UTS: INSTITUTE FOR SUSTAINABLE FUTURES

NETWORKS RENEWED

TECHNICAL ANALYSIS

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ABOUT THE AUTHORS

The Institute for Sustainable Futures (ISF) was established by the University of Technology Sydney (UTS) in 1996 to work with industry, government and the community to develop sustainable futures through research and consultancy. Our mission is to create change toward sustainable futures that protect and enhance the environment, human wellbeing and social equity. For further information visit: www.isf.uts.edu.au

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EXECUTIVE SUMMARY

NETWORKS RENEWED

Networks Renewed is a major new project funded by the Australian Renewable Energy Agency (ARENA). It aims to demonstrate how solar PV, battery storage and inverters can support distribution networks in managing power quality. The project is focused on investigating the potential for smart inverters to regulate network voltage. The path to implementation will be established by two commercial-scale demonstrations of controlled solar PV and energy storage – one on the Mid North Coast in regional NSW, and one in suburban Melbourne in Victoria.

By the time this report has been published, the deployment of inverters and control technologies will have commenced for pilot-scale demonstrations to test candidate control algorithms, several of which have been published in the engineering literature. These will develop into market-scale demonstrations with the objective to achieve useful power quality improvements on selected network segments and also market trading revenues, should these materially improve the financial returns to customers from inverter control.

AIM OF THIS REPORT

This Technical Analysis has been undertaken to understand the current 'state of play' in technology and market development in order to design an innovative and informative market-scale demonstration.

The analysis first considers the problem of network voltage and the potential for smart inverters to resolve this through novel control methods. Managing voltage is an important function of network businesses, now and into the future, to ensure that Australia's electricity remains reliable. However, the rise of residential solar and other inverter-connected distributed energy generators has changed the landscape for network voltages, as outlined in Figure 1. This creates both opportunities and challenges. Uncontrolled solar and storage may exacerbate voltage fluctuations on the network, leading to more frequent voltage excursions. However, controlling them strategically may actually enhance network power quality. In fact, the 'smart' technologies that can control voltage now exist in new off-the-shelf inverters, but they are yet to be tested by the market.

Essentially, there is an opportunity for network businesses to tap into these new smart inverter capabilities to solve voltage problems in locations where solutions are most needed. With the establishment of an updated AS4777 standard this year, network businesses now require all new inverters to have smart-grid capabilities. The question is: How smart do we want these inverters to be? There are a number of novel controls to implement smart inverter capabilities that have been examined in the literature. Appendix E provides a 'menu' of candidate methods that have been considered for the experimental development of the Networks Renewed project.

Given the suite of possible controls, this report outlines the project's experimental approach to delivering first-of-a-kind demonstrations in Sections 4.2 and 5.1. This approach also considers the market potential and policy landscape to ensure that the demonstrations will test the options that deliver the greatest economic value. And although the project will necessarily address present-day levels of solar PV through experiments, network models validated by experimental data will also anticipate how well the demonstrated technology is likely to perform in a future with higher levels of solar PV.

Technical performance needs to be coupled with commercial success if smart inverters are to replace traditional network investments. The Technical Analysis concludes by emphasising the importance of using the project's experimental findings, including its commercial aspects, to inform a comprehensive business case.

CONTENTS

1 INTRODUCTION

Australia's interconnected power system is geographically one of the largest in the world, and some customers are very widely dispersed, while others are in high-density urban centres. Very different network types are needed to deliver electrical energy to these customer groups, which means that different approaches are needed to maintain their reliability and power quality.

Voltage regulation is a particular power quality issue that is emerging for network businesses as more residential solar is deployed. However, newly developed inverter technology may offer a means for solar systems themselves to help networks regulate voltage.

Networks Renewed is an exciting project that will demonstrate this novel capability with Australian network businesses. Networks Renewed partners include Essential Energy (EE) which operates many long rural network segments, and United Energy (UE) which includes some of the highest customer-per-kilometre network segments in Australia.

1.1 THE VOLTAGE PROBLEM

1.1.1 Voltage is important

Managing voltage is important for network businesses because there are limits in place about how high or low the voltage is allowed to be. There are fixed limits either side of the nominal voltage of 230 V, allowing for a transition from the older 240 V standard. If the voltage is too low, lights can get dim. If it's too high, sensitive electronics can be damaged.

When thinking about electricity systems, an analogy using water in pipes can help. Voltage is like the pressure in the pipes, and the power lines are the pipes themselves. Using large amounts of power causes the voltage to drop. It's similar to standing in the shower when the washing machine comes on: all of a sudden the water pressure drops because other things are using the water too. Pressure is also affected by how close the appliance is to the source: if your washing machine and shower were connected right at the foot of the dam you would not notice a pressure drop from turning them both on at the same time. However in a typical home there are long pipes that add resistance to the flow of water and contribute to the pressure drop. In an electrical distribution system, it's the houses farthest away from the substation that are the most susceptible to sagging voltage when large amounts of power are being used.

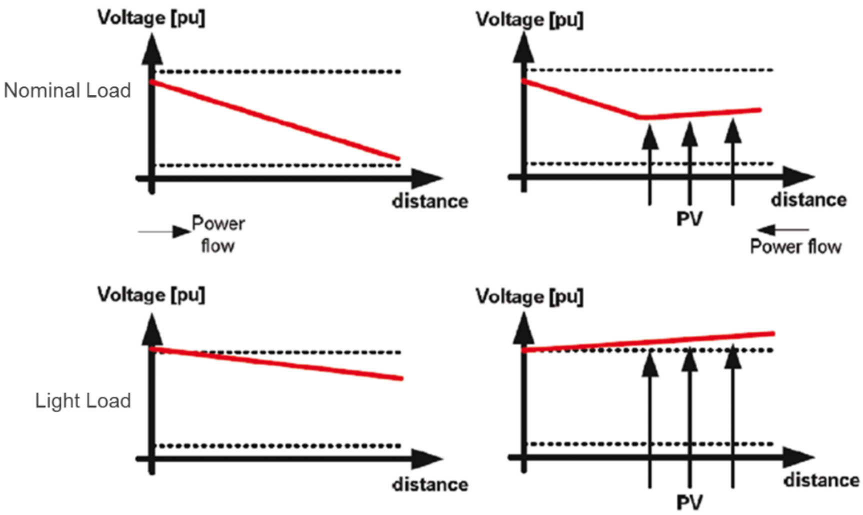
1.1.2 Why does solar make managing voltage more difficult?

Solar power systems and other generators distributed in the network change the landscape for voltage management. When inverters connected to solar power systems export power to the network, they can sense what voltage the grid is supplying and are able to raise the voltage at their point of connection in order to export all the power available from the solar panels (further background on the inverter technology itself is in Appendix C). This presents both opportunities and challenges. Raising the voltage in order to export power is very useful when high power demand is bringing the voltage down. But in times of low demand the voltage will already be high, and solar power and inverters may tip the balance and raise the voltage above the allowable level.

The indicative diagram on the top right of Figure 1 shows the impact of solar PV on the voltage profile. The export of solar PV onto the network causes voltage rise on the network. The magnitude of the voltage rise is a direct function of the impedance of the network at the connection point; power lines designed for higher capacity have lower impedance. As we get further away from the substation, network impedances are typically higher and the network therefore becomes more susceptible to voltage rise from the export of solar PV.

As the graph in the bottom right of Figure 1 shows, in distributors with large penetration of solar PV, a combination of both light load and high PV generation can cause voltages to exceed limits in some instances.

Figure 1: Simple illustration of voltage rise due to solar PV generation[1]



Among different types of power quality disturbances, long-duration over-voltage close to the connection point of a solar PV inverter has been the most prevalent type to arise due to the installation of solar PV systems. The severity of the over-voltages is directly dependent on the impedance or strength of the distribution network. These over-voltages become severe when either the load supplied by the solar PV system is low, or a large solar PV system is connected to a weak network with high impedance. When this happens, the over-voltage protection trips in the inverter, which switches itself off, and the export of power to the distribution network stops. Often, the removal of the PV system from the network returns voltages to acceptable limits, and the inverter will then detect that acceptable conditions have returned and attempt to reconnect, once again pushing up voltage and leading to a continuing cycle of tripping off and reconnecting. This means the PV system in unable to supply consistent power, and less benefit can be gained from the solar panels.

Thus, we need to rethink traditional strategies for voltage management as we include more decentralised supply from solar power and other distributed generators.

1.1.3 Inverters can help … through reactive power

Intelligently controlled inverters can help to regulate network voltage as well as manage peak demand and provide other services. Of primary interest is their ability to provide reactive power support to networks (more information on reactive power is in Appendix A). To do this, they use high-speed power electronics to change the voltage and current waveforms presented to the network, as described in more detail in Section 3.2.1 below. The effectiveness of this strategy depends on network impedance – that is, it depends on whether it is more reactive and carries reactive power, or more resistive and dissipates real power.

This is where the opportunity lies to renew our networks: In addition to real power transfer, devices that create or absorb reactive power can be used to help manage the voltage on the network.

[1] This diagram is from a report by the University of Wollongong, reproduced with thanks.

Both real power P and reactive power Q affect voltage, and to a first approximation their influences are proportional to the network impedance R and reactance X respectively. At a location where the network voltage is V the voltage change depends on real and reactive power at a customer's connection point according to:

$$\Delta V \approx \frac{PR + QX}{V}$$

In some areas, the network is sufficiently reactive for inverters to be able to manage voltage within acceptable limits using reactive power alone. This will often be the case in urban networks with high customer density. In other areas the network can be more resistive and inverters can manage voltage more effectively by modifying the flow of real power, for example by reducing the power output of solar PV generation, or by charging or discharging a battery. This will often be the case in rural networks that are 'voltage constrained', that is, when networks reach the limit of their ability to regulate voltage before they reach their thermal capacity limit.

In practice, these strategies for voltage regulation interact with: managing peak demand; providing other potential grid or market services; and meeting customer expectations of the solar PV and batteries on their premises. For example, for solar PV inverters that are not oversized compared to the solar PV array, absorbing some reactive power might reduce the solar power output, but this is preferable to disconnecting the solar generation due to an overvoltage condition. Although solar PV arrays are passive at night and during the evening peak period, their inverters can potentially inject or absorb reactive power, even at night. Battery inverters can store solar output and use it to supply peak load as an economic strategy for the customer while they simultaneously regulating voltage for the network. In these cases, including a component of reactive power can increase the effect on voltage but decrease the real power transfer.

Both solar PV generators and batteries are capable of participating in electricity markets, for instance by providing Frequency Control Ancillary Services (FCAS) using time-responsive inverter controls and earning revenues that help to pay for other services. On clear days solar PV generators can provide a frequency lower service by reducing their output, or they can provide a frequency-raising service by increasing their output if they have held back some output in anticipation. Batteries can participate at any time they have spare capacity. The available inverter strategies depend on the time of day, as shown in Table 1.

Table 1: Control opportunities for solar PV and battery storage inverters

Technology	Day	Peak	Night
Solar PV inverters	Reactive power support, solar power reduction, energy and FCAS markets	Potentially reactive power support as a STATCOM	Potentially reactive power support as a STATCOM
Battery inverters	Reactive power support, solar power storage, energy and FCAS markets	Reactive power support, supply peak load, energy and FCAS markets	Reactive power support, energy and FCAS markets

Further detail on how inverters can be used for voltage regulation is in Section 3.

1.2 RENEWING NETWORKS

1.2.1 What are we trying to do?

The aim of this project is to position Australian networks so they can use solar PV inverters and battery energy storage inverters to manage voltage successfully, even with high levels of solar PV generation. Networks Renewed will demonstrate that advanced, distributed control of inverters connecting small-scale solar PV and battery energy storage can have a positive impact on network performance, make economic sense for network businesses, be attractive for customers, and increase a network's capacity for hosting more renewable energy.

By working with network and technology partner companies, Networks Renewed will demonstrate controlled customer inverters at 'market scale' to produce substantial and accurately measureable improvements in voltage regulation on specific urban and rural distribution network feeders. The project will deploy sufficient inverter-connected resources to influence network performance at scale and test conclusively their potential to deliver services, including voltage regulation and other services that contribute to a viable business case for inverter services. The partner companies participating in Networks Renewed will gain first-hand experience in integrating these technologies and capturing their value.

1.2.2 The questions that drive us

The core technical research question for the project is:

How can inverters connecting customer solar PV and batteries be controlled to address power quality issues (especially voltage regulation), and what penetrations of customer solar PV can then theoretically be achieved?

A viable technical approach needs to work alongside other inverter functions to ensure that, taken as a whole, using inverters in this way is good value for money. This determines the parallel economic research question:

Is using customer inverters more cost effective than traditional network enhancements, and correspondingly, what is the value to networks of services delivered by customer inverters under effective control?

This value includes voltage regulation, and potentially peak demand reduction and market services.

Finally, by bringing a technical approach and economic values together into a business case, the project will examine the potential service options that are available to customers with solar PV, including voltage regulation, peak demand reduction, and market services. Further, the business case will investigate the types of network programs, customer initiatives and third-party businesses that can support these options.

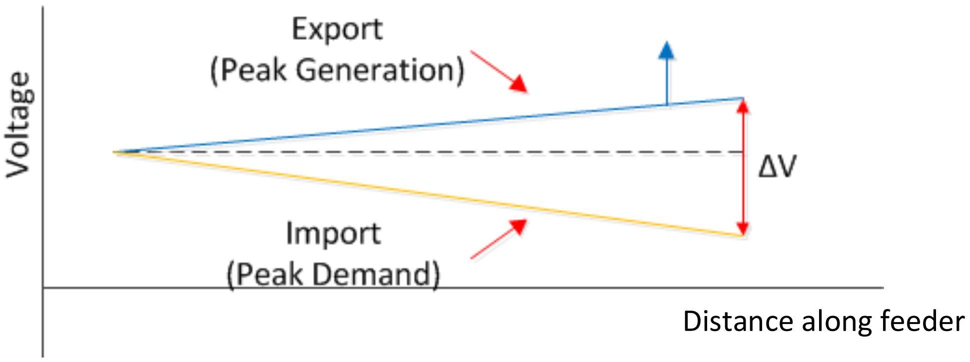
2 VOLTAGE IN THE TIME OF SOLAR

2.1 VOLTAGE (AND SOLAR) IN AUSTRALIA

As outlined in Section 1, correct voltage regulation is an absolute requirement for Australian network businesses. However, introducing solar PV generation has changed the power flow on network feeders that connect customers to distribution substations.

Solar generation during the day tends to raise network voltage. Peak demand in the evening is only marginally reduced by solar generation and tends to lower network voltage. These effects are most pronounced towards the end of the feeder, furthest from the substation, where voltage can be more tightly pegged to a system level. Figure 2 illustrates the widening voltage envelope along a feeder.

Figure 2: The widening voltage envelope along a network feeder



Thus, the hosting capacity of distribution networks may create the first real barrier to the so-far unstoppable growth of solar. Australians' healthy appetite for a clean energy future has been demonstrated by the continuing growth of customer-connected solar photovoltaic (PV) systems: presently at over 5 GW and not slowing, even as the debate continues about a fair feed-in value for solar energy (further background on Australian solar PV trends is in Appendix B). This suggests that voltage excursions reported by customers, or smart customer meters, will rise in the future. Without a cost-effective means of addressing these voltage constraints, network businesses may be inclined to dis-incentivise future installations of solar PV or pass on connection costs to new installations.

2.2 OUR PARTNERS' VOLTAGE

The pilot-scale and market-scale demonstrations will include both urban (UE) and rural (EE) network segments so that we can examine the different challenges of voltage regulation in these environments.

Regarding voltage, it is important to note that the nominal voltage and the low and high limits have changed due to the introduction of a new standard, based on the European standard, which network businesses can adopt over a timeframe of their choosing. Essential Energy will begin to allow final distribution voltages to drop from the present limit of 226 V down to the new standard of 216 V at its own discretion, given that older and non-compliant customer appliances will continue to be used for some time.

2.2.1 United Energy's network

Voltage control on UE's LV network in Victoria is managed by design in terms of the design load limit and the network length (voltage drop calculation) and the use of off-load tap changers on the primary side of distribution transformers.

Changes in the Australian Standard for voltage regulation from an upper limit of 415V +6% (240V +6%) to 400V +10% (230V +10%) has meant that the grid's legacy components, and even some newly manufactured components, are not designed to the current voltage standard. Along with other factors, like aging infrastructure connection issues, this has led to average grid voltages in some areas of the network tending toward the higher allowable limit (Figure 3). While the majority of excursions are over-voltages, under-voltage events do still occur on some feeders throughout the year, as shown in Figure 4.

Figure 3: Substation A voltage profile – September 2016

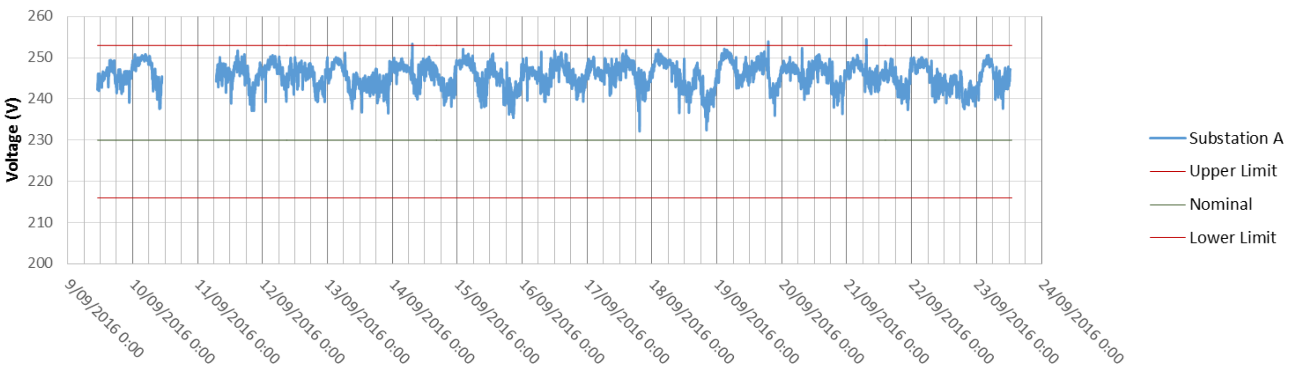


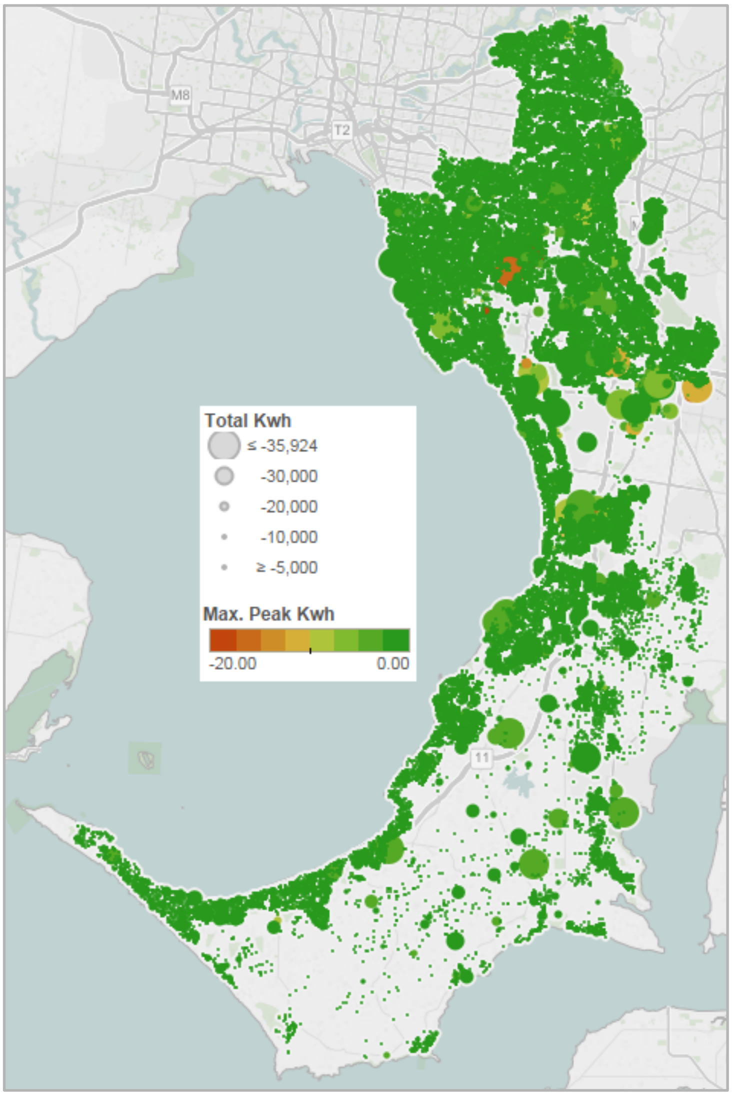
Figure 4: Substation C – Monthly voltage excursion events recorded by smart meters

Without adequate preparation, adding PV generation onto these lines could create additional opportunities for over-voltage excursion events, particularly when solar PV generation is high and electricity demand is low. Furthermore, the intermittency of solar PV makes it difficult to predict the interplay between PV generation and demand, and this creates challenges for network utilities when setting voltages at transformers.

As at the end of April 2016, there were more than 50,000 rooftop solar PV systems installed in the UE distribution network, with a total installed capacity of more than 150MW. Today, about 8.7% of the UE's customers (9.2% of UE's residential customers) employ grid-connected solar PV systems for their domestic consumption. There are already 10 distribution substations that have more than 100kVA of installed solar PV system capacity, however there are not yet many distribution substations within the UE service area that have a total installed solar PV system capacity higher than 30% of the distribution substation kVA rating.

Figure 5 shows the distribution of solar PV across the UE network. The map demonstrates that UE has pockets or clusters across its distribution network where the penetration of solar PV is particularly high. According to this map the Northern region of the UE network has higher installed PV capacity, with clusters clearly visible in the outer eastern and outer south-eastern suburbs of Melbourne. Currently, over 5% of the LV distribution substations on UE's network have solar PV penetration levels that exceed 30%. Furthermore, new solar customers are steadily connecting to the UE distribution network every month. In 2015 alone, UE recorded a monthly average of 700 new solar customers.

Figure 5: Heat map of UE installed solar PV system capacity



2.2.2 Essential Energy's network

EE's annual planning report identifies some ongoing issues with inclusion of distributed solar PV generation:

> *"Essential Energy's distribution network continues to experience isolated issues relating to voltage rise from embedded generation units, resulting in over voltage tripping of the inverters, and in some cases supplying customers with voltages in excess of Australian Standard limits. Since the inclusion of a one per cent voltage rise limit in the Service and Installation Rules of New South Wales, issues related to individual customers, i.e. issues due solely to voltage rise in customer service mains have reduced, with the majority of issues identified related to legacy systems."*

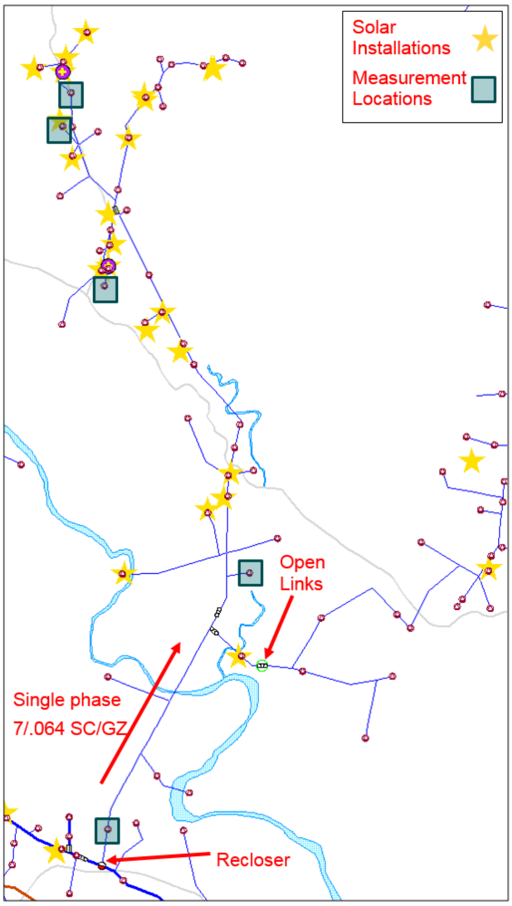
Power factor, related to reactive power, can also be an issue:

> *"When mobile diesel generation is used on LV street circuits during planned outages, solar installations resynchronise and supply real power only, requiring the mobile generation to supply much of the reactive power for the LV loads along with the small amount of remaining real power. This poor power factor situation can lead to tripping of the mobile generation. To prevent this, local embedded generation must be manually disabled during planned outages where temporary generators are used."*

EE realises that changes in the Australian Standard for voltage regulation to a nominal 230 V has the potential to disrupt the satisfactory operation of 240 V appliances, and will therefore endeavour to maintain voltage to the point of supply at 230 V, +10%, -2% for 95% of the time (10 minute average). Voltage issues can be particularly difficult to mitigate in regional areas where feeders typically cover long distances and the voltage variance can be large. Roughly 60% of validated power quality complaints on EE's network in the Central Tablelands of NSW are voltage related, and solar PV installations on regional feeders have been identified as a key factor in significant voltage excursions.

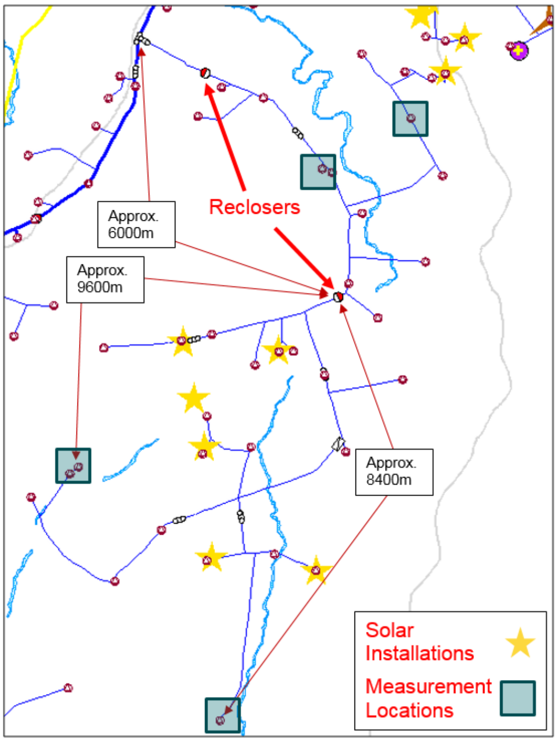
For example, in October of 2013, customer complaints of inverter tripping due to high voltage triggered an investigation on 'Feeder A', which revealed voltages of over 253 volts. This feeder is mapped in Figure 6. The investigation also revealed that minimum voltages were below the network standard of 216 volts. Therefore, the high voltage issues could not be mitigated with high voltage tap changes, as this would cause minimum voltages to drop even further below the requirement. The voltage issues were correlated to a significant amount of solar in the region, with around 45kW of capacity on a single branch of the network on which 48 customers connect over a distance of 9.5km. The correlation between voltage rises and solar feed-in was supported by data showing that the issue did not occur on cloudy days.

Figure 6: Solar installations on Feeder A exhibiting voltage excursions



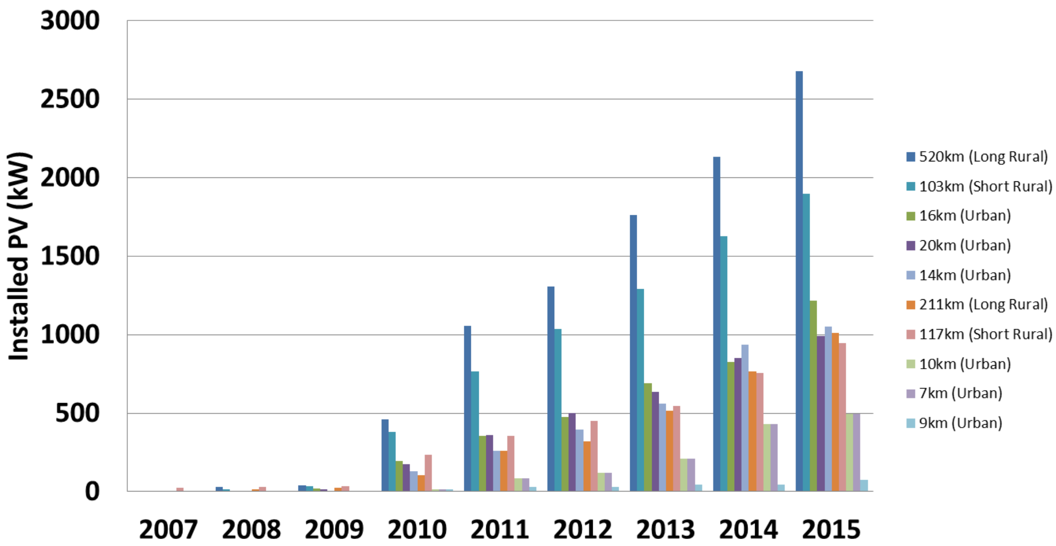
A similar example from the same region occurred in January 2016 when EE received complaints from a customer with multiple faulty appliances. This customer is connected to 'Feeder B', which is mapped in Figure 7. High voltages were recorded on the premises and a tap change was performed, although high variances of around 35 volts still persisted in the area. Testing indicated that the high voltage was due to high solar PV penetration (48kW) in the area, long high-voltage feeder distances and connector sizes. Again, the correlation to solar was suggested through data showing that voltage rises did not occur during days of cloud cover.

Figure 7: Solar installations on Feeder B exhibiting voltage excursions



These examples show that there are areas where solar PV uptake on specific feeders, relative to the number of customers, is far higher than the average. Figure 8 provides an example of the variability of PV installation rates on feeders within the same zone on EE's network. Of note is the fact that these two feeders have significantly higher than average PV penetration and are also 520km and 103km long respectively. As noted above, voltage is already difficult to manage on long feeders and, with the addition of PV capacity along the line, these areas may be susceptible to serious voltage issues.

Figure 8. Cumulative solar PV penetration - Zone ALU



3 HOW DO WE FIX IT?

3.1 TODAY'S SOLUTIONS[2]

The historical approach to voltage regulation for network businesses is based on the assumption that power flow is unidirectional along the feeder that connects a distribution substation with customers. Under this assumption, voltage falls from the substation to the end of the feeder. Hence, the problem is stated as:

How can we set voltage for customers so that it's not too high at one end of the feeder, but not too low at the other end?

A number of tools are available to manage voltage on the network, and this section provides a summary of the most common solutions deployed by utilities. Networks generally select the appropriate tool by modelling the voltage along a feeder under minimum and maximum customer demand.

Table 2 provides a summary of the most common voltage solutions currently deployed by utilities.

Table 2. Network solutions for voltage control

Network solution and method of correction	Comments
Transformer taps Typically 5 or 7 tap settings on a distribution transformer, at 2.5% voltage increments, set at highest allowable voltage for minimum demand so that sagging voltage at far end of feeder is within allowable envelope.	Insufficient for longer feeders where voltage sag is very large. Requires manual setting.
On load tap changers (OLTC) Respond to changes in demand, automatically changing voltage at the zone substation without interrupting power supply through adding or subtracting to the transformer winding. OLTCs are typically equipped with Line Drop Compensators (LDCs).	Imprecise measure as voltage is changed for all feeders connected to zone substation. Potentially high maintenance with high operation costs.
Mechanical voltage regulators Use a solenoid to operate a mechanical switch to disconnect or adjust power flow when there is a voltage excursion. The majority of regulators are HV, although some LV regulators are used to address specific issues on subsections of LV circuits.	Potentially high maintenance with high operation costs if excursions are frequent. The number of voltage regulators that can be placed in series is typically limited by the reduction in fault current, which can lead to protection grading issues.

[2] United Energy Document: UE PL 2203 – Power Quality Strategy and Plan 2015/16 – 2024/2025, Version 3, November 2015.

United Energy Document: UE PL 2204 – Steady-State Voltage Strategy 2015/16 – 2024/2025, Version 2, June 2015.

Power electronic voltage regulators Power-electronic devices that can maintain voltage at a point in a network feeder under varying load conditions. Power electronic based regulators have a much faster response time compared to mechanical regulators, however cost and the available size of electronic based regulators typically limits applications to subsections of LV circuits. Can include LDCs, which maintain constant voltage at locations remote to the regulator. Long rural networks often use series voltage regulators (SVRs).	Can provide fast response to sudden voltage change. Can be operated remotely. Available size range limits use to small parts of LV networks.
Network reconfiguration Transfer customers on far ends of feeder to adjacent transformer, or strategically install new transformer.	Limited to more urban networks with multiple customers and transformers in same area.
Load balancing Transfer customers between phases on a three-phase feeder to achieve balanced load, subject to variations between residential customers at different times of the day.	In some circumstances, may help to accommodate a higher number of PV systems.
Capacitors, reactors, and static VAr compensators (STATCOMs) Sinking or sourcing reactive power. Shunt connected capacitors typically installed at substations and switched capacitors along feeders to control reactive power flow, voltage and network losses. Reactors can reduce voltage rise in single-wire-earth-return (SWER) lines.	Flexible set of solutions for different circumstances. Reactive power may not be effective on high impedance networks.
Reconductoring and upgrading distribution transformers Larger conductors used to reduce network impedance, making it easier to regulate voltage within the required limits. For distribution transformers with underground cables and short overhead lines to supply customers, the transformer can be upgraded to a larger power rating.	Allows for future growth in demand and PV capacity. High capital cost.
Line-drop compensators (LDCs). These devices work with other regulators and OLTCs to consider the expected line drop between the regulator and a target location due to the current flow in the line. At times of higher current flow, voltage drop will be higher requiring greater corrective from the regulator.	Provides other regulating equipment with the ability to respond to voltage conditions at separate locations.

3.2 INVERTERS FOR TOMORROW

As prefaced in the Introduction, new smart inverters connecting solar PV generators and battery energy storage systems to the distribution network have a large, and mostly untapped, potential to help regulate voltage on distribution networks.

While a large number of inverters are now installed across Australian distribution networks, connecting 5.2 GW of solar PV capacity, only a small number of these inverters can be considered ‘smart’ with advanced capabilities for network support.

However, the goalposts are shifting and a substantially revised version of the Australian standard AS4777, that governs inverter-connected generation including storage, came into force on 9 October 2016. This standard links to the framework for controlling demand-side resources defined by AS4755, called the 'demand-response enabled device' (DRED) standard. The revised AS4777 provides a basic level of control interface so that advanced inverter capabilities can be accessed by network operators. Most inverters presently available in Australia do not meet these new standards. Although smart-grid capabilities are not mandated in the standard, network operators will require them in their connection approval processes, so in effect only smart inverters will now be installed.

From 2013 onwards an estimated 50-60% of installed inverters are expected to have smart grid capabilities. Although all of these inverters are in principle available for the voltage regulation services that are the focus of Networks Renewed, and other advanced network services, perhaps only half of these are easily programmable. For example, most inverters produced in China cannot have smart grid capabilities activated on site because their settings are in flash memory set at the time of production.

Compared to the number of solar PV systems, there are not many battery inverters currently installed in the market (probably less than 10,000 units in total) and of those almost none have any smart-grid capability. It is only this year that any significant volume of battery inverters with smart-grid functions will be deployed into the Australian market. Battery energy storage inverters for residential applications and using transformer-less designs have exactly the same capabilities as modern solar PV inverters, except that they can consume as well as produce real power.

3.2.1 How are new inverters 'smart'?

'Smartness' is not a technical term for inverters, but it does refer to a set of specific capabilities recognised by the industry. The typical capabilities of smart inverters[3] are shown in Table 3. Manufacturers can usually provide these features at negligible additional cost because they are controlled by software installed in the standard inverter hardware. Additional costs are incurred for the communication systems needed to use these features and for using inverters with a higher power capacity. The latter can enable a level of reactive power without reducing the amount of real power provided by the solar PV generator or battery system.

Table 3: Common functions of smart inverters

Function	Description
Connect/disconnect	Physically connects or disconnects from the grid in an orderly way
Adjust maximum generation level	Sets maximum generation which can be used to implement a curtailment order from the network or system operator
Adjust power factor	Adjusts reactive power level to provide a given leading or lagging power factor
Volt-VAR mode	Adjusts reactive power level to an explicit level that may be a function of real power or voltage
Frequency ride-through	Sets frequency parameters governing the conditions under which connection should be maintained
Voltage ride-through	Sets voltage parameters governing the conditions under which connection should be maintained

[3] Emerson Reiter, Kristen Ardani, and Robert Margolis, *Industry Perspectives on Advanced Inverters for U.S. Solar Photovoltaic Systems: Grid Benefits, Deployment Challenges, and Emerging Solutions*, National Renewable Energy Laboratory, 2015

Event/history logging	Provides logged data on request
Status reporting	Provides status information on request

A particular feature of smart inverters is their capacity for dynamic grid support. New inverters have the capability to 'ride through' short-term disturbances in frequency or voltage, and this increases the stability of the grid. While anti-islanding has long been regarded as important for network safety, as the number of local generators (both wind and solar PV) connected to networks increases, automatic disconnection can make network disturbance worse. When backed up by suitable control systems, smart inverters can quickly change their output in a direction that assists grid stability by providing ancillary services and reactive power support. This is an important step in the transition to a greater proportion of local generation in the energy mix.

There are many demonstration projects of smart inverter control worldwide. These are generally led by network businesses, and explore the impact of smart inverters on electricity networks and their usefulness to the network. Very few of these, however, address voltage regulation except as a by-product of managing real power flow, for example, to reduce peak demand or to increase self-consumption of solar PV generation. Appendix D provides four examples of projects where the ability of inverters to absorb reactive power was used intentionally to help regulate network voltage.

The fact that there are so few examples to cite indicates that Networks Renewed is positioned to make a valuable contribution to knowledge and is likely to be regarded as an important project internationally.

4 WHAT SHOULD WE DO NOW?

4.1 TECHNOLOGY INNOVATION

Networks Renewed has the opportunity to test the boundaries of current engineering practice through implementing advanced control methods. This section discusses the control options, their implications for network management and the potential innovations to be explored.

4.1.1 The gap lies in control

Currently available control strategies for inverters rely on each inverter acting singly and using only locally-sensed information. There are different ways of setting either the power factor presented to the grid, or the reactive power absorbed, for example:

- setting the power factor to a constant value
- setting the power factor according to the level of real power input or output
- setting the power factor according to the customer voltage (V)
- setting the reactive power according to the customer voltage (V).

The functions employed are analogous to 'droop control' for frequency regulation, which originated with the governor systems employed to vary the input pressure of steam turbines and maintain a constant speed of rotation. For voltage regulation, the term droop control is often used, although the applicable control theory is different because the ways that frequency and voltage are carried across the network are different.

However, uncoordinated voltage regulation responses by individual inverters may lead to unexpected outcomes when many inverters are acting simultaneously. There may also be a problem of equity: customers connected towards the end of network feeders are more likely to experience voltage excursions and thus their PV systems may have a higher burden. To address this problem, a coordinated response could be more effective, and could lessen the burden on particular PV systems and inverters at the end of a feeder.

Numerous academic studies have formulated advanced control strategies that share information and responses among multiple inverters and potentially other network elements such as OLTC transformers. Nonetheless, there are few *practical* demonstrations of advanced control for voltage regulation, which is where Networks Renewed can make a strong contribution to the state of the art.

In general, advanced control can be achieved by:

- local intelligent control in which additional data and sensing are used to improve control decisions by individual inverters or controllers, or

- aggregated control in which a set of inverters is managed as a group with some central processing based on distributed data and sensing.

All advanced control methods require some integration with the network management practices of the distribution network business. At the very least, the network business needs to understand the impact of inverter controls, and to have a model to predict their anticipated response on each feeder under different load and generation conditions.

Several published control methods are reviewed in Appendix E. These have been selected on the basis of citations – that is, they have each received a lot of attention in the engineering literature, and so they can be regarded as landmark papers. They also span a wide range of potential methods that allow dynamic control of inverter settings.

4.1.2 Control options can be mapped

There are many advanced control methods, and implementing any one of them would be a considerable state of the art innovation. Strategically, it is important to understand the advantages and disadvantages of the available control options for the pilot-scale and market-scale demonstrations. This is attempted below considering three variables:

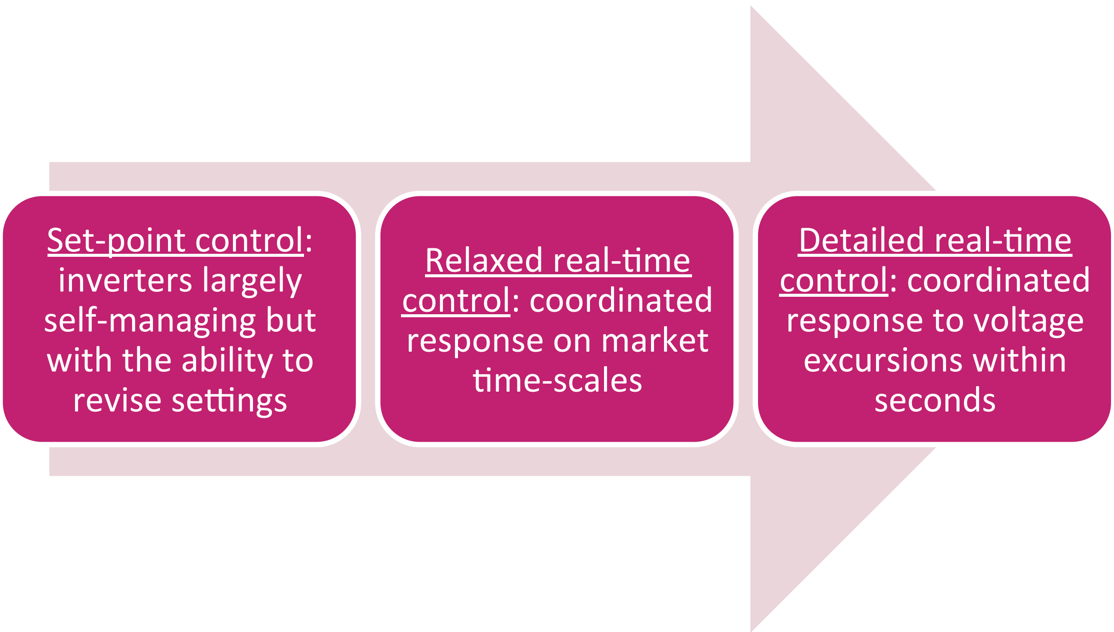
1. real-time versus set-point control
2. data and communication requirements
3. control integration with distribution network operations.

Real-time versus set-point control

Two approaches that go beyond basic 'droop control' methods are envisaged in Appendix E: local intelligent control and aggregated control. In practice, the main difference between local and aggregated control is the frequency of the exchange of data between inverters and a system manager. The frequency can range from occasional updates to regular or real-time control signals.

The key distinction is that detailed real-time control should be capable of sensing and addressing short-term voltage excursions within the allowed durations of the applicable network standards. Relaxed real-time control relies on local inverter responses to address short-term voltage excursions, but it can still coordinate responses to market-related events or other less time-critical applications. Figure 9 summarises the three control regimes that are reasonable to consider for the demonstrations.

Figure 9: Choices for the responsiveness of inverter control



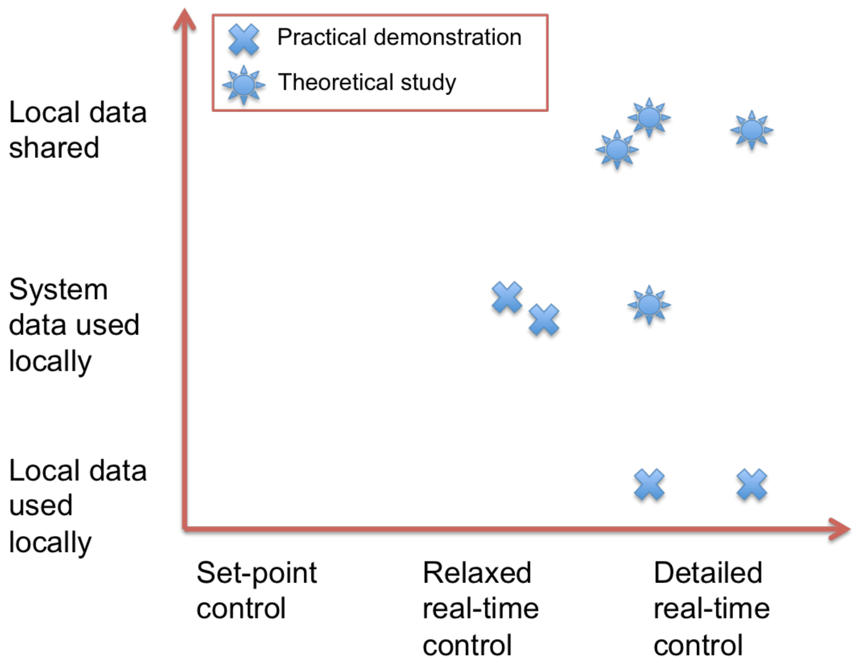
Data and communication requirements

Control requires data, so the choice of control methods is also related to, and potentially governed by, the available data for control decisions. Network operators may seek a range of controls and/or data streams associated with the next generation of inverters. A non-exhaustive list in loose order of level of integration is as follows:

- Non-real time data provision: access to historic data of system conditions and control set-points at inverters, collected and provided at regular but not real-time intervals. This enables offline load flow modelling and/or analysis of other system conditions.
- Direct broadcast (one way): an ability to broadcast a control signal that is received and acted upon by all inverters in the network; individual units are not provided with individual signals. This is analogous to the way network operators have historically controlled overnight hot water systems with ripple control.
- Direct signalling (one-way) to individual (addressed) devices, enabling the network operator to differentiate between the control signals it gives devices.
- Direct signalling (two-way) to devices to allow the network operator to respond to data collected by devices in real time and update control set points or response patterns as desired.
- Direct signalling (two-way) to devices and integration of other network information systems (DMS), allowing real time load flow assessments and/or control strategies that include responses from other system elements (e.g., control strategies that include behaviour or On Load Tap Changers (OLTC)).

Figure 10 attempts to map in a qualitative way the control methods in the related projects and literature reviewed in Appendices D and E respectively, according to the control regime and the data requirements of each. Networks Renewed can be a mechanism to facilitate the transition from existing industry practice to aspirational control methods.

Figure 10: Mapping of control methods from academia and industry



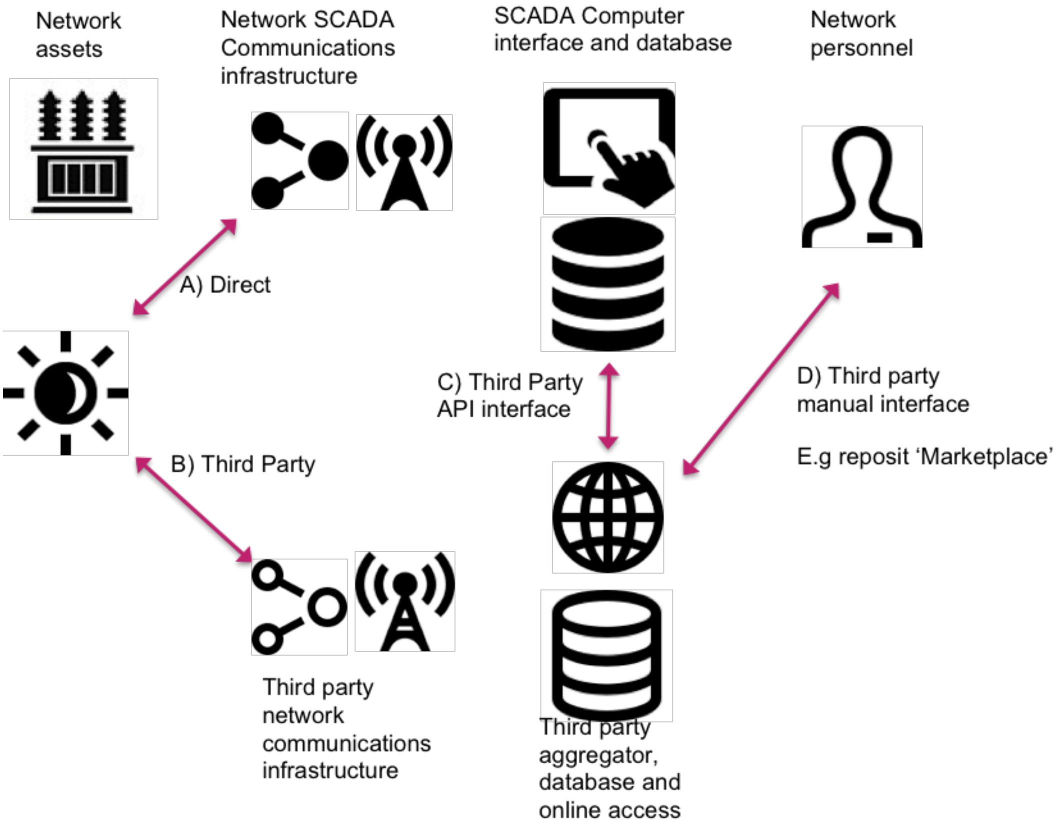
Control integration with distribution network operations

All advanced control methods require some integration with the network management practices of the distribution network operator. At the very least, the network operator needs to understand the impact of inverter controls, and to have a model for their anticipated response on each feeder under different load and generation conditions. The methods and the outcomes the control methods facilitate for a network operator differ in the degree of integration required.

Network operators use a Supervisory Control And Data Acquisition (SCADA) system to monitor and control devices they own. Such a system will typically include many distributed devices with data capture and control functions, a communications infrastructure, and a control room. The distributed devices are often called Remote Terminal Units (RTUs) that will have some automated (programmed) responses and routines that will operate network assets independently and send data back to the control room. The industry has well recognised communications protocols for integrating many different manufacturers' devices into a SCADA system such as Modbus, DNP3 or IEC61850.

To integrate with a network operator's control system, solar inverters must interface with some point of that network operator's infrastructure. The diagram in Figure 11 shows the main possibilities for integration points.

Figure 11: Possible integration points with a network operator's infrastructure



Referring to Figure 11, the following questions need to be considered to assess the best method of integration:

- Does the network operator wish to facilitate the communication between inverters, or will a third party provide this functionality more cost effectively (A vs. B above)?
- Will the system be integrated directly into the network operator's SCADA system (such as A or B+C above) or will the network operator log in to a different third party product to enact control and access data (D)?
- How will data and control security be upheld? Networks require highly secure IT systems.
- Does the network wish to implement a control strategy that includes other pre-existing network elements (requires A or B+C above)?
- If a third party aggregator is used, how fine or coarse will network's control be over devices? Will a network operator's requirements be served by broad control of the aggregate 'fleet', leaving the details to the aggregator? Or is the aggregator merely providing a communications service and leaving the 'thinking' to the network's SCADA system?

4.2 NETWORKS RENEWED: AN EXPERIMENTAL APPROACH

There are important unknowns that Networks Renewed is exploring, notably the effectiveness and market value of voltage regulation services, and the ideal design of a demonstration to quantify these unknowns cannot be determined in advance. Therefore, the experimental approach begins with pilot-scale demonstrations to explore several network situations at a preliminary level, involving a relatively small number of customers. This will inform the design of market-scale demonstrations described in Section 5.1. In parallel with physical demonstrations, software models of the relevant network segments will be validated by the experimental results, and the models will then be used to estimate how the measured voltage regulation impacts will scale to address future penetrations of solar PV.

4.2.1 Pilot-scale demonstrations

At the time of writing, the two network partners in Networks Renewed have commenced customer engagement for their pilot-scale demonstrations. They have segmented their demonstrations to achieve a good coverage of the network conditions of interest to them.

UE will test five solar-storage units at ***dispersed*** customer sites to measure the local influence of inverter controls in different circumstances, and another five solar-storage units at customer sites ***concentrated*** on a single distribution substation to test methods for coordinated inverter actions using different control algorithms.

EE will test storage units at 20–30 customer sites near the end of a lengthy ***rural*** distribution feeder where solar PV generation is creating voltage excursions, and advanced solar ***PV-only*** inverters at another 10–20 customer sites in an urban setting where reactive power controls are expected to be effective for regulating voltage.

Both networks will use control and communications technology that is commercially available through Reposit Power, who is also a partner to the project.

During the pilot-scale demonstrations it will be critical to arrive at the control approach that will be used for voltage regulation during the market-scale demonstration. This will establish the path forward for the market-scale demonstration described in Section 5.1.

There will be opportunities for innovation during the market-scale demonstration, and due to the short period of pilot-scale trial operation, some more advanced control methods cannot be implemented until the market-scale demonstration. Nevertheless, innovation during the market-scale demonstration should not interfere with the creation of significant run-lengths of experimental data by which the technical and economic performance can be assessed. The market-scale demonstration is described as the project's future path.

The stages used to arrive at suitable control methods are summarised in Table 4 where some differences between trial sites are also highlighted. Notably, EE's PV-only sites will clearly have restricted control actions available, and UE's dispersed sites will not be able to provide reactive power services due to legacy inverter systems.

Table 4: Stages of the experimental plan for the pilot-scale demonstration

<table>
<tr><th>Experiment</th><th>United Dispersed</th><th>United Concentrated</th><th>Essential Rural feeder</th><th>Essential PV only</th></tr>
<tr><td>Commissioning</td><td colspan="4">Ensure inverters are functioning to their specifications and network and customer site measurements are recorded correctly.</td></tr>
<tr><td>Point influence</td><td colspan="3">Under a range of network, load and generation conditions, guide the inverter (P, Q) around the available envelope and record the impact on customer and network voltage (if any).</td><td>Guide inverter Q between limits and curtail P partially and fully.</td></tr>
<tr><td>Commanded response</td><td>Test responses based on P through battery management</td><td colspan="3">Guided by network modelling and point influence results, test a range of bespoke responses to voltage conditions and measure the overall impact on the relevant feeder or distribution substation.</td></tr>
<tr><td>Autonomous response</td><td>Not applicable unless common control platform</td><td colspan="3">Implement and test an automated local response based on local data, and additional data as available, according to a mathematical model.</td></tr>
<tr><td>Advanced response</td><td>Not applicable unless common control platform</td><td colspan="3">Guided by engineering literature, modelling outcomes, and experimental observations, implement modified and more elaborate control strategies to determine the best control option(s) for market-scale demonstration.</td></tr>
</table>

Commissioning

After installation the following functionalities need to be demonstrated at each pilot-scale demonstration site:

- effective control of inverters within the anticipated (P, Q) envelope
- interrogation or regular reporting (every 5 minutes or more frequently) of (P, Q, V) measured by local metering at customer sites
- availability of coincident network (P, Q, V) measurements depending on available hardware at substations or other network locations.

Point influence

Under a range of typical network conditions, the inverters should be cycled over a range of (P, Q) settings potentially including the full boundary of their (P, Q) envelope, and the impact on customer V should be measured. Potentially, coincident network measurements can be taken, although limited or no measureable impact may be found from a single inverter action.

These results should be compared with an expected response, either from basic AC circuit theory, or from a preliminary load-flow model that would include the influence of the customer's service line.

Commanded response

At this stage the experimental program needs to be supported by load-flow modelling of each demonstration network segment. This will inform proposed voltage regulation actions that should be used in response to measured network conditions – as determined either by network measurements or customer measurements.

The network operator will implement the voltage regulation actions using a control interface for aggregated dispatch of inverters at the demonstration sites. The (P, Q) or (P, pf) settings may be different for each inverter and will generally vary according to each customer's location on the network.

The experiment should include regular 'notch tests' in which the inverters are returned to well-defined default settings to make a with/without comparison. Potential customer impacts from these switching operations should be anticipated and mitigated if necessary.

Autonomous response

The project may find that effective voltage regulation can be done using autonomous responses at customer inverters, with local action determined by local data or broader data if available. In principle, this can be a robust approach because it is not dependent on continuous internet connectivity.

This assumes a decision-making capability at each customer site and the ability to program it as part of this experiment. Although this capability certainly exists in Reposit Power's control system, programming it specifically for tailored voltage regulation experiments may be difficult depending on their software development process and priorities, which are governed by a commercial operating environment.

An alternative approach is to ***simulate*** a local, autonomous approach using the control interface used for aggregated dispatch of inverters, as long as customer (P, Q, V) measurements can be obtained. Bespoke software would process these measurements, calculate the individual responses that customer inverters would be expected to implement autonomously, and the dispatch those responses using the control interface. This would be sufficient for demonstration purposes provided that the whole control loop could be completed quickly – probably, a 5-minute cycle would be sufficient, but this needs to be discussed with network partners.

It is premature to determine how to disperse responses across multiple inverters, as a mathematical understanding of the (P, Q, V) relationship is needed, informed by load-flow modelling on the demonstration network segments.

Advanced response

During the pilot-scale demonstration the performance of commanded and automated voltage regulation methods can be compared to the methods simulated in the engineering literature, and alternative control strategies can be proposed by the project team, to formulate advanced control strategies. These may involve some interaction with network elements such as tap-changing transformers, depending on the availability of suitable controls.

There is unlikely to be time to formulate and implement an advanced response during the pilot-scale demonstration. These methods would be developed for implementation during the market-scale demonstration subject to obtaining a sufficient run-length of technical and economic data from whatever methods are selected.

4.2.2 Matching measurements to models

Networks Renewed has an experimental program that can address only the existing amounts of solar PV on the network segments involved. Its goal, however, is to prove methods that will help to manage future, larger amounts of customer solar PV. This connection can be made through software modelling.

All network businesses use ‘load-flow’ modelling to understand the performance of power delivery and exchange on their networks. Load-flow calculations are iterative. They start with knowledge of customer load (real and reactive) and an estimate of the voltage at the end of the network segment. The voltage drop between customers along the segment is calculated, metre-by-metre, up to the substation or transformer at the start of the network segment. If this does not reproduce the voltage measured at the substation, the estimate of the voltage at the end is modified up or down by an amount proportion to the discrepancy of the measured and calculated substation values. The voltage drops between customers are then recalculated, and so on until the voltage at the substation is correctly matched. Importantly, load-flow calculations work whichever way the network power is flowing: when there is solar energy input, some network segments will experience a voltage drop, and some will experience a voltage rise, according to the direction of power flow.

Validation

In principle, given correct inputs, a load-flow model calculates the impact of any real-power or reactive-power control strategy. Usually however, the resistance R and reactance X per unit length of the network are not precisely known, and there are additional complexities such as the impact on circuit resistance and reactance of the service line across the customer’s property to their connection point and meter box, again not precisely known. Also, the customers’ inverters may not perform exactly the service that is requested of them, having some tolerances in their design and variability in their manufacture.

Measured voltage responses to customer inverter actions can be used to correct the input data and form accurate load-flow modelling. Both UE and EE already have models of many network segments implemented in commercial power-system analysis software called PSS Sincal. PSS Sincal has a wide range of capabilities beyond load-flow modelling, which makes it possible to use a common approach to modelling candidate control methods in Networks Renewed.

Load-flow modelling alone cannot tell an operator how to control customer inverters to get the best network outcome. However, it will be an important aid for selecting control approaches for the market-scale demonstration, and for further development of control approaches as desired.

Projecting into the future

The goal of Networks Renewed is to show how customer inverters can help with voltage regulation on future networks. Projections of uptake of solar PV by state are available from project partner the APVI. It is possible to estimate a range of the number of customers that may have solar PV on the network segments used for the demonstration, and the total installed capacity, by using the APVI projections,. Using the validated load-flow model, the impact of demonstrated control strategies in future network scenarios can be estimated.

Project stakeholders will gain an increase in their level of understanding of the penetrations of solar PV that can be supported on networks that access voltage regulation services using advanced inverter controls.

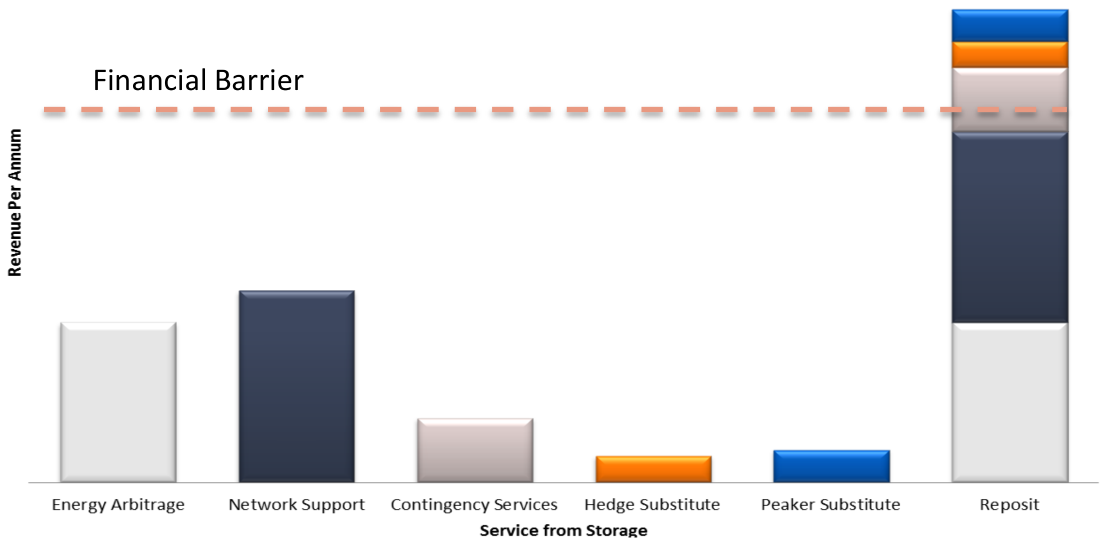
4.3 BUSINESS INNOVATION

The Australian Energy Market Commission (AEMC)[4] encourages any viable participation in the wholesale electricity and ancillary services markets to broaden the competitive landscape, and this ultimately provides more efficient and cost-effective energy for customers. Battery energy storage is a newcomer to the competitive market and its impact will certainly grow as its uptake grows.

4.3.1 There are many value propositions for smart inverters

Battery energy storage is a multi-purpose tool and its many applications can provide value to several stakeholder groups: customers, network businesses, retailers and the market (and system) operator, as shown in Figure 12 and Table 5. Capturing multiple types of value simultaneously is called ‘value stacking’ and this has been the goal of energy storage proponents since this potential was realised.[5] Both the Victorian and the NSW demonstrations for Networks Renewed create the potential to achieve stacked benefits, at least for customers and the network operator.

Figure 12: Stacking revenues from energy storage



[4] Australian Energy Market Commission, *Draft Rule Determination: National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule*, 2016

[5] Jim Eyer and Garth Corey, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, Sandia National Laboratories, SAND2010-0815, 2010

Table 5. Potential stacked benefits arising from distributed battery systems

Stakeholder	Stacked Benefits
Customer	Increase in return on investment (ROI) of PV asset via energy arbitrage and self-consumption of solar energy. Accessing value from network support services for the local distribution business. Market returns from contingency services for the system operator and participation in aggregated trades in the wholesale energy market.
Network	Managing network voltage through battery inverter capabilities. Managing peak demand and peak local supply to defer network augmentation, perhaps indefinitely, leading to a capital offset value stream. Sharing the cost of storage and value obtained from it with customers to give economically efficient outcomes on both sides. Managing the increased variability of net customer demand due to increased residential solar uptake. Improving network reliability, though this is not clear or well understood at this time.
Retailer	Diversifying its business model. Improving customer retention rates. Hedging risks on the wholesale market. Accessing value from providing ancillary services. Accessing valuable data from their customers to gain an insight into how they consume their energy. New way of communicating and engaging with their customers.
Market	Greater access for new market participants to broaden market competition.

4.3.2 The question of ownership

Introducing battery energy storage on the customer side of the meter, but applied to network applications such as voltage regulation, raises the question of ownership.

Networks Renewed is investigating two existing ownership models for a practical comparison: customer ownership with Essential Energy in NSW, and network ownership with United Energy in Victoria. Most battery energy storage demonstrations in Australia have been implemented by distribution networks and the networks have owned the battery assets. This is the simplest arrangement for network-side energy storage. However, the growth of energy storage may be dominated by residential systems in the near term, which suggests that customer ownership is an important model to consider for network applications.

There are some additional factors that encourage customer ownership:

- Although there may be little difference in technical terms, it appears less invasive when customers, rather than the network, own assets on their premises.

- Networks subsidising part of an asset the customer ultimately owns creates a powerful incentive – customers feel empowered.
- Customers can get paid by networks for access to their energy for network support – another powerful incentive.
- Customer ownership also means that networks have a very low $/kW cost to access that capacity – the customer shares the cost of that capacity.
- The customer is then responsible for the maintenance and upkeep of the system – so there are no ongoing operating costs for networks, aside from payments for access.

Potentially, the customer ownership model can also apply to ‘community’ energy storage facilities that are not located on customer premises but rather at separate grid-connected locations. This leads to the concept of ‘virtual storage’ that is largely a software challenge to fairly allocate storage to consumers and manage billing and settlement accordingly. It appears most attractive where transport costs are free, for example in embedded networks like apartment buildings or campuses. It could also be possible as a cost-sharing exercise between customers and the network business in situations where it is inefficient or impracticable to connect storage on the customer side of the meter, as might be the case in some apartment buildings.

Experience to date with solar PV generation suggests that consumers wish to own the device and value the tangibility of the asset. It remains to be seen whether the same will hold true for battery energy storage.

4.4 MIND THE (POLICY) GAP

Australia’s energy rules were made when the system was different – when coal was king and electricity flows were nearly all one way, from centralised coal generators to consumers. But the system is rapidly changing, with new technology options and increasing numbers of prosumers, who both consume and generate. This has occurred because of a number of factors: the near doubling of electricity prices over the last decade, the dramatic reduction in the cost of solar PV (as described in Section 2.2), and the support policies for rooftop solar. Projects like Networks Renewed need to navigate regulatory and institutional complexity to safely and efficiently deliver the value possible from new energy technologies and business models.

To ‘renew’ our networks we need to both understand this complexity and influence changes where required to make our regulation fit for purpose. This section describes some of the key regulatory and policy influencers for both the technologies and business players involved in Networks Renewed. Further detail on these elements is provided in Appendix F.

Government policy and incentives have played a major role in the expansion of the Australian solar PV market, mainly through feed-in tariff schemes. However, most feed-in tariffs have now been dramatically reduced or removed altogether. Presently, consumers are charged around 25c/kWh for the electricity they consume, whilst they are only paid around 5-7c/kWh for electricity they feed into the grid. Now that the market has matured, it is more pertinent to discuss incentives in terms of how they reflect the true value and benefits of DERs.

Changing technologies have, in the past, created challenges for network businesses, sometimes leading to restrictions on DER deployment. Already ‘caps and curtailment’ have been leveraged by network businesses to maintain network stability in the context of rising solar and storage. For example, in Queensland Energex and Ergon originally restricted exports to the grid from battery storage until they could better understand management and impact implications. While these export constraints have been lifted it is important to consider the way the network businesses will manage the reliability of the distribution network in the future as the uptake of DERs and asynchronous generation continues to increase.

Industry-led work to understand the needs of our evolving electricity market is already underway through the development of Energy Network Australia’s Electricity Network Transformation Roadmap (ENTR). This project is investigating a number of alternative business models and considering a more service-oriented approach to electricity distribution, which is very relevant to the environment for Networks Renewed and the potential business models that can be investigated. In particular, the business models tested in the market-scale demonstration will need to align with the final ring-fencing guideline released by the AER in November 2016. Complementing this, and other regulatory influencers impacting behind-the-meter resources connected by smart inverters, will be the key to Networks Renewed developing a long-term successful value proposition for both consumers and network businesses.

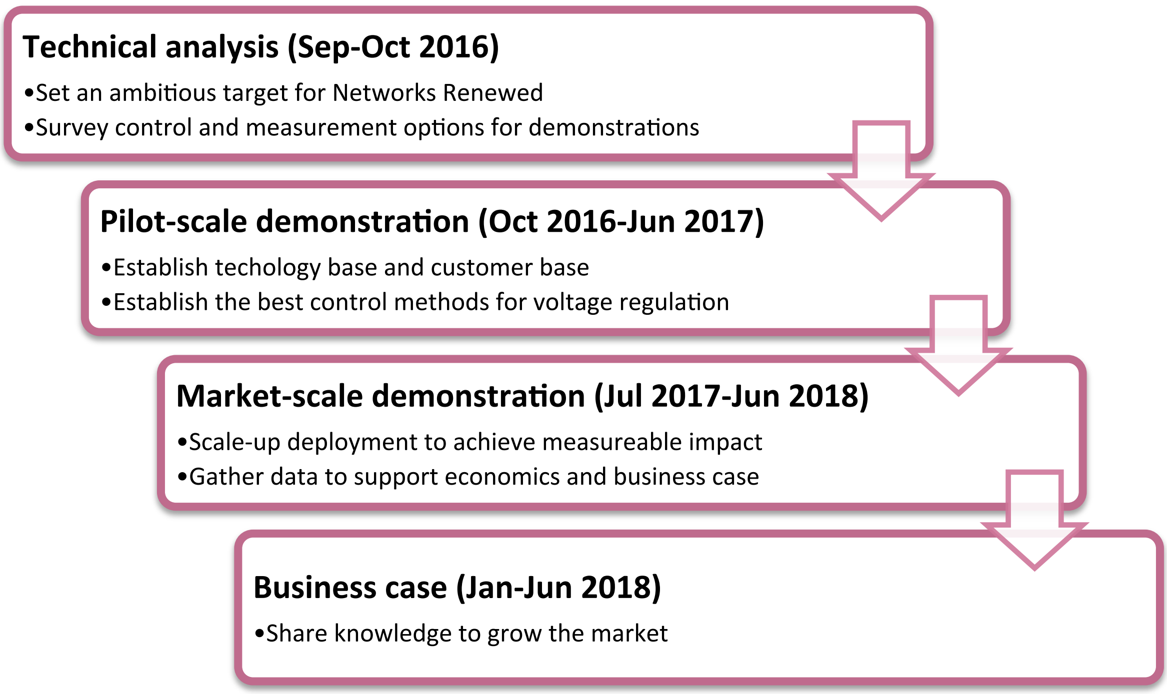
5 THE PATH FORWARD

The first deployment phase of Networks Renewed is in progress through customer engagement at the time of writing. It is a pilot-scale demonstration that will establish customer engagement and deployment processes, and implement potential inverter control algorithms for voltage regulation. This has been described in Section 4.2.1 where the experimental design was explained with a focus on components of the pilot-scale demonstration undertaken by EE in NSW and UE in Victoria.

The path forward will be determined by what is learnt from the pilot-scale demonstration. From July 2017 a market-scale demonstration will ramp up the deployment so that significant network impact can be achieved by June 2018. The demonstrations will deliver market returns, as well as physical network outcomes, to test comprehensive business cases for the project partners.

By disseminating key technical and commercial findings, and assessing options to develop a business case based on services to manage networks with high PV penetrations, Networks Renewed can fulfil its promise of enabling more distribution-connected solar PV generation. The project's progression through demonstration to dissemination is shown in Figure 13.

Figure 13: Overall progression of Networks Renewed



5.1 MARKET-SCALE DEMONSTRATIONS

From July 2017 both network partners will expand the scale of their demonstrations on a semi-commercial basis: that is, they will include some subsidy to reflect anticipated near-term reductions in the cost of battery energy storage, but otherwise they will follow a commercial model that is intended to be scalable and replicable in other networks. UE will increase the number of solar-storage units under its control until there is sufficient network impact to provide a useful voltage correction. EE will increase the total number of inverters under its control to the order of 100, depending on customer appetite for the technology.

An important dimension being tested by Networks Renewed is the ownership model for energy storage to provide voltage regulation services. UE is following a utility-ownership model in which the customer makes a contribution to the cost of storage. The unit is controlled by UE to provide network services, ensuring it remains to the customer's advantage. EE is following a customer-ownership model in which customers purchase energy storage outright, and obtain revenues for providing network services.

Utility ownership of assets on the customer's side of the meter is a pertinent issue in Australia, as discussed in Appendix F, so the UE demonstration is important in showing how this ownership model can be mutually beneficial to customers and networks.

The revenues in the EE model are passed on via another Networks Renewed partner, Reposit Power, that controls distributed customer inverters for both customer and network benefits, in return for network services payments from the network business. This is an untried business model in Australia and is rare worldwide.

The network segments for the market-scale demonstration are yet to be selected, and the number and distribution of customer sites on each segment have not yet been determined. Either the existing pilot-scale demonstrations can be expanded if greater impact is needed to achieve good voltage regulation, or else a broader sampling of network and customer characteristics can be achieved by selecting additional network segments. The UE pilot-scale demonstration includes some 'dispersed' customer sites. The network conditions at these locations, and their potential as market-scale demonstration sites, will be quantified.

5.2 SCALING TO THE FUTURE

Continued growth of solar PV is fairly predictable for the next 10 years, and is illustrated in Appendix B. However the future is unknowable in detail – in particular, it is hard to say how this solar PV capacity will be distributed among network feeders.

Some distribution substations within the UE service area have a total installed solar PV capacity higher than 30% of the distribution substation kVA rating. The PV-only part of the EE pilot-scale demonstration approaches this penetration level, while the rural feeder has a much lower penetration that is nevertheless having a significant voltage impact due to the length of this feeder.

Solar PV penetration may continue to grow to very high levels on some feeders, exceeding the substation kVA rating and raising the possibility of self-supporting feeder mini-grids if suitable control and protection is available. Alternatively, solar PV penetration may reach a generally accepted limit somewhere between, say, 30% and 80% of the substation kVA rating, before connection of additional systems becomes problematic for the network business, even when using new voltage regulation technology like that demonstrated by Networks Renewed. In the latter case, solar PV growth can continue on other network feeders, and the overall growth may be somewhat diminished compared to customer aspirations.

In Networks Renewed both scenarios will be explored by modelling. The experimental plan includes load-flow modelling validated by measurements, as described in Section 4.2.2, which will allow the impact of control strategies to be estimated for a variety of future solar PV penetration levels. The two most important outcomes will be: testing smart inverter control methods at commercial scale; and an increased understanding of the extent to which smart inverter controls can regulate voltage at a variety of solar PV penetration levels on a variety of network feeders.

5.3 WILL THEY BUY IT?

The project concludes with a business case because the growth model for smart inverter controls has to be simple commerciality. The value must be realised for both the customer and for the network business. The market-scale demonstration will be large and comprehensive enough to measure this, with sufficient subsidy from ARENA to anticipate credible near-term technology cost reductions.

This commerciality is, however, linked to a number of non-commercial factors that drive the uptake of solar PV and battery energy storage. Customers have a strong appetite for both. While there are economic benefits, and payback times are particularly good for solar PV and increasingly attractive for batteries, other motivations have been widely studied and are equally important. These include a sense of independence, contributing to reducing greenhouse gas emissions, backup power for important loads, being early adopters of brand new technology, and taking part in the transformation of the electricity industry.

Network businesses also need to adopt the technology. Voltage regulation services need to be cost effective and they need to have an established track record of success, compared to traditional network investments, before network business will procure them. The choice of mechanism for delivery of the voltage regulation services is a secondary issue. The DNSP needs to determine whether to own solar PV and battery inverters that are installed behind customer meters, or to procure services from assets owned by customers. Particularly for energy storage, the value chain can be quite complex, as shown by the range of beneficiaries in Table 5, and the business model may require corresponding complexities to ensure that this value is fairly shared between stakeholders. Ensuring that network businesses can see the benefits, and the value, of smart inverter services compared to other methods, will be a crucial project outcome.

Networks Renewed will explore, through market-scale demonstration, the ambitions of both customers and network businesses to participate in new business models built around network services and specifically voltage regulation. The final project deliverable will be a report on key factors driving commercial performance. These factors will be both observed in the market-scale demonstration, and extrapolated to the near-term conditions in Australia. This report will be delivered in the context of comprehensive technical reports about the demonstration that will be of interest to network businesses and technology vendors seeking to learn about the opportunities provided by distributed voltage regulation. The project’s real impact will be achieved through effectively disseminating information about cost-effective and practical solutions to voltage regulation in a solar world.

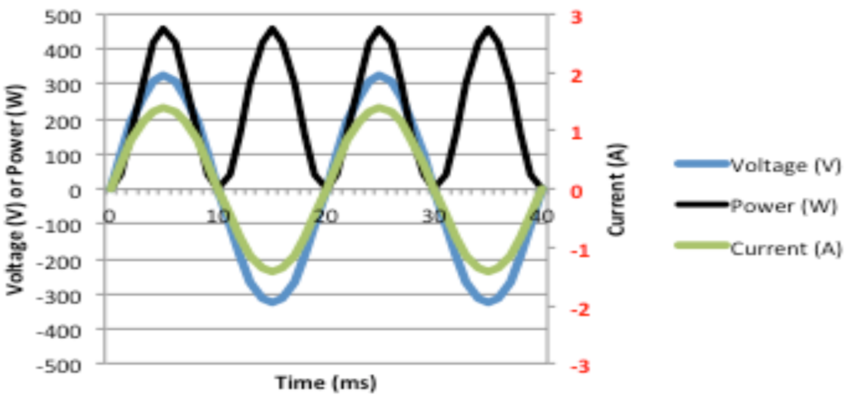
APPENDICES

A: WHAT IS REACTIVE POWER?

Ever since Nicolai Tesla fathered the modern electrical distribution system we have used Alternating Current (AC) for our electrical needs. Alternating current means the current and voltage flowing through the lines alternates forwards and backwards (positive and negative). In Australia this happens at a rate of 50 cycles per second (or 50 Hz).

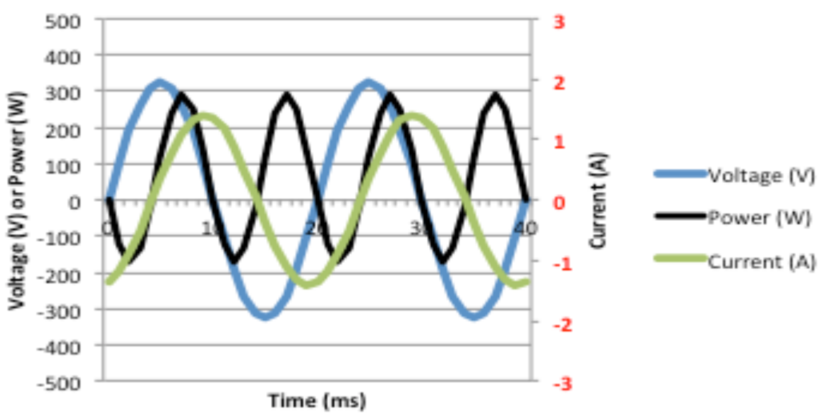
Simple appliances that use electricity, like a light globe or heater, resist the flow of electricity. The alternating voltage pushes the current through the resistance and as a result energy is used and work is done, for example through heating up the heating element. Because the voltage is alternating, in the first half of the cycle it pushes the current in one direction, it then drops to zero, and then alternates to the other direction, pushing current in the other way. As the voltage goes up, the current goes up, as the voltage goes down, the current goes down. When current and voltage mirror each other in this way, they are said to be *in phase* and this is illustrated in Figure 14 which shows voltage, current and instantaneous power for two AC cycles (40 milliseconds for 50 Hz AC). When an appliance uses power in this way, electrical engineers call it *real power (P)*.

Figure 14: Real power flow with voltage and current in phase (PF = 1)



Unfortunately, most appliances are not that simple; their circuits store a small amount of energy each cycle. Electric motors of all sizes, from washing machines to large factories, are a prime example and even fluorescent lights behave this way. As the voltage starts to decrease, the current continues to flow. Even when the voltage is zero and enters the negative part of the cycle, there is still current flowing. This can be seen in Figure 15 in which current is sometimes flowing in the opposite direction to the supplied voltage because the appliance is pushing some of the stored energy back out again.

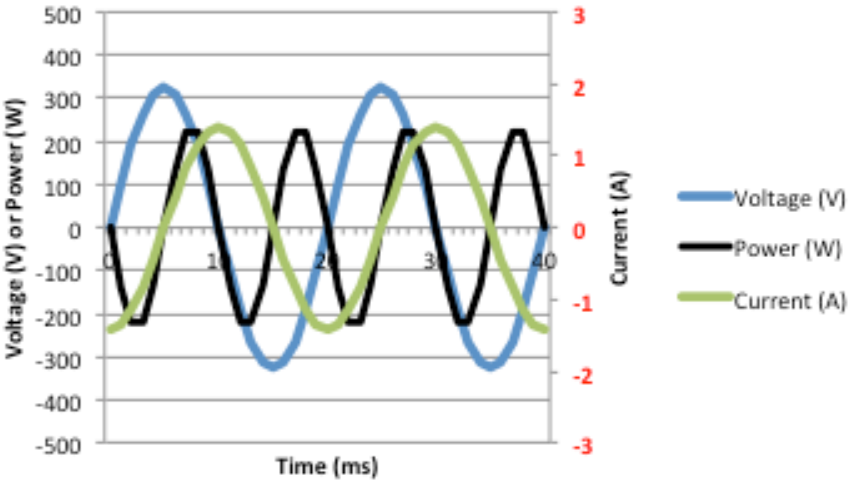
Figure 15: Some reactive power with voltage leading current by 75° (PF = 0.26)



In the worst case, the current is highest when voltage is zero, and current is zero when voltage is at its peak. In this situation they are said to be *out of phase*. An appliance like this uses only *imaginary power,* also called *reactive power (Q)*. Why imaginary? Electrons slosh back and forth 50 times a second but never actually do any useful work. This is the case in Figure 16 where the instantaneous power goes forwards (positive) as much as it goes backwards (negative) so that there is no average power flow.

If you were able to look at the current flowing through your lines you would see the combined current flow of the reactive (Q) and real (P) power. This combination of P and Q power is called *apparent power (S)*.

Figure 16: Reactive power only with voltage leading current by 90° (PF = 0)



B: AUSTRALIAN SOLAR TRENDS

For the purposes of understanding the impact of distributed energy resources on networks, the scope of this report is largely restricted to residential and commercial and industrial (C&I) installations. Utility scale solar is referenced where relevant for the purpose of comparison.

The Australian solar market

Historic trends in annual Australian solar PV installations between 2007 and 2015 for primary customer groups is shown in Figure 17. The total cumulative installed capacity for the same time period is shown in Figure 18. Australia reached 5GW of installed solar at the end of 2015, and in June 2016 was at over 5.3 GW.[6]

Figure 17: Annual PV installations by sector

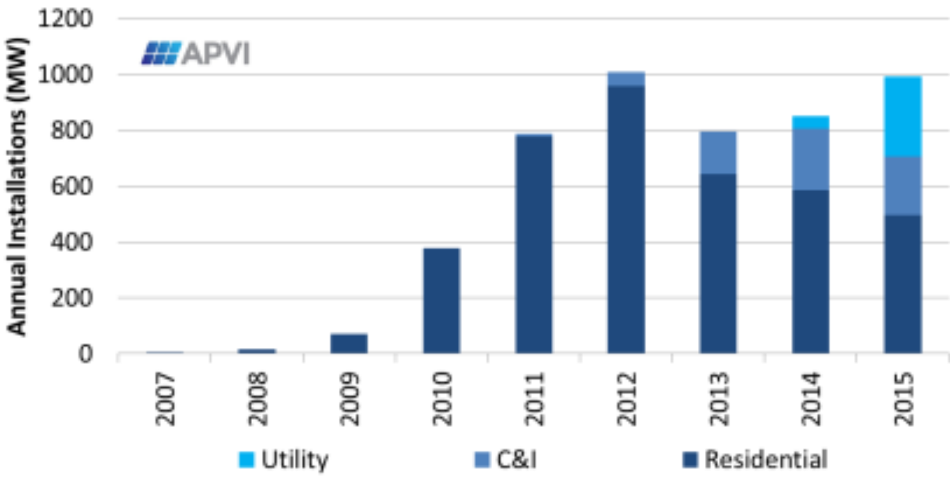
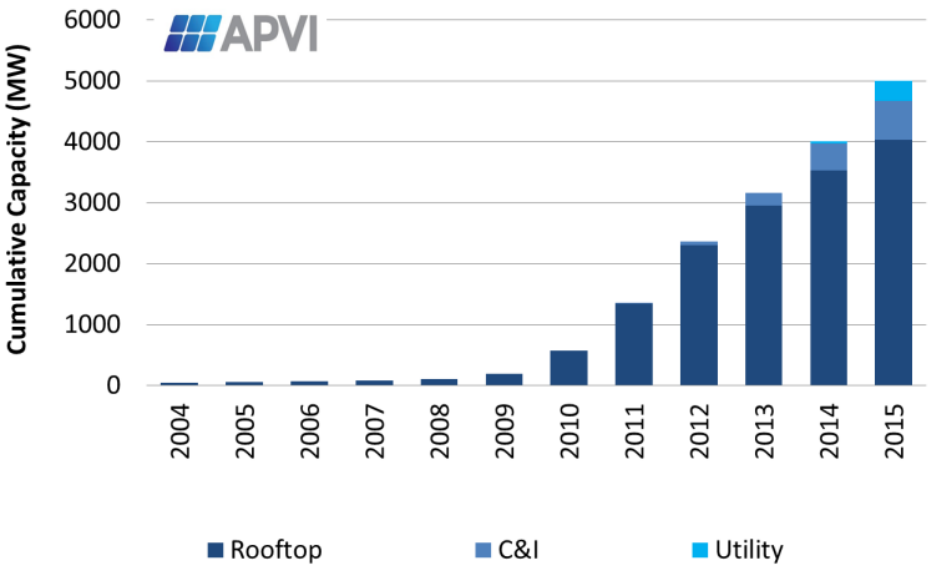


Figure 18: Total Installed PV capacity by sector



[6] APVI, *Solar PV Maps and Tools*, 2016 available at http://pv-map.apvi.org.au/ (accessed 1 January 2016)

The Australian solar market is unique internationally in that it has been predominantly driven by residential uptake.

As a result of some early government initiatives that delivered attractive feed-in tariffs to early adopters, the residential market escalated from a low base of around 15 MW/annum in 2008 and increased fourfold each year to peak at 958 MW in 2012. By the end of 2012, many governments had removed the generous feed-in tariff programs, leading to a boom in installations in 2012 and a significant retraction in 2013.

Over that time period, the cost of installed solar declined, largely due to competitive pressures in the hardware supply chain. In 2012, Levelised Cost of Energy (LCOE) from installed solar reached grid parity in Australia, with the LCOE of installed solar competing with residential grid electricity at 20c/kWh.[7]

Since 2013, there has remained a sustained market in residential solar, dropping marginally year on year to around 500 MW/annum in 2015. It is worth noting, however, that the small decline in total installed capacity at the residential level masks a more significant drop in the number of systems installed. The annual installed capacity remains robust because the average system size has been increasing consistently, from 3.5 kW at the end of 2012, to 5.5 kW by the end of 2015.[8]

As a result of this growth, Australia set some international benchmarks in 2015:

- With installed price of AUD 2.30/W (USD 1.60), Australia has the lowest installed costs for residential solar in the world.
- With over 1.5 million residential rooftops, Australia has the largest single installed base of residential solar in the world.

With further reductions in the price of hardware and new technology offerings, there is an expectation that the residential installations will recover, or at least not decline further. Customers who initially took advantage of the feed-in tariffs were early technology adopters. Surveys indicate that these customers are still highly engaged and are now interested in upgrading their solar investment and/or investing in new technologies such as those offered through Networks Renewed.

Solar growth potential in Australia

The Australian PV Institute (APVI) projections for PV growth in Australia are based on historical trends and market information. An accelerated uptake projection would require one or more of the following to occur (low expectation in the near term):

- policies to promote distributed generation, for example net feed-in-tariff arrangements, carbon pricing, accelerated decommissioning of high carbon intensive energy generation.
- a drop in the Australian dollar (presently 1 AUD = 0.75 USD is assumed).

The following are taken into consideration:

- Announced utility scale solar plant commitments.
- There will be a drop in hardware price in/around 2017 as manufacturing moves to an over-supply situation again.

[7] Muriel Watt, *PV Grid Parity & Implications for Electricity Systems*, 2012
[8] Warwick Johnston and Renate Egan, *National Survey Report of PV Power Applications in Australia*, 2015, p. 44

- Rooftop solar pricing is very competitive and not expected to see significant reductions in soft costs in the Australian market for Residential – some improvements may be expected for commercial as the market matures and contracting becomes more efficient.
- Total national electricity demand is expected to stay flat at 248-150 GWH out to 2030, consistent with AEMO projections.[9]
- National solar PV projections.

National projections are provided by customer segment (Residential, C&I and Utility) in Figure 19 and Figure 20.

Figure 19: National annual PV installations by sector (MW)

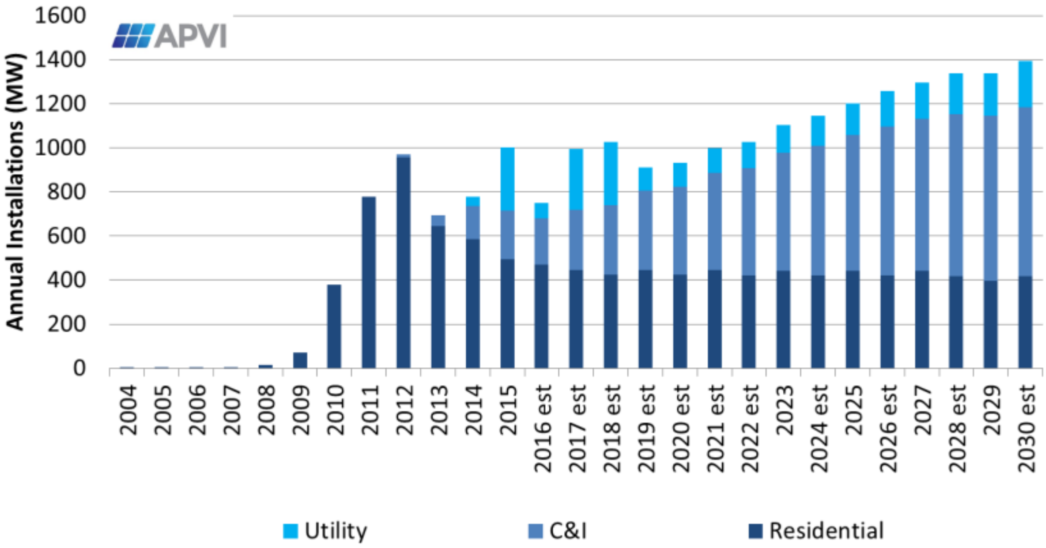
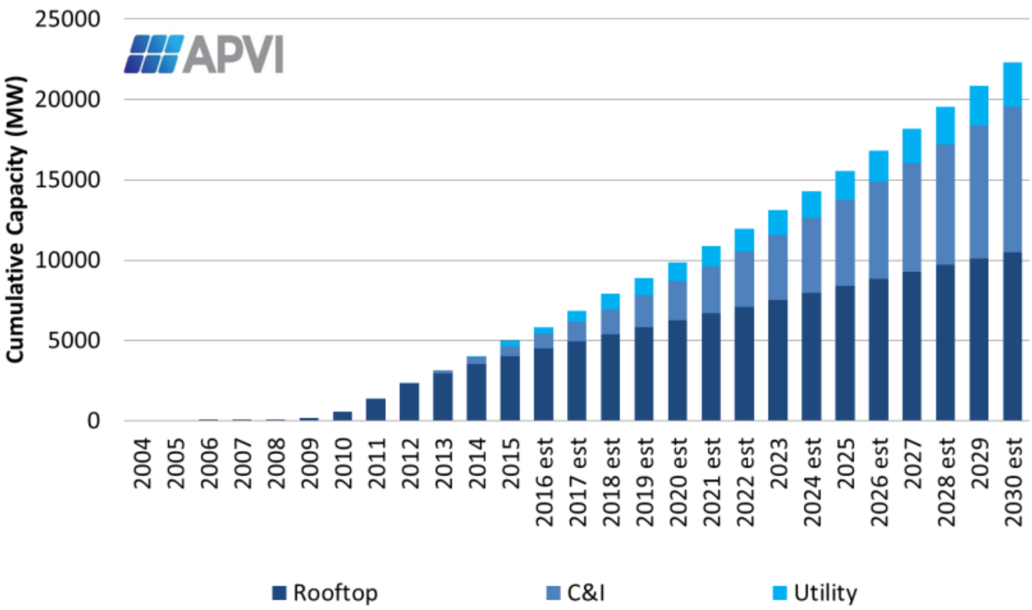


Figure 20: National total installed PV capacity (MW)



[9] AEMO, *National Electricity Forecasting Report Overview*, 2016 <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/-/media/080A47DA86C04BE0AF93812A548F722E.ashx>).

National average penetration is forecast to reach 52% by 2030 under business as usual, with 10.5 GW of rooftop solar installed and the commercial solar market grown to closely match that growth. That is, the majority of solar PV will continue to be connected behind the meter to Australian distribution networks.

AEMO econometric models predict saturation levels based on PV system cost trends and electricity prices. Saturation levels are based on 3.5kW per roof for 75% of suitable dwellings. Solar PV prices are set at $3/W in 2013 and decrease at 5% per year.

Table 6: National forecast solar PV penetration including Residential, C&I and Utility

Total Installed Capacity (MW)	2005 actual	2010 actual	2015 actual	2020	2025	2030	2035
APVI (BAU)	**61**	**571**	**5,109**	**9,778**	**15,120**	**20,869**	
AEMO [AEMO 2012]						**12,000(med)** **18,000(hi)**	
AEMO [AEMO 2016]							**20,000**
APVI [Watt 2012]			**5,000**	**8,000**			

Solar PV projections by state

While Australia is setting new benchmarks nationally in solar PV penetration, with 20% of households on average and over 1.5 million installed systems, the story is even more interesting at the state level. System size and total uptake differ widely across Australia, reflecting historical incentives, sunlight hours per annum (insolation) and market maturity. For detail on insolation, see Appendix B.

The total installed capacity in kW as at the end of June 2016, and percentages of dwellings with a PV system split by state and territory, are shown in Figure 21 and Figure 22 and split by system size in Table 7. Of note:

- Queensland continues to dominate total installed capacity with close to 1.6GW installed or 33% of the national capacity, with NSW second with 1.3GW (20%).
- NSW has significantly more commercial solar installations (i.e. >100kW) than any other state.
- Queensland leads on residential solar uptake, with a statewide average of 30.3% of dwellings in the state, with SA close behind at 29.4%.

Figure 21: Total installed capacity in kW as at end June 2016 by state[10]

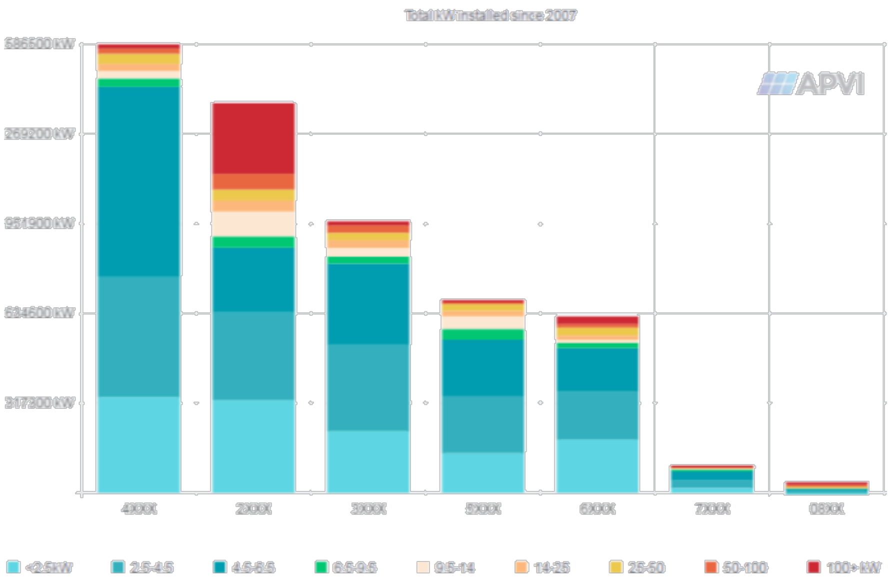


Figure 22: Percentage of dwellings with PV in June 2016 by state (APVI).

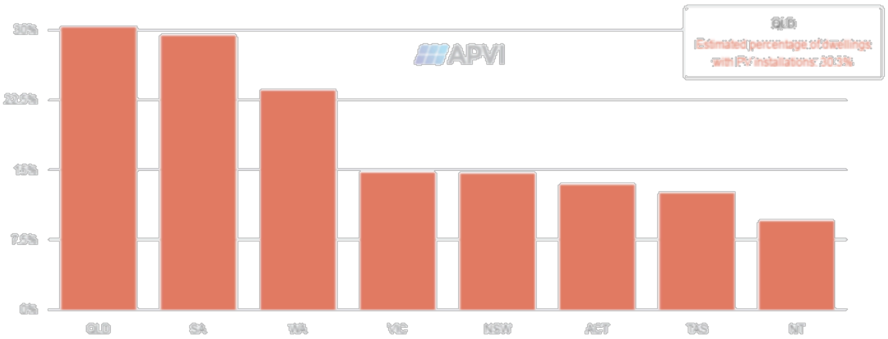


Table 7: Total installed capacity and percentage dwellings by state (APVI).

State	QLD	SA	WA	VIC	NSW	ACT	TAS	NT
Installations	**484,316**	199,198	207,596	293,400	342,303	17,023	27,450	5,927
Dwellings	**30.3%**	**29.4%**	23.5%	14.7%	14.6%	13.4%	12.5%	9.5%
Total capacity (MW)	**1,585**	682	622	957	1,300	75	96	39
MW_capacity under_10_kW	**1,468**	588	530	835	885	47.1	84.7	21.6

[10] APVI, Solar PV Maps and Tools, 2016 available at http://pv-map.apvi.org.au/ (accessed 1 January 2016.

MW_capacity 10_to_100_kW	106.6	92.5	68.8	109.4	**196.6**	6.3	11.7	9.9
MW_capacity over_100_kW	11	2	23.7	12.3	**219.4**	22.1	0.2	7.6
Count under_10_kW	479,302	193,614	204,777	288,007	332,630	16,701	26,719	5,601
Count 10_100_kW	4,999	5,577	2,802	5,365	**9,642**	313	730	310
Count over_100_kW	15	7	17	28	31	9	1	16

Historic trends show that the installation rate has stabilised in each state (noting that the near-term data (early 2016) is incomplete as systems take up to 6 months to be registered).

Uptake, shown by percentage of available dwellings continues to climb, even for Queensland and SA that have reached a statewide average of 30%. Some areas of Queensland and SA are forecast to be the first to reach saturation levels for residential rooftop PV in about 2030. Parts of Victoria are projected to follow three years later, with Tasmania following in 2035–36.

Table 8: Projections of percentages of dwellings with PV by state (APVI).

%	2015	2020	2025	2030
QLD	30.3	35	41	47
SA	29.4	34	39	45
WA	23.5	35	40	46
VIC	14.7	26	31	36
NSW	14.6	25	29	34
ACT	13.4	24	27	32
TAS	12.5	23	26	30
NT	9.5	27	32	37
National Average	19.5	28.6	33.2	38.4

Uptake of battery energy storage

The cost of PV also impacts the uptake of battery systems. Storage generally makes sense for customers only when combined with solar PV generation. As government incentives for PV decrease, customers will be looking to the market to recoup some of those savings.

The storage market is maturing and competition is increasing with more and more hardware manufacturers entering the race to make the cheapest, most attractive systems for customers. For residential products, costs are decreasing and economies of scale are increasing. The resulting price reductions are driving uptake of the technology.

The 5th Council of Australian Governments (COAG) Energy Council meeting in August 2016 heard that it may be 10–20 years before battery storage will be able to exert an influence on grid stability and support.[11] 'It was a remarkably conservative and pessimistic view of a technology that is showing a trend of rapid cost falls,' responded the ACT Climate Change and Energy Minister, Simon Corbell, echoing a wider view that battery energy storage now has a highly competitive market that is expected to grow rapidly in the short term. Less than two months later, when energy ministers met again to discuss implications of the statewide blackout in South Australia on 28 September 2016, they may not have realised that a number of residential battery systems were present and responded correctly on that day when the rapid drop of grid frequency signalled the onset of system blackout.[12] Had they been present in large numbers on the SA distribution network, it is possible that their rapid response would have made a crucial difference and averted the blackout.

Energy storage has the potential to play a key role in future energy infrastructure. Technological advancements and ongoing price reductions in energy storage technologies present an opportunity to harness the technology for the benefit of the electricity network. Utilities are able to use the technology to defer augmentation projects, as well as stabilise grid voltages through behind-the-meter installations of solar PV systems and energy storage devices within residential customer premises.

Battery energy storage is anticipated to grow rapidly at residential scale across Australia. The time frame presented to COAG was probably based on the statement in a recent CSIRO report[13] to the AEMC that compared the costs of batteries with the costs of gas peaking plants in the context of resolving potential gaps in peaking capacity i.e. to provide load-following services in some NEM states by 2035. That is one application of batteries. The same report projected that baseline costs of mature, advanced lead acid and Lithium-ion (Li-ion) battery technologies will decline by 53% by 2025 and by 68% by 2035. For baseline battery costs and large residential customers, the report estimated that payback periods for newly installed storage and solar PV systems on a flat tariff will decline from 9–12 years in 2015 to 4–6 years by 2035 in most NEM states. These are indicators of rapid growth in the number of residential battery systems connected to distribution networks.

Early on, market uptake will be led by projects that subsidise the cost of storage for customers, such as Networks Renewed. This helps to reduce the financial barriers that would otherwise make the technology cost prohibitive and improve customer familiarity with the technology. However, vendors are already starting to see a shift toward self-driven markets without subsidy, which indicates that the market is maturing.

[11] Giles Parkinson, Corbell Slams AEMO's "conservative" View on Battery Storage, *RenewEconomy*, 2016
[12] Reposit Power, personal communication, October 2016
[13] T.S. Brinsmead et al., *Future Energy Storage Trends: An Assessment of the Economic Viability, Potential Uptake and Impacts of Electrical Energy Storage on the NEM 2015–2035*, CSIRO, 2015.

C: WHAT ARE INVERTERS?

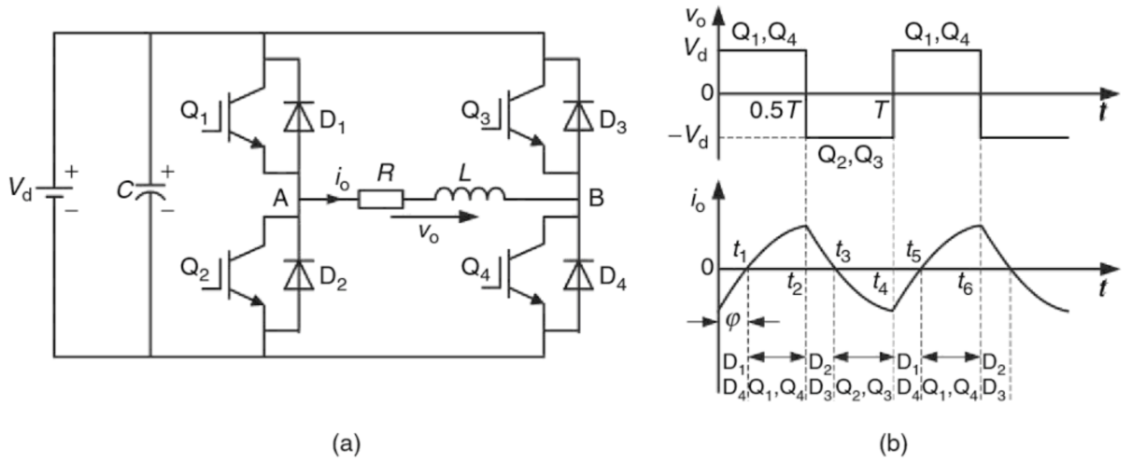
An inverter is a power electronics device that produces AC output from DC input. In other words, inverters are the devices that convert solar or battery-generated electricity into the same language of our national electricity distribution network.

Most electrical power systems are supplied with power by large rotating machines that maintain frequency through their speed of rotation and their large inertia. Hydropower turbines, steam turbines, and large gas turbines are connected by a shaft to generator windings, and their output frequency is equal to the speed of rotation multiplied by the number of windings. They are called ‘synchronous’ generators for this reason. Their speeds are locked together by the three-phase AC[14] transmission network that behaves very much like an enormous rotating shaft, and their combined mass creates the ‘system inertia’ which is a terrific force to keep the grid frequency stable. A power system dominated by fossil fuel, hydro, and nuclear generation behaves like a single mechanical system.

In contrast, most forms of renewable energy and energy storage produce either DC[15] output like solar PV generators, or AC output like wind turbines with variable frequency that cannot be directly coupled to the grid frequency. These are called ‘asynchronous’ generators and they connect to the grid using power electronic inverters. Solar PV systems and batteries behave as voltage sources for inverter switching circuits that produce an approximation to a sinusoidal output current.

An illustrative inverter circuit using four semiconductor switches is shown in Figure 23. Switching combinations apply the DC voltage source to the load in different directions and the resulting waveform is smoothed by a capacitor. Inverters can use more rapid switching with pulse-width modulation to provide more detailed control over the output waveform. An unsmoothed waveform of this kind is shown in Figure 24.

Figure 23: A basic inverter circuit (a) supplying a load R and its output (b) voltage and current waveforms[16]



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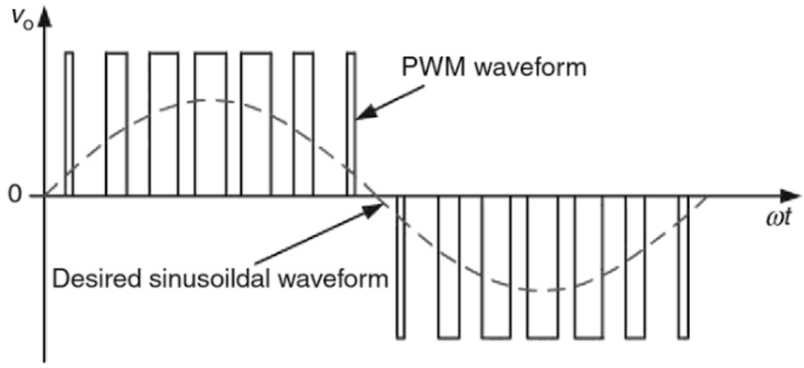
[14] Alternating Current (AC) is the predominant mode of electricity transmission in distribution networks because transformers can be used to step voltage up and down as required

[15] Direct Current (DC) is the mode of electricity flow at the terminals of solar PV panels and batteries, with electrons moving consistently in the same direction, prior to conversion to AC by an inverter.

[16] http://store.elsevier.com/Electric-Renewable-Energy-Systems/Muhammad-Rashid/isbn-9780128044483/

Figure 24: Unsmoothed voltage waveform of a pulse-width-modulated (PWM) inverter



Inverters are designed to lock onto an existing grid frequency and synchronise with it. It is possible for an inverter to define the grid frequency through its programmed output, serving as the frequency reference, and this can be done in an island or remote power system or in an isolated mini-grid. This facility is not used for grid-connected inverters because synchronous generation still dominates large power systems – but this may change in the near future.

Solar PV and battery energy storage inverters

Solar PV inverters can program their output voltage and current waveforms to have a wide range of real and reactive power characteristics. They are called 'two-quadrant' inverters because, on a graph of reactive power Q against real power P, the inverter output (P,Q) can occupy only the top of the graph because P is positive or out of the generator. Within this constraint, both leading and lagging power factors can be achieved for voltage regulation.

A special requirement of solar PV inverters is maximum power point tracking (MPPT) which follows the DC voltage versus current characteristic of the PV panels as operating conditions change to maximise the power flow into the inverter.

Battery energy storage inverters are identical to solar PV inverters in almost all respects, but they can have an additional level of functionality. Advanced battery inverters are called 'four-quadrant' inverters if they can provide reactive power when charging and discharging the battery, that is, for both positive and negative real power. Thus, energy storage can be used to address the voltage rise issues caused by the export of PV on the LV distribution network in one of two ways: passive voltage regulation and active voltage regulation.

Passive voltage regulation uses energy storage to absorb excess PV generation and thereby prevent export into the network during times of light load and high solar output. Passive voltage regulation prevents the voltage rise problem from getting worse, however it is limited by the available energy storage capacity.

Active voltage regulation, on the other hand, uses four-quadrant inverters to control the batteries to sink and source both real and reactive power to the network in order to regulate voltages at the point of connection, in response to line conditions. If network voltages are high, active voltage regulation can be used to add load to the network by charging the batteries from the grid and increase voltage drop due to line resistance. Active voltage regulation can also be used to modify the reactive power content and increase the voltage drop. Both strategies will lower the voltage at the connection point and their relative effectiveness depends on the X/R ratio of the cables and components. This also works conversely where active voltage regulation can increase the voltage at the connection point if the network voltages are low.

Nearly all battery inverters now being installed are capable of connecting solar PV as well, in a so-called 'DC-coupled' arrangement in which both solar PV and batteries connect to the DC side of the same inverter. This is cost effective and also more technically efficient than using separate inverters for solar PV and batteries. However, retrofitting batteries in a customer energy system that already includes solar PV generation will require a separate inverter unless such customers elect to change their solar PV inverters at the same time to produce a better integrated system. It is likely that many customers who install batteries will take this opportunity to replace their existing solar inverters with a DC-coupled option to benefit from the newer technology and, perhaps, to expand their solar PV capacity.

The essential anti-islanding requirement

Grid-connected inverters for solar PV and batteries have always had to fulfil basic requirements of network security and personal safety, in order to gain connection approval under any country's electricity network standards or 'grid codes'. They must convert DC electricity to AC at a voltage, frequency, and phase that matches the network so that the network connection is functional and does not create disturbance or damage the device being connected.

Another primary requirement is to disconnect from the network when the network fails (and failure is determined by network frequency or voltage being outside defined ranges). This is called the 'anti-islanding' requirement because if local generators continue to output power they may support part of the network in an uncontrolled way. The anti-islanding requirement is important for the safety of network personnel or members of the general public who may work on or encounter fallen electricity cables – such cables should not be energised by local generation sources as this would create a risk of electrocution or fire.

A consequence not appreciated by many customers is that having their own solar PV generation or energy storage does not mean they will have an electricity supply during a blackout. Unless special backup-power features are installed, potentially for critical circuits rather than general appliances, the usual situation is that solar PV and batteries will automatically disconnect from the network and the customer during a blackout.

D: RELATED PROJECTS

It is essential to consider related experiences of smart inverter testing worldwide prior to undertaking a large-scale demonstration in Australia. Reviewing previous and current industry projects will allow us to both learn from their successes or failures, and to ensure Networks Renewed provides a meaningful addition to the international knowledge base. Four recent investigations into voltage regulation through reactive power are reviewed in brief below.

Managing distributed generation in Germany

Many of the advances in inverter technology for connecting customer solar PV have been driven by the demanding German environment with its expansive solar policies. Responding to high levels of distributed PV penetration, Germany has introduced new requirements for its distribution grids and these have required smart inverter capabilities to be available. As a result the market for smart inverters received a significant stimulus which has improved their availability worldwide. The new requirements include[17]:

- Retrofitting of existing PV systems larger than 10kW with watt-frequency curtailment capability. This reduces the output of systems when frequencies exceed the grid's 50.2 Hz limit.
- All new PV systems must provide under-frequency ride-through.
- Systems above 3.68 kW must provide reactive power support and subtract reactive power when output exceeds 50% of their capacity.

Such requirements have allowed up to 40 per cent more solar capacity within a single network feeder.[18] The third requirement provides an important precedent showing the effectiveness of reactive power control by solar PV inverters in managing network voltage.

Hawaiian inverter requirements

As of 2015, 15 per cent of Hawaii's installed capacity comes from solar power, and 97 per cent of that solar is residential. To manage this penetration of distributed generation, the main grid utility, the Hawaiian Electric Company (HECO), worked with equipment suppliers and installers to develop new standards[19] and introduced mandatory capabilities for all newly installed inverters in 2015.

Voltage. HECO's normal voltage is between 85 and 113 per cent of nominal voltage. At voltages between 113 and 120 per cent, inverters remain connected. However, if voltage stays within that range for 0.9 seconds, or if it exceeds 120 per cent, the inverter will stop producing power and wait 5 minutes for the grid to return to the acceptable range. If voltage stays between 85 and 50 per cent of nominal for 5 seconds, or if the voltage drops below 50 per cent for over 0.07 seconds, the inverter will again stop producing and wait 5 minutes for the grid to return to its normal range.

Frequency. The HECO grid's normal frequency range is between 57 and 62.5 Hz and, as with voltage, inverters must ride through short periods outside this range. If frequency rises above 62.5 Hz, inverters must stop producing and wait 5 minutes for the grid to return to normal before returning to operation.

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[17] Ben York and Nadav Enbar, 'Utilities Tackle Smart Inverter Deployment', *Solar Industry*, June 2016
[18] 'How Solar Inverters Can Stabilize the Grid - Above Zero Energy', *Abovezeroenergy*, 2015
[19] Justin Dyke, 'Hawaiian Grid Requirements Explained: Interim Ride through', 2015

Coordinated DER testing in San José, California[20]

In July 2016 a pilot project was announced between General Electric (GE), Californian utility Pacific Gas and Electric (PG&E), microinverter makers Enphase, and rooftop solar vendor SolarCity to demonstrate the coordinated use of smart inverters and distributed storage for grid support. This pilot project emerged after a proposal by the California Independent System Operator (CAISO) to allow DER providers to exist as a new form of grid market player, allowing them to participate in demand response as other utilities do.

Using a distributed energy resource management system (DERMS) provided by GE, PG&E will monitor and control distributed energy resources (DERs) in up to 150 homes and 20 commercial premises.

Beginning in September 2016, the pilot will undertake three demonstration projects located on two PG&E feeders in San Jose. The first two projects will focus on demonstrating aggregated control of DERs for dispatch. The third project will test the DERMS platform with the aim of demonstrating voltage and reactive power support and dynamic capacity.[21]

Ergon's Virtual Power Station

CSIRO has recently developed Virtual Power Station (VPS) technology, which links distributed energy resources like rooftop solar and batteries to provide electricity as a single steady supply. The VPS overcomes the limitations caused by solar PV’s intermittency and is capable of immediate dispatch to match electricity demand on the network.

With $850,000 of ARENA funding, CSIRO has now partnered with Selectronic, SMA, Tritium, University of Newcastle, Lend Lease and Ergon Energy to undertake the Virtual Power Station 2 (VPS2) project. The VPS2 project, which builds on CSIRO’s pilot scale 20 site VPS demonstration in 2011, will demonstrate centralised coordination of demand loads, generation and storage across 50 to 100 sites. The project aims to provide a way of matching supply from distributed energy resources to household demand, and to develop a means of sharing economic benefits between a broad range of stakeholders, including electricity customers, distributors and the community.

Essential Energy’s Grid Interactive Inverter Program

The Grid Interactive Inverter program has been undertaken over several years under the Demand Management Innovation Allowance to evaluate the many benefits available from four-quadrant inverter technology.

A partnership was established with an Australian manufacturer and prototype four-quadrant 20 kVA inverters were produced and installed in February 2010. A test site was established in Queanbeyan, adjacent to the Essential Energy Research and Demonstration Centre and an existing solar array. This was followed by installation of two three-phase 20 kVA STATCOMs in the Bega area in February 2012. Field trials began in January 2012 following early commissioning tests and replacement of the original prototype units at Queanbeyan. Stable operation was achieved at both sites with significant improvement in voltage characteristics.

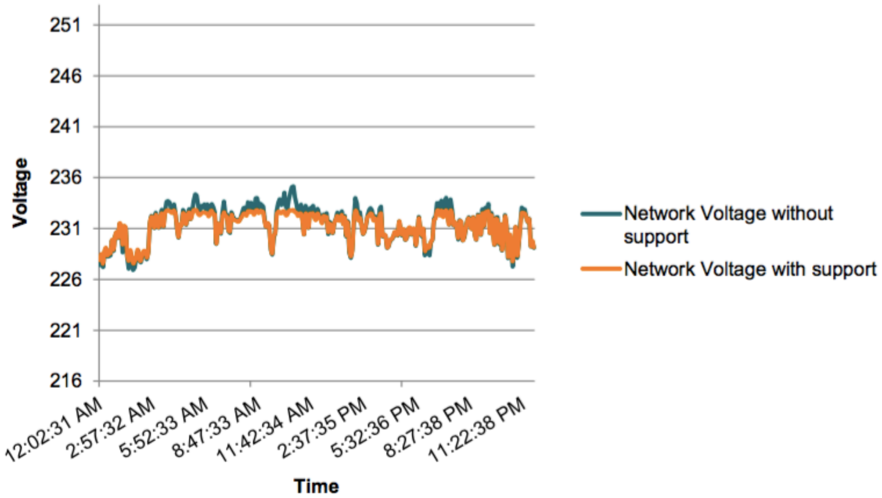
Opportunities were recognised to use consumers’ own equipment to provide reactive support, with a smaller unit capacity, and achieve cost reductions through higher production volumes. This has the added benefit of providing greater distribution of the support. Consequently, a number of four-quadrant 5 kVA inverters were produced and a test site was established at the Clearwater Zone Substation in Port Macquarie to perform longevity

[20] Jeff St. John, ‘PG&E to Plug Enphase Smart Inverters and SolarCity Storage Systems Into Its Grid Control Platform’, *Greentech Media*, 2016
[21] Herman K. Trabish, ‘Connecting the Dots: PG&E DERMs Pilot Aims to Manage Multiple Aggregator Platforms’, *Utility Dive*, 2016

and functionality tests. It is evident from Figure 25 that this site performed almost faultlessly with no known issues other than those raised during the initial testing.

During the initial stages of this program there was no similar low cost, commercially available technology for low power, low voltage or single phase systems. However, semi-commercialised products have subsequently become available and these are continually assessed against the existing product to ensure the most efficient outcomes of the program. The utilisation of four-quadrant inverters as a generic supply quality improvement technology on Essential Energy's distribution network may include development of incentive schemes to leverage spare network support capacity from suitable renewable energy connection equipment.

Figure 25: Voltage regulation effect of 5 kVA inverter at a Port Macquarie test site



The main difference between EE's Grid Interactive program and the Networks Renewed project is around distributed support from such technology, in particular, from customer side inverters/STATCOMS integrated with renewables through an open market approach.

E: ADVANCED CONTROL REVIEW

There is a large amount of literature about methods for voltage regulation using reactive power at customer nodes on a network. These publications are generally not linked to demonstrations, so their practical value hasn't been verified by application. However, they are valuable for exploring the range of potential control methods to create a 'menu' of candidate methods that may be considered for Networks Renewed. The four publications highlighted below have been selected on the basis of citations in the engineering literature and can be regarded as landmark papers. The recent review paper by Mahmud and Zahedi (2016)[22] can be consulted for a wider set of control methods.

Coordinated active power-dependent voltage regulation

The method of voltage control put forward by Samadi et al. (2014)[23] enhances a method proposed by the German Grid Code (GGC). The GGC method employs a generic Q(P) curve across all PV inverters to support regulation of reactive power as a means to control the voltage profile throughout the grid. This method does not consider the location of individual inverters and it can therefore cause unnecessary consumption of reactive power, as well as creating potential instability in the system where local conditions are not consistent with the generic Q(P) curve used.

The method in this study is enhanced by a coordinated approach to calculating the Q(P) characteristics at each PV system using local information and a voltage sensitivity matrix. Each matrix is constructed of submatrices that are derived from partial derivatives of power-flow equations. These submatrices relate local voltage magnitude (|V|) and phase angle (θ) to active and reactive power. Each submatrix element is an interpretation of the potential voltage variation at a Bus *i* with a change in the active or reactive power at Bus *j.* As this calculation method only relies on local data, no communication between PV systems is necessary.

The study investigated two methods of active power-dependent (APD) voltage control: target bus (TB) voltage regulation and voltage profile (VP) regulation whose control parameters, slope factor (*m*) and active power threshold (P_{th}) are derived from voltage sensitivity matrix. Slope factor is derived differently for each method.

In the APD-TB method, reactive power is regulated at each node such that voltage variation at the target-bus remains at zero. The APD-VP method, on the other hand, employs weighting factors that identify the importance of voltage regulation at a given bus location compared to other buses. This weighting factor is derived as a function of local voltage magnitude sensitivity indices, which are elements of the local sensitivity matrix.

The authors carried out a complex system grid simulation to test their proposed control methods. The grid consisted of 35 houses and 24 unevenly distributed PV systems (69% solar PV penetration by number of customers). The grid configuration and the distribution of PV systems can be seen in Figure 26.

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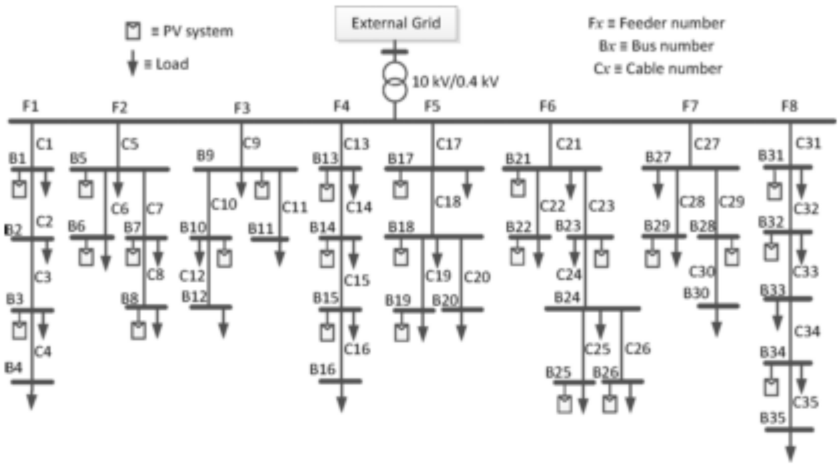
[22] Nasif Mahmud and A. Zahedi, Review of control strategies for voltage regulation of the smart distribution network with high penetration of renewable distributed generation, *Renewable and Sustainable Energy Reviews*, 64 (2016), 582–595.

[23] Afshin Samadi, Ebrahim Shayesteh, Robert Eriksson, Barry Rawn and Lennart Söder, Coordinated Active Power-Dependent Voltage Regulation in Distribution Grid With PV Systems, *Renewable Energy*, 71 (2014), 315–23

Figure 26: Simulated grid by Samadi et al. (2014)



LOCATION AND NAMEPLATE POWER OF PVS IN THE COMPLEX GRID

PV system nameplate power	Bus number of installed PV
15 kW	B13, B26, B31
20 kW	B6, B8, B10, B16, B21, B23, B29, B34
25 kW	B3, B5, B7, B9, B15, B17, B18, B26, B28
30 kW	B1, B19, B32

In the simulation, both of the proposed methods successfully regulated voltage within the designated limits. Additionally, the simulation showed that voltage regulation was achievable with greatly reduced reactive power consumption when compared to the standard method proposed by the GGC. Figure 277 and Figure 28 show these results.

Figure 27: Impact of control strategy on voltage in Samadi et al. (2014)

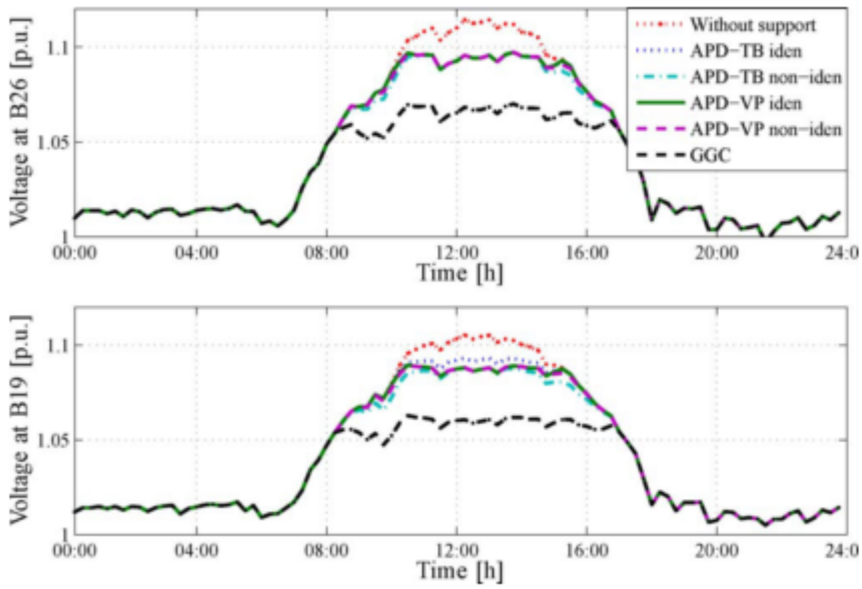
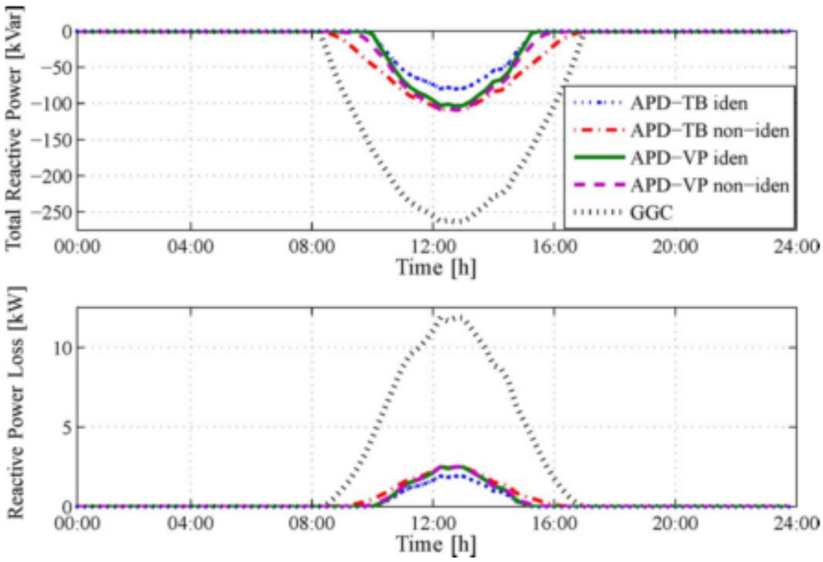


Figure 28: Impact of control strategy on reactive power in Samadi et al. (2014)

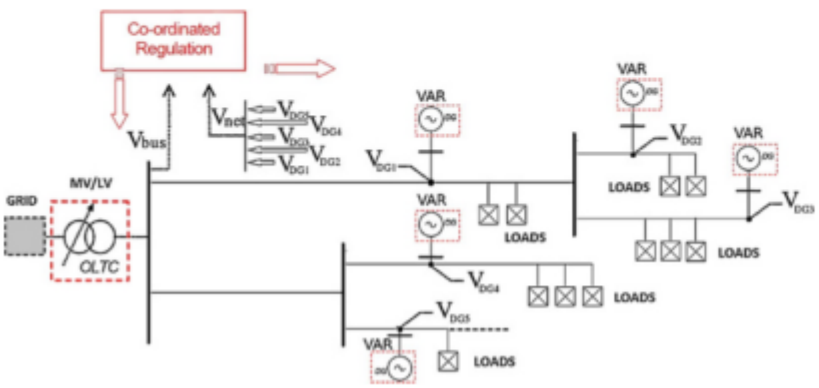


The authors conclude that there are '*substantial advantages that the proposed methods have over the GGC in terms of voltage maintenance and loss reduction in distribution feeders*'. They also conclude that neither the TB nor the VP method showed a clear advantage over the other. However the TB method consumes less total reactive power, while the VP method reduces inverter reactive power loading when thresholds are identical.

Coordinated volt-var control

Juamperez et al. (2014)[24] propose a control strategy using centralised control of active and reactive power from PV, matched with OLTC to mitigate voltage rise. To optimise active and reactive feed, a multi-objective genetic algorithm (MOGA) is used, which identifies the optimal combination of bus voltage magnitude, transformer tap settings and reactive power inputs for the purpose of maintaining voltage control. The feeder is divided into four areas, which simplifies formulation of the OLTC reference by allowing it to use average voltages for each area. Each area is given a weighting factor, which identifies the potential effect of reactive power outputs in those buses. Typically, this will be related to the distance of the buses to the transformer station. The simulation is summarised below in Figure 29.

Figure 29: Network feeder simulated by Juamperez et al. (2014)



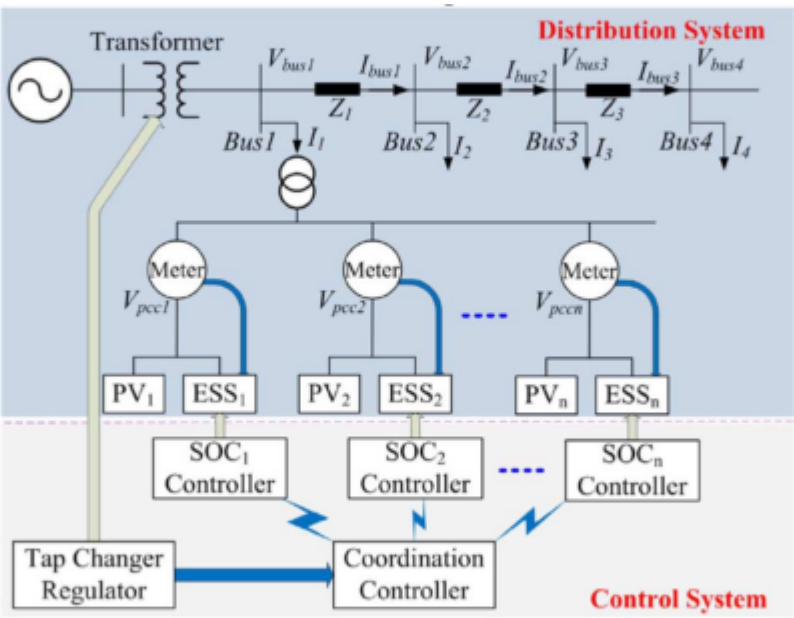
[24] Miguel Juamperez, Guangya Yang, and Søren Bækhøj Kjrær, 'Voltage Regulation in LV Grids by Coordinated Volt-Var Control Strategies', Journal of Modern Power Systems and Clean Energy, 2 (2014), 319–28

This control method was tested using a model that is representative of a typical Denmark network. There are 71 residential loads on the grid and solar installation is limited to 5kVA per customer. PV penetrations scenarios of 10% and 60% (by number of customers) were used along with high and low load cases.

Coordinated control of distributed energy storage system (ESS) with tap changer transformers

The strategy explored by Liu et al. (2012)[25] integrates an OLTC transformer control method with coordinated charging and discharging of a distributed ESS. Figure 30 shows the study's system control diagram.

Figure 30: Coordinated OLTC and battery control used by Liu et al. (2012)



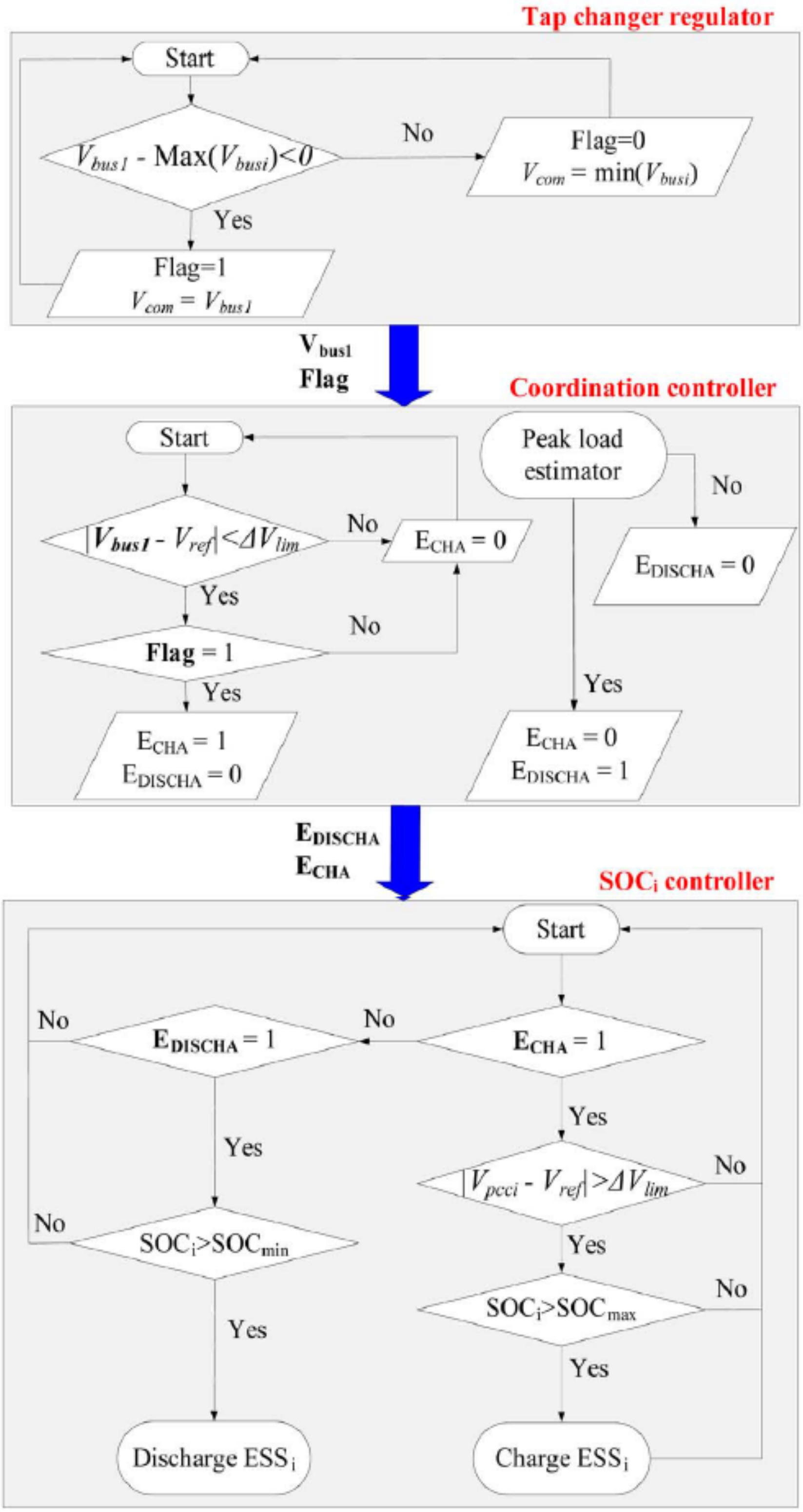
In the system, overall control is achieved through the actions of, and communication between, the tap changer regulator (TPC), the coordination controller (CC), and state-of-charge (SOC) controllers. As a first response to voltage increases, the tap changer control instigates traditional line drop compensation (LDC) to bring Bus 1 back within the system limits. Completion of Bus 1 regulation is communicated to the CC, which then initiates ESS charging only if Bus 2 or Bus 3 are outside voltage limits and if the SOC is less than the SOC maximum. Battery discharge is also regulated by the CC, and is activated by peak load estimation. This achieves peak shaving, but only occurs if the SOC is greater than a specified minimum limit.

Figure 31 shows the control algorithms employed by the TPC, CC and SOC controllers, as well as the variables that are communicated between them.

For most battery cell chemistries, there is an exponential increase in cycle life as the maximum depth of discharge (DOD) is reduced. Therefore, the life of batteries in the ESS can be significantly extended if the minimum SOC is kept relatively high. In this study, the minimum SOC was 80% to achieve a ten-year cycle life (3300 cycles).

[25] Xiaohu Liu, Andreas Aichhorn, Liming Liu, and Hui Li, 'Coordinated Control of Distributed Energy Storage System with Tap Changer Transformers for Voltage Rise Mitigation under High Photovoltaic Penetration', IEEE Transactions on Smart Grid, 3 (2012), 897– 906

Figure 31: Control algorithms employed by Liu et al. (2012)

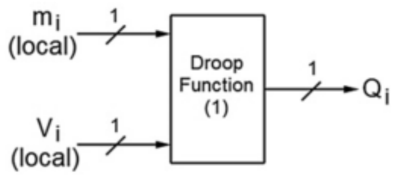


Coordinated reactive power control

Castilla et al. (2016)[26] put forward two new reactive power control methods that take advantage of communication capability between inverters.

The first of these novel methods (named Control Strategy 3 in the study) takes a conventional droop function method, of the kind described in Section 4.1.1, and adds a coordinated level of control through communication between inverters. The conventional droop function method simply injects reactive power according to locally measured voltage as indicated in Figure 32.

Figure 32: Basic droop control signal flow defined by Castilla et al. (2016)



Communication between inverters is arranged to equally distribute reactive power generation among inverters. To achieve this, inverters broadcast the amount of reactive power they are generating; hence the average reactive power Q_{avg} can be calculated. At this point a proportional-integral (PI) compensator takes Q_{avg} and Q_i to calculate a slope compensator md with gains Kp,Q and Ki,Q. The slope compensator md is added to mi and the resulting updated slope value ma replaces mi in the conventional droop function, whose output is now an equalised reactive power. This calculation is represented in Figure 33.

Figure 33: Control Strategy 3 signal flow defined by Castilla et al. (2016)

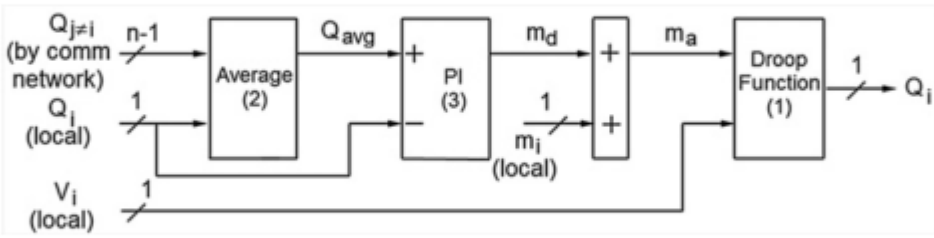
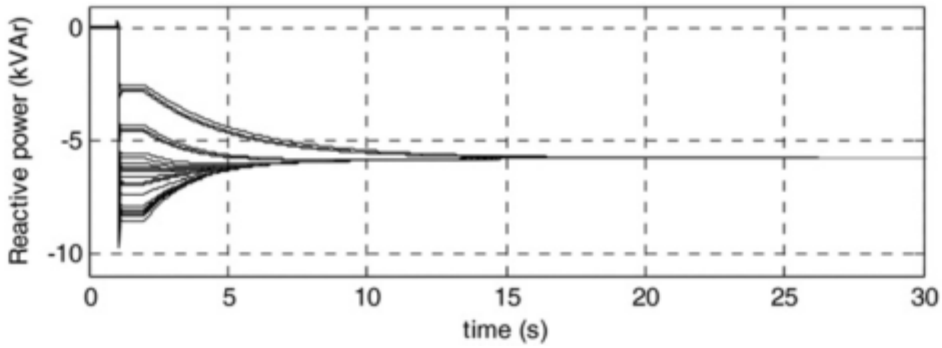


Figure 34 shows reactive power at 24 network nodes at time (t) as Control Strategy 3 is enacted. Between t = 0 and t = 1, no control is enacted and reactive power equals zero. Then, between t = 1 and t = 2, the conventional droop function is enabled and reactive power is generated independently according to local voltage only, achieving different values at each node. After t = 2, Control Strategy 3 is enabled and the reactive power of each node converges to a common value.

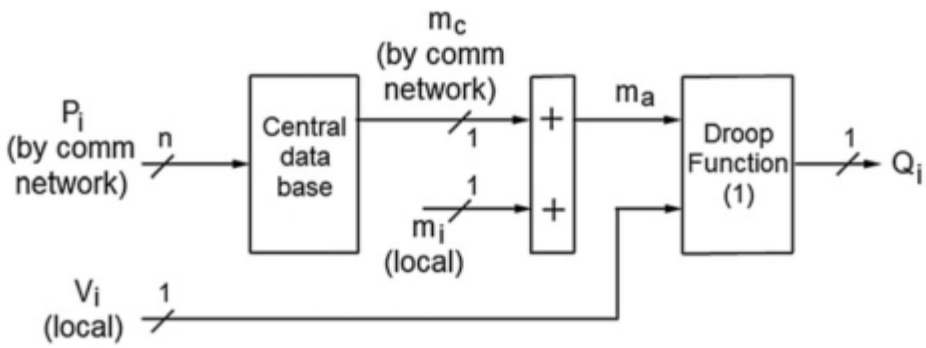
[26] Miguel Castilla, Manel Velasco, Jaume Miret, Pau Martí, and Arash Momeneh, 'Comparative Study of Reactive Power Control Methods for Photovoltaic Inverters in Low-Voltage Grids', IET Renewable Power Generation, 10 (2016), 310–18

Figure 34: Reactive power at 24 control nodes using distributed droop control



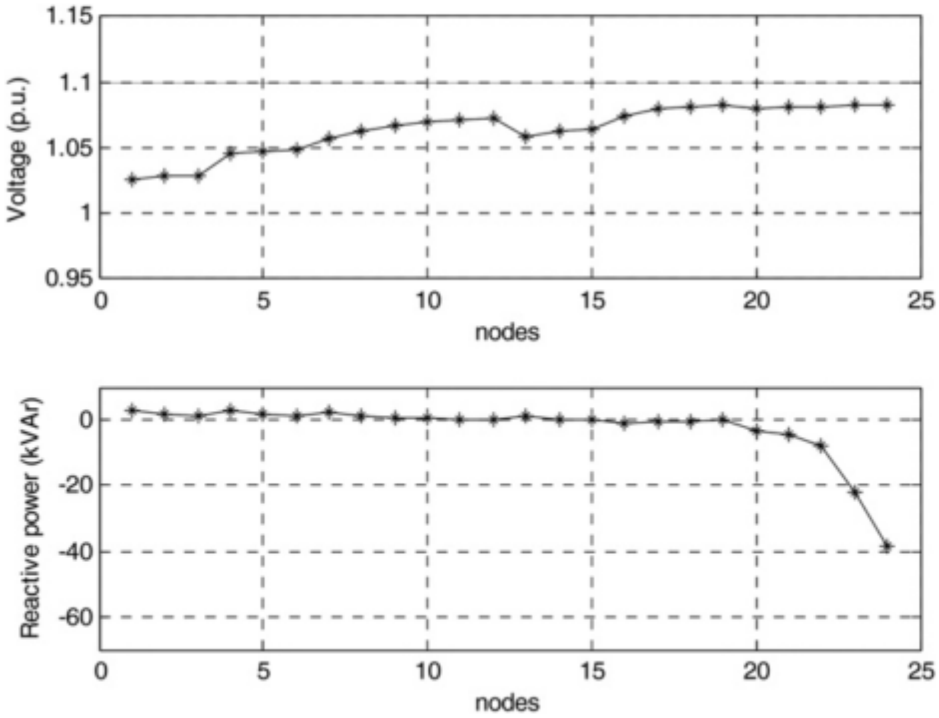
The second novel strategy (named Control Strategy 4 in the study) takes the same two-level approach to Control Strategy 3. However, at the second level of control, where mi is modified to determine ma, the objective is entirely different. In this strategy, the slope value is modified to achieve minimised whole system power losses, including those in PV inverters and underground cables. An additional difference in this strategy is the use of a master/slave communication configuration, as opposed to the multi-master configuration used in Control Strategy 3. To calculate the slope modifier mc in this strategy, several non-linear optimisation methods are available; this study employed the Nelder-Mead non-linear minimisation method. Figure 35 summarises Control Strategy 4.

Figure 35: Control Strategy 4 signal flow defined by Castilla et al. (2016)



The optimisation method in this strategy uses a cost function that measures both power losses and the highest voltage occurring at any node. Figure 36 shows how Control Strategy 4 would affect voltage and reactive power at grid nodes given a specific voltage scenario. It should be noted that this strategy results in more burden being placed on inverters further downstream (i.e. node 24).

Figure 36: Voltage and reactive power impact of Control Strategy 4



The research team modelled Control Strategies 3 and 4 and compared them against a base case with no control scenario, Control Strategy 1, a conventional droop function control scenario, Control Strategy 2, and a scenario involving a STATCOM placed at node 24 (the most downstream node in the system), Control Strategy 5. It should be noted that the design of Control Strategy 5 was based on the results of the Control Strategy 4 analysis, which showed node 24 taking on the majority of the burden of control. Performance was measured considering the following ideal outcomes:

(i) the voltage across the distribution grid is minimum

(ii) the power factor in the point of common coupling is maximum (unity),

(iii) the power losses in the power system are minimum, and

(iv) the extra cost to get these features is minimum (zero).

The results are shown in Table 9. The authors concluded the following:

- Strategy 2 is cost effective and achieves minimum voltage, but there is a high efficiency cost.
- Strategy 3 does control voltage but is less effective than Strategies 2, 4 and 5.
- Whilst expensive, Strategy 4 is the best technical solution. The expense is due to the need for high power inverters at critical nodes and additional communication infrastructure.
- Strategy 5 was a good solution with medium cost from one high power converter but with no additional communication infrastructure. However, the authors did note that the ideal location for the STATCOM was only found by the results of Strategy 4.

Table 9: Comparative results from 5 control strategies

Strategy	Vimax (pu)	PF	Losses (%)	Extra cost
1	1.0954	0.9998	6.5813	0
2	1.0825	0.9000	8.1385	0
3	1.0861	0.9226	7.5769	Low
4	1.0825	0.9812	7.5087	High
5	1.0825	0.9755	7.5976	Medium

F: POLICY LANDSCAPE

This section seeks to summarise some of the most pertinent regulatory and policy issues that may impact the ability for smart inverters to provide additional value to the network. These issues are addressed from two perspectives: the technologies themselves; and the DNSPs who will implement them.

Policies that affect the technologies

Government has a strong role to play in the uptake of new technologies, in particular to drive their progress along the innovation chain and to mitigate the risk they could potentially pose. While many government policies are impacting the transition to smart grids, two key issues affect the technologies investigated in Networks Renewed: residential solar incentives and standards related to the connection of DERs.

Residential solar

The Australian solar market to date has been predominantly driven by early government initiatives, delivering attractive feed-in tariffs[27] to early adopters.

However, with little or no feed-in tariffs incentive for solar power systems, there remains an ongoing discussion and revision of the **fair** value for the energy produced by rooftop solar and exported into the grid. The challenge lies in assessing the value of the energy itself, while attempting to achieve an equal distribution of network costs across customers, while also accounting for the entire suite of benefits offered by distributed renewable generation e.g. reducing peak load, deferring major network infrastructure investments as well as CO_2 emission reduction. For this reason, feed-in tariffs are still an active policy topic, particularly at the state level.

Consumer perception is also important. At present, consumers are charged in the order of 25c/KWh for the electricity they consume, while only receiving in the order of 5-7c/kWh for exported electricity. This discrepancy can be perceived by customers as excessive, a perception which can be exacerbated by the relative opacity of current residential charges for electricity.

Policy uncertainty can hinder market growth, and history indicates that recent technology advances have occurred significantly faster than policy and regulation has been able to adapt to. However, clear and appropriately flexible government policies (e.g. carbon pricing, cost reflective pricing and feed-in tariffs) can provide strong incentives to encourage the efficient uptake and use of DERs to meet network needs, as embodied in Networks Renewed.

DER standards

With new technology there invariably comes the argument for standardisation. In the case of smart grids this discussion largely centres around safety and interoperability to ensure that the market remains technology agnostic and happily competitive. For Networks Renewed, the key standards that either exist or are in development are:

- AS/NZ 4777.2:2015 – Grid connection of energy systems via inverters
- AS4755-2007 – Demand response capabilities
- AS61000.3.100 – Steady state voltage limits in public electricity systems

[27] A higher rate paid for electricity fed back into the grid from a designated renewable electricity generation source such as rooftop solar (definition sourced from www.energymatters.com.au)

AS/NZ 4777.2. This is the primary standard for connecting solar PV and/or storage systems, related to both safety and installation. As noted earlier, the key development in standards affecting Networks Renewed is the updated version of AS/NZS 4777.2:2015, which came into effect on 9 October 2016. The key updates of note[28] are:

- Multiple phase systems now have a balance requirement.
- The set-points and limits are now required to match those of DNSPs.
- Inverters must have a demand response and power quality response mode.
- Electricity safety requirements must align with international standards.

In essence, AS/NZ 4777.2 will help align inverters with international standards and ensure that all new inverters will have greater capabilities to provide standardised network support services in the future. Ideally, this will pave the way for new business models that can access the complete suite of network benefits of newly installed DERs.

AS4755-2007. This standard outlines the framework for demand response capabilities for electrical products and demand response-enabling devices (DREDs), which include grid-connected inverter energy systems. The purpose of this standard is to assist policy makers and businesses (e.g. DNSPs and third party providers) to deliver demand response programs effectively. This will be particularly relevant to Networks Renewed when considering peak load management in the NSW trial with Essential Energy.

AS61000.3.100. This standard defines the limits and provides a method to measure voltage compliance in the national electricity system as outlined in Table 2.

Residential energy storage

Regulations and guidelines for energy storage are sometimes not compatible with the range of technology options that are now available. This can lead to a lack of clear guidance for customers and installers. New regulations and guidelines are under development and it is important that Networks Renewed project partners stay well informed so that demonstrations will conform to best practice for some time to come.

The Australian building code and associated standards contain guidelines for the placement of storage internal to a building. This documentation was written prior to the emergence and proliferation of lithium-ion storage systems, and as such contains strict rules based upon the hazards associated with lead-acid technology (class 9, non-residential) including mechanical venting and two-hour fire rating. These may be in the process of being reviewed given the change in technologies available in the market.

Meanwhile, the Clean Energy Council (CEC) has released an installation guideline[29] for grid-connected batteries that has been mandatory since 1 October 2016. The guide discusses the location for battery energy storage systems and requires that 'In domestic dwellings, batteries shall not be located in habitable rooms (as defined by the National Construction Code (NCC) 2015)'. This requirement is being contested by some vendors on the basis that some technologies are more benign than others, especially when high-quality management systems can prevent thermal runaway.[30] Care needs to be taken in selecting the location of batteries installed at each customer site in the Networks Renewed demonstration.

[28] 'Changes to Standards, *Clean Energy Council*, 2015
[29] 'New Battery Storage Guidelines Provide Confidence for Consumers', *Clean Energy Council*, 2016
[30] Ergon (2016) INTCDER final report, Appendix E.

A second guide to battery installation[31] has been published by the Australian Energy Storage Council. It includes a timely call to action on current Australian Standards, which don't cover many critical areas, creating potential safety hazards for battery installers, battery owners and operators, and the general public. Many high-quality systems are now available on the market, but some are 'barely adequate' and, should they fail, there is a significant risk of harm to customers and the subsequent reputational damage to the whole industry would be immense.

While advocacy is an important role, the two battery installation guidelines are not very consistent, which may create confusion unless some harmonisation and collaboration are achieved.

Policies that affect the networks

While many DNSPs have evolved since the NEM was established, with increased privatisation and customer focus, all are still economically regulated by the Australian Energy Regulator (AER). In practice, this means that the regulatory framework can hinder the most efficient network investments, particularly in relation to economical demand-side and decentralised energy projects.[32] This is perhaps not surprising given the legacy of centralised generation in the NEM and steadily increasing peak demand. However, this inertia of business-as-usual investment decision-making can (and does) prevent DNSPs from unlocking the benefits of new technological developments, such as smart inverters.

An example of how the system is changing for good is outlined below in the box case study – The Death of Solar Taxes.

[31] Peter Cockburn, *The Australian Battery Guide*, 2016
[32] https://theconversation.com/people-power-is-the-secret-to-reliable-clean-energy-63877

THE DEATH OF SOLAR TAXES

Historically, the rapid uptake of residential solar has seen some DNSPs seek to limit the level of intermittent distributed generation. With rooftop PV penetration exceeding 50% of households in some suburbs, many DNSPs have raised concerns about instability such as ‘voltage flicker’ (see Section 1.2.3 above). A common reaction to this over the past few years has been to ‘cap’ or ‘curtail’, with many DNSPs proposing new measures to limit residential solar’s influence on the grid, including: new ‘solar taxes’[1], maximum use ‘demand tariffs’, and changes to connection guidelines to curtail solar exports. However, most of these measures were stopped at the gate by consumer backlash and/or AER decisions. With the advent of new ‘smarter’ solar and solar-related technologies, the focus has now moved to using solar technologies to solve the problem they are seen to create, as is clearly shown in the deep level of engagement of DNSP partners in the Networks Renewed project. However, at the end of this project, what may still stand in the way are the appropriate regulatory incentives to promote these solutions over traditional, and more expensive, network investments.

Following the Power of Choice review, both the AEMC and AER have sought to introduce new mechanisms to better support non-network investment alternatives. The AEMC’s recent summary of these mechanisms is provided in **Table 10** below.

Table 10: Existing mechanisms that support network investment

Mechanisms supporting efficient network investment

There are mechanisms in place that incentivise network businesses to seek the lowest cost solution for delivering their services, including embedded generation and other non-network solutions. The proposed rule builds on these existing mechanisms.

Cost reflective network pricing arrangements Starts 2017 Distribution network businesses develop prices that better reflect the cost of network services so consumers can make more informed decisions about their electricity use, including on-site consumption.	**Network support payments** Amended 2013 Payments from network businesses to reflect cost savings of delaying or avoiding network investment or for avoiding use of the transmission network.	**Regulatory investment tests** Started 2013 Non-network solutions must be considered as an alternative to building more infrastructure for larger projects.	**Network planning framework** Started 2013 Network businesses prepare an annual report that sets out demand and capacity forecasts, and identifies emerging constraints on the network.
Efficiency Benefit and Capital Expenditure Sharing Schemes Amended 2012 Provides incentives for network businesses to reduce costs, including through non-network solutions.	**Demand Management Incentive Scheme** Starts 2016 Provides new incentives for network businesses to invest in non-network solutions.	**Demand Management Innovation Allowance** Starts 2016 Funding for innovative projects that can reduce the need for future network investment.	**Small generation aggregator framework** Started 2013 Enables small generators to sell electricity through a third-party, making it easier for those parties to offer non-network solutions.

Source: *http://www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits/Draft/AEMC-documents/Infographic-draft-determination.aspx?utm_medium=email&utm_campaign=AEMC+Weekly+Update+-+22+September+2016&utm_content=Local+Generation+Network+Credits+infographic&utm_source=www.vision6.com.au*

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http://reneweconomy.com.au/2015/network-tariff-changes-to-slash-rooftop-solar-uptake-by-half-38409

http://www.solarchoice.net.au/blog/news/new-solar-connection-guidelines-for-queensland-come-effect-1-july-240614

Work is also underway to help identify the needs of our evolving electricity system, in particular through the development of Energy Network Australia's (ENA) Electricity Network Transformation Roadmap (ENTR). The ENTR is investigating the path for DNSPs, including consumer-focused business models, as the energy supply chain evolves and business models change. The key question that arises is: how can DNSPs evolve in the transitioning energy system to deliver the most efficient network investment without compromising the competitive market? An example of a future scenario where DNSPs move to a more service-oriented model is described further in the box case study – The Rise of Distribution System Operators?

THE RISE OF DISTRIBUTION SYSTEM OPERATORS?

The rapid emergence of Decentralised Energy Resources (DERs) creates major opportunities and challenges for Distribution Network Service Providers (DNSPs). The trend towards more local generation and storage and more responsive demand asks DNSPs to reimagine their roles and business models in a less centralised and less network ownership-intensive future.

This change will likely involve not just a change in *flow* (from centrifugal distribution to multidirectional grid) and *scale* (from large centralised generation to many decentralised resources) but also in *role* (from network owner and operator to DER manager and facilitator). It is also likely that successful DNSPs will need to actively enable local trading, judging by the enormous interest in peer-to-peer consumer solutions in multiple service areas. This transition has been described as a shift from a *"Distribution Network Operator (DNO)"* to a *"Distribution System Operator (DSO)"* role that strategically coordinates and dispatches network, generation and demand-side opportunities to meet customer needs efficiently.

DNSPs will need to ensure an efficient balance between centralised and decentralised resources, and between network and non-network options. In principle, DNSPs are already required to fulfil this role through their "Demand Side Engagement Strategies" and in particular, their Regulatory Investment Test (RIT) process. However, the extent to which engagement with non-network solutions and DER providers becomes core business for DNSPs, or is undertaken by third parties, will determine which entities fulfil the DSO role. In any case, DNSPs will be a pivotal party in expanding the focus of energy infrastructure investment to include decentralised and/or non-network alternatives.

While the idea of new and more competitive business models that are customer service-oriented is attractive, transitioning DNSPs may still be restricted by the regulatory environment. Electricity distribution ring-fencing has been strongly debated in the sector as the AER seeks to determine which parties can access and control behind-the-meter resources. The AER released its final ring-fencing guideline[33] in November 2016. The guideline only allows a DNSP to provide direct services to customers through a separate entity, outside of its own regulated monopoly i.e. with legal separation and separate accounting. Networks Renewed will need to carefully consider this guideline, particularly when designing the United Energy demonstration that will investigate network ownership of behind-the-meter storage.

[33] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016

Thus, Networks Renewed is a well-timed project in a moment of regulatory and institutional flux. The outcomes of the project are likely to both depend on and help determine the best models of DNSPs' transitions to the efficient use of behind-the-meter DERs. The demonstrations will need to adapt to changing standards, incentives and regulations. The outcomes will also hopefully inform these as we continue to engage with the AER's DMIS and the ENA's ENTR development, and contribute our objective results to the public discourse surrounding the AER's ring-fencing guidelines. By the end of the project, there will hopefully be more certainty and a more level playing field for smart solar and storage to provide the network support services in place of unnecessary and costly network investments.

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