐ High Neutral Current ☐ Other (please specify)

Comment:

[80] Please indicate which qualities are of concern

2. **In which part(s) of your networks are you seeing issues due to embedded generation?**

☐ Low-voltage ☐ Medium-voltage[81] ☐ High-voltage ☐ Other (please specify)

<u>Comment:</u>

3. **What do you believe are the primary causes of the issues you are seeing on your networks due to embedded generation?**

<u>Comment:</u>

4. **What are the penetration-levels on your networks of the following EG technologies?**

Technology	MW	Number	%
Solar PV (at-scale or distributed)			
Wind			
Battery storage			
Diesel / Gas Generators			
Other (please specify)			

<u>Comment:</u>

[81] Specify voltage levels if relevant

5. **Which type(s) of embedded generation are causing issues in your networks?**

Comment:

Comment:

6. **What do you think are the barriers for higher penetration levels of embedded generation in your networks? Please also state the type(s) of network if applicable (e.g. low source impedance, conductor impedance and length, adequate protection).**

7. **What of the following mitigation approaches have you taken or are you considering to manage the impacts of embedded generation?**

- ☐ Ramp-rate restrictions
- ☐ Size restrictions / disallowing connection of EG
- ☐ VAr compensation (e.g. statcoms, capacitor banks, smart inverters)
- ☐ Balancing network
- ☐ Changing transformer taps
- ☐ Voltage regulation devices
- ☐ Other (please specify)

Comment:

8. Where do you see the greatest value for your networks for embedded generation? (e.g. reduced network capital expenditure)

Comment:

9. What would be the key drivers for enabling and encouraging higher penetration levels of embedded generation in your networks? Please also state the type(s) of network which might benefit from increased levels of embedded generation (e.g. reduced ADMD and reduced network requirements)

Comment:

Comment:

10. Does embedded generation play a meaningful part in network planning and in deferral of network augmentation?

11. What protection mechanisms are being deployed, upgraded or refined in light of new embedded generation and (particularly) reverse power flow? (e.g. changed settings on Regulators, adjustment to Line Drop Compensation)

Comment:

12. **What embedded generation do you own/operate, where is it typically deployed and what role does it generally play?**

Comment:

13. **What are the emerging trends for embedded generation uptake for your customer base and over the next fifteen years how do you believe you will need to respond?**

Technology	Comment
Distributed Solar	
Behind-the-meter Storage	
Off-grid EG / Back-up Power	
Community / Commercial EG (e.g. medium scale)	
Other (please specify)	

14. What mechanisms do you have to support the managed growth of embedded generation?

Comment:

15. Are there any standards that you believe need improvement to properly address the impacts of embedded generation? (e.g. AS4777 needs to keep pace with IES technology)

Comment:

16. Are there any areas of embedded generation that you believe could benefit from standards-development in those spaces?

Comment:

17. Are you aware of overseas standards that Australia should incorporate to better address the impacts of embedded generation?

Comment:

Regulatory Context

18. **Please rate on a scale of 1-10 the adequacy of current regulatory instruments in meeting DNSP and customer needs to facilitate safe, effective and efficient connection of EG (either network or customer connected) [1-2 = entirely inadequate, 3-4 = inadequate, 5-6 = neutral, 7-8 = adequate , 9-10 = perfectly adequate]**

Regulatory Instrument	Rating (1-10)
NER Chapter 5	
NER Chapter 5A	
AER Connection Charge Guidelines for Electricity Retail Customers	
Service and installation rules (State-specific)	
Other (please specify)	

Comment:

19. **Where you have found current regulatory instruments to be inadequate, please provide a brief description of your main concerns.**

Comment:

20. **If possible, please also provide any proposed solutions where regulatory instruments have been found inadequate.**

Comment:

21. **Please rate on a scale of 1-10 the primary cost components (or resource effort) related to connecting EG (either network or customer connected) to your network? [1-2 = insignificant cost or effort, 3-4 = minor cost or effort, 5-6 = moderate cost or effort, 7-8 = major cost or effort, 9-10 = entire cost or effort]**

Components	Rating (1-10)
Administrative	
Hardware (meters)	
Site inspections	
Installation work inspections	
Network studies	
Augmentation	
Other (please specify)	

Comment:

22. **Please rate on a scale of 1-10 the primary regulatory cost drivers related to connecting EG (either network or customer connected) to your network? [1-2 = insignificant driver, 3-4 = minor driver, 5-6 moderate driver, 7-8 major driver, 9-10 sole driver]**

Cost Drivers	Rating (1-10)
Safety	

Reliability	
Quality of supply	
Service and installation rules	
Other (please specify)	

Comment:

23. Are the regulatory cost drivers detailed above sufficient or should they be strengthened or relaxed in some way? Please explain.

Comment:

24. Has your network required augmentation as a result of high penetration of embedded generation (either network or customer connected) which could not be fully recovered through the current regulatory framework?

☐ Yes ☐ No

If Yes, what was the specific regulatory barrier?

Comment:

25. If No, is there a concern that this will be a future issue due to continued embedded generation penetration?

Comment:

26. **Do you have any suggestions for how the current regulatory framework may be reformed to allow for more efficient recovery of costs associated with connecting embedded generation (either network or customer connected)?**

Comment:

Commercial impacts

27. **Please rate on a level of 1-10 the (direct or indirect) commercial impacts on network businesses of ever increasing penetration levels of EG into the distribution network.**
    [1-2 = insignificant impact, 3-4 = minor impact, 5-6 = moderate impact, 7-8 = major impact 9-10 = extreme impact]

Commercial Impacts	Rating (1-10)
Costs of physical connection services	
Under-recovery of network value from EG customers (e.g. cross-subsidy between solar PV customers and non-solar PV customers)	
Inability to recover augmentation costs resulting from high embedded generation penetration	
Installation of additional power quality monitoring and control equipment	
Costs of related services (load, power quality surveys etc.)	
Other (please specify)	

28. **Do you have any suggestions for regulatory or policy options to address these impacts? (excluding cost reflective network pricing)**

Comment:

29. **Do you see potential for a mechanism that allows DNSPs to pay owners of embedded generators to supply peak demand support?**

☐ Yes ☐ No

30. **How should such a mechanism be structured:**

- ☐ Direct payment? (based on actual contribution)
- ☐ Discounted bill? (annual average estimate)
- ☐ Discounted tariff? (annual average estimate)
- ☐ Other (please specify)

Comment:

31. **Should it be within or outside of the RIT-D process? Please provide justification**

Comment:

If you have any additional information that you believe is relevant to the impacts and potential benefits for embedded generation, please detail them below:

Comment:

Appendix B – Analysis of embedded generation/distributed energy resources uptake and network impact forecasting techniques

Introduction

Electricity utilities in Australia are potentially entering into a time of declining network utilisation at some locations, which places upward pressure on network prices and hence retail electricity prices. A range of factors, including economic volatility, improving household energy efficiency, and in particular, the increasing prevalence of embedded generation (EG), have contributed to reduced electricity consumption and deteriorating network utilisation. This is especially the case with residential solar photovoltaics (PV). At the same time, peak electricity demand is growing due to a wide use of air conditioners. Future large-scale adoption of electric vehicles (EVs) will significantly increase cumulative load on the electricity grid, but also present opportunities to manage peak demand (Paevere et al. 2014). Of particular current interest to utilities is the distortionary effect that large uptake of EVs and solar PV (including off-grid systems) is having on household electricity consumption patterns and its cumulative effect on the electricity distribution network.

This report reviews the past research, technologies and reports that address these questions. By highlighting the strengths and weaknesses of the different approaches, this report identifies priorities for improving medium to long-term uptake forecasting of EG. Since these questions are complex, past methodologies have only partly addressed the questions or considered a limited number of variables involved.

Review of methodologies

As part of providing valuable information addressing the medium to long-term forecasting questions for utilities, methodologies in research papers and reports tended to predominantly look at forecasting adoption of technologies that will have a major influence on cumulative and peak electricity demand from the electricity grid. These technology-forecasting methodologies can be broadly grouped into techniques focusing on residential and non-residential uptake sectors.

Technology forecasting — residential sector

Forecasting technology uptake across building stock allows utilities to estimate the incremental change to load, given assumptions of electricity consumption and usage of the technology. The most common approach to forecasting technology uptake is based on mathematical diffusion and choice modelling methods.

Modelling approaches to diffusion commenced in the 1960s, particularly with the introduction of the well-known Bass model (1969) and the logistics model Mansfield (1961). These models basically mimic the Rogers (1962) adoption curve over time (innovators, early adopters, early majority, late majority, laggards), which is of a sigmoidal form. Over the past 50 years, these methods have been applied to a wide range of appliances to estimate the percentage of consumers adopting over time. The early Bass and logit models only considered basic variables representing innovation and imitation. They were limited to appliances that already had adoption beyond the innovator cycle, to allow calibration to the adoption cycle.

In later years, these basic diffusion models were extended to incorporate features that influence adoption. For example, a Generalised Bass Model (Bass et al. 1994) was produced that can accommodate pricing and advertising variables based on observed data. Other attempts included Horsky (1990), who incorporated a basic utility function of wage, amusement factor (or non-financial benefits), price and savings. This was extended by Higgins et al. (2011) to accommodate ceilings of adoption and interactions between intervention options. The literature expanded rapidly with diffusion models (Greene et al. 2005; Horne et al. 2005; Jaccard and Dennis 2006; Soderholm and Klaassenn 2007) that incorporate a utility function based on regression to represent the different features of the technology (e.g. price, going costs, appeal) that the consumer would consider for adoption.

Technologies that are considered to potentially have the largest medium to long-term impacts on the electricity grid are solar PVs, water heaters and batteries connected to PV and EVs. The diffusion of PVs and EVs has been extensively studied in Australia and overseas. Application of diffusion models to each of these technologies requires identifying the variables that impact adoption, the strength of each variable, and a way to calibrate a mathematical diffusion model using these variables.

Choice experiments have been an effective approach to identifying key features important to the adoption of these types of technologies. This involves modelling consumer preferences for these technologies to derive the effect of key attributes, such as installation cost, energy efficiency and out-of-pocket expenses after rebates.

Islam and Meade (2013) conducted a discrete choice experiment in Ontario, Canada, to estimate key attributes of consumer adoption intention of PVs over time. The authors use these attributes in a discrete time survival mixture analysis to estimate future probabilities of adoption for different consumers. Yamaguchi et al. (2013) used consumer preferences to estimate the marketing effort component of a Bass diffusion model.

In Australia, discrete choice data gathered from stated preference experiments have been used to understand the drivers and interaction effects of uptake of different types of water heaters. Bartels et al. (2004 and 2006) surveyed 129 plumbers and 312 consumers in Sydney who purchased a water heater. The stated choice experiment allowed the respondent to indicate important features to the purchase of their gas or electric water heaters. In the case of solar PVs, the Australian Renewable Energy Agency (ARENA 2013) quantified the effect of different demographic and economic drivers to PV adoption across different regions of Australia. They used actual PV uptake data by postcode and applied a regression to a range of variables in Australian Bureau of Statistics (ABS) demographic data. While these methods help understand drivers of consumer behaviour to adoption, their application to forecast future uptake needs to be linked with diffusion models.

Once methods such as choice experiments have identified key variables, they can be used in mathematical-based diffusion and discrete choice models as part of producing future forecasts in the residential sector. Discrete choice modelling has been extensively used for technology diffusion (Jun and Kim 2011; Kim et al. 2005) due to the ability to consider the sensitivity of multiple product options available to consumers, which is an important consideration for EVs and PV systems. There have also been applications for the diffusion of EV options (Lin and Greene 2010; Higgins et al. 2012) and energy-efficient appliances (Murphy et al. 2007; Jaccard and Dennis 2006). Linear utility functions, which can be derived from choice experiments, have been extensively incorporated into a choice model to represent the different values of the product features (e.g. price, rebate, annual costs) to the consumer (Horsky 1990; Revelt and Train 1998; Greene et al. 2005; Soderholn and Klassen 2007).

When considering a medium-to-long forecasting horizon, there is the need to incorporate product replacement along with first-time purchasers into a choice or diffusion model (Revel and Train 1998; Olson and Choi 1985; Jun and Kim 2011). Initially, consumers are mostly first-time purchasers of PV systems, though they can replace or upgrade to a larger system. In the case of EVs, a consumer will have the choice to replace the internal combustion engine vehicle with a similar vehicle or an EV.

There have been some diffusion model extensions that incorporate repeat purchases either due to an upgrade or upon product failure (Revelt and Train, 1998; Olson and Choi, 1985). A multiproduct choice model by Jun and Kim (2011) considers replacement timing to be dependent on a survivability (or failure) probability function. It assumes consumers will replace a PV system or water heater upon failure of the existing one. Higgins et al. (2014) considered the case where the timing of product replacements is a function of failure distribution, along with a utility of other attributes associated with replacement. When implemented, it accommodates the socio-demographic differences of consumers who are early versus late replacers of their existing appliance, as well as the effects of incentives to reduce the time to replacement. This is important for understanding the timing of uptake of different types of EVs into the Australian market.

Solar photovoltaic systems

Forecasting the future adoption of solar PV systems is of significant interest to governments (due to the cost of incentives and feed-in tariffs), and to utilities due to impacts across the electricity grid. Utilities require forecasts with a much higher geographical granularity, as the different rates of uptake at different locations will have implications on substations and feeders.

Over the past few years, there have been several reports on national or state level PV projections in Australia. AEMO (2012) provides projections out to 2022 based on basic financial features of PVs and solar generation. These national level trends cannot be disaggregated into small units representing substations (a few thousand dwellings) or feeders (a few hundred dwellings or less), due to large differences in uptake rates and installation sizes between locations. They usually do not accommodate physical features/constraints of PV installations such as roof space and PV/inverter size. In a more recent report, AEMO (2015) produced PV and battery storage forecast uptakes to 2017/2018 and 2034/2035 at state level. The report provides no information about the mathematical forecasting model used, other than noting an economic model with the primary variable being payback period for each PV and battery option. A major limitation of using payback period without other variables is that it does not account for the high purchase price barrier to households for many options. A further limitation of the method is that forecasts at state level do not accommodate the typology of building stock and roof space availability, which would produce a ceiling of adoption significantly lower than forecasts based on financial variables.

From a utility's perspective, medium-to-long to long-term forecasting of PV adoption requires knowledge of number and distribution of size of installation at each location, along with how the size of new and existing installations change over time. Application of choice and diffusion models at high geographical sensitivity in the Australian residential sector is made possible using ABS census data. The 2011 ABS census data contains valuable information about the number of households, housing types, number of vehicles and other demographics for each SA1 geographical unit in Australia. Each SA1 unit contains about 180 households, which is granular enough to derive valuable load and peak demand information for feeder and substation analysis. Choice or diffusion models with high geographical sensitivity have received very limited attention in the literature to date, let alone in the case of technologies such as EVs and PVs. Bhat and Guo (2004) and Sener et al. (2009) develop spatially explicit choice models that accommodate socio-demographic differences and zone dependencies.

In the case of solar PV, Higgins et al. (2014a and b) implemented a choice-diffusion model for uptake of different size installations of solar PV across each ABS SA1 in Townsville and New South Wales. Since consumers may update or replace the PV/inverter over time, an additional variable was included to accommodate the reduced risk or cost of replacing the existing technology with the same type. A consumer can upgrade their PV system by either adding more panels or upgrading to a larger inverter at a lower cost than a complete replacement.

Diffusion models, particularly the Bass and logit models, have been applied extensively to forecast uptake of solar PVs with and without consumer incentives (Yamaguchi et al. 2013; Guidolin and Mortarino, 2012; Higgins et al. 2011). These models contain features or additional parameters (e.g. Generalised Bass Model) based on marketing, prices and costs, which allow sensitivities to interventions (e.g. incentives, tariffs) to be tested. In practice, the adoption of solar PV systems and batteries is more complicated than represented by a basic diffusion model, since households often upgrade their solar PV or add a battery later on. There have been some diffusion model extensions that incorporate repeat purchases either due to an upgrade or upon product failure (Revelt and Train, 1998; Olson and Choi, 1985).

Distributed electricity storage in the form of batteries connected to residential dwellings, with or without solar PV, has the potential to shift electricity load away from the peak periods. This has been shown for battery storage via vehicle-to-grid strategies, through trials and simulations in Brazil (Drude et al. 2014) and Australia (Paevere et al. 2014), given price tariffs that provide adequate incentives. Based on industry sources, Ernst et al. (2011) consider two end-user price scenarios for lithium-ion batteries in large production. For 4, 12 and 20-kWh batteries, the end-user prices are €2,000, 6,000 and 10,000 according to the first scenario, and €4,000, 12,000 and 20,000 for the second scenario. Rudolf and Papastergiou (2013) suggest 1,500 €/kWh for lithium-ion batteries, which is a very high cost. However, this technology has the highest energy density of all available storage technologies.

Forecasts of battery storage (connected to PV) uptake have had much less attention compared to PV systems alone. The choice-diffusion model developed by Higgins et al. (2014b) for uptake of solar PV and batteries under different price tariffs required several technical innovations by accommodating the:

- compatibility of each solar PV or battery option to dwelling types

- price of adding a battery to an existing solar PV or upgrading/downgrading a solar PV (e.g. increasing the number of panels), which is less than the price for a first-time adopter
- representative effects of modelled choice probabilities in the presence of large differences in price and annual electricity savings between the PV/battery options.

Also, solar PVs now have an established market, whereas batteries have so far had negligible market penetration and are much more expensive. Incorporating both solar PV and batteries in a single choice-diffusion model was more difficult as a result. The study by Higgins et al. (2014b) indicated that about 5.5% of households in Townsville would own a battery by 2025 under the current flat tariff structure. The results were sensitive to the price tariff, and more so to assumptions of future price projections of batteries and PVs. The percentage of households in Townsville with PV in 2022 was forecast to be about 37%, up from 18% in 2013. The AEMO (2015) report indicated that there would be approximately 450,000 new PV installations in Queensland by 2025, which would lead to 45% of building stock having PV systems.

The results on PV-plus-battery uptake shown by Higgins et al. (2014b) were considered conservative by some experts in Australian utilities. Under the current price tariffs, about 5% of Townsville households would have a PV-plus-battery installation, which is less than the approximate 9% (for Queensland) indicated by AEMO (2015). Uptake projections for both PV and PV-plus-battery in Higgins et al. (2014b) were considerably less than those in the AEMO study. This is likely due to the model in Higgins et al. (2014b) accommodating additional variables (e.g. house size and type, purchase price, demographics) that would represent barriers to households adopting PVs and batteries, and thus leading to more conservative forecasts.

Future adoption of PV-plus-batteries is likely to be influenced by additional variables to those considered in choice-diffusion models. These include differences in energy use behaviour within a particular demographic or housing type, which may make batteries more attractive in lower-consumption households. Non-financial variables that should considered for battery forecasts include remote connections (where it is expensive to extend an electricity network) and behaviour towards fast electricity price rises.

Electric vehicles

Unlike solar PV systems, consumer decisions to purchase technologies such as EVs are influenced by a larger range of variables, including costs/benefits, performance, appeal/status, risk, psychographics (e.g. attitude to reducing energy consumption), demographics and physical limitations. Gardner et al. (2011) identified the importance of such criteria for EVs using surveys and focus groups.

Over the past 10 years, a large number of studies have forecast future adoption and vehicle stock of battery electric vehicle (BEV) and plug-in hybrid electric vehicles (PHEV) across the world. This includes California (Becker et al. 2009), the broader United States market (Orhach and Fruchter 2011; Won et al. 2009) and Iceland (Shafiei et al. (2012). A range of methodologies are used to produce these state and national level forecasts, including Bass diffusion and agent-based modelling. In Australia, national EV (BEV and PHEV) sales forecasts to 2040 were produced by AECOM (2009) based on choice modellings. Graham et al. (2009) forecast different types of EVs (PHEV, BEV, mild hybrid) to 2050 using a partial equilibrium modelling approach. Jarvinen et al. (2011) forecast uptake of passenger EV sales using a simple method that allocates high and low scenarios to new car sales trends.

There were major differences in the results between these studies, with the AECOM report indicating only 20% of vehicle sales in 2020 being internal combustion engine vehicles, and about 25% of vehicle sales in 2015 being traditional hybrid vehicles. By 2040 about 85% of all vehicle sales were PHEV or EVs. The Graham report provided scenarios based on oil price projections, with all forecasts showing internal combustion engine vehicles comprising 90%+ km travelled in 2020, but dropping to 20% of all vehicle km by 2040. The Jarvinen report indicated a massive difference in EV sales at 2020 between their low and high scenarios, where 2% of total vehicle sales were EVs in the low scenario (also used in AEMO's 2015 report), increasing to 22% under the high scenario. The large differences in these forecasts would also have led to large differences in medium to long-term load forecasts on the electricity grid.

Paevere et al. (2014) showed that to understand and plan for the impacts of EV charging loads on local electrical distribution networks, and to potentially exploit the opportunities for peak shaving using stored energy in EV batteries, it is necessary to consider at least four interacting layers of spatial and temporal variability in the analyses and projections. These four layers are distribution system capacity, EV uptake, EV usage and charging patterns, and household energy demand (Paevere et al. 2014). The spatial variability in each of these layers for the purposes of EV grid impacts assessment is described below.

Geographically sensitive diffusion models for EV uptake have been very limited. One example is by Lin and Greene (2010), who partition the vehicle market into 1458 segments based on region, driver type, technology attitude and home charging availability. Higgins et al. (2012) accommodate geographical differences by introducing a location-by-demographic typology into the model. This was done using more than 9000 ABS census geographical units of residential housing stock (about 250 households per unit), which were further partitioned by demographics and building features. This allows the population of consumers to be partitioned into category combinations of location by income by house type by household size, or by number of vehicles, etc. This is then linked to the financial and non-financial variables used in the model. Unlike PV systems, which are mostly first-time purchases, potential EV consumers face the decision of how long to wait for improved next-generation technologies, thus creating a demand for dynamic diffusion models (Kim et al., 2005). An important consideration for applying a diffusion model to EVs is the incorporation of multiple financial and non-financial benefits, as well as the evolution of the demographics, building stock or market size across the landscape. For the case of a single product, Higgins et al. (2012) capture these considerations by integrating multicriteria analysis with an extension of the Bass diffusion model. While the model showed geographical differences in forecast adoption, it used the national forecast by Graham et al. (2009) to calibrate for an aggregated forecast for Victoria to 2032.

To understand the impact of vehicle adoption on load forecasts, Paevere et al. (2014) models the energy demand by time of day for each ABS SA1 geographical unit of housing using a household energy model (Ren et al., 2012), as well as a range of information on travel patterns (VISTA 2009). The paper showed the sensitivity of peak loads to off-peak charging and vehicle-to-grid scenarios.

Overall, the biggest limitation to understanding the impacts of future EV adoption on electricity grid loads is the ability to develop a reliable aggregated forecast. The two national level studies outlined above showed major differences to 2020. EV forecasting relies on assumptions on vehicle/battery price projections, future vehicle options available, and their features and energy costs. EV forecasts are sensitive to uncertainty in these assumptions, regardless of technical methodology used. A large range of non-financial drivers that affect the type of EV a consumer would buy (and when) are still not well understood. Studies such as Gardner et al. (2011) and Axsen and Kurani (2010) have used surveys, focus groups and trials to help better understand the consumer perceptions and social interactions to purchasing an EV in the future. The research challenge is how to use this type of information in various methodologies to improve forecasts of EV adoption at a national level.

Technology forecasting — non-residential sector

Commercial buildings contributed to about 4.7% of gross energy consumption (or 277 petajoules) in Australia in 2009 (ABARES 2011), with stand-alone offices representing a 25% share of this gross consumption (DCCEE 2012). Office buildings have the highest energy savings opportunity compared with other commercial stock, with an estimated total energy reduction opportunity of 5142 GWh by 2020 (Climate Works 2010). The largest opportunities are in rationalisation, insulation, heating, ventilation and air conditioning, lighting and electronics. However, retrofitting existing buildings is more difficult than creating new green buildings, and requires the cooperation of a wide range of stakeholders such as landlords, tenants, contractors, local and state government. Also, while the technology may be available, issues such as cost and demand from landlords, tenants and policy makers will determine the priority and timeframe in which existing buildings are retrofitted (Miller and Buys, 2008).

A few studies have simulated future energy consumption in office buildings under an assumed behaviour (e.g. replace at end of life) or scenarios of when retrofits are likely to take place (Coffey et al. 2010). Foliente and Seo (2012) forecast energy consumption from commercial office building in Australia and model different reduction opportunities, including solar PV. However, uptake of retrofit options varies depending on social, financial and geographical conditions.

Estimating the likely uptake of retrofit packages across building stock over time is currently very difficult. Tools are needed to accommodate the:

- complex diffusion process of adoption over different time steps by spatial scales, demographics and building types
- variables that influence landlord and tenant actions in different locations, such as demographics, socio-economic indicators, income and debt levels
- evolution of building stock and demographics in different regions or precincts
- wide range of office building materials, sizes and usages, including mixed usage
- different incentive requirements for responsibilities for landlords versus tenants

- some retrofits are the responsibility of the landlord depending on the conditions of the lease agreement
    - in some situations, retrofits are dismantled by the tenant at the end of the lease
- soft and hard barriers to adoption, which vary with retrofit package; the main barrier categories (Marquez et al. 2012) are
    - capital constraints and investment priorities
    - capital and implementation costs
    - market structures and supply constraints
    - regulatory structure and supply constraints
    - information gaps
    - workforce and skill barriers
- electricity metering in some buildings, which can make it difficult to distribute cost savings to tenants to encourage adoption of energy-efficient retrofit.

The Australian residential sector has highly spatially granular ABS data on building stock and demographics, but a similar dataset does not exist for commercial buildings. The most reliable disaggregated datasets are by local government area, with a breakdown of building stock (including floor area) into floor height and age categories.

The range of building electricity usage patterns is much higher than in residential buildings, and ground-up methods to electricity modelling are more difficult. As a result, there has been very limited research forecasting uptake of appliances and retrofit in commercial buildings that affect electricity usage. Higgins et al (2013) developed and implemented a diffusion model to forecast uptake of different energy-efficient retrofits in office buildings, with application to New South Wales office buildings. One of the biggest limitations was the lack of information on existing retrofits across office building stocks, particularly when disaggregated below state level.

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Appendix C – Maximising network benefits: overview of relevant literature

This appendix presents a brief description of the aim and method for the references reviewed in the report. Each reference is tagged with the relative embedded generation (EG) technology. Even though a reference may use only one particular EG technology for its study, the findings of the study are generally applicable across different EG technologies. All EG technologies can provide power and voltage levelling, frequency support, are dispatchable and can defer infrastructure upgrades. In the case of uncontrollable energy sources, such as PV and wind, some form of storage may also be required. The effectiveness of each EG technology in providing these benefits and the technical complexity of operation will differ between different EG technologies, as will the cost.

Photovoltaics and storage

Transmission and distribution deferral using photovoltaics and energy storage

Reference [4] examines real data for a number of distribution networks in Salt Lake City. The data consisted of 15-minute load and solar resource data. A load growth rate of 4% is assumed and substations examined are rated around 10 MVA. Photovoltaic (PV) generation profiles were generated using solar resource data. The paper investigates how PV reduces peak load, both commercial and residential. The reduction in peak load reduces the number of overload hours experienced by the transformer. In this system, a transformer is defined as requiring replacement once the number of overload hours for the year is greater than 1%. The increase in the number of years before replacement is required due to PV reducing peak load, compared with no PV, is the number of deferred years. The paper does not define the PV penetration level. The study finds that for a projected 2016 load, the number of hours that a substation transformer is overloaded decreases from 510 to 179 for 10% penetration and to 35 for 20% penetration. This defers the transformer upgrade by two and four years, respectively.

Mitigation of rooftop solar photovoltaic impacts and evening peak support by managing available capacity of distributed energy storage systems

Reference [5] proposes a new control method for managing the charging/discharging of a battery in a battery/PV system. The system is shown to reduce fluctuations in voltage due to PV and reduce voltage rise during midday. Redirecting PV real power to charge the battery also mitigates voltage rise, while energy stored in the battery during the day can then be used to reduce peak load in the evening. A simplified description of the charging/discharging approach is that charging is gradually increased from low levels in the morning to peak charging around midday. Charging is then gradually decreased from peak at midday into the afternoon; this is essentially matching the charging target profile to the expected PV generation profile. Battery discharging begins at low levels at the start of the evening peak and gradually increases into the peak of the evening load period. The results show a reduction in reverse power flow during the PV peak generation period, as well as evening peak-load support from battery discharging.

Sizing strategy of distributed battery storage system with high penetration of photovoltaic for voltage regulation and peak-load shaving

Reference [6] presents a battery sizing strategy to obtain the most economically feasible battery energy storage system (BESS) size. The sizing is determined by optimising the cost benefit of the BESS. The cost of the BESS is weighed against the following operational cost reductions: peak demand, workload of on-load tap changers (OLTCs) and step voltage regulators (SVRs), and peaking power generation. Battery life is also taken into account. The results show a reduction in OLTC and SVR operation as well as peaking power operation. Despite these reductions, the authors find that no battery/PV investment brings about an economically feasible investment.

Coordinated control of grid-connected photovoltaic reactive power and battery energy storage systems to improve the voltage profile of a residential distribution feeder

Paper [8] examines the potential for PV combined with storage to improve the voltage profile of residential feeders. The improvement is to include both the mitigation of voltage rise due to PV and voltage drop during peak demand periods. All EG devices are in communication and control is coordinated. Control functions include reactive power support, and real power support through charging/discharging of battery storage. The results show the change in voltage profile for urban and rural cases when only reactive power support is provided. With only reactive power support, breaches of the lower voltage limit still occur in the rural case. When real power from the battery is also injected into the feeder, voltage levels remain above the lower voltage limit.

Frequency support functions in large photovoltaic power plants with active power reserves

The European Network of Transmission System Operators for Electricity is proposing that large-scale, centralised PV (LSCPV) plants provide frequency support functions [9] (Figure 57). It suggests that PV plants inherit some of the features provided by synchronous-based power plants, including inertial response, synchronising power, primary frequency control, secondary frequency control, and the provision of active power reserve and reactive power reserve. To be able to provide frequency support, PV plants would need to operate in frequency-sensitive mode (see Section 3.4.6). To accommodate frequency-sensitive mode, the PV plant would either have to be integrated with storage or operate under their maximum available capacity, or create the reserve using the curtailed power. The LSCPV plant model frequency support efficacy, frequency-sensitive mode and inertial response is tested by initiating a frequency event (major loss of generation) on the Institute of Electrical and Electronics Engineers (IEEE) system. For the two test scenarios, with the LSCPV plant providing frequency-sensitive mode and inertial response support, the system recovered more quickly. A daily load profile was also applied to the system and the frequency deviation across the day was recorded. The frequency distribution was shown to deviate less when LSCPV plant frequency support was present.

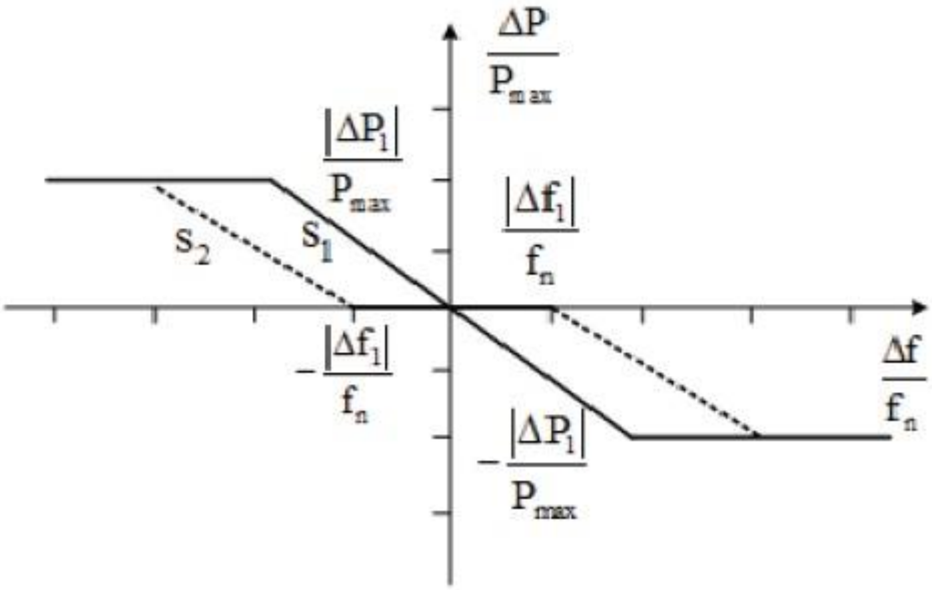

Figure 57. European Network of Transmission System Operators for Electricity requirement for frequency-sensitive mode for large-scale, centralised photovoltaic plant [9]

This work tests the concept of LSCPV providing frequency support functionality, frequency-sensitive mode and inertial response. A model of an LSCPV plant, including controls to provide the frequency support, is presented.

Network impacts of high penetration of photovoltaic solar power systems

Reference [10] presents a breakdown of the potential grid benefits offered by integrating PV, BESS and a static synchronous compensator (STATCOM). The benefits include:

- MW and MVAR (volt-amps reactive) support during critical contingencies
- voltage regulation support
- low-voltage ride-through during faults, provided by PV inverters
- ancillary services
- postponement of transmission upgrades in constrained circuits.

Rule-based control of battery energy storage for dispatching intermittent renewable sources

The work presented in paper [12] is similar to [11]; the main difference is that a BESS is used instead of a hybrid energy storage system. A control strategy is presented that minimises the power fluctuations of variable renewable EG (wind or solar) to make its power dispatchable.

The effectiveness of this control strategy and BESS is tested using an actual PV system and wind farm data. For a 1.5 MW-PV system, the BESS reduces the percentage of undesirable deviations (anything greater than 100 kW, positive or negative) from 16 to 4%.

Impact of high photovoltaic penetration on distribution transformer insulation life

Paper [13] estimates the extension in operating life for a typical distribution transformer (DTx) (200-kVA, 22/0.415-kV) due to rooftop PV generation. The transformer supplies a suburban area with a high penetration of rooftop PV systems. Using one year of residential load data drawn from the Perth Solar City High Penetration PV Trial, the insulation ageing impact is estimated. Each phase is analysed to investigate the impact of imbalanced load across phases on transformer loss-of-life (LOL). One year of ambient temperature data is used as an input into the LOL model of the transformer. The test scenario shows the saving in LOL is 0.2, 14 and 160 days for phases A, B and C, respectively.

A vision and strategy for deployment of energy storage in electric utilities

In 2005, American Electric Power (AEP) pushed energy storage to the distribution level in the form of sodium sulfur batteries located at distribution substations. Storage sizes are 1, 2 and 4 MW, with 7-hour discharge capability. AEP is now developing and planning to install smaller, more broadly distributed, energy storage units for fringe-of-grid customers ([14]). Termed community energy storage, the units will be 25 kW operated as fleets to provide aggregate benefits at the MW scale using existing communication and control technologies. AEP found that power system reliability was improved when storage is pushed further out on the system.

Diesel, gas, steam and hybrid generation systems

Quantification of the distribution transformer life extension value of distributed generation

Paper [15] presents a method for quantifying the economic benefits of DTx life extension through EG. The proposed approach is applied to actual distribution transformers installed in five sample cities in Iran to provide realistic estimates of the benefits in monetary terms. The types of EG considered in the study include PV, wind, combined heat and power (CHP) and microturbines. The results give the life extension and estimated economic value (US$/year) for each city for each EG type.

Impact of distributed generation on distribution investment deferral

Paper [16] assesses the impact of EG on distribution network investment deferral in the long term. Due to the randomness of the variables that affect such matters (e.g. load demand patterns, EG hourly energy production, EG availability), a probabilistic approach using a Monte Carlo simulation is adopted. Several scenarios characterised by different EG penetration and concentration levels and EG technology mixes, are analysed. EG types include PV, wind and CHP. For several test scenarios, the paper calculates the increase in admissible load growth due to EG. For one particular scenario, the results show wind to be the worst performer, with the other technologies performing equally well, providing an increase in admissible load growth of nearly 250% at 100% penetration.

Distribution transformer loss-of-life reduction by increasing penetration of distributed generation

The method described to calculate the reduction in LOL in a DTx due to EG in [15] is first presented in this paper [17]. It is applied to an actual distribution system in Iran using different combinations of EG including PV, wind, CHP and microturbines, half PV/Wind, PV/CHP and wind/microturbine. The results show the reduction in LOL rate over the life of the DTx; one figure plots the annual LOL rate for each technology and combination of technology against penetration level. Relative to the reference LOL rate, the best result is achieved through the microturbine at 15% penetration. The LOL rate is reduced from 1.2 to 0.15, an 87.5% reduction.

Evaluation of investment deferral resulting from micro-generation for extra-high-voltage distribution networks

In paper [18], CHP is deployed at different locations for four different penetration levels to assess the deferral in investment for a practical United Kingdom extra-high-voltage (EHV) network (33—132 kV). The savings associated with investment deferral depend on the length of time before which an asset needs upgrading. The results provide the reduction in investment as a percentage of the required investment if no EGs were installed. Savings were calculated for EG evenly distributed and allocated in proportion to load, and penetration percentage is the installed EG capacity as a percentage of the total load. The savings calculated were large; up to 82% reduction for a 32% penetration level.

Adequacy and security evaluation of distribution systems with distributed generation

Paper [19] calculates the increase in network reliability delivered by the installation of EG in rural Brazil. The rural network consists of conventional generation with EG distributed among subsystems. The paper investigates how effectively EG maintains subsystem voltage and frequency after either i) a change in state of the EG within the subsystem, ii) a load state transition, or iii) a protection device event. These events are termed islanding. Its effectiveness is measured by comparing the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), with EG and without. The paper finds that EG does improve reliability within the rural network. The frequency and duration of inadequate services for the whole system dropped from 3.6 occurances/year and 2 h/year to 0.18 occ./year and 0.0978 h/year, respectively. There was also an average of 1.4 islanding events a year, of which 92% were successful.