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Study of Grid-connect Photovoltaic Systems - Benefits, Opportunities, Barriers and Strategies

FINAL REPORT

for

The Office of Energy

Western Australian Government

by

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Document navigation

To assist with navigation through such a large document, the Table of Contents includes hyperlinks and the UNSW logo on the title page is linked to the Table of Contents.

About CEEM and this report

The UNSW Centre for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from the Faculty of Business, the Faculty of Engineering, the Australian Graduate School of Management, the Institute of Environmental Studies, and the Faculty of Arts and Social Sciences, working alongside a growing number of international partners. Its research areas include the design of spot, ancillary and forward electricity markets, market-based environmental regulation, the integration of stochastic renewable energy technologies into the electricity network, and the broader policy context in which all these markets operate.

This report presents an analysis of the potential impact of integrating photovoltaics (PV) into the Western Australian electricity networks (the South West Interconnected System (SWIS) and North West Interconnected System (NWIS)) and regional grids. It extends previous CEEM analysis of the Newington Olympic Village at Homebush Bay in NSW, and focuses particularly on assessing PV's ability to reduce peak generation requirements, defer network augmentation, reduce system losses, influence power quality and reliability, and reduce the cost of supply. It then identifies existing market opportunities for PV, examines whether these capture the identified benefits, and identifies barriers preventing PV systems from taking full advantage of these opportunities. Lastly it discusses strategies for capturing the identified system benefits.

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Executive Summary

Aims

The primary aims of this report are to:

- identify where PV is providing benefits to the Western Australian electricity system,
- estimate the financial value of these benefits,
- determine who receives these benefits and who pays for them,
- propose strategies to reward PV for the electricity system benefits that are currently not recognised in the market,
- estimate the total value to PV of current and proposed support strategies, then
- discuss the impact of the current and proposed support strategies on deployment of PV in Western Australia.

Thus, this report is not concerned with the wider social and environmental drivers which might justify increased uptake of PV, and so does not aim to develop or propose specific deployment mechanisms. It aims only to propose mechanisms to reward PV for the system benefits it provides but for which it is currently not rewarded.

The possible benefits provided by PV that are assessed in this report are:

- providing electricity supply,
- providing capacity,
- deferring network augmentation,
- reducing line losses,
- influencing power quality and reliability in the SWIS and 'Edge of SWIS', and
- reducing generation costs in regional areas.

Methodology

The impact of PV on the Western Australian SWIS and regional grids was assessed using half hour load, insolation and PV data. Table 1 lists the load locations and Figure 1 shows the locations of the load, PV and solar insolation data used in this study.

Table 1 Locations of load data

	Location
SWIS	Forrest Ave
	Midland Junction
	North Perth
	Osborne Park
Edge of SWIS	Katanning
	Geraldton
	Merredin 132/66
Regional	Carnarvon
	Marble Bar
	Meekatharra
	Port Hedland

Load data

Perth locations were chosen because they were likely to have a load profile that peaks in the middle of the day and so provide a good match to PV output. Two of the selected substations had a summer peak with a commercial profile and so were a good match to north facing PV output (Forrest Ave and Osborne Park). Two substations had an early afternoon summer peak due to a mixed commercial/residential profile and so provided a possible match to west facing PV (Midland Junction and North Perth).

The three 'Edge of SWIS' locations were chosen to provide diversity in load and solar insolation characteristics, and according to the length of the network they serviced. Katanning substation was selected because the associated feeder is particularly long (over 200km) and is in a region in need of augmentation. The Geraldton substation was selected because it is distant to Katanning and so may have different solar insolation characteristics, is linked to the Kalbarri 20kWp PV system, and has an early afternoon summer peak that could correlate well with PV output. The Merredin 132/66 substation was selected because it was one of the few Edge of SWIS substations that had a summer peaking profile in 2006 and was reasonably distant to Katanning and Geraldton and so again, may have different load and solar insolation characteristics.

The regional locations were selected on the basis of having a high cost of supply, a good solar resource and potential correlation of load with PV output. Carnarvon was selected because of the availability of PV data from the Carnarvon Solar Farm, and because the Carnarvon power station is in need of an upgrade and potential alternative energy sources are being considered. Marble Bar was selected because it has a high cost of supply (from diesel generators) and is to be replaced within the next two years and so provides an opportunity for integration of PV into a diesel system. Meekatharra was selected because it has a high cost of supply (also from diesel generators) and is distant to Marble Bar and so likely to have a different solar insolation profile. Port Hedland was selected because it is part of the NWIS (rather than being only in a small town), and is of particular interest to Horizon Power, which is currently considering supply options, and it also provides an opportunity to evaluate the potential benefits of using PV along the Pilbara coast.

PV and insolation data

Limited amounts of actual PV data were available. However, apart from that for the Carnarvon and Kalbarri PV systems, they were often for short periods, or for periods that didn't match the load data, or wasn't near to the load locations. Thus, solar insolation data were used to simulate PV data for all load locations. However, since 2004, detailed insolation data have been collected in only one WA location, and so it was necessary to use 2003/04 load data for the SWIS and Edge of SWIS comparisons. Only 2005/06 load data were available for the regional locations and so Reference Meteorological Year (RMY) insolation data were used (which is a composite of the 12 months of best fit). In this case the solar data used does not necessarily match the real data for the years studied and so the correlation results presented here between load and PV output are indicative only.

If solar technologies are to play an increased role in WA's energy supply, more solar insolation and PV system monitoring are needed.

The solar data were used in the PvSyst simulation program to simulate hourly PV output data, assuming a number of different orientations – north, north west, and west with a tilt of either 25, 45 or 90 degrees. PV data from smaller systems were used if they corresponded to the times and approximate locations of demand peaks. The Hybrid Optimization Model for Electric Renewables (HOMER) was also used to assess the impact of integrating PV into the regional grid at Marble Bar.

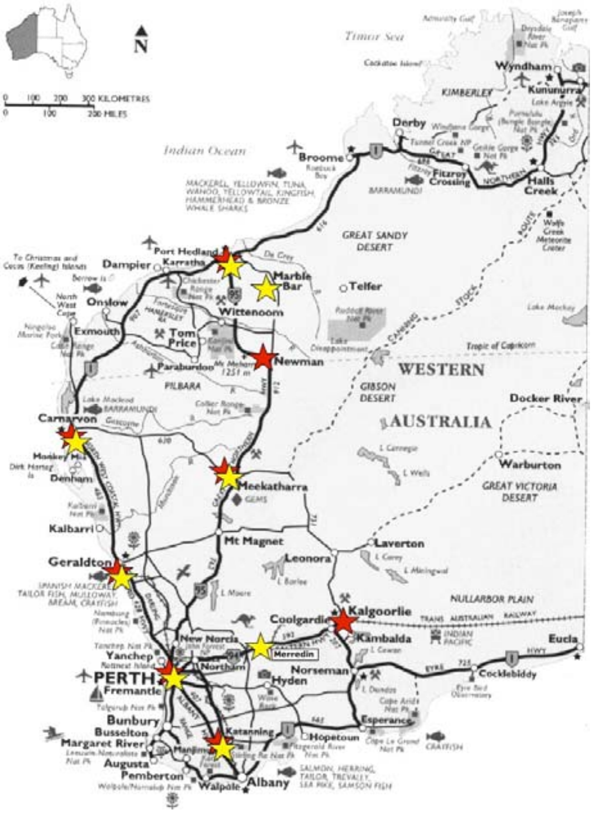

Figure 1 Map of load and ACDB data sites in WA, Yellow Stars: locations of load data, Red Stars: locations of solar insolation data

Results & Discussion

Impact of PV on the electricity system

If PV can be relied upon to reduce future load peaks it could result in cost savings through:

- offsetting high-cost peaking generation,
- more effective use of existing infrastructure,
- deferral of additional generation and/or network infrastructure.

PV can also be used to influence power quality and reliability, reduce losses on long rural feeders and avoid the direct and indirect cost of fuel. The following summarises the report findings concerning PV's ability to deliver these benefits.

South West Interconnected System

The following firstly describes the correlation between simulated PV and load, then the various values PV could provide in the SWIS.

Correlation between PV and load

The correlation between PV output and local load was studied to determine PV's contribution to offsetting peak loads.

It was found that the SWIS (Perth) locations' peak load periods generally had a good overall correlation to either simulated north-facing or west-facing PV. However, where there were significant residential loads, the peak tended to occur later in the day, and so PV was not as successful in offsetting peak load – see Figure 2 and Figure 3.

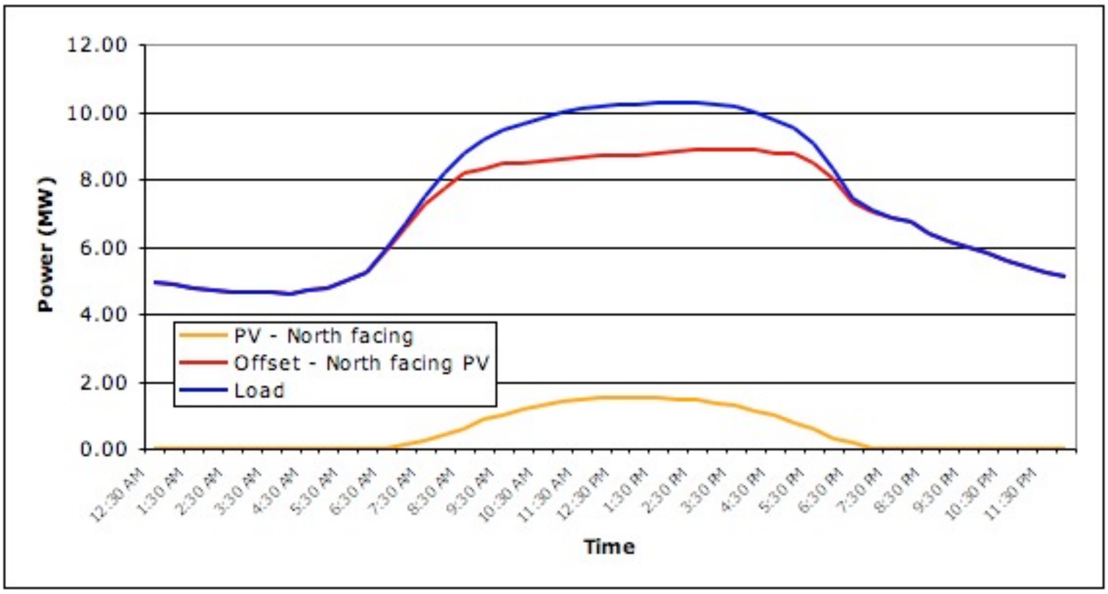

Figure 2: Daily Summer Average, Forrest Ave

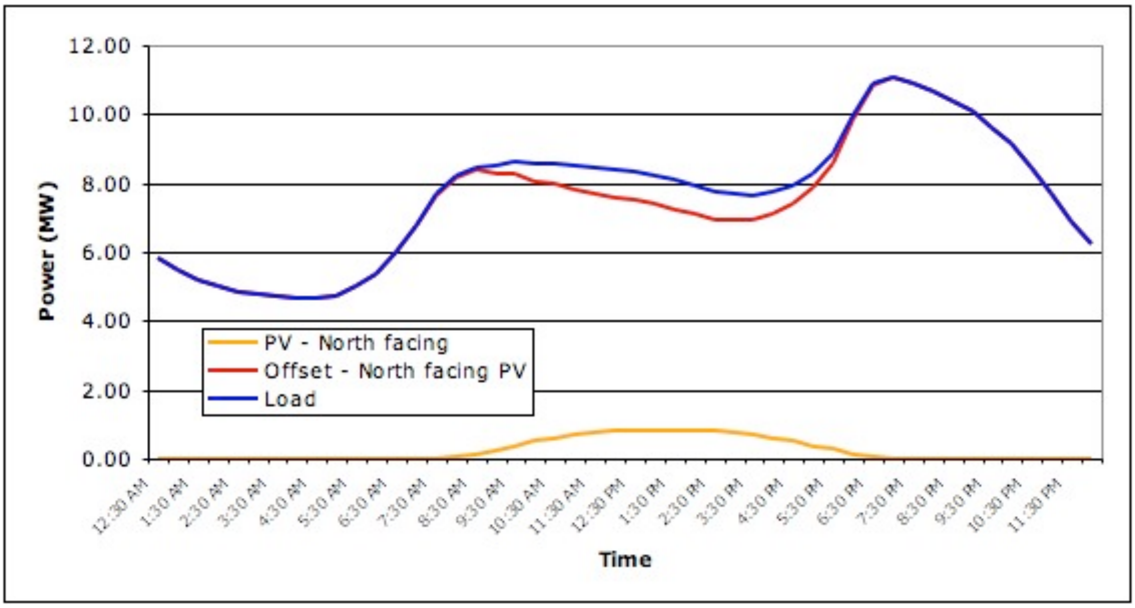

Figure 3: Daily Winter Average, North Perth

Simulated PV sometimes correlated well with peak loads, but on other occasions it didn't (eg. Figure 4 compared to Figure 5).

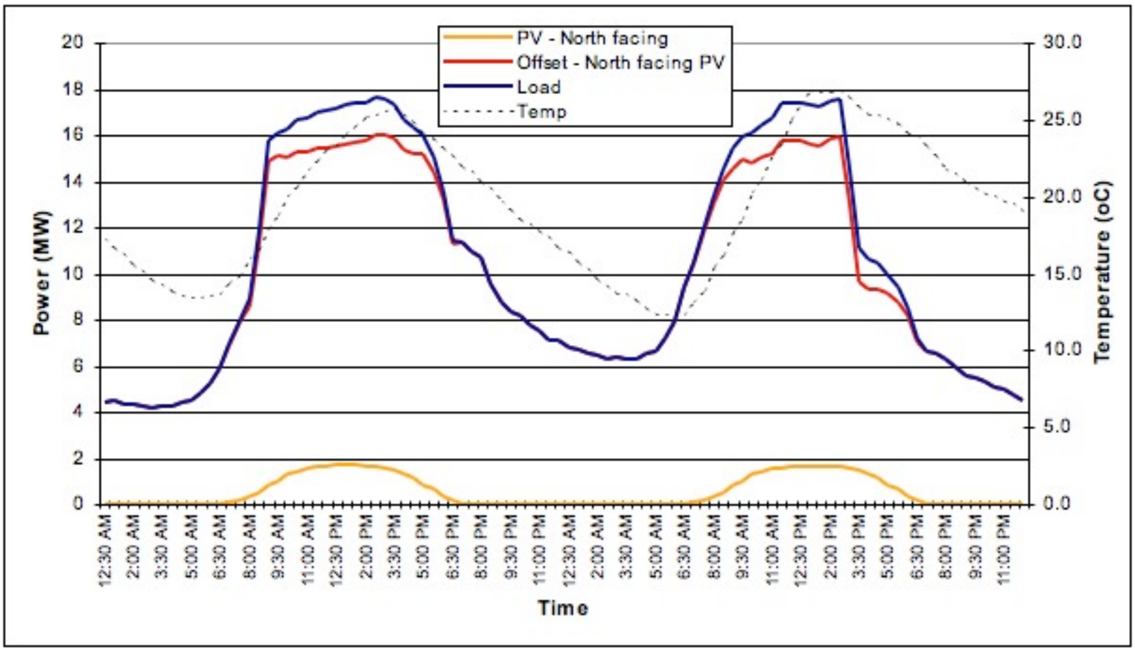

Figure 4: Autumn peak days, Forrest Ave

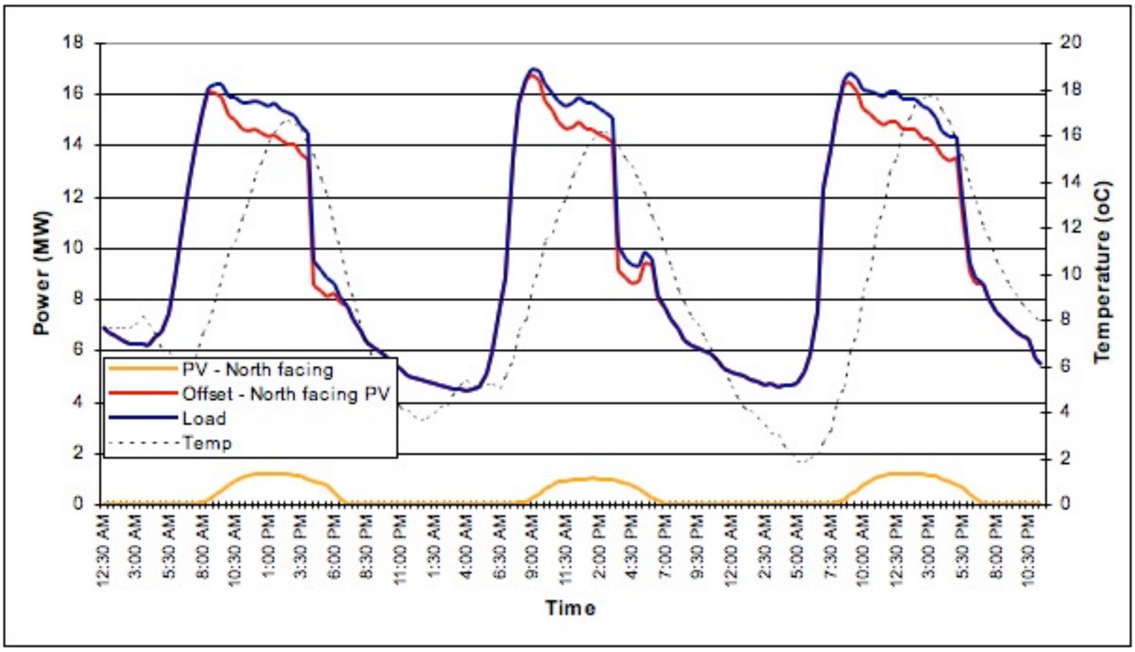

Figure 5: Winter peak days, Forrest Ave

Load duration curves can be used to help assess PV's potential to reduce the load at the very highest load points – which determine the capacity for which networks must be designed and built.

Using load duration curves it is possible to calculate PV's contribution to reducing the load as a percentage of its rated output. For example, if the very highest point of a load duration curve was reduced by 0.9MW with 2MW of PV, this means that PV contributed 45% of its rated capacity at that time. For the SWIS locations this contribution ranged from 33% to 60%, and from 21% to 55% on average for the top ten load periods.

Commercial value of offsetting conventional generation

The value of electricity from PV was estimated using half hour Marginal Cost Administrative Prices. A 1kW simulated PV system produced electricity with an annual value of about $140. Assuming a 12% discount rate over 20 years, this equates to almost $1.30/W, compared to the current PV cost of around $13/W.

Commercial value of providing capacity

Small PV systems do not participate in the Reserve Capacity Mechanism under the Wholesale Electricity Market. However, a retailer that has a customer with a PV system benefits from a decrease to the value of its IRCR, as the PV system reduces the sum of its customers' demand. There are many complications in calculating the way the market would decrease the value of the IRCR, as this is dependent on excess capacity, the retailer's share of demand and the price of capacity credits. Here it has been assumed that the value of the IRCR reduction due to PV is equal to the available PV capacity multiplied by the capacity credit price.

The IRCR reduction values calculated for a 1kW PV system were about $66/yr for north-facing and $94/yr for west-facing arrays, which equate to 59c/W and 84c/W respectively, assuming a 12% discount rate over 20 years.

Combined commercial value of electricity and generation capacity

The combined discounted net value was about $1.90/W and $2.15/W for simulated north-facing and west-facing PV respectively, which are about 14.5% and 16.5% of the installed cost of PV.

Deferring network augmentation

For PV to defer network augmentation, it must be producing power with a very high degree of certainty in a particular location at particular times in the future. From this research it has been shown that PV's contribution during peak load periods varies greatly, ie. from 33% to 60% of its rated capacity in the SWIS locations studied.

In addition, PV must provide sufficient firm capacity to cover load growth for a certain period of time. In the examples studied here, and assuming PV could provide 50% of it's rated capacity during peak times, about 2MW of PV would be required to defer a 33MW transformer for one year. The value it would provide in doing this is about 12c/W, or about 24c/W with perfect and free storage, significantly below the current installed cost of PV.

PV's ability to offset peak loads, and therefore defer network augmentation, would be enhanced if it were incorporated into a demand management strategy that focuses on reducing power demand at times when PV is not operating, especially in the late afternoon. Of course, a demand management strategy on its own could reduce energy use at peak times without the need for PV.

If PV is to be installed for other reasons (for example: technology showcasing; improved building performance such as shading, insulation or lighting; or industry development and associated job creation), it would have incremental network benefits, although they would depend on location and timing. PV output does not have to match load exactly to provide some support – for instance, when generation occurs prior to peak loads it can reduce load and thus pre-cool transformers, so enhancing their ability to deal with peaks, especially on hot days.

Power quality and reliability

PV's contribution to power quality (both positive and negative) is largely determined by the type of inverter used to connect to the grid. If inverters that conform to Australian Standards are used, PV is unlikely to have a significant negative power quality impact and should not result in inactive networks becoming 'live' and therefore dangerous. PV can have a positive power quality impact only when it is operating. It may not provide the type of support required and there are generally cheaper alternatives available. Thus, while PV may be able to help with power quality, this ability is likely to have little positive impact on its commercial viability.

Edge of SWIS

Correlation between PV and load

The Edge of SWIS locations' peak load periods were generally not well matched to either simulated north-facing or west-facing PV (eg. Figure 6).

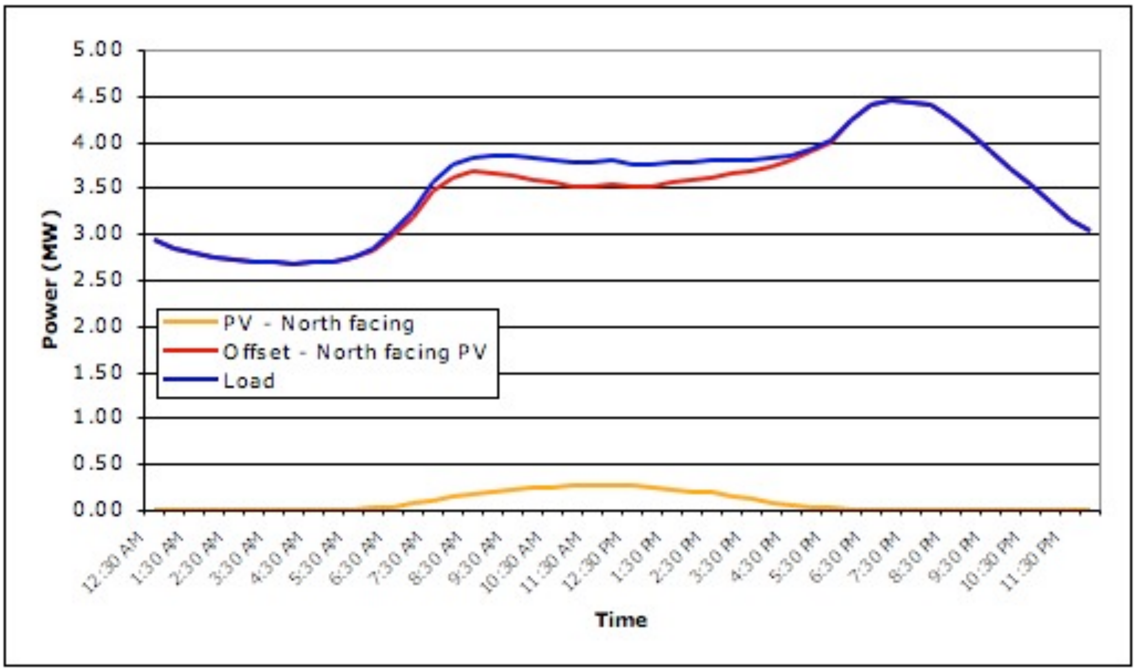

Figure 6 Daily Annual Average, Merredin

Simulated PV had a lower and more uneven correlation with the very highest peak loads than it did for the SWIS locations, and where it did correlate, later periods on the same day or cluster of days often became the new peaks when PV was added (eg. Figure 7 and Figure 8).

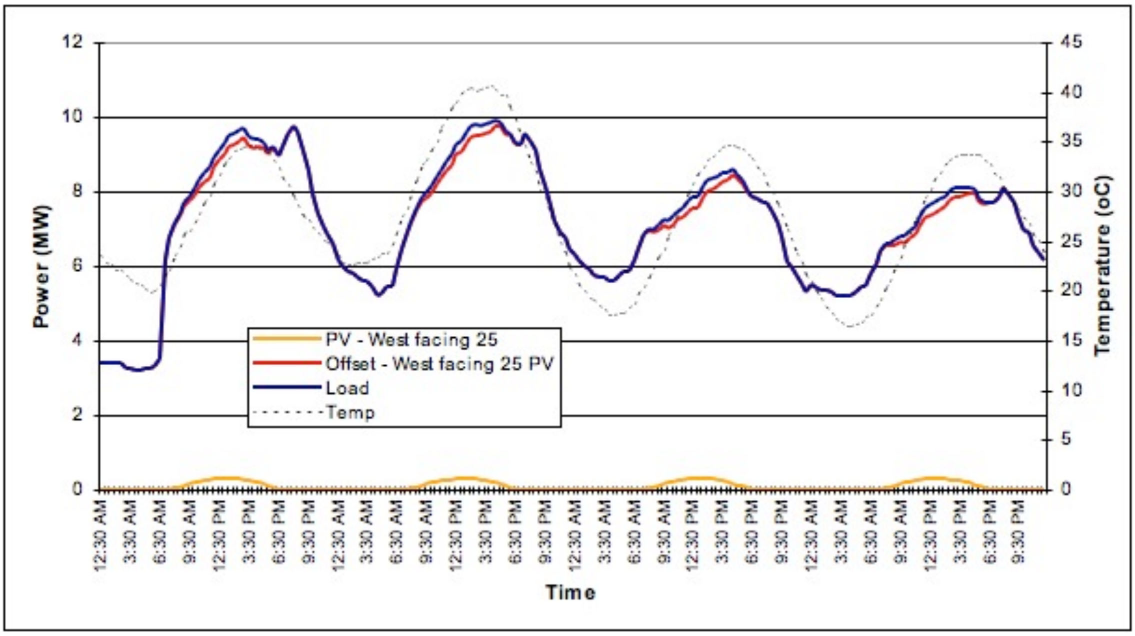

Figure 7: Summer peak days: Merredin (west-facing PV)

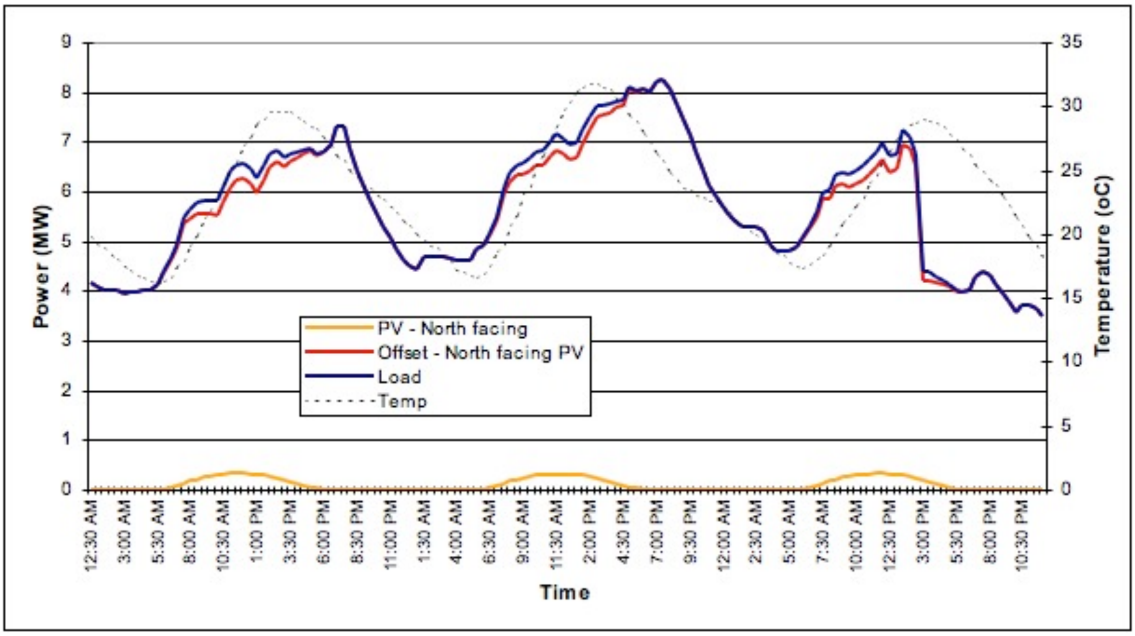

Figure 8: Autumn peak days: Merredin

As a result, the load duration curves were not greatly reduced by PV.

PV's contribution to reducing the peak load as a percentage of its rated output ranged from 12.5% to 40.5%, and from 35% to 59% on average for the top ten load periods.

Commercial value of offsetting conventional generation

A 1kW simulated PV system produced electricity with an annual value of between $105 and $145, depending on the location and orientation which, assuming a 12% discount rate over 20 years, equates to between $0.95c/W and $1.30/W.

Commercial value of providing capacity

The IRCR reduction values calculated for a 1kW PV system ranged from about $34/yr to $64/yr for north-facing and from about $53/yr to $95/yr for west-facing, which equate to a range of from 31c/W (north-facing) to 85c/W (west-facing) assuming a 12% discount rate over 20 years.

Combined commercial value of electricity and generation capacity

The combined discounted net value averaged about $1.90/W and $1.85/W for simulated north-facing and west-facing PV respectively, which are about 14.5% of the installed cost of PV.

Deferring network augmentation

Because of the generally poor correlation with peak load, it appears unlikely that PV would provide more than 25% of its rated output as firm capacity during peak periods in Edge of SWIS regions. Applying the same methodology as was used for the SWIS locations, the financial value provided by PV deferring network augmentation in Edge of SWIS areas is about 7c/W, and increases to 14c/W with perfect and free storage.

Reduction of system losses

To maximise PV's contribution to reducing losses, it should be matched as closely as possible to load, meaning that PV systems without storage in Edge of SWIS areas may not be well suited to this task. However, where PV is installed for other reasons, it would still contribute to some reduction in overall losses. The IMO publishes transmission loss factors (TLFs) and distribution loss factors (DLFs), where the TLFs represent marginal losses on the transmission system and the DLFs represent average losses on the distribution system. To obtain the total Loss Factor for a particular location, the TLF is multiplied by the relevant DLF.

The electricity losses avoided because of PV can be estimated by multiplying the total Loss Factors by the PV generation. To give an indication of their value, they can then be multiplied by an indicative wholesale generation cost (here calculated to be 7.85c/kWh for north-facing and 8.55c/kWh for west-facing). For the locations studied here, the annual value for a 1kW system ranged from $19 to $31 depending on location and orientation, which equate to 17c/W and 28c/W respectively, assuming a 12% discount rate over 20 years.

Summary of PV Benefits in the SWIS and Edge of SWIS

The electricity system benefits provided by PV that have a significant market value compared to the installed cost of PV are:

- offsetting conventional generation during daylight hours
- providing firm capacity in the SWIS and 'Edge of SWIS'

Additional benefits provided by PV that have low values compared to its installed cost are: deferring network augmentation and reducing line losses.

In the SWIS and Edge of SWIS, the discounted total value of all these benefits over 20 years is just under $3/W for both north and west-facing PV at a 6% discount rate and about $2/W at a 12% discount rate. Note that the value per kWh for west-facing PV (~16.1c/kWh) is greater than for north-facing PV (~13.5c/kWh) because of lower electricity output for west-facing (both at a 12% discount rate) – see Table 2. In a well functioning market, these values should be passed on to retailers.

Table 2 Summary of approximate benefits provided by PV in the SWIS and Edge of SWIS

Benefit	**Approximate average value /W**		**Approximate average value /kWh**	
	North	West	North	West
Offsetting convent. gen.	$1.20	$1.20	7.8c	8.6c
Providing firm capacity	$0.55	$0.75	3.5c	5.1c
Deferring network aug	$0.12	$0.12	0.8c	0.8c
Reducing line losses	$0.22	$0.21	1.4c	1.6c
Total	$2.09	$2.28	13.5c	16.1c

Note that these values are indicative averages only. The actual values will vary from system to system and will be influenced by a number of factors including orientation, location, temperature, shading and maintenance of the panels and balance of system equipment.

Regional towns and grids

Correlation between PV and load

It was found that the regional locations' peak load periods were generally well matched to either simulated north-facing or west-facing PV. However, sometimes periods of slightly lower peaks were not as well matched to the simulated PV, and so became the highest peaks. In these regional areas, PV's contribution to reducing the load duration curve as a percentage of its rated output ranged from 25% to 85%, and from 52% to 73% on average for the top ten load periods.

Reduction of cost of supply

Marble Bar and Meekatharra are supplied exclusively by diesel generators so PV output at any time of the day will reduce diesel use and possibly the cost of supply. Carnarvon and Port Hedland are mostly supplied by gas-fired turbines so the generation costs are much lower than at Marble Bar and Meekatharra.

If PV generation is valued at the cost of conventional generation for Horizon Power at Carnarvon (13.39c/kWh), Marble Bar (39.11c/kWh), Meekatharra (35.5c/kWh), and Port Hedland (7.07c/kWh), its value is as shown in Table 3. It can be seen that for some locations PV's value in offsetting conventional generation is a significant proportion of its installed cost. Where diesel is predominantly used, PV's value to retailers far exceeds the cost of the REBS.

Table 3 Value of electricity generated by 1kW simulated PV: Generation cost

Location	Value in year 1	Disc Value per Watt[a]
Carnarvon	$190	$3.00
Carnarvon Solar Farm	$220	$3.50
Marble Bar	$550	$8.65
Meekatharra	$500	$7.85
Port Hedland	$100	$1.60

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2

HOMER software was used to model the impacts of the installation of large-scale PV systems in Marble Bar. It was used to assess PV's potential contribution to reduce diesel use and greenhouse emissions, as well as provide estimates of the resultant capital and operating costs. Use of a 100kW PV system resulted in a slightly higher per kWh cost (43.5c/kWh) than diesel alone (43.1c/kWh) – see Table 4. Hence the electricity price increase resulting from the addition of 100 kW of PV to the Marble Bar power station would be less than 0.5c/kWh, but the diesel savings (~50,000 litres/yr) and the CO_2 reduction (~135,000 t CO_2/yr) would be significant.

Table 4 Costs[1] for a diesel and diesel +100kW PV – Marble Bar

	No PV	100kW PV
Capital cost ($)	1,050,000	1,592,000
Net Present Cost ($)	8,119,130	8,194,658
Cost (c/kWh)	43.1	43.5
Diesel use (L/yr)	712,179	662,240
CO_2 emissions (kg/yr)	1,921,361	1,786,632

The impacts of higher diesel prices and a price on CO_2 emissions are shown in Figure 9 and Figure 10. According to this modelling, once diesel passes about $1.20/L, the electricity generation cost with 100kW PV installed is less than for diesel alone. The CO_2 cost needs to be greater than $60/tonne for the diesel/PV system to be cheaper. The impact of different capital costs for the PV and inverters is shown in Figure 11. These are chosen to reflect reduced contributions from the RRPGP, which could offset any reduced costs of PV due to technology improvements in the future. It is clear that the RRPGP has a significant impact on the final electricity price. This modelling used standard flat plate PV systems, but large-scale concentrator systems now being installed in SA and NT may be more cost-effective.

[1] Is the cost of the entire system including three 320kWp diesel generators.

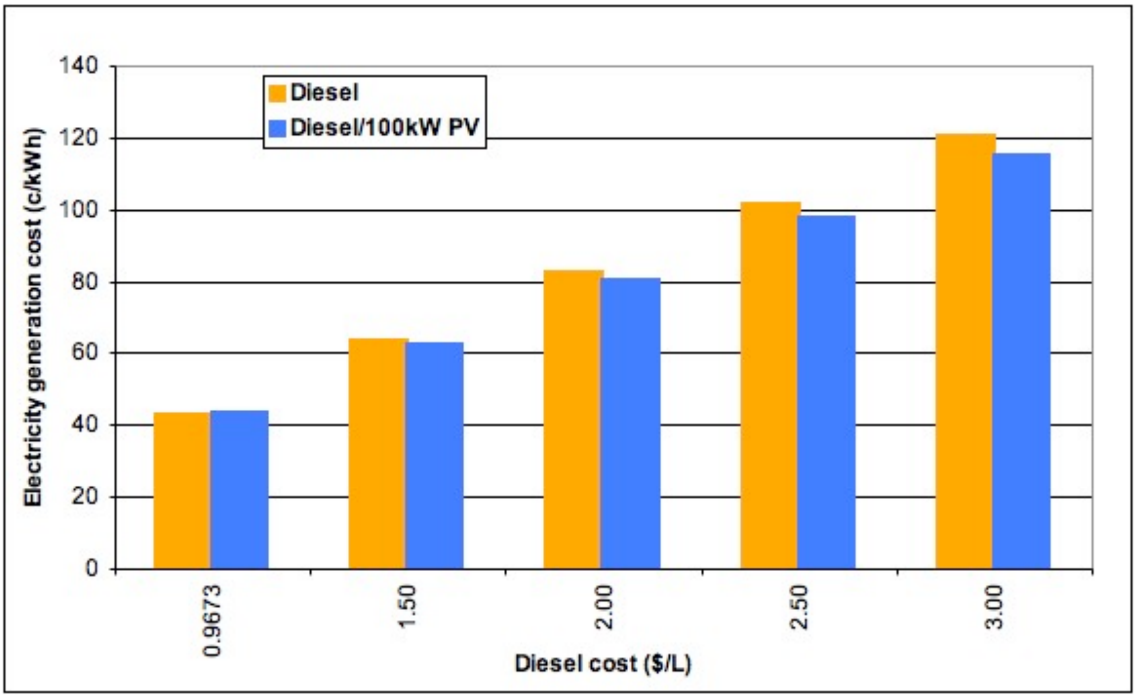

Figure 9 Influence of diesel price on per kWh cost

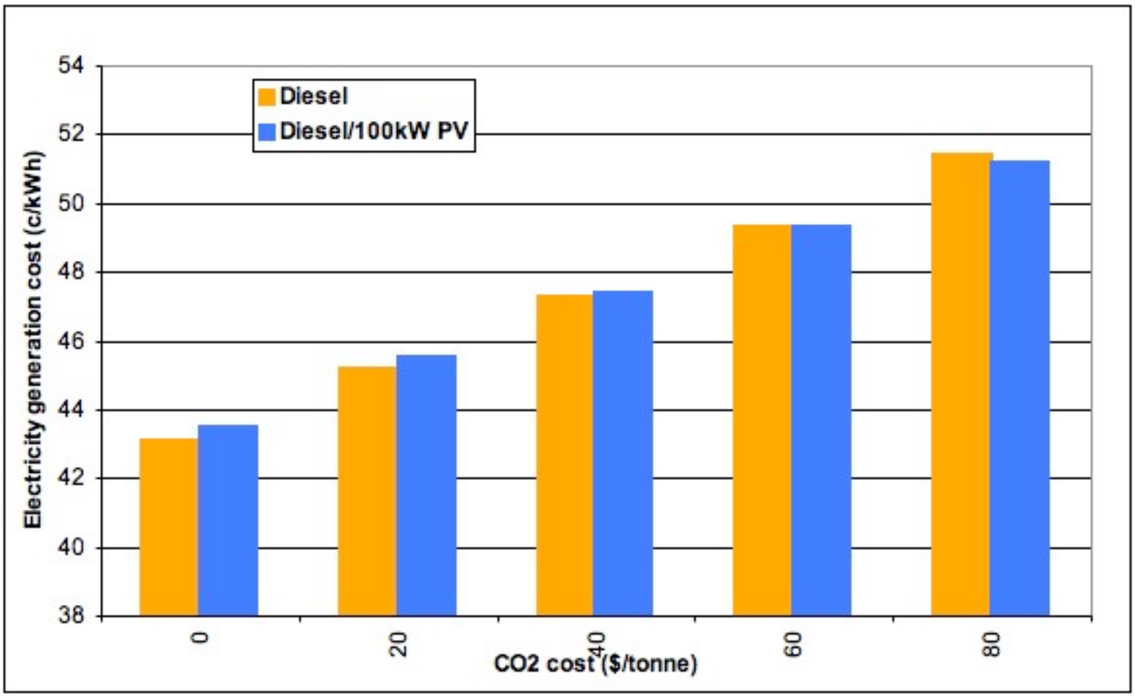

Figure 10 Influence of CO_2 price on per kWh cost

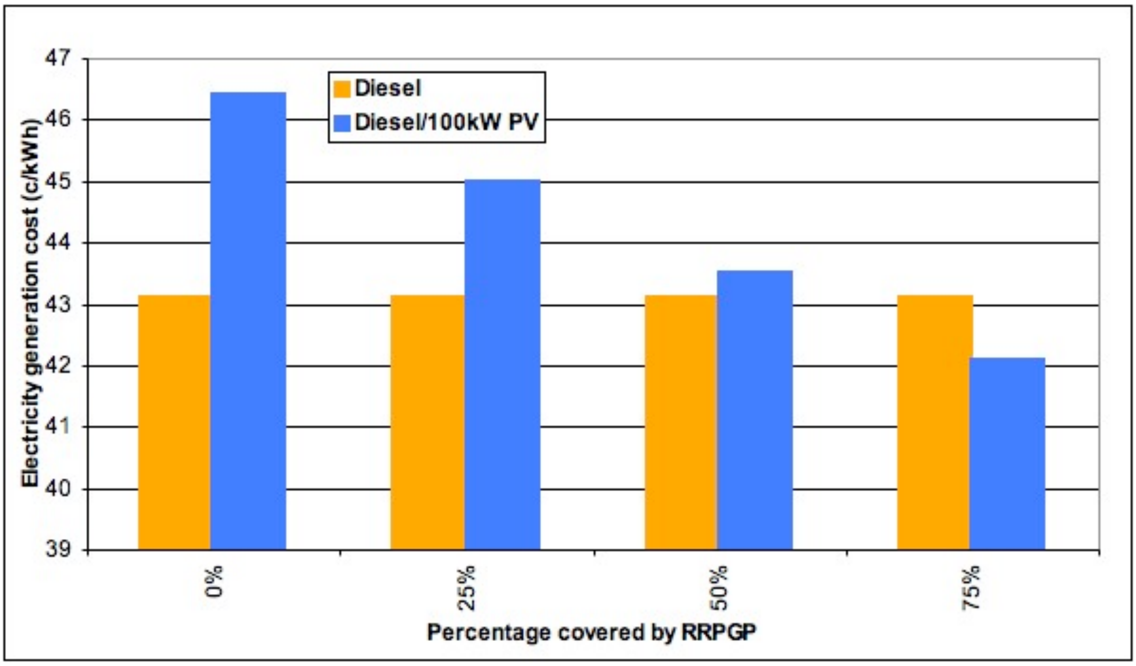

Figure 11 Influence of RRPGP on per kWh cost

Existing opportunities for PV

Value is currently available to residential PV in WA through REBS and from RECs, while those connected to the SWIS also benefit from the PVRP, whereas systems displacing diesel in regional areas also benefit from the RRPGP. Systems owned by businesses are not eligible for the REBS. The net value currently available to PV in SWIS and regional locations is estimated below.

Net amount available to PV

The net dollar amount available to PV includes:

- electricity value;
- RECs; and
- PVRP (in the SWIS);
- RRPGP (outside the SWIS).

Assuming the PV system is owned by an end-user, the electricity value in this situation would depend on the owner’s electricity use tariff structure, their PV generation tariff structure and whether the latter was applied to total generation or to net export. In this analysis net metering is assumed, meaning that the system owner is paid for all generation at their electricity use tariff. The following provides estimates of the total net dollar amount currently available to PV in different locations in WA. The value is accrued over 20 years, discounted at either 6% or 12%, and assumes the tariff increases as per Section 2.

Table 5 to Table 8 show indicative averages only and will vary from system to system and will be influenced by a number of factors including orientation, location, temperature, shading and maintenance of the panels and balance of system equipment.

In the SWIS (Table 5 to Table 7), it can be seen that the value currently available to PV almost covers the installed cost of residential systems (approx. $13,000), while community systems earn $1,500 less. Although businesses may be able to depreciate the installed cost against tax, the initial investment is still significantly more than the value currently available (because of no PVRP) – especially if they receive a low buyback rate. Note also that connection costs can add between $700 (single phase) and $1,200 (three phase), significantly more than in other jurisdictions.

Table 5 Net value of electricity, PVRP and RECs for a hypothetical 1kW residential system in the SWIS and Edge of SWIS

	Residential A1	SmartPower
Electricity	$3,700	$4,750
PVRP	$8,000	
RECs	$520	
Total	$12,220	$13,270
ROI	4.70%	5.10%

Table 6 Net value of electricity, PVRP and RECs for a hypothetical 1kW community system in the SWIS and Edge of SWIS

	Residential A1	SmartPower
Electricity	$3,700	$4,750
PVRP	$6,500	
RECs	$520	
Total	$10,720	$11,770
ROI	4.12%	4.53%

Table 7 Net value of electricity and RECs for a hypothetical 1kW business system in the SWIS and Edge of SWIS

	R3 Business	6c/kWh
Electricity	$2,850	$1,000
RECs	$520	
Total	$3,370	$1,520
ROI	1.30%	0.58%

In regional areas (Table 8), the value currently available to PV covers about 85% of the installed cost of a residential system and all the installed cost of a business system if accelerated depreciation is applied – although connection costs can be between $500 and over $1,600.

Table 8 Net value of electricity, RRPGP and RECs for hypothetical 1kW systems in regional areas

	A2 Residential	L2 Business
Electricity	$4,000	$3,150
RRPGP	$6,500	
RECs	$520	
Total	$11,020	$10,170
ROI	4.2%	3.9%

Strategies for capturing benefits

Thus, it appears that residential PV is being appropriately rewarded for the system benefits it provides on the SWIS. However, businesses installing PV in the SWIS and receiving only the SWIS conventional generation cost, and PV installed in regional areas with a high conventional generation cost and paid only a REBS tariff, are not sufficiently rewarded. The following discusses strategies both to more accurately value these benefits and allow PV to take advantage of them.

PV installed by businesses in the SWIS

As shown in the previous summary tables, PV installed by businesses most likely provides significant value to retailers and is potentially a better match to local load than are residential systems. However, even if businesses were paid, for example, the R3 Business tariff, the net value available would still be small compared to PV's installed cost - Table 9. Thus, in the absence of other support such as the PVRP, installation would depend on the recognition of other values provided by PV, such as improved corporate image or building aesthetics.

Table 9 Net value of electricity and RECs for a hypothetical 1kW business system in the SWIS and Edge of SWIS

	R3 Business
Electricity	$2,800
RECs	$520
Total	$3,320
ROI	1.30%

A survey of commercial building owners could ascertain their current electricity usage/cost/tariff type as well as their potential interest in PV. This could include assessing their interest in different types of policy support, such as capital grants or a FiT, and their ability to maximise the investment through capital expense write offs, publicity, increases in property value etc., as well as their expected return on investment. Their potential level of interest in a tradeoff against energy star measures would also be useful. Novel financing arrangements may also be appropriate.

Conventional generation cost FiT

In some regional areas the cost of conventional generation is very high (ie. where there is predominantly diesel generation). Paying PV system owners a FiT equal to the conventional generation cost (which excludes distribution costs etc.) should be revenue neutral for Horizon Power. The FiT should be paid on all PV generation, not just export, because all PV generation is offsetting conventional generation. The FiT should guarantee payment to the system owner for a minimum of 10-15 years (to create financial certainty); and the program should run for a minimum of 15 years (to enable industry development), meaning the FiT is paid out over 25-30 years (systems installed in year 15 will still earn a FiT for the following 15 years). To maximise new deployment, and to facilitate the introduction of standard metering arrangements, the FiT should be provided to new and extended installations only, where the latter receive the FiT only for the extension. If this is considered politically unacceptable, existing system owners could receive a FiT at a reduced rate – however, this would decrease the funding available for new installations. Where the size of the FiT tracks the cost of conventional generation, it is not a subsidy, and so may change each year for a particular system. Note that it may be necessary to place a floor on the value of the FiT to provide some certainty to system owners should the price of conventional generation decrease below this floor – in which case the FiT would include a subsidy.

Table 10 shows the value of electricity assuming a FiT based on conventional generation in two regional locations, together with the value of deemed RECs and RRPGP.

In Marble Bar (serviced by diesel), the discounted net value for both residential and business systems is significantly greater than the installed cost of PV (including connection costs) – especially if a business claims accelerated depreciation of the system. In areas such as Carnarvon (predominantly gas-fired), discounted net values are still a significant proportion of the installed cost.

Table 10 Net value of electricity, RRPGP and RECs for hypothetical 1kW systems in regional areas

	Marble Bar (39.11c/kWh)		Carnarvon (13.39c/kWh)	
Discount rate	6%	12%	6%	12%
Electricity	$10,850	$8,650	$3,800	$3,000
RRPGP	$6,500			
RECs	$520			
Total	$17,870	15,670	10,820	10,020
ROI	6.9%	6.0%	4.2%	3.9%

Although a FiT lower than the conventional generation costs in Marble Bar and Meekatharra should still more than cover the installed cost, any decreased rate should be in the context that a FiT equal to the conventional generation cost doesn't increase

Horizon's generation costs overall.[2] It is also possible that installation of systems in places such as Marble Bar and Meeketharra may cost more than the indicative cost used here (ie. $13,000 for a 1kW system), and maintenance costs may also be higher than average.

Government could have a role to play in the provision of reliable information regarding the installation and operation of remote on-grid PV systems. Reducing diesel use for electricity generation could have balance of trade benefits as most of the diesel used in WA comes from the refinery at Kwinana and more than half the crude oil for that refinery comes from outside Australia. Increased deployment of PV systems in rural and remote areas will have greenhouse gas reduction benefits and should also result in local job creation, not only for installation but also for maintenance, and reduced electricity costs should also have economic benefits.

Impact of strategies on deployment

Over the next five or so years the main influences on PV uptake are the PVRP and the RRPGP. In their absence only the diesel-based FiT could have a significant impact. Assuming WA receives similar proportions of the PVRP and RRPGP funding as it has in the past, the PVRP will drive about 365kW and the RRPGP will drive about 3.2MW of PV installation. It is difficult to estimate increased uptake resulting from the proposed FiT, however, it may significantly increase installation rates in regional areas.

[2] The Tariff Equalisation Fund (TEF) is used to compensate Horizon Power for the difference between their cost of supply throughout their entire operations and their revenue stream, so strictly speaking, a FiT equal to the conventional generation cost doesn't increase demands on the TEF.

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Glossary

Capacity The maximum rated output of a source of electrical power such as a coal-fired power station or a PV panel.

Certified Reserve Capacity The capacity of a power station or the amount of demand side management which has been certified to provide reserve capacity through the RCM. For more information see Appendix 6.8 or http://www.imowa.com.au/.

Deeming The process of granting some form of value in advance, for example, granting PV 15 years worth of RECs upfront.

Discounting Reducing the value of future cash flows, for example, a 6% discount rate would mean that $100 received in 1 year's time is worth as much as $94 received now (0.94x$100), and $100 received in 2 years time would be worth as much as $88.36c received now (0.94x0.94x$100).

Dispatchable generator A generator that can alter their power output more or less on demand. This includes coal-fired power stations (which take many hours to start up or stop) and gas-fired open cycle turbines and hydro (which can start up or stop in minutes).

Distributed generation Electricity generators that are connected to the electricity distribution network. They are generally small (from around 100kW down to less than 1kW) and closer to the sources of load.

Distribution Loss Factor (DLF) Represent average losses at a particular point on the electricity distribution system. When multiplied by the Transmission Loss Factor they give an estimate of the total losses at a particular point on the electricity network. In WA they are published by the IMO.

Feed-in tariff (FiT) An amount of money paid per unit of electricity produced by a generator. It is greater than the standard tariff and may be paid on all electricity generated or only on what is exported to the grid. For more detail see page 99.

Hybrid Optimization Model for Electric Renewables (HOMER) A micropower optimisation model developed by the National Renewable Energy Laboratories (NREL) that can be used to evaluate the designs of both off-grid and grid-connected power systems that include a range of renewable technologies, diesel generators as well as battery storage and grid connection. For more information see page 35 and http://www.nrel.gov/homer/.

Independent Market Operator (IMO) A body corporate that is responsible for the administration and operation of the Western Australian Wholesale Electricity Market in accordance with the Market Rules. The IMO's aim is to provide and maintain an effective infrastructure for the efficient operation of the Wholesale Electricity Market in Western Australia. For more information see http://www.imowa.com.au/.

Individual Reserve Capacity Requirement (IRCR) The requirement for market customers (ie. electricity retailers) to purchase sufficient RCCs to cover their customer’s expected demand and reserve margin. For more information see Appendix 6.9 or http://www.imowa.com.au/.

Intermittent Generator A generator that is not dispatchable because its output is dependent on energy inputs that are not under its control. For example, wind turbines and PV panels.

Kilowatt hours (kWh) One thousand watthours, where a watthour is the production of 1 watt of power for 1 hour.

Load duration curve Used to illustrate the distribution of load throughout a year. Is created by ordering the year’s load points from highest to lowest from left to right on a chart. They are useful when assessing how much of the load occurs for a given period of time. For example, a very ‘peaky’ load may result in a load duration curve which shows that 50% of the load occurs for only 10% of the time. Load duration curves are used in Appendices 6.4 to 6.6.

Market Participant Participates in the wholesale electricity market (as opposed to the retail electricity market that services end users).

Megawatt hours (MWh) One million watthours, where a watthour is the production of 1 watt of power for 1 hour.

Methodologies 1, 2, 3 The methodologies used here to calculate the creation of RCCs or the reduction in IRCR. For more detail see *Commercial value of PV providing firm capacity* on page 46.

Mandatory Renewable Energy Target (MRET) A Commonwealth Government program that requires liable parties (generally electricity retailers) to purchase a set amount of renewable energy each year, reaching 9,500 GWh by 2010. For more information see Appendix 6.9 and http://www.greenhouse.gov.au/markets/mret/.

Net Present Value (NPV) The total value of future and current cash flows in an investment. It generally involves discounting future cash flows. If the NPV is positive the investment would generally go ahead.

Network augmentation The process of increasing the capacity of a transmission or distribution network, which is necessary because the load serviced by that network is increasing.

Photovoltaic Rebate Program (PVRP) A Commonwealth Government program that provides cash rebates for the installation of solar photovoltaic systems on homes, schools and community use buildings. It currently provides $8/W up to 1kW for residential systems and 50% of the system cost (up to 2kW) for school and community use buildings. For more information see Appendix 6.9 and http://www.greenhouse.gov.au/renewable/pv/index.html.

Renewable Energy Buyback Scheme (REBS) Both Horizon Power and Synergy operate buyback schemes for excess electricity generated by small grid-connected renewable energy systems, as required under their regulations. These are available to residential customers, non-profit organisations and educational institutions. They are essentially net metering schemes with buyback rates equal to the electricity purchase rate, less the GST component. For systems installed by business customers, Horizon Power will negotiate an individual purchase contract. For more information see Appendix 6.9 or contact Horizon Power or Synergy.

Reserve Capacity Mechanism (RCM) Used to ensure there should be sufficient generation capacity for operation of the WA electricity market. For more information see Appendix 6.8 or http://www.imowa.com.au/.

Reserve Capacity Obligation (RCO) The amount of reserve capacity that a power station or provider of demand side management has to provide through the RCM. For more information see Appendix 6.8 or http://www.imowa.com.au/.

Reserve Capacity Requirement (RCR) The SWIS RCR is based on the expected maximum system-wide demand and includes a contribution to the reserve margin. For more information see Appendix 6.8 or http://www.imowa.com.au/.

Return on Investment (RoI) The amount of before-tax annual profit of an investment, usually expressed as a percentage of the original total cost invested. It normally allows for depreciation, discounting and inflation.

Renewable Remote Power Generation Program (RRPGP) A Commonwealth Government program that provides financial support to increase the use of renewable generation in remote parts of Australia that presently rely on fossil fuel for electricity supply. It covers up to 50% of the capital cost of renewable generation and essential enabling equipment. For more information see Appendix 6.9 and http://www.greenhouse.gov.au/renewable/rrpgp/index.html.

Short Term Energy Market (STEM) A daily forward market for electricity that allows Market Participants to refine their long term bilateral contract positions before submitting their net contract positions (combined bilateral and STEM) to the Independent Market Operator (IMO). It is equivalent to the National Electricity Market spot market.

SmartPower tariff A tariff provided to Synergy’s residential customers. For more information see http://www.synergyenergy.com.au/Residential_Segment/SmartPower/SmartPower.html.

South West Interconnected System (SWIS) The WA electricity network that covers the area from Kalbarri in the North down to Albany in the South and East to Kalgoorlie. For a map see http://www.synergyenergy.com.au/Residential_Segment/Electricity_Connections/Synergy_Service_Area.html.

Time-of-Use (ToU) tariffs Tariffs where the amount charged is different at different times of the day. The tariffs may also be different on different days of the week and during different months or seasons.

Transmission Loss Factor (TLF) Represent marginal losses on the electricity transmission system. When multiplied by the Distribution Loss Factor they give an estimate of the total losses on the electricity network at a particular location. In WA they are published by the IMO.

1 Introduction

1.1 Background and Study Objectives

A new electricity market began operation in Western Australia (WA) on 21 September 2006 as part of the restructuring of the State's electricity industry. This restructuring has also involved a break-up of former utility Western Power into different state-owned electricity corporations: Synergy an energy retailer in the South West Interconnected System (SWIS); Verve Energy – responsible for electricity generation assets in the SWIS; Western Power - responsible for electricity transmission and distribution in the SWIS and Horizon Power - responsible for electricity supply in areas outside the SWIS. Independent generators and retailers also participate in the new market. The Independent Market Operator (IMO) acts as both market administrator and market operator, whilst also providing a market surveillance role.

As part of the new Wholesale Electricity Market (WEM), a market was established for reserve capacity credits in order to ensure sufficient generating capacity is available to meet anticipated demand for future years. The two components of this new electricity market – energy and capacity - change the context that previously existed for independent power producers and for new generating technologies.

A PV Working Group was established through the Office of Energy in 2006 to examine the potential benefits that PV provides to the electricity network and the opportunities created for grid-connect PV in the new market and to identify any remaining barriers to PV use on the grid. This report will assist the PV Working Group in its task. Its objectives are to assess:

1. the impact of solar photovoltaic (PV) on the major networks and regional electricity systems;
2. existing market opportunities for PV and barriers preventing PV systems from taking full advantage of these opportunities;
3. strategies for capturing identified system benefits of PV and for overcoming identified barriers; and
4. the potential impact that these strategies could have on the uptake of PV.

For metropolitan and CBD regions of the SWIS, the study is to include analyses of the following potential impacts:

- Reduction in peak load (both supply cost and network benefits)
- Deferred network augmentation
- Power quality and reliability.

For Edge of SWIS regions it is also to include analysis of:

- Reduction of system losses

And for regional grids it is to include analysis of:

- Reduction of cost of supply
- Reduction in peak load

1.2 Status of supply and demand on the Western Australian electricity system

1.2.1 SOUTH WEST INTERCONNECTED SYSTEM (SWIS)

Annual energy consumption on the SWIS is growing at a rate of 2.2% per annum, with peak demand growing at 3.2%. General economic growth, including large resource projects are providing the underlying drivers for growth. Ambient temperature is considered to be the largest determinant of load, with air conditioning load contributing 25-50% of the load on extreme peak days. Winter peaks are also increasing due to increased use of reverse cycle air conditioners for heating, reduced use of wood and tighter regulations on un-flued gas heaters. Current capacity (4,115 MW for 2007/08 and 4,600 MW for 2008/09) is sufficient to meet projected demand, including reserve capacity, until 2008/09 after which new capacity will be needed. Reserve capacity is set on the basis of loss of the largest generating unit, which for 2008 will be 320 MW. Reserve capacity also covers frequency control and intermittent embedded generators. Demand management through pre-agreed load shedding in peak periods is also incorporated into the planning process, with up to 130 MW currently negotiated (IMO, 2006; OoE, 2006).

1.2.2 REGIONAL POWER SUPPLY

Horizon Power is responsible for generating or procuring, distributing and selling electricity in areas of the state outside of the SWIS. It currently services the Pilbara, Kimberley, Gascoyne, Mid West and southern Goldfields (Esperance and Hopetoun) including about 28 towns and isolated communities. It supplies power to 12,000 customers on the North West Interconnected System (NWIS) in the Pilbara and 24,000 customers in the Non-Interconnected System (NIS).

At present all generation capacity in the NWIS is privately owned with supply contracted to Horizon Power. Both private generators and Horizon Power-owned facilities supply the NIS. In the NIS, Horizon Power purchases power from 5 wind farms, the Ord river hydro and a number of small-scale PV systems (including the Carnavon solar farm).

1.3 The Potential Role of Photovoltaics

PV offers a wide range of potential values; energy, environmental, energy security, economic (including industry development) and social (including job creation). Many of these values are currently treated as externalities in economic analysis and electricity industry commercial arrangements only capture some aspects of these values through their market design and structure. Furthermore, PV has very different technical characteristics in comparison with conventional energy sources, including its intermittent generation, small unit size and integration into the distribution system. This challenges existing industry arrangements that have generally evolved around larger-scale centralised thermal plant.

Despite its intermittency, one of the key attractions of PV is its daytime generating profile. In many electricity systems, load is higher during the day than at night, and in many areas annual system peaks now occur in summer due to air conditioning loads. Both these load characteristics correlate in general, time of day, terms with the output of PV generation, noting that both are also weather-dependent. The load and insolation characteristics in question determine how closely load and PV output correlate. Our ability to predict the future correlation, rather than present or past behaviour, affects the value of installing PV. Present or past behaviour can only be used with caution to predict the future. This study examines load and PV characteristics in a number of locations in Western Australia in order to estimate PV's ability to contribute additional value.

Other aspects of value which are not the focus of this report but may be important when considering whether or not to provide specific support or encouragement for PV installations include:

- the ease of siting PV in urban areas (subject to roof area, orientation and solar access), with no operating noise and few aesthetic concerns,
- the short installation time for PV,
- the long lifetimes of PV panels, and balance of system components, if appropriately maintained,
- the high level of local content in system design, installation and after sales service, and
- emission-free generation with no on-going requirement for fuel or water.

1.4 Report Structure

Section 2 of this report explains the sources of load, insolation and PV generation data used for the analysis of the impact of PV systems on the electricity system and the analysis methodology used, including the use of the Hybrid Optimization Model for Electric Renewables (HOMER).

Section 3.1 uses these data to assess the impacts of PV on the Western Australian electricity system, and estimates the financial value of these impacts. It focuses on PV's ability to offset conventional base-load generation, provide firm capacity, defer network augmentation, influence power quality and reliability and reduce line losses in the SWIS and 'Edge of SWIS', and assesses PV's ability to offset peaking generation and reduce generation costs in regional areas.

Section 3.2.1 firstly summarises the electricity system benefits provided by PV that were identified in Section 3.1, then identifies who receives these benefits and estimates their value. It then discusses the relative costs and benefits of PV for retailers.

Section 3.2.2 identifies the total value of the opportunities currently available to PV in WA.

Section 3.3 proposes strategies to reward PV for the electricity system benefits identified here that are currently not recognised in the market.

Section 3.4 estimates the total value of the opportunities to PV if the strategies discussed in Section 3.3 are implemented and combined with the existing support programs. It also discusses the potential impact of proposed support strategies.

Section 4 draws together the report's findings and discusses additional support strategies.

2 Methodology for analysing the impact of PV on the SWIS and regional grids

The impact of PV on the Western Australian SWIS and regional grids was assessed using half hour load, insolation and PV data as described below. As stated in the Introduction, this involved an assessment of PV's ability to reduce peak load, defer network augmentation, influence power quality and reliability, reduce system losses and reduce the cost of supply in different situations – see Table 11 and the explanations below. The assessed locations are given in Table 12 and were chosen for analysis because they have different load characteristics and cost structures (because they have different types of generation, length of networks and load profiles) and so provide different opportunities for PV.

Assumed tariff increases

In Section 3.2 the value of PV to the WA electricity system is provided both per kWh and per Watt. The former is most useful when comparing PV's benefits to the value paid for generated electricity (eg. through REBS). The latter incorporates discounting and inflation over 20 years and enables comparison with the installed cost of PV – about $13/W. Inflation is assumed to be 2.5% per year except for electricity tariffs, where government increases are taken into account. The WA Government has recently announced a number of annual regulated tariff increases – for example the Business R3 tariff will increase by 9% in 2007/08, then 5% each year until and including 2011/12 (for our calculations we have then assumed 2.5% per year from then on). The other tariffs referred to in this report, for which the WA Government may announce increases at a later date, have an estimated 13% increase in 2009/10, then 5% increases until and including 2011/12, then 2.5% per year after that. These are estimates only, based on an approximate weighted average of the recent tariff increases, and are no indication of likely government policy.

Reduction of peak load

Analyses were undertaken of:

- the seasonal correlation between load and simulated PV output;
- four periods of peak demand, selected to represent different seasons and load profiles;
- load duration curves to assess simulated PV's ability to offset annual peak demand periods; and
- scatterplots to evaluate general correlations between load, simulated PV and temperature.

In analysing the correlation between load and simulated PV output, we often assumed large amounts of PV so that its impact would be visible on charts. However, in some locations, such as the CBD, these amounts of PV are unlikely to be feasible in the near term. For the SWIS and 'Edge of SWIS' locations this analysis also involved a financial assessment of PV's ability to reduce peak loads using two methodologies to estimate the Certified Reserve Capacity and one methodology to estimate PV's contribution to reducing a market customer's Individual Reserve Capacity Requirement – for more detail on how this is done see *Commercial value of PV providing firm capacity* on page 46. The value of electricity generated by PV was also calculated using three different tariffs.

Deferral of network augmentation

This part of the analysis involves a technical discussion of the correlation between PV output and load identified in the previous section for SWIS and 'Edge of SWIS' locations, the causes of peak demand periods, the constraints imposed by network planning requirements and reliability guidelines, the need to provide commercial value, and what these mean for PV's potential to defer network augmentation. This includes an estimation of the financial value provided by PV deferring network augmentation, determined with respect to the current unsubsidised cost of PV.

Influence on power quality and reliability

We assess the influence of PV on quality and reliability of supply by means of a technical discussion of the impact of PV and inverters on power quality and the effect of correlation of load and PV output, illustrated using the SWIS and 'Edge of SWIS' case studies. We consider intermittency, islanding, harmonics, voltage support and power factor correction.

Reduction of system losses

We assess the influence of PV on system losses by a technical discussion of the correlation between PV output and load for the 'Edge of SWIS' locations as well as the correlation between voltage, current and system losses, and what these mean for PV's potential to reduce losses on regional feeders. There is also a financial analysis of PV's ability to reduce line losses according to transmission loss factors (TLFs), which estimate marginal losses on the transmission system, and distribution loss factors (DLFs), which estimate average losses on the distribution system. This analysis is undertaken for two different tariffs.

Reduction of the cost of supply

This analysis involves an assessment of PV's ability to displace high-cost generation and reduce greenhouse gas emissions. For all locations this involved assessing the deployment of PV from the perspective of an end-user such as a home owner or businesses. For one location, that uses diesel generation exclusively, this was performed from the perspective of Horizon Power installing their own, most probably larger, PV systems. This latter assessment involved the use of the system modelling software HOMER - see Section 2.3 below.

Table 11: Analysis of the benefits of PV at the substation level

Location	Assessment of PV's ability to:
SWIS	Reduce peak load
	Defer network augmentation
	Influence power quality and reliability
Edge of SWIS	Reduce peak load
	Defer network augmentation
	Reduce system losses
	Influence power quality and reliability
Regional	Reduce peak load
	Reduce the cost of supply

2.1 Load data

Selection of the SWIS and the 'Edge of SWIS' substations and feeders was based on information provided by Western Power. Selection of regional grids was based on information provided by Horizon Power. The Western Power substations' data files all had a significant number of Tag, Limit, Quality (TLQ) indicators of suspect data that were manually assessed. Where only a few consecutive data points were suspect, they were interpolated from adjacent data. Where there were a large number of suspect data points, the entire day was removed prior to further analysis.[3] The Horizon Power data were mostly of good quality with only a relatively small number of suspect data points, which were interpolated from adjacent data if necessary.

Table 12 summarises the load data used, and the site locations are shown in Figure 1. Charts of the raw data for the SWIS and Edge of SWIS locations are in Appendix 6.1 where suspect data appear as zero points. Where data for a number of transformers were provided for a particular substation, a single transformer was selected for further analysis – primarily based on data quality but also whether that transformer was thought to be representative of the substation as a whole.

2.1.1 SWIS

Perth locations were chosen because they are likely to have a load profile that peaks in the middle of the day and so a good match to PV output. The *Transmission Load and Circuits Report* for the 2006 summer and winter peaks (WP, 2006c) was used to identify two Perth substations that had a summer peak with a commercial profile and so a good match to north facing PV output (Forrest Ave and Osborne Park). Similarly, two substations which had an early afternoon summer peak due to a mixed commercial/residential profile and so a possible match to west facing PV were chosen (Midland Junction and North Perth).

[3] Where a stretch of zero data points occurred on a year's peak load day, that day was included in further analysis.

2.1.2 EDGE OF SWIS

The 'Edge of SWIS' locations were chosen to provide diversity in load and solar insolation characteristics, and according to the length of the network they serviced. The Katanning substation was selected because the associated feeder is particularly long (over 200km) and they are in a region in need of augmentation.[4] Initially the Albany substation and the Denmark and Willyung feeders had also been chosen but were discarded because they were too near to Katanning and so have similar load characteristics and solar insolation, and are shorter and so less likely to suffer from line losses and have power quality and reliability problems.

The Geraldton substation and Kalbarri/Chapman feeder were selected because they are distant to Katanning and so may have different solar insolation characteristics, are linked to the Kalbarri 20kWp PV system, and have an early afternoon summer peak that could correlate well with PV output.

The Merredin 132/66 substation was selected because it was one of the few 'Edge of SWIS' substations that, according to the *Transmission Load and Circuits Reports* (WP, 2006c), had a summer peaking profile in 2006 and was reasonably distant to Katanning and Geraldton and so again, may have different load and solar insolation characteristics.

2.1.3 REGIONAL GRIDS

Given that the aim of assessing regional locations was to determine PV's ability to reduce the costs of supply, they were selected on the basis of having a high cost of supply, a good solar resource and potential correlation of load with PV output. Using July 2005 to June 2006 data for all of Horizon Power's power stations, a number were identified that had a summer peak in the early to mid afternoon. From these were selected the following locations:

Carnarvon: selected because of the availability of PV data from the Carnarvon Solar Farm and because the Carnarvon power station is in need of an upgrade, and potential alternative energy sources are being considered.

Marble Bar: selected because it has a high cost of supply (from diesel generators) and is to be replaced within the next two years and so provides an opportunity for integration of PV into a diesel system.

Meekatharra: selected because it has a high cost of supply (also from diesel generators) and is distant to Marble Bar and so likely to have a different solar insolation profile.

Port Hedland: selected because it is part of the NWIS (rather than being only in a small town), and is of particular interest to Horizon Power, which is currently considering supply options, and it also provides an opportunity to evaluate the potential benefits of using PV along the Pilbara coast.

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[4] See http://www.wpcorp.com.au/mainContent/projects/EdgeGrid/Edge_of_grid.html for more detail.

Table 12 Available Load Data at selected substations

Location	Transformers[a]	Units[b]	Time span	Peak [c]
SWIS				
Forrest Ave (S) [d]	TX2, TX3	MW, MVAr	1/1/03 to 5/3/07	~12pm
Midland Junction (S)	TX1, TX2, TX3	MW, MVAr	as above	~4pm
North Perth (S)	TX2, TX3	MW, MVAr	as above	~4pm
Osborne Park (S)	TX1, TX2, TX3	MW, MVAr	as above	~2pm
Edge of SWIS				
Katanning (S)	TX2	MW, MVAr	1/1/03 to 7/2/07	6-8pm
Gnowangerup (f)		A	as above	
Geraldton (S)	TX1, TX2, TX3	MW, MVAr	1/1/03 to 20/3/07	~2:30pm
Kalbarri/Chapman (f)		A	as above	
Merredin 132/66 (S)	TX1, TX2	MW, MVAr	as above	~4pm
Regional				
Carnarvon	NA		1/7/05 to 30/6/06	~3pm
Marble Bar	NA		1/7/05 to 30/6/06	~3pm
Meekatharra	NA		1/7/05 to 30/6/06	~4pm
Port Hedland	NA		1/7/05 to 30/6/06	~2:30

a: The transformers for which data were supplied
b: MW, megawatts; MVAr, megavars, A, amps.
c: Annual peak according to the *Transmission Load and Circuits Report*
d: S – substation, f – feeder

2.2 PV data

The PV data provided by system owners were often for short periods, or for periods that didn't match the load data, or wasn't near to the load locations (the PV data provided is summarised in Appendix 6.2). Because of this, solar insolation data provided by the Bureau of Meteorology was used to simulate PV data for all load locations. The larger Carnarvon and Kalbarri PV systems provided PV data that were suitable for analysis. In some circumstances PV data from smaller systems were used if they corresponded to the times and approximate locations of demand peaks.

2.2.1 SIMULATING PV DATA

Ground-based irradiation readings (total irradiation on a horizontal plane and diffuse) in Australia have been phased out over time and quite dramatically from 2001 onwards. Broome is the only site left in WA that is part of the National Solar Radiation Network and provides adequate irradiation measurements. Satellite-derived data is another source of irradiation values but is currently of limited suitability and availability for WA. A recently completed project has updated the Australian Climate Data Bank (ACDB) using sophisticated modeling and algorithms to fill in data gaps and provide hourly data up to the end of 2004 for numerous WA locations (see Appendix 6.2). For each location the ACDB can be used to generate a Reference Meteorological Year (RMY) which is a composite of the 12 months of best fit (as opposed to the currently used Test Reference Year (TRY) or single year of best fit).

Thus, in the first instance, ACDB data for the 2003 and 2004 years were used for the SWIS and 'Edge of SWIS' locations, and RMY data were used for the regional locations. The ACDB data sites used for each of the load sites is in Table 13 and Figure 1. These data were used in the PvSyst simulation program to simulate hourly PV output data assuming a number of different orientations – north, north west, and west with a tilt of either 25, 45 or 90 degrees. Full details of the PV simulation parameters and assumptions for the north-facing arrays at each ACDB site are in Appendix 6.3. Use of RMY or other derived data is not ideal for this study, because it reduces the real-time correlation between load and potential PV output, especially when load is temperature or weather sensitive. Hence our results should be considered indicative only and not necessarily representative of PV output over the analysed time periods.

The data will also not be representative of the average year in any particular location. For example, although here the average output for a north-facing 1kW panel in Perth for 2003 and 2004 is 1,610kWh and for Geraldton is 1,645kWh, the Office of the Renewable Energy Regulator's indicative average values, based on longer term data sets, are 1382kWh (Perth) and 1536kWh (Geraldton).

Table 13 ACDB sites used for each load site

	Load	ACDB
SWIS	Forrest Ave	Perth
	Midland Junction	Perth
	Osborne Park	Perth
	North Perth	Perth
Edge of SWIS	Geraldton	Geraldton
	Katanning	Katanning
	Merredin	Kalgoorlie
Regional	Carnarvon	Carnarvon
	Marble Bar	Newman
	Meekatharra	Meekatharra
	Port Hedland	Port Hedland

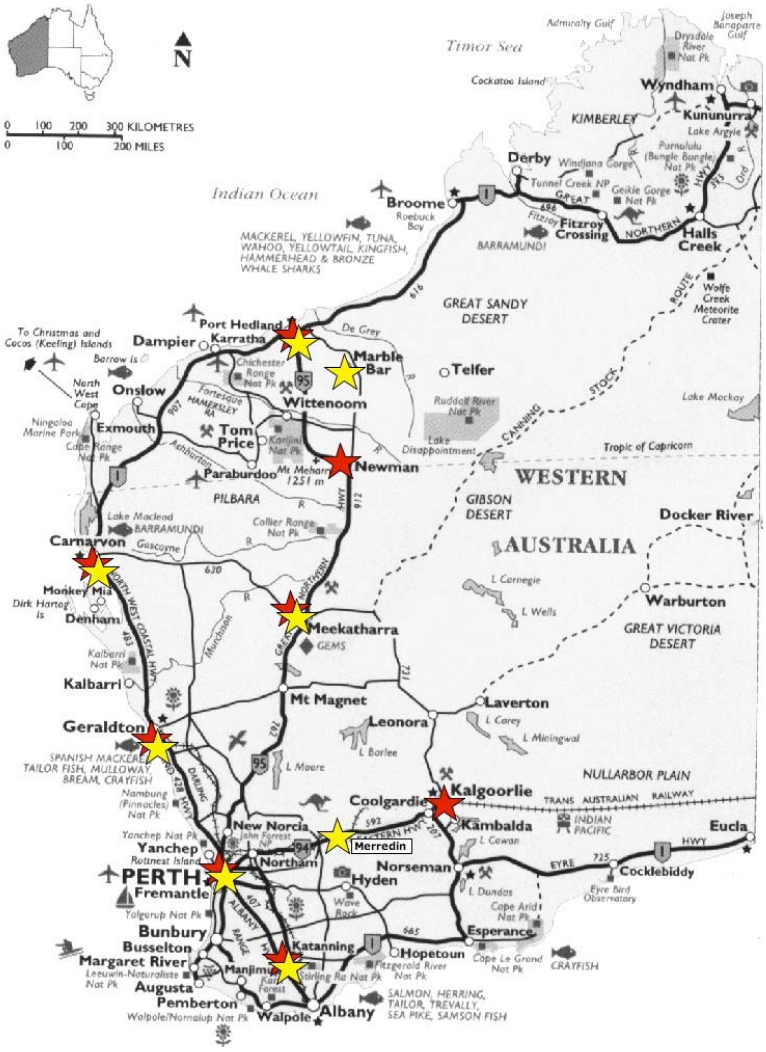

Figure 12 Map of load and ACDB data sites in Western Australia

Yellow Stars: locations of load data
Red Stars: locations of solar insolation data

2.3 Simulating integrated diesel/PV systems: HOMER

The Hybrid Optimization Model for Electric Renewables (HOMER) was used to assess the impact of integrating PV into the regional grid at Marble Bar. In particular, it was used to assess PV's impacts on costs as well as on diesel use and greenhouse gas emissions. It is a micropower optimisation model developed by NREL that can be used to evaluate the designs of both off-grid and grid-connected power systems that include a range of renewable technologies, diesel generators as well as battery storage and grid connection.

HOMER simulates the operation of a system by making energy balance calculations for each of the 8,760 hours in a year. For each hour, HOMER compares the electric and thermal demand in the hour to the energy that the system can supply in that hour, and calculates the flows of energy to and from each component of the system. For systems that include batteries or fuel-powered generators, HOMER also decides for each hour how to operate the generators and whether to charge or discharge the batteries.

HOMER determines whether a particular configuration is feasible (whether it can meet the electric demand under the conditions specified), and estimates the cost of installing and operating the system over the lifetime of the project. The system cost calculations account for costs such as capital, replacement, operation and maintenance, fuel, and interest.

Details of the HOMER configuration parameters used for Marble Bar are on page 78.

3 Results

3.1 Analysis of the impact of PV systems on the electricity system

Electricity production is generally most valuable during times of peak load. This is because these periods determine the total amount of generation capacity that should be available to the system, as well as the load capacity for which the transmission and distribution networks must be designed and built. Load is most likely to have to be curtailed due to insufficient generating capacity at times of system-wide peak demand or due to insufficient network capacity at times of down-stream peak demand.

A common characteristic of both the WA SWIS and the Australian National Electricity Market (NEM) is that the load profiles are very ‘peaky’ and as a result, a significant amount of the generation, transmission and distribution infrastructure is used only a small proportion of the time. If PV could be relied upon to reduce the future load peaks it could result in cost savings because it could offset high-cost peaking generation, because the existing infrastructure is used more effectively, and because construction of additional generation and/or network infrastructure could be deferred. PV can also be used to influence power quality and reliability, reduce losses on long rural feeders and avoid the direct and indirect cost of fuel. This would be most valuable where generation costs are high, for example when diesel fuel is used. These capabilities are discussed below in the WA context.

In the SWIS, the Reserve Capacity Mechanism (RCM), is used to ensure there should be sufficient generation capacity for operation of the electricity market – see Appendix 6.8. This involves the RCM valuing the provision of capacity, whether or not electricity is also generated. Hence, in the following sections, PV’s energy value and contribution to capacity are calculated separately.

However, there are no market mechanisms for valuing PV’s contribution to deferring network augmentation, nor any that recognise it’s influence on power quality and reliability or reduction of line losses. In addition, in regional grids, the tariffs currently paid for PV generation are unlikely to reflect the full benefits of offsetting diesel generation.

3.1.1 South West Interconnected System (SWIS)

This section firstly

- Assesses the correlation between PV output and load in four Perth substations chosen to represent commercial and mixed commercial/residential loads (this analysis is most relevant to assessing PV’s ability to provide local network support),
- Estimates the value of PV offsetting conventional generation in the four Perth locations (page 46),

- Uses three different methodologies based on the Reserve Capacity Mechanism (RCM) to estimate the value of PV's ability to provide firm capacity in the SWIS (page 46),
- Combines the values provided by PV in offsetting conventional generation and providing firm capacity (page 50),
- Assesses PV's ability to defer network augmentation in the CBD (page 50), and
- Assesses PV's influence on power quality and reliability (page 55).

Correlation between PV output and load peaks

The following summarises the findings for a selected transformer in each of the four Perth substations that are expected to continue to have either commercial load profiles (Forrest Ave TX2 and North Perth TX2), or mixed commercial/residential load profiles (Midland Jnct TX1 and Osborne Park TX1), and for simulated PV in these locations from July 2003 to June 2004. Each of the substations has been analysed in great detail (see Appendix 6.4), and Table 14 presents a concise summary of the outcomes for the peak periods for each location to illustrate the variability of the correlation between load and simulated PV.

The purpose of this analysis is to assess the degree to which PV could provide firm capacity during times of peak demand and defer network augmentation. As discussed in the Section *Commercial value of offsetting conventional generation* (page 46), the market mechanisms currently available in WA to value PV's ability to provide firm capacity during times of peaking generation are based on it most probably being available at the required times, with the task spread over the SWIS. In contrast, for PV to defer network augmentation, it must be available in a particular location with a very high degree of certainty at particular times in the future. Western Power uses both n-1 and n-2 planning criteria, meaning that infrastructure such as substations are designed with parallel paths so that if, for example for the n-1 criterion, one transformer fails, the remainder will be able to meet the expected maximum load. An n-2 criterion is used in places of higher load such as the Perth CBD. If the remaining transformer(s) rely on PV for firm capacity, it must be available at the (uncertain) times when a transformer fails in the future. Thus, it is easier for PV to provide firm capacity during times of peaking generation than to defer network augmentation.

With respect to providing firm capacity during times of peak demand, the Perth locations' peak periods were generally well matched to either simulated north-facing or west-facing PV, especially if the peaks that appeared to be due to operational changes by Western Power were excluded (eg. switching between transformers). Figure 13 shows the average daily summer load and simulated PV output for Forrest Ave, where there is a good correlation because of the predominance of commercial loads. However, where there were significant residential loads, the peak tended to occur later in the day – see Figure 14 which shows the average daily winter load (which had the highest seasonal peak for the year) and simulated PV output for North Perth. As a result, PV would be expected to generate financial value through the creation of capacity credits or by reducing IRCR's. As shown in the Section *Commercial value of offsetting conventional generation* (page 46), this is in fact the case. Note that in future the amount of capacity credits assessed for a particular PV installation may depend on its measured performance in reducing peak demand following its installation.

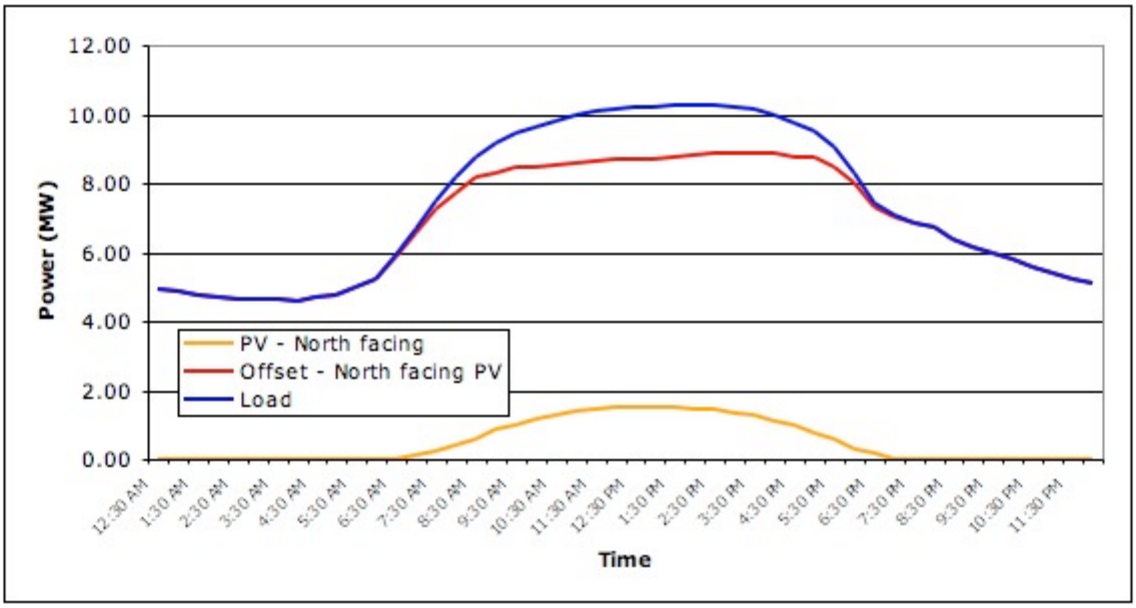

Figure 13: Daily Summer Average
Forrest Ave TX2 Load, Forrest Ave Simulated North-facing PV (2MW) and Net Load after PV Offset
Dec 2003 to Feb 2004

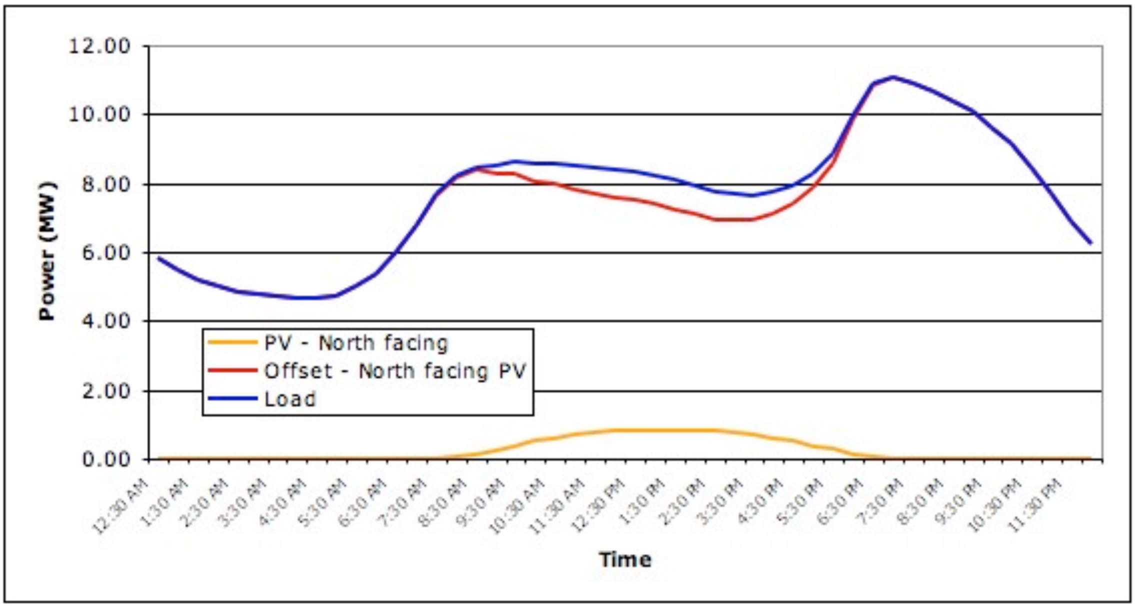

Figure 14: Daily Winter Average
North Perth TX2 Load, North Perth Simulated North-facing PV (2MW) and Net Load after PV Offset
June 2004 and July/Aug 2003

However, as described in Table 14, simulated PV had somewhat lower and more uneven correlation with the very highest peak loads than for peak loads in general. For example, although Forrest Ave's peak load day for the year correlated well with PV (Figure 15), the next peak load days, which occurred in winter, did not (Figure 16). Interestingly, North Perth, which had an annual winter peak, had its peak load day in summer (apparently due to operational changes by Western Power; Figure 17), with the 'average' peak days also in summer, and all with good matches to simulated PV (Figure 18).

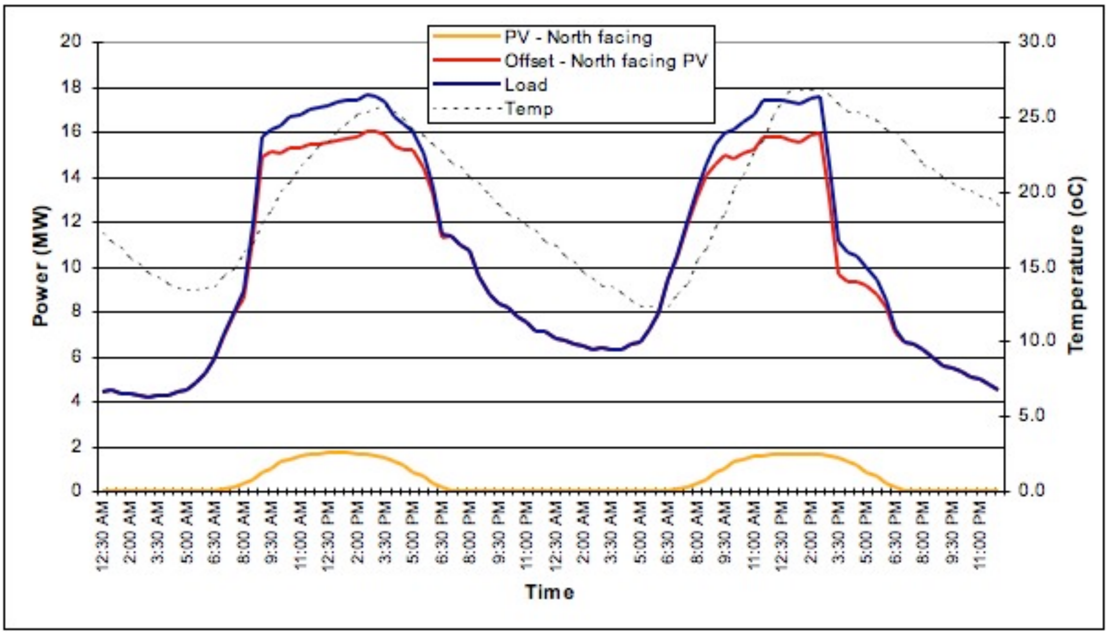

Figure 15: Autumn peak days
2nd to 3rd March 2004
Forrest Ave TX2 Load, Forrest Ave Simulated North-facing PV (2MW) and Net Load after PV Offset

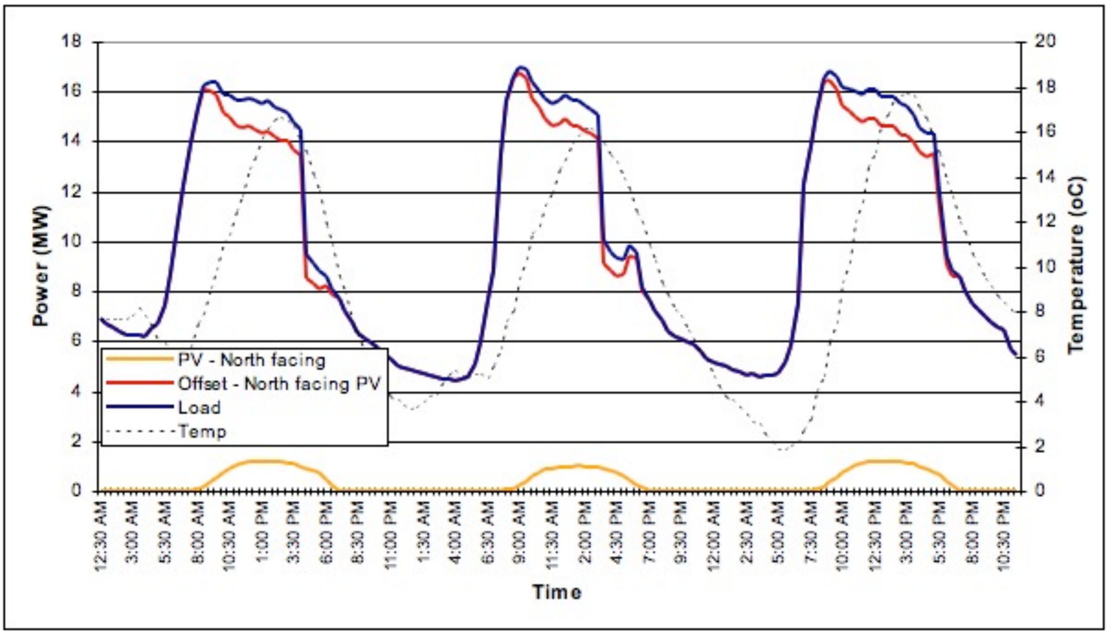

Figure 16: Winter peak days
16th – 18th July 2003
Forrest Ave TX2 Load, Forrest Ave Simulated North-facing PV (2MW) and Net Load after PV Offset

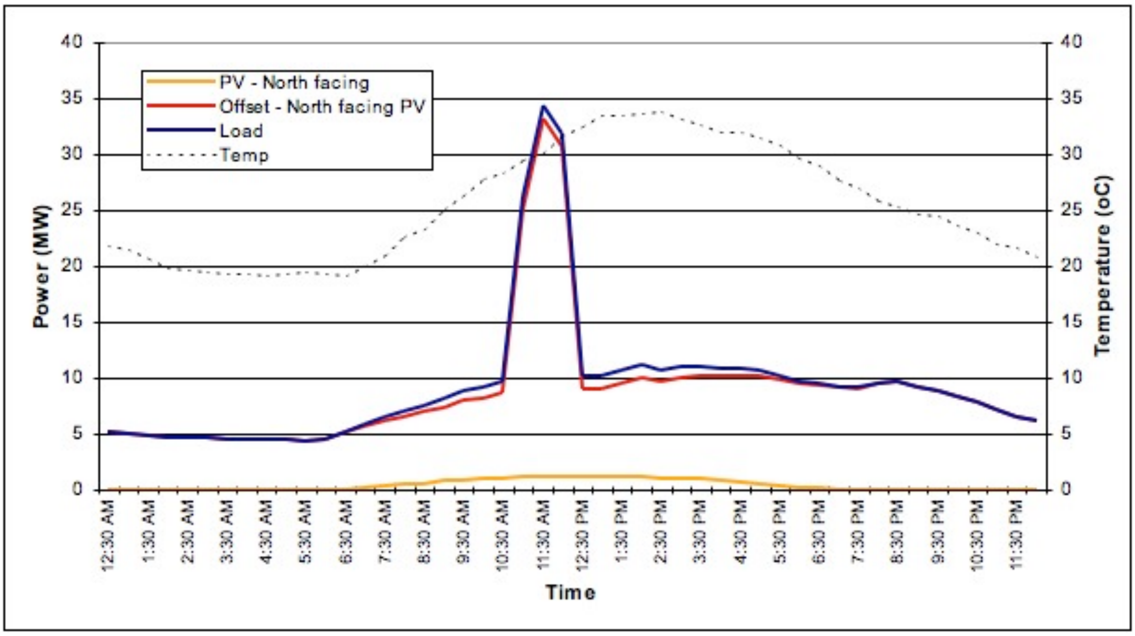

Figure 17: Summer peak day
17th Dec 2003
North Perth TX2 Load, North Perth Simulated North-facing PV (2MW) and Net Load after PV Offset

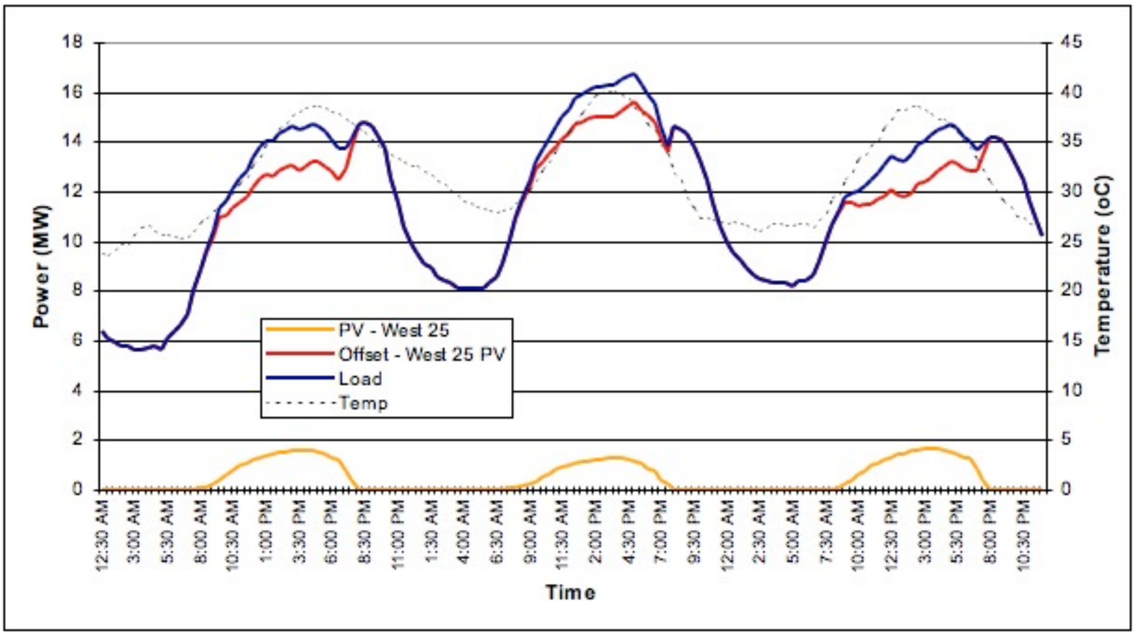

Figure 18: Summer peak day (west-facing-45 PV)
16th-18th Feb 2004
North Perth TX2 Load, North Perth Simulated West-facing-45 PV (2MW) and Net Load after PV Offset

To assess PV's contribution to deferring network augmentation, load duration curves can be used. They sort the load points from highest to lowest and so give an indication of the proportion of time that is spent at different load levels. They help assess PV's potential to reduce the load at the very highest load points – which determine the capacity for which networks must be designed and built. Figure 19 shows the load duration curve for Forrest Ave for the year, and displays the stepped pattern typical of a site with two main load periods. Figure 20 shows the top 50 half hour load periods, together with the impact of simulated north-facing PV or simulated west-facing PV on each of those load periods. It can be seen that although the very highest load periods were well matched to, and so greatly reduced by, simulated PV, slightly lower load periods were not. Figure 21 shows the same load duration curve except that the offset load periods have now also been ordered from highest to lowest. As a result, time periods that were lower before PV was applied have now become the new peak periods. It can be seen that the simulated north-facing PV resulted in the lowest offset load duration curve.

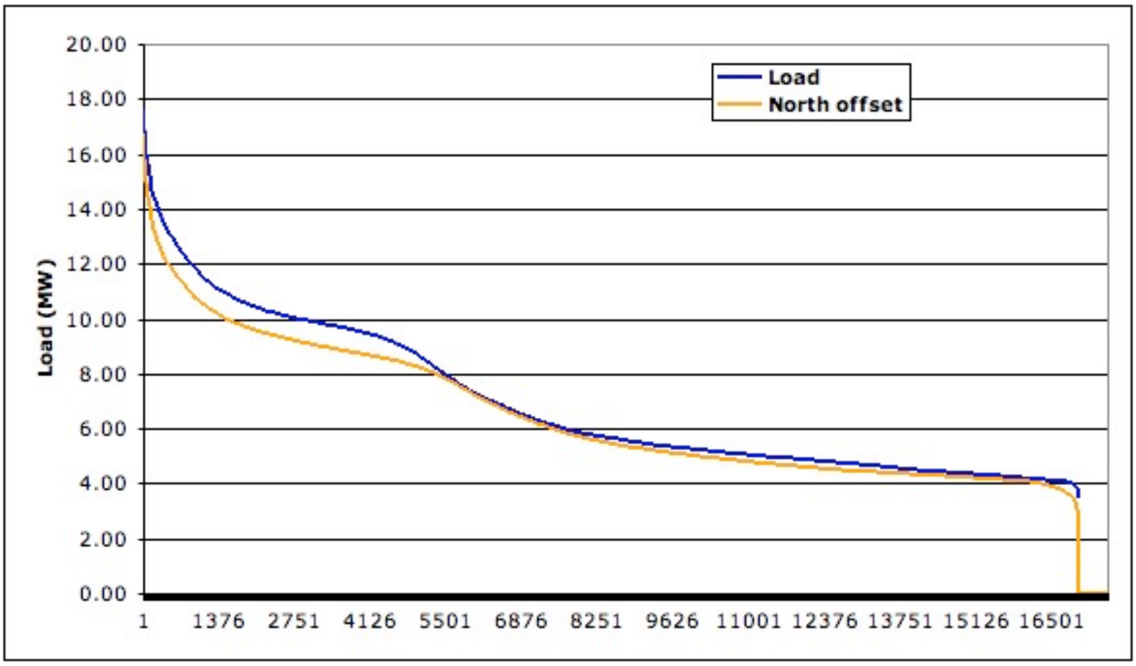

Figure 19: Load Duration Curve - July 2003 to June 2004
Forrest Ave TX2 Load and Forrest Ave TX2 Net Load after PV Offset (2MW)

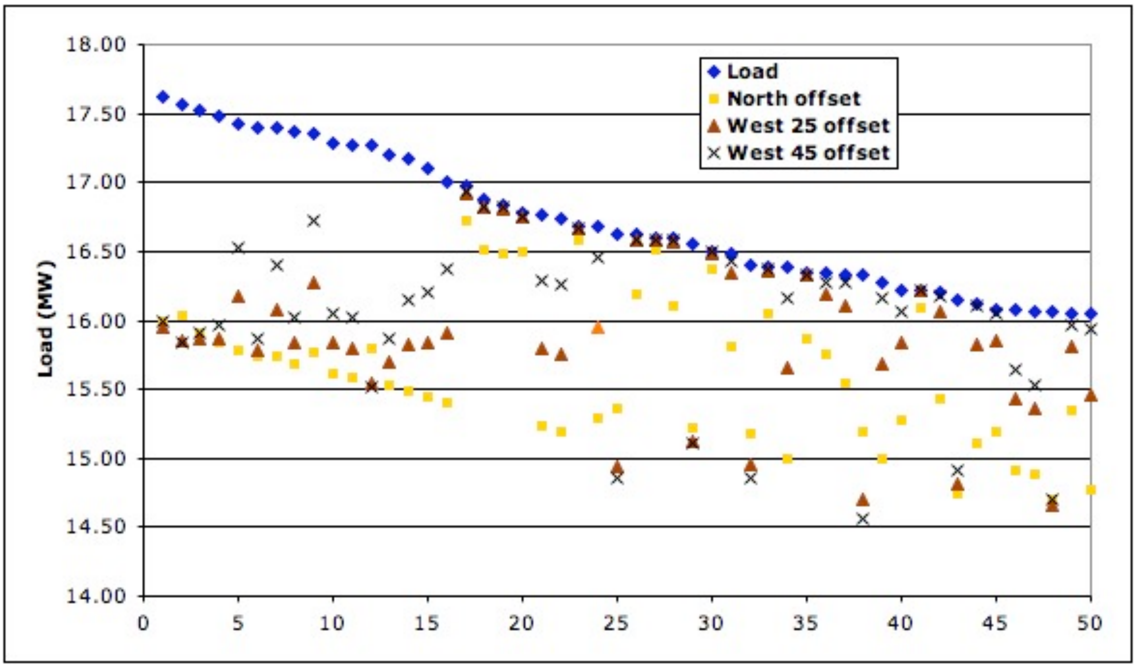

Figure 20: Load Duration Curve - top 50 load periods (linked)
North, and West (25^o and 45^o inclinations)
Forrest Ave TX2 Load and Forrest Ave TX2 Net Load after PV Offset (2MW)
July 2003 to June 2004

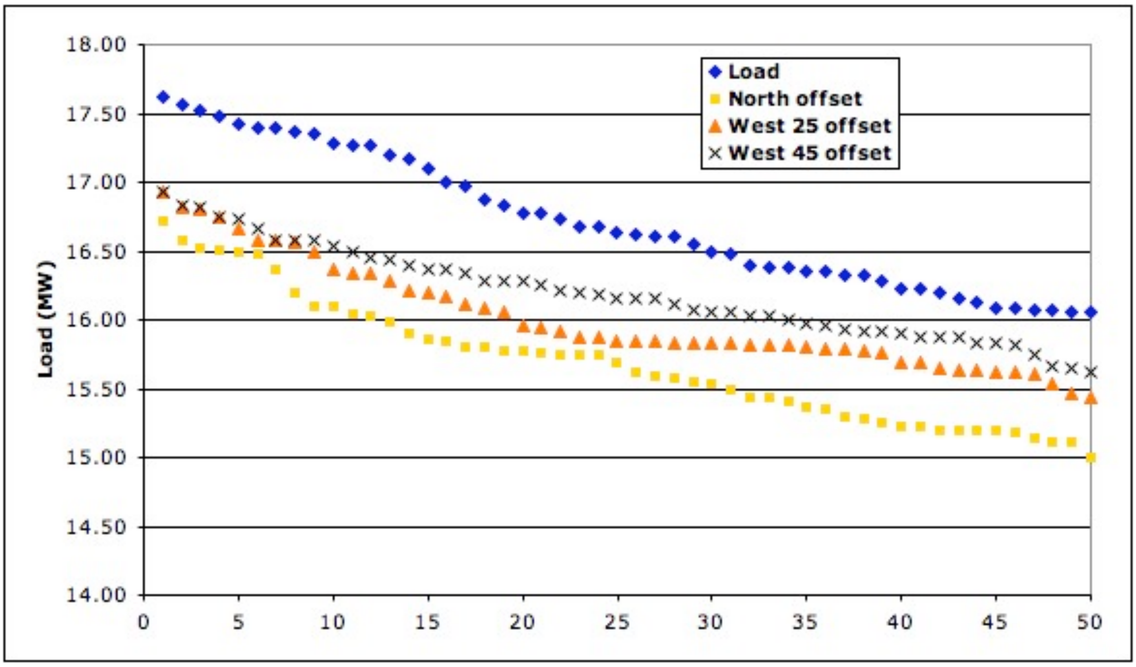

Figure 21: Load Duration Curve - top 50 load periods
North, and West (25^o and 45^o inclinations)
Forrest Ave TX2 Load and Forrest Ave TX2 Net Load after PV Offset (2MW)
July 2003 to June 2004

For each substation, Table 14 includes percentage values that are derived from load duration curves. These percentage values are defined as follows.

A: Is the contribution by simulated PV at the year's peak 30-minute load period as a percentage of the simulated PV's rated output. For example, a value of 81% means that a 1MWp PV system produced 0.81MW of power during the year's peak 30-minute load period.

B: Is the same as "A" but averaged for the year's top ten peak 30-minute load periods.

C: Is the contribution by simulated PV to reducing the year's net peak load as a percentage of the PV's rated output. This is different to "A" because, for example, while PV may contribute 81% of its rated output during the peak load period, it may contribute much less output at a slightly lower load period, which then may become the year's highest net load period. Thus "C" is a measure of how much simulated PV was able to make the highest net 30-minute load lower than the actual peak 30-minute load.

D: Is the same as "C" above but averaged for the year's top ten peak 30-minute load periods.

In summary, in periods where load and simulated PV were well matched, simulated PV contributed between 60% and 80% of its rated peak capacity to load reduction. However, periods of slightly lower peaks were sometimes not as well matched to simulated PV, and so became the highest offset peaks. As a result, simulated PV's ability to reduce the year's net peak load (as per "C" above) was much lower, for example reduced from 81% to 45% for Forrest Ave TX2 (see Table 14). Note that in all peak periods assessed here, where simulated PV was not well matched to load, the load appears to be due to operational changes by Western Power either in the early morning or in winter or both. Thus, changing the timing of these changes could significantly increase PV's ability to contribute to reducing peak load (this is discussed in more detail below).

For a much more detailed analysis of each Perth substation's correlation with simulated PV see Appendix 6.4. Placing a financial value on simulated PV's ability to meet the peak load periods and so defer network aumentation is discussed in the Section *Deferral of Network Augmentation* (page 50).

Note that this analysis focussed on a single year and that load change from year to year (eg. the peak periods occur on different days and sometimes in different seasons). It also used simulated PV data rather than actual. It is recommended that any PV installed in or near the Perth CBD be monitored and compared to current load data. The impact of changes to Western Powers' operational activities that result in peaks could also then be assessed.

Table 14 Summary of PV contribution in peak periods at SWIS locations

Location	A	B	C	D
Forrest Ave TX2	81%	81%	45%	51%
The ten top half-hour demand periods occurred in March, and involved rapid load increases in the early morning, probably due to operational changes by Western Power (eg switching load between transformers). On both days, the simulated north-facing PV was a good match to the load. The second highest cluster of peak load days assessed here occurred in July where on a series of days the load rapidly increased in				

<table>
<tr><td colspan="5">the early morning, again probably due to operational changes by Western Power. Simulated north-facing PV was not a good match, resulting in only minimal load reduction. The third highest cluster of peak load days assessed here occurred in Oct and again involved a rapid increase in the early morning, but was well matched to simulated north-facing PV. The fourth highest cluster of peak load days assessed here occurred in March when it was hot (over 30°C) and again was well matched to simulated north-facing PV.</td></tr>
<tr><td>Midland Jnct TX1</td><td>61%</td><td>62%</td><td>60%</td><td>55%</td></tr>
<tr><td colspan="5">The ten top half-hour demand periods occurred in Jan. The highest load day reached over 40°C, with a broad load peak from 9am to 6pm, and highest at around 2pm. Simulated north-facing PV was able to make a good contribution over most of this time, while simulated west-facing PV at 25 degree tilt reduced the peak load periods slightly more. The second highest cluster of peak load days assessed here was in Feb and was also over 40°C, with the peak occurring at 4pm, when the simulated north-facing PV was producing 60% of rated PV output. Simulated west-facing PV at 25 degree tilt reduced the peak by 82% of rated PV output. The third highest cluster of peak load days assessed here occurred in Nov and peaked at around 12:30pm, which was a good match to simulated north-facing PV output. The fourth highest peak load day assessed occurred in July, and involved a sudden increase from 10 to 20MW, peaking at around 11:30am, possibly because of operational changes by Western Power, and was a poor match for simulated north-facing PV output.</td></tr>
<tr><td>North Perth TX2</td><td>56%</td><td>21%</td><td>56%</td><td>21%</td></tr>
<tr><td colspan="5">The three highest half-hour demand periods occurred in Dec and the next 7 occurred in June. On the Dec peak day the load suddenly increased from 10 to almost 35MW, peaking at around 11:30am. Although the temperature was quite high at 34°C, the suddenness of the peak is consistent with operational changes by Western Power. Simulated north-facing PV coincided well at this time. The second highest peak load day assessed here was in June and had a broad load peak from 8am to 1:30pm, highest at around 8:30am. The suddenness of the peak, and low temperature (16°C) mean it was probably caused by operational changes by Western Power. Simulated PV made little contribution. The third highest cluster of peak load days assessed here was in Feb, peaked at 5pm, and was probably caused by high temperatures, which reached over 40°C on that day and over 38°C the day before. Simulated north-facing PV made a relatively small contribution at the peak, while 2MW of simulated west-facing PV at 45 degree tilt made a greater contribution, reducing the load by 1.35MW. The fourth cluster of peak load days assessed were in March and were quite hot, reaching over 41°C, with the peak occurring at 4pm, when the simulated north-facing PV was able to make a reasonable contribution, while west-facing-45 simulated PV reduced the peaks further still.</td></tr>
<tr><td>Osborne Park TX1</td><td>33%</td><td>47%</td><td>33%</td><td>47%</td></tr>
<tr><td colspan="5">The ten top half-hour demand periods occurred in July and Feb. The highest peak load day for the study period, in July, had a load that rapidly increased from around 6MW to around 17MW, peaking at around 10:30am. The low temperature (less than 20°C) together with the rapid increase and decline indicates this peak is probably due to operational changes by Western Power. Simulated north-facing PV had a good match to load however output was quite low. The second highest cluster of peak load days assessed here, in Feb, were driven by high temperatures – over 38°C on day 1 then over 40°C on day 2. The peak occurred relatively early in the day (11am) and so had only partial match to simulated north-facing PV. The third and fourth highest clusters of peak load days assessed here, in March and Decwere driven by high temperatures and had a good match to simulated north-facing PV.</td></tr>
</table>

Commercial value of offsetting conventional generation

This section estimates the annual commercial value of simulated PV's contribution to offsetting conventional generation in the four Perth locations. All calculations use the simulated PV output for July 2003 to June 2004. Rather than use a flat estimated price for conventional generation, real time Marginal Cost Administrative Prices (MCAP)[5] have been used together with the real time PV output data.[6] Values are given for both north-facing and west-facing PV and both 6% and 12% discount rates are used – although, as discussed later, this value accrues to the electricity retailer and so a 12% discount rate is more appropriate. The commercial value provided by PV ($1,200 to $2,000/kW) is a small proportion of its installed cost of $13,000/kW. See Table 15.

Table 15 Commercial value of electricity generated by 1MW simulated PV

Discount rate	PV Orientation	Value in year 1	Discounted Value [a]	Disc Value per Watt [b]	ROI [c]
6%	North-25	$137,430	$1,968,400	$2.00	0.76%
	West-25	$143,803	$2,059,660	$2.05	0.79%
12%	North-25	$137,430	$1,230,930	$1.25	0.47%
	West-25	$143,803	$1,287,990	$1.30	0.50%

a: Over 20yrs

b: Values rounded to nearest 5c

c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Commercial value of PV providing firm capacity

This section estimates the commercial value of simulated PV's ability to provide firm capacity during peak load periods in the four Perth locations using three different methodologies based on the Reserve Capacity Mechanism[7] (here termed Methodology 1, 2 and 3).

Methodology 1 is currently the approved methodology for calculating the Certified Reserve Capacity for intermittent generating facilities[8] according to WAGov (2006). Methodology 2 is a proposed but unused methodology that focusses on the 250 trading intervals in the SWIS with the highest load.

Methodologies 1 and 2 refer to methods that could be used to determine PV's Certified Reserve Capacity if it were to participate in the Reserve Capacity certification process. In this case the PV system would be assigned capacity credits based on its Certified Reserve Capacity. This is not to say that PV should necessarily participate in the Reserve Capacity Mechanism, rather, these methodologies are used here to illustrate different approaches to value PV's potential contribution to providing firm capacity.

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[5] The MCAP normally equals the STEM clearing price (the spot price) but may vary if the real time effective demand deviates from the total expected demand by more than 5% ie. the MCAP incorporates the Balancing Mechanism. More information can be found in the Wholesale Electricity Market Design Summary Sept 2006 (http://www.imowa.com.au/Attachments/MarketSummarySeptember2006.pdf)

[6] Note that because the simulated PV data is from 2003/04 and the MCAP data is from 2005/06, the values obtained are indicative only but should capture general seasonal and average daily price trends.

[7] The operation of the RCM is explained in Appendix 6.8.

[8] Known as Methodology B in WAGov (2006)

While there is no charge to apply for certification as a supplier of Certified Reserve Capacity, the owner of a PV system that wishes to do so must register as a Market Participant with the Independent Market Operator (IMO), which costs $420, and there is also a charge of $210 to register as an Intermittent Generator[9]. Generating facilities over 30MW also need to register with the Economic Regulation Authority.[10] These fees may be more than the Reserve Capacity Credits (RCCs) earned by a residential sized system (see below).

Methodology 3 is based on the current default treatment of unregistered PV systems. It is assumed that the PV systems contribute to reducing the retailer's metered demand and therefore reduces the value of its Individual Reserve Capacity Requirement (IRCR).

Note that although both 6% and 12% discount rates are used, as discussed below, the value of offsetting high-cost generation accrues to the retailer - making a 12% discount rate more appropriate. In this section both discount rates are used to illustrate the impact of different discount rates.

Methodology 1

This is generally[11] calculated using the amount of electricity produced during the half hour Trading Intervals that fell within the last three years up to and including the last Hot Season, divided by 52,560. Thus, it is a measure of the average power produced over this period. To correlate the use of this methodology with the above analysis of the correlation between PV output and peak loads we have used the simulated north-facing PV and simulated west-facing PV, both at 25 degree tilt derived from the combined ACDB data for Perth for 2003 and 2004. The results are shown below in Table 16. Methodology 1 would produce very little income for simulated PV, with a discounted value of between $0.22/W and $0.35/W for simulated north-facing PV compared to the current installed cost of around $13/W.[12]

Table 16 SWIS Reserve Capacity Credit Outcomes: Methodology 1

	1MW Simulated North-facing PV		**1MW Simulated West-facing PV**	
Capacity Credits	0.192		0.184	
Value in year 1[a]	$19,200		$18,400	
Discounted Value[b]	6%	12%	6%	12%
	$275,000	$172,000	$264,000	$165,000
Disc Value per Watt	$0.28/W	$0.17/W	$0.26/W	$0.17/W
ROI [c]	0.10%	0.06%	0.10%	0.06%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

[9] Both these fees are paid once only.
[10] For more information see http://www.era.wa.gov.au/2/420/51/licensing_infor.pm
[11] Unless 3 year's data are unavailable, in which case estimates can be made.
[12] According to 2006 PVRP data provided by the Australian Greenhouse Office.

Methodology 2

This is calculated using the 250 Trading Intervals (that fell within the most recent hot season or the intermediate season prior to that) in which electricity demand on the SWIS was highest. The awarded RCCs are equal to the level of PV output that was exceeded 90% of the time during those 250 Trading Intervals.[13] Again, we have applied the methodology to the simulated north-facing PV and simulated west-facing PV, both at 25 degree tilt, derived from the ACDB data, although this time for the entire SWIS over the period 1st Dec 2003 to 31st March 2004. The results are shown below in Table 17. This methodology provides more income to PV than Methodology 1 – 40% more for simulated north-facing PV and, interestingly, 170% more for simulated west-facing PV. According to this methodology, simulated west-facing PV provides almost twice as much reliable capacity at peak times than simulated north-facing PV.

Table 17 SWIS Reserve Capacity Credit Outcomes: Methodology 2

	1MW Simulated North-facing PV		1MW Simulated West-facing PV	
Capacity Credits	0.268		0.505	
Value in year 1[a]	$26,800		$50,500	
Discounted Value[b]	6%	12%	6%	12%
	$384,000	$243,000	$722,000	$455,000
Disc Value per Watt	$0.38/W	$0.24/W	$0.72/W	$0.46/W
ROI [c]	0.15%	0.09%	0.27%	0.17%

a: Assuming a RCC price of $100,000/MW/yr

b: Over 20yrs at a 2.5% inflation rate

c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Methodology 3

As outlined in Appendix 6.8, a Market Customer's (ie. a retailer's) Individual Reserve Capacity Requirement (IRCR) is based on its share of the median[14] value of total metered demand in the SWIS during the three highest demand half hour intervals of the four highest demand days in a particular year, as well as the number of assigned capacity credits in the SWIS. The final calculated IRCR takes into account temperature-dependent and non-temperature-dependent loads. Historically, temperature-dependent loads (eg. residential loads) have been assigned reserve capacity requirements 30-40% above their maximum demand.[15]

Here, to assess simulated PV's contribution during these times, we have taken the median value of the simulated PV output during the three highest demand half hour intervals of the four highest demand days for the SWIS from the 1st Dec 2003 to the 31st

[13] If the level of demand on the SWIS is ordered with the highest at 1 and the lowest at 250, the Capacity Credits awarded are equal to the corresponding PV output at level 225.

[14] Median: the middle number in a given sequence of numbers, taken as the average of the two middle numbers when the sequence has an even number of numbers.

[15] See http://www.imowa.com.au/10_5_1_f_ix_individual_rc_requirement_ratios.htm for the IRCR ratios.

March 2004,[16] then increased it by 30%.[17] This then estimates simulated PV's contribution in terms of avoided IRCR. The results for 1MW simulated PV are shown below in Table 18.[18]

The amounts shown in Table 18 approximate the IRCR avoided by Market Customers, and are significantly greater than for either Methodology 1 or 2. This is because Methodology 3 focuses only on a median contribution during 12 load periods and includes the 30% 'uplift', whereas Methodology 2 focuses on a 10th percentile contribution over 256 load periods and Methodology 1 focuses on an average contribution over 52,560 load periods. The 12% discounted net present values (which would be most relevant to a Market Customer as it is a business) according to Methodology 3 are about 10% of the unsubsidised installed cost of simulated west-facing PV.

Table 18 SWIS[a] Capacity Credit Outcomes: Methodology 3, 1MW Simulated PV

	1MW Simulated North-facing PV		**1MW Simulated West-facing PV**	
Reduction in IRCR	0.66		0.94	
Value in year 1[b]	$66,000		$94,000	
Discounted NPV[c]	6%	12%	6%	12%
	$946,000	$591,000	$1,340,000	$838,000
Disc Value per Watt	$0.95/W	$0.59/W	$1.34/W	$0.84/W
ROI [d]	0.36%	0.23%	0.52%	0.32%

a: Simulated PV for Perth only
b:Assuming a RCC price of $100,000/MW/yr
c: Net present value over 20yrs at a 2.5% inflation rate
d: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

[16] The full year from July 2003 to June 2004 was not available from Western Power, however it is likely the annual peaks will be within this summer period.

[17] 30% is used because the restructured WA electricity market was not operating during 2003/04 and so the reserve capacity in the system is not known, nor is the forecast weather/demand. Therefore an 'uplift' factor had to be applied that was consistent with the historical 'uplift' applied to temperature-sensitive loads.

[18] Although the values given in Table 18 give a 'Reduction in IRCR' in MW, it is likely that the value for the retailer would in fact be a combination of a reduced IRCR and and a reduced cost for each capacity credit. Here it is assumed that the resulting combined value would be the same as the value that would occur with the reduction in IRCR given in the table, with a constant capacity credit price.

This assumption is made because neither demand side management efforts nor the installation of PV systems (that are not registered with the IMO) would necessarily reduce the capacity credits certified by the IMO. However, as excess capacity credits are registered or as the need for capacity decreases, based on a simple supply/demand balance, it is reasonable to assume that the price of capacity credits would decrease over time.

Commercial value of offsetting conventional generation and providing firm capacity

PV's value in providing firm capacity is greatest when calculated in terms of its ability to reduce a Market Customer's IRCR (ie. using Methodology 3). The value so created, combined with a its value for offsetting conventional generation results in a discounted net value of about $1.85/W and $2.10/W for simulated north-facing and west-facing PV respectively – see Table 19. The IRCR value makes up about 32% and 40% of the discounted net value for north-facing and west-facing systems respectively.

Table 19 Commercial value of electricity generated by 1MW simulated PV: Offsetting conventional generation and providing firm capacity

PV Orientation	Disc Value per Watt [a]			
	Conventional generation	Firm capacity	Total [b]	ROI [c]
North-25	$1.25	$0.60	$1.85	0.71%
West-25	$1.30	$0.85	$2.15	0.82%

a: Over 20yrs at 12% discount rate
b: Values rounded to nearest 5c
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Deferral of Network Augmentation

Western Power's network planning procedures and connection requirements

WP (2006b) sets out the planning criteria for the transmission and distribution network for the SWIS and the technical requirements to be met by Western Power as network service provider and by users who wish to connect generation and load facilities to the SWIS network.

Clause 3.6 of WP (2006b) sets out requirements for the connection of generators of up to 10MW to the distribution network in the SWIS. Clause 3.7 applies to energy systems using inverters of up to 10kVA single phase and 30 kVA three phase. Clause 3.6 requirements state that the reliability of the distribution system and the equipment of other users are paramount and address:

- "the possibility that generating units embedded in distribution systems may affect the quality of supply to other users, cause reverse power transfer, use up distribution capacity, create a distribution system switching hazard and increase risks for operational personnel; and
- the possibility that a small power system connected to a distribution system could become islanded on to a de-energised part of the distribution system resulting in safety and quality of supply concerns."

Clause 3.7 of WP (2006b) requires that small inverter-connected generator installations must comply with relevant Australian Standards and international standards, have both an import and an export meter and be tested for correct functioning at least once every five years. Protection systems for voltage, current, frequency and islanding must be provided (with specified voltage and frequency tolerance bands) and synchronising must be automated. Western Power, as network service provider, retains the right to disconnect the generator installation if it considers that it posses a threat to safety, quality of supply or the integrity of the distribution network.

WP (2007) discusses the network planning approach used by Western Power and describes the current and project status of the network with regard to augmentation requirements. WP (2007) also discusses design and operating criteria for the network to meet the design criteria with respect to reliability and quality of supply. WP (2006a) reports on delivered reliability and quality for the 2005-06 year.

Table 1 of WP (2007) summarises the immediate transmission network constraints identified in this planning cycle, while Table 5.1 of WP (2007) sets out committed large distribution projects (2007-2009). This document also identifies future potential transmission and distribution constraints and network development options in response to those constraints. These are set out in Table 6.1 of WP (2007).

WP (2007) invites project developers to bring forward alternative generation or demand side options for consideration:

“Western Power would particularly like to hear from parties who are considering investments that, based on the information provided here, would appear to either:

- delay requirements for network development options; or
- accelerate requirements for network development options”

Figure 2.1 in WP (2007) (shown in Figure 22 below) shows how demand management and embedded generation opportunities would be considered in the planning process. However, it appears that Western Power waits for third parties to bring forward those opportunities. WP (2007) does not identify any demand management and embedded generation opportunities that have been taken up to date as an alternative to network augmentation.

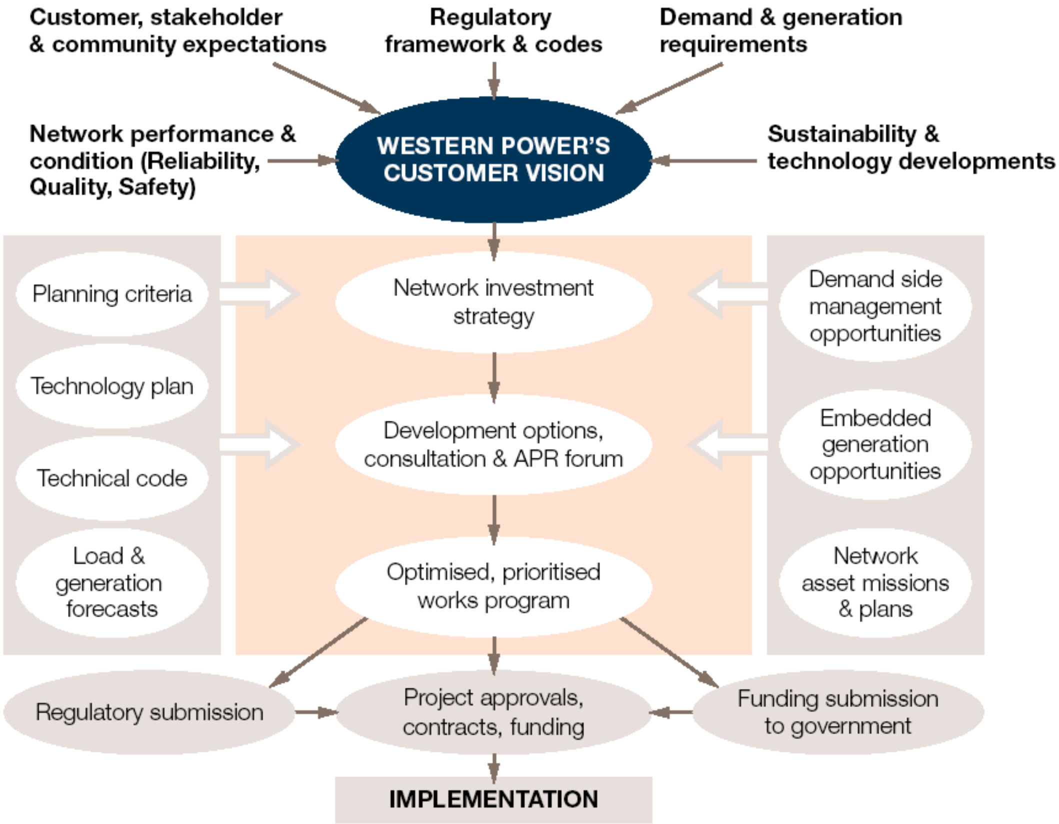


Figure 22 Overview of Western Power's Network Planning Process

From WP (2007)

Use of PV to defer network augmentation

Unless special provisions have been made for small inverter-connected generator installations, it appears that under the present network planning arrangements, third parties would need to bring Western Power's attention to the potential for their projects to defer network augmentation in sufficient time for those projects to be considered and possibly incorporated into the network planning cycle. Financial compensation for the deferral value would presumably also have to be negotiated at that time.

The National Electricity Rules (NER) recognise the potential for embedded generation to provide network-related benefits, including loss reduction, deferral of network augmentation and reliability enhancements. The NER includes an example of how this might work in practice. The Ministerial Council on Energy commissioned a review of network incentives for distributed generation and demand side response, which has recently been released (NERA, 2007). It identifies a range of potential barriers, some related to network revenue and pricing, others not. The Western Australian Government will presumably consider the relevance of the NERA report to the SWIS as part of the on-going MCE process.

Part 2 of the NERA review contains a number of case studies of which the first is a large-scale rollout of PV. It refers to two previous studies, one a study of Newington Village undertaken by CEEM and the other a study of the Kogarah Town Square (KTS)

PV project undertaken by Energy Australia. NERA report that the KTS study concluded as follows:

"The investigation identified that while the time of peak PV output and peak KTS site load correlated well (the load was primarily driven by commercial use), the PV output was only a fraction of its potential capacity and thus the demand reduction was much less than anticipated. In fact, over the period, the reduction in peak demand represented only 9% of site peak demand and the PV output was highly volatile relative to customer load. This reduction represented only 28% of the PV capacity that the KTS PVPS was, according to manufacturers, expected to produce."

Overall, the NERA review concludes that:

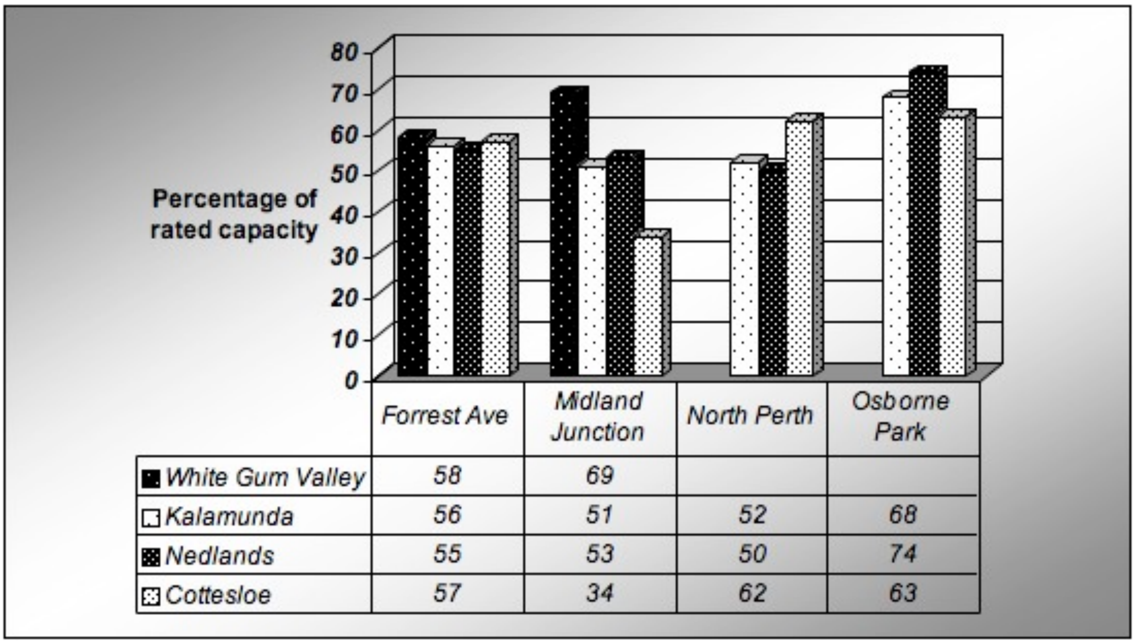
"In summary, these evaluations found that PV installations had little influence on peak demand arising from residential customers. This was principally due to the timing of peak residential demand not coinciding with that of PV output. Therefore the ongoing requirement for stand-by capacity to cover times when PV output is insufficient to cover a residential customer's consumption needs remained largely unchanged".

NERA's conclusions regarding the likely value of PV in deferring network and/or generation investment are summarised in Table 2.1 of Part 2 of the NERA review. These conclusions emphasise that PV is more likely to be useful in deferring network investment for sections of the network serving commercial or industrial rather than residential load behaviour, and that uncertainty as to its production at times of peak-demand limits its usefulness.

Deferring network augmentation in the SWIS CBD region

As outlined in the Section *Correlation between PV output and load peaks* on page 38, for PV to defer network augmentation, it must be producing power with a very high degree of certainty in a particular location at particular times in the future. For the four Perth locations assessed here, simulated PV contributed between 33% and 60% of rated capacity to reducing the annual peak loads. It is possible that in a real life situation, PV would contribute less of its rated capacity. For example, in Newington Village, the 30 systems assessed contributed on average only 29.5% of their rated capacity to reducing peak load - although these systems were not maintained well and were in recessed metal boxes and so suffered serious temperature derating (Watt, 2005). The two real systems assessed in detail here, Carnarvon Solar Farm and Kalbarri, contributed 75% and 33.5% of their rated capacity respectively to reducing the peak load, and 68% and 41% of their rated capacity respectively to reducing the top ten peak loads.

The data provided for the four residential-scale PV systems – White Gum Valley, Kalamunda, Nedlands and Cottesloe - were of sufficient quality to assess their contribution to meeting the peak load in the four SWIS locations between 25th Nov 2006 and 6th March 2007. Figure 23 shows their contribution as a percentage of their rated output. It can be seen that although the four systems contributed very similar proportions of their rated capacity during Forrest Avenue's peak period, and reasonably similar contributions for North Perth and Osborne Park, their contributions during Midland Junction's peak were much more variable.



	Forrest Ave	Midland Junction	North Perth	Osborne Park
White Gum Valley	58	69		
Kalamunda	56	51	52	68
Nedlands	55	53	50	74
Cottesloe	57	34	62	63

Figure 23 Contribution of real systems to meeting peak loads[19]

It is also possible that occasional cloud cover could block insolation on a future hot day, reducing PV's contribution to meeting air conditioning loads. Locating PV systems over a wide area, while still linked to a particular feeder, may help overcome shading problems as they are unlikely be impacted simultaneously by small passing clouds or shadows. However, the use of a large number of separate PV systems generally decreases aggregated peak output because they are unlikely to all be pointing in exactly the same direction.

For PV to defer network augmentation, and so provide financial value, it must provide sufficient firm capacity to cover load growth for a certain period of time. According to WP (2006d), installation of a new 132/22-11kV, 33MVA transformer, including high voltage circuit, switchboard and capacitor banks in the metro area costs $3.03 million, which equates to approximately $100,000/MW. Peak load in the SWIS is projected to increase by 3.2% per year (OoE, 2006), so if PV were to be used to defer a 33MW transformer for one year, it would need to provide 1.06MW of firm capacity. Assuming that PV contributes 50% of its rated capacity to offsetting peaks at any one time, about 2MW of PV would be required to defer a 33MW transformer for one year. Taking the Weighted Average Cost of Capital (WACC) for Western Power to be 7.67%, installing 2MW of PV would save about 7.67% of $3.03 million in the first year, which is $232,400. Thus the financial value provided by PV deferring network augmentation is about 12c/W, significantly below the current installed cost of PV of around $13/W. Even if some form of storage was used and so PV was in effect able to contribute 100% of its rated capacity at peak times, this financial value would only be increased to 24c/W – less once the cost of storage was included. Such large amounts of PV would also require large roof areas, which could be a problem in Perth city.

[19] White Gum Valley data were not available for the North Perth and Osbrne Park peaks.

As discussed above (Section *Correlation between PV output and load peaks,* page 38), some of the peak loads at Forrest Ave TX2, North Perth TX2 and Osborne Park TX1 were probably due to operational changes such as switching from one transformer to another. Changing the timing of these changes could increase PV's ability to contribute to reducing peak load. Such operational changes can be because of scheduled maintenance or a forced outage. Although scheduled maintenance can be timed to coincide with peak PV output, it may be constrained by the need to schedule a series of tasks into a working shift. Forced outages are by their nature unable to be scheduled to coincide with PV output. Although networks often fail when the load is highest - so one with a commercial profile could be most likely to fail when PV output is likely to be high – they can also fail for a variety of other reasons such as water and storm damage.

PV's ability to offset peak loads would be enhanced if it were incorporated into a demand management strategy that focuses on reducing power demand at times when PV is not operating, especially in the late afternoon. Of course, a demand management strategy on its own could reduce energy use at peak times without the need for PV. It is also likely that a diesel generator would be more cost effective than PV at reducing peak loads because:

- it has a lower capital cost,
- a smaller capacity would be required because it has a higher capacity factor,
- it is more relocatable and so could more easily be used to delay augmentation in a number of different areas, and
- it has relatively low running hours and therefore diesel use and costs.

If PV is to be installed for other reasons (such as technology showcasing, improved building performance, such as shading, insulation or lighting, or industry development and associated job creation), it would have incremental network benefits, although they would depend on location and timing and may have very little impact on financing PV systems (ie. the benefits are likely to be smaller than for PV installations specifically timed and located to defer network augmentation). PV output does not have to match load exactly to provide some support - when it occurs prior to peak loads it can pre-cool transformers and so enhance their ability to deal with peaks, especially on hot days.

Power Quality and Reliability

PV's contribution to power quality (both positive and negative) is largely determined by the type of inverter used to connect to the grid. If inverters that conform to Australian Standards are used, PV is unlikely to have a significant negative power quality impact. The existing standards in Australia (AS4777.2) and internationally for small PV systems require that the inverter must produce less than 5% total harmonic distortion (THD) on injected current with tight limits on specific harmonics. This is much more stringent than for loads of equivalent rating (as specified in the IEC61000 series of documents)[20]. Similarly, AS4777.2 requires that inverters operate at close to unity power factor (ie inject only real power into the grid) unless they have been specifically approved by electricity utilities to control power factor or voltage at the point of connection (eg. the Kalbarri model).

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[20] IEC: International Electrotechnical Commission

PV is not a dispatchable generator and so has intermittent output that is only partially controllable ie. it can be decreased but not necessarily increased. The implications of this issue have been addressed in detail in the above, ie. PV can only offset peak loads and so offset high-cost peaking generation and defer network augmentation when there is sufficient solar insolation. Intermittency is also relevant to the Section *Reduction of System Losses* in 'Edge of SWIS' locations (page 70) in that it can only reduce losses when operating. As discussed below, PV can only inject real power when there is sufficient solar insolation, and while the inverter is capable of providing reactive power even in the absence of insolation, most disconnect in this situation.

Harmonic Issues:

There are generally two types of control schemes used in PV inverters. One type operates as a sinusoidal voltage source behind an inductive impedance and the other operates as a sinusoidal current source. Most PV inverters at present are the current source type because this control scheme makes it easier to meet grid connection standards and provide rapid overcurrent protection on the output stage of the inverter.[21] This type of PV inverter operates as an ideal source of sinusoidal current (to the degree that a PV resource is available).

However, a large number of loads are not ideal sinusoidal current loads. Loads expect the power system to be a sinusoidal voltage source and many of them demand non-sinusoidal currents and currents out of phase with the supply voltage. The net effect of a large number of loads of this type is that the supply system has to provide a considerable amount of out of phase and harmonic currents, and the flow of these currents on the network creates harmonic voltages that then can affect other loads. Adding PV inverters which provide sinusoidal currents at unity power factor means that the inverters supply the in-phase sinusoidal component of the loads and the grid is left to still supply out of phase current and harmonics. Thus, while the current source PV inverter generally does not make the situation worse, it does not contribute to the supply of the out of phase and harmonic currents required by loads. The voltage source type of inverter would assist by contributing the harmonic currents required by loads but this type of inverter is at present not common in the market place. Currently inverters are not required to be characterised as being voltage source or current source and hence it is very difficult for purchasers of equipment to select a particular type.

Another complicating factor is that when a voltage source inverter is connected to a grid which has poor harmonic voltage, and the inverter produces harmonic currents to assist in correcting the grid voltage (within the limits of its rating), it's energy output is reduced. This is equitable provided the owner of the inverter is also the cause of the harmonics on the grid and so they are assisting with correction of their own problem. However the owner of the inverter may be experiencing high harmonic flows, and so reduced energy output, because of the poor harmonic performance of other customers on the power system. This is another reason why current source inverters are common - their output is not affected by the grid's voltage harmonics.

In summary, the most common type of inverters (current source) do not provide the harmonic support required by the grid. Voltage source inverters can provide harmonic support but do so at an energy cost and there are a variety of harmonic compensators that are likely to be cheaper. Labeling that identified the type of inverter (voltage or

[21] For more information see Appendix 6.7.

current source) would help purchase of voltage source or current source inverters as required, as would financial compensation for reducing energy losses if voltage source inverters are installed. Note that, unless specially configured, inverters disconnect from the grid when there is insufficient sunlight to cover the switching losses, meaning that no voltage support would be provided in the evening.

In this study it has not been possible to assess the need for harmonic compensation because we would need specific harmonic voltage data at a number of points along the grid. This sort of information would only be collected if there were significant problems in a particular area.

Power Factor Issues:

Poor power factor on the grid increases line losses and exacerbates voltage regulation. Many inverter topologies are readily adaptable to provide current that is out of phase with the grid voltage and so provide power factor correction. In fact many inverters may be controlled to operate in all four quadrants but are constrained by their software control to only provide unity power factor injection of real power into the grid. Changes to the software control would enable the inverter to supply positive or negative reactive power (VAr control) as well as real power, with the limitation being the current rating of the inverter. For example if a PV inverter is rated at 10kVA then it may inject real power of 10kW and no reactive power, or it may inject 10kVAr (reactive power) and no real power, or combinations of lesser real and reactive power.[22]

The provision of VAr compensation comes at an energy cost.[23] For example a 10kVA inverter, which is 94% efficient at full power output, will be dissipating 600W. While that same inverter is delivering 10kVAr and no real power the inverter is 0% efficient and will still be consuming 600W (or probably a little more because the part of the conduction path in the inverter is through reverse conducting diodes with slightly higher voltage drop than the forward conducting transistors). As is the case for provision of harmonic control, the owner of the inverter may not benefit from the VAr compensation it provides.

If an inverter is to be used for VAr compensation, possible methods to activate this compensation are:

- Measurement of the power factor at the point of connection and attempting to unity power factor correct the load at that point.
- Provide voltage support using VAr compensation (ie. the Kalbarri model)
- Use time of day VAr injection to assist with voltage control.

Simple VAr compensation can probably be provided more cost effectively by capacitors. The energy loss in capacitor banks is also considerably less than for the equivalent inverter VAr compensation. The main advantage of inverter VAr compensation is that it is infinitely variable and very fast in response to changes in the power system. In areas where rapid changes in voltage are experienced due to large load transients (eg motor starts) then an inverter VAr compensator may be justified.

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[22] At Kalbarri the inverter is rated at 75kVA and the connected PV is rated at 20kW and so even when injecting all the real power associated with the PV the inverter has significant reactive power capability (72kVAr) still available for VAr compensation.

[23] Inverters can provide reactive power in the absence of PV output. The energy cost would then be drawn from the grid.

The efficiency of inverters generally increases with their rating and so the losses associated with VAr compensation decrease in $/VAr terms. Thus it is probably better to use a single large inverter, whether it is a single large PV inverter or a single purpose built static VAr compensator (SVC), than to use multiple smaller units (eg. multiple small PV inverters with VAr control). Nevertheless, where many smaller PV systems are installed by building owners, the cost is not borne by the utility but the benefits would still accrue.

In areas of higher population density the grid impedance is more reactive and hence there are greater opportunities for VAr compensation to assist with voltage control. In rural grids where the grid impedance is more resistive, the effectiveness of VAr control for voltage compensation is diminished.

In summary, PV inverters are capable of VAr compensation to assist with voltage control on the grid, although this comes at an energy cost. How the VAr compensation is valued and who pays for the energy has generally not been addressed. A single large inverter will be a more energy efficient option than multiple small PV inverters. Although large load transients may justify an inverter, capacitors are likely to be a more cost effective source of VAr compensation. The alternative options to achieve the same results as a PV inverter are fixed or switchable capacitors, or SVCs for fast voltage control.

In this study it has not been possible to fully evaluate the possible effectiveness of VAr control of PV inverters on the Western Power SWIS system as the data available included only substation real and reactive power flows. Voltage data could have been obtained but this would have been of limited value as the lines of interest contain a number of voltage regulators which operate to adjust the voltage on the lines. These regulators change the voltage seen by loads and the voltage data does not identify when the regulation changes occur. Because of this it is impossible to model the effect of PV on such a system without a lot more detail regarding the complete distribution system impedances and also the algorithms used by the voltage regulators to determine their ratios. The issue of increased voltage regulator operation with varying PV input will depend on the penetration of PV but this cannot be investigated without detailed models of the network.

Islanding:

To avoid islanding (where inverters continue to inject power into a section of the grid that is no longer live because it has been disconnected from the main grid and associated generators), Australian Standard AS4777.2 requires that inverters must disconnect from the grid in response to loss of grid power. However, this disconnection requirement also reduces PV’s ability to provide reliable energy and line support. On a weak grid, an inverter may cut out prematurely or, more likely, may not reclose (ie. reconnect to the grid). AS4777 specifies that the autoreclose function needs the grid to be stable (voltage and frequency within specified tolerance limits) for 60 secs, which on a weak grid may not occur for some time. Networks are designed to reclose after 10 secs and so for the next 50 secs the PV will not be providing network support. Note that it is possible for the network operator to specify different tolerance limits. Short-term reversible storage could also be used to bridge the gap until the PV inverter recloses.

3.1.2 *EDGE OF SWIS*

This section firstly assesses the correlation between PV output and load in three 'Edge of SWIS' substations. It then estimates the value of PV offsetting conventional generation in the three 'Edge of SWIS' locations (page 64), then uses three different methodologies based on the RCM to estimate the value of PV's ability to provide firm capacity during times of peaking generation (page 64). The values of PV offsetting conventional generation and providing firm capacity are then combined (page 69). Following this, PV's ability to defer network augmentation in 'Edge of SWIS' locations is assessed (page 69), as is its ability to reduce line losses (page 70) and its influence on power quality and reliability (page 72).

Correlation between PV output and load peaks

This section summarises the findings for a selected transformer in each of the three 'Edge of SWIS' substations (Geraldton TX1, Katanning TX2 and Merredin TX1) and for simulated PV in these locations from July 2003 to June 2004. It also summarises the impact of the Kalbarri PV System on Geraldton TX1 for the same period. Each of the substations has been analysed in great detail (see Appendix 6.5), and Table 20 presents a concise summary of the outcomes for the peak periods for each location to illustrate the variability of the correlation between load and simulated PV.

The purpose of this analysis is to assess the degree to which PV could provide firm capacity during times of peak demand and defer network augmentation. As discussed in Section 3.1.1 on the SWIS, the market mechanisms currently available in WA to value PV's ability to provide firm capacity during times of peaking generation are based on it most probably being available at the required times in the future, with the task spread over the SWIS. In contrast, for PV to defer network augmentation, it must be available in a particular location with a very high degree of certainty at a particular set of future times.

With respect to providing firm capacity during times of peak demand, the 'Edge of SWIS' locations' peak loads and simulated PV were generally not well matched, and where they were, the reduction of peaks by simulated PV resulted in later periods on the same day or cluster of days becoming the new peaks. Figure 24 shows the average daily annual load and simulated PV output for Merredin, which is similar to those for Geraldton and Katanning. As a result, simulated PV would be expected to generate little financial value through the creation of capacity credits or by reducing IRCRs. As shown in the Section *Commercial value of offsetting conventional generation* (page 64) this is in fact the case.

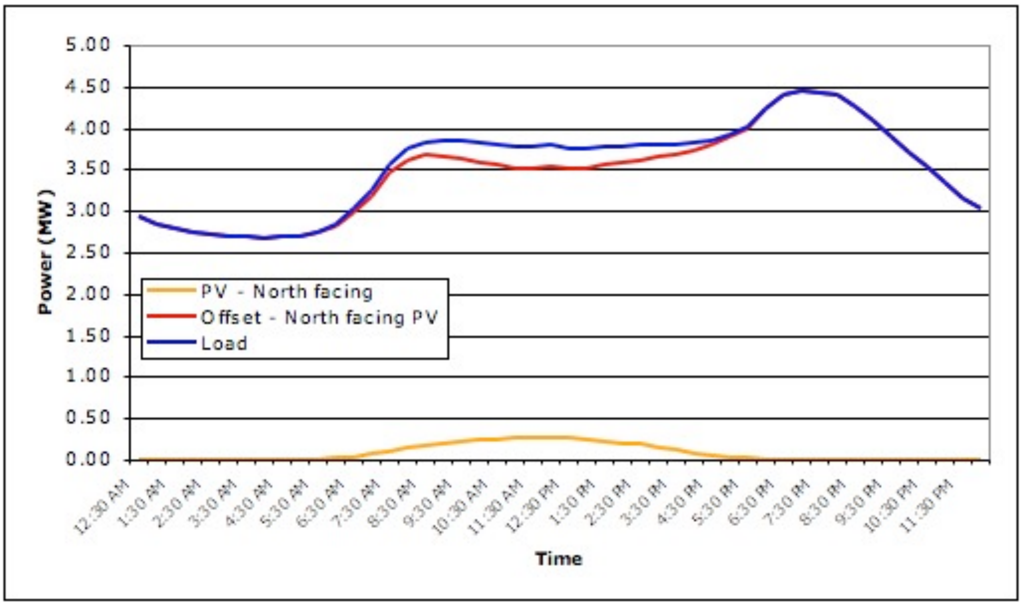

Figure 24: Daily Annual Average
Merredin TX1 Load, Merredin Simulated North-facing PV (400kW) and Net Load after PV Offset
July 2003 to June 2004

As shown in Table 20, simulated PV had a lower and more uneven correlation with the very highest peak loads than it did for the SWIS locations. For example, Figure 25 and Figure 26 show the peak load days for Merredin and it can be seen that the peaks occur late in the day when PV output is reduced.

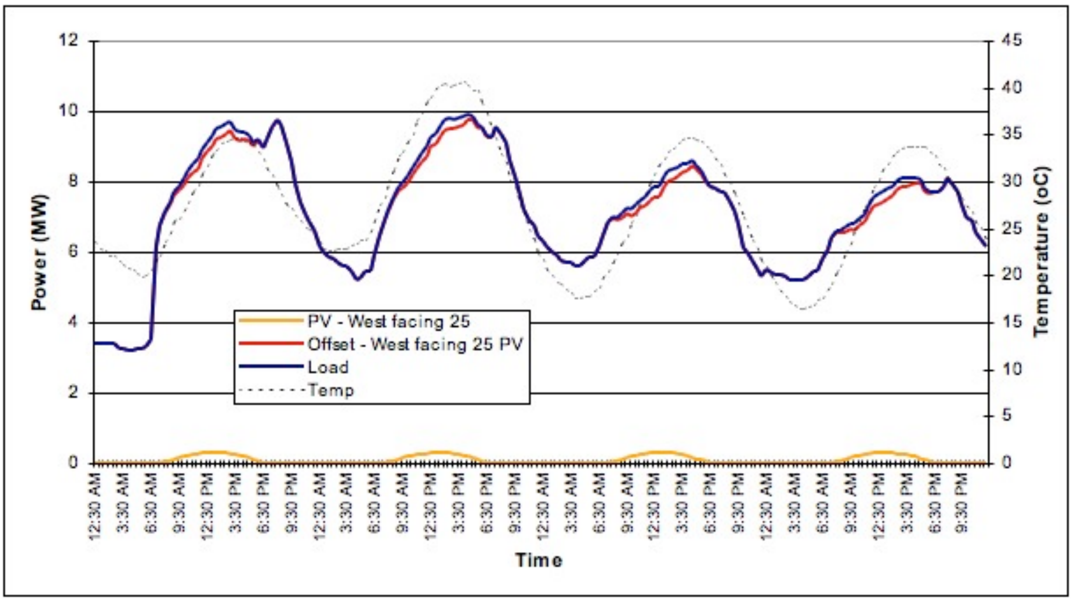

Figure 25: Summer peak days (west-facing-25 PV)
3rd-6th Feb 2004
Merredin TX1 Load, Merredin Simulated West-facing-25 PV (400kW) and Net Load after PV Offset

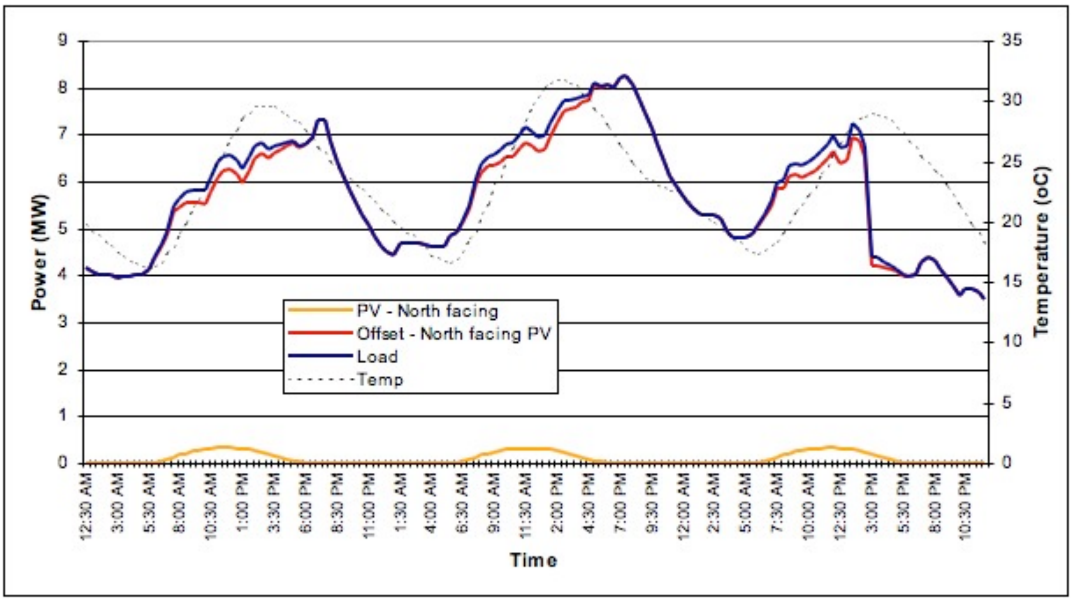

Figure 26: Autumn peak days
17th-19th March 2004
Merredin TX1 Load, Merredin Simulated North-facing PV (400kW) and Net Load after PV Offset

As for the SWIS, load duration curves have been used to assess PV's contribution during peak load periods. Figure 27 shows Merredin's load duration curve and it can be seen that the peak load periods are not greatly reduced by simulated PV.

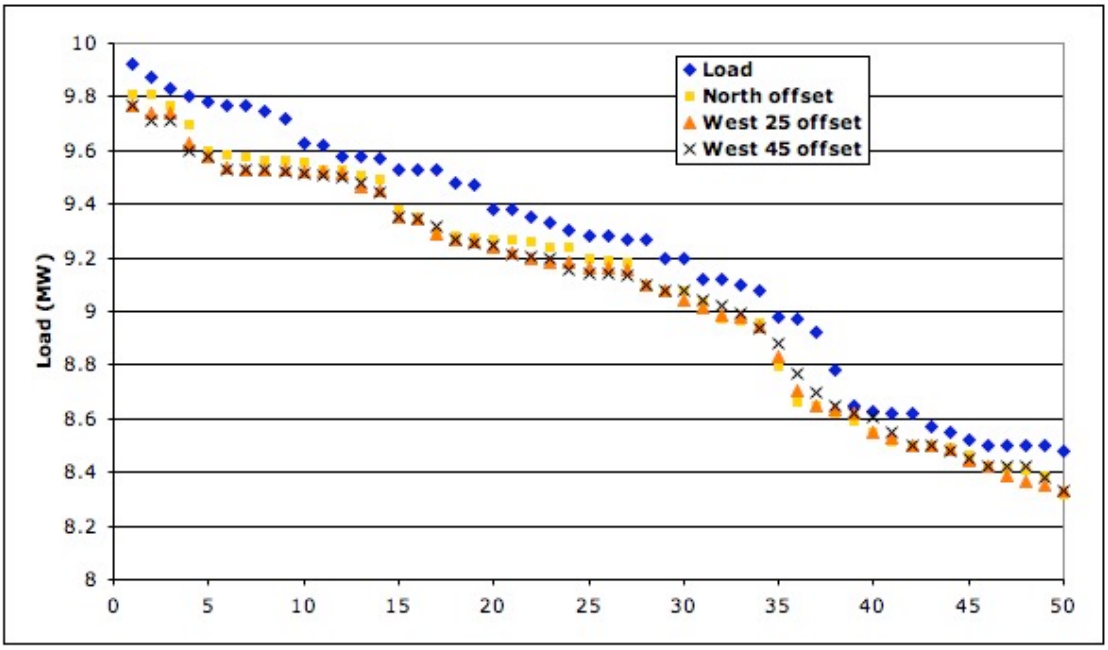

Figure 27: Load Duration Curve - top 50 load periods
North, and West (25° and 45° inclinations)
Merredin TX1 Load and Merredin TX1 Net Load after PV Offset (400kW)
July 2003 to June 2004

For each substation, Table 20 includes percentage values that are derived from load duration curves. These percentage values are again defined as follows:

A: Is the contribution by simulated PV at the year's peak 30-minute load period as a percentage of the PV's rated output. For example, a value of 73.5% means that a 1MWp PV system produced 0.735MW of power during the year's peak load period.

B: Is the same as "A" but averaged for the year's top ten peak 30-minute load periods.

C: Is the contribution by simulated PV to reducing the year's peak net load as a percentage of the simulated PV's rated output. This is different to "A" because, for example, while PV may contribute 73.5% of its rated output during the peak load period, it may contribute much less output at a slightly lower load period, which then may become the year's highest net load period. Thus "C" is a measure of how much the simulated PV was able to make the highest net load period lower than the highest actual load period.

D: Is the same as "C" but averaged for the year's top ten peak 30-minute load periods.

In summary, in most cases simulated PV output was not well matched to the peak load, for example contributing only 12.5% of rated capacity in Katanning. In periods where load and simulated PV were well matched, simulated PV contributed up to 73.5% of its rated peak capacity to load reduction. However, periods of slightly lower load were sometimes not as well matched to simulated PV, and so became the highest net load. As a result, simulated PV's ability to reduce the year's peak net load (as per "C" above) was much lower, for example reduced from 73.5% to 40.5% for Geraldton TX1 (see Table 20). The Kalbarri PV system is illustrative of how real PV data may deviate from simulated PV data, contributing only 38% of rated output during the Geraldton TX1 peak load period. As occurred for the SWIS, many of the peak periods corresponded to operational changes by Western Power, and so changing the timing of these changes could increase PV's ability to contribute to reducing peak load. However, in general the load profiles included a significant residential component and so tended to peak in the late afternoon or evening, and in winter in Katanning.

For a much more detailed analysis of each substation's correlation with simulated PV see Appendix 6.5. Placing a financial value on simulated PV's ability to meet these peak load periods and so defer network aumentation is discussed in the Section *Deferral of Network Augmentation* (page 69).

Note that this analysis focussed on a single year and that load patterns change from year to year (eg. the peak periods occur on different days and sometimes in different seasons). Thus future load and PV production patterns may differ from their historical counterparts. This analysis also used simulated PV data rather than actual, and the load data is three years old and summer peaks could well have increased since then. It is recommended that any PV installed be monitored and compared to current load data. The impact of changes to Western Powers operational activities that result in peaks could also then be assessed.

Table 20: Summary of simulated PV's contribution during peak periods at 'Edge of SWIS' locations

<table>
<tr><th>Location</th><th>A</th><th>B</th><th>C</th><th>D</th></tr>
<tr><td>Geraldton TX1</td><td>73.5%</td><td>71.5%</td><td>40.5%</td><td>59%</td></tr>
<tr><td colspan="5">The ten top half-hour demand peaks occurred in Dec and were not particularly hot days, and it is likely the highest peak is due to operational changes by Western Power. Simulated north-facing PV was a good match. The second highest peak cluster of peak load days assessed here occurred in May and again appear to have been influenced by operational changes, and peaked in the early evening when PV could have little impact. On the third highest peak cluster of peak load days assessed here (in July) the load rapidly increased from around 8MW to around 20MW, again most probably because of operational changes by Western Power. Simulated north-facing PV matched the load on some days quite well but is a poor match on the other days. The fourth highest peak cluster of peak load days assessed here occurred in March and was relatively hot (33^{o}C), was probably due to operational changes and occurred very early in the day, well before PV would make any significant contribution</td></tr>
<tr><td>Geraldton TX1 – Kalbarri PV</td><td>38%</td><td>45.5%</td><td>33.5%</td><td>41%</td></tr>
<tr><td colspan="5">Compared to the simulated PV in:
Dec: the Kalbarri scaled output is slightly broader but not as high as the simulated north-facing PV data, and so does not have as great an impact.
May: because the load peaks occurred so late in the day the Kalbarri scaled output had little if any effect on the load profile.
July: the Kalbarri scaled output is sometimes greater than the simulated north-facing PV and broader on each day, the latter presumably because of tracking, and so reduces peak demand more than the simulated PV.
March: the Kalbarri scaled output is much broader than the simulated north-facing PV and so while not as high in the middle of the day has a greater impact on the early morning load peak.</td></tr>
<tr><td>Katanning TX2</td><td>12.5%</td><td>14%</td><td>12.5%</td><td>35%</td></tr>
<tr><td colspan="5">The ten top half-hour demand periods occurred in Feb and Nov. The highest peak load day for the study period (in Feb) and the following day were not particularly hot and had very unusual load profiles that reflect either operational changes by Western Power or large loads going on and off-line. The load peaked in the evening, at a time when even west-facing PV would make little significant contribution. The second highest peak load day (in Nov) again was not hot and appears to be due to operational changes or sudden large loads. The peak occurred in the middle of the day and so was well matched to simulated north-facing PV. The third highest cluster of peak load days assessed here (in March), again appears due to operational changes or sudden large loads, and includes a complete loss of load for 20hrs. The peak occurred at 8:30am and so was not well matched to simulated north-facing PV. The fourth highest of the peak load days assessed here (in July) had a classic residential winter profile, peaking between 6:30 and 7pm, and so was not at all matched to even west-facing simulated PV.</td></tr>
<tr><td>Merredin TX1</td><td>52.5%</td><td>55%</td><td>37.5%</td><td>45%</td></tr>
<tr><td colspan="5">The ten top half-hour demand periods occurred in Feb. The highest peak load day occurred in a cluster of days where maximum temperatures were above 30^{o}C,</td></tr>
</table>

reaching over 40°C on one day. The peak periods occurred in the late afternoon and so were not well matched to simulated PV. The second highest cluster of peak load days assessed here (in March) occurred where temperatures were not particularly high (just over 30°C), and the highest peak period occured at 7:30pm when even simulated west-facing PV had no impact. The third peak load day assessed here (in June) had a very unusual load profile, with a sudden 5MW increase at 8am, steadily dropping to early afternoon before peaking again at around 6:30pm. The impact of simulated PV was to reduce the midday dip. The fourth cluster of peak load days assessed here (in Nov) occurred when maximum temperatures were between 30 and 42°C, and the peaks occurred in the middle of the day and so were well matched to simulated north-facing PV.

Commercial value of offsetting conventional generation

Here we use the same approach as we used for the four Perth locations to calculate the commercial value of offsetting conventional generation in the three 'Edge of SWIS' locations (see page 46). Only a 12% discount rate is used because, as discussed, the value of offsetting conventional generation accrues to the retailer. Again, it is clear that the commercial value provided by PV ($1,500 - $2,000 per kW) is a small proportion of its installed cost of $13,000/kW. See Table 21.

Table 21 Commercial value of electricity generated by 1MW simulated PV

Discount rate	PV Orientation	Value in year 1	Discounted Value [a]	Disc Value per Watt [b]	ROI [c]
Geraldton TX1	North-25	$135,900	$1,217,235	$1.20	0.47%
	West-25	$144,015	$1,289,895	$1.30	0.50%
Geraldton TX1	Kalbarri PV	$135,585	$1,214,380	$1.20	0.47%
Katanning TX2	North-25	$133,670	$1,197,220	$1.20	0.46%
	West-25	$137,025	$1,227,280	$1.25	0.47%
Merredin TX1	North-25	$124,860	$1,118,331	$1.10	0.43%
	West-25	$107,325	$961,275	$0.95	0.37%

a: Over 20yrs at 12% discount rate
b: Values rounded to nearest 5c
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Commercial value of PV providing firm capacity

This section estimates the commercial value of simulated PV's ability to provide firm capacity during peak load periods in the three 'Edge of SWIS' locations, using Methodology 1, Methodology 2 and Methodology 3 in the same way as for the Perth locations. For the reasons discussed, only a 12% discount rate is used (see *Commercial value of offsetting conventional generation*, page 46).

Methodology 1

The estimated values of RCCs created for the 'Edge of SWIS' locations using Methodology 1 are shown below in Table 22 to Table 25. Very little income is generated for simulated PV, with a discounted value of about $0.20/W for simulated north-facing PV, and less for simulated west-facing PV, compared to the current installed cost of about $13/W.

Table 22 Geraldton Reserve Capacity Credit Outcomes: Methodology 1

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.196	0.192
Value in year 1[a]	$19,600	$19,200
Discounted Value[b]	$176,000	$172,000
Disc Value per Watt	$0.18/W	$0.17/W
ROI [c]	0.07%	0.07%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 23 Kalbarri Reserve Capacity Credit Outcomes: Methodology 1

	1MW Scaled Kalbarri PV
Capacity Credits	0.180
Value in year 1[a]	$18,000
Discounted Value[b]	$162,000
Disc Value per Watt	$0.16/W
ROI [c]	0.06%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 24 Katanning Reserve Capacity Credit Outcomes: Methodology 1

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.187	0.176
Value in year 1[a]	$18,700	$17,600
Discounted Value[b]	$168,000	$158,000
Disc Value per Watt	$0.17/W	$0.16/W
ROI [c]	0.07%	0.06%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 25 Merredin Reserve Capacity Credit Outcomes: Methodology 1

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.191	0.146
Value in year 1[a]	$19,100	$14,600
Discounted Value[b]	$171,000	$131,000
Disc Value per Watt	$0.17/W	$0.13/W
ROI [c]	0.07%	0.05%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Methodology 2

The estimated values of RCCs created for the 'Edge of SWIS' locations using Methodology 2 are shown below in Table 26 to Table 29. As for the SWIS locations, this methodology generally created more value than Methodology 1, with simulated west-facing PV creating more commercial value than simulated north-facing PV, reaching 59c/MW at Katanning. The high value is possible at Katanning despite the load not being particularly well matched to simulated PV because Methodology 2 is based on the SWIS load overall, not just Katanning's load.

At Merredin this methodology created significantly less commercial value than did Methodology 1. This occurred because at the 225th trading interval for the period assessed, the simulated PV output at Merredin was very low. To minimise this sort of effect, it may be fairer to take a weighted average of the previous three years' hot seasons rather than only the previous one.

Table 26 Geraldton Reserve Capacity Credit Outcomes: Methodology 2

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.234	0.415
Value in year 1[a]	$23,400	$41,500
Discounted Value[b]	$209,000	$372,000
Disc Value per Watt	$0.21/W	$0.37/W
ROI [c]	0.08%	0.14%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 27 Kalbarri Reserve Capacity Credit Outcomes: Methodology 2

	1MW Scaled Kalbarri PV
Capacity Credits	0.189
Value in year 1[a]	$18,900
Discounted Value[b]	$169,000
Disc Value per Watt	$0.17/W
ROI [c]	0.07%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 28 Katanning Reserve Capacity Credit Outcomes: Methodology 2

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.265	0.516
Value in year 1[a]	$26,500	$51,600
Discounted Value[b]	$238,000	$462,000
Disc Value per Watt	$0.24/W	$0.46/W
ROI [c]	0.09%	0.18%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 29 Merredin Reserve Capacity Credit Outcomes: Methodology 2

	1MW Simulated North-facing PV	1MW Simulated West-facing PV
Capacity Credits	0.048	0.12
Value in year 1[a]	$4,800	$12,000
Discounted Value[b]	$43,000	$107,000
Disc Value per Watt	$0.04/W	$0.11/W
ROI [c]	0.02%	0.04%

a: Assuming a RCC price of $100,000/MW/yr
b: Over 20yrs at a 12% discount rate and 2.5% inflation rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Methodology 3

As stated earlier, Methodology 3 is used to approximate the IRCR avoided by Market Customers. The results for 1MW simulated PV are shown below in Table 30. Note that although values for Kalbarri are given it would not be eligible to use Methodology 3 because it is a generator, not a Market Customer. Again the values are significantly greater than for either Methodology 1 or 2. As for Methodology 2, Katanning has the highest value, followed by Geraldton, with the discounted net present values ranging from 2.4% to 6.5% of the installed cost for simulated west-facing PV.

Table 30 Edge of SWIS Capacity Credit Outcomes: Methodology 3, 1MW Simulated PV

Location	Orientation	Reduction in IRCR	Value in year 1[a]	Discounted Value[b]	Disc Value per Watt	ROI [c]
Geraldton TX1	North-25	0.64	$64,000	$573,000	$0.57	0.22%
	West-25	0.71	$71,000	$633,000	$0.63	0.24%
Geraldton TX1	Kalbarri PV	0.52	$52,000	$461,000	$0.46	0.18%
Katanning TX2	North-25	0.64	$64,000	$574,000	$0.57	0.22%
	West-25	0.95	$95,000	$850,000	$0.85	0.32%
Merredin TX1	North-25	0.34	$34,000	$307,000	$0.31	0.12%
	West-25	0.53	$53,000	$471,000	$0.47	0.18%

a: Assuming a Capacity Credit price of $100,000/MW/yr

b: Over 20yrs at a 12% discount rate and 2.5% inflation rate

c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

The use of storage should increase the level of correlation between PV output and load. However, according to a recent review by the Australian Government, "long-term energy storage that shifts large amounts of energy in time for applications such as energy arbitrage, peak-overloaded transmission/distribution upgrade deferral or overcoming intermittency of generation from renewable energy sources faces a difficult cost challenge" (AG, 2005). The levelised annual cost of energy storage technologies can be calculated by adding up the amortised installed cost of the system, the operating and maintenance cost, fuel cost, and replacement costs. For four hours of storage, batteries currently available cost between $400/kW/year (lead-acid flooded cell) – which are cheaper than flywheels - and $800/kW/year (NiCad) (AG, 2005). Over a 20 year operating life of a PV system, these costs equate to $8/W and $16/W after discounting. Assuming an RCC is worth $100,000/MW/year, its 12% discounted value over 20 years is about $1.45/W. Assuming that an RCC accurately reflects the value of providing capacity to the SWIS, a battery wouldn't even cover its own costs, let alone provide additional value to PV.

Commercial value of offsetting conventional generation and providing firm capacity

As for the SWIS locations, PV's value in providing firm capacity is greatest when calculated in terms of its ability to reduce a Market Customer's IRCR. The value so created, combined with its value for offsetting conventional generation results in a discounted net value between about $1.60/W and $1.80/W for simulated north-facing and west-facing PV respectively – see Table 31. The IRCR value makes up between 21% and 26% of the discounted net value for north-facing and west-facing systems respectively.

Table 31 Commercial value of electricity generated by 1MW simulated PV: Offsetting conventional generation and providing firm capacity

PV Orientation	Disc Value per Watt [a]		Total [b]	ROI [c]
	Conventional generation average	Firm capacity		
North-25	$1.15	$0.50	$1.60	0.61%
West-25	$1.15	$0.65	$1.80	0.69%

a: Over 20yrs at 12% discount rate

b: Values rounded to nearest 5c

c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Deferral of Network Augmentation

Similar issues apply for deferring network augmentation in fringe areas as in the main part of the SWIS, with the following additional characteristics:

- Rural loads can be highly variable compared to the rating of a rural feeder and lack diversity (ie. a relatively small number of loads that therefore influence the net profile). Relocatable and responsive embedded generation would then be best suited to allowing deferral of network augmentation. PV systems without storage can be relocated but are not well suited to match such variable loads.
- Supply interruptions, voltage drop and quality of supply issues are often more significant for long feeders in outer rural areas than for urban or shorter rural feeders. Thus, the ability of embedded generation (of any kind) to contribute to improving availability and quality or supply is important in that context. As previously discussed, PV systems without storage are not well suited to this task. The situation may be further complicated by the presence of (series) voltage regulators, which are often installed in long rural feeders.
- On the other hand, there may be an opportunity to substitute stand-alone supply systems for a spur line in an outer rural area, allowing the spur line to be de-commissioned and thus save maintenance and refurbishment costs. There may also be a role for PV water pumping and other specialised applications. However, other stand-alone supply technologies may be more appropriate for large variable loads, such as shearing sheds or intermittently used large irrigation systems.

Deferring network augmentation in 'Edge of SWIS' regions

As discussed earlier, for PV to defer network augmentation, it must be available with a very high degree of certainty in a particular location at a particular time. For the three 'Edge of SWIS' locations assessed here, simulated PV contributed between 12.5% and 40.5% of rated capacity to reducing the annual peak loads. Real PV systems may contribute less, for example Kalbarri contributed 33.5% of its rated capacity to reducing the peak load at Geraldton TX1. Thus, PV's potential to contribute network benefits in 'Edge of SWIS' locations is lower than for the Perth locations. Note that apart from Katanning, the 'Edge of SWIS' locations assessed in this report were specially selected to have the closest correlation to likely PV output.

The value of PV's ability to defer network augmentation in 'Edge of SWIS' locations can be calculated using the same approach as for the SWIS locations (page 50). In regional areas the 33MVA transformer cost is slightly higher at $3.43 million, and it is unlikely that PV could contribute more than 25% of its rated capacity to reducing peak loads. In this case, the financial value provided by PV deferring network augmentation is about 7c/W. Even if some form of storage was used and so PV was in effect able to contribute 100% of its rated capacity at peak times, this financial value would be increased to only 14c/W – even less once the cost of storage was included.

As for the SWIS locations, if PV is to be installed for other reasons (such as technology showcasing, improved building performance, such as shading, insulation or lighting, or industry development and associated job creation), it would have incremental network benefits, although they would have very little impact on financing PV systems (ie. the benefits would be smaller than for deferring network augmentation).

Reduction of System Losses

Resistive losses in distribution feeders are roughly proportional to the square of the current flow, while shunt losses are related to the local voltage, which varies along the feeder. Current-related losses can be reduced by power factor correction (if not already done) and by embedded generation. However, it should be noted that reducing current magnitude and improving power factor will also reduce line voltage drop, which in turn will increase voltage-related losses (particularly transformer iron losses if magnetic saturation starts to occur). Thus, loss reduction may not be as great as expected.

To maximise PV's contribution to reducing losses, it should be matched as closely as possible to load. As previously indicated, PV systems without storage are not well suited to this task because PV generation may not correlate well with load and both current-related and voltage-related losses would increase again if there was reverse power flow. However, where PV is installed for other reasons, it would still contribute to some reduction in overall losses. The IMO publishes transmission loss factors (TLFs) and distribution loss factors (DLFs), where the TLFs represent marginal losses on the transmission system and the DLFs represent average losses on the distribution system. To obtain the total Loss Factor for a particular location, the TLF is multiplied by the relevant DLF.

Table 32 gives the TLFs for each of the three 'Edge of SWIS' substations (WP, 2007a). These have been used to estimate the amount of electricity lost and therefore the amount of loss that could be avoided by hypothetical 1MW PV installations at each location over the period July 2003 to June 2004.

To give an indication of the value of these savings, the electricity losses avoided have been multiplied by the average value of PV offsetting conventional generation as summarised in Section 3.2.1, ie. 7.85c/kWh (north-facing) and 8.55c/kWh (west-facing). Note that because TLFs are based on marginal losses, their use to calculate losses avoided by PV assumes the PV output is perfectly correlated with load. This would only occur if storage was used, so it is likely the financial benefits in the absence of storage would be even less than given in Table 32.

Table 32 Transmission Loss Factors and estimated electricity losses avoided and value for simulated 1MW PV systems at three 'Edge of SWIS' locations

		TLF	Losses avoided (kWh)	Annual value of avoided losses	Discounted value of avoided losses [a]
Geraldton TX1	N	1.1059	180,904	$0.014/W	$0.13/W
	W		178,133	$0.015/W	$0.13/W
Katanning TX2	N	1.0508	85,938	$0.007/W	$0.06/W
	W		80,989	$0.007/W	$0.06/W
Merredin TX1	N	1.0673	113,504	$0.009/W	$0.08/W
	W		87,223	$0.007/W	$0.06/W

a: Over 20yrs at a 12% discount rate

The losses avoided on the distribution network can be estimated from site-specific DLFs, or if these are not available, then from system-wide average DLFs. For example, the SWIS-wide average DLF is 1.054 and the highest DLF in WA is for Black Swan Nickel in Kalgoorlie at 1.1517 (WP, 2007b). Here, to allow for the fact that PV systems could be installed anywhere on the distribution network, and that this section focuses particularly on fringe locations, we have used a DLF of 1.10.

Table 33 provides the same information as Table 32 but includes the impact of distribution losses for PV systems connected on the networks that feed into the three 'Edge of SWIS' substations. It can be seen that the financial values of the total losses avoided are very low compared to the cost of installing PV. The DLFs assume that PV output is correlated to average load. Use of storage to increase the level of correlation would not materially improve the financial viability of a PV system, especially when the costs of storage are taken into account.

Table 33 Total Loss Factors and estimated electricity losses avoided and financial values for three 'Edge of SWIS' locations

		Total Loss Factor	Losses avoided (kWh)	Annual value of avoided losses	Discounted value of avoided losses [a]
Geraldton TX1	N	1.2165	369,836	$0.029/W	$0.26/W
	W		364,171	$0.031/W	$0.28/W
Katanning TX2	N	1.1559	263,733	$0.021/W	$0.19/W
	W		248,546	$0.021/W	$0.19/W
Merredin TX1	N	1.1740	293,457	$0.023/W	$0.21/W
	W		225,510	$0.019/W	$0.17/W

a: Over 20yrs at a 12% discount rate

These avoided losses result in savings for the retailer because their electricity purchase price (from the PV system embedded in the distribution network) does not incorporate the TLF and DLF. However, it can be seen that although there may be significant losses on regional feeders, the value of avoided losses due to distributed generation is very small compared to the installed cost of PV systems and so is unlikely to have any direct impact on the financial viability of PV.

Power Quality And Reliability

The issues regarding the provision of harmonic support using inverters at fringe of grid areas are the same as for metropolitan and CBD locations, as are the issues related to islanding and intermittency. However, provision of voltage regulation is different because the system impedances seen at the point of connection are considerably more resistive, and the higher the resistance to reactance (R/X) ratio of the line the less effective VAr compensation becomes for voltage control. With high R/X ratios the opportunities for voltage regulation using VAr compensation are considerably reduced if not completely eliminated, and real power injection is more effective for voltage regulation. Thus, PV inverters connected to fringe of grid lines can provide voltage regulation at the point of connection provided the real power input of the inverter correlates in time with the load on the system.

The Merredin and Geraldton transformers assessed here had a moderate correlation to simulated PV output in summer but not the other seasons, and Katanning load did not correlate to simulated PV output in any season. This, combined with their lower cost, makes capacitors a better option for providing voltage support on ‘Edge of SWIS’ lines. For example, capacitors could be installed in conjunction with large induction motors (the worst offenders) so that they were switched with the motor rather than relying on PV inverters with power factor correction capability. However, where inverters are to be installed for some other reason, they would provide VAr support in proportion to the PV output. Some research has been carried out where PV systems using batteries could provide dispatchable power and thus improve power system voltage regulation at the point of connection.[24] The main problems are the high cost because of both the PV and the batteries and considerable maintenance requirements for the batteries.

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[24] Shogo Nishikawa, Kazuhiko Kato, “Demonstrative research on grid-interconnection of clustered photovoltaic power generation systems”, 3rd World PV Energy Conversion Conference May 11-18, 2003 Osaka Japan.

3.1.3 REGIONAL TOWNS AND GRIDS

Horizon Power supplies electricity to the North West Interconnected System and to 28 separate regional grids throughout Western Australia. The cost of supply to these areas can be much higher than to customers on the SWIS where there are higher generation costs (where the generators are smaller and often use diesel fuel which is expensive), there are fewer customers and they are more geographically dispersed. For example the generation cost at Marble bar is 39.11c/kWh.[25] However, in some areas, such as Port Hedland, where gas supply is plentiful, the generation costs are much lower – at around 6.6c/kWh. On the 6th June 2001 the State Government announced that it would establish the Tariff Equalisation Fund (TEF) which would be used to make regional customers' tariffs similar to those of customers on the SWIS. Thus, the TEF is used to cover the cost differential between Horizon Power's revenue and what it costs to supply its regional customers' electricity.

The project 'Request for Quote' required quantification and comparison of the costs of PV generation and existing diesel generation in selected regional grids or towns. Following discussions with Horizon Power, the loads at Carnarvon, Port Hedland, Marble Bar and Meekatharra were chosen for analysis despite only Marble Bar and Meekatharra being reliant on diesel generators. As stated in Section 2.1.3, each location was selected for the following reasons.

Carnarvon: was selected because of the availability of PV data from the Carnarvon Solar Farm and because the Carnarvon power station is in need of an upgrade and potential alternative energy sources are being considered.

Marble Bar: was selected because it has a high cost of supply (from diesel generators) and is to be replaced within the next two years and so provides an opportunity for integration of PV into a diesel system.

Meekatharra: was selected because it has a high cost of supply (also from diesel generators) and is distant to Marble Bar and so likely to have a different solar insolation profile.

Port Hedland: was selected because it represents a different scenario as it is part of the NWIS (rather than being only in a small town), and is of particular interest to Horizon Power who are currently considering supply options, and it provides an opportunity to evaluate the potential benefits of using PV along the Pilbara coast.

Thus, the following analysis is divided into two sections. The Section *Reduction Of Peak Load* compares load data for the above four locations to simulated PV data using the same format as used for the SWIS and Edge of SWIS locations except that, because the emphasis is not on providing network support, a financial analysis is not carried out. Instead this section assesses the level of correlation between simulated PV and load, and provides information which Horizon Power may find relevant if it uses PV to avoid the use of additional diesel generators. The section *Reduction Of Cost Of Supply* on page 78 evaluates simulated PV's ability to reduce diesel use and the cost of supply in Carnarvon, Marble Bar, Meekatharra and Port Hedland.

[25] This is only the generation component ie. it does not include the transmission and distribution component.

Reduction Of Peak Load

This section summarises the findings for each of the three 'regional' substations (Carnarvon, Marble Bar and Meekatharra), as well as for three substations in Port Hedland (Anderson Street [AST], Murdoch Drive [MDR] and Wedgefield [WFD]), using load data from July 2005 to June 2006 and simulated PV data from the Real Mean Year (RMY) database. Because the RMY database is a reference year, these findings should be treated only as indicative of what may happen in an average year. Each of the substations has been analysed in great detail (see Appendix 6.6), and Table 34 presents a concise summary of the outcomes for the peak periods for each location to illustrate the variability of the correlation between load and simulated PV.

In general, the loads and simulated PV output were well matched. Carnarvon peaked around midday in summer and had a good match to simulated north-facing PV (Figure 28), while Marble Bar and Meekatharra (Figure 29) peaked in summer but in mid afternoon and so were better matched to simulated west-facing PV. Of the three Port Hedland substations, all peaked in summer with AST in mid afternoon, MDR slightly later and WFD slightly earlier. As a result, AST and MDR were best matched to simulated west-facing PV while WFD was better suited to simulated north-facing PV.

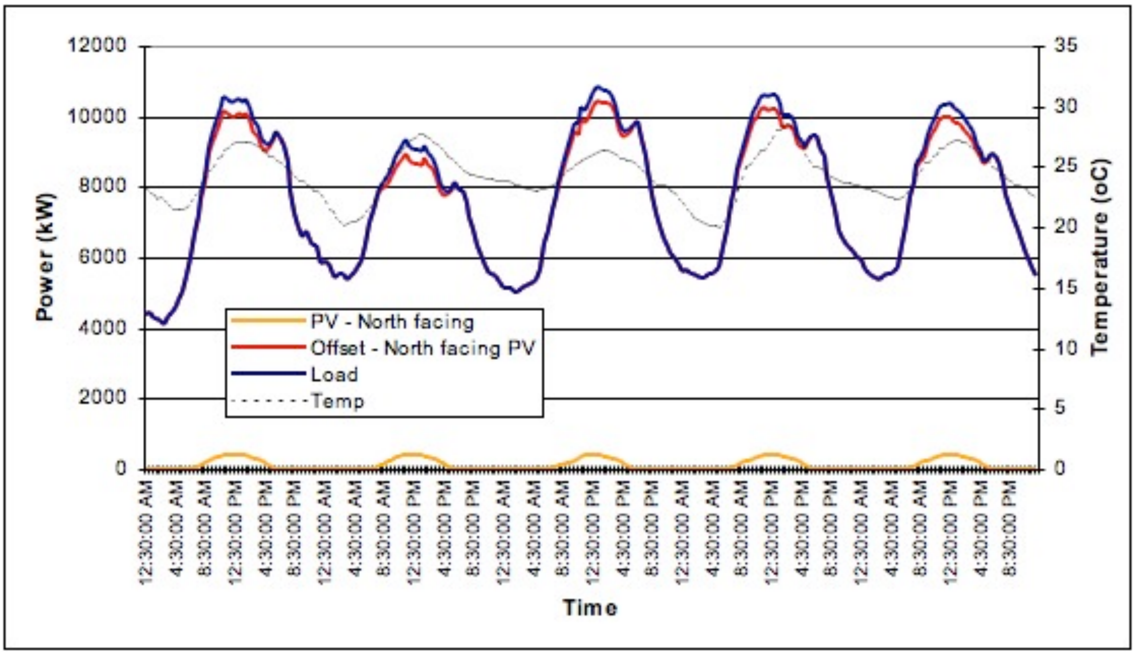

Figure 28: Autumn peak days
13th to 17th March 2006
Carnarvon Load, Carnarvon Simulated North-facing PV (500kW) and Net Load after PV Offset

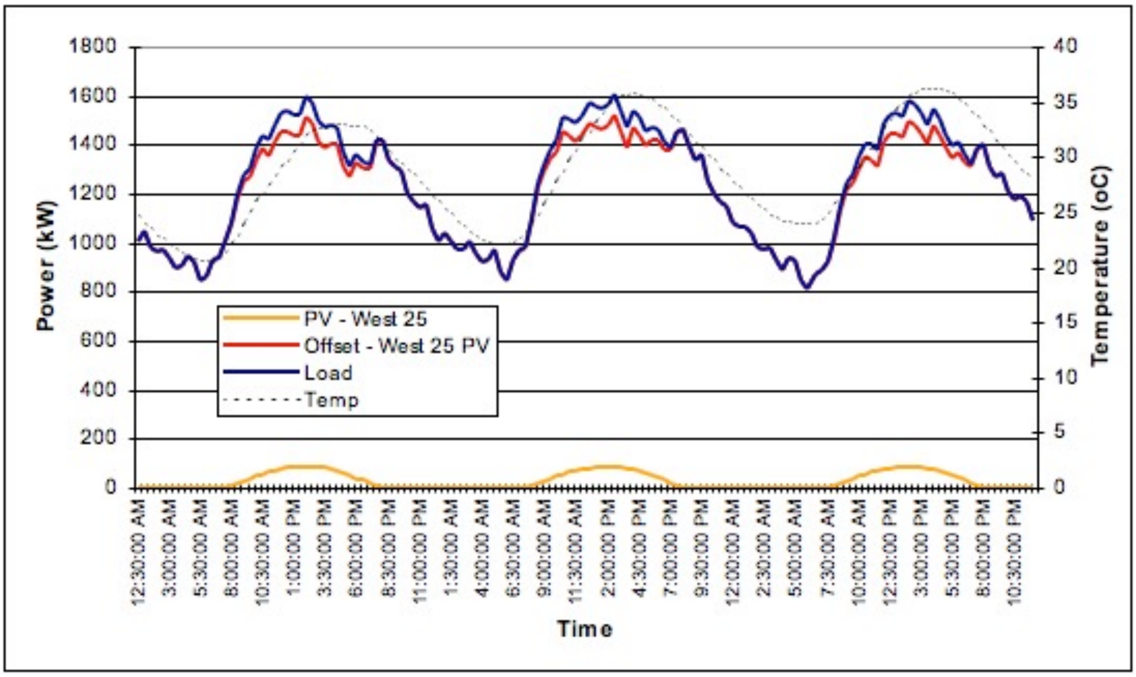

Figure 29: Spring peak days (west-facing-25 PV)
23rd-25th Nov 2005
Meekatharra Load, Meekatharra Simulated West-facing-25 PV (100kW) and Net Load after PV Offset

However, as occurred for both the SWIS and 'Edge of SWIS' locations, although in many cases simulated PV contributed between 60 and 85% of its rated capacity to peak load reduction, sometimes periods of slightly lower peaks were not as well matched to the simulated PV, and so became the highest peaks. This occurred in both Marble Bar (Figure 30) and Port Hedland AST (Figure 31) as discussed in Table 34. The percentage values in Table 34 are as defined for the SWIS and 'Edge of SWIS' analyses.

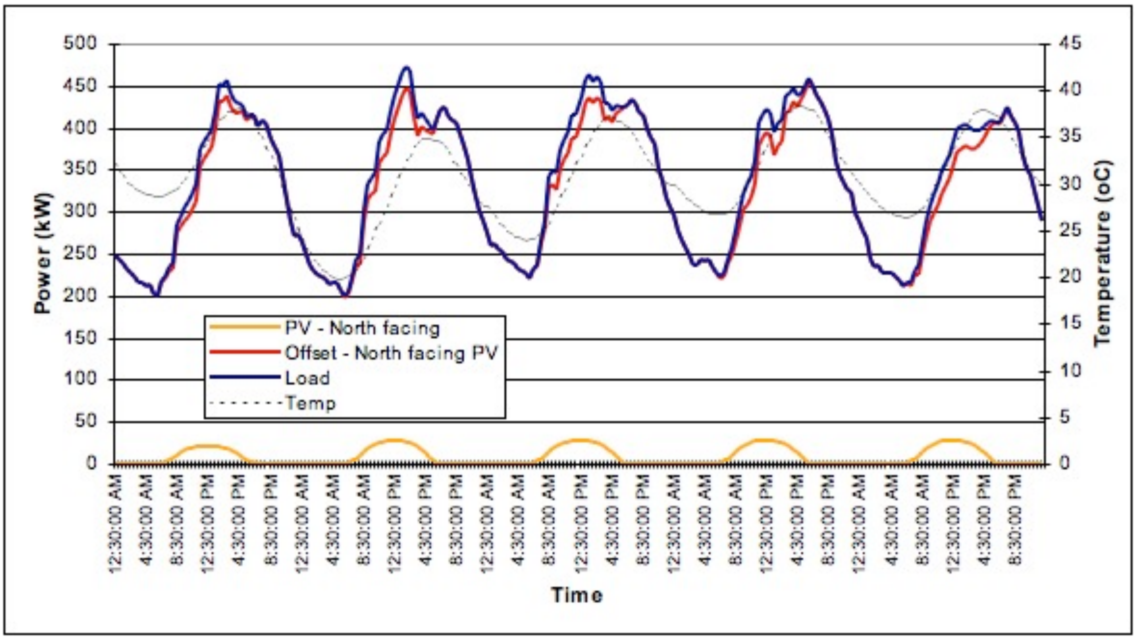

Figure 30: Summer peak days
6th – 10th Dec 2005
Marble Bar Load, Marble Bar Simulated North-facing PV (40kW) and Net Load after PV Offset

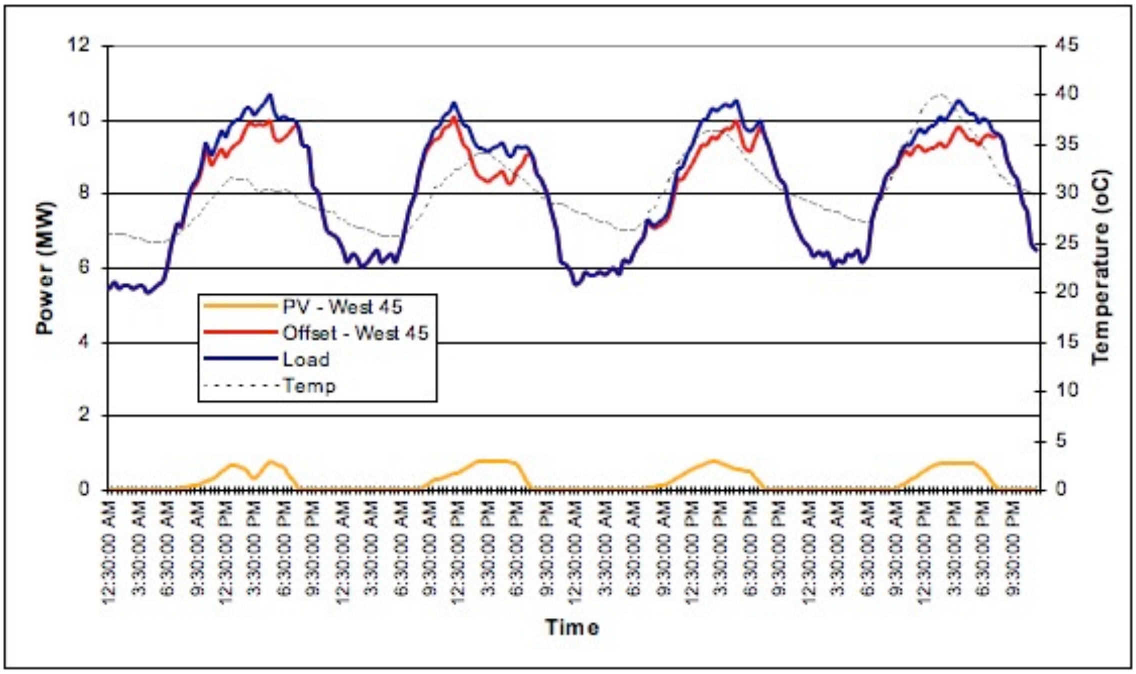

Figure 31: Summer peak days (west-facing-45 PV)
13th-16th Feb 2006
Port Hedland (AST) Load, Port Hedland (AST) Simulated West-facing-45 PV (1MW) and Net Load after PV Offset

Table 34: Summary of simulated PV's contribution in peak periods in regional locations

Location	A	B	C	D
Carnarvon	79%	73%	79%	73%
The ten highest half-hour demand periods occurred in March, on days which were not particularly hot and were a good match to simulated north-facing PV. The second and third (both in March) and fourth (in Feb) highest peak load day clusters assessed here were also not particularly hot and had a good match to simulated north-facing PV.				
Carnarvon – Carnarvon Solar Farm	75%	73%	75%	68%
The main differences to the simulated north-facing PV during the peak demand days assessed here are that the Carnarvon Solar Farm PV output was sometimes slightly lower but lasted about 1 hour later in the day.				
Marble Bar	76%	73%	35%	58%
The ten highest half-hour demand periods occurred in Nov, Dec and Jan. The highest peak load days (in Dec) were well matched to simulated north-facing PV, while the second highest peak load day (in Jan) was better matched to simulated west-facing PV. The third highest cluster of peak load days assessed here (in March), were relatively well matched to simulated north-facing PV.				
Meekatharra	85%	70%	85%	65%
The ten highest half-hour demand periods occurred in Nov, with the peaks occurring in the early afternoons, and were fairly well matched by simulated north-facing PV. The second highest cluster of peak load days (in Jan) peaked mid afternoon, and so are best matched to simulated west-facing PV. The third highest cluster of peak load days (in Jan) was best matched to simulated north-facing PV, while the fourth highest cluster (in March) was best matched to simulated west-facing PV.				
Port Hedland AST	74%	68%	25%	53%
The ten highest half-hour demand periods occurred in Feb and March and most occured in mid to late afternoon during periods of high to very high temperatures and so were best matched to simulated west-facing PV.				
Port Hedland MDR	60%	68%	60%	52%
The ten highest half-hour demand periods occurred on a single day in mid Jan and over three successive days in mid Feb. The highest peak load day (in Jan) involved a sudden increase of over 2MW between 1 and 2pm which was well matched to simulated north-facing PV. The second highest peak load day (in Feb) occurred in a cluster of days where the peaks tended to occur mid to late in the afternoon, and so were better matched to simulated west-facing PV. The third and fourth clusters of peak load days tended to peak mid to late in the afternoon, and were better matched to simulated west-facing PV.				
Port Hedland WFD	58%	62%	58%	60%
The ten highest half-hour demand periods occured in mid Feb 2006 except for two which occur at the end of Nov 2005. The highest peak load day (in Feb) occurred in a cluster of high temperature days and was reasonably well matched to simulated north-facing PV. The second, third and fourth highest clusters of peak load days assessed here were again high temperature days and peaked around midday and so were well matched to simulated north-facing PV.				

Reduction Of Cost Of Supply

Both Marble Bar and Meekatharra are supplied exclusively by diesel generators, and so PV output at any time of the day will reduce diesel use and possibly the cost of supply. In addition, from the above analysis it can be seen that the loads at Meekatharra and to a lesser extent Marble Bar during the study period (July 2005 to June 2006) were well matched to either simulated north or simulated west-facing PV. Thus, in both locations, PV should be able to offset diesel generation during most times of peak demand.

Carnarvon and Port Hedland are mostly supplied by gas-fired turbines and so the generation costs are much lower than at Marble Bar and Meekatharra. Thus, there are less opportunities for PV to reduce the cost of supply. Again, as can be seen from the above analysis, the demand in both these locations is reasonably well matched to either simulated north or simulated west-facing PV output.

For these four locations, the following analysis looks at the deployment of PV from the perspective of an end-user such as a home owner or business. For Marble Bar it also uses HOMER software to model Horizon Power installing their own, most probably larger, PV systems.

End-user small-scale PV systems

This section estimates the annual commercial value of simulated PV's contribution to offsetting conventional generation in the four regional locations. All calculations use the simulated PV output for the period July 2005 to June 2006. The cost of conventional generation for Horizon Power is: Carnarvon (13.39c/kWh), Marble Bar (39.11c/kWh), Meekatharra (35.5c/kWh), and Port Hedland (7.07c/kWh)[26]. Note that the conventional generation cost does not include Horizon Power's network costs as these would occur regardless of the PV generation. The discount rate is taken to be 12% because, as discussed later, this generation value accrues to the electricity retailer. Because the emphasis in this section is reduction of diesel use, the PV orientation is chosen to maximise electrical output, not necessarily to offset peak loads. As a result, for all locations, the PV orientation is north-facing with a tilt of 25 degrees. See Table 35.

Table 35 Value of electricity generated by 1MW simulated PV: Generation cost

Location	Generation cost[a]	Value in year 1	Discounted Value[b]	Disc Value per Watt	ROI [c]
Carnarvon	$0.1339	$190,974	$3,012,120	$3.00	1.15%
Carnarvon Solar Farm	$0.1339	$221,287	$3,489,800	$3.50	1.35%
Marble Bar	$0.3911	$548,626	$8,652,460	$8.65	3.35%
Meekatharra	$0.3550	$498,071	$7,853,810	$7.85	3.00%
Port Hedland	$0.0707	$102,663	$1,618,940	$1.60	0.65%

a: Generation cost for Horizon Power
b: Over 20yrs at a 12% discount rate
c: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

[26] Costs obtained from Horizon Power.

Horizon Power large-scale PV systems

Horizon Power may choose to install their own PV systems, since this would give them greater control over the installed capacity and how it is maintained, operated and integrated into their existing network. The following analysis focuses on the installation of large-scale PV systems in Marble Bar.

HOMER was used to assess PV's potential contribution to reduce diesel use and greenhouse emissions, as well as provide estimates of the resultant capital and operating costs. The same load and simulated PV data used for the *Reduction Of Peak Load* section (p74) were used as inputs for HOMER. The modeling parameters for Marble Bar are given in Table 37. All configurations resulted in less than 1kWh of unmet load for the year.

These are first-order assessments and so intended to be only indicative of possible options. Significantly more rigorous and detailed assessments should be performed before any investments are made. HOMER generates a large number of outputs and these are readily available on request.

MARBLE BAR

Marble Bar is located in the northen half of Western Australia, just south-east of Port Hedland. It is essentially a mining town (tin, manganese and some gold) with a population around 350. There are currently 86 residential and 32 commercial electricity customers served by Horizon Power. Its electricity is currently supplied by five diesel generators with a summer peak capacity of 955kW and a winter peak capacity of 1,130kW (WP, 2006e). These generators are near the end of their operating life, and Energy Generation has been selected to replace them, most likely with three new Detroit 60 series 320kWe generators, or equivalent.[27]

For the HOMER modelling it was assumed that three new Detroit 60 series 320kWe generators were installed but were limited to running at a maximum of 80% capacity (which is standard practice for Horizon Power). The full cost of the new generators is included in the following analysis. Both a 40kWp and a 100kWp PV system were modeled and the resultant capital cost, net present cost, cost/kWh of electricity generated, diesel use and CO_2 emissions are given in Table 36. Note that these values are for the system as a whole, including the generators, diesel etc.

According to the HOMER modeling, only two generators would be required to meet the load, although note that this modeling assumed no load growth. Because of the n-1 planning criterion (the system has to be able to meet demand even if the largest component fails), and to accommodate load growth, here it was assumed that three generators would be used. The calculated per kWh cost for diesel generators without PV is slightly higher (43.1c/kWh) than the cost of 39.11/kWh provided by Horizon Power. Use of the 40kW PV system resulted in a slightly higher per kWh cost than diesel alone (43.3c/kWh), and the 100kW system increased costs a little more (43.5c/kWh). Hence the electricity price increase resulting from the addition of 100 kW of PV to the Marble Bar power station would be less than 0.5c/kWh, but the diesel savings (~50,000 litres/yr) and the CO_2 reduction (~135,000 t CO_2/yr) would be significant.

[27] Personal communication from Horizon Power

The impacts of higher diesel prices and a price on CO_2 emissions are shown in Figure 32 and Figure 33. The default values are taken to be zero for CO_2 and 96.73c/L for diesel.[28] According to this modelling, once diesel passes about $1.20/L, the electricity generation cost with 100kW PV installed is less than for diesel alone. The CO_2 cost need to be greater than $60/tonne for the diesel/PV system to be cheaper.

The impact of different capital costs for the PV and inverters is shown in Figure 34. These are chosen to reflect reduced contributions from the RRPGP, which could offset any reduced costs of PV due to technology improvements in the future. It is clear that the RRPGP has a significant impact on the final electricity price. Its removal would require diesel to be about $2.20/L for the diesel/PV (100kW) system to produce electricity at the same cost as the diesel-only system (ie. 90.1c/kWh).

Because of different loads and insolation levels in each month, the PV contribution differed throughout the year – see Figure 35, Figure 36 and Figure 37 which show the relative power contribution by each of the generators and by PV at the different levels of PV penetration.

These modelling results indicate that according to the parameters in Table 37, installation of large-scale PV reduces diesel use and greenhouse emissions but slightly increases the cost of electricity generation in Marble Bar. If the cost of CO_2 increases above $60/tonne CO_2 or diesel costs increase to greater than about $1.20/L, installing large-scale PV may reduce the costs of generation.

Thus, even after incorporating the benefits of PV (reduced diesel use), the existing market mechanisms do not favour large-scale installation of PV in locations such as Marble Bar. The most likely driver for PV in the future is higher diesel prices, however even this requires significant support from programs such as the RRPGP.

Table 36 Costs[29] for 40kW and 100kW PV – Marble Bar

	0kW PV	40kW PV	100kW PV
Capital cost ($)	1,050,000	1,267,000	1,592,000
Net Present Cost ($)	8,119,130	8,145,568	8,194,658
Cost (c/kWh)	43.1	43.3	43.5
Diesel use (L/yr)	712,179	691,922	662,240
CO_2 emissions (kg/yr)	1,921,361	1,866,710	1,786,632

[28] These are the prices currently paid by Horizon Power.

[29] Is the cost of the entire system including three 320kWp diesel generators.

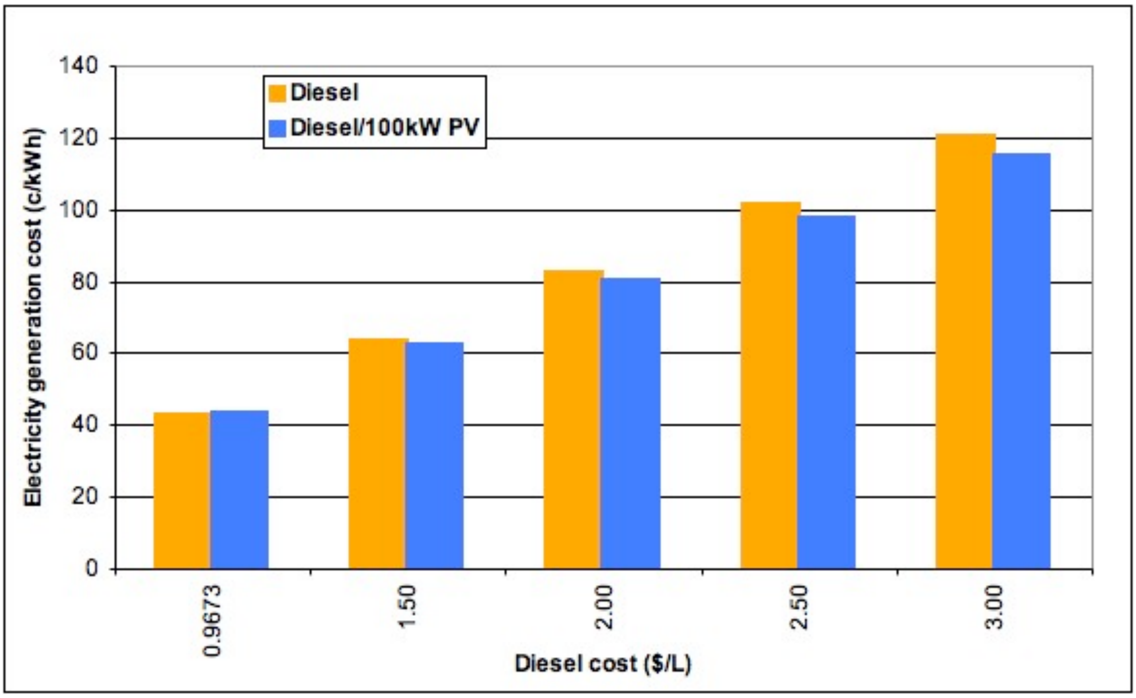

Figure 32 Influence of diesel price on per kWh cost

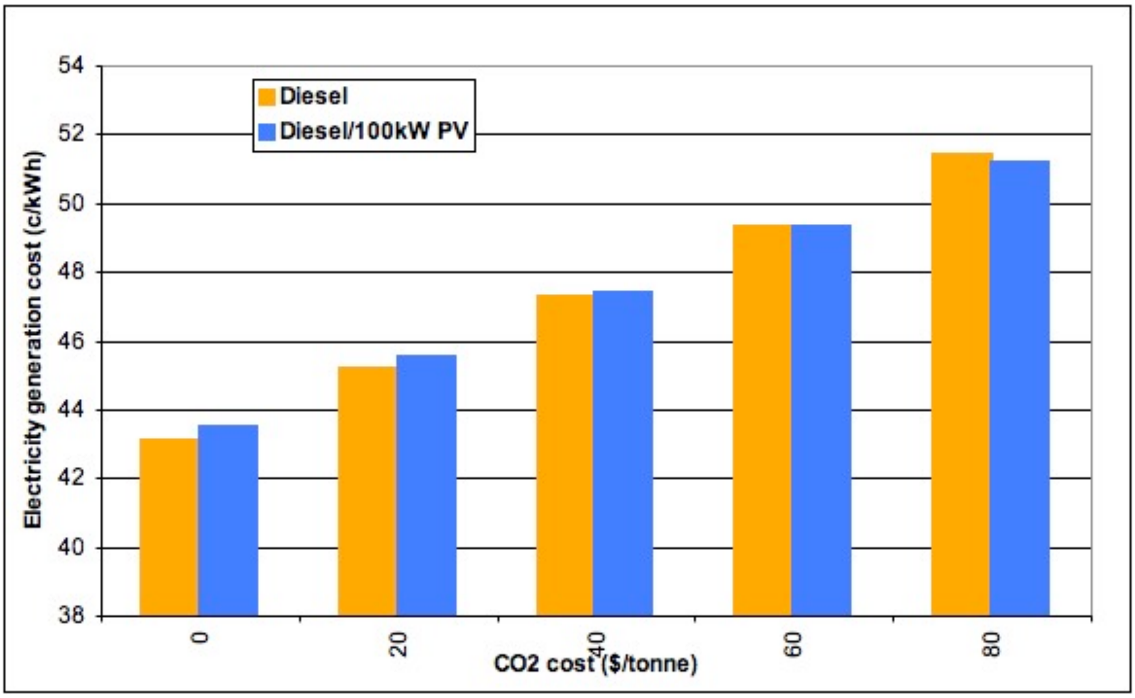

Figure 33 Influence of CO_2 price on per kWh cost

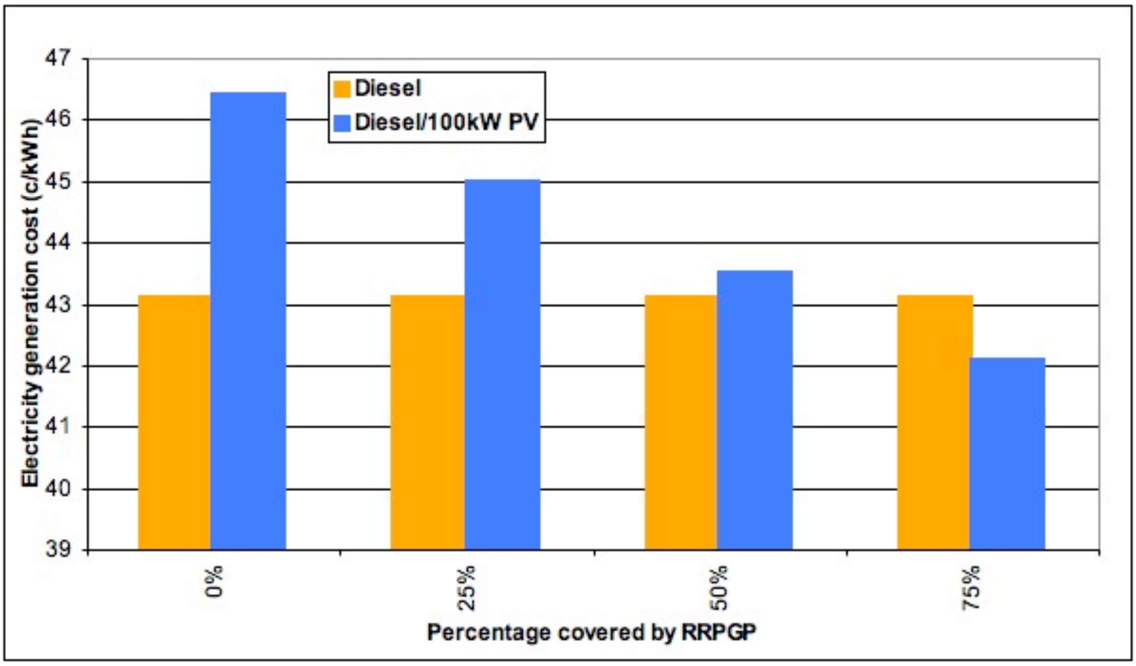

Figure 34 Influence of RRPGP on per kWh cost

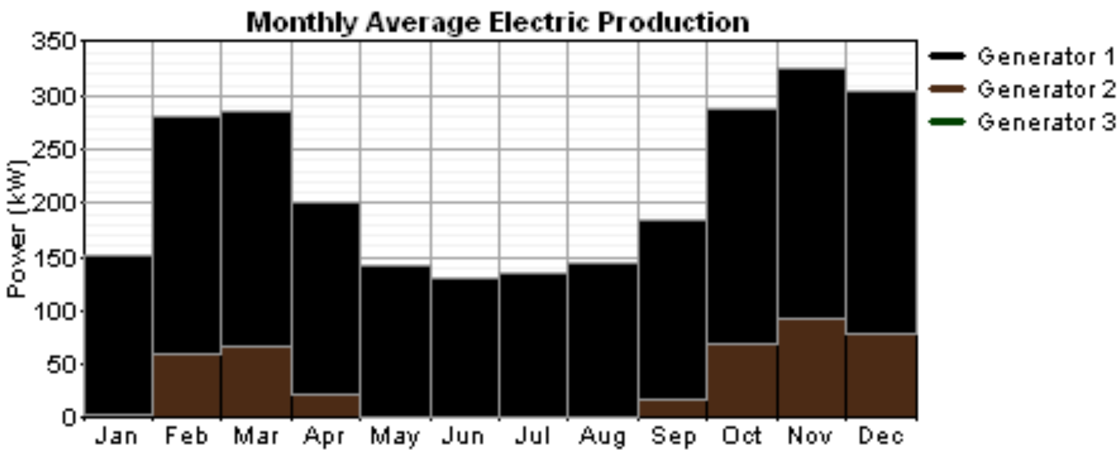

Figure 35 Monthly use of Generators – no PV

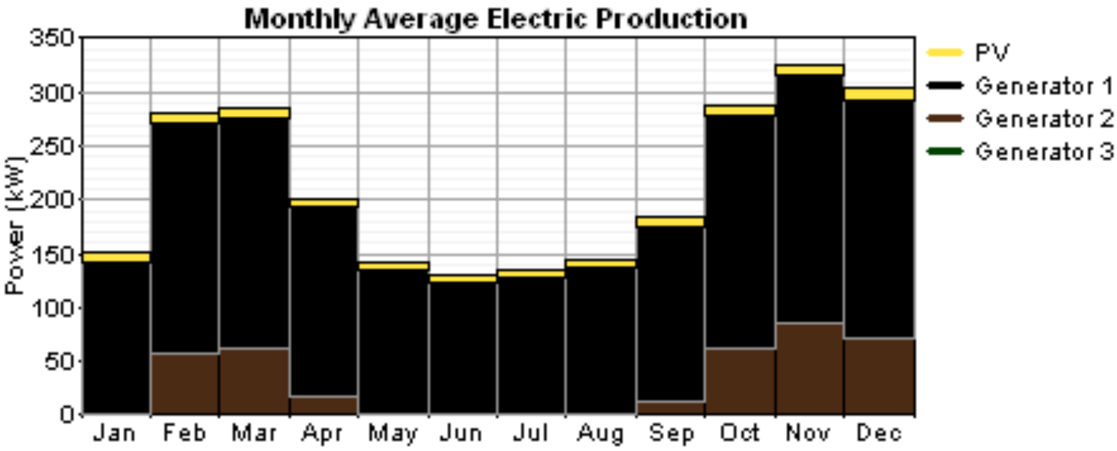

Figure 36 Monthly use of Generators – 40kW PV

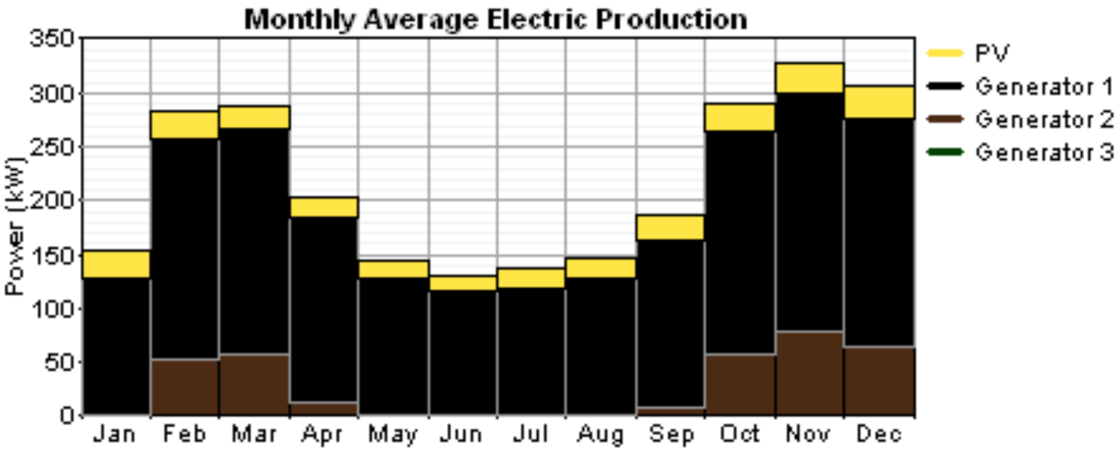

Figure 37 Monthly use of Generators – 100kW PV

Table 37 HOMER parameters for Marble Bar

Component	Marble Bar
Diesel generator [a]	320kWe
Capital cost	$350,000
Operation and maintenance costs	$2.33/hr
Operating lifetime	20 yrs
Minimum load ratio	30%
Diesel characteristics [a]	
Lower Heating value	42.2 MJ/kg
Density	840 kg/m3
Carbon Content	88%
Sulphur Content	0.05%
Inverter	40kW or 100kW
Capital cost [b]	$17,000 or $42,000
Operation and maintenance costs	$300/yr or $850/yr
Efficiency	90%

Lifetime	20 yrs
PV system	40kW or 100kW
Capital cost [b]	$200,000 or $500,000
Operation and maintenance costs	$1,000/yr or $2,500/yr
Lifetime	20 yrs
Derating factor [c]	80%
Ground reflectance	20%
Positioning	North-facing 25^{o} tilt
Reserve margins	
Operating reserve [d]	10% above hourly load
Solar reserve [e]	25%
Financial assumptions	
Interest/discount rate	7.67%
Project lifetime	20 years

a: Characteristics of diesel generaters and fuel provided by Horizon Power
b: Assumes 50% of capital cost met by RRPGP
c: HOMER does not currently include temperature derating. The 80% value used here is an average derating.
d: Total generation capacity must be 10% above load in any 1 hour interval
e: The system must be able to cope with an instantaneous 25% drop in PV output

3.2 Analysis of existing opportunities for PV

The following is divided into two sections;

Section 3.2.1 firstly summarises the electricity system benefits provided by PV that were identified in Section 3.1, then identifies who receives these benefits and estimates their value. It appears likely that these benefits flow to retailers, who also provide the only market mechanism currently available to support PV (the Renewable Energy Buyback Scheme (REBS))[30], so this section then discusses the costs and benefits of PV for retailers.

Section 3.2.2 brings together the REBS with the more general programs (PVRP, RRPGP and MRET) to give the total value of the opportunities currently available to PV in WA.

Section 3.3 discusses strategies to reward PV for the electricity system benefits identified here that are currently not recognised in the market.

Section 3.4 estimates the total value of the opportunities to PV if these strategies are implemented and combined with the existing support programs. It also discusses the potential impact of proposed support strategies.

Section 4 draws together the report's findings and discusses additional support strategies.

PV operates within within two distinct markets in WA; customers connected to the SWIS and those serviced by Horizon. For systems connected to the SWIS, the electricity market is defined in the context of the Reserve Capacity Mechanism, the STEM, network access, the regulatory test and the balancing process. Their relevance to PV is discussed in Appendix 6.8. Appendix 6.9 summarises the current programs and policies that may drive deployment of PV in WA (eg. REBS, PVRP, RRPGP and MRET), and Appendix 6.10 outlines various barriers to PV deployment in WA.

3.2.1 SYSTEM BENEFITS PROVIDED BY PV

As discussed in the previous section, the electricity system benefits provided by PV that have a market value that is significant compared to the installed cost of PV are: offsetting conventional generation during daylight hours as well as providing firm capacity during times of peaking generation in the SWIS and 'EdgeEdge of SWIS', and offsetting very high-cost conventional generation in regional areas. Additional benefits provided by PV that have low values compared to its installed cost are; deferring network augmentation and reducing line losses. While PV/inverters are unlikely to make power quality worse, they are also unlikely to improve it to any financially significant degree, and cheaper and more effective options are available. The average benefits provided by PV in the SWIS and 'Edge of SWIS' are summarised in Table 38. Note that although the total value provided by PV per W is very similar for north and west-facing PV, the value per kWh is greater for west-facing PV because of lower

[30] The PVRP, RRPGP and REC payments available to PV systems are here classed not as market mechanisms but as programs, and so are included in Section 3.2.2.

electricity output compared to north-facing PV. This has relevance to retailers since the REBS is paid on a per kWh basis. If all these benefits were fully recognised by existing market mechanisms, their discounted value per W would be insufficient to cover the installed cost of unsubsidised PV. The per kWh value is similar to the REBS values paid by retailers – this is discussed further in *Costs and benefits for SWIS electricity retailers* on page 88.

Note that all the following values are indicative averages only. They will vary from system to system and will be influenced by a number of factors including orientation, location, temperature, shading and maintenance of the panels and balance of system equipment.

Offsetting conventional generation in SWIS and 'Edge of SWIS

The benefits of PV offsetting conventional generation accrue to the retailer. The market value provided by PV in this way, according to the discounted values in Table 15 and Table 21 ranged from 95c/W to $1.30/W over 20 years depending on the location and orientation - with an average value of around $1.20/W for both north-facing and west-facing PV. These are equivalent to the cost of conventional generation of about 7.85c/kWh and 8.55c/kWh for north-facing and west-facing PV respectively. West-facing PV has a higher per kWh value because output coincides with higher spot prices in the SWIS. Despite this, its per W value is that same as for north-facing because the latter has a higher kWh output.

Providing firm capacity in SWIS and 'Edge of SWIS'

Assuming that a PV system is not earning Reserve Capacity Credits (at the time of writing no PV systems were registered to create RCCs), the benefits of PV providing firm capacity currently accrue to retailers because they have reduced IRCR costs. The IRCR value so generated, according to the discounted values in Table 18 and Table 30, ranged from 31c/W to 85c/W over 20 years depending on the location and orientation – with an average value of around 55c/W for north-facing and around 75c/W for west-facing PV. This is equivalent to an average value of around 3.5c/kWh (north-facing) and around 5.1c/kWh (west-facing).

Offsetting high-cost baseload generation in regional areas

Although residential system owners in regional areas are paid the REBS rate for electricity generation, the generation they are offsetting is sometimes far more costly than the REBS rate. In these circumstances the benefits of PV generation accrue to smaller electricity customers in the SWIS because the amount to be covered by the Tariff Equalisation Fund is reduced. The market value provided by PV in this way, according to the discounted values in Table 51, ranged from $1.60/W to $8.65/W in total over 20 years depending on the location. These are equivalent to around 7.1c/kWh and around 39c/kWh respectively.

Deferring network augmentation

The benefits of PV deferring network augmentation accrue initially to the network operator. In a well functioning market, these benefits would be passed on to the retailer through reduced network charges. The market value provided by PV in this way, according to the analysis on page 54, was about 12c/W depending on the location and orientation – which is equivalent to an average value of around 0.8c/kWh.

Avoiding line losses

The benefits of PV-avoided line losses in the network result in savings for the retailer because their electricity purchase price (from the PV system embedded in the distribution network) does not incorporate the TLF and DLF.[31] The market value provided by PV in this way, according to Table 33, ranged from 19c/W to 28c/W in total over 20 years depending on the location and orientation – with an average value of around 22c/W for north-facing and around 21c/W for west-facing PV. This is equivalent to an average value of around 1.4c/kWh for north-facing and 1.6c/kWh for west-facing PV.[32]

Table 38 Summary of approximate benefits provided by PV in the SWIS and Edge of SWIS

Benefit	**Approximate average value /W** [a]		**Approximate average value /kWh**		**Who benefits**
	North	West	North	West	
Offsetting convent. gen.	$1.20	$1.20	7.8c	8.6c	Retailer
Providing firm capacity [b]	$0.55	$0.75	3.5c	5.1c	Retailer
Deferring network aug [c]	$0.12	$0.12	0.8c	0.8c	Retailer [d]
Reducing line losses	$0.22	$0.21	1.4c	1.6c	Retailer
Total	$2.09	$2.28	13.5c	16.1c	

Note that these values are indicative averages only. The actual values will vary from system to system and will be influenced by a number of factors including orientation, location, temperature, shading and maintenance of the panels and balance of system equipment.

a: Over 20yrs at a 12% discount rate. A 6% discount rate increases the totals to $3.34 and $3.64 for north and west-facing PV respecively

b: The ratio of the /W to the /kWh values will not be the same for the conventional generation and firm capacity values because the /W conventional generation values are proportional to electrical output whereas the /W firm capacity values are proportional to the reduction of IRCR.

c: The north-facing and west-facing values are identical because both north-facing and west-facing PV are assumed to provide 50% of their rated capacity to meeting peak network loads.

d: Assuming full pass through of savings to the retailer

[31] Transmission Loss Factor and Distribution Loss Factor

[32] Note that the actual losses avoided will vary greatly depending on the location of the PV system on the distribution network, and well as the correlation between its output and the loads on the transmission and distribution networks.

Costs and benefits for SWIS electricity retailers

The per kWh values given in Table 38 can be compared to the REBS tariffs provided by the retailer. For the Residential A1 tariff the cost of providing it is the flat retail rate of 13.94c/kWh.[33] For the SmartPower tariff and the R3 Business ToU tariff[34], the average cost must be calculated using half hour data because the tariffs change over time. According to the data that was used to calculate the values in Table 38, the amounts paid by the retailer for the electricity produced by simulated PV in the SWIS and Edge of SWIS locations would have been about 14.90c/kWh for north-facing PV and 15.20c/kWh for west-facing PV under the SmartPower tariff, and about 16.70c/kWh for both north-facing and west-facing PV under the R3 Business ToU tariff. As stated earlier, the impact of GST not being included in the REBS has been ignored here because that only applies to exports and the amount exported can vary greatly from system to system. A rough rule of thumb could be to assume that 30% of PV generated power is exported, meaning that the above REBS values could be reduced by about 2.7%.

Retailers in WA also incur costs for MRET and the TEF. For MRET, the costs are determined by the retailer's purchases at the wholesale acquisition point plus any electricity exported into the network of the retailer's service area by embedded generators. All electricity generated by PV, whether exported or used on site, reduces the amount purchased at the wholesale acquisition point. Therefore, the PV electricity that is exported makes no difference to a retailer's liability (it would be slightly reduced because of reduced losses) while that which is used on site reduces the retailer's liability. Because the MRET liability is fixed for each year, reducing the liability of the retailer with PV connected would increase the liabilities of other retailers. A retailer's TEF liability is assigned through network charges, and although the electricity produced by a PV system does not directly incur transmission and distribution costs for the retailer, it reduces the amount of electricity to which these costs are applied and so increases the per unit costs. Thus PV is likely to have little if any affect on a retailer's TEF liability. Currently the MRET and TEF are less than a few percent of the retail price and so are not considered significant here.

It can be seen that the approximate average value provided by PV to retailers (Table 38) is very similar to the estimated cost of the REBS to retailers. Although the retail prices for residential customers are fixed until 2009/10, the R3, T1 and S1 tariffs have recently been increased. Whether the tariff increases take into consideration the REBS paid to PV systems is a matter of government policy. The per kWh cost to Horizon Power of providing the REBS in regional areas is equal to their A2 Residential tariff (13.94c/kWh). The value to Horizon Power of the electricity generated varies greatly between regions – as shown by the costs of generation in Table 51. In areas serviced by gas-fired generation the generation cost is less than the REBS rate, whereas in areas serviced by diesel generators the generation cost may be far more than the REBS rate. This issue is discussed further in Section 3.3 where a FiT for regional areas is proposed.

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[33] Synergy measure import from the grid and export to the grid separately and although they apply the same tariff to both, they don't include the GST component to the export tariff which is therefore 10/11ths of the import tariff. Here this has been ignored because on average most of the electricity generated by the PV system would be used on-site and so would in effect earn the import tariff that includes the GST component. The average effective tariff earned would be somewhere between the import tariff and the import tariff minus GST.

[34] Currently not eligible for REBS but included here for comparitive purposes.

3.2.2 *CURRENT COMBINED VALUE OF MARKET MECHANISMS AND GENERAL PROGRAMS*

The following estimates the commercial value currently available to PV in WA through the identified market mechanisms combined with the more general subsidy programs such as the PVRP and RRPGP. In short, all residential systems can benefit from the REBS and from RECs, while those connected to the SWIS also benefit from the PVRP, whereas systems in regional areas also benefit from the RRPGP. The value available to PV through the REBS in the SWIS, 'Edge of SWIS' and regional areas over 20 years is estimated below, then combined with the RECs and the PVRP or RRPGP values to give the total available to PV. Although systems owned by businesses are not eligible for the REBS, they are included in this section so their values can be compared to those obtained for residential systems. Similarly, although FiTs based on the costs of conventional generation are not available in regional areas, they are included for for comparison to the REBS currently available.

Section 3.3 then suggests how market mechanisms may be modified to create additional value for PV. Section 3.4 then assesses the impact of the modified market mechanisms on the financial viability of PV systems.

Value currently available to PV for electricity generation

Assuming the PV system is owned by an end-user, the commercial value of electricity produced would depend on their electricity use tariff structure, their PV generation tariff structure and whether this was applied to total generation or only to net export. Alternatively, it is possible that a retailer purchasing the electricity may prefer to treat the PV system purely as a generator and so pay closer to wholesale rates in the SWIS, for example 6c/kWh.[35] The following compares the impact of net metering using three different tariff structures and the use of a 6c/kWh value placed on PV generation.[36]

If the PV system is sized so that the PV output is always less than an end-user's demand, they will not export to the grid, just reduce demand, and so net metering may apply.[37] Where net metering is in place, the electricity generated by PV reduces electricity use and so in effect earns the tariff paid for electricity use. Of the tariffs currently available in Western Australia, Time-of-Use (ToU) tariffs are expected to provide the best financial return for PV because they are generally higher when PV output is higher.

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[35] Feedback from industry participants indicated that 6c/kWh was the consensus estimate for the conventional generation cost in the SWIS.

[36] Note that only the A1 Residential tariff and the SmartPower tariff are currently eligible for the REBS and businesses can negotiate with their retailer regarding payment for electricity generated onsite.

[37] It is also possible that a system may occasionally result in export for a short time, even when the system owner is a net user of electricity over a billing period. Synergy measure import from the grid and export to the grid separately and although they apply the same tariff to both, they don't include the GST component to the export tariff which is therefore 10/11[ths] of the import tariff. Here this has been ignored because on average most of the electricity generated by the PV system would be used on-site and so would in effect earn the import tariff that includes the GST component. The average effective tariff earned would be somewhere between the import tariff and the import tariff minus GST.

SWIS

Table 39 gives the estimated commercial value of electricity generated by simulated PV for the Perth locations[38] assuming the PV is installed by a home owner on Synergy's residential A1 tariff of 13.94c/kWh. Alternatively a residential system may also be on Synergy's SmartPower ToU tariff (see Figure 38) in which case the commercial value of electricity generated is given in Table 40. For residential systems a discount rate of only 6% is used. All calculations are for the period July 2003 to June 2004.

Table 42 gives the estimated commercial value of electricity generated by simulated PV for each of the Perth locations assuming that a business is on Synergy's R3 Business ToU tariff (effectively 20.86c/kWh peak and 6.44c/kWh off peak, Table 41), and a 12% discount rate is used. Table 43 gives the estimated commercial value of electricity generated by simulated PV for each of the Perth locations assuming a flat buy-back tariff of 6c/kWh.[39] In this case, where the PV system owner is being treated as a generator, a discount rate of 12% is used.

In terms of the commercial value of electricity produced in a single year, the Residential SmartPower tariff provided the highest return, followed by the R3 Business tariff then the Residential A1 tariff then the 6c/kWh tariff. However, when the different discount rates are taken into account, the R3 Business tariff dropped below the Residential A1 tariff. In all cases, north-facing PV provided the highest return.

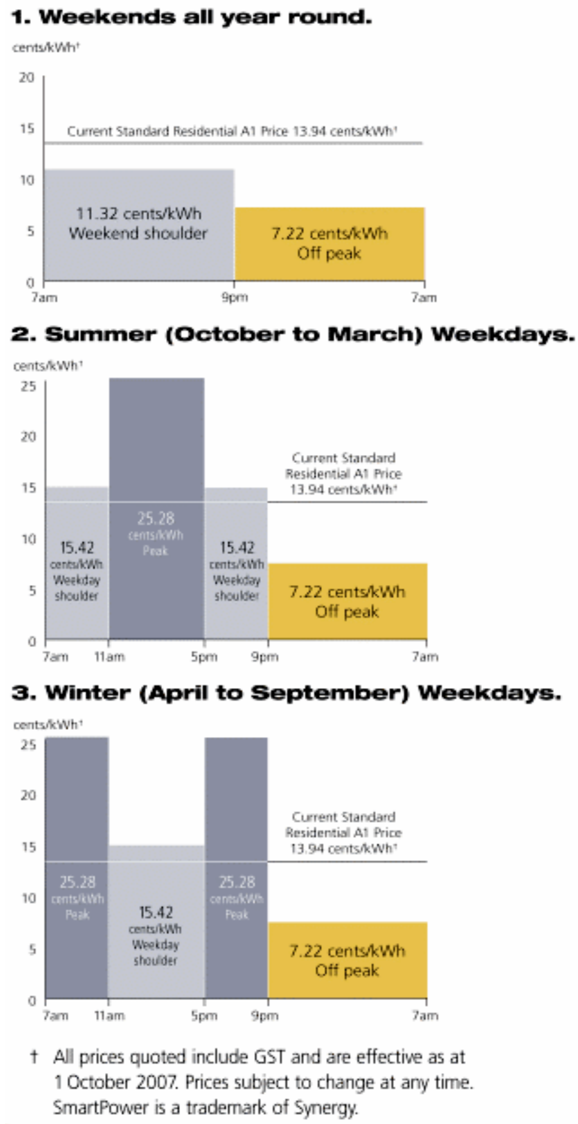

Figure 38 Synergy's Residential SmartPower Tariff Structure[40]

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[38] All the Perth locations used the same simulated PV. The values for both north-facing and west-facing PV are given.

[39] Feedback from industry participants indicated that 6c/kWh was the consensus estimate for the conventional generation cost in the SWIS.

[40] From Synergy's website http://www.synergyenergy.com.au/Residential_Segment/SmartPower/SmartPower.html

Table 39 Commercial value of electricity generated by 1MW simulated PV: Residential A1 Tariff (13.94c/kWh)

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Perth	North-25	$240,958	$3,799,990	$3.80	1.45%
Perth	West-25	$232,253	$3,663,450	$3.65	1.40%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 40 Commercial value of electricity generated by 1MW simulated PV: SmartPower Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Perth	North-25	$308,256	$4,861,580	$4.85	1.87%
Perth	West-25	$298,139	$4,702,120	$4.70	1.81%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 41 Synergy's R3 Business Tariff Structure

Period	Day	Time (Western Standard Time)	Time (Western Summer Time)
Peak (20.85c/kWh)	Mon - Fri	8:00am-10:00pm	9:00am-11:00pm
Off peak (6.43c/kWh)	Mon - Fri	After 10:00pm and before 8:00am	After 11:00pm and before 9:00am
	Sat - Sun	Anytime	Anytime

Table 42 Commercial value of electricity generated by 1MW simulated PV: R3 Business Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Perth	North-25	$277,753	$2,913,200	$2.90	1.12%
Perth	West-25	$273,389	$2,867,428	$2.85	1.10%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 43 Commercial value of electricity generated by 1MW simulated PV: 6c/kWh Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Perth	North-25	$99,965	$985,950	$1.00	0.40%
Perth	West-25	$99,850	$984,740	$1.00	0.40%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The ROI = (discounted total returns / years invested) / initial investment.

Edge of SWIS

Table 44 gives the estimated value of electricity generated by simulated PV for each of the Edge of SWIS locations assuming the PV is installed by a home owner on Synergy's residential A1 tariff of 13.94c/kWh. A residential system may also be on Synergy's SmartPower ToU tariff (see Figure 38 above) in which case the commercial value of electricity generated is given in Table 45. For residential systems a discount rate of 6% is used. The PV orientation has been chosen to maximise the commercial value of electricity generated. All calculations are for July 2003 to June 2004.

Table 46 gives the estimated commercial value of electricity generated by simulated PV for each of the Perth locations assuming that a business is on Synergy's R3 Business ToU tariff (effectively 20.85c/kWh peak and 6.43c/kWh off peak, Table 41), and a 12% discount rate is used. Table 47 gives the estimated commercial value of electricity generated by simulated PV for each of the Edge of SWIS locations assuming a flat tariff of 6c/kWh.[41] Again, where the PV system owner is being treated as a generator, a discount rate of 12% is used. Again, although the Kalbarri PV system would not be eligible to earn Synergy's R3 Business tariff and residential A1 tariff, these commercial values are calculated for comparison to the simulated PV at Geradlton.

As for the SWIS locations, the Residential SmartPower tariff gives the highest estimated return for a single year, followed by the R3 Business tariff then the Residential A1 tariff then the 6c/kWh tariff. Again, when the different discount rates are taken into account, the R3 Business tariff drops below the Residential A1 tariff. In all cases, north-facing PV provided the highest return.

Table 44 Value of electricity generated by 1MW simulated PV: Residential A1 Tariff (13.94c/kWh)

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Geraldton TX1	North-25	$238,130	$3,755,610	$3.75	1.44%
Geraldton TX1	Kalbarri PV	$232,625	$3,668,670	$3.65	1.41%
Katanning TX2	North-25	$235,821	$3,719,197	$3.70	1.43%
Merredin TX1	North-25	$235,103	$3,707,867	$3.70	1.43%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The ROI = (discounted total returns / years invested) / initial investment.

Table 45 Value of electricity generated by 1MW simulated PV: SmartPower Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Geraldton TX1	North-25	$305,510	$4,818,280	$4.80	1.85%
Geraldton TX1	Kalbarri PV	$299,286	$4,720,114	$4.70	1.82%
Katanning TX2	North-25	$301,195	$4,753,376	$4.75	1.83%
Merredin TX1	North-25	$296,561	$4,677,143	$4.70	1.80%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The ROI = (discounted total returns / years invested) / initial investment.

[41] Feedback from industry participants indicated that 6c/kWh was the consensus estimate for the conventional generation cost in the SWIS.

Table 46 Value of electricity generated by 1MW simulated PV: R3 Business Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Geraldton TX1	North-25	\$279,454	\$2,931,036	\$2.95	1.13%
Geraldton TX1	Kalbarri PV	\$267,785	\$2,808,644	\$2.80	1.08%
Katanning TX2	North-25	\$270,925	\$2,841,582	\$2.85	1.09%
Merredin TX1	North-25	\$258,456	\$2,710,803	\$2.70	1.04%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The ROI = (discounted total returns / years invested) / initial investment.

Table 47 Value of electricity generated by 1MW simulated PV: 6c/kWh Generation Tariff

Location	PV Orientation	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Geraldton TX1	North-25	\$102,495	\$1,010,850	\$1.00	0.39%
Geraldton TX1	Kalbarri PV	\$100,126	\$987,483	\$1.00	0.38%
Katanning TX2	North-25	\$101,501	\$1,001,050	\$1.00	0.39%
Merredin TX1	North-25	\$101,192	\$998,001	\$1.00	0.38%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The ROI = (discounted total returns / years invested) / initial investment.

Regional

Table 48 gives the estimated value of electricity generated by simulated PV for each of the regional locations, and according to the output of the Carnarvon Solar farm, assuming the PV is installed by a home owner on Horizon Power's A2 Residential tariff of 13.94c/kWh. Table 49 provides the same information for businesses on the L2 Business tariff (17.47c/kWh),[42] and Table 50 and Table 51 provide the same information assuming the system owner is paid a flat tariff of 6c/kWh.[43] For residential systems the discount rate is taken to be 6% and for commercial systems the discount rate is taken to be 12%. Because the emphasis in this section is reduction of diesel use, the PV orientation is chosen to maximise electrical output, not necessarily to offset peak loads. As a result, for all locations, the PV orientation is north-facing with a tilt of 25 degrees. All calculations are for the period July 2005 to June 2006.[44]

The L2 Business tariff gives the highest estimated return for a single year, followed by the A2 Residential tariff then the 6c/kWh tariff. Although the Business tariff provides a higher return than the residential tariff on a yearly basis, it's discounted value is lower because of the higher discount rate.

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[42] Both these are flat tariffs as Horizon Power does not have a Time of Use tariff. The L2 Business tariff decreases to 15.76c/kWh if more than 1650 units per day are used. We have assumed this is not the case.

[43] Feedback from industry participants indicated that 6c/kWh was the consensus estimate for the conventional generation cost in the SWIS.

[44] Note that the conventional generation cost does not include Horizon Power's network costs as these would occur regardless of the PV generation.

Table 48 Value of electricity generated by 1MW simulated PV: A2 Residential Tariff (13.94c/kWh)

Location	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Carnarvon	$249,165	$3,929,920	$3.95	1.50%
Carnarvon Solar Farm	$288,714	$4,553,160	$4.55	1.75%
Marble Bar	$245,065	$3,864,960	$3.85	1.50%
Meekatharra	$245,107	$3,864,960	$3.85	1.50%
Port Hedland	$253,681	$4,000,400	$4.00	1.55%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 49 Value of electricity generated by 1MW simulated PV: L2 Business Tariff (17.47c/kWh)

Location	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [b]
Carnarvon	$312,261	$3,079,850	$3.10	1.20%
Carnarvon Solar Farm	$361,824	$3,567,650	$3.55	1.40%
Marble Bar	$307,123	$3,029,200	$3.05	1.15%
Meekatharra	$307,175	$3,029,200	$3.05	1.15%
Port Hedland	$317,920	$3,136,010	$3.15	1.20%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 50 Value of electricity generated by 1MW simulated PV: 6c/kWh Generation Tariff 6% discount rate

Location	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [c]
Carnarvon	$107,289	$1,692,089	$1.70	0.65%
Carnarvon Solar Farm	$124,216	$1,959,047	$1.95	0.75%
Marble Bar	$105,558	$1,664,781	$1.65	0.64%
Meekatharra	$105,499	$1,663,858	$1.65	0.64%
Port Hedland	$109,369	$1,724,881	$1.70	0.66%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Table 51 Value of electricity generated by 1MW simulated PV: 6c/kWh Generation Tariff 12% discount rate

Location	Value in year 1	Discounted Value[a]	Disc Value per Watt	ROI [c]
Carnarvon	$107,289	$1,058,135	$1.05	0.41%
Carnarvon Solar Farm	$124,216	$1,225,076	$1.25	0.47%
Marble Bar	$105,558	$1,041,058	$1.05	0.40%
Meekatharra	$105,499	$1,040,481	$1.05	0.40%
Port Hedland	$109,369	$1,078,642	$1.10	0.41%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2
b: The Return on Investment (ROI) = (discounted total returns / years invested) / initial investment.

Summary of combined value of electricity generation, RECs, PVRP, and RRPGP

The following summarises the average benefits available to PV in different locations through electricity sales based on the above analysis. It also includes benefits available through RECs, the PVRP and the RRPGP.

As stated above, all the following values are indicative averages only. They will vary from system to system and will be influenced by a number of factors including orientation, location, temperature, shading and maintenance of the panels and balance of system equipment.

SWIS Residential

In addition to revenue through electricity sales, residential PV can be funded through the PVRP and by using deemed RECs available through MRET. The PVRP is currently $8/W up to a maximum of $8,000. The value of RECs deemed over 15 years for a 1kW system is currently between $440 and $600 depending on location and assuming a REC value of $25 (ORER, 2006).[45] Thus the total value estimated to currently be available to residential PV in the SWIS and Edge of SWIS for both the Residential A1 and SmartPower tariffs is given in Table 52 (assuming $520 from 1kW deemed RECs).

Table 52 Net value of electricity, PVRP and RECs for a hypothetical 1kW residential system in the SWIS and Edge of SWIS

	Residential A1	SmartPower
Electricity	$3,700	$4,750
PVRP	$8,000	
RECs	$520	
Total	$12,220	$13,270
ROI	4.70%	5.10%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2

[45] Although the MRET scheme is due to end in less than 15 years, PV systems can still currently be deemed for 15 years.

The current installed cost of a 1kW PV system is about $13,000. As discussed in Appendix 6.10, grid-connection costs can be between $700 (single phase) and $1,200 (three phase). Therefore, the combined value available almost covers the full installation cost of a system this size.

SWIS Community

Community PV can also be funded through the PVRP and by using deemed RECs available through MRET. The PVRP currently covers 50% of the installed cost up to 2kW. Thus the total value estimated to currently be available to community PV in the SWIS and Edge of SWIS for both the Residential A1 and SmartPower tariffs is given in Table 53.

Table 53 Net value of electricity, PVRP and RECs for a hypothetical 1kW community system in the SWIS and Edge of SWIS

	Residential A1	SmartPower
Electricity	$3,700	$4,750
PVRP	$6,500	
RECs	$520	
Total	$10,720	$11,770
ROI	4.12%	4.53%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2

The combined value available covers a significant proportion of the installed cost of a system this size – although, again, the current grid-connection costs reduce this value by between $700 (single phase) and $1,200 (three phase).

SWIS Businesses

PV installed by a business cannot be funded through the PVRP[46] but can earned deemed RECs. Businesses are also not eligible for REBS but can negotiate with their retailer regarding a buyback rate. Table 54 presents the estimated market value currently available to a 1kW hypothetical business PV system in the SWIS or Edge of SWIS. Values for both the R3 Business tariff and a 6c/kWh tariff are used to give an indication of the possible range.

Table 54 Net value of electricity and RECs for a hypothetical 1kW business system in the SWIS and Edge of SWIS

	R3 Business	6c/kWh
Electricity	$2,850	$1,000
RECs	$520	
Total	$3,370	$1,520
ROI	1.30%	0.58%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2

[46] Here, display home builders and housing estate developers are counted as residential.

Where a commercial PV system can be considered a business expense, expenditure can be written off against tax. Hence a 1kW PV system costing $13,000 can receive a tax benefit of up to $3,900 over the system life. In the 2007 budget, the Australian Government changed the guidelines for depreciation of business plant and equipment expenditure. The diminishing value rate has increased from 150% to 200% so that expenditure can be written off for tax purposes more rapidly (Aust. Govt., 2007) and in line with the expected life of the equipment. This means that a 1kW PV system costing $13,000 can receive a tax benefit of $2,250, discounted at 12% over 20 years, bringing the system cost down to around $10,750. Despite this, the total value currently available for business owners covers a relatively small proportion of the installed cost, especially when connection costs are taken into account.

Regional Systems

PV installed in regional areas that offsets diesel generation is eligible for the RRPGP which covers half the system costs.[47]. Table 55 presents the estimated market value currently available to a 1kW hypothetical PV system in regional areas serviced by Horizon Power. The residential systems assume the A2 Residential Tariff (13.94c/kWh) and are discounted at 6% over 20 years. As for the SWIS, business systems are not eligible for REBS but can negotiate with Horizon Power regarding a buyback rate. Values for both the L2 Business Tariff (17.47c/kWh) and a 6c/kWh tariff are used to give an indication of the possible range, and are discounted at 12% over 20 years.

Table 55 Net value of electricity, RRPGP and RECs for hypothetical 1kW systems in regional areas

	A2 Residential	L2 Business	6c/kWh
Electricity	$4,000	$3,150	$1,100
RRPGP		$6,500	
RECs		$520	
Total	$11,020	$10,170	$8,120
ROI	4.2%	3.9%	3.1%

a: Over 20yrs at a 6% discount rate and assuming tariff increases as per Section 2

As for the SWIS, the combined value available covers a significant proportion of the installed cost of a PV system. If accelerated depreciation is applied to a business system, it is possible these values could cover the entire installed cost. Note that, as discussed above, Horizon Power charges an Assessment Fee of $107 plus metering costs ranging from $398 to $528 for single phase and from $863 to $993 for three phase systems. Assuming a residential system is installed on an existing single phase connection, the total cost is $635, and for installation on an exiting three phase business, the total cost is $1,100.

[47] Note that systems in Horizon Power's areas may be eligible for the PVRP, however these issues are still being discussed.

3.3 Strategies for capturing benefits of PV and for overcoming barriers

As outlined above, it appears that residential PV is being appropriately rewarded for the system benefits it provides on the SWIS. However, businesses installing PV in the SWIS and Edge of SWIS and receiving only the SWIS conventional generation cost, are not sufficiently rewarded. Similarly, where PV is installed in regional areas with a high conventional generation cost and is paid only a REBS tariff, it is not sufficiently rewarded. The following discusses strategies to both more accurately value these benefits and allow PV to take advantage of them.

Section 3.4 estimates the total value of the opportunities to PV if these strategies are implemented and combined with the existing support programs.

Section 4 draws together the report’s findings and discusses the impact of proposed support strategies.

Businesses in the SWIS and ‘Edge of SWIS’

As discussed in Section 3.2.1, PV installed by businesses most likely provides more value to retailers than the conventional generation cost. Thus it seems reasonable for them to be paid a higher tariff - such as their current retail tariff through REBS. As discussed earlier, the costs of connecting to the grid are a significant barrier for installation of PV. This issue is currently being addressed by the PV Working Group and so is not within the scope of this report. Note that, as identified earlier, the new Technical Rules requirement for customers to arrange and pay for their inverters to be checked at least once every five years by a qualified professional could also result in potentially high costs.

Ease of implementation

Making businesses eligible for the REBS may have some administrative burden for retailers but should be relatively straight forward. Reducing the costs of grid-connection may be a little more complex. It is currently being addressed by the PV Working Group along with other grid-connection issues.

Expected cost

Making businesses eligible for the REBS may result in slightly increased costs to retailers. However, as noted above, these could be identical to those incurred by energy efficiency and DSM initiatives, which are being encouraged. At this stage the outcomes of the PV Working Group are unknown but ideally their suggested changes to the grid-connection procedure should result in the costs being distributed equitably between the system owner and Western Power.

Expected Effectiveness

Allowing businesses to be eligible for REBS should be effective in stimulating their interest in PV. However, because they are not elgible for the PVRP, a PV system is unlikely to pay for itself over 20 years and so installation would depend on the recognition of other values provided by PV such as improved corporate image. The effectiveness of the final grid-connection procedure is unknown at this stage.

Table 56 Ranking of ease, cost and effectiveness in capturing benefit or removing barrier

Strategy	Ease	Cost	Effectiveness
Business eligibility for REBS	high	low	med to high
Reduction of connection costs	unknown	unknown	unknown

Mechanism for evaluating benefit provided

The effectiveness of business eligibility for REBS and any reduction in connection costs will be reflected in the rate of deployment of PV. Take-up rates will also be affected by accompanying promotion, as evidenced in SA.

Conventional Generation Cost FiT in Regional Areas

Home-owners who install PV connected to Horizon Power's network are paid through the Renewable Energy Buyback Scheme, effectively earning the A2 Residential Tariff minus the GST component on export. Businesses can negotiate a contract for larger systems. However, in some areas (ie. those serviced using diesel generators) the conventional generation they are offsetting is far more costly than the REBS rate, around 35c/kWh. It seems reasonable that in these areas system owners be paid a Feed-in-Tariff (FiT) equal or similar to Horizon Power's cost of conventional generation. The Tariff Equalisation Fund (TEF) is currently used to compensate Horizon Power for the difference between their cost of supply throughout their entire operations and their revenue stream. Thus, the costs incurred through a FiT would reduce Horizon Power's revenue and so automatically be compensated through the TEF. Note that this mechanism need not be restricted to residential-sized systems but could apply equally to any system connected to Horizon Power's networks.

As with most policy mechanisms, a FiT's design is critical to it achieving its intended objectives. There are two main variations of the FiT approach: in the first case, all the electricity produced by the PV system, irrespective of how much is used by the customer or fed into the grid, qualifies for the FiT. Alternatively, only the PV electricity that is surplus to the customer's requirements is paid the FiT. The remainder has the same value to the customer as their retail electricity rate. In regional grids, given that all PV output, whether it is used on-site or not, is offsetting high-cost generation, all output should be paid the FiT.

Other key design issues are:

- *Timeframe:* In order to create market certainty, attract investment and deliver meaningful economic and environmental dividends; a FiT should guarantee payment to the system owner for a minimum of 10-15 years; and the program should run for a minimum of 15 years, meaning the FiT is paid out over 25-30 years (systems installed in year 15 will still earn a FiT for the following 15 years).
- *New installations only:* To maximise new deployment, and to facilitate the introduction of standard metering arrangements, the FiT should be provided to new and extended installations only, where the latter receive the FiT only for the extension. If this is considered politically unacceptable, existing system owners

could receive a FiT at a reduced rate – however, this would decrease the funding available for new installations.

- *Size of tariff:* Where the size of the FiT is greater than the cost of conventional generation, and so is seen as a subsidy, the FiT should be fixed for the systems installed in any one year and can be changed for the systems installed in successive years (but would then be fixed for those systems). For example, a system installed in the first year would receive say 30c/kWh for the next 15 years, while a system installed in the second year may receive only 28c/kWh and would receive this for the next 15 years. However, where the size of the FiT is equal to or less than the cost of conventional generation, and so is not seen as a subsidy, it should track the cost of conventional generation and so may change each year for a particular system. In Horizon Power's situation, the FiT can be determined each year according to the current cost of conventional generation and so would more accurately reflect the value of PV output if, for example, the cost of diesel increases over time. Note that it may be necessary to place a floor on the value of the FiT to provide some certainty to system owners should the price of conventional generation decrease below this floor – in which case the FiT would include a subsidy.

As for the SWIS and 'Edge of SWIS' regions, the costs of connecting to the grid can be a significant barrier for installation of PV. Again, this issue is currently being addressed by the PV Working Group and so is not within the scope of this report.

Ease of implementation

This should require little if any changes to the administrative process associated with the TEF – although it may require additional reporting if expenditure on the FiT is to be itemised separately. It would require administrative changes for Horizon Power (eg. for billing) and it would require separate metering of generation by the PV system, not just an import/export meter at the point of connection to the grid.

Expected cost

Diverting a proportion of the TEF to the system owner should be revenue neutral since they are only being paid for the generation that Horizon Power is no longer required to supply. If the FiT is slightly less than the generation cost, the financial burden on the TEF would actually be reduced. Installation of a separate meter (if a dual channel interval meter is not used) and associated wiring would increase costs, although these should only be in the order of \$100 to \$200 and could be paid by the system owner.

Expected Effectiveness

This strategy aims to more accurately reflect the cost benefit of PV offsetting high-cost generation. Its effectiveness depends entirely on the level of the FiT. If it is similar to the cost of conventional generation and is appropriately promoted then the effectiveness could be expected to be high.

Table 57 Ranking of ease, cost and effectiveness in capturing benefit

Strategy	Ease	Cost	Effectiveness
FiT based on conventional generation cost	medium to high	low	high

Mechanism for evaluating benefit provided

The benefit discussed here is the offsetting of high-cost generation. Given that any generation by plant connected to a regional grid will do this, the metered electricity produced by PV systems can be used to evaluate the degree to which PV is providing this benefit. Paying such systems a FiT based on the cost of conventional generation will ensure system owners are rewarded for this benefit. Horizon could presumably use any electricity so purchased to meet its own commitments for GreenPower and MRET (if it purchases the RECs), so has an added incentive to encourage installations and to maintain accurate records.

3.4 Impacts of implementation of strategies

The following estimates the total value of the opportunities to PV if the two strategies discussed in Section 3.3 are implemented and combined with the existing support programs such as the PVRP and the RRPGP.

SWIS Businesses

Table 58 presents the estimated market value currently available to a 1kW hypothetical business PV system in the SWIS or Edge of SWIS assuming that it is paid the R3 Business tariff and earns deemed RECs.

Table 58 Net value of electricity and RECs for a hypothetical 1kW business system in the SWIS and Edge of SWIS

	R3 Business
Electricity	$2,850
RECs	$520
Total	$3,370
ROI	1.30%

a: Over 20yrs at a 12% discount rate and assuming tariff increases as per Section 2

As discussed earlier, where a commercial PV system can be considered a business expense, expenditure can be written off against tax, reducing the effective cost of a $13,000 system to around $10,750. Thus the total value currently available covers a relatively small proportion of the installed cost, especially when connection costs are taken into account.

Regional systems

Table 59 presents the estimated market value available to hypothetical PV systems in regional areas serviced by Horizon Power, assuming that a FiT equal to the conventional generation cost is applied to all PV generation. Marble Bar and Meekatharra have conventional generation costs far greater than the current REBS rates while Carnarvon’s conventional generation cost is similar to current REBS rates. The residential systems assume a 6% discount rate, the business systems assume a 12% discount rate, both over 20 years.

Table 59 Net value of electricity, RRPGP and RECs for hypothetical 1kW systems in regional areas

	Marble Bar (39.11c/kWh)		Meekatharra (35.5c/kWh)		Carnarvon (13.39c/kWh)	
Discount rate	6%	12%	6%	12%	6%	12%
Electricity	$10,850	$8,650	$9,850	$7,850	$3,800	$3,000
RRPGP			$6,500			
RECs			$520			
Total	$17,870	15,670	$16,870	14,870	10,820	10,020
ROI	6.9%	6.0%	6.5%	5.7%	4.2%	3.9%

a: Over 20yrs and assuming tariff increases as per Section 2

In areas with a high cost of conventional generation, the discounted net value for both residential and business systems is significantly greater than the installed cost of PV – especially if a business claims accelerated depreciation of the system. In areas such as Carnarvon, where the conventional generation cost is closer to the REBS rates, discounted net values are still a significant proportion of the installed cost.

Although a FiT lower than the conventional generation costs in Marble Bar and Meekatharra should still more than cover the installed cost, any decreased rate should be in the context that a FiT equal to the conventional generation cost doesn't increase Horizon's generation costs overall. It is also possible that installation of systems in places such as Marble Bar and Meeketharra may cost more than the indicative cost used here (ie. $13,000 for a 1kW system), and maintenance costs may also be higher than average.

Also, as discussed above, Horizon Power currently charges an Assessment Fee of $107 plus metering costs ranging from $398 to $528 for single phase and from $863 to $993 for three phase. Assuming a residential system is installed on an existing single phase connection, the total cost is $635, and for installation on an exiting three phase business, the total cost is $1,100. These are higher than being charged elsewhere in Australia and act as a deterrent to PV at present.

Impact on Rates of PV Uptake in WA

It is not possible to estimate PV uptake rates as a result of any of the changes discussed above with any level of certainty. Uptake rates around the world in response to market incentives or capital support programs have varied widely. Local awareness, attitudes to the environment and to climate change, availability of product and finance, affordability and promotion all play a part. In its PV Industry Roadmap, the Australian PV industry modelled possible PV uptake rates in response to anticipated PV price reductions, due to technology development, and electricity price increases. Scenarios based on growth rates over the past decade in Australia and internationally were examined. For instance, Australian growth rates have averaged around 15% per year, while international rates have averaged 35%, and are expected to average 20-25% over the coming decade. Germany has averaged 60%, as its soft loans and feed-in-tariffs have made PV an attractive investment.

The combination of grants, REBS for business systems and cost reflective feed-in-tariffs in regional areas described above would make PV an attractive investment for many WA residential and business electricity customers. Hence higher take-up rates could be anticipated. Grid installations in WA have averaged 26.5 kW per year under PVRP and now total 179 kW. Assuming WA accesses the PVRP in proportion to its population (ie. 10% of Australia), about $3 million per year would be available, which at $8/W means about 375kW per year could be installed, however this will depend on availability of systems and trained personnel to install and certify them. Installation in regional areas driven by high FiTs would be limited by the amount available to WA through the RRPGP. To date, $38 million of RRPGP funding has resulted in about 7.3MW installed capacity in WA - 1.9MW of PV and 5.4MW of wind. About $58 million of the original allocation to WA remains to be spent. Assuming the original or new RRPGP funding is available until June 2011, then overall the RRPGP will result in about 3.2MW of installed PV in WA.[48] Once the PVRP and RRPGP grants cease, effective PV prices could double (assuming no price reductions in that time). Cost effectiveness would then depend more on the presence of subsidy schemes such as the PVRP or RRPGP, electricity prices by that time, on buy-back rates available, on any renewable energy target mechanism remaining in place, or on a carbon price.

[48] Personal communication, SEDO.

4 Discussion

Uptake of grid-connected PV through the PVRP has been slow in WA, with only one or two systems being installed per month. However, grid uptake has increased over the most recent 2 quarters, as public awareness of climate change has increased, and the higher PVRP rebates, applicable from May 2007, may add to demand growth. Although this may reduce the need for specific WA Government support for the residential grid connected PV sector, attention will still need to be given to financial and administrative costs associated with connection procedures.

In addition, the lack of real PV data meant that simulated PV data had to be used for this report. Acquisition of high quality data at a number of locations should be considered a priority if the correlation between PV and load, and PV's impact on that load, is likely to continue to be of interest. This could be incorporated into other programs such as Solar Schools, but should also include real time monitoring of both load and PV generation data for residential and business systems. Such data could also be used to assess PV's contribution during the peak load periods relevant to the RCM, and therefore the degree to which PV should be financially rewarded for providing capacity at these times.

The following summarises the report findings and suggested strategies.

Offsetting conventional generation and providing firm capacity

PV output has good correlation with average summer loads and so reduces the need for high-cost peaking generation, and reduces a Market Customer's Individual Reserve Capacity Requirement (IRCR). The reduction in IRCR as calculated using Methodology 3 in this report, when combined with the value of offsetting conventional generation, accounts for most of the value (about 85%) provided by PV. These values, combined with the values provided by deferring network augmentation and reducing line losses (discussed below), most likely accrue to the retailer, and are similar to the REBS rate offered under the Residential A1 tariff.[49]

Deferring network augmentation - SWIS

While PV generally has a good correlation with CBD loads, the value it provides in terms of deferring network augmentation is very low compared to the cost of PV. It is also likely to be unable to provide the certainty required to meet Western Power's n-1 and n-2 network planning criteria. However, if it is to be installed for other reasons, its contribution to reducing peak loads could be enhanced through the use of appropriate demand management strategies that include appropriate scheduling of planned maintenance and strategies to reduce power demand at peak times. Mechanisms to encourage PV deployment in the CBD include capital grants, feed-in-tariffs, leasing arrangements and stamp duty concessions on new buildings or on the first sale after

[49] Although the electricity produced by a PV system does not directly incur transmission and distribution costs for the retailer, it reduces the amount of electricity to which these costs are applied and so increases the per unit costs. Therefore the transmission and distribution component of the retail tariff cannot be excluded.

installation. Differential rates could be used to encourage west-facing systems in regions with afternoon load peaks. Specific sectors could be targeted, such as shopping centres, using more tailored policies, as has been done for schools.

Businesses that connect PV systems to the grid are currently not eligible for REBS and so would have very low returns on a PV investment. Given that businesses that install PV are likely to generate electricity in potentially constrained areas such as the CBD, they should be encouraged to do so (although PV’s network value is low compared to its installed cost, it provides most value in areas with a commercial (daytime) load profile). Making businesses eligible for REBs would encourage installation of PV, however any subsidy costs would accrue to the retailer. Similarly, community groups and educational institutions should be eligible for REBS using the SmartPower tariff. A maximum system size (say 100 kW to be consistent with the MRET deeming arrangements) could be used.

Recommendations regarding policy drivers would benefit from feedback from the parties they target. A survey of commercial building owners could ascertain their current electricity usage/cost/tariff type as well as their potential interest in PV. This could include assessing their interest in different types of policy such as capital grants, a FiT etc, and their ability to maximise the investment through capital expense write offs, publicity, increases in property value etc., as well as their expected return on investment. Their potential interest in a tradeoff against energy star measures would also be useful. Novel financing arrangements may also be appropriate – see *Leasing arrangements* and *Taxation benefits* below.

Deferring network augmentation & Reducing line losses – Edge of SWIS

The poor match between high loads and PV output means that PV is unlikely to provide effective network augmentation in ‘Edge of SWIS’ areas. The value it may be able to provide through reduced line losses is small compared to the installed cost of PV. To match energy supply with demand, large amounts of storage would be required in conjunction with PV installations, increasing costs significantly. If PV is to be installed privately or for other reasons, consideration should be given to configuring it to maximise network augmentation and reduce line losses. In some circumstances it may be financially preferable to decommission long, lightly loaded rural spur feeders and replace them with Remote Area Power Supplies – see Section *Excision and conversion to RAPS* below.

Providing power quality and reliability

Harmonic support: the most common type of inverters (current source) do not provide the harmonic support (out of phase current and harmonics) normally required by the grid. Voltage source inverters can provide harmonic support but do so at an energy cost. There are a variety of harmonic compensators that are likely to be cheaper than voltage source inverters. At present there appears to be a decreasing availability of voltage source style inverters in the market place and also it is generally difficult without testing to establish what style of control is used in an inverter because there is no classification of the inverter for voltage or current source control. As PV penetration into the grid increases voltage source style control may be beneficial. More research is required and it may become important to then have the inverters marked according to control classification.

Power factor support: Although inverters (in the absence of PV output) are capable of VAr compensation to assist with voltage control in metropolitan and CBD locations, capacitors are likely to be a more cost effective option. Where inverters are to be installed for other reasons, they could be configured to provide VAr compensation if Western Power considers it useful for the installation location. Since this comes at an energy cost there would be a need to value the VAr compensation and compensate for energy losses (which will be smaller in larger inverters).

In regional areas, voltage control requires real power and so is only possible when PV output correlates with system load. There are very few 'Edge of SWIS' locations where this occurs, Geraldton and Merridin being selected for this study in part because they were two of the few where it does. The weather-dependent nature of PV output means that even in these locations it cannot be relied on to provide voltage control unless some form of storage is used, and this would increase costs.

Islanding and intermittency: Inverters are generally configured with tolerance limits that may result in them disconnecting prematurely or not reclosing at all on weak grids. Under current standards, they also do not reclose until those limits are met for 60 seconds, while networks reclose after 10 seconds. To increase PV's ability to provide line support, the network operator could specify more reasonable tolerance limits and shorten the reclose time. Some form of short-term storage could also be used to bridge the gap between the network and the PV inverter reclosing. The whole area of inverter ride-through, inverter voltage and frequency windows raises important issues of islanding prevention, timing and stability which are emerging as issues to be further investigated as the number of grid connected PV systems increases in the distribution system.

Reducing the cost of supply – Regional areas

According to the HOMER modeling runs for Marble Bar, which assumed 50% of the capital costs of PV systems were met through RRPGP, use of PV reduced diesel use and greenhouse emissions but increased net present costs slightly. Although placing a price on greenhouse emissions made PV systems more favourable, it is likely that diesel prices could have a stronger influence on relative costs. This modeling used standard flat plate PV systems and large-scale concentrator systems may be more cost-effective. For example Solar Systems' proposed heliostat solar concentrator power station near Mildura is targeting less than $3/W (compared to around $13/W for standard flat plat systems).

However, conventional generation offset by PV on regional grids (up to around 35c/kWh) may be far more costly than the current REBS rate (13.94c/kWh). It seems reasonable that system owners be paid a Feed-in-Tariff (FiT) equal to Horizon Power's cost of conventional generation for the grid they are connected to. This level of financial return should drive significant deployment of PV in regionsl areas.

One of Horizon Power's Key Performance Indicators is to reduce their greenhouse intensity by 5% over 5 years, from 0.86 to 0.81 kg/kWh. They also have a program focussing on installing 0.5 to 1MW power systems in aboriginal communities. Thus it is likely that government policies that enable Horizon Power to install PV systems will be well targeted and so they should be a 'first point of call' regarding advice on appropriate policies. Clearly maintenance of the RRPGP is critical to remote area PV systems being financially viable, and there are likely to be additional opportunities for government involvement. For example, the provision of reliable information regarding the installation and operation of remote on-grid PV systems would be helpful, not only for Horizon Power but also for individuals or businesses.

Reducing diesel use for electricity generation could have balance of trade benefits as most of the diesel used in WA comes from the refinery at Kwinana and more than half the crude oil for that refinery comes from outside Australia. Increased deployment of PV systems in rural and remote areas should result in local job creation, not only for installation but also for maintenance, and reduced electricity costs should also have economic benefits.

Grid Connection Costs

The costs of connecting to the grid in WA are a significant barrier for installation of PV. These costs are higher than in other States and are currently being addressed by the PV Working Group, so is not within the scope of this report.

The new Technical Rules requirement for customers to arrange and pay for their inverters to be checked on installation and at least once every five years by a qualified professional could also result in potentially high costs. This is not required elsewhere and should not be necessary if appropriate Australian Standards are followed and installation is undertaken by a certified installer.

Streamlining and minimisation of procedures and costs for PV grid interconnection, perhaps with a checklist, would be a useful means of providing would-be PV owners with confidence that the process is straightforward and that they are not being unfairly charged.

ADDITIONAL STRATEGIES

The following discusses a number of strategies that can be used to support PV in different locations depending on the local circumstances and which of PV's attributes is being targeted.

Excision and conversion to RAPS

In certain fringe of grid locations, because of reduced load over time, line losses and reliability concerns, coupled with the high costs of line maintenance, it may be cost-effective to decommission long, lightly loaded rural spur feeders and replace them with Remote Area Power Systems (RAPS)[50]. Although a number of financial models are possible, it is likely the simplest and most effective would be for the customer to simply receive a quarterly electricity bill as they currently do, and for the RAPS to be owned and operated by Horizon Power, which would then remain responsible for all operation and maintenance.

This proposal would require an assessment of the relative responsibilities and costs to Horizon, Western Power and Synergy, and regulatory changes to extend Western Power's operations beyond the SWIS to RAPS. One alternative could be for remote loads to remain connected to the grid but have RAPS backup in the short term, however this could result in unnecessary financial and technical complications and require

[50] These need not only use PV but could also use other distributed generation options

maintenance of feeders, thus increasing costs. Horizon Power could also be given responsibility for excised regions, however some form of compensation would be required since Western Power would be passing on a difficult operational problem.

Leasing arrangements

For companies in particular, it may be more attractive to lease rather than buy PV systems. This may fit in better with leased premises and may also have taxation benefits, since lease costs can be deducted from the current year's tax against long term depreciation for purchased PV systems. Companies such as Verve Energy may supply PV systems for lease, with various options for future ownership. Alternatively, they may tender for 3rd party services. Reducing the initial high capital cost burden may make PV more attractive to the commercial sector and hence encourage CBD installations. Leasing of residential systems has been tried by utilities such as the Sacremento Municipal Utility District. However, they have now moved to other support models as PV costs have fallen, State capital grants have become available and customer acceptance has increased. Leasing may also be a good option for fringe of grid or off-grid installations, where systems may subsequently be moved to another customer if the grid is augmented or the customer grid-connected.

Taxation benefits

Many international jurisdictions use tax benefits to support PV (see for instance www.dsire.org and www.pvpolicy.org). With the major taxation opportunities resting with the Federal government, for WA, stamp duty and local government taxes would be the most relevant. Stamp duty concessions could be made available for company or non-exempt property or developments incorporating PV. Local Governments could be encouraged to reduce annual rates or development application fees where PV is to be used. Taxes on fossil fuel use can also be used to reduce payroll taxes generally, or taxes on new, more environmentally friendly industries, thus providing indirect benefits for PV.

MRET

MRET does not provide enough income to PV to make it an attractive investment compared to cheaper forms of renewable energy, and very few of the residential systems have so far registered to generate RECs. It has been suggested by the PV industry that MRET be altered to provide more support for PV by allowing more than one REC to be generated for 1 MWh of PV-electricity or that a portfolio target be used, where a certain number of RECs must come from PV. These options could be considered as part of the State based extensions to MRET which are currently under development.

GreenPower

GreenPower generally supports lowest cost renewables and so is not a significant driver for PV, unless a GreenPower product specifically specifies PV. In his May 2007 Climate Action Statement, the WA Premier has indicated that the WA Government will purchase 20% GreenPower for its own electricity use by 2010. The Government could specify a portion of this to be solar power if it wished to provide specific stimulus to this market sector.

Information

General education and customer support services are needed. Independent contact points for enquiry before and after installation or customer networks for information exchange and support, and procedures to deal with problems would all assist customer confidence, and hence potential take-up rates of PV. Some aspects of such services could be provided via the Energy Ombudsman's office, with funding support from government

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6 Appendices