Magnetic Island and Townsville Solar City

A Case Study of Increasing PV Penetration in Electricity Networks

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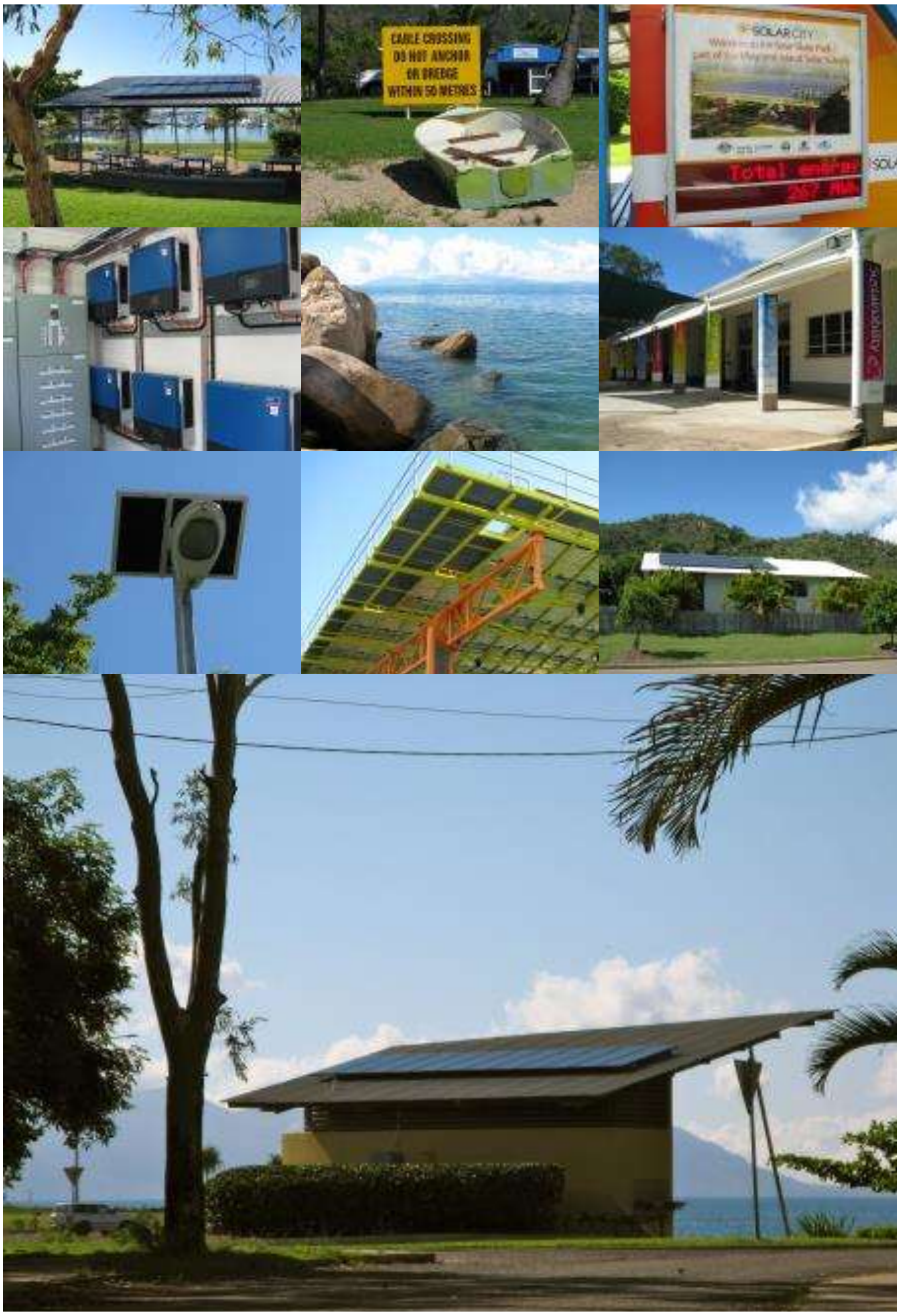

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EXECUTIVE SUMMARY

The Case Study

This report presents the results of a case study undertaken into technical issues posed by growing photovoltaic (PV) penetrations in the distribution networks of Magnetic Island and the adjacent city of Townsville in North Queensland, Australia, and their management by the local network utility, Ergon Energy. Magnetic Island is an isolated section of the Australian National Electricity Market (NEM)[1], which is connected to the Townsville electricity supply system by two undersea cables. Ergon Energy is the Distribution Network Service Provider (DNSP) responsible for the provision of electricity to regional Queensland hence both Magnetic Island and Townsville.

This case study is the third in a series of case studies aimed to give Australian and international audiences insights into some of the key technical challenges and management options to facilitate high PV penetrations in Australian electricity networks. The previous case studies examined PV penetration in Alice Springs, Northern Territory, and Carnarvon, Western Australia[2]. These case studies are being undertaken as a part of a broader ARENA supported research project entitled "*Support for Australian participation in an international RD&D collaboration on Photovoltaics – IEA PVPS Task 14: High Penetration of Photovoltaic systems in electricity grids*". A key objective of this research project is to facilitate the integration of higher PV penetrations in Australia and internationally.

Townsville Solar City

Magnetic Island is 11 km at its widest point, and located approximately 8 km off the coast of Townsville, Queensland. Townsville itself is connected to the NEM via 275 kV transmission lines, while Magnetic Island is connected to the Townsville network via two 11 kV, 12 km long undersea cables, the smallest with a capacity of 5.4 MW. By 2003, Ergon Energy, the utility providing network and retail services to the area, had identified an emerging constraint in relation to the capacity of the undersea cables, requiring an investment of $18.6 million (NPV, 2006 Australian dollars), to add a third undersea cable and upgrade the voltage from 11 kV to 22 kV. Townsville, with Ergon Energy as the primary project proponent, applied in 2006 to become part of the Australian Government Solar Cities program, with one of the main aims being to demonstrate the use of energy efficiency, demand management and solar technologies to defer the expensive network augmentation that would otherwise be required.

Ergon Energy, along with many Australian network service providers, is currently experiencing challenges related to ageing infrastructure and a changing environment. Large numbers of air conditioning units have increased load, and particularly peak demand over the past decade, while more recently rising electricity prices, environmental concerns and a range of government programs have seen a growing interest in distributed energy options. Within this context, and accompanying rapid price decreases, a large number of distributed PV systems have been, and continue to be, installed throughout Ergon Energy's network. There are now over one million households in Australia that have a residential PV system and total capacity now exceeds 2.5GW – approaching 4% of total Australian generation. Queensland has the greatest residential PV deployment of any State.

[1] The NEM is the interconnected system that serves the vast majority of electricity customers in Eastern Australia. It includes the States and Territories of Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory, representing around 90% of the total Australian population and electricity demand.

[2] All case study reports are available on the APVA website: www.apva.org.au, or on the new APVI website: www.apvi.org.au.

Almost all of these systems have been deployed within the past three years – a remarkable, customer led transformation within the electricity sector. PV is likely a precursor to a potentially wide range of other distributed energy options to come, and poses a range of issues, given its location within the distribution network at customer premises, power electronics interface, and the highly variable and somewhat unpredictable nature of the solar resource. PV is already presenting challenges for network service providers, forcing changes to engineering and business practices. As such, the engagement of these providers in addressing distributed PV can play a valuable role in facilitating future deployment of other distributed energy systems.

As a result of participation in the Solar Cities program, a relatively high penetration of distributed PV systems has been achieved on Magnetic Island, compared to the current Australian experience. The penetration level is 22% (measured as PV capacity:peak load ratio, see Table 1), which is estimated to peak at around a 32% PV contribution to load in some time periods, and 35% on one of the two 11kV feeders. PV penetration levels have increased rapidly throughout Ergon Energy's network. Indeed a number of other network regions now have higher penetrations of distributed PV than Magnetic Island. For example, Hervey Bay is at 26.6% PV capacity:peak load ratio (14.3 MW of PV capacity installed with a 53.1 MVA peak load).

Table 1: PV Penetration Levels on Magnetic Island

PV Penetration Measure	PV Measure	Estimated Value	System Measure	Value	% PV Pen.
PV Capacity Penetration	Installed Nominal PV Capacity	1102 kW	Annual Peak Load	5050 kW	22%
PV Peak Power Penetration – Summer	Est. Summer Midday PV Peak Power	583 kW	Ave. Summer Midday Load	2914 kW	20%
PV Peak Power Penetration – Winter	Est. Winter Midday PV Peak Power	497 kW	Ave. Winter Midday Load	1984 kW	25%
PV Peak Power Penetration – Average	Est. Average Midday PV Peak Power	392 kW	Average Midday Load	2372 kW	16.5%
PV Annual Energy Penetration	Est. Annual PV Energy	2 GWh	Annual Gross System Load	39 GWh	5%
Maximum instantaneous PV penetration[3]	PV Generation at time of max. PV penetration	698 kW	Load at time of max. PV generation	2158 kVA	32%

Magnetic Island and Townsville Solar City provide a particularly useful case study as there has been extensive metering of the PV systems installed under the program; a number of trials have been conducted relevant to managing high penetrations of PV, some of which are described in this case study; and Townsville has hosted a number of high profile PV systems. Ergon Energy's broader experiences with PV are also discussed throughout this report.

[3] Annual peak PV:load ratio

Magnetic Island has a semi-arid tropical climate, with a mild wet season and relatively little cloud cover throughout the year, resulting in a mean monthly solar exposure ranging between 4.5 $kWh/m^2/day$ in June and around 7 $kWh/m^2/day$ in November, which is well above the global average. There is a permanent population of around 2,500 people, but, as the island is a popular tourist destination, this can increase significantly during the holiday season. Most business on the island services the tourist or permanent population and there is very little light industry and no heavy industry.

Characteristics of the distribution network

Two 11 kV submarine cables connect the mainland to the island at Nelly Bay, where two 11 kV feeders extend east and west across the island, supplying a total of 1992 customers across the 4 main residential areas of Magnetic Island. The peak load between November 2011 and October 2012 was just over 5 MW on December 27th 2011 while energy demand for an average winter day peaks at around 3370 kW, and 3417 kW in summer, with load growth being historically driven by increases in the use of residential air conditioning.

The majority of the PV systems on Magnetic Island are small scale (< 10 kW) residential systems, with several larger systems of up to 22 kW and one 100 kW system at the public Solar Skate Park. At the time of writing, there were a total of 326 PV systems installed on the island, giving a total installed generation capacity of 1102 kW, including the 100 kW system. The majority (735 kW) of the systems were installed between mid 2008 and the end of 2011 as part of the Solar Cities program, while an additional 367 kW has been installed since mid-2008 with support from the Queensland Government Solar Bonus Scheme and the Australian government Renewable Energy Target scheme.

As such, there is a high and increasing number of customers with PV systems on Magnetic Island. The peak PV penetration (PV generation contribution to meeting load) from November 2011 to October 2012 was 34% for the whole island, and 35% for one of the 11 kV feeders, occurring during September. 44% of the 84 distribution transformers have more than 20% of connected customers with PV installed. In general the PV is reasonably well distributed across the entire island with 65% of distribution transformers having a penetration level of up to 15% (based on installed PV capacity / transformer rating). One distribution transformer has a 75% PV penetration, with a rating of 10 kVA and 7.5 kW of PV connected. The next highest distribution transformer penetration is 52%, with 26 kW of PV on a 50 kVA transformer.

Key Experiences to date

The last decade has seen a range of challenges for Australian distribution networks, faced with the challenges of aging assets and peak demand growth. Recent rapid distributed PV deployment comes within this complex and changing context. This report attempts to focus on the PV-related issues, but these issues are often difficult to separate from other distribution network issues, such as the issues associated with high peak demand from air-conditioning.

Table 2 below summarises Ergon Energy's experience to date with PV issues, and current and proposed strategies for managing any adverse past or potential impacts. The information is from interviews conducted with Ergon Energy employees, and data collected for this report. The main issue experienced by Ergon Energy due to high penetration PV has been voltage related. None of the other potential power quality issues: reverse power flow, power factor distortion or harmonics, are currently of significant concern. Protection staff, however, raised network stability concerns in relation to islanding, though there is no evidence of this having occurred to date. All instances of voltage issues that have arisen have been addressed by Ergon Energy, and the company continues to trial and, where appropriate, introduce new technologies and procedures for both mitigating current voltage issues and avoiding new problems as PV capacity on Ergon Energy's network increases.

Table 2: Summary of the experiences of high PV penetration in Magnetic Island and Townsville

Summary of the experience	Current/Proposed Management Strategies
LV Distribution System Voltage Management **A combination of large loads and distributed PV are causing a wide range of voltages to be seen on LV feeders, particularly on high impedance parts of the network, where voltages have been problematic before significant amounts of PV was installed, but may have gone undetected.** **Inverter high voltage disconnect settings greater than Ergon Energy's 255 V requirement (to comply with a statutory limit of 254.5 V) are being used by some installers.**	**Current:** In the event of a power quality complaint: • Advise customer if customer installation impedance too high • Balancing PV and loads across phases • Upgrade service mains or LV feeder - in some cases this merely brings forward planned overall upgrades • Augment or relocate the relevant Distribution Transformer (DTx) • Lower the tap on the DTx • Review operation and settings of network equipment General: • Fault Loop Impedance test to determine likely voltage rise and action prior to installation of PV systems • Education of installers to use correct inverter settings and check network impedance via Fault Loop Impedance Test **Trials:** • STATCOMs for voltage regulation • Low Voltage Regulators • Reactive power injection • Variac test to check inverter setpoints after installation **Other Relevant Developments:** • AS4777 changes to reduce voltage drop at customer installation inverter switchboard <1%, switchboard – mains <1%
Phase Imbalance **Customers' (loads and PV systems) are not balanced across phases. Unbalanced power flow can cause neutral phase voltage to rise and increase voltages on phases.** **Ideally, phase balancing would occur at time of PV system installation, but Ergon Energy does not currently have data on customer phase of connection.**	**Current**: • Balancing across phases in the event of a power quality complaint

Summary of the experience	Current/Proposed Management Strategies
Reverse Power Flow **PV generation > load can cause reverse power flow, which is of concern to protection staff and may reduce efficiency of the network.** **This is not currently of concern on Magnetic Island, and even in urban areas with a high penetration of PV, power quality engineers have not seen any switching or disconnection issues.**	**Current**: • Require network studies for proposed systems >5kW (detailed below)

Protection and PV System Islanding
 	
The major protection concern is related to the possibility of failure of inverter anti-islanding protection, due to a quasi-stable island, where PV feeds and masks a fault, or other failure of the anti-islanding mechanism.
 	
No PV system islanding incident has been recorded. Outside of the protection group, this is not a major concern.
	Current:
	• Protection study required for systems >30 kW
	• Systems of sufficient size that could export power such that the load and generation are balanced are not approved
	• Ergon Energy inspects all large PV installations before connection
	• Additional requirements for large systems may include:
	  ○ Inverter capable of absorbing VARs/inverter to operate with a set PF
	  ○ Supplementary HV protections, such as overcurrent protection at the point of connection, neutral V displacement earth fault protection on the high side of the transformer
	  ○ Protection relays as per IEC60255
	  ○ Additional (parallel) active anti-islanding protection on top of what is required by AS4777
	  ○ SCADA monitoring for systems > 1MW

Network Planning and PV System Approval **Many applications for PV systems are being received, particularly associated with announcements of closures of government incentive schemes.** **Growing numbers of applications for large systems (>30kW) are now also being received, requiring network studies.**	**Current:** • Systems < 5kW are currently automatically approved, but this limit is under review. • Systems > 5kW require approval from asset management to ensure network capacity sufficient. • Systems >30kW are treated as large connections, and subject to a network load flow study by regional distribution planning team and a protection study. **Proposed:** • Guidelines for application to install large PV system under preparation to streamline process.

Summary of the experience	Current/Proposed Management Strategies
Harmonics **Australian utilities have been concerned about the aggregate effect of large numbers of inverters producing harmonics of the same order. Harmonics can cause over heating and failure of equipment such as transformers and customer motors and also may cause neutral currents.** **This is a low priority issue. Measured harmonics have been well within required standards and too small to be of concern, even where high penetrations exist. Air-conditioning has been shown to be a much more significant source of harmonics than PV inverters at high penetrations.**	**Current:** • ENA and the AS4777 standards working group continue to monitor the situation and ensure harmonics from PV systems are not problematic. **Proposed:** • Where THD is an issue, Ergon Energy has identified the use of Static Compensators (STATCOMs) as a measure that can reduce the issue
Power Factor **PV inverters operate at unity power factor, so do not contribute directly to this problem, however, where a large percentage of the load is being supplied by PV systems, the residual load can comprise a high percentage of reactive power.** **This problem has not been experienced in Ergon's network to date. This issue is expected to become more significant as Ergon Energy begins using STATCOM devices to manage voltage issues**	**Proposed:** • Inverters can potentially be used to supply reactive power.

Trials Conducted

This case study also presents results from the following selection of relevant projects and trials of new technology implemented by Ergon Energy on Magnetic Island and Townsville, mainly within the Solar Cities project. Many of these were undertaken with the purpose of broader network management, rather than specifically to address a PV-related issue. However, they have presented an opportunity to test approaches to improving management of high penetrations of PV and enabling increased PV hosting capacity in the future.

- **Upgrade and relocation of DTx TVS55**. Distribution Transformer TVS55 was rated at 200 kVA with 25 PV systems connected, amounting to 62 kW of generation. This was, at the time, the highest amount of installed PV on any DTx. After Ergon performed load flow modelling on the subdivision it was decided to upgrade TVS55 and also to move it closer to the subdivision in order to reduce the voltage drop between the DTx and the customers. Although this was not a voltage issue related to PV, upgrade of small transformers and relocation has been demonstrated as an option for voltage management.
- **Installation of low voltage regulators at Smart Lifestyle Centre**. The Smart Lifestyle Centre (SLC) was experiencing high voltage levels during the middle of the day when the 17 kW PV system installed at the Smart Lifestyle Centre was exporting and demand was low. To resolve this problem a Low Voltage Regulator (LVR) was installed on all three phases at the

SLC. The LVRs performed as expected with voltage levels at the SLC being maintained at 230 V throughout the day.

- **Redflow battery trial**. Ergon undertook a Redflow (zinc bromide) battery trial and data monitoring project to assess the impact of distributed storage on the network. The project has provided clarity for the work required to connect battery systems to the grid and other valuable lessons on integrating storage into the network.
- **Reactive Power Injection Trial – Solar Skate Park.** Ergon Energy conducted reactive power injection trials utilising the 100 kW Solar Skate Park (SSP) PV system. The trials demonstrated the effectiveness of reactive power injection for managing voltage levels. Ergon has also conducted trials at the SSP to determine the effectiveness of automated control for self-regulation of voltage levels.
- **St Andrews Close Grid Smart Grid Trial.** A trial similar to that conducted for the 100 kW SSP system, reactive power injection, was also conducted at St Andrews Close, a residential area in Townsville. The aim of the trial was to test whether Volt/VAR control could be used to maximise PV system output whilst at the same time managing voltage levels. Under the trial, phases A and B behaved as expected with a reduction in voltage across all seasons at both the transformer and at the end of the line (EOL) when the inverters were configured for 100% of available reactive power. However, phase C exhibited an increase in voltage when its inverters were injecting 100% of available reactive power, at the End of Line. Reverse power flow occurred on phase C, with the EOL voltage higher than the transformer voltage, likely due to an imbalance in PV generation and load connected across the phases. This trial illustrated the importance of balanced connection arrangements across phases when attempting to manage voltage levels through such methods as Volt/VAR control.

Benefits of PV on the Network

While the PV output does not coincide with peak loads on Magnetic Island, which are driven by residential air-conditioning on summer evenings, PV does contribute to overall reduced loading on the network and, importantly, deloads the network during daylight hours on these peak days, which tend to be very sunny. PV has also been an important part of the overall engagement strategy of the Townsville Solar City project, and has provided an opportunity for Ergon Energy to participate actively in the management of distributed energy and investigate opportunities to deploy emerging smart grid and distributed technologies.

Conclusions

High and growing penetrations of, mainly small, distributed PV systems exist within Ergon Energy's distribution network. Magnetic Island is one such example of high PV penetration. To date, some voltage issues have arisen in high impedance sections of the network, but these have been successfully resolved. These issues have occurred within the context of wider challenges, such existing voltage management issues associated with highly variable and peaky demand, which have largely gone undetected and hence unmanaged in the past.

Voltage issues to date have been successfully resolved through network balancing, adjustment and minor augmentation. Ergon Energy has developed tests to detect voltage issues before or directly after PV system installation, and is engaging with installers to ensure correct inverter settings and use of these tests.

Despite some concerns about the potential for PV system islanding, no other significant impacts are currently being experienced. Minor reverse power flow has not caused any network operation problems, while inverters have not produced significant harmonics or caused power factor issues.

There are different views within Ergon Energy on the potential risks of islanding but, again, no recorded instances have yet occurred. Nevertheless, Ergon Energy is proactively exploring management approaches for dealing with the higher PV penetrations, and other distributed energy technologies, that seem certain to come.

1 INTRODUCTION

This report presents the results of a case study undertaken into the technical challenges posed by and the management of the growing photovoltaic (PV) penetration in Magnetic Island and Townsville in North Queensland, Australia. Magnetic Island is an isolated section of the National Electricity Market (NEM)[4], which is connected to the Townsville electricity supply system by two 12 km long 5.4 MW undersea cables. Ergon Energy is the utility responsible for the provision of electricity to the island.

This case study is the third in a series of case studies to be undertaken as part of a broader Australian research project titled *"Support for Australian participation in an international RD&D collaboration on Photovoltaics – IEA PVPS Task 14: High Penetration of Photovoltaic systems in electricity grids".* This research project is being co-ordinated by the Australian Photovoltaic Association (APVA[5]), in conjunction with the University of New South Wales (UNSW) and CSIRO with funding from the Australian Renewable Energy Agency (ARENA[6]), formerly the Australian Solar Institute (ASI).

The broad aims of the overarching research project are to:

- enhance understanding of the technical, economic and regulatory requirements needed to achieve high levels of PV penetration in electricity grids in Australia; and
- support Australia's active participation in the International Energy Agency's Photovoltaic Power Systems Program Task 14 (IEA PVPS Task 14[7]) which provides a forum for all IEA countries to share knowledge and experiences on the integration of high levels of PV into electricity grids.

In addition to the case studies, a broad survey of Australian DNSPs is also being undertaken within the research project in order to ascertain approaches adopted to accommodate PV across Australia.

More detailed information on the IEA Task 14 program is provided in Appendix 1.

Previous case studies include the isolated grids serving the Alice Springs township in the Northern Territory, and Carnarvon in Western Australia, which presented opportunities to review both system-level and distribution system challenges associated with high penetrations of PV. In Alice Springs, although the amount of PV installed on the network increased from almost none in 2008 to 3 MW in 2011, (on a grid with peak demand of 55 MW occurring at 4pm on Summer afternoons), the highest PV penetration (PV generation as a percentage of load) was around 8.5%. Apart from tripping of PV inverters due to frequency excursion, there has not been any material impact on network operation as a result of the increase in PV penetration levels. In the Carnarvon power system with 23 MW diesel/gas generation capacity, a peak load of around 11.5 MW and around 1.1 MW of PV capacity installed, the highest PV generation as a percentage of load was around 13%, with up to 70% penetration of PV on distribution transformers (PV capacity as a percentage of

[4] The NEM is the interconnected system that serves the majority of electricity customers in Australia, spanning the majority of the following states and territories: Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory

[5] www.apva.org.au

[6] www.arena.gov.au

[7] www.iea-pvps.org/index.php?id=58

transformer capacity). There have been reported cases of frequency excursion causing inverter tripping, isolated reports of voltage rise and reverse power flow, and utility concerns about maintaining spinning reserve capacity to cover the simultaneous loss of all of the PV, but again, no significant measured impacts on network operation.

Magnetic Island and Townsville Solar City was selected as a case study for the following reasons:

- Townsville was selected in 2006 by the Australian Government as part of the Solar Cities program, and as such has received funding support for the implementation of solar energy and energy efficiency programs, including the Magnetic Island Solar Suburb Initiative (MISSI)[8], which has supported a robust measurement and monitoring program. Since 2006 the amount of PV on the island has increased to 325 systems and 1002 kW and is considered to have high penetration levels of PV by Australian standards.
- Magnetic Island has supply capacity limitations associated with the submarine cables (5.4 MVA) that link it to the mainland electricity supply systems and, with growing electricity demand on the island, has been interested to explore options other than augmentation of the existing submarine cables. Participation in the Solar Cities program and the MSSI has enabled Ergon Energy to defer augmentation of the submarine cables via innovative load management trials.
- Ergon Energy has a high and growing PV penetration throughout its network area, and has been actively pursuing options to increase hosting capacity to allow more PV installations to connect to its networks. The results from the trials undertaken by Ergon Energy on Magnetic Island and in other parts of their network will provide data for Australian distribution networks concerned about managing high penetrations of PV systems.

Considering the above reasons for Magnetic Island's selection for this case study, the primary aims of this report are to:

- Document the technical experiences of Ergon Energy, the network operator, in integrating high levels of PV on the island and more broadly across their networks.
- Investigate whether the existing levels of PV penetration on Magnetic Island's LV networks are causing power quality issues.
- Discuss the primary concerns that Ergon Energy have in relation to increasing PV penetration levels.
- Document the actions being taken by Ergon Energy to facilitate successful PV integration.

The remainder of this report consists of the following sections:

- Section 2 outlines the approach used in undertaking the case study;
- Section 3 describes the Magnetic Island electricity supply system and the distribution and penetration levels of PV on the island;
- Section 4 discusses Ergon Energy's key experiences to date with increasing levels of PV penetration on the island and in their overall network area, including the results of trials;
- Section 5 summarises the key findings of the Case Study.
- Appendix 1 gives an overview of the Task 14 IEA PVPS Program.

[8] http://www.townsvillesolarcity.com.au

2 CASE STUDY APPROACH

Ergon Energy is the distribution network supply utility for north Queensland, including Magnetic Island, and has been instrumental in providing the network data and information required to compile this report. The case study included interviews in Ergon Energy's Brisbane and Townsville offices and a field trip to Magnetic Island. Engineering departments were engaged to give their opinion on the technical issues the network is experiencing and how the network can be managed in light of these issues. Local network personnel were also engaged to reveal the issues experienced on the network first hand. Strategies for further PV system integration were also discussed.

The focus of discussions with Ergon Energy personnel was on the technical challenges associated with integrating a high penetration of PV systems in Magnetic Island. The main issues covered in discussions are listed below:

- PV power output variability (e.g. rapid PV power fluctuations due to clouds)
- Network voltage management (e.g. higher voltage on feeders due to high PV power injection)
- PV systems dropping out (e.g. multiple inverters cutting out due to high/low network voltage or frequency)
- Reverse power flow through network equipment (e.g. through zone sub transformers)
- Power factor management (e.g. power factor support/problems)
- Harmonics (e.g. harmonics from inverters)
- Protection issues (e.g. protection equipment not operating due to PV systems feeding faults)
- Islanding (i.e. stand-alone operation of part of the network in the event of a network failure)
- Other network operational issues (e.g. tap-changer cycling, inverter behaviour during recloser operation).

In addition to the interviews conducted, the following information and data was provided by Ergon Energy:

- Magnetic Island 11 kV feeder load and Solar Cities PV output data from 2009-2012
- Data and reports from specific PV investigations showing the impacts that the PV systems are having on the network
- Data and results from trials of management strategies to mitigate the network impacts associated with PV integration
- Planned future solutions and approaches to managing high penetrations
- Information relating to the successful storage and DSM implementation, the extent to which these have been integrated with PV or have allowed a higher penetration of PV, and costs/benefits.

Table 1 gives a list of the Ergon Energy and external personnel who participated in interviews or contributed to the case study.

Table 1: List of Case Study Participants

Name	Org.	Org. Position	Case Study Role
Dean Condon	Ergon	Installation Manager/Technology Innovation Engineer	Lead contact for case study, assisted in case study planning, managed all aspects of site visit and requests for information and data, interview participant
Dean Comber	Ergon	Manager Inverter Energy Systems	Interview participant
Michael Gorman	Ergon	Principal Engineer Power Quality	Technical expertise
Michelle Taylor	Ergon	Manager Technology Development	Assisted in case study planning, interview participant
Ben Thorley	Ergon	Power Quality Complaints Response Team Lead Townsville	Interview participant
Graham Berryman	Ergon	Area Asset Manager	Interview participant
Patricia Sorbello	Ergon	Engineer, Regional Asset Management, North	Interview participant
Rob Coggan	Ergon	Principal Engineer Protection	Interview participant
Matt Wuersching	Ergon	Work Group Leader Solar PV Installation Team	Interview participant
Ian Reid	Ergon	Major Customer Project Sponsor	Interview participant
Ian Cruickshank	Ergon	Manager Solar City	Assisted in case study planning, interview participant
Julie Heath	Ergon	Community Engagement Manager Solar City	Interview participant
Wayne Preston	Ergon	Project Manager Tariff Trials	Interview participant
Peter Goggin	Smart Grid Partners	Director	Interview participant

3 THE MAGNETIC ISLAND ELECTRICITY SUPPLY SYSTEM AND PV PENETRATION LEVELS

Magnetic Island is located approximately 8 km off the coast of Townsville, Queensland. There is a permanent population of around 2500, but as the island is a popular tourist destination this can increase significantly during the holiday season. The majority of Magnetic Island's residents commute to Townsville for work. Most businesses on the island service the tourist or permanent population; there is very little light industry and no heavy industry.

Magnetic Island has a tropical semi-arid climate[9] with very little variation in mean daily temperature throughout the year. A mild wet season extends from December until April. The mean monthly minimum temperature ranges from 14 ^{0}C in June to 24 ^{0}C in January and the mean maximum temperature ranges from 25 ^{0}C in June to 32 ^{0}C in December, resulting in a residential air-conditioning dominated peak load on summer evenings.

Magnetic Island experiences on average 120 clear days, 144 partly cloudy days and 101 cloudy days annually, with a mean monthly solar exposure of 6.9 kWh/m^2/day, ranging between 4.5 kWh/m^2/day in June and 7.4 kWh/m^2/day in November[10], or more than 2000 kWh/m^2/year, well above the global average.[11] By comparison, Sydney has a mean solar exposure of 4.7 kWh/m^2/day, ranging from 2.5-6.7 kWh/m^2/day throughout the year[12].

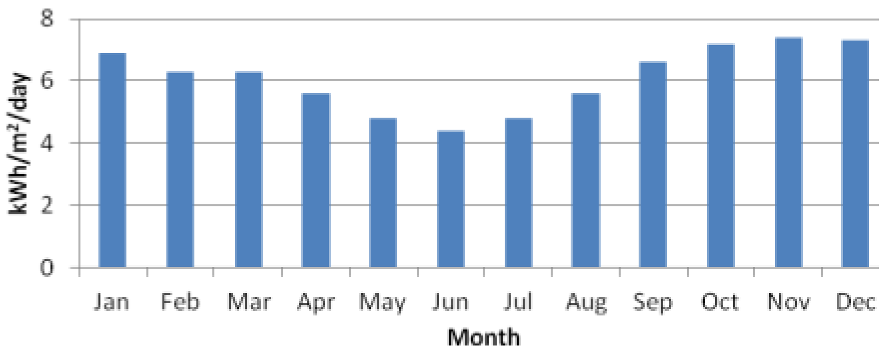


Figure 1: Mean monthly solar exposure on Magnetic Island[13]

3.1 The Magnetic Island Electricity Supply System

Magnetic Island is equipped with two 11 kV submarine cables, each 12 km in length, with capacity 5.4 MVA and 5.8 MVA, which connect the mainland to Nelly Bay. Two 11 kV feeders extend out from Nelly Bay, one to Picnic Bay and the other to Horseshoe Bay. At June 2011 there were 1830

[9] http://www.nprsr.qld.gov.au/parks/magnetic-island/about.html

[10] Magnetic Island monthly climate statistics from Australian Bureau of Meteorology (BoM) Climate Data Online: http://www.bom.gov.au/climate/data/index.shtml?bookmark=200

[11] http://www.dlr.de/tt/Portaldata/41/Resources/dokumente/institut/system/projects/reaccess/ssedni60.jpg

[12] BoM Climate Data Online, Monthly Statistics: http://www.bom.gov.au/climate/data/index.shtml?bookmark=200

[13] Magnetic Island Monthly mean daily global solar exposure from BoM: http://www.bom.gov.au/jsp/ncc/cdio/weatherData/av?p_nccObsCode=203&p_display_type=dataFile&p_stn_num=032193

customers connected to the grid.[14] Ergon Energy is responsible for provision of electricity to Magnetic Island in its capacity as network operator and retailer. In 2003, Ergon Energy identified supply capacity limitations associated with the Magnetic Island submarine cables (5.4 MVA) that link it to the mainland electricity supply systems.

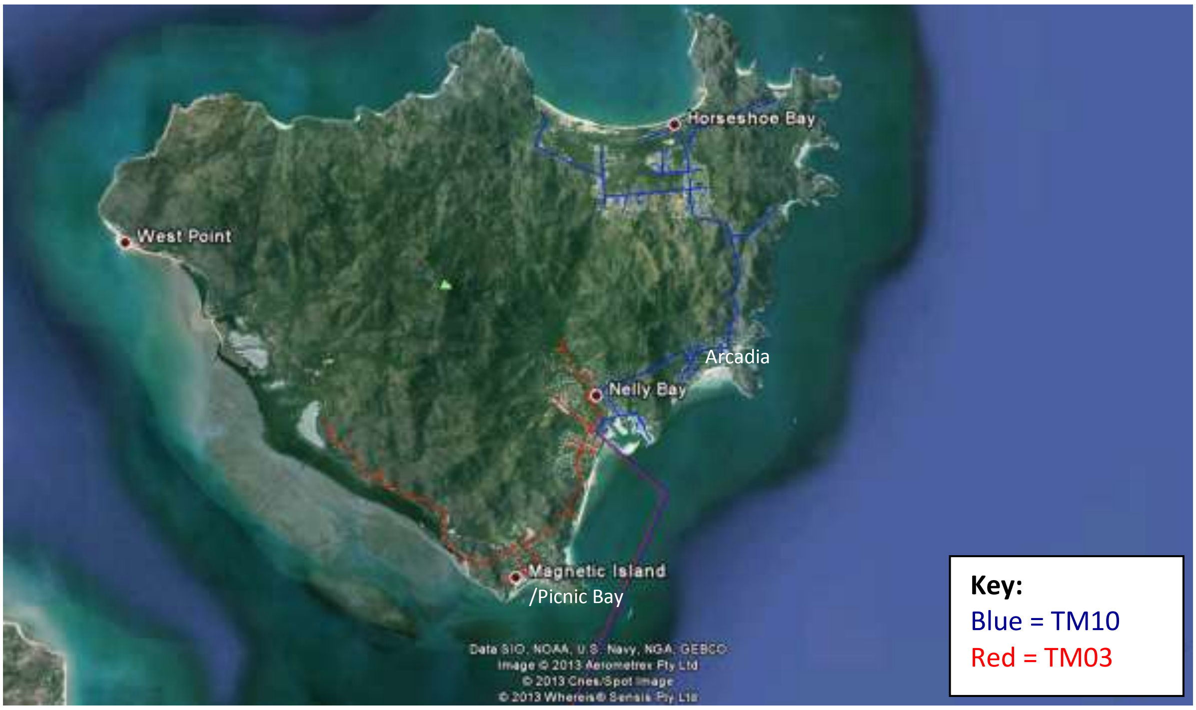


Figure 2: The Magnetic Island medium voltage (11kV) network

The load on Magnetic Island is clustered around the 4 main residential areas of Arcadia, Horseshoe Bay, Nelly Bay and Picnic Bay. The distribution of load across the island is shown in Table 2. Nelly Bay has the highest number of customers and the largest average DTx capacity/customer, since larger customer loads on average are hosted in the Nelly Bay area. These include a supermarket and two large resorts, as well as a number of small commercial customers and many residential customers. The other areas have predominantly residential customers, with a few more commercial loads at Horseshoe Bay.

Table 2: Distribution of load by residential area

Area	Customers	Number of DTx's	Min DTx Rating (kVA)	Mean DTx Rating (kVA)	Max DTx Rating (KVA)	DTx capacity/customer (kVA)
Arcadia	278	7	100	229	500	5.76
Horseshoe Bay	416	30	10	148	315	10.7
Nelly Bay	860	33	5	300	1000	11.5
Picnic Bay	303	15	10	230	1000	11.4

[14] Townsville Solar City (2011), Annual Report 2011: http://www.townsvillesolarcity.com.au/Portals/0/docs/Townsville%20Solar%20City%20Annual%20Report%202011_final_distribution.pdf

Figure 3 shows the average daily summer and winter load for the island, for the years 2011/2012. As the majority of residents commute to Townsville for work each day, there is relatively low demand during the day, with peaks before work and after. The island exhibits a typical double hump daily demand curve associated with predominately residential areas. The humps become more accentuated during the colder periods of the year, but the island is summer peaking. The actual demand is strongly temperature dependent, due to significant air-conditioning load on the island.

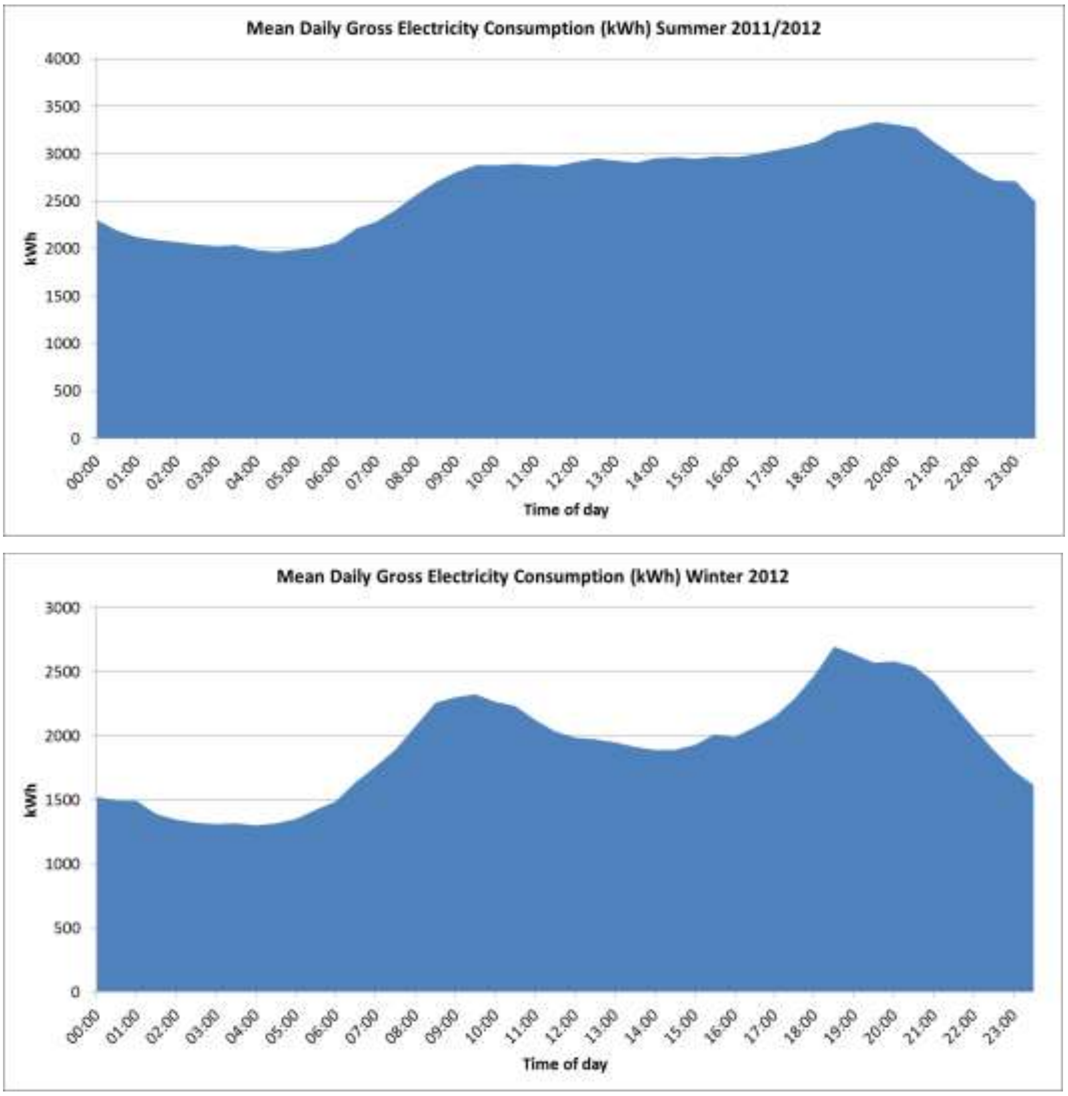


Figure 3: Average day load profile by season[15]

Due to Magnetic Island's transient tourist population, electricity demand increases dramatically during the holiday season, especially over the Christmas New Year's Eve break. Figure 4 shows the difference in demand at this time compared to the rest of the year.

[15] Townsville Solar City Annual Report 2012

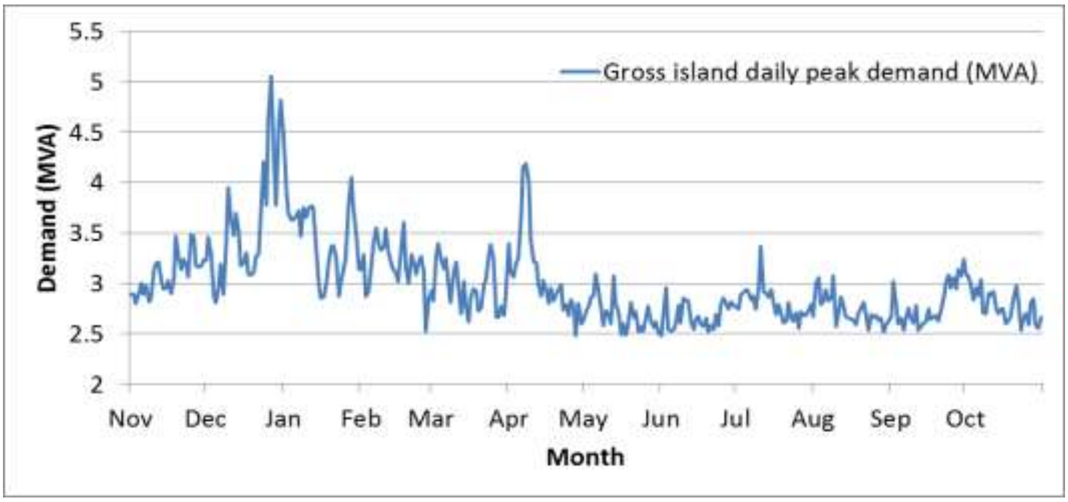


Figure 4: Gross island daily peak demand from November 2011 to October 2012, showing holiday season peaks

The submarine cables serving Magnetic Island are sized to meet this short duration high demand period and are heavily underutilised for the remainder of the year. The load duration curve of Figure 5 confirms this underutilisation with demand greater than 4000 kW occurring less than 1% of the year.

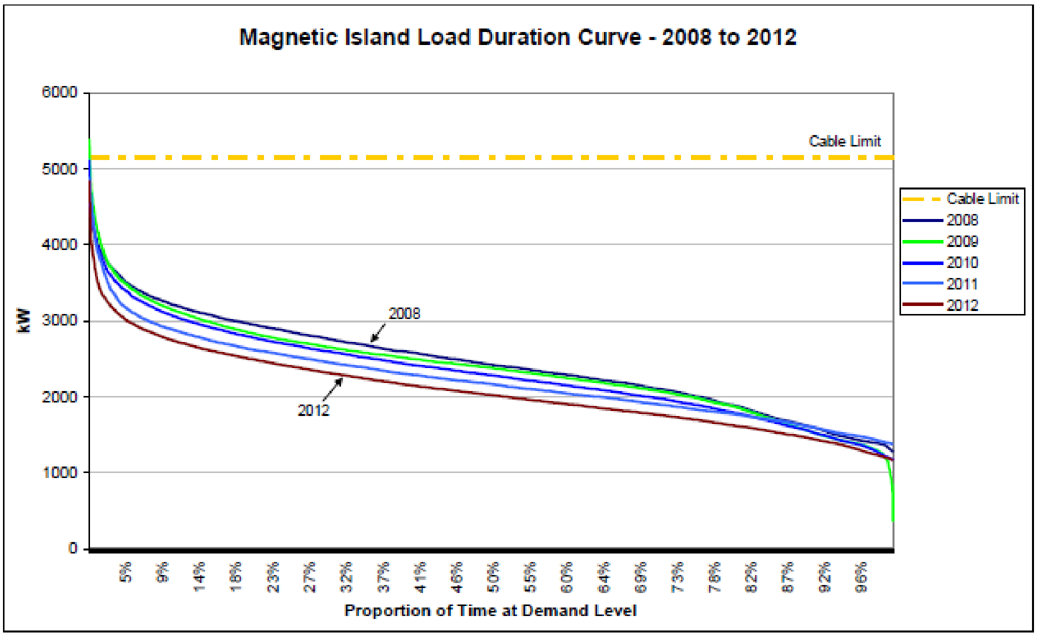


Figure 5: Load duration curve[16]

[16] Townsville Solar City Annual Report 2012

Load levels based on 2012 data are summarised below in Table 3.

Table 3: Magnetic Island load summary for November 2011- October 2012

System Load Description	Time of Day	Value (kW)	% of Cable Capacity
Summer Peak Load	20:30	5050	89
Summer Average Day Peak Load	19:30	3417	63
Summer Average Day Midday Load	12:00	2914	55
Winter Peak Load	20:00	3370	62
Winter Average Day Peak Load	20:30	2735	51
Winter Average Day Midday Load	12:00	1984	38

3.2 Townsville Solar Cities Program

By 2003, Ergon Energy had identified an emerging constraint in relation to the capacity of the undersea cables, requiring an investment of $18.6 million (NPV, 2006 Australian dollars), to add a third undersea cable and upgrade the voltage from 11 kV to 22 kV. Townsville, with Ergon Energy as the primary project proponent, applied in 2006 to become part of the Australian Government Solar Cities program, with one of the main aims being to demonstrate the use of energy efficiency, demand management and solar technologies to defer the expensive network augmentation that would otherwise be required.

The aim of the Ergon Energy-led Consortium was: *"Trialling a sustainable distributed utility business model incorporating the installation of 500 solar photovoltaic systems and 2500 smart meters and the implementation of Demand Management measures such as energy efficiency, load management and cost-reflective pricing trials [in order to] demonstrate the impacts of concentrated deployment of these technologies and measures, including the deferral of electricity network investment in a fully integrated programme"*.[17]

Figure 6 shows that energy efficiency and load shifting activities undertaken through the MSSI have resulted in a 1% reduction in peak load between 2008 and 2011, compared to a projected increase of 9% over the same period, thus far deferring the undersea cable augmentation.

[17] Townsville Solar Cities Business Case

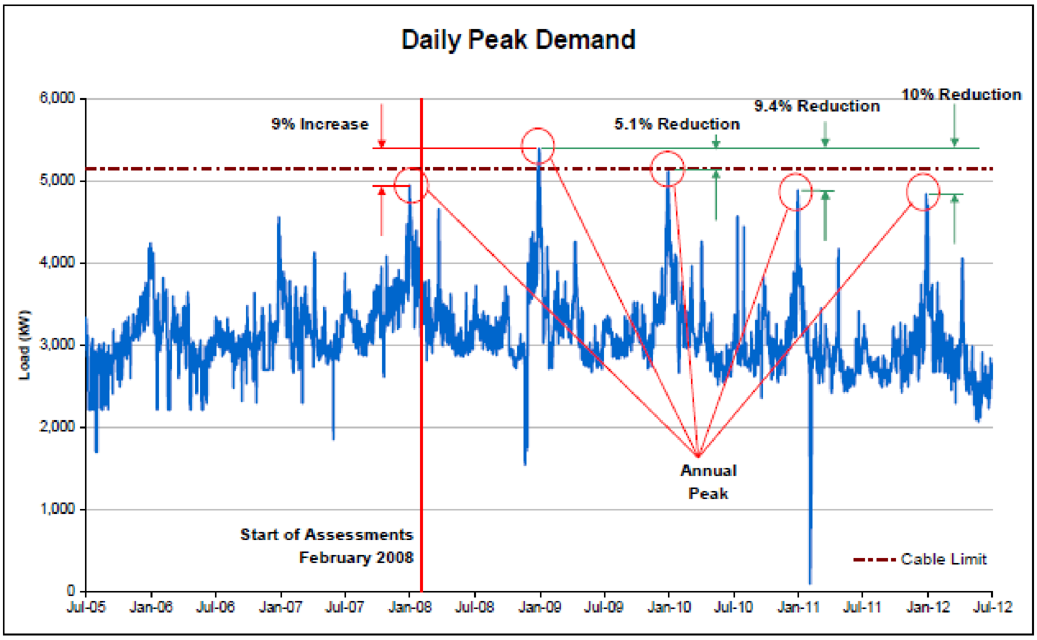


Figure 6: Daily peak demand decreases achieved through MSSI[18]

3.3 Other Policy Influences on PV in Magnetic Island

In addition to the Federal Government's Solar Cities Program, incentives at both State and Federal government level have encouraged the uptake of rooftop PV systems on Magnetic Island and across Ergon Energy's network. Table 4 below depicts a summary of the Queensland Government Feed in Tariff (FiT), called the Solar Bonus Scheme. Other schemes of note are the Federal Government's Renewable Energy Target scheme (renewable energy certificates (RECs) for each MWh deemed to be generated by systems up to 10100 kWp) and the associated solar credit multiplier (until 2013, a REC multiplier, stepping down over time from 5x to 2x, applied to the first 1.5 kWp of PV installed)[19].

Table 4: Summary of State and Utility Feed in Tariffs available in Magnetic Island.

Date	Details
From July 2008	44 cents/kWh net FiT for systems up to 5 kW; retailers may choose to offer additional payments above this as exported PV generation is 'assigned' to them.
From July 2012	FiT reduced to 8 cents/kWh with, in some cases, an additional 6-8 cents retailer contribution

3.4 PV Systems on the Network

The majority of the PV systems on Magnetic Island are small scale (< 10 kW) residential with less than 10 larger systems of up to 22 kW. Most of the larger systems are located at Nelly Bay with one

[18] Townsville Solar Cities Annual Report 2012

[19] Australian Government CleanClean Energy Regulator: http://ret.cleanenergyregulator.gov.au/. .

large system at Picnic Bay, one at Arcadia, and the 100 kW Solar Skate Park system installed at Horseshoe Bay. The Solar Skate Park project was implemented to trial a large iconic PV installation with a community engagement element.[20] The project involved collaboration between the Magnetic Island community, Townville City Council and Ergon Energy.

Of the systems installed on the island, 212 were installed through the MSSI program, with a generation capacity of 735.5 kW, including the 100 kW Skate Park system. These systems are owned and operated by Ergon Energy. The occupants of houses with MSSI systems installed do not receive any financial benefit from the PV systems, which are separately metered and have no impact on their electricity bills.

In addition to the Ergon Energy-owned PV systems installed through the MSSI program, 114 customers have invested in PV systems with a capacity of 366.8 kW, in order to take advantage of the incentives available through the Queensland Solar Bonus Scheme and the Federal Renewable Energy Target.

At the time of writing, there were a total of 326 PV systems on Magnetic Island, with a total installed capacity of 1102 kW. More than 15% of customers on Magnetic Island have a PV system.

3.5 PV System Distribution

The distribution of PV systems by number and installed capacity for each residential area is given in Table 5. In the final column, the PV penetration is expressed as the ratio of installed PV capacity compared to distribution transformer capacity in each area of the island.

20 http://www.townsvillesolarcity.com.au/Portals/0/docs/Townsville%20Solar%20City%20Annual%20Report%202011_final_distribution.pdf

Table 5: Distribution of PV systems by residential area (excluding 100 kW Skate Park)

Area	Scheme	No. customers	Sum of DTx Capacity (kVA)	No. PV Systems	% of Customers with PV Systems	Installed PV (kW)	Average PV system size (kW)	Installed PV as a % of total DTx capacity kW/kVA (%)
Arcadia	NSSI	369	1531	29	12.7%	63.37	2.19	7.48%
	SBS			18		51.1	2.84	
Horseshoe Bay	NSSI	384	3096	65	29%	167.57	2.62	10.2%
	SBS			47		149.1	3.17	
Nelly Bay	NSSI	909	8442	95	14.6%	338.53	3.56	5.54%
	SBS			38		129.5	3.41	
Picnic Bay	NSSI	323	1542	22	10.2%	65.83	2.99	6.68%
	SBS			11		37.1	3.37	
TOTAL	**NSSI**			**211**		**635.3**	**3.01**	
	SBS			**114**		**366.8**	**3.22**	
GRAND TOTAL		**1985**		**325**	**16.37%**	**1002.1**	**3.08**	

3.6 PV Systems Output

Figure 7 gives the PV generation (kWh) for each month from November 2011 to October 2012, estimated by multiplying the measured output from the MSSI systems by the ratio of total versus MSSI rated PV capacity to obtain output equivalent to that from all systems on the island.

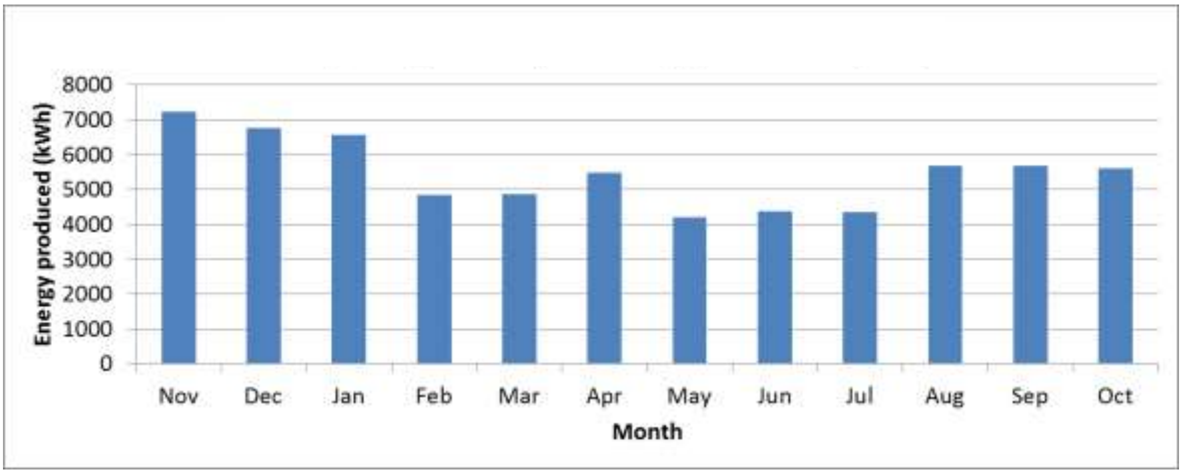


Figure 7: Energy Generated from PV on Magnetic Island Nov 2011 – Oct 2012 by month

The average daily energy produced by PV systems on Magnetic Island is 5470 kWh, and the annual peak PV output for November 2011 – October 2012 was 701 kW.

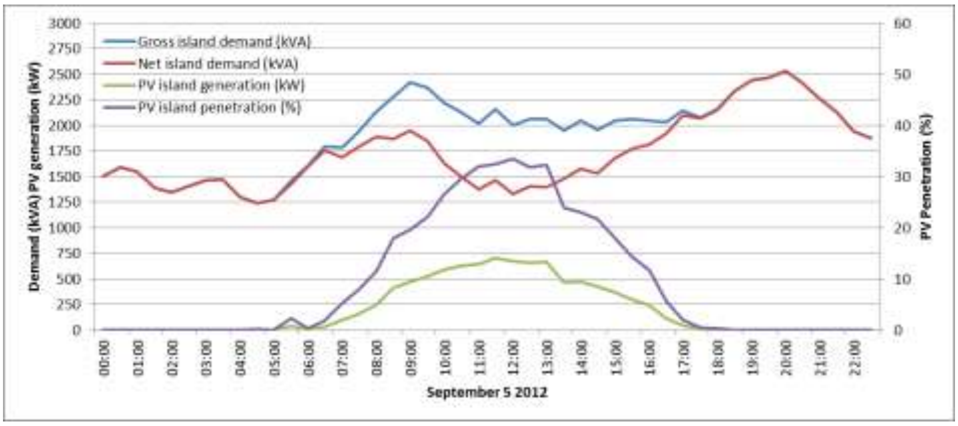
Table 6 below presents a number of ways of measuring the PV penetration levels on the network on the basis of PV capacity, output, and average and peak system loads.

Table 6: Summary of the PV penetration and load levels on the Magnetic Island network

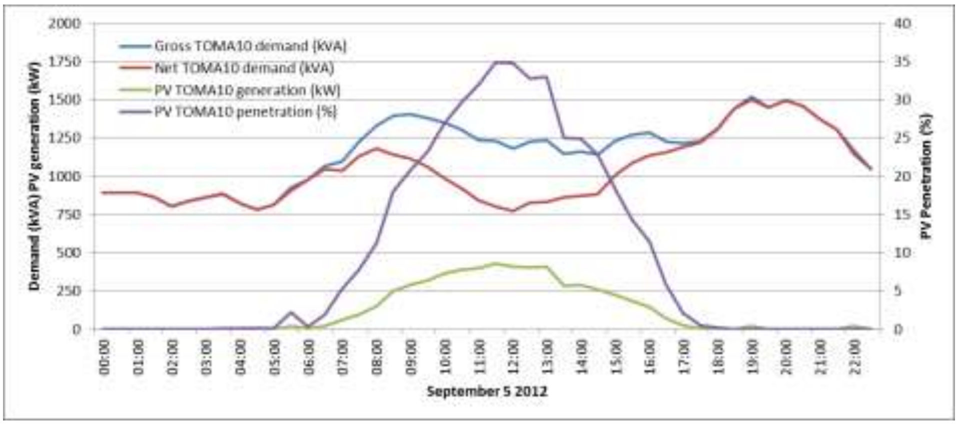
PV Penetration Measure	PV Measure	Estimated Value	System Measure	Value	% PV Pen.
PV Capacity Penetration	Installed Nominal PV Capacity	1102 kW	Annual Peak Load	5050 kW	22%
PV Peak Power Penetration - Summer	Est. Summer Midday PV Peak Power	583 kW	Ave. Summer Midday Load	2914 kW	20%
PV Peak Power Penetration - Winter	Est. Winter Midday PV Peak Power	497 kW	Ave. Winter Midday Load	1984 kW	25%
PV Peak Power Penetration - Average	Est. Average Midday PV Peak Power	392 kW	Average Midday Load	2372 kW	16.5%
PV Annual Energy Penetration	Est. Annual PV Energy	2 GWh	Annual Gross System Load	39 GWh	5%
Maximum instantaneous PV penetration[21]	PV Generation at time of max. PV penetration	698 kW	Load at time of max. PV generation	2158 kVA	32%

Figure 8 shows the PV contribution to load on the day where the PV generation:load ratio reached its annual peak. Gross demand (the sum of the PV generation and the residual load), net demand (PV generation subtracted from gross demand), PV generation and PV penetration (PV generation as a percentage of gross demand) are displayed for (a) the island and (b) TOMA10 (one of the two 11 kV feeders on Magnetic Island) for the period November 2011 – October 2012. The penetration reaches about 32% on the Island on September 5, with PV generation of 698 kW. On that day, PV penetration peaked at 35% on TOMA10.

[21] Annual peak PV:load ratio



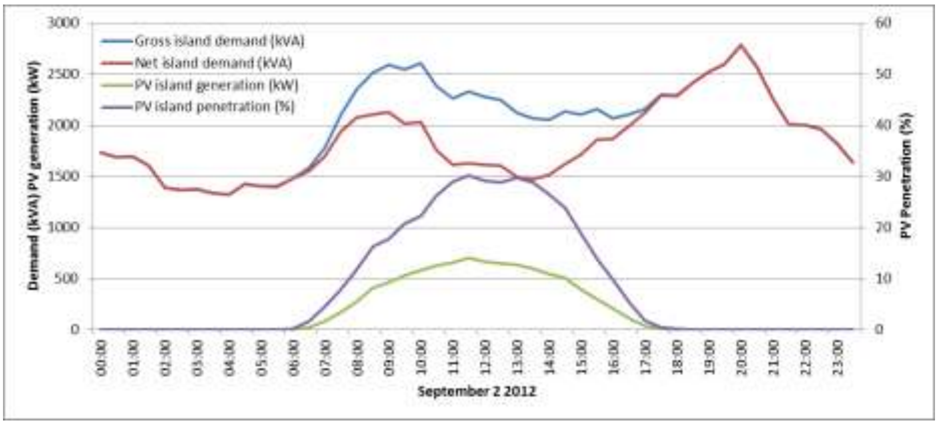
(a)



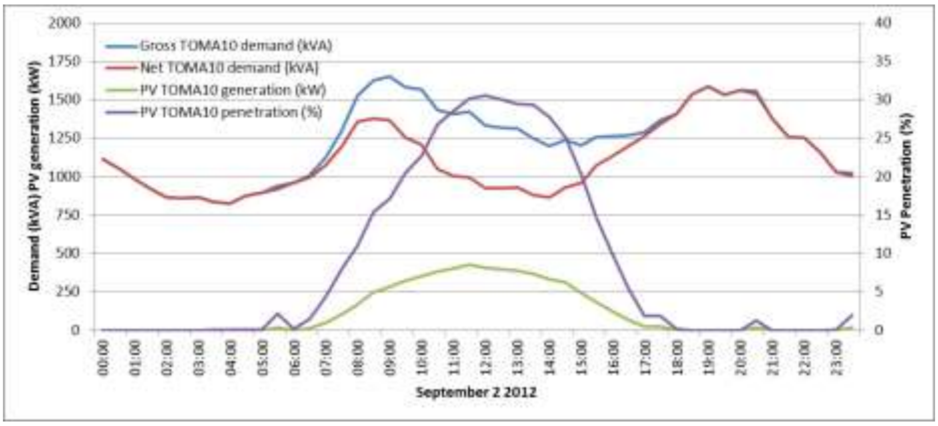
(b)

Figure 8: (a) Island and (b) TOMA 10 peak PV penetration day for period Nov 2011 – Oct 2012

Figure 9 shows the load and PV contribution on September 2, when PV generation reached its maximum for the analysis period, though higher demand reduced the penetration of PV. PV output peaked at 701 kW, only marginally higher than 698 kW reached during the peak penetration day. By comparison the highest PV generation during summer (when one would expect the highest PV generation for the year to occur) was only 606 kW. The average peak PV generation for Summer is 457 kW and 464 kW for Spring. It is possible that increased temperatures impact sufficiently on efficiency to offset the increased incident irradiance, or that shading and cloud cover reduce output. In addition, since Magnetic Island is within the equatorial region, tilt angles on rooftop PV systems are possibly more favourable during Spring/Autumn, while atmospheric conditions are also likely to be clearer.



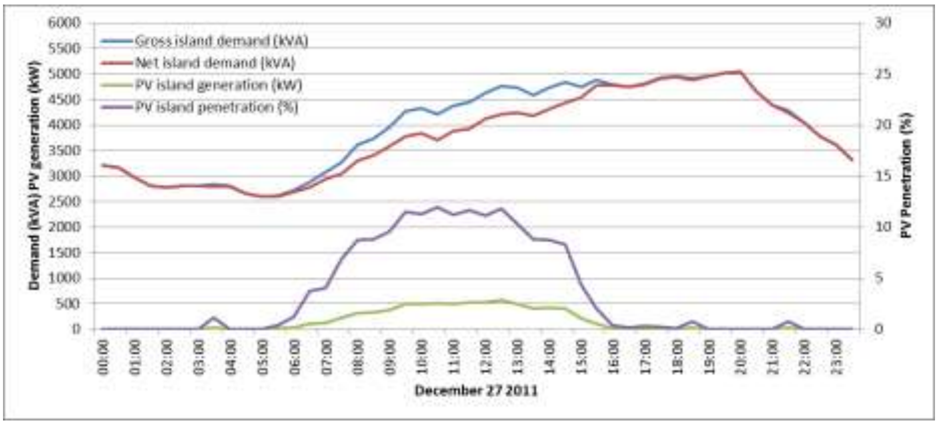
(a)



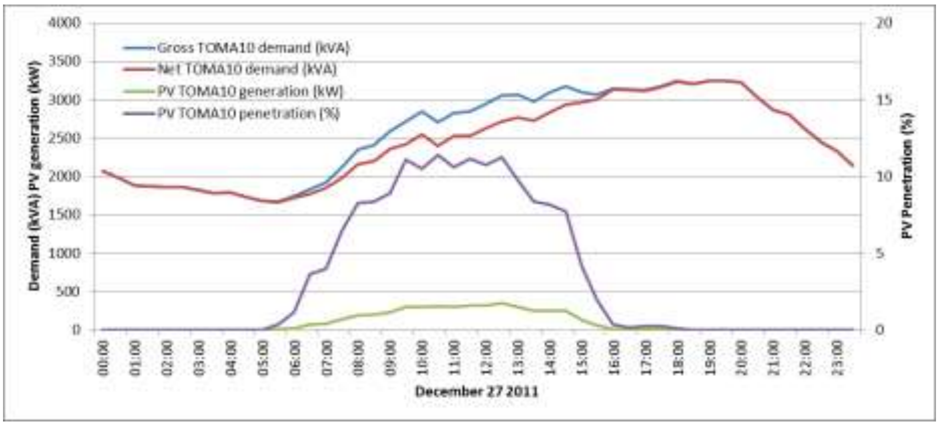
(b)

Figure 9: (a) Island and (b) TOMA10 highest PV generation day for period Nov 2011 – Oct 2012

The annual peak demand on Magnetic Island occurred on December 27 during the Christmas holiday season (Figure 10a). Peak PV generation on this day was 560 kW and peak PV penetration 12%. It can be seen that PV plays a useful role in reducing the morning peak and reducing load on the system during the day, but makes no contribution to reducing the evening peak. Overall, PV generation was 20% less than on the highest PV generation day. It is well known that there is a correlation offset between PV generation and residential peak load on a daily time scale, with PV generation highest around midday and peak load occurring during the evening. What the above figures reveal is that for Magnetic Island there is also a correlation offset on a yearly time scale with peak yearly demand occurring during Summer and PV generation at its highest during Spring. For Magnetic Island, the offset is exacerbated by the increase in demand over the Christmas holiday season.



(a)



(b)

Figure 10: (a) Island and (b) TOMA10 highest peak demand day for period Nov 2011 – Oct 2012

Figure 11 and Figure 12 give the daily maximum gross demand (with the contribution from the distributed PV added to the net demand), daily minimum gross demand, daily maximum PV generation and daily maximum PV penetration, mean and moving average for (a) the island and (b) TOMA10. Figure 11 shows an increase in demand for the island towards the warmer months, with the peaks at Christmas and Easter clearly evident. For the island, the difference in max and min demand ranges from approximately 750 kVA (occurring at different times throughout the year) and approximately 2 MVA at Christmas and Easter. PV peak generation for the island hovers between 500 – 700 kW throughout the year; the large drops in generation due to cloudy days. The peak PV penetration moving average (light blue line) best illustrates how PV penetration levels change throughout the year. A trough shape is evident, with PV penetration levels bottoming during February and peaking around September. Considering that the range in peak PV generation throughout the year being only 200 kW approximately (ignoring cloudy days), and the range in gross peak demand being upwards of 2.5 MVA, the change in gross demand is the main driver for variation in peak PV penetration.

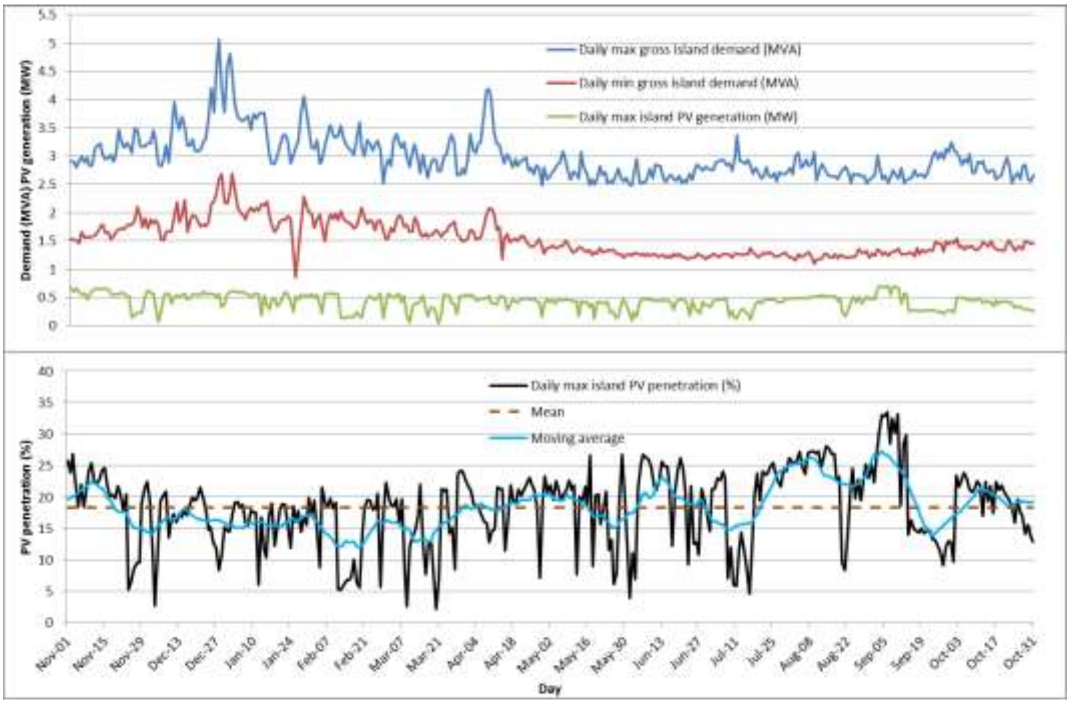


Figure 11: Daily max/min island demand, max PV generation/penetration

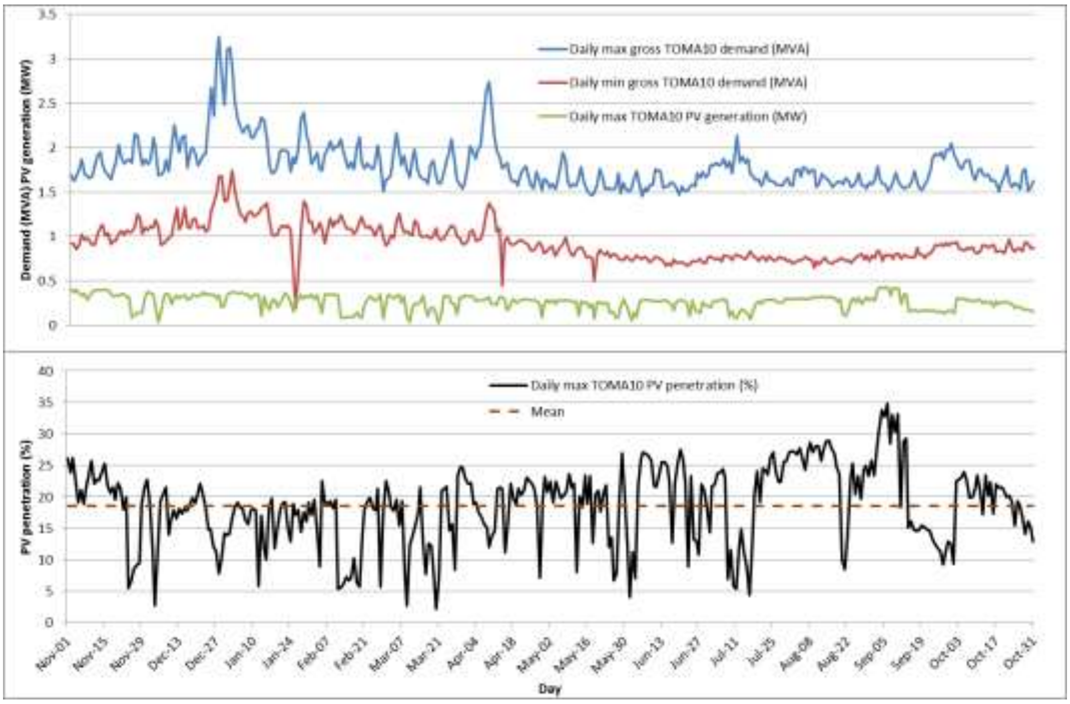


Figure 12 Daily max/min TOMA10 demand, max PV generation/penetration

3.7 PV Penetration Levels

Following are a number of distribution plots that use different metrics to represent the penetration level of PV systems at the distribution transformer (DTx) level. Figure 13 plots the number of DTxs against PV system count. 58 of the 82 DTxs have at least 1 PV system connected, while 14 (17%) of DTxs have 10 or more PV systems. The DTx with 25 systems connected is TVS55 located in Horseshoe Bay.

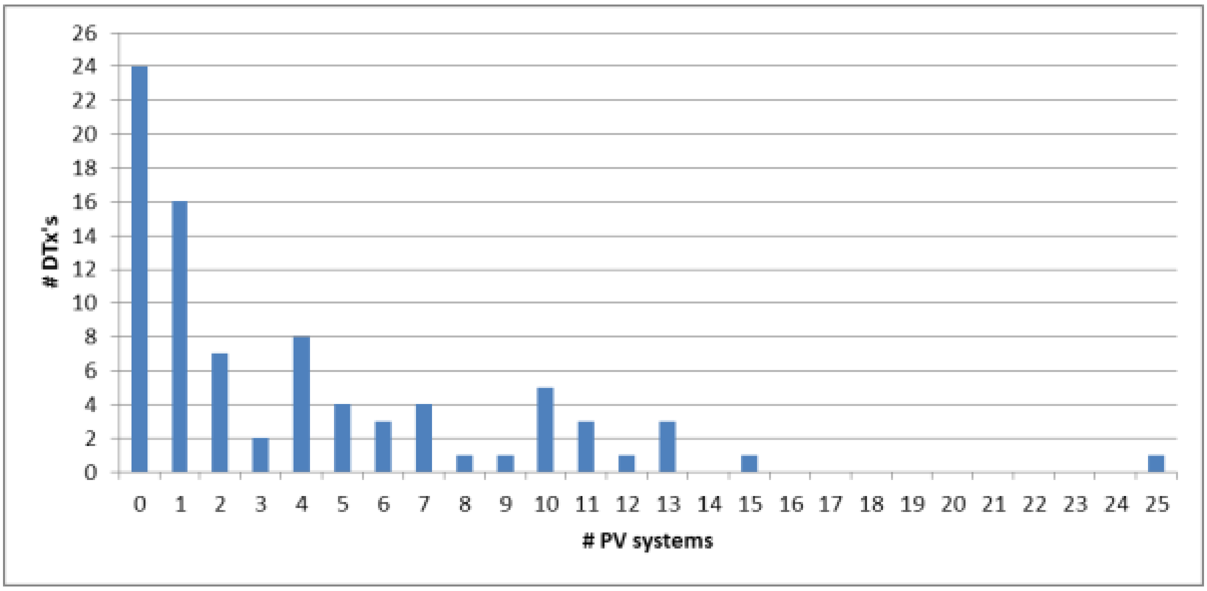


Figure 13: Number of PV systems on Distribution Transformers

Figure 14 plots the number of DTxs with different percentage of customers with PV systems. For 44% of DTxs have more than 20% of connected customers with PV installed. There are 3 DTxs with 100% of customers with PV installed, but these have only 1 or 2 customers connected to them. Interestingly the rating for one of these DTxs is 315 kVA and the one customer has a 17 kW system installed.

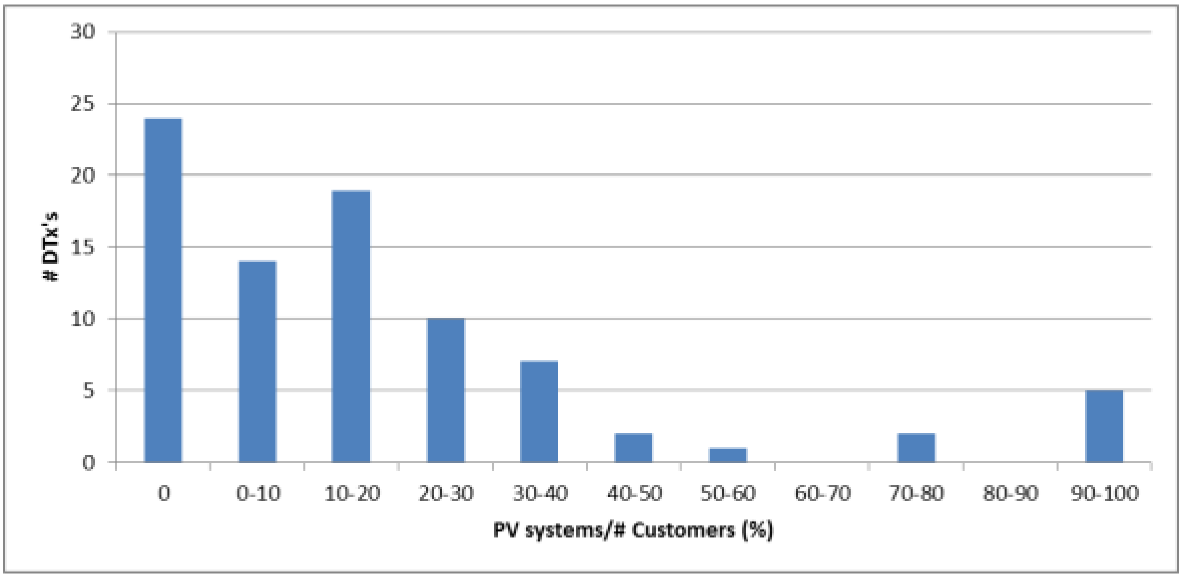


Figure 14: Frequency distribution of DTxs having different % of Customers with PV systems

Figure 15 plots the number of DTxs against total installed PV (kW). 21 of the 84 DTxs have upwards of 20 kW connected, 12 DTxs have between 20 and 30 kW installed and 9 other DTxs have more than 30 kW, representing 11%. The DTx with over 60 kW installed is TVS55at Horseshoe Bay, which has 25 PV systems connected.

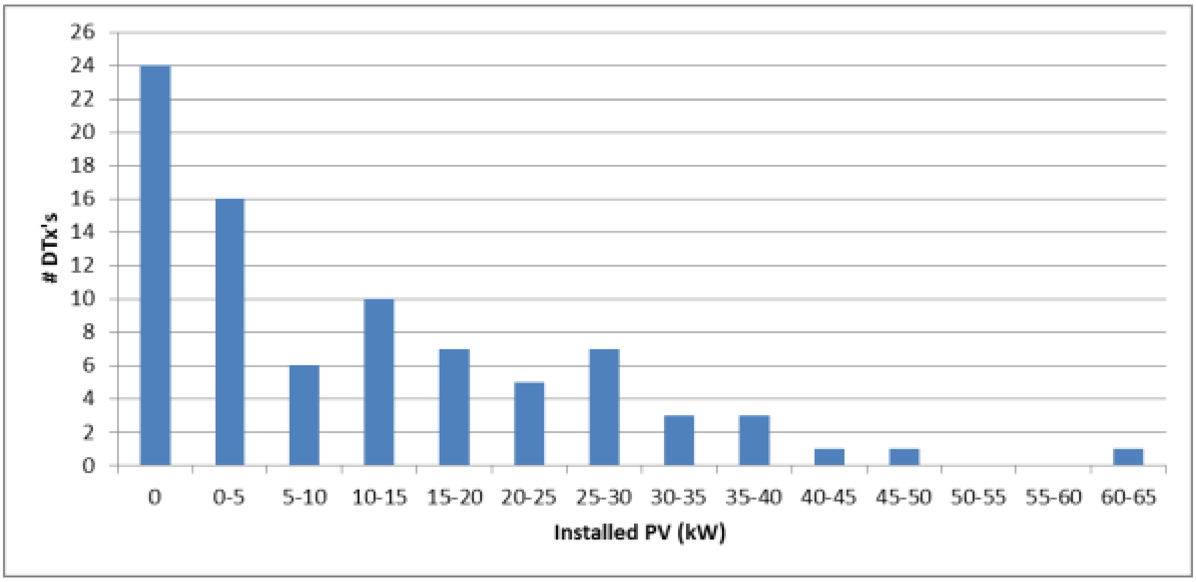


Figure 15: Number of DTxs with different amounts of installed PV (kW)

The final figure, Figure 16, in this group gives the distribution of DTxs across the conventional measure of PV penetration: ratio of installed PV (kW): DTx rating (kVA). 65% of DTx's have a penetration level of up to 15%. The DTx with 75% penetration level occurs on a DTx rated at 10 kVA, with one customer with a 7.5 kW system installed. The next highest distribution transformer penetration is 52%, with 26 kW of PV on a 50 kVA transformer.

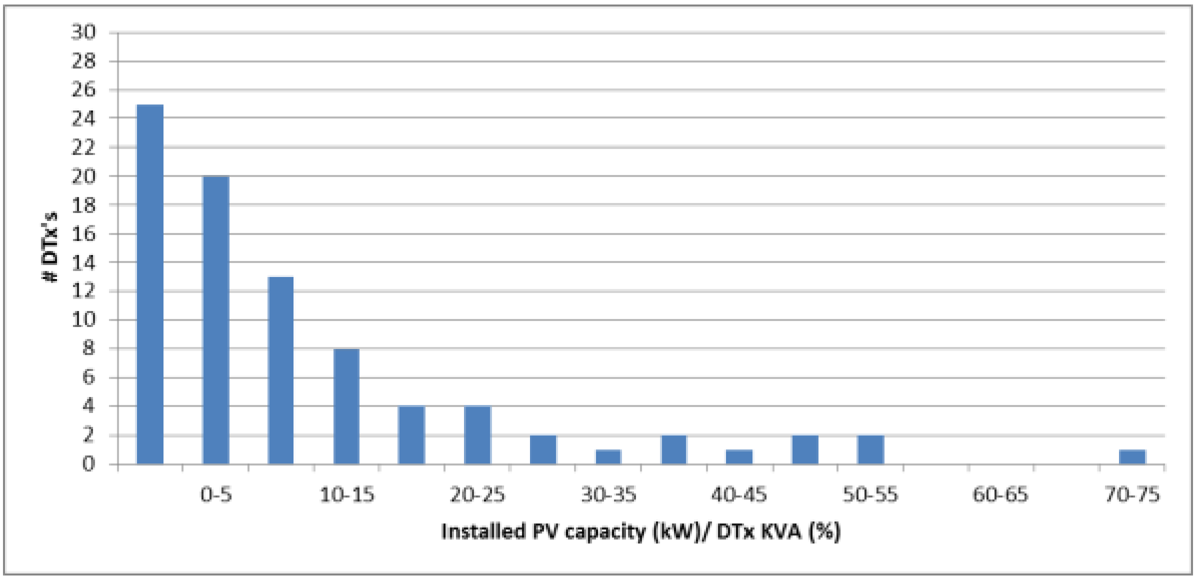


Figure 16: Number of DTxs with different penetration of PV (expressed as ratio of PV capacity (kW): DTx rating (kVA)

Table 7 gives transformer capacity per customer (kVA/customer) and PV penetration (ratio of PV capacity to DTx rating kW/kVA) for the ten DTx's with the highest PV penetration. The average number of customers per DTx (26) is on par with the island average of 25. The average size of PV systems on these heavily loaded transformers is 2.92 kW, close to the island average of 3.08 kW. While there are a greater number of PV systems connected to each DTx (7.7 compared to an island average of 3.8), the primary reason for the high PV penetration levels is the low DTx rating per customer ratio. The average DTx rating per customer ratio from Table 7 is only 3.3 kVA, compared to an island average of 9.84 kVA.

Table 7: PV penetration levels on heavily loaded distribution transformers in Magnetic Island.

Customers	PV systems	PV capacity (kW)	DTx rating (kVA)	DTx rating (kVA)Customer)	PV (kW)/DTx rating (kVA) (%)
2	2	7.5	10	5.0	75
28	9	26	50	1.8	52
1	1	5	10	10.0	50
53	10	25	50	0.9	50
19	3	12	25	1.3	48
5	4	10	25	5.0	40
32	11	38	100	3.1	38
40	10	37	100	2.5	37
80	25	62	200	2.5	31
10	2	3	10	1.0	30
			Average:	**3.3**	**47**

Table 8 gives a breakdown of the PV system penetration on TOMA10, the 22 kV feeder with the highest penetration on Magnetic Island.

Table 8: Breakdown of the PV system penetration on TOMA10

Feeder rating	5.4 MVA
Nominal PV system capacity on feeder	676 kWp
Nominal PV capacity penetration	12.5 %
Estimated PV Peak Output	430 kW
Mean Midday Load on feeder	1437 kVA
Annual PV peak power:load penetration	35 %

4 KEY EXPERIENCES TO DATE WITH INCREASING PV PENETRATION LEVELS

The purpose of this section is to outline the technical experiences of Ergon Energy as penetrations of PV have increased on Magnetic Island and within Ergon's network more broadly. Since Magnetic Island is connected to the main grid of the Australian National Electricity Market, the system issues noted in the Alice Springs and Carnarvon case studies are not relevant, and the PV system integration technical challenges currently being experienced are limited to those related to distribution network management and planning. The sections below discuss potential PV system impacts identified in the literature, the extent to which the impact has been manifest in Magnetic Island or Ergon Energy's broader networks, using specific examples, and strategies that are being implemented by Ergon Energy to mitigate the problems.

In summary, Ergon Energy is currently experiencing voltage control issues with the existing PV penetration on their network, including on Magnetic Island. None of the other potential power quality issues; reverse power flow, power factor distortion or harmonics, have been apparent on Magnetic Island or elsewhere in Ergon Energy's networks, although there have been protection concerns raised in relation to the risks of islanding. Ergon has successfully addressed all voltage excursion issues to date, through standard upgrading of cabling or through the installation of voltage control (as discussed in Section 4.2 on projects to manage high penetrations on Magnetic Island), and also has good procedures in place to reduce future voltage concerns. The demand for new PV systems and installation of air conditioning systems on Ergon Energy's network continues. Ergon Energy therefore expects voltage issues to increase and has some concerns about further power quality issues and protection issues that might emerge with a higher penetration of PV systems. In response, the company continues to trial and introduce new technologies and procedures for mitigating and preventing voltage and other power quality issues, including revisiting the assessment process for the application of larger scale PV systems.

4.1 Summary of Experiences

4.1.1 LV Distribution System Voltage Management

Due to impedance in the network, voltage on LV networks normally decreases between the MV connection and the last customer point of connection. Many Australian network areas include long, high impedance feeders, where voltage drop can be significant, and Australian network operators, including Ergon Energy, have therefore tended to set the distribution transformer tap such that the voltage at the last customer point of connection at peak demand will be within regulatory limits. This has been increasingly important as many Australian electricity customers have installed air-conditioners, increasing peak load and voltage drop problems. This approach does, however, potentially cause high voltage issues when minimum network flows are reduced as seen, for example, with distributed generation at times of lower demand.

In the presence of distributed generation, voltage drop is reduced as less current is required to flow through the feeder to satisfy the load. Voltage rise can also occur along part or all of the length of the feeder if the downstream load is exceeded by distributed generation, such that the inverter must supply power upstream toward the distribution transformer. If the distributed generation on the feeder exceeds the load, power may also flow back through the transformer to the MV network.

Many of the LV feeders on Magnetic Island where significant numbers of PV systems are installed are high impedance overhead conductors, where voltages have been set high to accommodate significant air conditioning loads. This has led to voltage rise problems on parts of the network in the area. This is a problem because over voltage on the network can impact on utility regulatory compliance, cause problems with some equipment (both for the network and the customer), increase equipment power consumption and cause the PV inverters to disconnect from the network.

AS4777 requires the inverter to disconnect from the network if the voltage exceeds the inverter high voltage set point, which must be between 230-270 V as shown in Table 9. Ergon Energy specifies that inverters must disconnect at 255 V, which is just outside Ergon Energy's statutory limit of 254.4V under the Queensland DNSP regulatory arrangements. Allowing for voltage drop within the premises, there is therefore minimal risk of statutory limits being exceed at the point of attachment. Upcoming changes to AS4777 will provide for more sophisticated operation of inverters under high voltage conditions, which will allow inverters to ride through short-term voltage non-compliance, protecting equipment but keeping inverters on line as much as possible, unless there is a significant deviation from normal network operation.

Disconnection of inverters from the network impacts on PV energy production and thus reduces financial returns from customer-owned PV systems. Since Ergon Energy owns the PV systems installed under the Solar Cities program, there are no financial implications for Ergon customers when the PV system disconnects. In other Ergon Energy network areas, inverter tripping is more likely to come to the attention of PV customers and, where voltages are in breach, these must be acted upon. The majority of voltage complaints arise near PV systems, as PV systems are measuring voltages, which are not otherwise generally being monitored. There has previously been little ongoing monitoring of voltage at the customer level throughout Australian distribution networks, and it is likely that both high and low voltage issues were often being experienced before the installation of significant numbers of PV systems. Indeed, without monitoring, high voltage issues are likely to go largely unnoticed. Since PV inverters have been installed throughout networks with high-voltage cut offs, they are effectively monitoring voltage, and alerting network operators to what may have been pre-existing problems.

Table 9: Allowable voltage and frequency ranges as per AS4777 and Ergon Energy connection guidelines. Note that an installer can modify the default inverter protection set points.

LV Parameter	Min	Max
AS4777 Voltage	200-230V	**230-270V**
QLD Voltage	225.6V	**254.4V**
AS60038 Voltage	216.2	**253 (moving to 243.8)**
Common default Inverter Voltage protection set points in Australia	200V	**270V**
AS4777 Frequency	**45-50Hz**	**50-55Hz**

Although Ergon Energy requires inverters to have an upper voltage setting of 255V, during the initial roll out of the MSSI program, a number of inverters were installed with default settings, probably of 270V. All of the MSSI inverters have now had their upper voltage setting adjusted to 255V. Ergon Energy is concerned that, more broadly across the network, installers are continuing to use wide voltage settings to prevent the inverter from disconnecting due to high voltages. Such settings may, under some circumstances, allow network voltages outside equipment ratings and network standards, and risk potential damage to equipment, whereas the presence of a PV system that trips on overvoltage can help alert utilities to voltage issues. Incorrect inverter setpoints have been difficult to test for, but Ergon Energy is developing a test using a Variac to check voltage at a PV customer's premises. If a system allows over-voltage then it can be considered defective and disconnected. The installer will then be required to reconfigure the inverter to comply with Ergon Energy requirements. Ergon Energy is also promoting the conducting by installers of a Fault Loop Impedance (FLI) test which measures the Active-Neutral impedance between the customer point of connection and the distribution transformer prior to installation of a PV system, in order to determine the voltage that a PV inverter would need to operate at in order to feed in to the network and whether unacceptable voltage rise is likely to occur. Larger PV systems will require a lower Fault Loop Impedance.

Of the 44 power quality complaints active in the Townsville and Magnetic Island region of Ergon Energy's network at the time of the case study (during a period of extremely high levels of PV installation activity as a result of the imminent closure of the Queensland Government's 44 c/kWh net FiT), 30 of these were from customers with or near to PV systems, and 14 were not, but it is unclear how many of these voltage issues were pre-existing but undetected before the PV systems were installed. There were no active complaints relating to the 293 PV systems on Magnetic Island. In the 6 years since the start of the MSSI, a number of voltage complaints have been received from parts of Magnetic Island, particularly on distribution transformer TVS55, where low voltage problems existed before the installation of PV systems, and in areas where already high voltages were exacerbated on some feeders by the PV systems. Transformer upgrade and relocation, and installation of low voltage regulators have been used to manage voltages at TVS55, as discussed in sections 4.2.1 and 4.2.2.

When a power quality complaint in the presence of a PV system is received by Ergon Energy, an inspection and spot test is carried out to determine whether the voltage at the point of connection is within mandated values. In some cases, the voltage issue occurs across a high impedance customer mains, in which case, the customer is responsible for rectifying the issue. According to AS3000 (The Wiring Rules), voltage drop or rise across the customer mains is limited to 5%. Installers must ensure that the wiring rules are adhered to as per Appendix C4, but installers usually do not have a good understanding of the network implications, and are often reluctant to advise customers that upgrades need to be carried out that will increase the overall cost of the PV system. New rules proposed for AS4777 will limit voltage rise/drop between the inverter and the switchboard to 1%, and between the switchboard and the point of connection to 1%. This will help to reduce the occurrence of voltage issues related to impedance on the customer side of the point of connection. Ergon Energy is also taking measures to educate and develop a closer relationship with installers through semi-regular workshops and regular emailed PV Industry Alerts. Workshops covering PV-related issues including voltage drop have been held over 2011-2013. Ergon Energy reports a good response to these measures from installers and customers, when they are better able to understand the network's requirements for PV system connection. As part of this communication, Ergon Energy is encouraging installers and sales companies to supply a Fault Loop Impedance value for the customer's premises at the time of application, in order to identify issues prior to installation.

Where high impedance customer mains existed in properties chosen for PV systems under the MSSI program, Ergon Energy took responsibility for the cost of upgrade, by changing the point of customer connection to the switchboard, thereby taking ownership of the customer mains.

Most commonly, however, voltage issues occur on the network side and, in this case, Ergon Energy carries out a network investigation, including establishing whether or not the customer installation is the cause of the problem, whether or not other PV systems in the area are causing the problem, reviewing the operation and settings of network equipment such as transformer settings and regulator operation, and voltage monitoring for at least one week if required. This enables Ergon Energy to determine which of the following options should be considered to rectify the problem:

- Change the phase of connection.
    - By balancing the load on the transformer, the PV generation and thus voltage rise is more evenly distributed over the phases and in many cases this will be sufficient to keep the network within mandated values. Ideally the phase of connection would be chosen during installation rather than as a response to a voltage problem. However, this is not always possible due to lack of information about connection of existing loads and PV systems across phases. Changing the phase of connection is a low cost option, as it only requires a network study to determine the extent of the load unbalance when PV is generating and a short amount of time for field staff to change the connection. It can also be quite effective, but depends on the existing level of unbalance in the network.
- Upgrade the service mains or LV feeder
    - Undertaking works to upgrade the service mains or LV feeder in an area in order to lower the impedance is the most common strategy to decrease the effects of voltage drop/rise in a network. In the event of a quality of supply complaint, Ergon Energy upgrades service mains from 6 or 10mm² to 25 mm² Al if required. All 6mm² Cu service mains are being targeted in an overall network upgrade so, in this case, PV installations are bringing forward planned expenditure, rather than causing additional cost.
- Augment the network
    - Where service mains are already of sufficient capacity, upgrading of the distribution transformer to a higher capacity which would have a lower impedance and less voltage drop/rise is considered. This approach is expensive in comparison to the other options and is generally used when upgrading service mains or phase change are not feasible. In addition, for large distribution transformers (>25 kVA), impedance does not increase significantly as capacity is increased. Installation of an additional distribution transformer and splitting of the LV feeder is another option that reduces voltages by reducing the length of the feeder and the number of customers attached. This measure does not provide a solution in most Ergon Energy network arrangements.
- Lower the distribution tap setting
    - By lowering the tap of the transformer the network voltage is lowered and this means that there is room for the PV systems to raise the voltage and stay within regulated standards. This is a low-cost option as it again only requires a network study and a small amount of hours of field staff time to change the tap. However 11 kV/415 V transformers are usually only capable of coarse adjustment and network voltages at times of peak load (and low PV generation) are commonly close to low voltage minimums allowed under network standards, as a result of large loads such as air-conditioners. Tapping down transformers could therefore cause voltages to drop below the network standards, which impacts network reliability statistics. Network studies need to be undertaken to ensure that this won't be the case. An outage to all connected LV customers is also required, which inconveniences customers (with loss of supply), and is administratively time-consuming, in terms of making and assessing the application and sending out notification letters to all impacted customers. While lowering transformer settings is frequent on SWER lines, this option has rarely been used by Ergon Energy on urban transformers, although tap changes have occurred where transformer upgrades have occurred, customers have been moved, or lines been split. Two online tap-changing distribution transformers are currently being trialled by Ergon Energy (not on the Magnetic Island network), and Ergon are looking for further suitable products to trial.

- Lower the zone substation set voltage
  - Zone substation set voltages are adjusted as required.

In addition, to the above, Ergon Energy is conducting two trials of Static Compensators (STATCOMs) for urban areas and rural townships. STATCOMs allow regulation of both under and over voltage and allow for voltages to be monitored and reactive power to be controlled on each phase to achieve local voltage regulation and phase balance. Ergon Energy has also conducted trials of low voltage regulators and reactive power injection on Magnetic Island, as described in section 4.2.

4.1.2 Phase Imbalance

The National Electricity Rules require networks to maintain difference in line to line voltages across phases within 2% using a 30 minute average. In Ergon Energy's network, PV systems have mainly been added to single phase residential customer connections, so are not necessarily balanced across phases. This could potentially change the balance across phases and cause a breach of statutory requirements, and also causes a rise in the neutral voltage, which increases voltages on the phase. As discussed above, Ergon Energy has been moving customers and PV systems across phases to reduce imbalance and issues with neutral voltage. Ergon Energy does not currently have documentation indicating which phase customers or inverters are connected to, so these changes are generally only made in response to problems.

4.1.3 Network Power Flow

As noted above, if the penetration levels of PV systems in a network are high enough, they can cause power to flow from the loads back through the MV network. This can result in reduced efficiency of distribution transformers and high reactive power flow, but of most concern to utilities is resultant network fault protection issues discussed below. In Magnetic Island there have been isolated instances of reverse power flow through the distribution transformers, but no protection issues have arisen. Ergon Energy has only a few transformers throughout the network (including in the Wide Bay area) where engineers believe there are currently likely to be times of reverse power flow, based on the PV capacity installed, transformer size and base load, but there is no measured data to confirm that reverse power flow is occurring, except where Ergon Energy is conducting specific technology trials and recording data at a Transformer. In these cases Ergon has measured reverse power flow at times. As part of the TVS55 relocation project, voltage measurements at the transformer were undertaken and voltages well above the no-load voltage, indicative of reverse power flow, were recorded.

4.1.4 PV Output Fluctuations

In vulnerable parts of the network, voltage fluctuations caused by high penetrations of PV or load switching can impact protection mechanisms. Rules apply to the rate of change of large loads (>30kW) switching to mitigate this problem. This is not currently of concern on Magnetic Island, and even in urban areas with a high penetration of PV, engineers have not seen any switching or disconnection issues. However, Ergon Energy has voiced concerns regarding the potential for larger PV systems to cause voltage fluctuations if they disconnect suddenly. In addition, voltage fluctuations are of concern on Ergon Energy's vulnerable SWER lines. In particular, if temporary supplies were introduced on these remote parts of the network after an outage, the system would act like an isolated system, with very low loads and high PV penetrations. Under such circumstances, Ergon Energy would prefer to disconnect PV systems where possible.

4.1.5 Network Planning and PV System Approval Process

As a rule, Ergon Energy allows any inverter less than 5 kW to be connected to the majority of the network without a full desktop technical assessment, with the exception of SWER lines, where inverters less than 2 kW are approved with no assessment. On the 33 isolated networks, all applications are assessed. Applications to install inverters over the stated thresholds are assessed by the Distribution Planning team, which may reduce the maximum system size allowed, or decline the application completely, if modelling shows that the network capacity is not sufficient, considering existing generation and loads on the network. An initial connection inspection is carried out for each new PV system, which includes a checking operation of the inverter anti-islanding protection.

Connection of large commercial PV systems to the network, such as the Skate Park system in Magnetic Island, require a significant network study to determine the suitability of the system and proposed network connection point. Applications to connect systems above 30 kW are assessed by Ergon Energy as major connections[22]. Ergon Energy has been receiving several enquiries per week from investors wishing to install PV systems >30 kW, and at the time of writing had 16, 20 and 35 MW systems under consideration.

Large connection proposals are assessed by the relevant regional transmission and distribution planning teams, which assesses network constraints using load flow studies incorporating load profiles and network constraints; and by the protection group, which assesses the potential export from the PV system against equipment capacity.

If equipment protection capacity is not breached, export is allowed (4 quadrant metering is required). If the impacts are considered too great, controlled export may be allowed, whereby a power relay operates when customer exports are greater than the limit nominated. If no export is allowed, an alternative point of connection option may be offered or, where augmentation is required, such as construction of a dedicated feeder back to a larger transformer, the costs are passed on to the customer. Additional requirements may be applied to approvals for large system connections, including:

- Inverter capable of absorbing VARs/inverter to operate with a set PF
- Supplementary HV protections, such as overcurrent protection at the point of connection, neutral V displacement earth fault protection on the high side of the transformer
- Protection relays as per IEC60255
- Additional (parallel) active anti-islanding protection on top of what is required by AS4777.

For PV systems > 1MW, SCADA monitoring systems may be required to notify Ergon Energy, so switching schemes can be adjusted to ensure protection capacity is not breached. PV systems greater than 2 MW are usually required to connect back to a zone substation (transforming down to 11 or 22kV). Ergon Energy inspects all large PV installations before connection.

Ergon Energy have sent out a letter to installers giving installation guidelines (mainly protection oriented) which have to be met for their system to be authorized, and at the time of writing was developing a guideline outlining the approval process and network requirements for large systems, in order to help applicants streamline the process.

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[22] A major customer connection is categorised as >1.5MVA of load or 10kW of generation on a single phase, 30kW on 3 phases. For loads, a $250 fixed fee applies for an offer of connection. To augment an existing supply when adding load, the electricity contractor is required to check whether the connection needs upgrading.

4.1.6 Network Fault Protection and PV System Islanding

Protection engineers are broadly concerned that, as PV penetrations increase in Ergon Energy's network, there is a possibility that reverse power flow through the MV system could impact on the protection relays and schemes. The two major concerns of Ergon Energy protection personnel relate to islanding. The first is the potential for a quasi-stable island, where PV feeds a fault[23], preventing detection of fault current, and posing a risk to personnel and a fire risk. The protection group has concerns about this situation being sustained beyond the 3-5 second timeframe for a reclose attempt, causing re-energizing without the fault being cleared, or reclosing out of phase. The second concern is that a stable island could form if the inverter's anti-islanding functionality does not engage. Concerns about anti-islanding failures are increased when PV systems and loads are well matched, especially in the presence of inertia and storage in the network. In this case, circuit breakers could potentially see no real or reactive power flow and fail to activate. This situation is unlikely where many small units are connected across phases, but the likelihood of balancing is higher with systems greater than 5 kW connected across three phases. The use of dynamic voltage control, such as STATCOMS, increases the risk of islanding, as it masks under/over voltage conditions, which is the most reliable form of anti-islanding protection.

The protection staff interviewed were of the view that if the PV output could potentially be equal to or greater than the minimum load, a risk of islanding exists. Protection staff are particularly concerned about lack of standardisation amongst inverter active anti islanding protection mechanisms. It is noted, however, that other staff within Ergon Energy were of the view that network protection is unlikely to be a major issue, and that international experience has been that islanding of PV inverters has not been an issue. Ergon Energy protection staff interviewed cited one example where there was concern that 2 x 415V inverter's anti-islanding protection failed to activate, but were not able to verify whether an anti-islanding failure had occurred.

4.1.7 Other Potential High PV Penetration Effects from the Literature

Harmonics

AS4777 limits the current harmonic output to 5% Total Harmonic Distortion (THD) for individual inverters, which is sufficient to prevent significant harmonics being seen on LV networks. However, Australian utilities have been concerned about the aggregate effect of large numbers of inverters producing harmonics of the same order. The presence of harmonics is of concern as it can cause over heating and failure of equipment such as transformers and customer motors and also may cause neutral currents. Of all the issues related to inverters on the network, many Australian utility personnel had been most concerned about the impact of harmonics. Ergon Energy conducted a desktop study that showed that PV inverters can have some upstream impacts, but that these are extremely small. Air-conditioning was shown to be a much more significant source of harmonics than PV inverters at high penetrations. For all PV inverters measured by network monitoring and due to individual quality of supply issues reported, harmonics have been found to be well within required standards. Under very high penetration scenarios where underlying THD as a percentage of power is high, and where PV is supplying the load, therefore increasing THD, harmonics could be a problem. The results of an Ergon Energy study released in 2011 gives measured data on the level of harmonics recorded at DTx TVS55 on Magnetic Island from 2009, with a high penetration of PV. The levels recorded were too small to be of concern. This is a low priority issue for Ergon Energy, but the Electricity Networks Association (ENA) and the AS4777 standards working group are looking to keep

[23] In Australian networks, a fault to earth activates a circuit breaker, whereas in some other countries, power systems ride-through earth faults.

harmonics under control in the future. Where THD is an issue, Ergon Energy has identified the use of Static Compensators (STATCOMs) as a measure that can reduce the issue.

Power Factor

Non-unity power factor is of concern because it can cause heating of transformers and reduce system efficiency. PV inverters operate at unity power factor, so do not contribute directly to this problem, however, where a large percentage of the load is being supplied by PV systems, the residual load can comprise a high percentage of reactive power. This problem has not been experienced in Ergon's network to date, but is expected to become more significant as Ergon Energy begins using STATCOM devices to manage voltage issues. Ergon Energy has noted that inverters can potentially be used to supply reactive power.

4.2 Ergon Energy Projects to Manage High PV Penetrations

Included in this section is a description of projects Ergon Energy has undertaken to manage the impacts of high penetration PV, primarily voltage management issues. Also discussed are the results of trials Ergon Energy has implemented to test techniques expected to reduce the impact of high penetration PV on the network.

4.2.1 Distribution Transformer TVS55 Relocation

DTx TVS55 is rated at 200 kVA with 25 PV systems connected, amounting to 62 kW of generation, the highest for any DTx. TVS55 is located at Horseshoe Bay. These large PV penetration levels were the result of the Solar Cities project. In the Solar Cities project infancy, when PV was only just beginning to be installed on the Island and on TVS55, Ergon was receiving a number of complaints of high and low voltage from customers and from one subdivision in particular. These complaints prompted Ergon Energy to record voltage levels at TVS55 as well as at a number of residences in the subdivision. Figure 17 shows the voltage for one customer (with a 4.86 kW PV system installed) during a period when recorded voltage levels were above the regulation limit of 254 V.

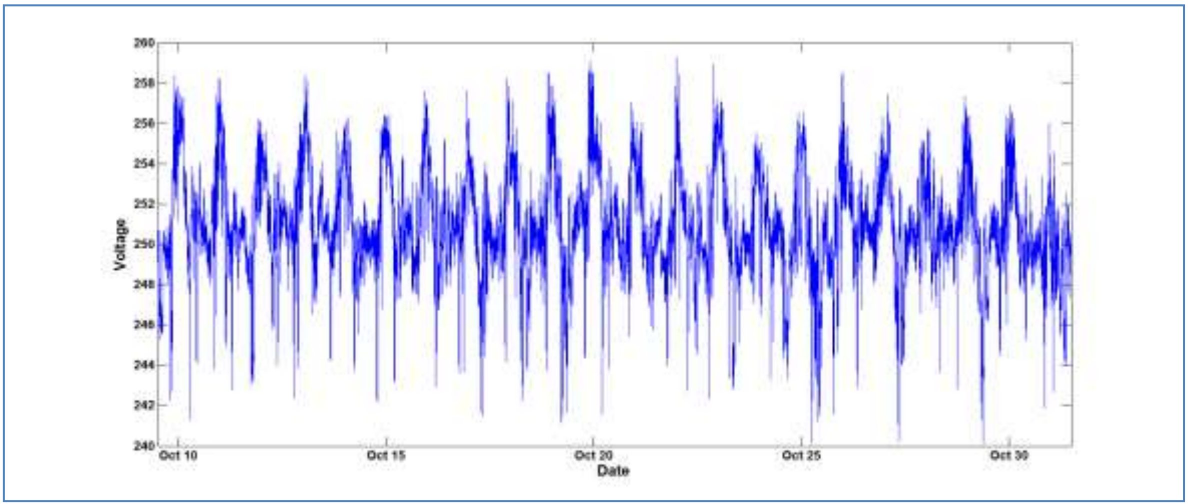


Figure 17: Voltage recording for customer connected to TVS55 during October 2009 before relocation and upgrade[24]

[24] 2009 Ergon Energy, TVS55 relocation project, internal report

Ergon Energy performed load flow modelling on the subdivision to determine the best course of action to bring voltage levels back to within regulation limits. It was discovered that high voltages were occurring during the middle of the day due to high tap settings on the DTx and low demand, in combination with what was at time a relatively small amount of PV exporting power. The low voltages occurred during the peak demand periods; the demand was just too great and the DTx rating too small and poorly positioned. The final decision was to upgrade TVS55 and also to move it closer to the subdivision, at the point where the subdivision underground cabling connected to the overhead line. There were instances of voltages breaching 254 V at TVS55 before the relocation and upgrade. Afterwards, voltages were found to be within regulation limits. Figure 18 gives a voltage recording at TVS55 after the upgrade. The decision was also in anticipation of an increase in PV penetration on the DTx. Increasing the rating and moving the DTx meant less voltage drop during demand periods. It also allowed for the tap setting to be dropped so high voltages didn't occur during the middle of the day.

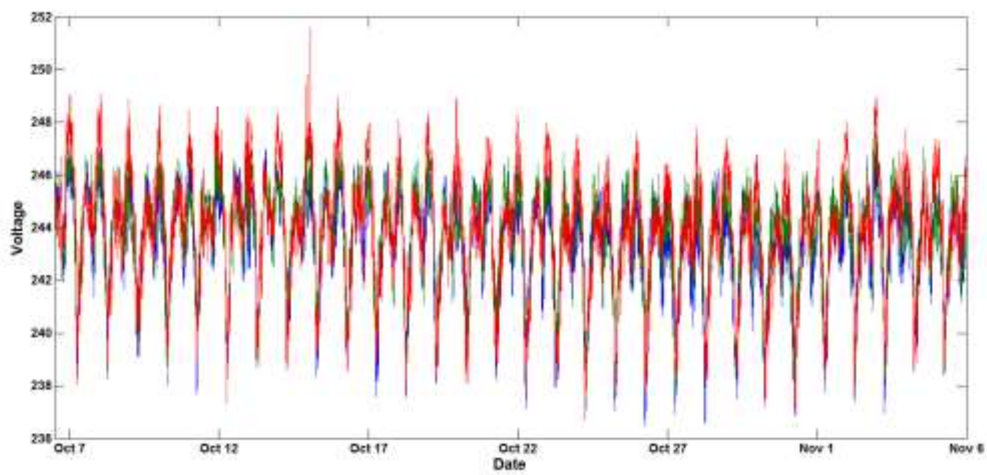


Figure 18: Voltage recording at TVS55 during October/November 2010 after relocation and upgrade[25]

4.2.2 Installation of Low Voltage Regulators at Smart Lifestyle Centre

There were also issues with high voltages occurring at the Smart Lifestyle Centre (SLC) located at the end of the feeder connected to TVS55. There is a PV installation (17 kW) at the SLC. The SLC experienced high voltage levels during the middle of the day when the PV system was exporting and demand was low. To resolve this problem a Low Voltage Regulator (LVR) was installed on all three phases at the SLC. The LVR, rated at 20kVA, is an AC to AC converter which can both buck and boost the voltage level. The LVR's were installed upstream of the PV system and SLC loads. The LVR's performed as expected. During the middle of the day, when the export of power from the SLC PV would result in high voltages at the SLC loads, the LVR would buck the voltage levels to 230 V. Figure 19 shows the voltage upstream of the LVR's and Figure 20 shows the voltage downstream. The data is for the same time period. The y-axis range for Figure 20 is set the same as for Figure 19 to give the relative range in voltage fluctuations and illustrating how well the LVR's manage the voltage. The LVR's also removed the possibility of low voltage at the SLC loads during the evening peak demand period, boosting the voltage to 230 V at these times.

[25] 2009 Ergon Energy, TVS55 relocation project, internal report

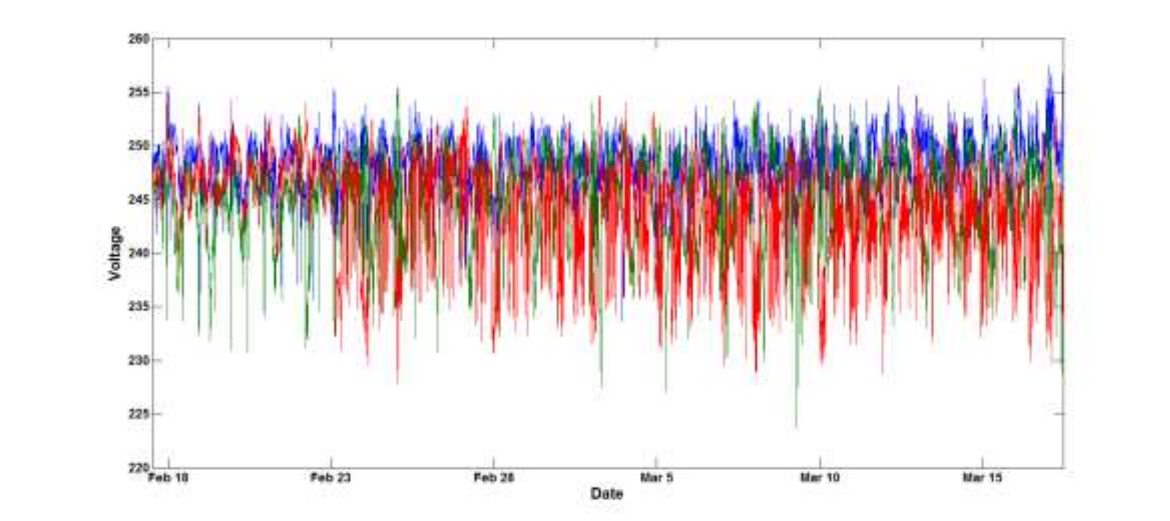


Figure 19: Voltage recordings upstream of LVR's at SLC during February/March 2011[26]

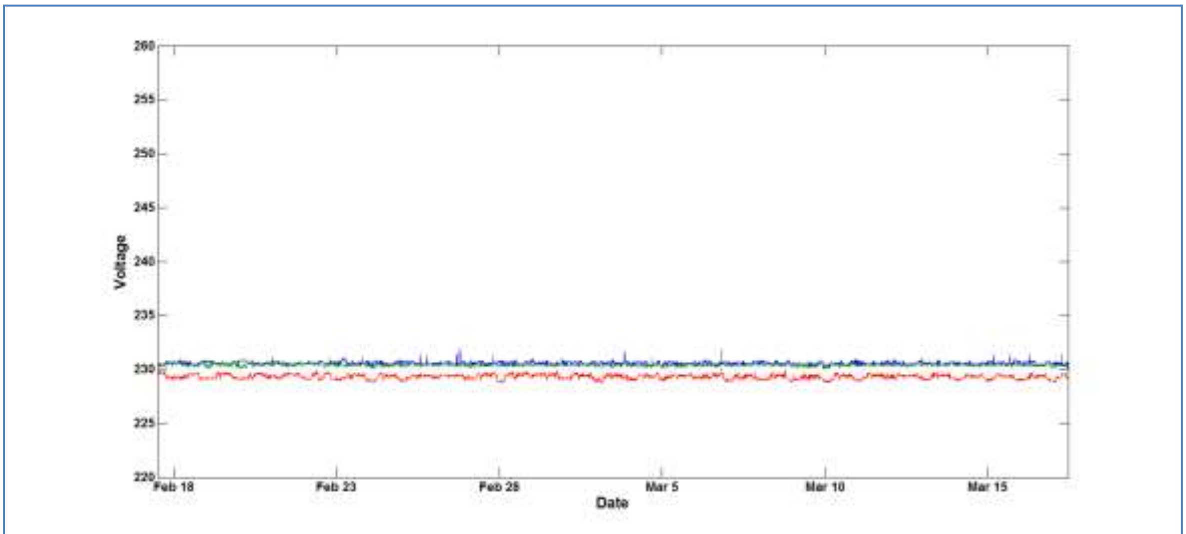


Figure 20: Voltage recordings downstream of LVR's at SLC during February/March 2011[26]

4.2.3 Redflow Battery Trial and Data Monitoring Project

During the period when voltage issues were being experienced around the Horseshoe Bay area on TVS55, Ergon undertook a Redflow (zinc-bromide) battery trial and data monitoring project to assess the impact of distributed storage on the network. Figure 21 gives a geographical layout of the area where the project was undertaken.

[26] 2011 Ergon Energy, Smart lifestyle centre low voltage regulator project, internal report

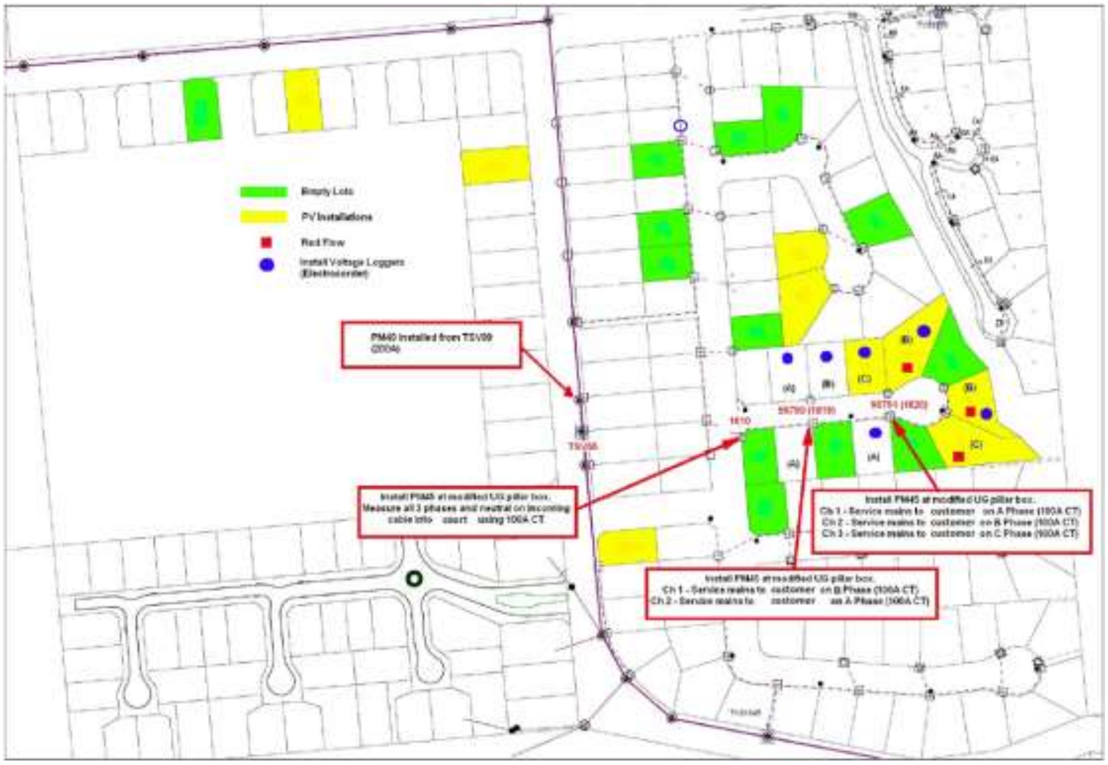


Figure 21: Geographical layout of Redflow project area[27]

Data logging consisted of:

- Gridsense Powermonic device on the feeder
- Gridsense Powermonic device on 2 underground pillars servicing the court
- Electrocorder voltage loggers and Ampy EM1200 smart meters at 6 premises

The 3 Redflow batteries installed as well as the PV systems had the following data recorded:

- Redflow voltage and current
- PV Generation
- Inverter charge and discharge.

The purpose of the trial was investigative; to gather load profile and PV generation data, see how the Redflow batteries performed and how their charging/discharging impacted on the network. The project did not result in a product that was ready for Ergon Energy to use, however, it has provided clarity for the work required to connect battery systems to the grid and other valuable learnings on integrating storage into the network. Table 10Table 10 gives the Redflow battery configuration.

[27] 2009 Ergon Energy, TVS55 relocation project, internal report

Table 10: Redflow battery configuration

Duration	Setting
2 weeks	Disabled
1 week	Charge during peak PV generation (9 am to 3 pm) and discharge during peak load (5 pm to 7 pm)
1 week	Charge during the night (12 am to 6 am) and discharge during peak load (5 pm to 7 pm)

There is limited data available from the trial. Figure 22 below, from an Ergon Energy internal report on the trial, gives the total house load (kW), PV generation (kW) and grid voltage for one customer for one day. The PV at this residence is rated at 3.24 kW and the Redflow battery has a capacity of 16 Ah. At midday approximately 1.3 kW was being exported back into the grid from the PV system, whilst remaining capacity is charging the battery. The battery then discharged its energy into the grid from 5 – 7 pm as per its configuration. Despite the battery absorbing some of the power which otherwise would have been exported into the grid, and therefore reducing voltage rise, voltages above regulation limits of 254 V are still recorded at the premises. On this day the PV system exported ~34 Ah of energy, in addition to the 16 Ah of energy it supplied to the battery. For the battery to absorb all of the PV energy it would need to be triple the capacity.

Batteries certainly compliment PV systems, they absorb their excess power during periods of low load, reducing voltage rise. This absorbed power can also then be used to reduce peak demand in the evening. Due to the large amount of downtime of these demonstration Redflow batteries during this trial there was insufficient data to draw any conclusions on the impact of their charging/discharging on the network.

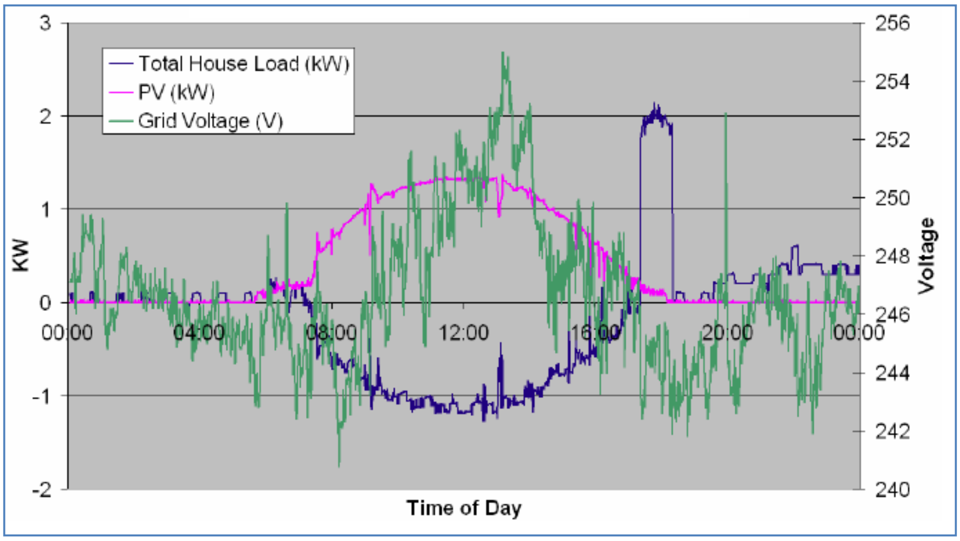


Figure 22: Total house load (kW), PV generation (kW) and Voltage (V) for premises with Redflow battery [28]

[28] 2011 Ergon Energy, 'Grid Effects, Investigation into the Effects of PVs and CFLs on the LV Distribution Network', internal report

4.2.4 Reactive Power Injection Trial – Solar Skate Park

Ergon Energy conducted a reactive power injection trial utilising the 100 kW Solar Skate Park (SSP) PV system. The SSP is next to the Smart Lifestyle Centre (SLC), located at the end of the LV feeder connected to TVS55. During the design phase for the SSP, it was identified that there would be an 18 V voltage rise on the LV feeder due to the SSP. To remedy this, the SSP was connected to a dedicated DTx, but also has the ability to manually disconnect from the dedicated DTx and connect to the TVS55 LV feeder. The reactive power injection trial was conducted with the SSP connected to both at different times.

The SSP interfaces to the network through 7 SMA Sunny Tripower inverters. Three scenarios were trialled: inverters injecting at unity power factor, power factor 0.8 under-excited (absorbing reactive power) and power factor 0.8 over-excited (injecting reactive power). Figure 23 shows the voltage profile with the inverters at unity power factor. As expected, there is voltage rise around the middle of day when PV generation is highest. Voltage levels are within regulation limits throughout the day. The SSP PV output peaks at around 80 kW on this day.

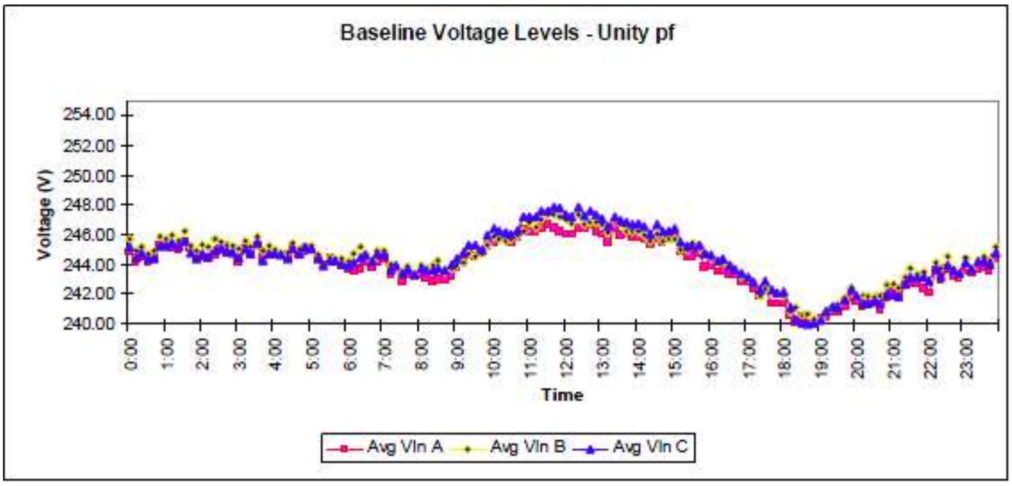


Figure 23: Voltage profile SSP at unity power factor[29]

Figure 24 shows the voltage profile when the SSP is absorbing VARs. As expected, voltage levels are lower than for when the SSP is operating at unity power factor. When absorbing VARs, a portion (greater than when generating at unity or injecting reactive power) of the generated (absorbed) current is in phase with the generally inductive current on the feeder due to the other loads and the inductive nature of the cabling. Because it is in phase this portion of current adds to the overall load, drawing inductive current from the grid and contributing to voltage drop.

[29] 2013 Dean Condon, Ergon Energy, 'Grid Connected Solar PV and Reactive Power in a Low Voltage Distribution Network'

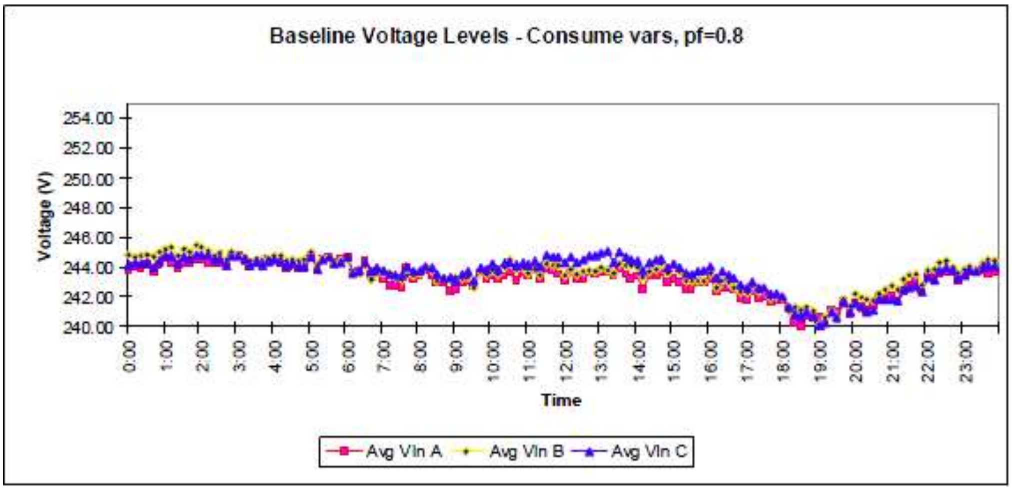


Figure 24: Voltage profile SSP absorbing VARs[29]

In contrast, when the SSP is injecting VARs, the voltage levels rise to around 250 V during the middle of the day, as shown in Figure 25. In this scenario, the portion of generated (injected) current is out of phase with the normally inductive current – it therefore acts to reduce the overall load resulting in a greater net current being exported and greater voltage rise.

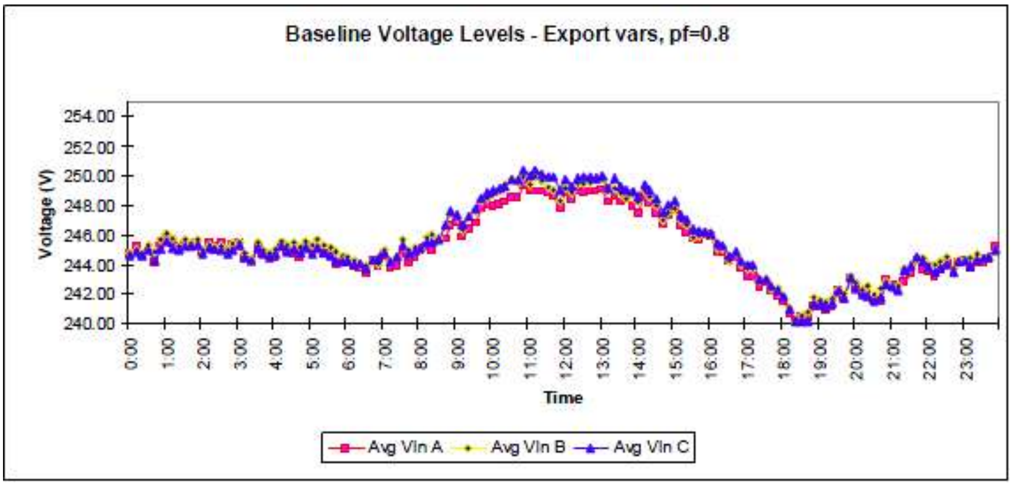


Figure 25: Voltage profile SSP injecting VARs[29]

4.2.5 St Andrews Close Grid Smart Grid Trial

Ergon Energy also conducted a second trial at St Andrews Close, a residential area, on managing voltage levels through reactive power injection - this is a recent trial with the report on results produced in February 2013. At St Andrews Close, a total of 14 customers are connected to a 100 kVA transformer, with 8 having rooftop PV systems sized between 2.5 and 5.0 kW. Each system has individual Volt/VAR control. It should be noted that St Andrews Close is located in Townsville and not on Magnetic Island. Even so, this trial is still considered worth mentioning in this report as it is indicative of Ergon's intention to continue supporting the installation and impact management of distributed PV on its network. The point of the trial was to test the hypothesis that Volt/VAR control could be utilised to maximise PV system output whilst at the same time managing voltage levels.

The trial gives results for a day in each season: Spring, Summer, Autumn and Winter. Results give the voltage levels across the day for each phase at the end of the line (EOL) and at the distribution transformer for two inverter configurations: 100% real power and 100% available reactive power. For all seasons, phases A and B behave as expected with a reduction in voltage at both the transformer and at the end of the line when the inverters are configured for 100% available reactive power. What is unexpected is that phase C actually exhibits an increase in voltage when its inverters are injecting 100% of the available reactive power – i.e. reverse power flow is occurring on phase C, with the EOL voltage higher than the transformer voltage. This reverse power flow in phase C could be the result of an imbalance in PV generation and demand across the phases and illustrates the importance of having balanced PV generation and load when utilising Volt/VAR control to manage voltage. Figure 26 gives the EOL voltage for Summer for 100% real and 100% available reactive power and shows the drop in voltage for phases A and B and the slight increase for phase C.

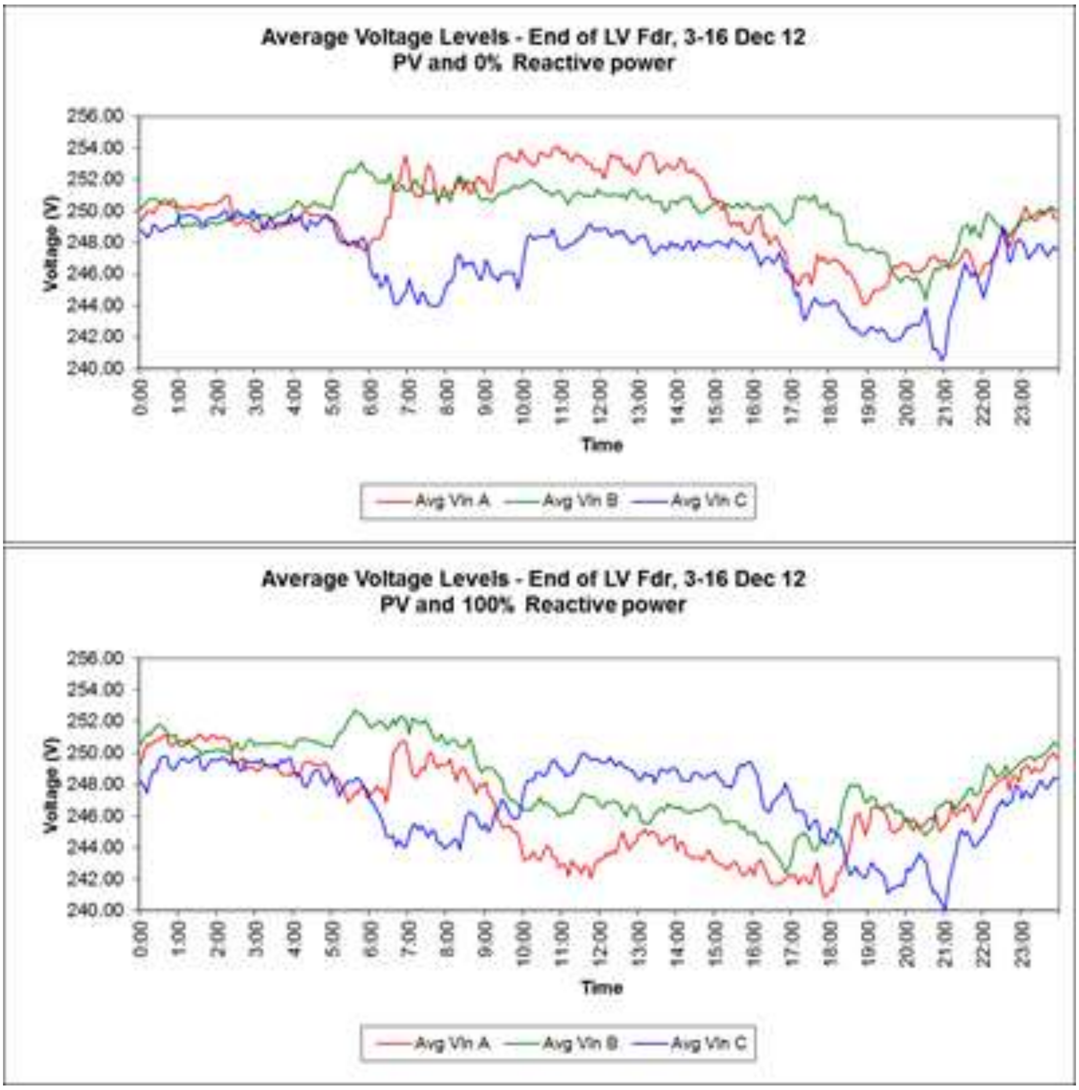


Figure 26: St Andrews close Volt/VAR trial: EOL voltage, Summer[30]

[30] 2013 Ergon Energy, 'Grid Smart PV Test Plan', Internal Report

5 BENEFITS OF PV SYSTEMS ON MAGNETIC ISLAND AND TOWNSVILLE SOLAR CITY

The total energy generated by PV on Magnetic Island between November 2011 to October 2012 amounts to approximately 2 GWh. This amounts to a reduction in greenhouse emissions of approximately 1800 tCO_2e (assuming that the PV offsets fossil fuel generation of average NEM emissions intensity 0.9tCO_2/MWh.[31]

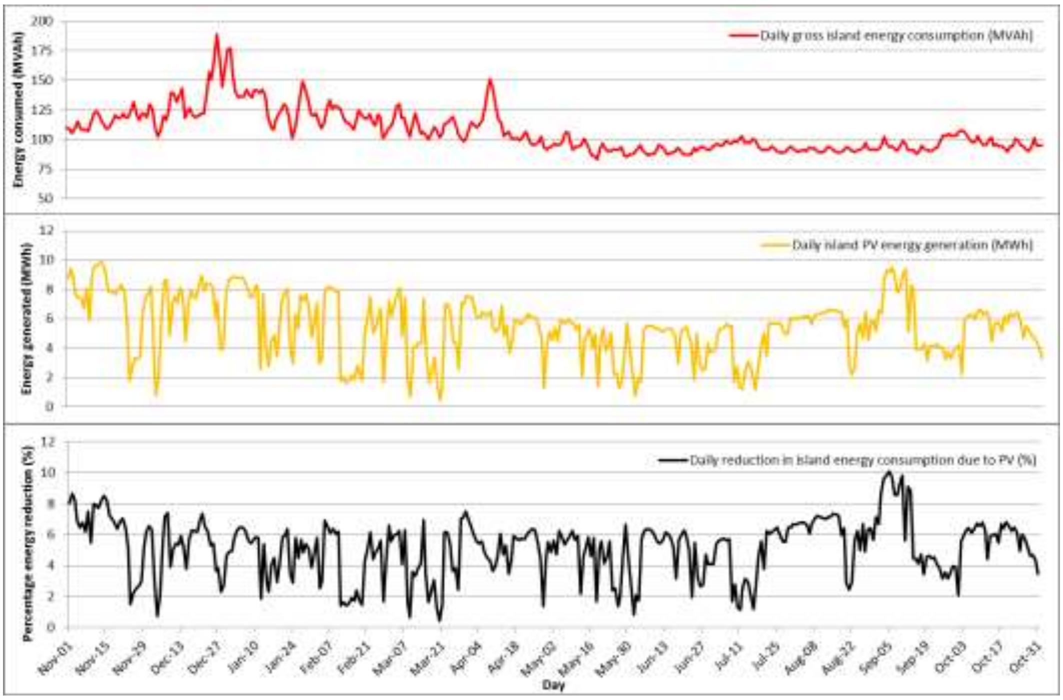


Figure 27: Reduction in energy demand from the grid for Magnetic Island due to PV generation (%)

PV does not contribute to reducing peak demand on Magnetic Island, which has a typical residential evening peak; but does contribute to reducing overall loading on network equipment and, importantly, contributes to deloading of DTxs on peak days in the lead up to peak demand. The Christmas period, Figure 28, produces 7 out of the 10 peak demand days for the year, including the highest 6. The other 3 occur during Easter. The reduced demand (shown in red) during the day due to PV means a reduction in thermal stress on TOMA10 leading into the peak and improved lifetime through reduced loading throughout the year.

[31] 2011 Productivity Commission, 'Emission Reduction Policies and Carbon Prices in Key Economies', Appendix D: Australia's Electricity Generation Sector, http://www.pc.gov.au/__data/assets/pdf_file/0004/109921/13-carbon-prices-appendixd.pdf

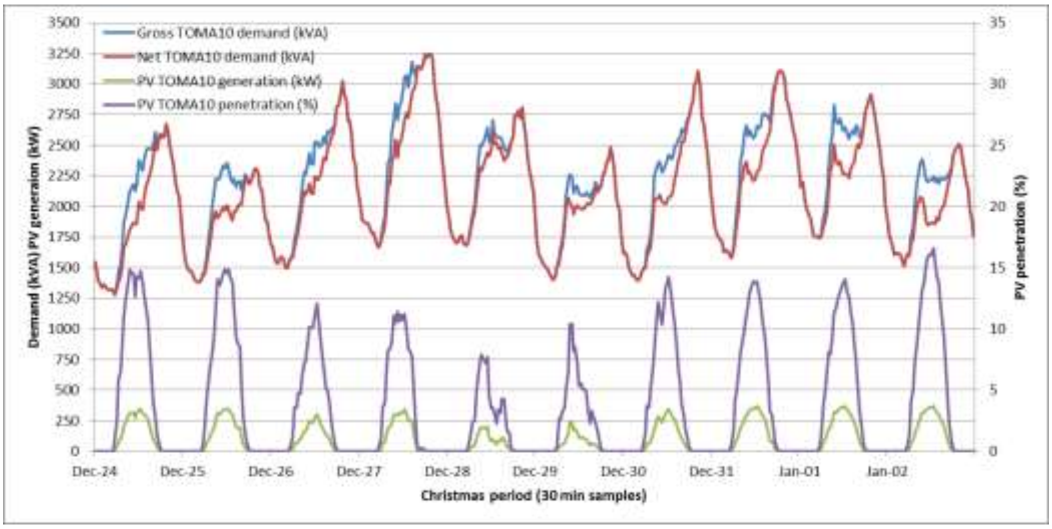


Figure 28: Impact of PV de-loading on TOMA10 on peak day

PV on Magnetic Island has been a key part of the engagement of customers within the overall strategy of the Solar City program. In addition, through addressing the challenges associated with increasing PV penetrations, Ergon Energy has become active in the management of distributed energy opportunities within their distribution system. PV, combined with management approaches, storage, tariffs and smart grid technology, such as those trialled within the Solar City program, have the potential to beneficially alter load profiles and reduce future network peaks.

6 CONCLUSIONS AND FUTURE WORK

This section summarises the key conclusions from the Magnetic Island case study in the context of the IEA PVPS Task 14 framework and presents areas requiring further investigation.

6.1 Conclusions

Through the Townsville Solar Cities initiative, a large number of PV systems have been installed on Magnetic Island. Additional systems have been installed in response to other State and Federal government support programs. In total, there are now 325 distributed PV systems on Magnetic Island, with an average size of 3.08 kW (excluding the 100 kW Skate Park system). The peak penetration of PV (expressed as the ratio of PV output kW to load) was 33% between November 2011 and October 2012. 35% of distribution transformers have a ratio of installed PV capacity to transformer capacity greater than 15%.

PV deployment over the past three years in the Ergon Energy area, and the Australian electricity industry more generally, represents a remarkable transformation of the electricity industry driven by customers responding to supportive PV policies, falling PV prices (driven in turn by growing deployment), growing environmental concerns and rising retail electricity tariffs. The technology provides clean energy with no operating emissions, greenhouse gases or other pollutants, and is becoming increasingly cost effective by comparison with other generation options. However, it does present a range of novel issues, given its location in the distribution network at customer premises, its power electronics interface, and the highly variable and somewhat unpredictable nature of the solar resource. As such, it presents a range of new challenges for network service providers.

Ergon Energy is currently experiencing voltage control issues with the existing PV penetration on their network, including on Magnetic Island. None of the other potential power quality issues: reverse power flow, power factor distortion or harmonics, have been apparent on Magnetic Island or elsewhere in Ergon Energy's networks, although there have been protection concerns raised in relation to the risks of islanding. Ergon Energy has successfully addressed all voltage excursion issues to date, through standard upgrading of cabling, network balancing and settings, or through the installation of voltage control, and also has good procedures in place to reduce future voltage concerns.

The demand for new PV systems and installation of air conditioning systems on Ergon Energy's network continues. Ergon Energy therefore expects voltage issues to increase and has some concerns about further power quality issues and protection issues that might emerge with a higher penetration of PV systems. In response, the company continues to trial and to introduce new technologies and procedures for mitigating and preventing voltage and other power quality issues. These include energy storage, although there is insufficient data to date to make any conclusion on its impact, two successful trials on Volt/VAR control to manage reactive power and reduce voltage levels, the introduction of tests to detect potential voltage issues before and directly after PV installation, and revisiting the assessment process for the application of larger scale PV systems.

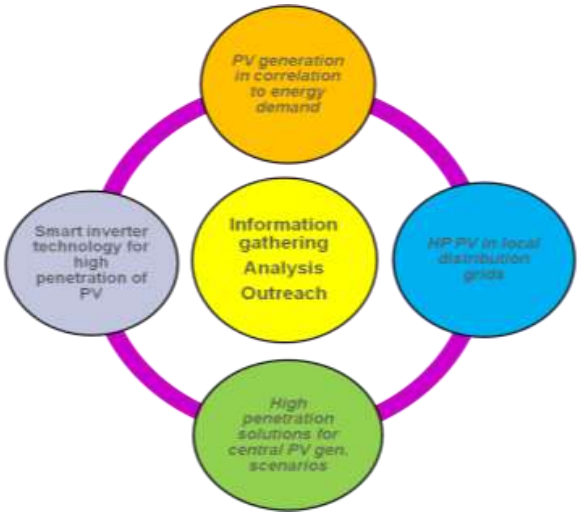
To date Ergon Energy has successfully managed the integration of high levels of distributed PV on Magnetic Island. The results from ongoing trials will also provide Ergon Energy with a greater understanding of PV integration challenges as distributed PV deployment continues to expand, and will assist the understanding of challenges and opportunities created by growing PV penetrations elsewhere in Australia.

APPENDIX 1 - IEA PVPS TASK 14 ON HIGH PV PENETRATION IN ELECTRICITY GRIDS

The International Energy Agency (IEA) Photovoltaic Power Systems Programme (PVPS) conducts joint projects in the application of photovoltaic conversion of solar energy into electricity (see www.iea-pvps.org/). Currently six research projects, so-called Tasks, are operating within the IEA PVPS Programme: Tasks 1, 8, 9, 12, 13 and 14.

IEA PVPS Task 14 (www.iea-pvps.org/index.php?id=58#c92) provides a forum for all IEA countries to share knowledge on the grid integration of PV in High Penetration scenarios. Currently, experts from research organisations and industry in Australia, Austria, Canada, China, Denmark, France, Germany, Italy, Israel, Japan, Norway, Portugal, the U.S.A, Spain, Sweden and Switzerland are participating in Task 14.

The work being undertaken in Task 14 is in the areas shown in the diagram below.



Specific activities being carried out within each area include:

- Cross-cutting subtask: Information Gathering, Analysis and Outreach
  - Setup of a repository for information and exchange of models.
  - Collection and analysis of state of the art information about existing high penetration PV installations.
  - Gathering a collection of existing modelling information.
  - Selecting and refining a set of pertinent cases for publication.
- Subtask 1: PV generation in correlation to energy demand.
  - Development of Prediction Tools.
  - Network driven demand side management.
- Subtask 2: High penetration PV in local distribution grids
  - Review of State-of-the-Art.
  - Optimized Reactive Power Balancing.
  - Optimized Active Power Control Strategies.
  - Change from Distribution to Supply Grids, and Dynamic Studies.
- Subtask 3: High penetration solutions for centralised PV generation scenarios
  - System-wide PV generation analysis and forecasting.

- Power system operation planning with PV integration.
- Power system augmentation planning with PV integration.

- Subtask 4: Smart inverter technology for high penetration of PV
  - Opportunities for Smart PV inverters in High-Penetration scenarios.
  - Technical capabilities and Inverter Topologies.
  - Remote control and communication for Smart Inverters.