Investigating the Impact of Solar Variability on Grid Stability

Prepared by

CAT Projects & ARENA for public distribution

March 2015

This report was produced with funding support from the Australian Renewable Energy Agency (ARENA). ARENA was established by the Australian Government as an independent agency on 1 July 2012 to make renewable energy technologies more affordable and increase the amount of renewable energy used in Australia. ARENA invests in renewable energy projects, supports research and development activities, boosts job creation and industry development, and increases knowledge about renewable energy.

Ekistica Pty Ltd, trading as CAT Projects ABN 74 126 787 853

1 EXECUTIVE SUMMARY

Photovoltaic (PV) technology has in recent years become a significant form of power generation on many electricity networks. Electricity utilities who manage these networks have raised concerns regarding the impact of high penetration by photovoltaics into these distribution grids. These concerns generally focus on issues of grid management, and operation and planning, particularly where there is variability in PV system output due to cloud cover. Variability in PV irradiance is often cited as a major impediment to high levels of PV penetration into existing electrical networks.

This report is the result of a research project undertaken by CAT Projects and ARENA during 2013 and 2014. The project investigated the impacts of solar radiation variability on PV power output in existing electrical grids. The key aim was to develop an improved estimate for the maximum penetration of grid-connected solar generators achievable without energy storage. The research took into account the solar generators' distribution across the geographical area of the grid based on the hypothesis that *the impact of weather variation is mitigated by the distribution of solar generators across the geographical extent of the grid* – i.e. clouds passing across the area will not affect all generators simultaneously.

The study aimed to quantify the mitigation of geographical distribution on instantaneous weather effects by comparing the data from an array of pyranometers, anemometers and temperature sensors installed across the extent of the Alice Springs electricity grid.

Research for this project was undertaken in Alice Springs, Northern Territory during 2013 and 2014. Three methods of data collection were employed:

1. **Remote Monitoring Stations**: These stand-alone stations were purposely designed, constructed and installed across the greater Alice Springs area to provide solar irradiance and wind data for this study;
2. **Desert Knowledge Australia Solar Centre (DKASC):** A long term solar demonstration facility located in Alice Springs that is able to provide high level solar irradiance and wind data; and,
3. **Power and Water Corporation (PWC):** the local utility company and project partner provided load data for the whole of Alice Springs.

In May of 2013, the first of eight new remote monitoring stations were commissioned. By June of the same year all nine monitoring sites were operational and from July 2013 full monthly data sets for all sites were being generated.

Key conclusions include:

1. **Pyranometers, by themselves, should not be considered as a useful real time predictive tool in PV output**. Given the vagaries of wind effects and the impact of spatial distribution, they are unable to forecast the extent of the variability that exists in a given electricity grid.
2. There is an assumption that large multinodal electricity grids are inherently stable (i.e. they do not experience large short term variances in demand) and that the addition of significant PV input and associated intermittency potential could cause disruptions that would increase the risk of operational problems. However, results from this project indicate that the **Alice Springs grid** (which is analogous to many other grids in regional and remote areas as well as many sections of the National Energy Market) **encounters a significant level of load variance as part of normal operation**. In other words, the network already accommodates a high degree of variability without compromising on operational outcomes.
3. Furthermore, results show that for Alice Springs **the variance created by the installation of a further 10MW** of **dispersed PV inputs into electricity grids can end up being very similar to the step-change 'noise' variance which currently occurs in the network**. The results demonstrate empirically that it is possible to install large amounts of PV, potentially exceeding 60% of demand, into existing networks without disrupting the underlying variance that normally exists in grids, as long as there is adequate spatial distribution of the PV input.

While it is not surprising that the impact of solar intermittency can be reduced by geographically dispersing PV arrays, the statistical significance of the impact was beyond initial expectation.

In this project, the highest levels of solar variability and corresponding aggregate load in the Alice Springs network were selected to demonstrate this point. In both cases the level of intermittency when a distributed array is put in place comes close to the level of variability extant within the load profile in the first place.

Namely, a weekday in January after school had returned (highest load) and a weekend in September (lowest load), as shown in Figure 3 and Figure 4, below.

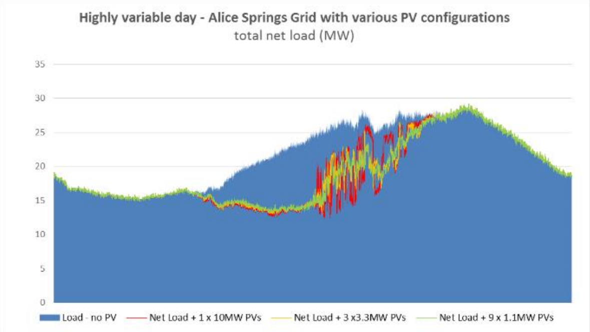

Figure 1: Highest level of solar variability and corresponding aggregate load – lowest load day 29 September 2013

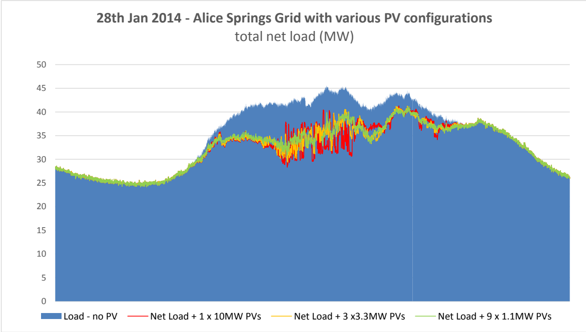

Figure 2: Highest level of solar variability and corresponding aggregate load – highest load day January 28 2013

The graphs above show the extant demand (Blue) matched against the effective aggregate demand seen by the generators under the three different scenarios:

- Existing demand + 10MW single PV array (Red);
- Existing load + 3*3.3MW PV arrays (Yellow);
- Existing load + 9*1.1MW PV arrays (Green);

As can be seen, the apparent instability in the demand evident with the inclusions of a single 10MWp array is substantially reduced when the arrays are separated into nine 1.1MWp arrays. This can be further quantified by measuring the statistical variance of the step changes in the demand over the course of the day and then comparing that to the variance when the different models are overlaid.

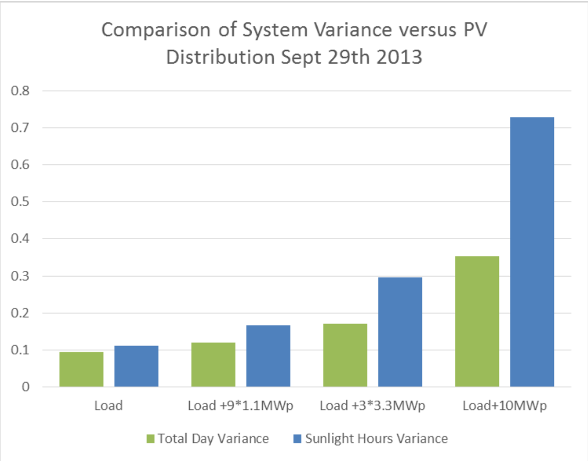

Figure 3: Measures of variance in step changes Sept 29th, 2013

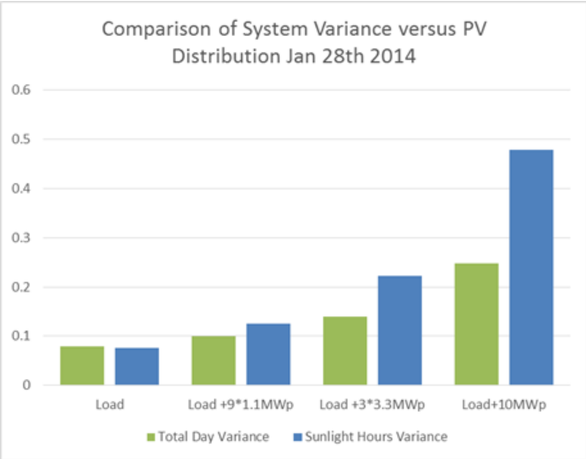

Figure 4: Measures of variance in step changes for Jan 28th, 2014

The graphs above, demonstrate that the statistical level of variability that would be seen by the system generators is higher with the larger presence of PV in the network than if it was not there at all, however it is ***no greater than the most significant variance that the generation units within the system currently accommodate***. The extant variance in the network in sunlight hours for September is 0.11, with the variance in January including nine 1.1MW PV plants is 0.12, thus demonstrating that the existing spinning reserve strategies could accommodate further PV integration without substantive change.

It is important to note, however, that the conclusions reached above are in the context of the **entire** network and power system, and there may be **local** areas of the networks where such installations are not appropriate due to other gird constraints including voltage rise, current limits and frequency variability etc.

Sites must be spatially dispersed to achieve this effect but as long as there is reasonable spatial dispersion then by far the most important determinant in reducing the variability of PV generation is to increase the total number of sites. The appropriate distance to achieve the full effects of spatial diversity is dependent on the average wind speeds for the region in question – in Alice Springs it was found to be between 3-5km. Locations with higher wind speeds may require larger distances.

While undertaking this project, future research directions became apparent, including:

- This type of study should be replicated in other grids (for example in a coastal location) in order to establish the degree of spatial diversity of PV input that is optimal given differing prevailing weather conditions, i.e. average wind speeds;
- Further research and economic modelling is required to compare the **cost imposition of different options** for PV input. That is, for example, the cost of installing nine 1.1MW systems, versus three 3.3MW systems, versus one 10MW system; and
- Analysis of the **size, number and spatial diversity to optimise PV input** (and limit the effects of variance) into the grid should be undertaken with a view to determining the **marginal benefit of additional diversity** and/or the extent to which the benefits of diversity diminish if the separation of systems gets too great.

2 CONTENTS

3 LIST OF TABLES AND FIGURES

3.1 LIST OF TABLES

3.2 LIST OF FIGURES

4 ACKNOWLEDGEMENTS

This report was prepared as an outcome of a project developed in partnership between the Northern Territory Power and Water Corporation and CAT Projects. Power and Water Corporation provided significant in-kind support, including material, data and manpower without which the project would not have been at all successful.

The project received funding from the Australian Renewable Energy Agency.

The authors of the report wish to specifically acknowledge the contribution of Trevor Horman from Power and Water Corporation.

5 BACKGROUND

Photovoltaic (PV) technology has in recent years become a significant form of power generation on many electricity networks. Electricity utilities who manage these networks have raised concerns regarding the impact of high penetration by photovoltaics into these distribution grids. Concerns generally focus on issues of grid management, operation and planning, particularly where there is variability in PV system output due to cloud cover. Variability in PV irradiance is an often cited as a major impediment to high levels of PV penetration into existing electrical networks.

This report is the result of a research project undertaken by CAT Projects and the Northern Territory Power and Water Corporation (PWC) supported by funding from ARENA during 2013/14. The project investigated the impacts of solar radiation variability on PV power output in existing electrical grids, specifically on the Alice Springs grid. The key aim was to develop an improved estimate for the maximum penetration of grid-connect solar generators achievable without energy storage. The research took into account the solar generators' distribution across the geographical area of the grid. This was based on the hypothesis that the impact of weather variation is mitigated by the distribution of solar generators across the geographical extent of the grid, which is that clouds passing across the area will not affect all generators simultaneously.

A second aim of this study was to understand the degree to which high penetration PV can be integrated into an electricity network without energy storage. Solar irradiance is the key determinant of PV system power output[1], and normally experiences a linear relationship. As solar irradiance rises and falls, PV system output corresponds.

Solar irradiance follows a predictable diurnal and seasonal pattern but is subject to the natural variability and unpredictability of local weather conditions, particularly intermittency of cloud cover. Intermittent solar radiation results in intermittency in PV generation. Where significant capacity of PV generation is installed on an electricity network this variability in PV generation can have a potentially negative impact on the local electricity network. The potential issues can be localized (feeder or substation level) or network wide depending on the existing network architecture and how the PV system integrates into this architecture.

Network level problems occur where intermittent changes in PV generation on a power network are unable to be accommodated by the base load generation over the time frame of the change. This potential mismatch in ramp rates in interconnected generation sources and the dynamics of the system load can lead to issues with power quality and even network outages. These changes are often cited as a limitation to the amount of PV system penetration installed into existing electricity grids. The potential impacts of intermittent generation occur at different time scales and the associated considerations include:

1. **Power quality**:
   Rapid changes in network demand or in supporting generation (i.e. PV) can cause power quality issues such voltage flicker, harmonic distortion.
   Response Time Scale: Seconds
2. **Operating reserve**:
   The spinning reserve of operating network generation is required to have sufficient total capacity and ramping capability to meet short term changes in network demand or in supporting generation (i.e. PV). Failure to do this will lead to power quality and system outage issues.
   Response Time Scale: Minutes
3. **Generating Unit-commitment and Scheduling:**
   Generation planning requires sufficient generation to be available at any time to provide the projected network demand and sufficient operating reserve.
   Response Time Scale: Hours to days

PV generation also impacts networks at the local level of feeders and substations. These impacts are complex (and not necessarily related to PV generation intermittency) and are highly specific to local conditions, such as demand profiles, network configurations and existing hardware limitations. These localised impacts are important and need to be a key consideration when determining the detailed architecture of high penetration PV integration within grids. However, these impacts are beyond the scope of this study, which focused on the network or system level of PV integration.

[1] A range of other factors also influence PV output, including module operating temperature, spectral response, inverter capacity clipping of irradiance extremes and others.

5.1 ALICE SPRINGS ELECTRICITY NETWORK

The Alice Springs electricity network is a relatively small 'island' grid which provides power to the greater Alice Springs area, including some defence facilities, aerodromes and remote communities up to 100km from the town centre. The network sees a peak demand of ~55MW in the summer months and meets this demand through a range of generators distributed across the network. In recent years the network has seen a rapidly increasing uptake of PV generation and at present the nominal capacity of PV on the network is ~ 4.0MW.

In investigating the question of the impact of variability on grid stability and other related questions, one of the key challenges is being able to test and analyse different scenarios in a scaled fashion that allow for comparison to grids in other locations and contexts. Alice Springs is uniquely placed within Australia to test and evaluate variability and issues surrounding higher level integration of solar PV into mainstream grids.

Alice Springs has some unique characteristics that allow it be a viable and useful proxy for larger grids:

1. A peak demand of around 55MW;
2. A grid that spans up to 100km in each direction;
3. Multiple sources of generation including:
    a) Diesel and natural gas reciprocating engines
    b) Natural gas turbines
    c) Independent Power Producers and Utility generation
    d) Utility scale PV supplied via a PPA to PWC Generation
    e) 66kV transmission, with 11kV and 22kV distribution

Given all of the above, it can be appreciated that lessons learnt in Alice Springs will be analogous to those that could be expected to be learnt in much larger grids, as well as many of the islanded grids in regional communities throughout Australia.

Generation and transmission in the Alice Springs network includes:

Generation

1. Gas/diesel generation stations
    a) Owen Springs: Three x 10.7MW natural gas reciprocating engines. Pilot fuel is about 1% distillate;
    b) Ron Goodin: 11.7MW gas turbine. And six lower merit order diesel generators. Many of these smaller units are scheduled for decommissioning;
    c) Brewer Estate: Four x 2MW spark ignition reciprocating engines;

2. PV generation (around 4.0MW, peak penetration around 8%):
    a) 1.2 MW PV systems – Residential;
    b) 1.8 MW PV systems – Commercial;
    c) 1 MW PV Plant (Uterne);
    d) The impact to date of PV on the network has been manageable, with the following considerations:
        - PWC has registered a noticeable impact of PV on network generation profile;
        - Voltage rise issues are becoming a concern at some local substations and feeders;
        - Some restrictions have been imposed, including residential systems now capped at 4.5kWp and commercial systems capped at a capacity that will ensure no export to the local network;

Transmission/Distribution Network

1. 66kV Transmission lines from Primary Generation point (Owen Springs) to main town area
2. 22kV and 11kV local distribution
3. Several private 11kV ring main networks e.g. Airport, Desert Knowledge Precinct etc.

The furthest extent of the grid is the community of Santa Teresa, 80km to the SSE of Alice Springs, as illustrated in Figure 5, below.

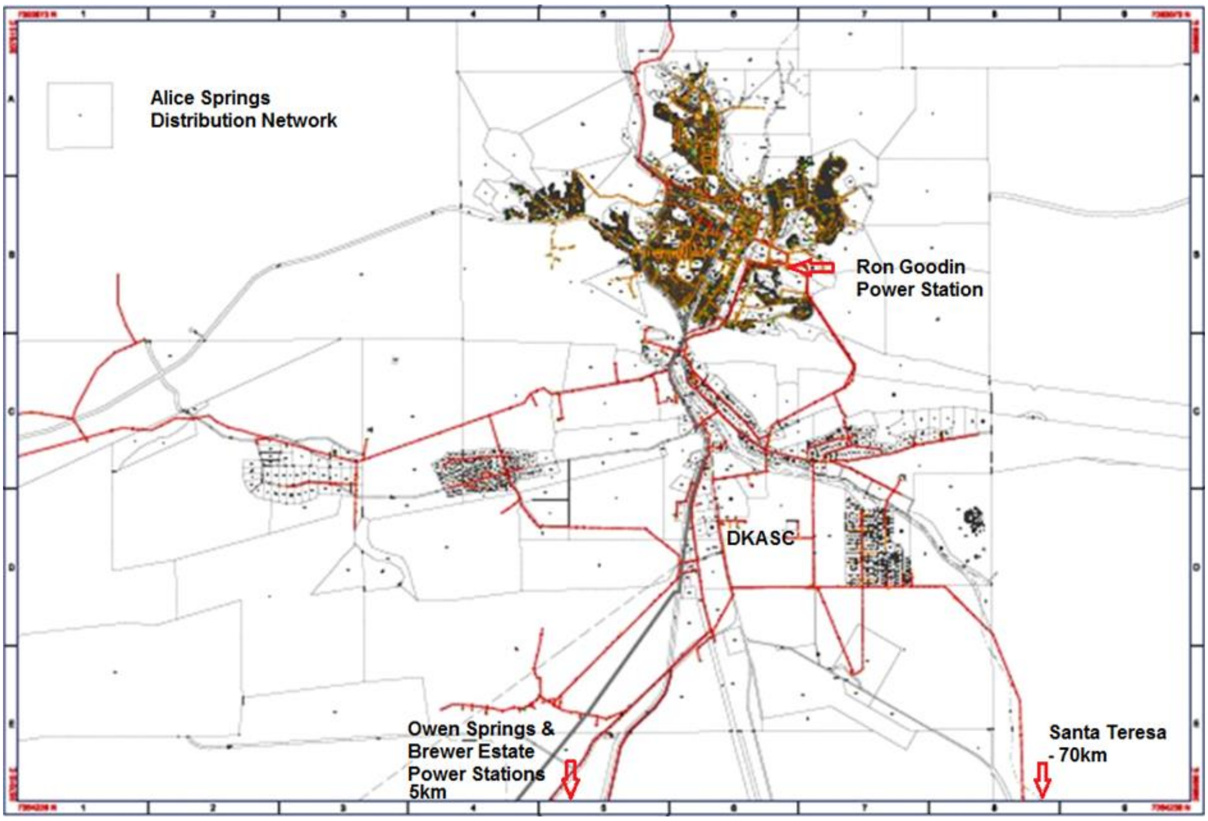

Figure 5: Alice Springs Network Layout

5.2 NETWORK DEMAND PROFILE

The Alice Springs network services a large and diverse range of loads. PWC's figure for peak demand in Alice Springs in 2014 is 53MW. PWC have projected this to rise to between 60MW and 63MW by 2020. The summers in Central Australia are long and hot with 35°C days being the norm, and frequent peaks to over 40°C. The winters are short but cold with night time temperatures commonly falling below 0°C. The net demand profile on the Alice Springs network is therefore largely dominated by two key factors:

1. Heating/Cooling loads
2. High working day demand versus low weekend demand

Figure 6, below, illustrates the seasonal profiles for both peak load and low load day's winter, summer and Spring/Autumn days in Alice Springs. These profiles are from selected days that provide the best representation of the high and low extremes over the monitoring period.

The peak load curves for each of the seasons show distinctly different profiles. The summer days are generally dominated by day time cooling loads that peak at around 15:00 hours at the time when schools and work places begin to close. The spring/autumn peaks follow the summer profile but are less pronounced. The winter days show morning and afternoon peaks but a generally flatter and much lower demand profile across the day. All the peak load profiles correspond to midweek working days.

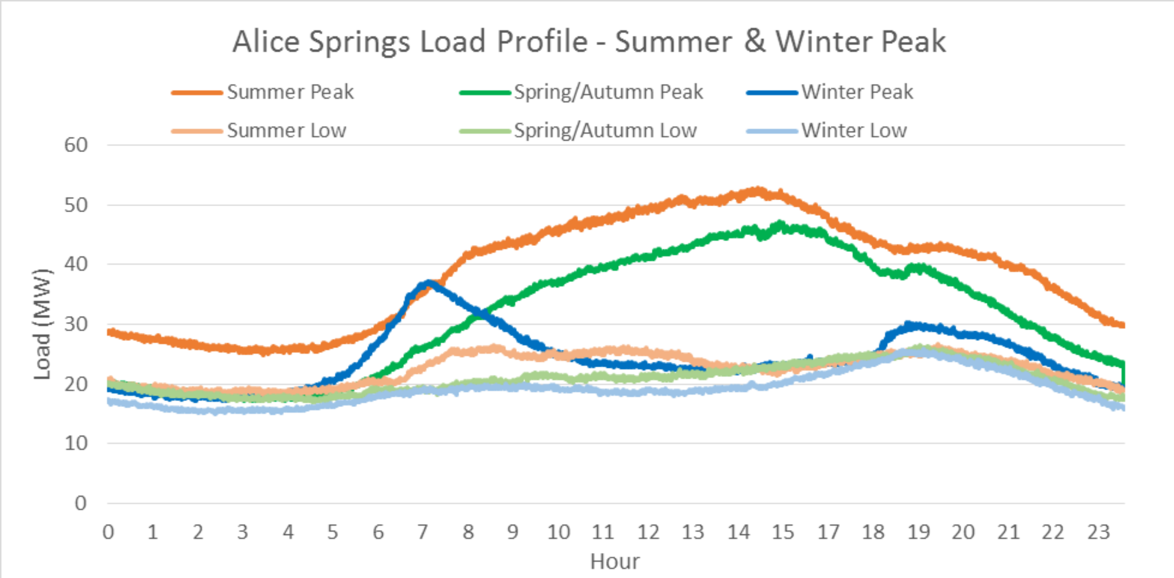

Figure 6: Alice Springs Load – Seasonal Profiles: Peak and Low

The low load seasonal profiles are very flat and correspond to weekend days where the ambient conditions are very mild in comparison to the seasonal average. The summer low load occurs on a cloudy cool day and winter low load occurs on a clear but warm winter day. The spring/autumn low follows the winter profile but is of a greater scale.

During the central day time period, PV generation is at its highest. This is the time when determining the impact of PV generation on the network is most important and the network demand at this time is of most interest in this study. Table 1 and Table 2 below provide a summary of the maximum, minimum and average demand for the peak and low load profiles between the times of 10:00 and 14:00. Considerable variability occurs in loads on the Alice Springs grid across the year, with daytime maximums in these times ranging from 27MW (winter peak) to 51.5MW (winter peak) and the minimums ranging from 18MW (winter low point) to 23.2MW (summer low point).

Table 1: Summary of Network Demand: From 10:00 and 14:00: Peak Period

Seasonal Demand: Peak: Hours 10:00 and 14:00	Max MW	Min MW	Average MW
Summer	51.5	43.6	48.0
Spring/Autumn	44.0	35.6	40.0
Winter	27.0	22.3	23.8

Table 2: Summary of Network Demand: From 10:00 and 14:00: Low Period

Seasonal Demand: Low: Hours 10:00 and 14:00	Max MW	Min MW	Average MW
Summer	26.3	23.2	25.0
Spring/Autumn	22.4	16.2	20.2
Winter	19.9	18.0	18.9

From both the load and weather data the minimum load during this time occurred in the winter months and fell as low as 16MW, and is likely to have corresponded to cool clear sky conditions in the winter months. In the summer months the minimum load during the peak PV generation period was around 23MW and corresponded to unseasonably cool and cloudy conditions.

It should be noted however that these demand profiles do not account for the 4MW of existing PV generation on the network. Though it is difficult to accurately estimate the net impact of the existing PV on the demand profiles, these demand values need to be modified to account for the portion of the load that is offset by existing PV generation. Without the PV the actual system demand would, depending on the irradiance and temperature conditions, expected to be higher by between 1 and 3MW. The estimated minimum network demand after this offset has been accounted for is summarised in Table 3, following.

Table 3: Estimated Minimum Network Generation: From 10:00 and 14:00. Excluding Existing PV

Seasonal Demand: Low: Hours 10:00 and 14:00	Min MW
Summer	25.0
Spring/Autumn	19.0
Winter	20.0

5.3 NETWORK DEMAND RAMPING

Instantaneous network demand is a key factor in determining the amount of PV that can be manageably integrated into the Alice Springs grid. The variability of this demand should also be understood. Step changes in the overall load are of interest because when they are coupled with step changes in PV generation they provide a total potential ramp rate that the base load generation is required to negotiate without causing power quality issues.

In Figure 7, below the frequency of measured step changes in total network demand per minute over the day time period are shown. What this shows is that over one minute intervals, the network demand generally ramps at a rate from 0.0 to 1.0MW and may ramp up or down as much as 2.0MW, but never exceeds this level. A similar pattern was seen for shorter time intervals (15 seconds) with the only difference being that the majority of step changes were in the 0.0 to 0.5MW range. From this data it seems safe to assume that allowing for a 2.0MW ramp in demand across the day time period will cover all likely circumstances.

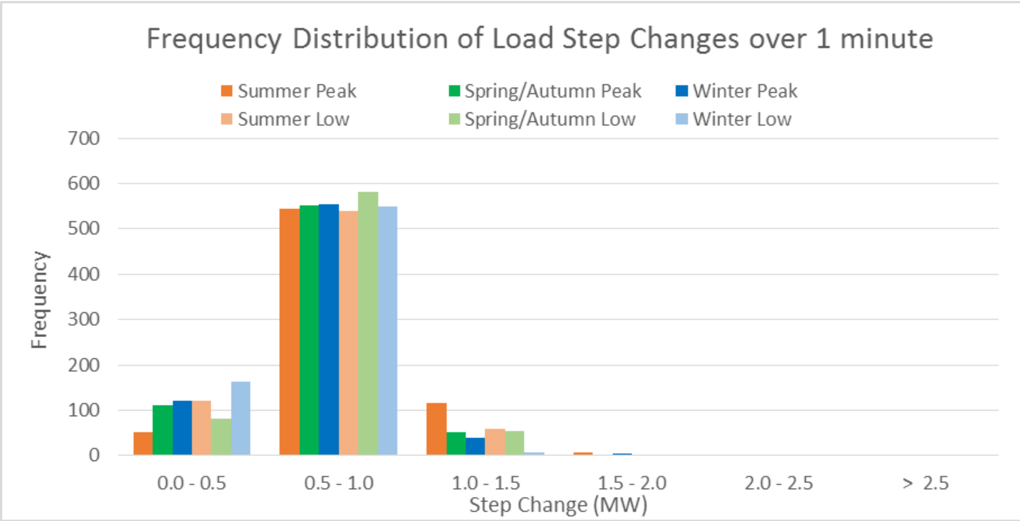

Figure 7: Summary of Step Changes in Network Demand

The same analysis, when completed for the entire data set, provides similar results. Figure 8 below shows the probability distribution for step changes in network demand over the entire assessment period. Clearly, for 99.99% of the time the network demand changes less than 1MW per time interval. Larger step changes do occur but are extremely rare and the 2MW maximum ramp in demand nominated above remains a reasonably conservative value to work with for our overall load assessment. The data does show a handful of very large step changes which are in excess of 5MW. These values are likely to represent localised load outages at the substation or feeder level, particularly as the distribution of these extreme values is much larger for the downside.

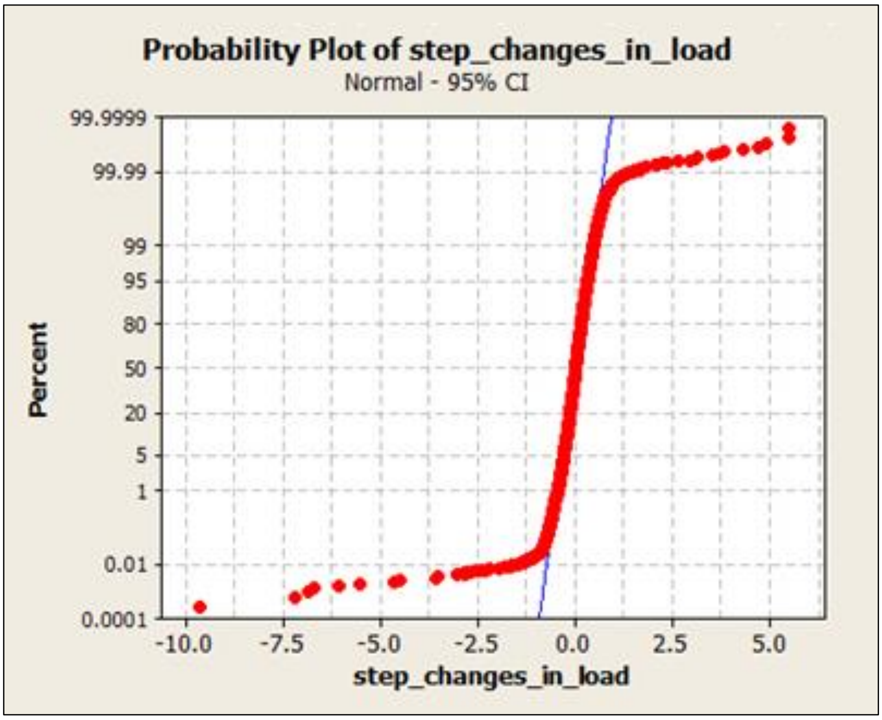

Figure 8: Probability distribution for step changes in network demand (1 minute average)

6 DATA COLLECTION AND METHOD

There were three key methods of data collection in this project.

1. **Remote Monitoring Stations**: The stand-alone stations were purposely designed, constructed and installed across the greater Alice Springs area to provide solar irradiance and wind data for this study
2. **Desert Knowledge Australia Solar Centre (DKASC):** A long term solar demonstration facility located in Alice Springs that is able to provide high level solar irradiance and wind data. In addition the site provides PV system performance data from 40 different PV technologies to a total grid connected site capacity of 250kWp and a data storage facility that has been utilized by this project
3. **Power and Water Corporation (PWC):** the local utility company and project partner provides load data for the whole of Alice Springs.
4. **Wind Data**[2]

The network of pyranometers across Alice Springs installed for this project provided real time 5 second irradiance data, from nine separate sites, that spread across a 15km radius from the central site at the DKASC. This data allows for the assessment of irradiance variability in terms of three key parameters, each of which has key implications for determining PV penetration into the Alice Springs network.

1. **Quantity of locations**: The total number of sites
2. **Spatial separation:** The distances between sites and within sites
3. **Temporal effects**: The time scales over which data is assessed

These parameters are integral to understanding the nature of irradiance variability and the optimum way of managing or containing the impacts of this variability so that PV penetration can be maximized. Details of data collection methods are described below.

6.1 REMOTE MONITORING STATIONS

At each of the eight new remote monitoring stations, the hardware deployed was all identical and included the following equipment

1. Monitoring equipment
    a) Thermopile Pyranometer: BF5 Sunshine Sensor
    b) Cup Anemometer: Meteo M&R PR2
    c) Potentiometer Windvane: Meteo M&R PRV
2. Datalogger: DT82EM
3. Wireless Communications: Telstra 3G
4. Standalone power supply: PV module, battery and charge controller
5. Pole: 10m (as supplied and installed by project partner Power and Water Corporation)
6. Steel enclosure, shade wings, mounting brackets, framing, cabling, conduit and other miscellaneous components

The following tables provide a summary of the all the key and operational parameters collected by the remote monitoring stations.

[2] In this study, wind data was not found to be a reliable mechanism for predicting cloud movements across the monitoring network. This was due to a range of other uncertainties associated with predicting the impact on irradiance from the movement of clouds. Consequently, the wind data was disregarded in the final analysis of this project and the key data set, solar irradiance was focussed on.

Table 4: Remote Monitoring Station: Key Parameters (Sites 1-8)

Parameter	Description	Units	Sample Rate
Global Irradiance	Global Horizontal Radiation (GHI), averaged over 5 seconds	W/m^2	5 seconds
Diffuse Irradiance	Global Diffuse Radiation (DHI), averaged over 5 seconds	W/m^2	5 seconds
Wind Speed	Wind Speed, averaged over 5 seconds	m/s	5 seconds
Gust Speed	Maximum instantaneous wind speed over sampling period	m/s	5 seconds
Wind Direction	Wind Direction	$0–359^o$	5 seconds

In addition to the weather parameters a range of non-weather parameters were also gathered to allow the operation of the remote stations to be monitored and therefore reduce the likelihood of system problems.

Table 5: Remote Monitoring Station: Operational Parameters (Sites 1-8)

Parameter	Description	Units	Sample Rate
Battery Voltage	Instantaneous battery voltage	V_{DC}	1 hour
Supply Voltage	Instantaneous supply voltage for the datalogger	V_{DC}	1 hour
Internal Temp	Instantaneous internal enclosure temperature	^{o} C	1 hour
Relay State	Pyranometer heating relay state	On/Off	1 hour
Sun State	Threshold radiation level sufficient to activate data sending	On/Off	5 seconds

6.2 DESERT KNOWLEDGE AUSTRALIA SOLAR CENTRE

At the Desert Knowledge Australia Solar Centre (DKASC) an additional BF5 pyranometer was also installed. The DKASC is the central point of the monitoring network and already has high resolution weather data being generated. However the pyranometer at the DKASC is an SPN1, the more advanced cousin of the BF5 Sunshine Sensor and the additional BF5 sensor at the DKASC was installed as an additional and direct reference against the remote stations.

Other system data is also available at the DKASC site including ambient and PV module temperatures, humidity, rainfall, in plane irradiance and spectral radiometry but is not utilised in this study. Table 6 and Table 7, below, provide information about the key and operational parameters of the monitoring station.

Table 6: DKASC Monitoring Station: Key Parameters (Site 9)

Parameter	Description	Units	Sample Rate
Global Irradiance	Global Horizontal Radiation (GHI), averaged over 5 seconds	W/m^2	5 seconds
Diffuse Irradiance	Global Diffuse Radiation (DHI), averaged over 5 seconds	W/m^2	5 seconds
Wind Speed	Wind Speed, averaged over 5 seconds	m/s	10 seconds*
Wind Direction	Wind Direction	$0–359^o$	10 seconds*

** This was changed to 5 seconds in December 2013*

Table 7: DKASC PV System Data

Parameter	Description	Units	Sample Rate
Total Power	Total AC power output, averaged over 10 seconds	kW	10 second
System Power	AC power output, averaged over 5 minutes for every PV technology at the DKASC	kW	5 minutes

6.3 POWER AND WATER CORPORATION

Due to technological limitations and data security concerns, Power and Water Corporation (PWC) were unable to provide a detailed breakdown of loads at the substation and feeder level. Therefore, data for this study was limited to single total network load value. Table 8, following, indicates the parameters of this data.

Table 8: Power and Water Corporation Load Data

Parameter	Description	Units	Sample Rate
Total Load	Total AC load for the whole Alice Springs grid	MW	15 second

6.4 LOCATION OF MONITORING SITES

A key aim of this project was to provide a wide spread network of solar radiation monitoring across the Alice Springs area that would provide data for the short term assessment goals of this project. It was also hoped that long term monitoring may be applied to ongoing research, resource assessment or integration into predictive systems for assisting high grid penetration into the Alice Springs power network. Figure 9, below, illustrates the location of the monitoring sites included in this study.

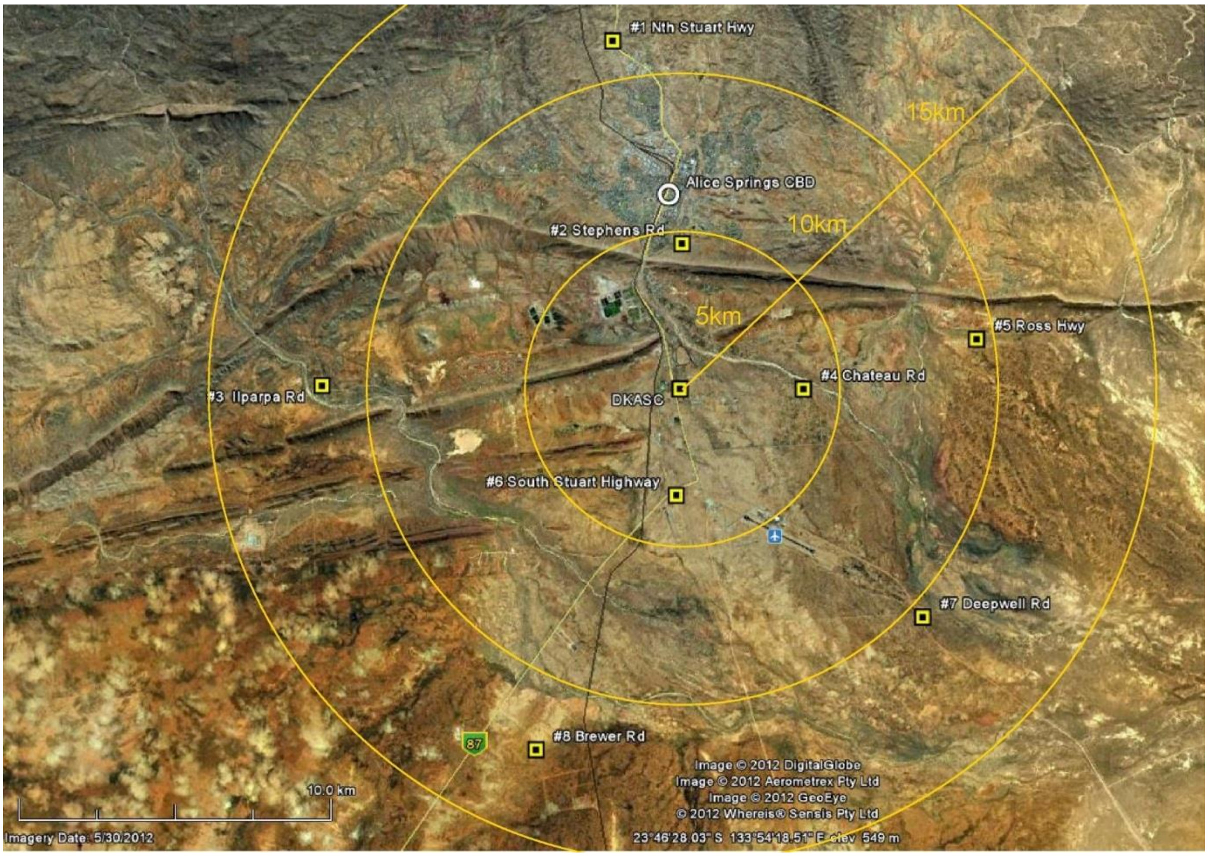

Figure 9: Map showing location of monitoring stations around Alice Springs, Northern Territory

A core part of this network is the DKASC which was established in 2008, and is operated and managed by CAT Projects. With the DKASC as the hub, eight additional monitoring sites were selected in consultation with PWC under the following basic guidelines and principles:

1. To provide broad monitoring coverage across the greater Alice Springs town area
2. Located within a 15km radius of the DKASC
3. Located near to the existing Alice Springs electricity network
4. Near to existing PWC infrastructure and with existing easements
5. Safely accessible by vehicle towed elevated work platform (EWP)
6. Clear area with no local shading or from trees or other obstructions
   Included 3G network coverage

7 PYRONOMETER DATA ANALYSIS

7.1 SOLAR IRRADIANCE - SINGLE SITE

Figure 10 shows two full days of irradiance data from the same monitoring location: Site #5. The samples are 5 second averaged values taken across the daylight hours. One day shows a clear sky and therefore a full irradiance profile and the other day with highly variable irradiance due to intermittent cloud cover. These two days represent the extreme ends of the spectrum in terms of irradiance variability and are a useful starting point to understand its impact on PV generation.

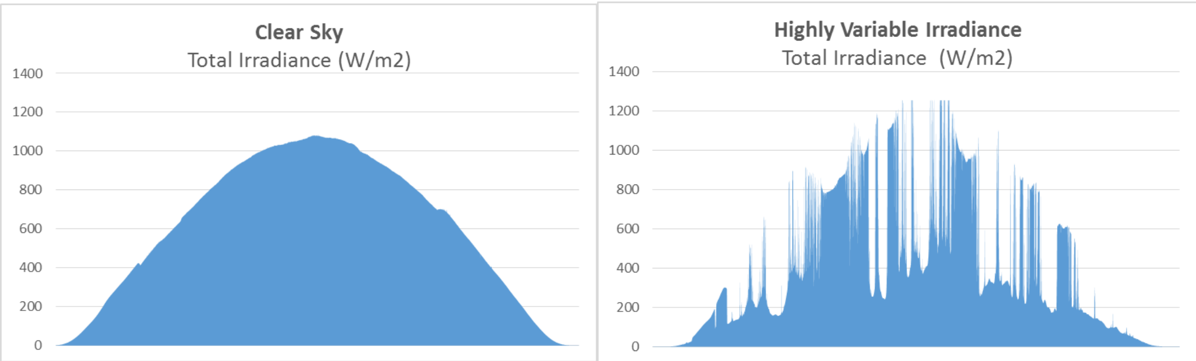

Figure 10 Clear Sky Irradiance and Highly Variable Irradiance due to Intermittent Cloud Cover

The clear sky day provides a very stable irradiance profile with the peak irradiance in the middle of this sunny day reaching around 1050 W/m^2 and very minor step changes to irradiance across the daytime period. The changes in irradiance for the clear sky day range from 0-30 W/m^2 (Figure 11) which represents less than a 5% step change in net irradiance between any given time interval. The same examination of the highly variable day shows a large degree of intermittency in the irradiance data with step changes in the irradiance as measured by the pyranometer of upward of 500 W/m^2 per time interval.

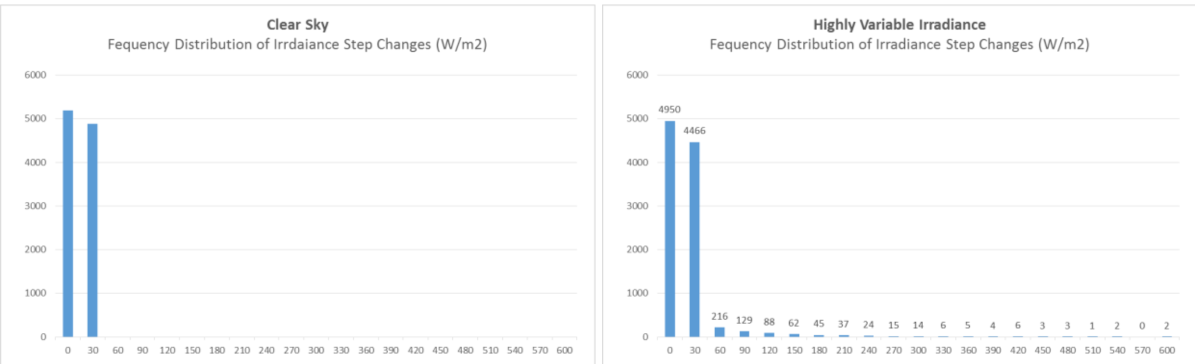

Figure 11 Clear Sky Irradiance and Highly Variable Irradiance: Frequency Distribution of Step Changes in Irradiance

Even for this highly variable day though, the vast bulk (over 90%) of the step changes in irradiance over the day still fall within the 0-30 W/m^2 range and when translated into changes in PV generation will have little impact on the network. The remaining 10% however are of more consequence to this discussion and it is evident from the data that the variability in irradiance in this portion of data can be significantly high, with some step changes, though rare, being in excess of 500 W/m^2. Such changes constitute a rise or fall of more than 50% of the total irradiance at that time interval. If this is applied to the notional output of utility scale PV system (up to 10MW) at this location it could cause significant issues with other sources of generation on the network ramping up or down to meet these changes.

7.2 SOLAR IRRADIANCE – MULTIPLE SITES

As noted in the section above, the solar irradiance and therefore the potential for PV generation from a single location can be subject to a great deal of natural variability. This variability is driven by intermittent cloud cover and in terms of PV generation it is difficult to mitigate against at a single site without the support of energy storage. The single site shown above was site #5 of the monitoring network. In Figure 12 below all the data for all nine monitoring sites is shown for the same highly variable day.

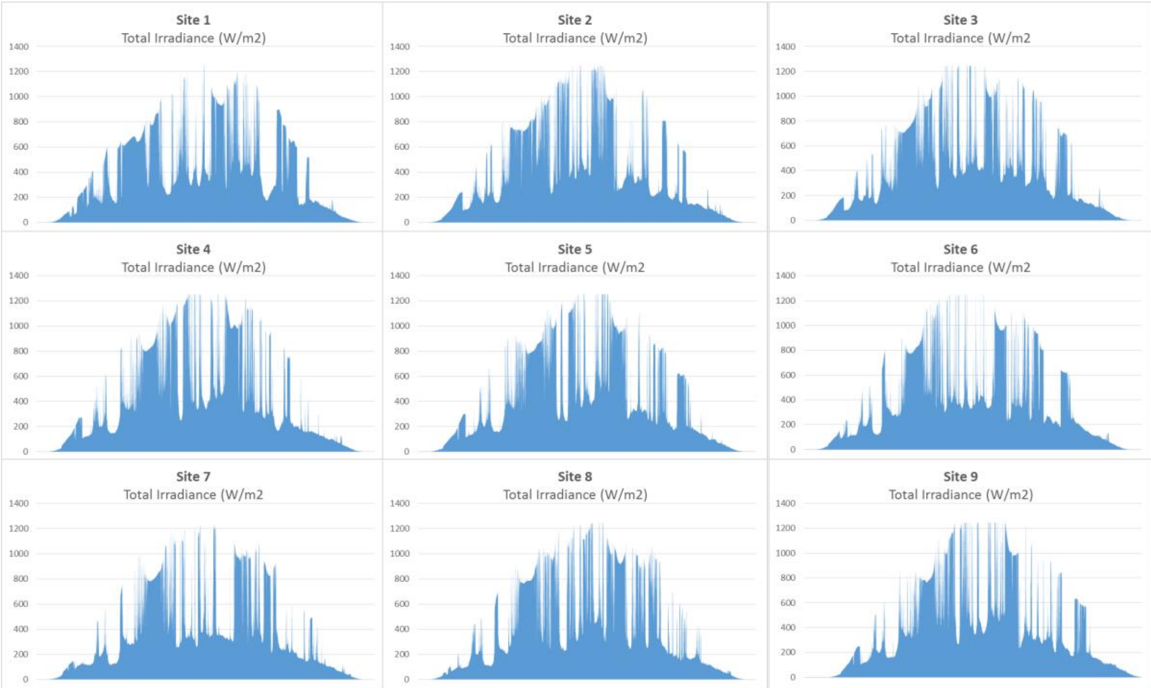

Figure 12: Irradiance for each site on Highly Variable Day (11-09-2013)

What we see in this figure is highly variable irradiance data at every site, as would be expected. Each site when examined on its own has the same issues for PV generation as noted previously for site #5. However if each site is seen as a separate PV system, all of equal size and all on the same network then their net irradiance will provide a good indication of the net variability of PV generation across the grid (Figure 13).

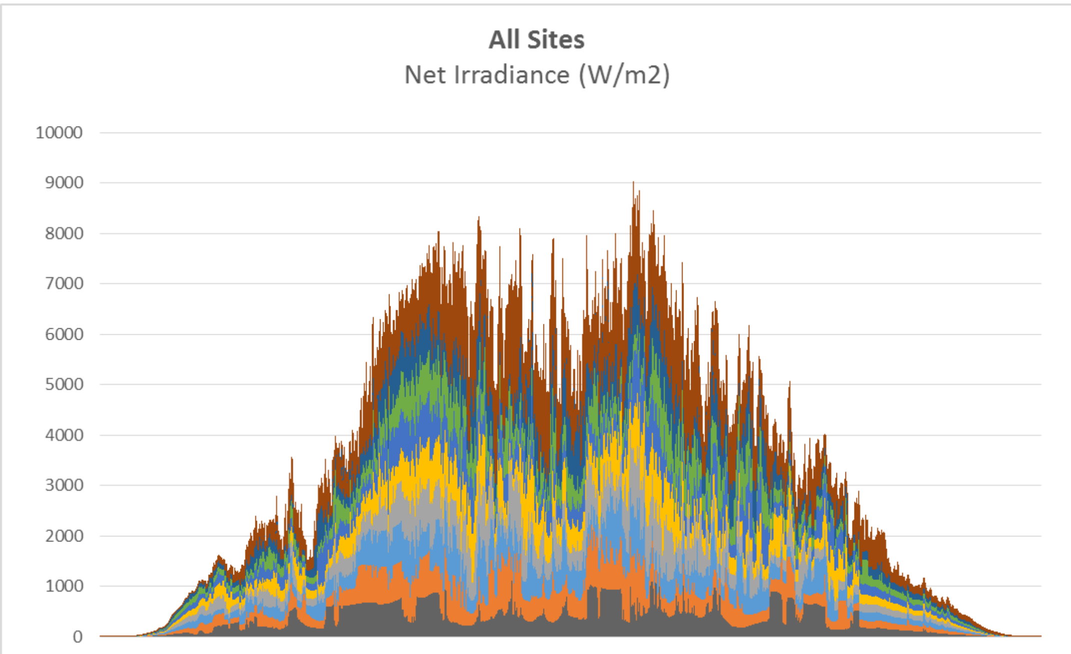

Figure 13 Net Irradiance: 9 Sites

What we see in the net irradiance is that many of the extremes in rises and falls of irradiance witnessed for individual sites are largely negated by the irradiance at other sites and over the sum of the nine sites we get a more stable irradiance and therefore a more stable PV generation picture.

To quantify this effect an examination of the effective step changes in irradiance is required. Figure 14 shows the step changes in the normalized net irradiance for all sites. The normalization allows direct and simple comparison of the net irradiance of all sites with the irradiance for a single site. What it shows is that the net irradiance is distinctly less variable. Where the single site had step changes up to and in excess of 500 W/m^2 for any given time interval the normalized irradiance of the combined rarely exceeds the 100 W/m^2 level and peaks at 140 W/m^2.

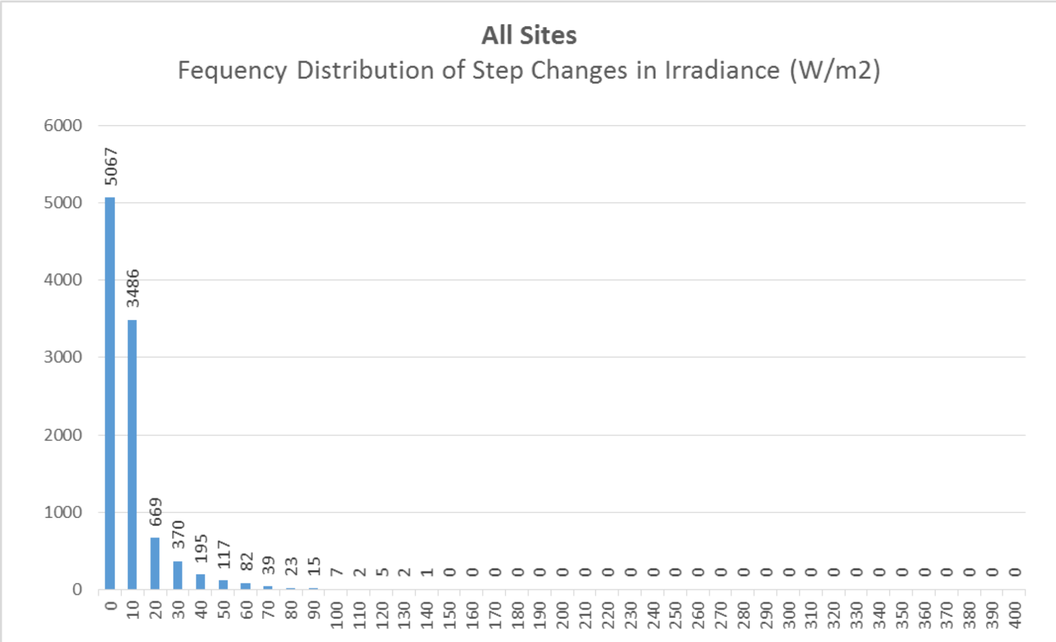

Figure 14: Frequency Distribution of Net Normalized Irradiance Step Changes

The data shown in Figure 14 and the preceding figure is for the single highly variable day from Figure 10. If we look at other highly variable days but with different irradiance profiles we find that the net irradiance is always significantly more stable than the single site data. Below is the graphical representation of data sets for another two variable days:

Irradiance summary for 27th September 2013

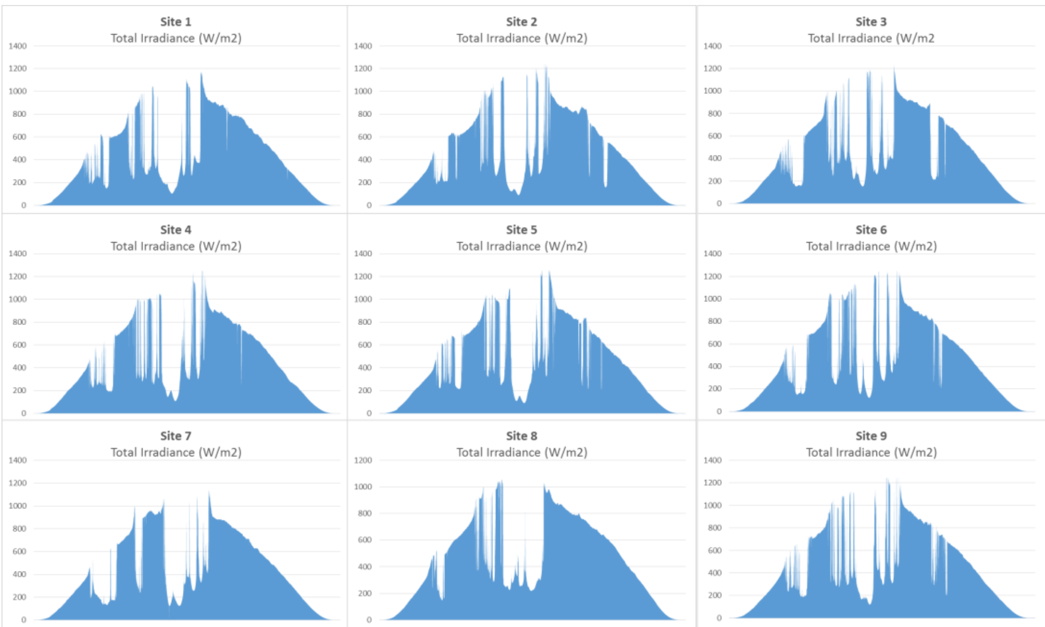

Figure 15 Irradiance for each site on 27-09-2013

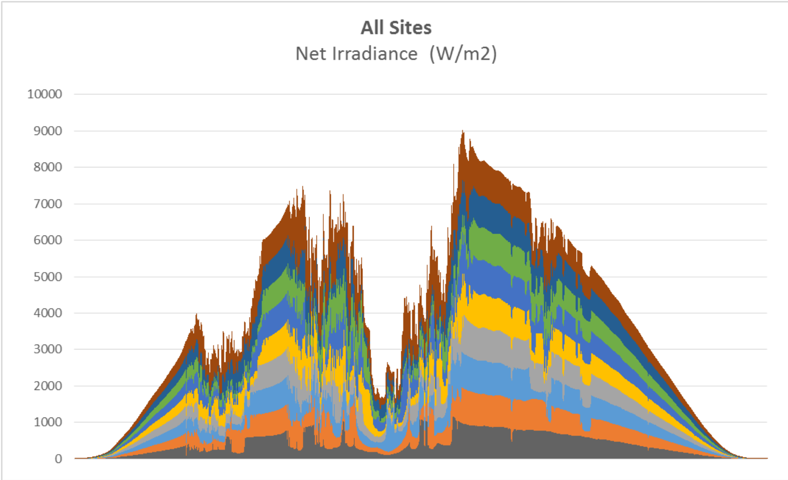

Figure 16 Net Irradiance: 9 Sites: 27-09-2013

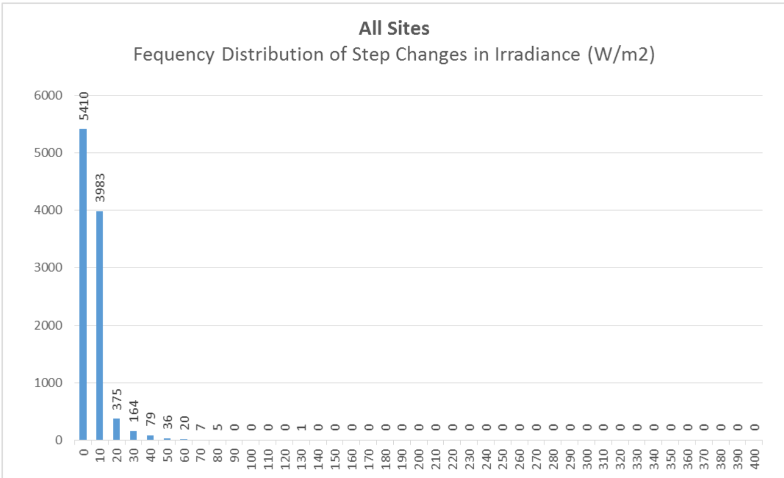

Figure 17 Frequency Distribution of Net Normalized Irradiance Step Changes: 27-09-2013

Irradiance summary for 11th October 2013:

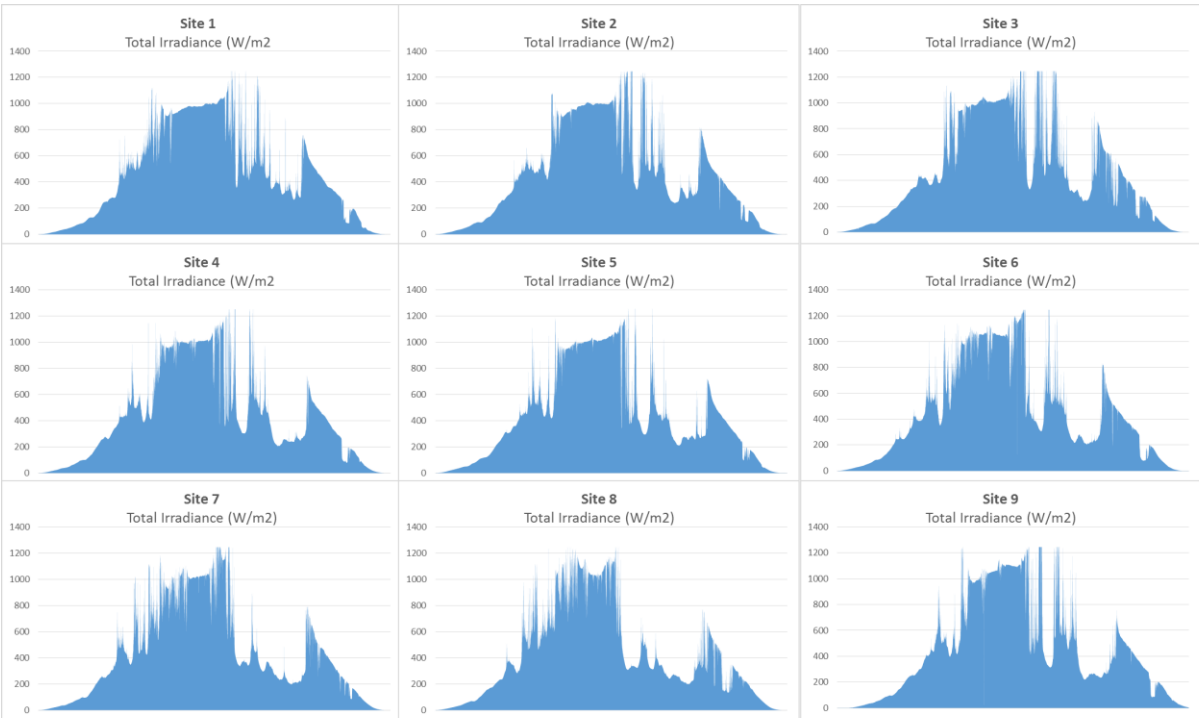

Figure 18: Irradiance for each site: 11-10-2013

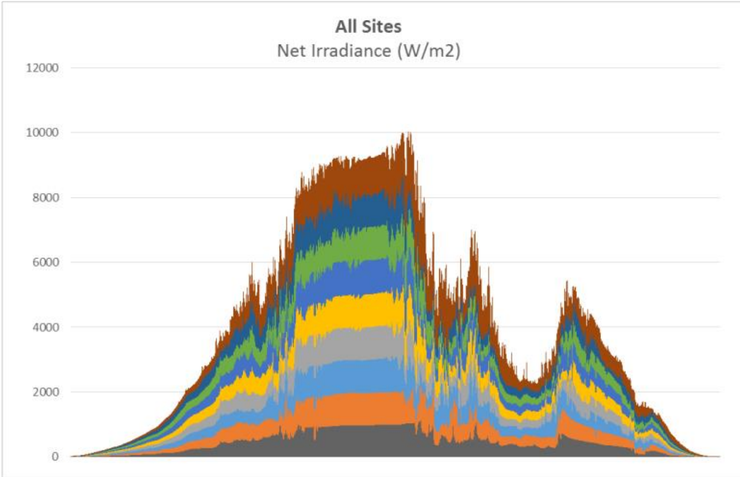

Figure 19 Net Irradiance: 9 Sites: 11-10-2013

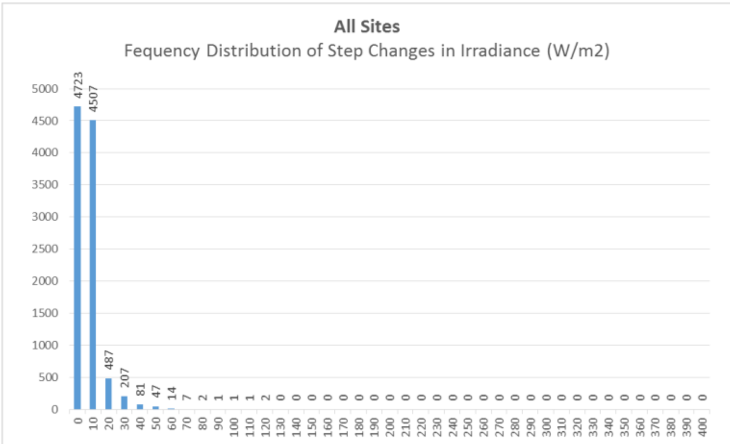

Figure 20 Frequency Distribution of Net Normalized Irradiance Step Changes: 11-10-2013

From these figures it can be seen that on both these other two highly variable days we also get significant smoothing of the irradiance variability. For these days, step changes in irradiance at individual sites were upwards of 500 W/m^2 but the net normalized step changes do not exceed 130 W/m^2 at any stage and for 99.7% (three standard deviations) of the samples the step change is 50 W/m^2 or less.

Each of the three day samples above were selected because of the extreme nature of their variability. The benefit of this is to gain a detailed understanding of some typical worst case scenarios for irradiance and their potential impact on PV generation. However it is also important to view these same issues over the entire data set to ensure that the findings for these single, but significant days correspond with the overall data set.

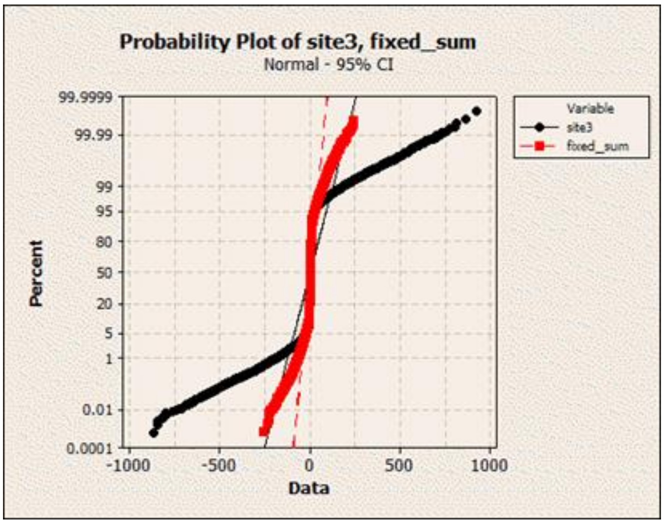

Figure 21 Probability distribution for step changes in irradiance. Comparison a single site vs net

Figure 21 plots the probability distribution for positive and negative step changes in irradiance across the entire data set for both a single site and from the net normalized values for all sites.

Again we see that a single site (noted in the figure as "site3") has a large variability relative to the net normalized value, yet is also clear that even for this single site the likelihood that a step change will exceed 250 W/m^2 at any point is less than 1%. The probability that the step changes will exceed 500 W/m^2 is a fraction of this again. This corresponds closely with data examined earlier for three individual days.

Similarly the probability distribution for the combined sites (noted in figure as "fixed sum") also correlates well to data from the individual days. The magnitudes of step changes in irradiance are greatly reduced – for over 99.7% of the samples (three standard deviations) the step change is 50 W/m^2 or less and the effective probability of the irradiance ramping by more 200 W/m^2 is less than 0.01% for any given time interval (5 second averaged).

It should also be noted again that to avoid weighting this result in favour of irradiance stability, the data assessed only includes the irradiance values for the daylight hours when PV generation occurs.

7.3 THE BENEFITS OF DISPERSION – QUANTITY VS DISTANCE

From the available irradiance data, it is clear that by increasing the number of sites there is a substantive decrease in the effective irradiance variability and that this has direct implications for reducing the variability of PV generation and therefore PV penetration levels of the Alice Springs network. This impact is very clear. What is less clear though are the benefits of dispersing the sites primarily due to the quantity of the sites or the spatial separation. In Figure 22 below, the probability distribution for four separate levels of dispersion for the irradiance monitoring are shown. These four scenarios are as follows

1. Single site: Site # 9. Centre site in the network of nine sites
2. All Nine Sites: Dispersed unevenly across 0-15 km radius from central location
3. Inner Five Sites: Within 5km radius of each other
4. Outer Five Sites: Outer ring. All sites sit on at edge of a radius 12-15 km from central location

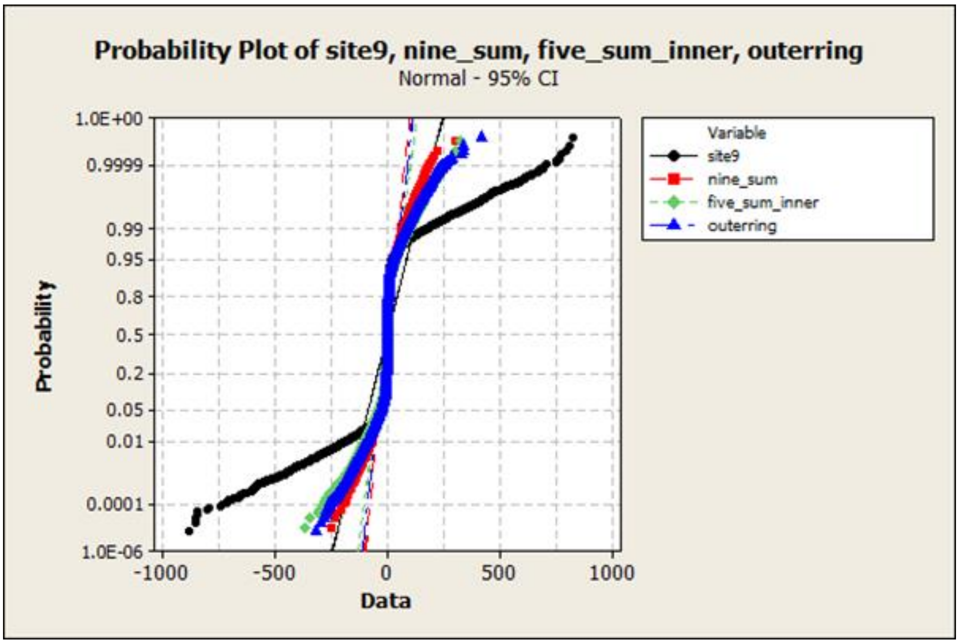

Figure 22 Probability distribution for step changes in irradiance: Comparison of four levels of dispersion

Both the single site and combined site results have been discussed in detail above, so what is of interest here is the results for inner and outer dispersion of five sites and how they compare to our existing findings. From this probability distribution we can see a number of clear patterns.

Both the inner and outer five-site dispersions show similar variability profiles, both with significant reductions in irradiance variability from the single site data. The nine-site dispersion however has notably reduced variability over a wider range of step changes – i.e. fewer larger step changes than the two sets of five-site data.

For the two five-site dispersions it can also be seen that the variability profiles are very similar. The inner circle of five monitoring sites which is dispersed over a 5km radius is only slightly more variable than the outer ring which is dispersed over 10-15km radius and therefore an area which is effectively nine times larger. So despite the much larger area, the benefits of this spatial dispersion on reducing irradiance variability is only moderate.

Similar results can be seen when the data is refocused down from the whole data set to the days of very high irradiance variability. Figure 23 shows the frequency distribution of step changes between four sites at a 5 km radius and four sites at a 10-15km radius. This data (which is again taken from 11th September 2013), shows again that whilst a small reduction in irradiance variability is achieved by spreading the sites out over a larger area, these benefits are relatively modest.

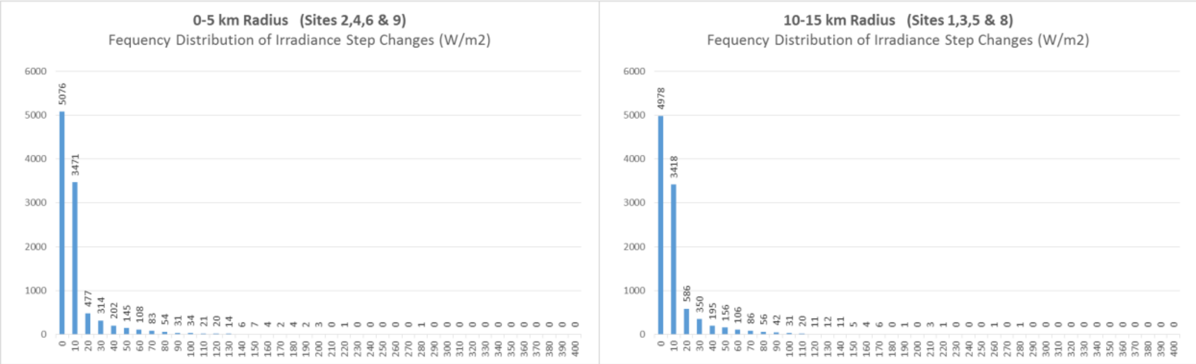

Figure 23 Frequency distribution: Comparison of impact of spatial dispersion on irradiance variability

Although the general trends can be seen in the data above, more analysis is required to quantify the relationship between irradiance variability and the quantity and spatial dispersion of sites. However from this initial analysis a number of preliminary conclusions can be drawn:

1. The quantity of sites is a decisive factor in reducing irradiance variability.
2. The greater the number of sites, the greater the reduction in variability. This relationship is not however linear with significant improvements in variability being achieved with very small quantities of sites.
3. Spatial dispersion of the sites reduces variability; however the benefits of spatial dispersion are not as strongly evident as the benefit of increasing the quantity of sites.

7.4 SOLAR IRRADIANCE – TEMPORAL IMPACTS

Most of the data presented to date on irradiance has been 5 second averaged readings. When this time interval is extended from 5 second to 1 minute or more we find that the variability of the data in terms of the frequency and quantum of step changes in irradiance also changes. The extent of this change depends on the how great the time interval that is examined. In Figure 24 below the data from the highly variable irradiance day (11/09/2013) is shown where the same data is averaged over longer time intervals.

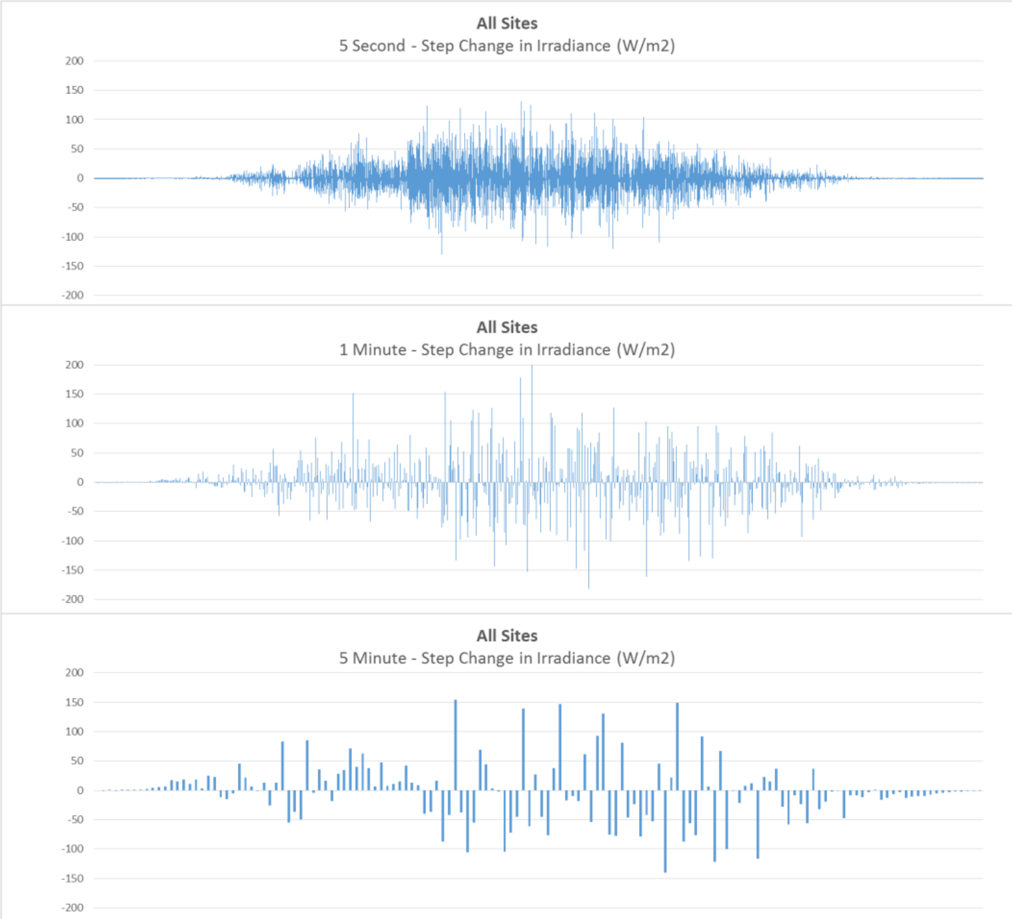

Figure 24 Net Normalized Irradiance Step Changes: 5 Second, 1 Minute and 5 Minute Time Intervals

The impact on irradiance variability of the extending this time interval is shown to be moderate but mixed. Over the three time intervals the quantum of the step changes does not change greatly, although some increase is evident for the one minute values. Although the quantum of the step changes is not noticeably different, the frequency or probability of these larger changes occurring is significantly higher (as shown in Figure 25).

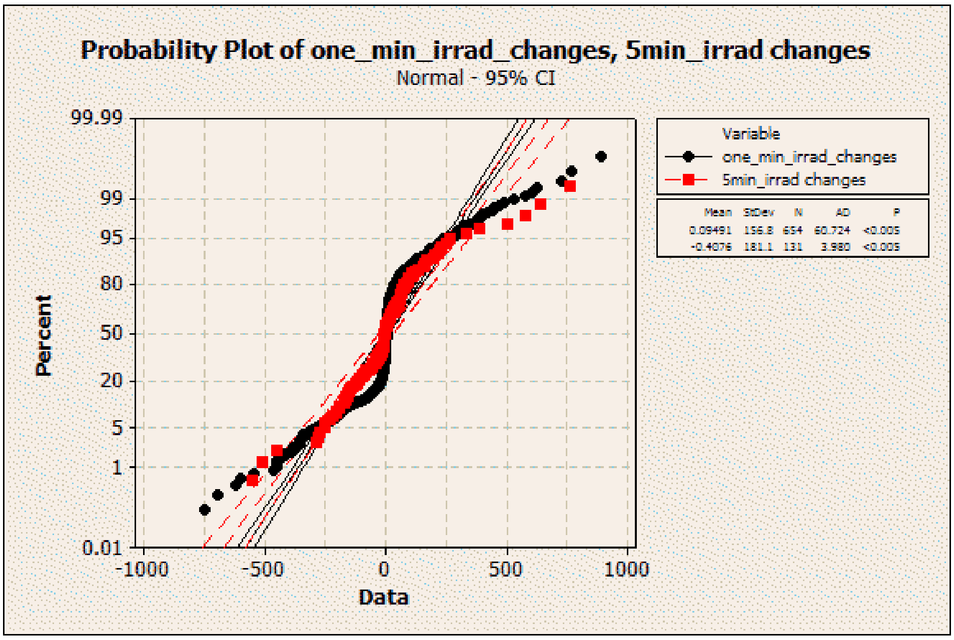

Figure 25 Probability Distribution. Net Normalized Step Changes: 1 Minute and 5 Minute Time Intervals

7.5 POINT SOURCE IRRADIANCE MONITORING AND PV PLANTS

On the subject of spatial dispersion there is an additional note that should be made at this point. The irradiance data in this study is sourced from a network of pyranometers, each with an active collecting area the size of a 0.1m diameter circle. In contrast, a 1 MW PV plant covers an area of approximately 200m x 200m and a 10MW plant covers an area of approximately 500m x 500m.

When understanding the impact of spatial dispersion on irradiance it is therefore important to also recognise that point-source pyranometers do not provide a perfectly accurate indication of the irradiance over a larger local area. Although there is of course a strong correlation, this is decreased as the area is enlarged beyond the point source.

Figure 26 & Figure 27 show the radiation data from a horizontal pyranometer and the normalised output of a large area array tilted at 20° at the same location. Although the data shows differences in absolute magnitude throughout the day due to different tilt angles of the two sources, it is clear that the magnitudes of the peaks and troughs, and hence the variability of the large area array, is less than that of the point source.

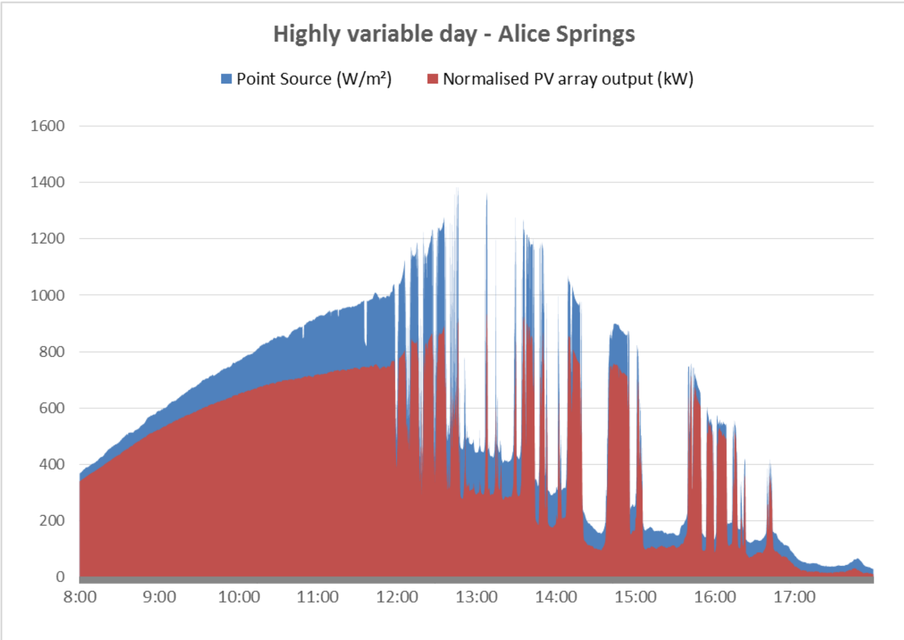

Figure 26 Point source irradiance data plotted against the normalised output of a large area PV array (10 second intervals).

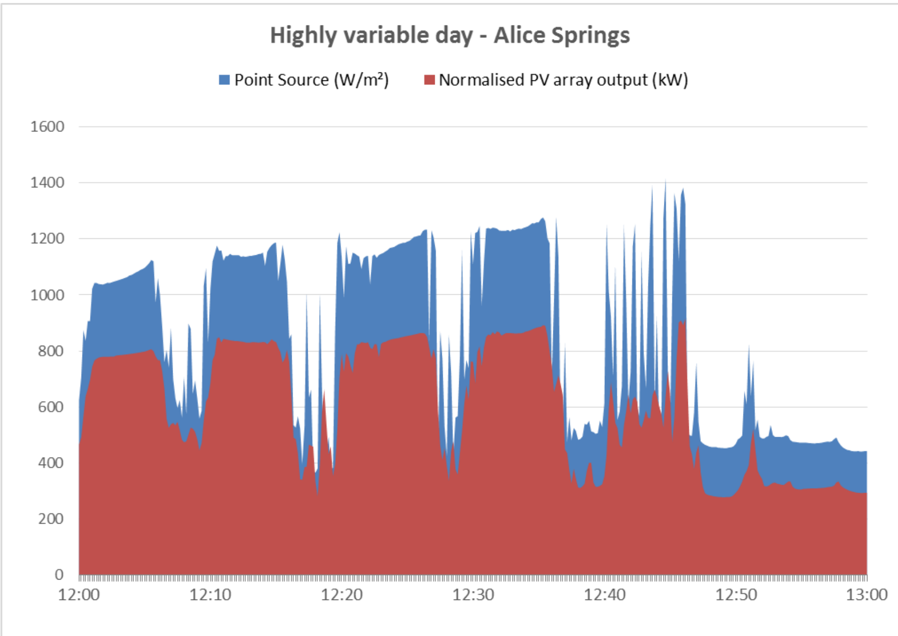

Figure 27 Selected data from above.

The differences in variability are more clearly demonstrated when the step changes are plotted as displayed in Figure 28 & Figure 29. Here it is evident that although there is a strong correlation in the variability of the two data sources, the step changes in large array output are clearly smoother and significantly smaller than those of the point source. Figure 30 shows that the difference in step change magnitude between a point source and a large array is significant and the frequency of the step changes is almost in sync with the point source.

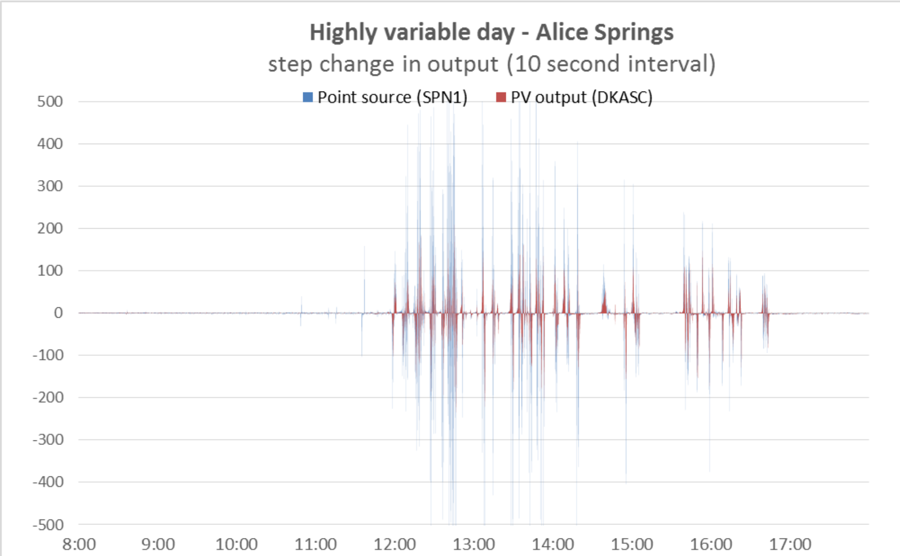

Figure 28 Step changes in pyranometer data and normalised large array output.

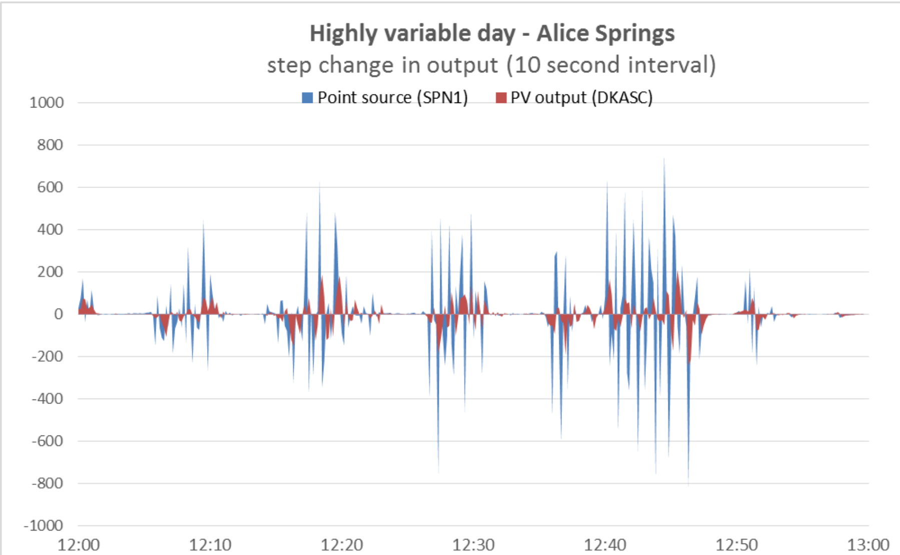

Figure 29 Selected section of above data showing finer detail.

Although there is a clear spatial dispersion benefit to the variability of a large area array over that of a point source, the relationship between the two sets of data is difficult to quantify in the form of a direct transformational model, however, the cumulative frequency distribution of the two data sources can be used to describe the smoothing effect on the variability.

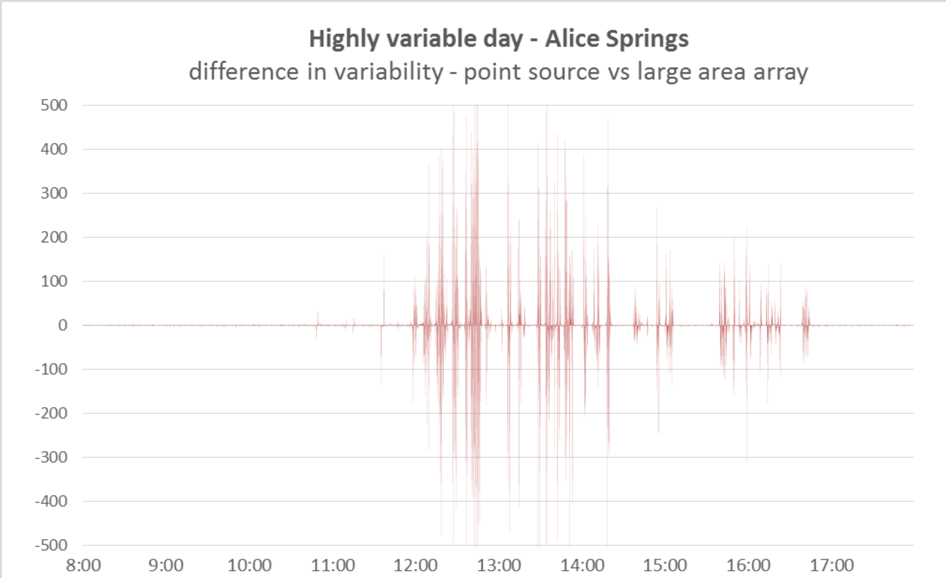

Figure 30 Difference in step change magnitudes between a point source and a large area array.

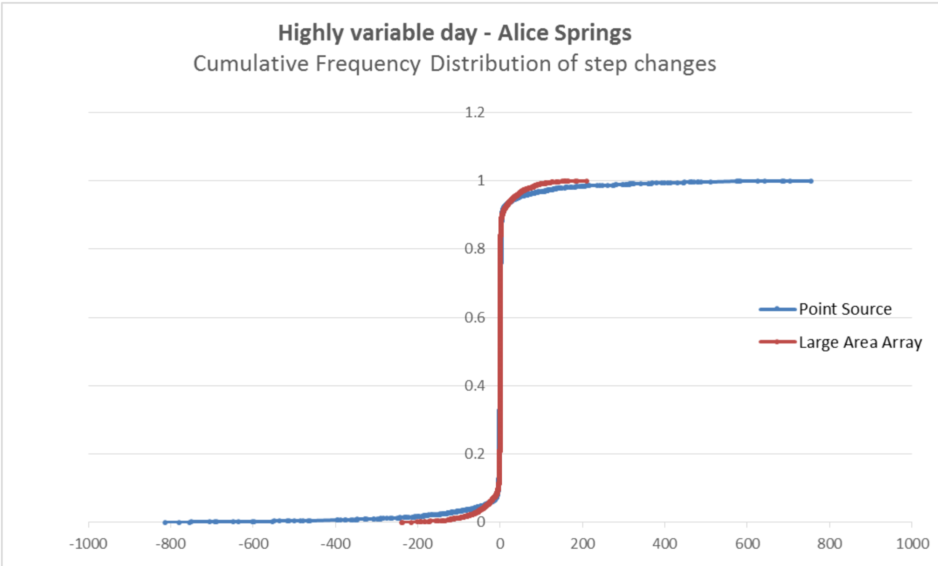

Figure 31 Cumulative distribution plots of a point source and a large area array.

As can be seen in the distribution plot above, the overall shape of the curves are very similar, indicating that both the point source and the large array will move rapidly up and down as a result of changes to irradiance. However it is clear that the large array, while changing with a similar velocity to the point source, does not change to the same magnitude. This is significant in that it highlights the extent to which larger PV arrays actually benefit from a degree of special diversity in their own right.

8 MODELLING IRRADIANCE, NETWORK DEMAND AND PV PENETRATION

8.1 MODEL OUTPUTS

In this report, large area PV array outputs have been modelled by scaling the magnitude of point-source radiation data. A certain degree of spatial dispersion inherent in a large area PV array is therefore not captured in the modelling. In reality the variability of a large area PV array is likely to be slightly lower than that found in our results.

To demonstrate the effects of spatial dispersion on the net variability of PV on the grid, measured load data from PWC was taken at 15 sec intervals and then overlaid with scaled point source data to simulate PV plant outputs of various sizes and locations using actual solar radiation data resampled to 15 second intervals for the days being analysed.

In general there are up to 300 days per year in Alice Springs that are largely cloud free. Clear sky days have very low irradiance variability and these days have been explicitly excluded from the analysis. Over the remaining days, a large number were analysed with broadly similar results. From this high variability subset, two days in particular have been selected because they both have similar levels of solar intermittency and individually they each represent either the peak (28th January 2014) or the trough (29th September 2013) of electricity demand on the Alice Springs network.

To understand the potential impacts of solar intermittency on the overall network during these high and low demand days three simulations were completed. These simulations model the impact of the installation of an additional 10MW of PV on to the Alice Springs network in concentrated, moderately dispersed and highly dispersed configurations as follows:

1. One 10MWp plant centrally located
2. Three 3.3MWp plants located 5km radially from the solar centre
3. Nine 1.1MWp plants located at the locations of the pyranometers as shown previously.

The results of these simulations are provided below.

8.2 28TH JANUARY 2014 (TUESDAY)

As noted above, 28TH January 2014 was selected for the simulation because of its highly variable irradiance; and being in the middle of summer on a weekday the average network load is near peak - the daytime network demand on this day is in the range 40-45MW.

Figure 32 below shows the variability of the existing Alice Springs network as it currently exists. Step changes in demand are typically 0.5MW per unit time (15 second intervals) but may be as large as 1.4MW and this variability in demand remains basically constant over the 24 hour cycle. That variability in demand remains basically constant is particularly notable as it shows that the 4MW of existing PV that is widely dispersed across the Alice Springs network has no discernible impact on the variability of the demand curve. This PV generation is effectively integrated into the demand data and there is no indications that during peak solar times (10:00 – 14:00) the scale of the step changes or overall variability changes at all.

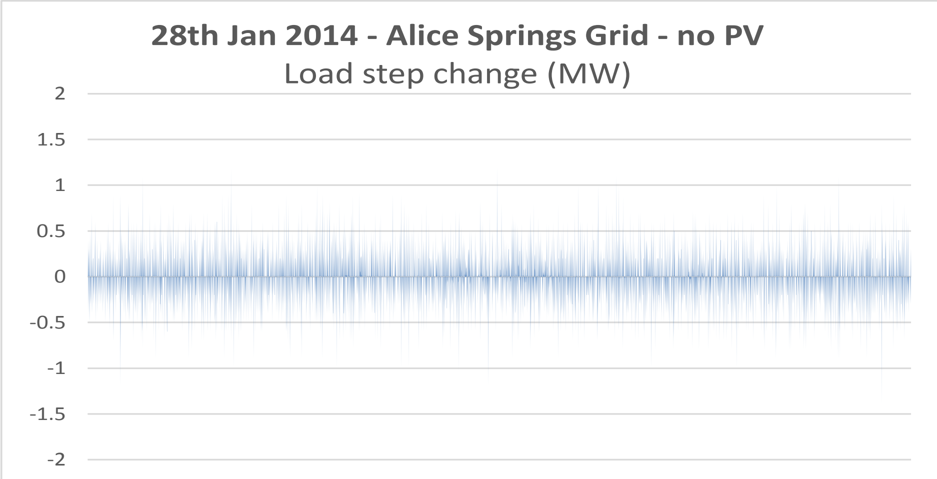

Figure 32: Step changes inherent in the Alice Springs grid with no additional PV included (15 second intervals over 24 hours)

It is a commonly held belief that the integration of embedded PV generators will introduce an unacceptable level of variability to the grid, creating difficulties with supply management and scheduling. This belief is based on the assumption that prior to the introduction of PV, that short term demand is inherently stable. Contrary to this assumption, analysis of the Alice Springs load shows that there is already significant variability within the network and that this variability is not directly related to the existing PV on the network.

Figures 31 to 33 (below) show the effects of embedding an additional 10MW of PV onto the Alice Springs grid in the three nominated configurations.

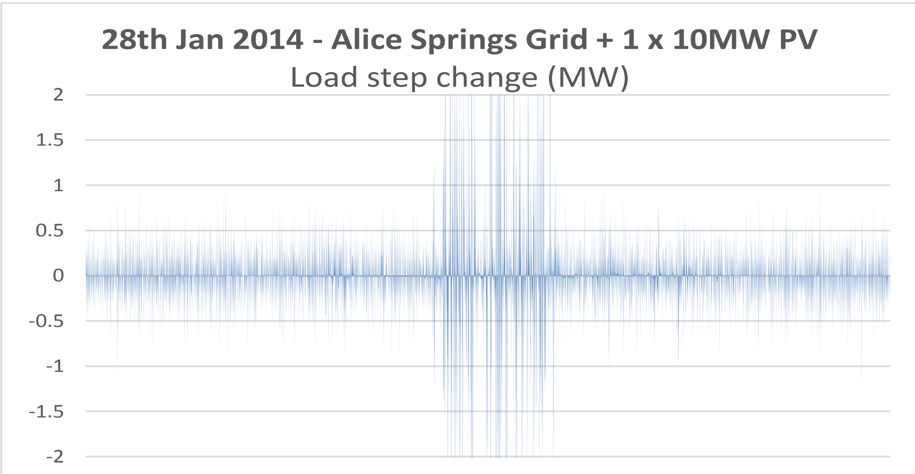

Figure 33: Step changes in the Alice Springs grid with the addition of a simulated 10MW centrally located PV plant (15 second intervals over 24 hours)

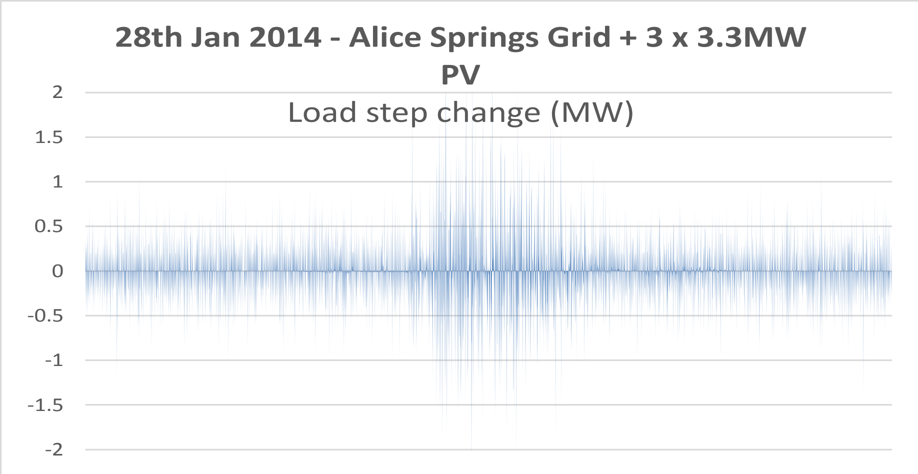

Figure 34 Step changes in the Alice Springs grid with the addition of 3 simulated geographically dispersed 3.3MW PV plants (15 second intervals over 24 hours)

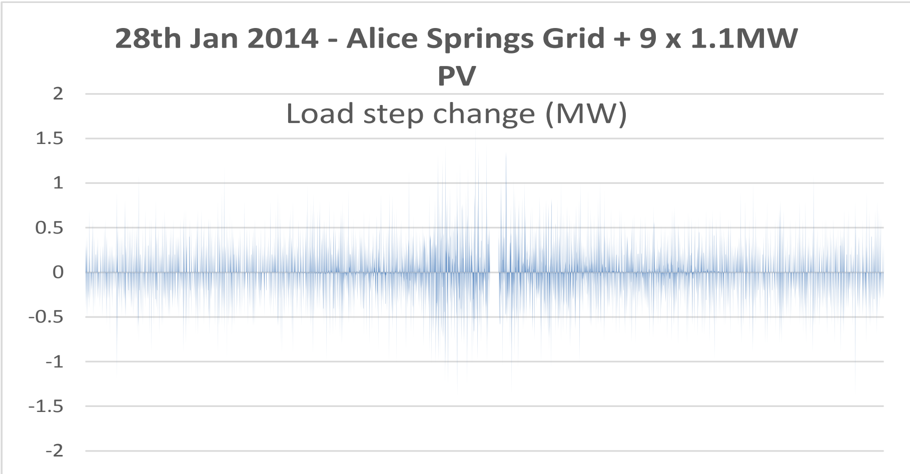

Figure 35 Step changes in the Alice Springs grid with the addition of 9 simulated geographically dispersed 1.1MW PV plants (15 second intervals over 24 hours).

It is clear from these three figures that the addition of 10MW of PV to the network will have an impact on the variability of the load as seen by the network generators. On a highly variable irradiance day such as the 28th January 2014 the midday demand variability increases and as would be expected, however, this increase is more marked in the 10MW centralized configuration and much less so in the more dispersed configurations. In particular it can be seen that the 9 x 1.1MW dispersion is only marginally more variable than the existing grid variability shown in Figure 32.

The daily demand curves for the base case and three PV array configurations are shown in figures 36 and 37, below. These demonstrate that the integration of PV into the network has only a moderate impact on the effective variability of the demand, and that the impact of PV intermittency is largely nullified by geographical dispersion of PV across the network.

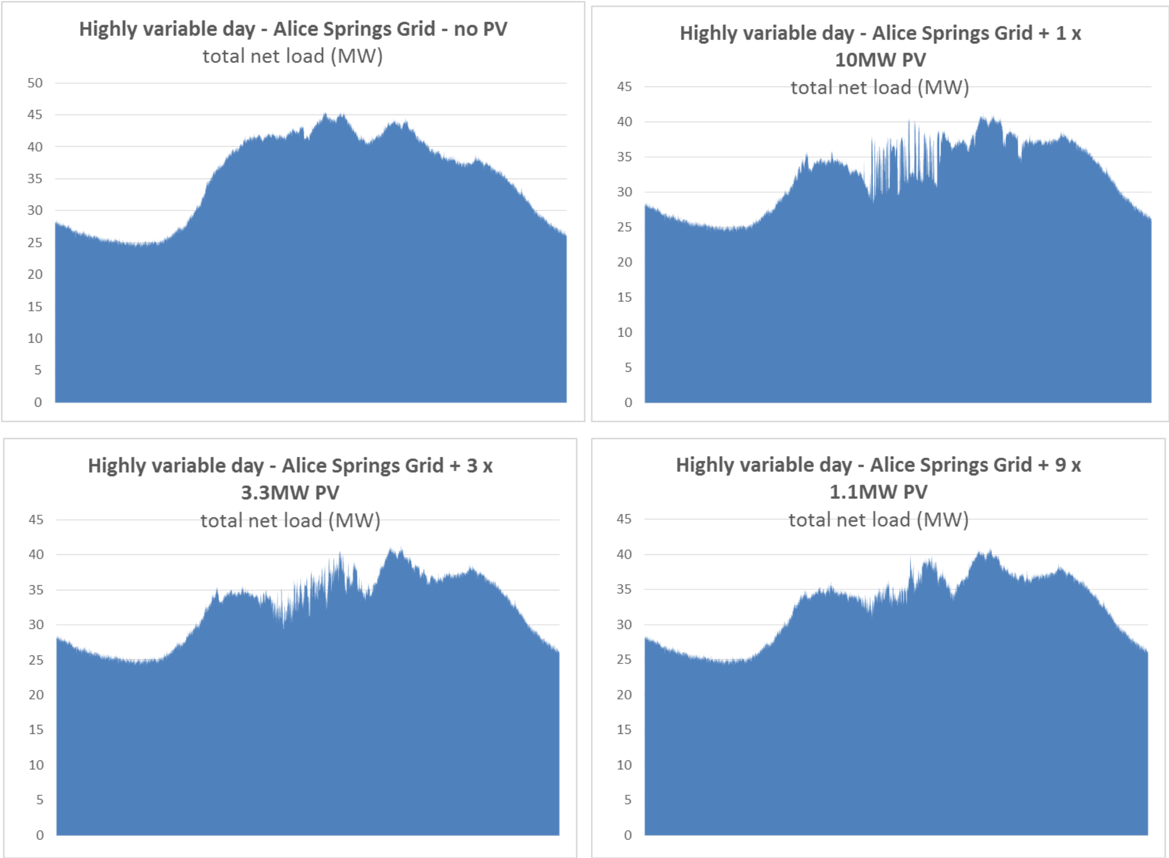

Figure 36: Net load - 28th January 2014. Comparison of Four Configurations (15 second intervals over 24 hours).

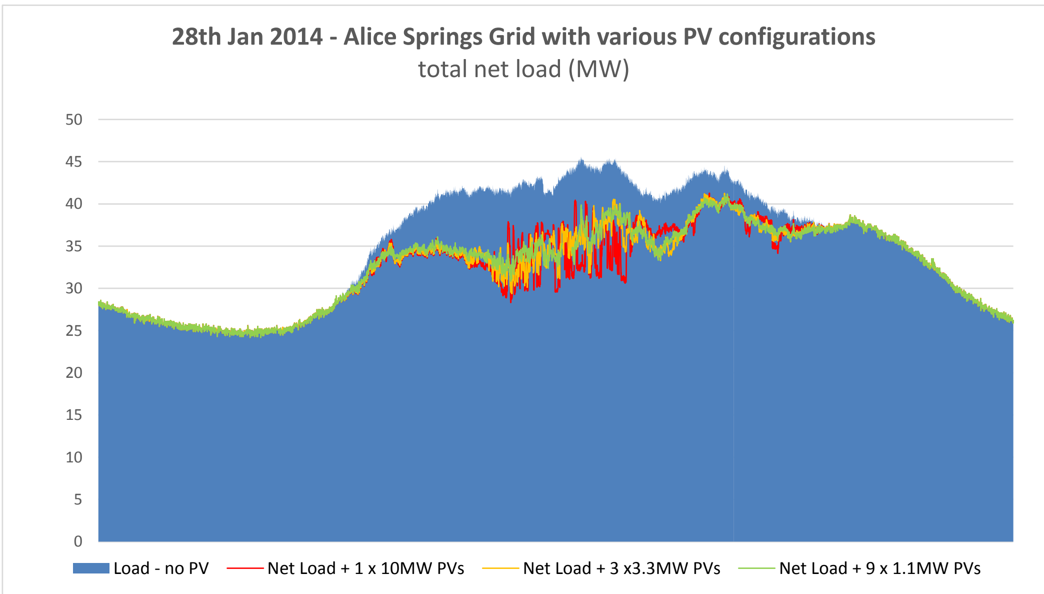

Figure 37: Net load - 28th January 2014. Comparison of Four Configurations (15 second intervals over 24 hours).

8.3 29TH SEPTEMBER 2013 (SUNDAY)

The 29TH September 2013 was also selected for the simulation because of its highly variable irradiance and because it represented the low load period for the network (a weekend day in spring is when the average network load is typically at its lowest) - the daytime network demand on this day is in the range 15-25MW.

Figure 38 below shows the variability of the existing Alice Springs network as it currently exists. Step changes in demand are typically 0.2-0.5 MW per unit time (15 second intervals) but may be as large as 1.0MW and this variability in demand only increases a small amount over the day and in proportion to the increase in network demand. Once again there is no discernible impact on the variability of the demand curve due to the existing 4MW of PV generation.

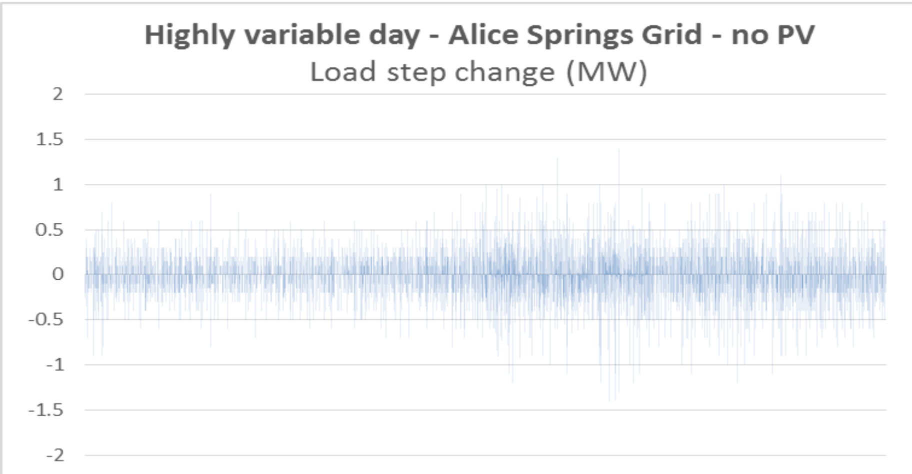

Figure 38 Step changes inherent in the Alice Springs grid with no additional PV included (15 second intervals over 24 hours).

Repeating the analysis that was carried out above for the peak demand day, the variability in demand for this low demand day shows similar results. It is clear from Figure 39 that the addition of a single 10MW PV plant results in a significant increase in variability, with the difference in variability plot heavily shadowing the baseline variability. In contrast, Figure 41 shows the difference in variability with the addition of 10MW of distributed PV falling within the range of the pre-existing grid's inherent variability. This further demonstrates the smoothing benefits of spatial dispersion when integrating large PV plants onto a relatively small grid.

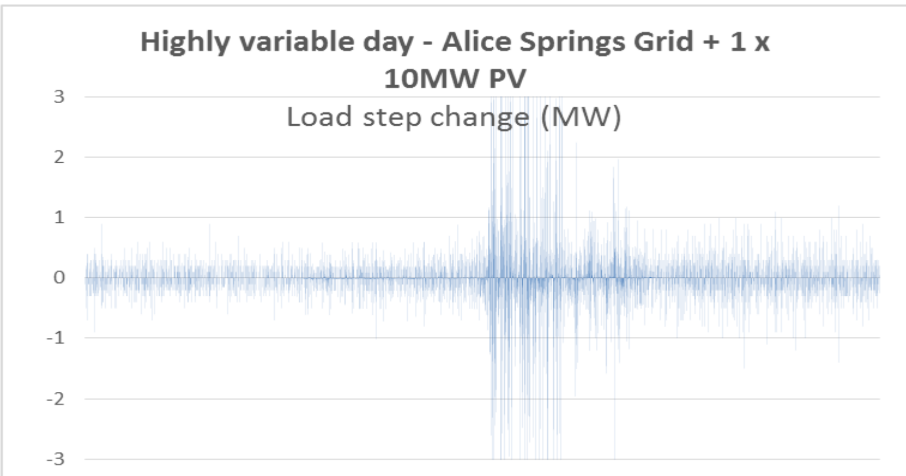

Figure 39 Step changes in the Alice Springs grid with an additional 10MW PV plant added (15 second intervals over 24 hours).

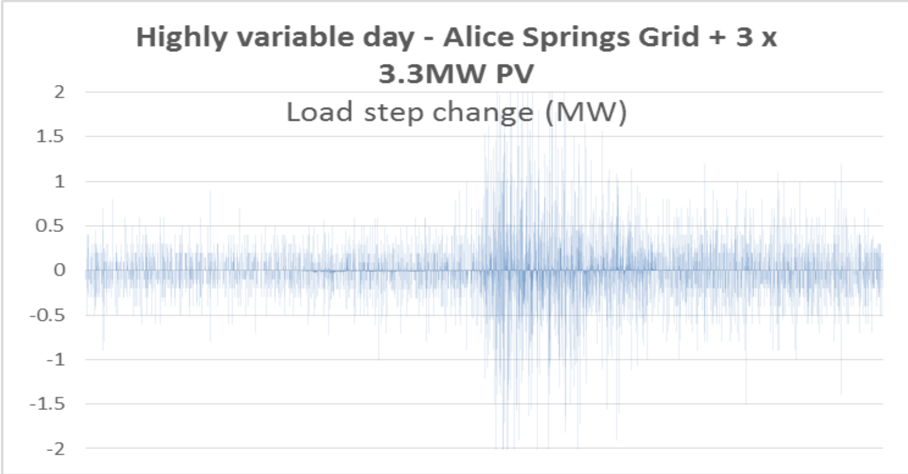

Figure 40 Step changes in the Alice Springs grid with an additional three 3.3MW PV plants added (15 second intervals over 24 hours).

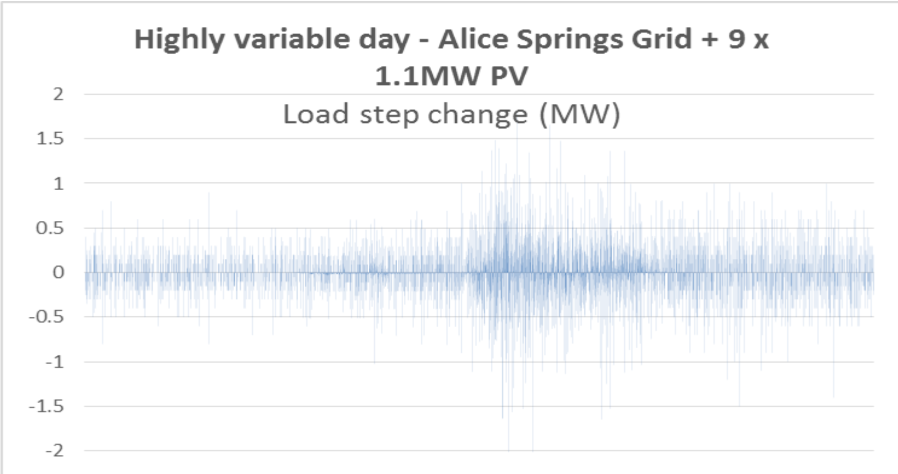

Figure 41 Step changes in the Alice Springs grid with an additional nine 1.1MW PV plants added (15 second intervals over 24 hours).

The daily demand curves shown in figure 42 (below) overlay the additional variability introduced by the PV configurations over the inherent variability of the grid. These figures demonstrate that the integration of an additional single 10MW PV plant into the Alice Springs network significantly increases the variability of the network demand profile which would potentially lead to challenges with generation. However it should be noted once again that extrapolating the variability in irradiance measured by a single point source pyranometer which occupies an area of 0.01m^2 to the variability in output for a 10MW PV plant that occupies an area over 300m^2 is overly pessimistic. The actual variability of the 10MW plant (as well as the other modelled options 3.3MW and 1.1MW) will be significantly less than the variability of the point source pyranometer. Yet even setting this aside it can be seen that the results of the 10 x 1.1MW configuration again verify that the impact of PV intermittency is largely nullified by geographical dispersion of the PV across the network.

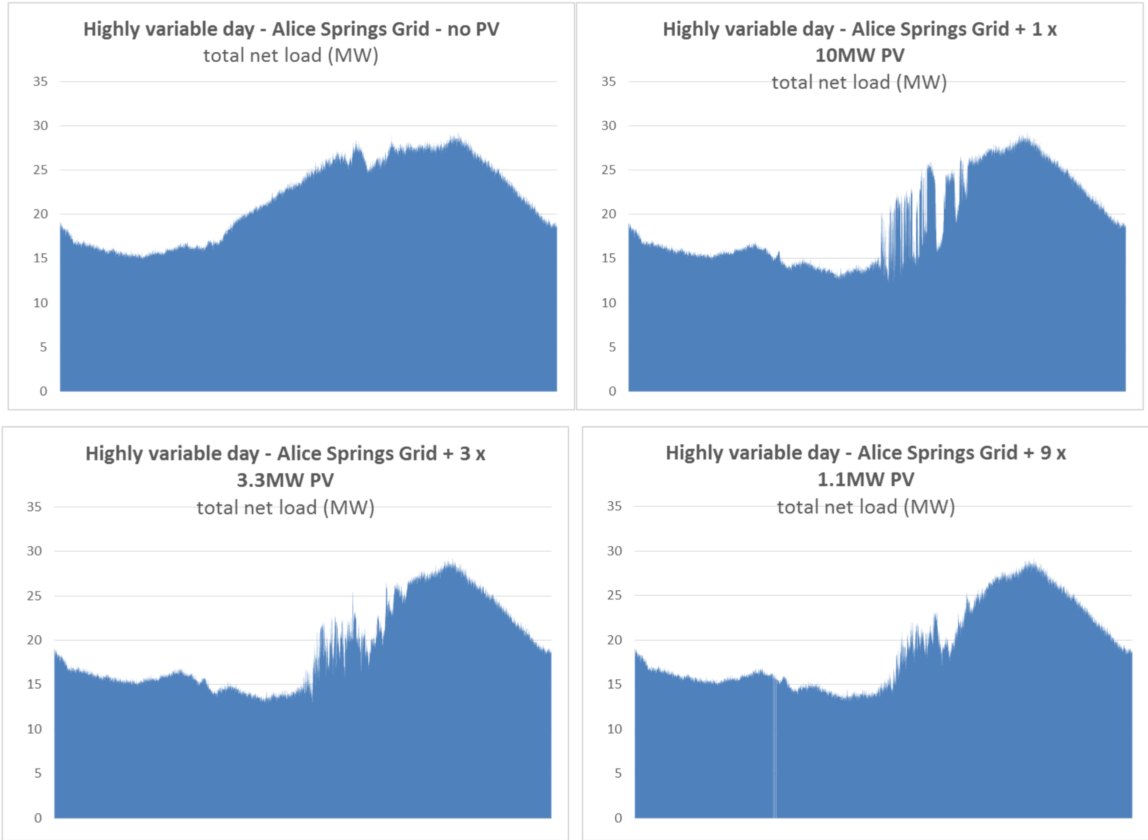

Figure 42 Net load on the Alice Springs grid without additional PV plants and with the addition of various combinations of PV plants (15 second intervals over 24 hours).

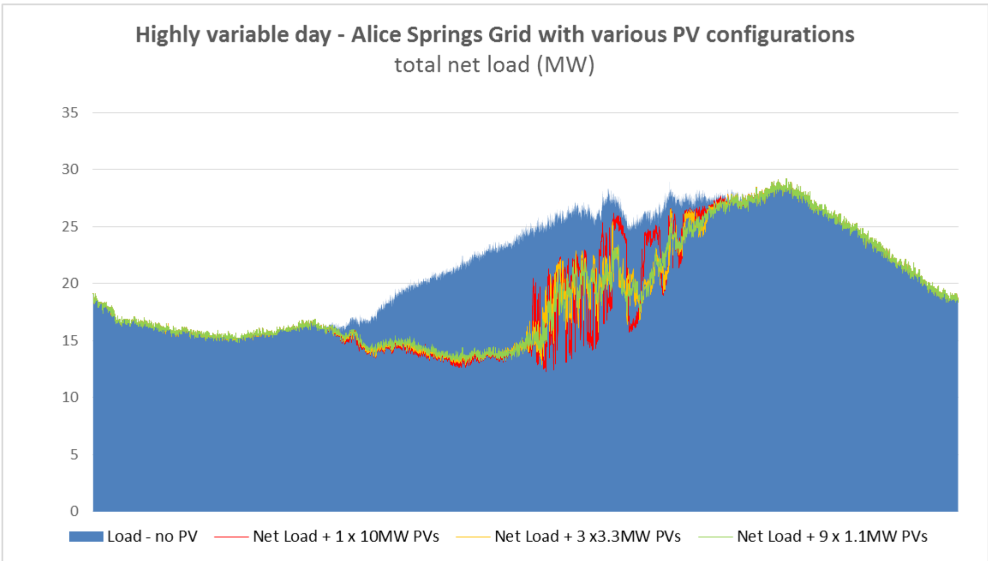

Figure 43 Net load on the Alice Springs grid with various PV plant configurations added (15 second intervals over 24 hours).

8.4 MEASURES OF VARIANCE

An alternative method of visualising the effect of the geographical dispersion of PV on the power system is to consider the net statistical variance of the power system under the various scenarios considered. Variance, as a statistical measure, is the measure of the spread of a range of measurements. In this context, the variance is a measure of the range of variability that is experienced by the power system over the course of a day under the respective scenarios.

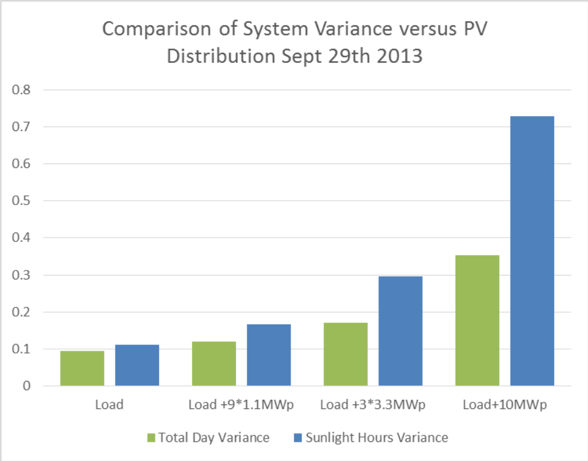

Figure 44: Highest level of solar variability and corresponding aggregate load – lowest load day 29 September 2013

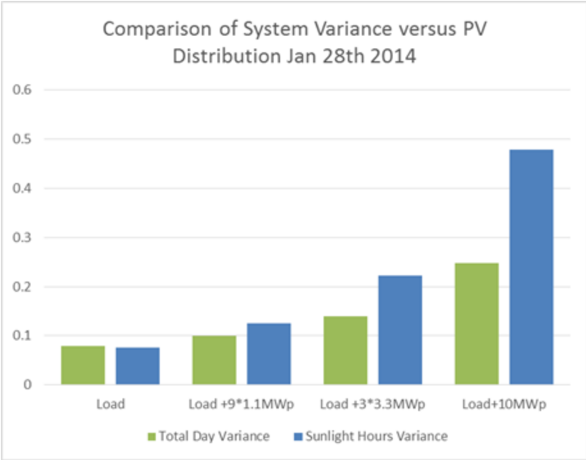

Figure 45: Highest level of solar variability and corresponding aggregate load – highest load day January 28 2014

The two graphs above plot the measured variance for each of the four scenarios:

- Existing load;
- Existing load + 10MW single PV array;
- Existing load + 3*3.3MW PV arrays;
- Existing load + 9*1.1MW PV arrays;

Further, to ensure that the data is not skewed by the time base of the measurement, the variance has been calculated for the entire 24 hours period (Green columns) and just for the daylight hours of 6:00AM to 6:00pm (Blue Columns). As variance is a measure of the spread of values being analysed, in this case, the spread of step changes, a smaller value indicates that the magnitude of the step changes is smaller, while a larger number indicate that the range of different step changes is larger.

The two graphs above show the dramatic difference in variance between the respective scenarios, with the variance in the modelled power system for a single 10MWp array being approximately 4 times that of a power system with nine 1.1MWp arrays. Further, it is noted that the variance in the power system for nine 1.1MWp is not substantially higher than that experienced by the grid without additional PV arrays.

As can be seen, the base variance in the power system on September 29th was around 0.11, and the variance of the modelled power system for nine 1.1MWp arrays on the 28th of January was only 0.12. That is, the level of variance that the power system would be required to accommodate with nine 1.1MWp arrays is **no worse than what the power system already accommodates**.

It could be argued that this is due to the level of variance in the power system due to the existing 4MWp of PV spread throughout the Alice Springs network, however, as noted the variance has been plotted for both the daylight hours (Blue), and the entire 24 hours period (Green). Peculiarly, the variance in the power system in January is actually higher during night time hours than it is during the day – it is unclear what the precise cause of this is.

9 CONCLUSION AND RECOMMENDATIONS

This project yielded some important and interesting findings. Firstly, variability in irradiance (and therefore PV generation) can be strongly mitigated against by dispersing PV generation geographically across the electricity network. The most effective way to disperse PV generation is by increasing the quantity of PV sites that are connected into the network. Sites must be spatially dispersed to achieve this effect but as long as there is reasonable spatial dispersion then by far the most important determinant in reducing the variability of PV generation is to increase the total number of sites.

The impact of the variability of the solar resource on the network can be dramatically reduced through geographic dispersion. In this project, the highest levels of solar variability and corresponding aggregate load in the Alice Springs network were selected to demonstrate this point. Namely, a weekday in January after school had returned (highest load) and a weekend in September (lowest load).

In both cases the level of intermittency when a distributed array is put in place comes close to the level of variability extant within the load profile in the first place. This can be further quantified by measuring the variance of the step changes in the load over the course of the day and then comparing that to the variance when the different models are overlaid.

With respect to the impact of dispersed PV, it can be clearly seen that the level of variance for a single 10MWp plant is over four times that for nine 1.1MWp plants separated as per the locations of the pyrometers. The ratios are very similar for both January and September.

Furthermore, the variance that would be seen by the system generators is higher with the larger presence of PV in the network than if it was not there at all, however it is ***no greater than the most significant variance that the generation units within the system currently accommodate*****.** The extant variance in the network in sunlight hours for September is 0.11, with the variance in January including nine 1.1MW PV plants is 0.12, thus demonstrating that the existing spinning reserve strategies could accommodate further PV integration without substantive change.

Key conclusions include:

1. **Pyranometers, by themselves, should not be considered as a useful real time predictive tool in PV output**. Given the vagaries of wind effects and the impact of spatial distribution, they are unable to forecast the extent of the variability that exists in a given electricity grid.
2. There is an assumption that large multinodal electricity grids are inherently stable (i.e. they do not experience large short term variances in demand) and that the addition of significant PV input and associated intermittency potential could cause disruptions that would increase the risk of operational problems. However, results from this project indicate that the **Alice Springs grid** (which is analogous to many other grids in regional and remote areas as well as too many sections of the National Energy Market) **encounters a significant level of load variance as part of normal operation**. In other words, the network already accommodates a high degree of variability without compromising on operational outcomes.
3. Furthermore, results show that for Alice Springs **the variance created by the installation of a further 10MW** of **Dispersed PV inputs into electricity grids can end up being very similar to the step-change 'noise' variance which currently occurs in the network**. The results demonstrate empirically that it is possible to install large amounts of PV, potentially exceeding 60% of demand, into existing networks without disrupting the underlying variance that normally exists in grids, as long as there is adequate spatial distribution of the PV input.

It is important to note, however, that the conclusions reached above are in the context of the **entire** network, and there may be **local** areas of the networks where such installations are not appropriate due to other gird constraints, voltage rise and frequency instability etc.

While undertaking this project, future research directions became apparent, including:

1. This type of study should be replicated in other grids (for example in a coastal location) in order to establish the degree of spatial diversity of PV input that is optimal given differing prevailing weather conditions, i.e. average wind speeds;
2. Further research and economic modelling is required to compare the **cost imposition of different options** for PV input. That is, for example, the cost of installing nine 1.1MW systems, versus three 3.3MW systems, versus one 10MW system; and

3. Analysis of the **size, number and spatial diversity to optimise PV input** (and limit the effects of variance) into the grid should be undertaken with a view to determining the **marginal benefit of additional diversity** and/or the extent to which the benefits of diversity diminish if the separation of systems gets too great.