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Estimating the Net Societal Value of Distributed Household PV Systems

by

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Executive Summary

This paper presents a methodology for estimating the net marginal societal value of distributed residential PV systems within the Australian National Electricity Market. It includes PV's potential direct marginal energy value including avoided losses, and marginal environmental value with respect to regional air pollutants and greenhouse gas emissions. This methodology is then applied for the example of 61 domestic rooftop PV systems located in Sydney. Results highlight that residential PV systems would seem to offer net societal benefits under reasonable assumptions of their energy and environmental values including the social cost of carbon, and given social discount rates. Much depends, however, on system performance including issues of orientation, maintenance and shading. While such evaluations of societal value are challenging, they have an important policy role in better aligning private incentives for and against residential PV deployment with the societal benefits that such deployment can bring.

Keywords: Photovoltaics, social valuation, electricity industries

Contents

1 Introduction

Photovoltaics (PV) has experienced remarkable growth over the past decade. While system costs have fallen significantly over this time, PV deployment has largely been driven by supportive government policies. More than 100 countries have implemented policies to support renewable power generation, and many of these include measures intended to specifically support PV deployment. Feed-in tariffs (FiTs), which provide a premium 'tariff' for eligible renewable generation, are the most widely implemented such mechanism for PV, and were in place in more than 65 countries and 27 states/provinces worldwide in 2012 (REN21, 2012). Other policy measures include capital subsidies and renewable portfolio standards. Such policy efforts have been driven by a range of factors that have varied by jurisdiction and over time. However, in essence they reflect a view that PV provides a range of societal benefits that are not currently reflected in existing energy markets and wider commercial arrangements. These include the energy security value and environmental value of renewable generation that offsets the use of highly polluting and diminishing, often imported, fossil fuels. Longer term benefits might include the investment and job creation potential of the PV industry, and the promise of reduced future PV costs with growing industry scale that will improve its societal value (NREL, 2008). Against these benefits, are a range of potential costs including not only the PV systems themselves, but potentially wider adverse impacts such as the use of toxic materials in their manufacture.

One formal economically oriented policy development approach is to estimate these various costs and benefits and seek the scale and nature of PV deployment that maximises net societal benefits. Specific PV policy measures then provide the means to better align self-interested, largely private, decision making by key stakeholders in PV deployment, with maximisation of PV's societal benefits.

The starting point for such policy development is estimating PV's societal costs and benefits and this is much harder in practice than might be expected. PV has diverse energy, environmental and social values that are highly context specific, have significant uncertainties and will vary with the scale and particular characteristics of its deployment. As just one example, the energy value of electricity within a power system depends on a wide range of factors from the mix of generation types and their fuels, to the nature and extent of the electrical network and underlying characteristics of demand. As such, electricity's energy value varies by time and location within a network, subject to a wide range of uncertainties (MacGill, 2010). PV generation itself has significant temporal and locational variability and unpredictability. As such, the energy value of PV systems are very context specific, strongly influenced by factors such as the match of PV generation to existing electricity demand and network capacities at different points in the grid, and the underlying generation mix. Both shorter-term operational and long-term investment costs and benefits are relevant. Similarly, the environmental value of PV generation depends on which types of other electricity generators are offset, and their particular environmental impacts.

In theory, ideal electricity markets would reflect these complexities and hence have time and location varying prices that reflected the immediate to longer term economic value of energy including its environmental impacts. This is, however, far from the case for existing market arrangements around the world, particularly at the retail market level. Rather than prices, these markets generally have energy and network tariffs (schedules of fees) that don't reflect the time and location varying economic value of electricity and associated environmental costs (Elliston et al., 2010; Outhred and MacGill, 2006). Even where there is some environmental pricing such as seen in electricity industries with carbon pricing, the prices paid may be very different to the underlying economic costs.

Despite these challenges there is considerable policy value in attempting to estimate the societal benefits of PV both in terms of how much, if any, policy support is warranted, and how best it might be targeted to maximise its value. In Australian jurisdictions, policy processes such as regulatory impact statements may include such assessments. With regard to PV, however, policy support has generally been developed and implemented without any comprehensive social cost-benefit analysis being undertaken (Victorian Auditor-General, 2011; NSW Auditor-General, 2011). There have been Federal Government efforts to estimate the Levelised Costs of Energy (LCOE) of a range of electricity supply options including different PV technologies, incorporating the impact of carbon pricing (BREE, 2012). The Productivity Commission (2011) has also attempted to estimate the effective societal abatement cost of emission reductions associated with a range of measures including PV policy support. This trend can also be seen at the international level, for example, an early study by Haas et al. (1999) shows that in Austria PV support had not yet been optimally designed. However, and as discussed in the next section, these efforts have applied narrow and simplistic evaluation frameworks.

In this paper we present a methodology for estimating key aspects of the net societal value of distributed residential PV systems within the Australian National Electricity Market (NEM). Almost all of the near two GW of PV deployed to date in Australia has been small (less than 5kW) domestic rooftop PV systems. Such systems represent particular challenges for societal valuation. They are located within the distribution network with all the challenges of network economics this presents. They are also commercially located within the NEM's highly abstracted and simplified retail electricity market. Furthermore, and very importantly, the performance of domestic rooftop systems has proven to vary very significantly according to the location and quality of installation including issues of system orientation and shading (Lewis, 2011).

The chosen methodology considers only a subset of potential societal costs and benefits and, as detailed later, makes a number of simplifying assumptions. The focus is on PV's potential direct energy value (including network value) and environmental value (including not only greenhouse gas emissions but also regional air pollutants). Furthermore, we only consider costs and benefits on the margin – that is, those costs and benefits associated with adding small amounts of PV that don't fundamentally change underlying energy market operation. We also make no estimates of job and investment value associated with PV industry development alongside greater PV deployment.

We then apply this methodology to estimate the societal value of domestic PV systems located in Sydney based on a year of actual performance data for 60 PV systems located in Western Sydney, and actual NEM outcomes over that period.

The structure of the rest of the paper is as follows. Section 2 presents a brief review of previous Australian and international work attempting to assess the societal costs and benefits of PV, and its various strengths and limitations. A possible methodological framework for making such assessments in the context of the Australian NEM is presented in Section 3. Section 4 provides details of the data and assumptions used to estimate the societal value of the 60 PV systems located in Western Sydney. The findings are presented in Section 5 and their potential relevance to policy makers is then explored in the concluding Section.

2 Previous work on societal valuation of PV

There is considerable and growing work exploring aspects of PV economics, however, only a limited subset of this is relevant to societal valuation. Much of the work has focussed on commercial assessments – that is, the potential costs and benefits to key stakeholders, particularly potential system owners, of PV deployment within particular commercial contexts. A particular focus of this work has been on grid parity. In this regard McKinsey & Company (2008) has ranked a range of countries on how close they were to grid parity by comparing residential electricity prices with the cost of PV electricity given the country's average solar resource. Borenstein (2007), Mills et al. (2008) and Darghouth et al. (2011) have investigated the impact of different electricity retail arrangements on PV customer returns in California. Radhi (2011) and McHenry (2012) assessed the NPV for PV owners in the Gulf Cooperation Council (GCC) countries and Western Australia respectively, obtaining negative values. Oliva and MacGill (2011b) assessed the PV value not only for PV customers but also retailers and distribution network service providers (DNSPs) in the Australian state of NSW, whilst the most recent determination of the Independent Pricing and Regulatory Tribunal (IPART) also estimated the value of PV exports close to the wholesale price of electricity (IPART, 2012).

As noted in the nineties by Haas (1995), in ideal energy markets the aggregated costs and benefits of all stakeholders would be equivalent to PV net societal benefit. In practice, energy markets suffer from virtually all possible forms of market failure from unpriced externalities to provision of essential public goods and monopoly infrastructure. Energy market prices generally don't reflect true underlying economics and the retail 'prices' – better termed schedules of fees – used for many of the assessments above are particularly problematic in this regard.

Other work based on estimates of Levelised Costs of Energy (LCOE) for different technologies including PV can potentially take a more societally focussed view and has played a particular role in policy development. For example the Australian government has undertaken an Australian Energy Technology Assessment (AETA) comparing the estimate LCOE of a range of technologies. BREE (2012, p. 80) obtains an average levelised PV cost in Australia of around 22 c/kWh, around three times the costs of the cheapest conventional technology. This assessment includes carbon pricing although, and as discussed later, the chosen price almost certainly doesn't reflect underlying societal costs of climate change. Borenstein (2012) estimated the levelised PV costs for a 5 kW PV system in California arguing that a social carbon costs of emissions greater than $US 316/tCO2 could make it competitive with the nearest cheapest generation technology. He concluded that since such social carbon costs are well below $US 100/tCO2 PV is still not competitive. A particular limitation of LCOE methods is that PV costs are not directly comparable with the costs of conventional generation within an electricity industry context. PV generation is highly variable and only somewhat predictable by comparison with dispatchable generation and that has major implications for the value that it can contribute within an electricity industry (MacGill, 2010). Another issue is that of the chosen discount rate used to establish directly comparable LCOEs between technologies that have high upfront but low ongoing costs such as PV, versus those that have low upfront but significant, and potentially highly uncertain, ongoing costs such as Open Cycle Gas Turbines (OCGT). Some LCOE estimates apply a high discount rate that is appropriate for private commercial rates of return, whereas other work applies a significantly lower societal discount rate that intends to reflect the longer-term perspective that societies, and their policy makers, should apply.

Examples of more sophisticated societal valuations of PV include Smeloff (2005), NREL (2008) and Borenstein (2008) which all undertook social PV valuations in the US context. While Smeloff, using a carbon costs of $100/tCO2, obtained social PV values ranging from 23 to 35.2 c/kWh (greater than PV system costs), NREL and Borenstein didn't explicitly address longer- term environmental values and obtained total social benefits for PV lower than system costs. More recent articles that estimate the value of PV for society include (Hammond et al., 2012; Yamamoto, 2012). Hammond et al. (2012) assess the value of PV from the householder and societal perspective in the UK, and conclude that under current PV policies neither pays back the investment. Using a more theoretical approach Yamamoto (2012) compares the value of FiTs and net metering arrangements for consumers, utilities and society to relate the reduction of electricity consumption with the social welfare of such payment schemes. In the Australian context Passey et al. (2007) found that PV benefits in the South West Interconnected System (SWIS) of Western Australia were lower than its costs as well. However, PV costs have reduced considerably since those estimations were carried out. More recently SKM MMA (2011a) valued PV benefits in the Australian NEM, although it ignored environmental benefits. It's estimation of a value for PV generation close to the wholesale price of electricity highlights the potential need for PV policy support to account for PV benefits that the current market arrangements don't provide to parties who deploy PV systems. By contrast, the Australian Productivity Commission (2011) used a study attempting to price the societal cost of PV driven emissions abatement in order to argue against policy support. However, its' chosen methodology and assumptions have been widely critiqued (APVA, 2011).

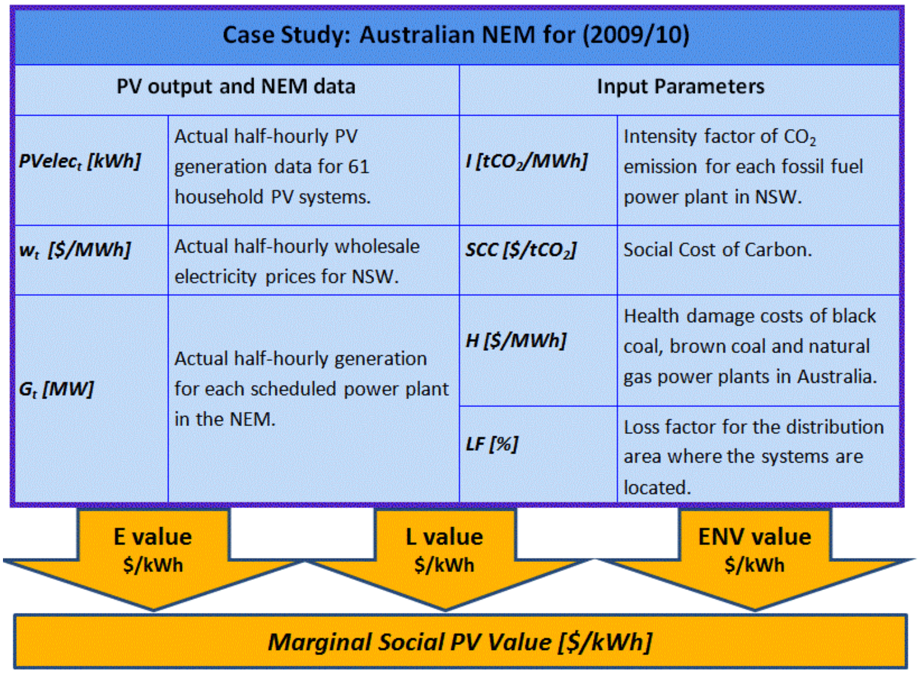
To summarise, there is still no general agreement on how societal valuations of PV should be undertaken including which costs and benefits should be included, and how they might be calculated. Such choices are also highly context specific depending upon, for example, the existing generation mix of the industry where PV is being deployed, and its commercial arrangements. Estimates to date have come up with mixed findings on whether PV presents net societal benefits or costs. However, the falling costs of PV seen over recent years, rising electricity costs in many countries and growing concerns regarding the potential catastrophic societal costs of unmanaged climate change would all suggest that existing estimates might usefully be revisited.

3 Methodology

In this section we firstly describe how we estimate the different components of the marginal societal PV value, henceforth denoted as SPVV. This framework is presented in Figure 1 and involves PV generation's contribution to avoided conventional energy generation (E), line losses (L) and emissions (ENV). The methodology involves calculations based on a year of actual operation of 61 PV systems, and associated NEM outcomes.

We also describe other benefits that PV may provide but which have not been included in our estimates for a range of reasons. These values include deferral of network augmentation, possible reductions of wholesale electricity prices, and improved security of supply and power quality impacts. While potentially highly valuable, current limitations in data and knowledge preclude their inclusion at this stage.

3.1 Marginal PV values included in the analysis



Case Study: Australian NEM for (2009/10)			
PV output and NEM data		**Input Parameters**	
$PVelec_t\ [\text{kWh}]$	Actual half-hourly PV generation data for 61 household PV systems.	$I\ [\text{tCO}_2/\text{MWh}]$	Intensity factor of CO_2 emission for each fossil fuel power plant in NSW.
$w_t\ [\$/\text{MWh}]$	Actual half-hourly wholesale electricity prices for NSW.	$SCC\ [\$/\text{tCO}_2]$	Social Cost of Carbon.
$G_t\ [\text{MW}]$	Actual half-hourly generation for each scheduled power plant in the NEM.	$H\ [\$/\text{MWh}]$	Health damage costs of black coal, brown coal and natural gas power plants in Australia.
		$LF\ [\%]$	Loss factor for the distribution area where the systems are located.

Fig. 1. Societal PV value methodology.

3.1.1 *Energy*

As noted earlier, in a restructured competitively based electricity industry, ideally the temporal and locational value of electricity would be reflected in prices. Whilst this is certainly not the case in retail markets, some electricity markets including the Australian NEM do have time and locational varying wholesale electricity prices. The Australian NEM prices electricity every five minutes (averaged to 30 minutes) for five market regions. It has been argued that these prices appear to be relatively economically efficient with respect to direct, short-term, marginal energy value – generally marginal generator costs – within these regions. The NEM is a compulsory gross-pool energy only market without a formal capacity market. A very high Market Ceiling Price, which is occasionally reached during times of supply scarcity, provides an effective capacity value for generators that are available when required at such times. Frequency control ancillary services are provided through eight very short-term markets; however, turnover in these is typically less than one per cent of spot market turnover. A range of derivative markets are used to support longer-term risk management and investment.

We assume, therefore that the marginal direct energy value of PV generation can be estimated by the time varying wholesale price in the NEM region of NSW. That is, if at time t, $PVelec_t$ is the PV generation and w_t is the wholesale spot price of electricity, then Eq. 1 shows E_t as the energy component of the PV value (i.e. the E value). Note that these prices have not, until mid-2012, included an environmental cost on greenhouse emissions – an issue to which we will return.

$$E_t = w_t \times PVelec_t \qquad (1)$$

3.1.2 Avoided Losses

Since PVelec is a form of distributed energy its generation will almost always be consumed locally, hence avoiding much of the energy losses in the transmission and distribution system that deliver electricity from large remote generating plant to end-users. Estimating such losses, however, is highly complex and location specific. Network losses generally increase as the load increases and so PVelec's contribution to avoided losses is greater when it matches the load profile. However, although this often occurs on networks with commercial loads, it won't necessarily occur on networks with residential loads, even in summer, as air conditioners' contribution to peaks occurs from late afternoon onwards (Passey et al, 2007).

An approach commonly used to estimate the financial value of avoided losses, for example as used by Passey et al. (2007), is to estimate avoided electricity losses from annual average loss factors at a system level or, preferably, according to more detailed location-specific loss factors. The value of these losses can then be priced at average wholesale electricity prices. The limitation of this approach is that it doesn't take into account the non-linear relationship between losses and power flow in network elements.

Our approach to estimate the value of avoided losses, based upon a more sophisticated method described in Borenstein (2008), calculates power losses with regard to the square of the power flows, and the change in this over time[1]. Thus, if G_t is the total generation injected to a specific location at time t, the avoided losses in that location l_t can be expressed as in Eq. 2.

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[1] On average in NSW PV owners consume onsite around two-thirds of the electricity generated by their PV systems (IPART, 2012), with the remainder consumed by nearby residences (SKM MMA, 2011a). Here we assume that the distribution losses to the nearby residences are negligible.

$$l_t = \alpha \times G_t^2 \qquad (2)$$

Where α is a constant that can be derived by combining historical half-hourly power supply data with the average aggregate losses in that location. If *LF* is the average percentage of the total power generation dissipated through losses in the network to deliver power to that area, then α can be obtained by Eq. 3.

$$LF \times \sum_{t=1}^{T} G_t = \sum_{t=1}^{T} \alpha \times G_t^2 \Leftrightarrow \alpha = LF \times \frac{\sum_{t=1}^{T} G_t}{\sum_{t=1}^{T} G_t^2} \qquad (3)$$

The change in the overall system losses when one unit of delivered electricity is displaced by one unit of electricity from distributed PV is therefore given by Eq. (4).

$$\frac{dl_t}{dG_t} = 2\alpha \times G_t \qquad (4)$$

Finally, by valuing the reduced losses at the wholesale spot price of electricity the final value of avoided losses L_t is as shown in Eq. 5.

$$L_t = 2\alpha \times G_t \times w_t \times PVelec_t \qquad (5)$$

Although more sophisticated approaches are also clearly possible, including separating fixed and variable losses, and including locational network loss factors the chosen approach seems suitable for a first order approximation.

3.1.3 Avoided Emissions

Unlike fossil-fuel generators, PV systems don't emit atmospheric pollutants during operation. Key air pollutants from fossil-fuel generators include CO2 which contributes to global warming, and regional SO2, NOx and PM10 emissions that can have a direct impact on community health (IEA, 2010). The environmental benefit of each kWh generated by a PV system is here taken to be equivalent to the avoided emissions of the generating plant whose output is being displaced i.e. that plant or those plants operating at the margin. Commonly, the value of this benefit can be assessed by multiplying the avoided emissions (eg. tCO2) by an estimated societal cost of those emissions (eg. $/tCO2).

There are significant challenges in estimating both the avoided marginal emissions of PV generation as well as the value of these reductions. The marginal generators displaced by PV generation vary with changing demand and the mix of available generating plant over time, and are also affected by network losses and a potentially wide range of generation and network constraints. The emissions intensity of these marginal plants will also vary over time as a function of their operational status. As such, precise estimates of PV abatement are particularly challenging to make.

One possible simplification is to use the average emissions intensity of all generation at the time of PV generation. For example, NSW electricity delivered to energy users (and hence potentially offset by PV generation) comes from a mix of black coal, gas-fired and hydro plant within the State, as well as imports from the Victorian and Queensland regions of the NEM which have predominantly brown and black coal respectively. The generation mix varies by time of day, day of the week and season subject to a range of uncertainties, and is changing over time due to wider market changes such as increasing wind generation.

An alternative approach is to estimate which plant is on the margin at a given time of PV generation. Generally, coal fired plant is on the margin at times of low demand and gas-fired generation is sometimes on the margin at higher demand times in NSW. However, there is considerable variation and the marginal generator may be located in another state, or be hydro generation at particular times. For simplicity, here we assume that PV displaces electricity with an emissions intensity equal to the half-hour weighted average emission intensity in NSW.

Valuing the societal cost of CO2 and other environmentally harmful emissions is highly abstracted and hence controversial. There are two common approaches to estimating this cost; as a control cost, for example through a carbon price imposed via an emissions trading scheme, and as a more general damage cost estimate – for the example of climate change, a social cost of carbon (SCC) arising from the impacts of climate change caused by greenhouse emissions. In theory the economically efficient price of carbon is that where the cost of controlling (reducing) a unit of emissions equals the societal damage costs it would otherwise impose. However, there are enormous uncertainties on damage costs given the limitations of current climate science (particularly on the adverse impacts from climate change) and the control costs of our abatement options (particularly over the longer term and with greater ambition on emission reductions). As such, carbon costs differ depending on the context, modelling and assumptions used.

There is a great deal of variation in the reported marginal damage costs of GHG emissions. Tol (2005), reviewing 88 estimates of the marginal damage costs of CO2 emissions reported in 22 published studies, obtained a median of $6/tCO2, a mean of $37/tCO2, and the 95 percentile of $139/tCO2, and concluded that the marginal damage cost is likely to be much smaller than $20/tCO2. Watkiss (2005) obtained a central illustrative estimate of $45-57/tCO2 for emissions in 2000. The ExternE (2005) estimated a conservative damage cost of $18/tCO2, although they conceded that not all impacts are included. Stern (2006) estimated a damage cost for emissions in 2006 of $110/tCO2 in a business as usual scenario based on the PAGE2002 model and using very low discount rates. Garnaut (2011) argues that in the US context the SCC is being systematically applied in decisions on the regulation of emissions from vehicles, appliances, and power generation and industrial facilities. In this case the central SCC is $21/tCO2 rising over time to $26/tCO2 in 2020. The same report shows that in the UK investors are assuming a higher SCC of $41/tCO2. As such, Garnaut recommended an initial carbon price for Australia in line with these SCC in the range of $20 to $30 per tonne of CO2. However these estimations are highly variable depending on both the year of the emission and the knowledge regarding damage impacts at the time of the estimation. More recently Hope (2011) presented costs of emissions in year 2009 using the PAGE2009 model, and obtained values of \$143/tCO2 for the Intergovernmental Panel on Climate Change (IPCC)'s A1B scenario and \$74/tCO2 for a called low emission scenario (LES). While the A1B scenario is essentially business as usual that assumes a more integrated world with a balanced emphasis on all energy sources, the LES scenario aims to have a 50% chance of keeping the rise in global mean temperatures below 2oC (i.e. a CO2 concentration of 450 ppm). These estimates are further complicated by the likelihood that the SCC will increase over time because the marginal damage cost of one additional unit of GHG increases with the total atmospheric GHG concentration (Watkiss, 2005)[2]. Here we use SCCs obtained from the latest version of the PAGE2009 model under the A1B and LES scenarios, being \$143/tCO2-e and \$73/tCO2-e respectively. While the 2002 version of this model was used in Stern (2006) to estimate the damage impacts of climate change, the A1B and LES scenarios are in accordance with a business as usual scenario and a more ambitious policy abatement scenario respectively.

These compare to the 2012/13 carbon prices recently modelled by the Australian government of just under \$30/tCO2-e for a High Price Scenario and \$23/tCO2-e for a Clean Energy Future scenario, where these are estimated to be in line with a world CO2 atmospheric concentration target of 450 ppm and 550 ppm respectively (Treasury, 2011). One explanation for the marginal damage costs being generally higher that the control costs is that the economic risks of unchecked climate change may be extremely high, including the societal costs of drought, flooding, socially contingent effects, impacts on human health, as well as on the ecosystems upon which we depend (ATSE, 2009).

The total environmental damage of electricity generation should include the health damage costs (HDC) associated with three main pollutants with the worst adverse impact on human health: fine particulate material PM10, sulphur dioxide SO2 and the various nitrogen oxides NOx (ATSE, 2009). These atmospheric emissions increase the incidence of respiratory and cardiovascular disease, causing increase morbidity and premature mortality in the community (ExternE, 2005).

Monetary valuations of these costs are complex and depend on a wide range of factors including the quantity and temperature of emissions, population exposed to emissions, exhaust velocity and chimney heights. ATSE (2009) estimated the HDCs of Australian power stations using results from ExternE (2005) for the EU context considering both market (eg. cost of treating the patient) and non-market (eg. patient's willingness to pay to avoid sufferings) valuations. They found HDCs of \$13/MWh for black and brown coal (about the same as their direct operating costs), \$0.7/MWh for gas-fired generation and \$1.7/MWh for PV – which are the values we use here[3].

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[2] All carbon costs were converted to 2012 Australian dollars and as per tCO2 for comparison purposes.

[3] In the US, Muller (2012) estimated that the social cost of coal-fired electric generation is 2.2 times higher than its social value added. Their social cost excludes climate change impacts but included health damage costs, decreased timber and agriculture yields, reduced visibility, accelerated depreciation of materials and reductions in recreation services.

Thus, if at time *t*, I_t is the displaced CO2 emission intensity, *SCC* is the marginal social cost of carbon and H_t is avoided health damage cost then the environmental PV value or ENV value ENV_t can be expressed as in Eq. 6.

$$ENV_t = \left(I_t \times SCC + H_t\right) \times PVelec_t \tag{6}$$

In conclusion, the total marginal social PV value $SPVV_t$ at time *t* incorporating its energy, avoided losses and avoided emissions is as shown in Eq. 7.

$$SPVV_t = E_t + L_t + ENV_t = \left(w_t + 2\alpha \cdot G_t \cdot w_t + I_t \cdot SCC + H_t\right) \times PVelec_t \tag{7}$$

3.2 Non-marginal PV Values which are not included in the analysis

The above analysis focuses only on the marginal value offered by PV. Other potential PV values, that either do not exist on the margin, or are particularly hard to estimate, include possible deferral of network augmentation, merit order impacts on wholesale electricity prices, security of supply and power quality impacts. All these increase at higher levels of PV penetration and can potentially result in significant additional benefits or costs, especially in the longer term. Although we do not attempt to quantify these potential values here, the following briefly discusses how the non-marginal values can contribute social benefits as well as costs.

3.2.1 Deferring Network Augmentation

Appropriately located PV systems in the grid may defer or avoid the augmentation of transmission and distribution infrastructure, potential offering significant economic value. The key challenge is to estimate how much PV in what locations at what times and with what expected operational characteristics might be able to contribute to avoided network expenditure through reduction in peak loads. Although in the NEM this benefit is captured directly by network service providers, they do operate under economic regulation which is intended to assume socially optimal augmentation of the network.

Assessing the value of deferral of network augmentation is enormously complex. Simplified approaches are available such as that of Borenstein (2008), where the reduction in transmission constraints, reflected in the California nodal prices, is used to establish a network value for PVelec. Passey et al. (2007) estimated network values for particular locations in the South West Interconnected System (SWIS) of Western Australia based on an assumed indicative deferral investment cost. Neither of these approaches is ideal. Oliva and MacGill (2011a) proposed an improvement to these approaches using estimated savings from deferral of particular planned network investments in Sydney. Such deferrals are triggered by a reduction in the projected peak demand in that location. For illustrative purposes we use this approach to estimate this value in Section 5.2.

3.2.2 Merit order impacts on Wholesale Prices

By reducing demand, distributed PV generation can reduce wholesale spot prices, which as discussed above, we have taken to represent the direct societal marginal energy value of electricity generation. The most recent estimate of this Merit Order Effect in Australia suggests that 5GW of PV across the NEM (there is currently about 1.4GW of PV), representing approximately 10% of peak demand, might reduce wholesale electricity prices by 10-25%, with lower penetrations of PV having a disproportionately higher impact as higher cost generation is displaced (ROAM Consulting, 2012). Sivaraman and Horne (2011) argue that PV deployment is a viable option to effectively hedge excessive spot market electricity prices in summer in the NEM given the highlighted coincidence of PV output with peak loads. However, there are very significant complexities and uncertainties associated with such estimates given the ways that electricity market operation and investment might respond to such impacts.

3.2.3 Security of Supply

PV is a form of distributed energy relying on a renewable energy resource and so can contribute to the security and reliability of power systems through greater fuel diversity and decentralised infrastructure. PV can also increase energy security of countries reliant on external sources of energy, such as fossil fuels or uranium (SKM, 2011a; Asmus, 2001). The quantification of these benefits is very complex and highly dependent upon the particular electricity industry context. Borenstein (2008) argues that monetary valuations of these effects are not particularly convincing.

3.2.4 Power Quality and Quality of Supply

PV generation is based on a highly variable and somewhat unpredictable solar resource and can therefore have both positive and negative impacts on power quality and quality of supply. Potential positive impacts can include reduced network flows and hence reduced losses and voltage drops. Potential negative impacts at high penetrations include voltage fluctuations, voltage rise and reverse power flow, power fluctuations, power factor changes, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues. The extent to which these impacts occur will depend very much on the local characteristics, especially including specific measures to enable higher penetrations of PV (Passey et al., 2011).

4 Analysis of NSW distributed PV systems: data and assumptions

4.1 PV and NEM data

We use actual half hourly PV generation data for a one year period from July 2009 to June 2010 (2009/10) obtained from 61 household PV systems of 1 kW of capacity located in the distribution network of Endeavour Energy in the suburb of Blacktown, Sydney, Australia. Our approach uses data from a relatively large number of households and so is more likely to be representative of the diversity of PV system performance seen with distributed residential systems due to issues including orientation and shading. The average annual PV production of these houses over that period was 1,200 kWh/kW/year. This value is slightly less than the average 1,286 kWh/kW/year for 1 kW PV systems during financial year 2010/11 in the Ausgrid distribution area in Sydney according to IPART (2012). As such, our results may slightly under-estimate the value of typical systems in Sydney. For wholesale electricity prices we use the half hourly regional reference price (RRP) for NSW published by the Australian Energy Market Operator (AEMO). This approach captures the correlation between PVelec and wholesale prices, which, as shown below, is a key driver of the SPVV. Additionally to obtain the constant α, the total NEM generation Gt and NSW displaced emission intensities It, we use half-hourly generation data obtained from AEMO.

This dataset appears reasonably representative of the long-term average wholesale price in NSW and the average household PV system in Sydney. For example, the average NSW wholesale price during 2009/10 was $44/MWh while the average NSW wholesale price of the last seven years was $46/MWh (AER, website).

To estimate Lt, the value of avoided losses according to Eq. 5, we multiplied the annual marginal loss factor (for losses in the transmission system) by the distribution loss factor (for losses in that distribution area), whose values are 1.0033 and 1.0827 respectively (AEMO, 2009a; 2009b). Thus the combined transmission and distribution system annual average loss factor for the suburb of Blacktown is 1.086.

4.2 Environmental costs

To calculate the avoided emissions we use the half-hourly weighted average emission intensity in NSW using the generation data from AEMO and the emission intensity factors of the scheduled generators from ACIL Tasman (2009). We multiply this average by the assumed SCC according to Hope (2011) which provides SCCs for emissions in 2009 from the PAGE2009 model under the A1B scenario and LES as mentioned above.

Similarly, to calculate the half-hour weighted average health damage value from avoided SO2, NOx and PM10 emissions, we use the scheduled generation data from AEMO multiplied by the health damage costs in Australia obtained from ATSE (2009). Given that these emission factors and health damage costs are based on full lifecycle assessments we consider as well as PV lifecycle emission cost of $5/MWh according to ATSE (2009). These values are shown in Table 1.

Health Damage Costs

Black Coal = 13 $/MWh
Brown Coal = 13 $/MWh
Natural Gas = 0.7 $/MWh
PV = 1.7 $/MWh

2009/10 CO_2 *Emission intensity in NSW*

Average = 0.98 tCO_2/MWh
Maximum = 1.02 tCO_2/MWh
Minimum = 0.94 tCO_2/MWh
Lifecycle PV = 0.106 tCO_2/MWh

SCC for CO_2 *emitted in year 2009*

A1B = 143 $\$/ tCO_2$
LES = 73 $\$/ tCO_2$

Table 1. Input parameters to evaluate PV environmental value.

4.3 Assessing changing values over time

We assume that the PV system lasts for 25 years and that the electricity generation in future years is reduced by a 0.5% annual performance degradation factor. We assume that the NSW wholesale prices increase each year according to the 'medium global scenario' of ROAM Consulting (2011a) and SKM MMA (2011b), which were prepared for the Australian government. These do not incorporate the impact of a carbon price because we take the SCC into consideration elsewhere. We assume the future SCC increases annually by 2.4% based on Watkiss (2005) who determined that rate of increase as the best fit to the mean SCCs from the PAGE2002 model. We note, however, that the FUND model rate of increase is slightly lower than that of PAGE2002 (Watkiss, 2005) and that Defra (2007) used a 2% increase rate.

Gt, the total generation injected to a specific location at time t, was increased each year according to the average of the Australian electricity demand projections by SKM MMA (2011c) and ROAM Consulting (2011b), both prepared for the Australian government for their current policy position, the Clean Energy Future scenario.

From the second year of operation onwards, it is assumed that PVelec displaces greenhouse emission intensities and avoids other pollutants damage costs as for 2009/10. The average emission intensity factor in the NEM is forecast to decrease in the future (Treasury, 2011). However, we don't include this impact because these estimates are largely based on increasing contributions from renewable energy generation and efficient market dispatch will generally see low operating cost generation such as renewables dispatched ahead of higher operating cost fossil fuel plants, which will therefore be on the margin. Increasing gas generation is seen. It is also possible that increasing gas prices will limit the degree to which gas-fired generation displaces coal-fired. We also assume that the average loss factor for Blacktown remains the same in the future.

The discount rate can have a very significant impact on the NPV. The so-called 'social rate of time preference' (SRTP) is defined as the value society attaches to present, as opposed to future, consumption (Ramsey, 1928). Evans (2004) estimated that the SRPT is 4.7% for Australia. Another value considered suitable for social analysis is the risk free discount rate, which is the theoretical rate of return of an investment with no risk of financial loss. While Harrison (2010) argues that such a rate in Australia is around 4%; according to IPART (2010) that rate is 2.4%. Garnaut (2011) proposed a social discount rate in Australia of 4%: being 2% for the risk free rate and 2% extra for the risks of climate change. As such, we use a real discount rate of 4% and conduct sensitivity analyses using 3% and 5%[4].

We carry out the future SPVV estimations for two climate change policy scenarios presented in Hope (2011) which essentially vary only the initial 2012/13 SCC: these are the IPCC's A1B scenario and a 'low emission scenario' (LES) mentioned earlier.

Finally, we estimate what we call social payback periods (SPPs), which are the periods of time that the cumulative annual SPVV takes to exceed the total costs of the PV system. We use an average price per watt of an installed PV system of $AUSD 3.5/W before any government rebates (Martin, 2012). Also we include the costs of inverter replacement of $AUSD 1,000/kW according to (CEC, 2011). We assume two inverter replacements in years 8 and 16, which is consistent with NREL (2006) and Borenstein (2008). After discounting the inverter replacement costs at 4%, the total PV cost per kW is $AUSD 4,800. Note that this does involve using a private PV system cost estimate, albeit at a social discount rate, to represent the societal cost. The accuracy of this will depend on how well, or poorly, these private costs reflect all societal costs and benefits.

5 Results

This section firstly presents the annual SPVV of the 61 residential PV systems in Western Sydney for 2009/10 and then the Net Present SPVV of these systems over their lifetimes. The latter is compared to the system's discounted costs to estimate if and when PV is socially beneficial under the assumptions used here.

5.1 Current Social PV Value

Using 2009/10 PV generation, NEM generation and wholesale prices data in Eq. 7, and considering a SCC in line with the business as usual scenario A1B, we obtain the annual SPVV for each household PV system of our 61 houses. Fig. 2 shows the SPVV and its components for each PV system in ascending order, together with their total PV generation over the year[5].

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[4] All mentioned discounts rates are in real terms.

[5] We convert all values to 2009 Australian dollars

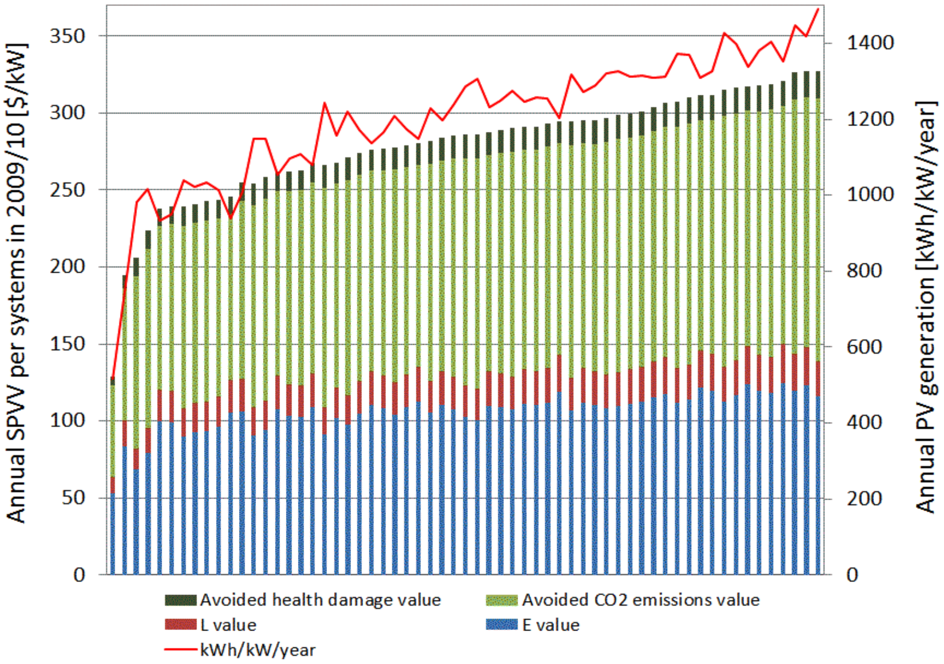

Fig. 2. Annual SPVV for 61 household PV systems in Sydney and their total annual generation.

It can be seen that different PV systems can have very different SPVVs. As we can see from Eq. 7 this value depends strongly on the total PV generation (with this correlation clear in Fig. 2) which will be a function of the local solar resource and possible micro climate impacts, system equipment performance, system orientation and other possible impacts such as shading. However, it also depends on how well a system's generation coincides with high spot prices and periods of higher emissions intensity. High spot prices generally match well with high PV generation in NSW because these high prices generally occur on hot summer days with high demand largely driven by air conditioner use. This result highlights that the societal value of distributed PV will be greatly impacted by the quality of system equipment, maintenance and installation.

Although the value of deferring network augmentation is not included in our SPVV analysis, we have aggregated the output of the PV systems assessed here and estimated this value for six locations in Sydney (including Rooty Hills, which is the suburb where the systems are installed). Deferral values were obtained from demand management reports prepared by the NSW Distribution Network Service Providers as part of one their demand management obligations (Ausgrid, website; Futura Consulting, 2011). Table 2 describe such deferral opportunities and the potential savings. Fig. 3 shows the distribution of these values for the PV systems assessed here. See Oliva and MacGill (2011a) for more details of this calculation which involves assessing the amount of PV generation from each system expected to be available at the time of expected future peak demand for these various Area/Zone substations.

Area/Zone Substation	***Savings [$/kVA]***	***Reason***
Broadmeadow	*103*	*Cheaper new 2 x 37MVA Substation instead of new 2 x 50MVA 132/11kV that save $1.27m*[6]*.*
Charlestown	*799*	*Defer by 2 years new 132/11kV Charlestown Substation whose cost is estimated at $40.5m.*
North Western Pennant Hills	*608*	*Defer by 2 years new 11kV cable whose cost is estimated at $3.75m.*
Sydney East	*161*	*Defer by 2 years new 33kV feeder whose cost is estimated at $8m.*
Willoughby	*550*	*Defer by 1 year new 132/11kV RNSH Substation whose cost is estimated at $30m.*
Rooty Hill	*204*	*Defer by 2 year new North Glendenning Substation whose cost is estimated at $23m.*

Table 2. Indicative values of deferral of network augmentation for six Area/Zone substations in Sydney.

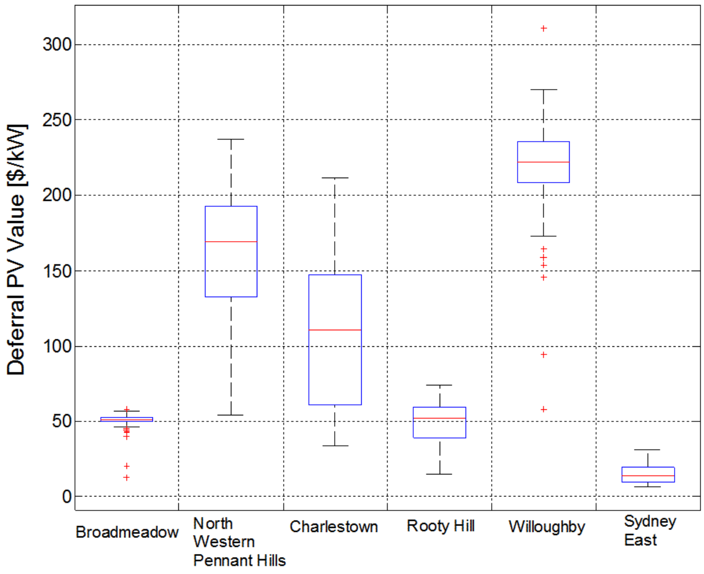

Fig.3. PV deferral value per kW of PV for different locations in Sydney. In each box, the central mark is the median, the ends of each box are the 25th and 75th percentiles, the whiskers extend to the most extreme data points not considered outliers, and outliers are plotted individually.

From Fig. 3 it is clear that PV's network augmentation deferral value is very different for different locations. This value varies according to both the $/kVA savings, as shown in Table 2, and with how well the PV output and substation load correlate. The suburb where these systems are located, Rooty Hills, has a relatively low value of

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[6] 'm' represents one million Australian dollars.

$48/kW. Locations where no augmentation is required for some time would have a very low value, as would locations with a very poor match between PV output and load – for example, Area/Zone substations where peak demand occurs on winter evenings.

5.2 NPV Analysis

Here we estimate the cumulative SPVV for each of the PV systems from 2012/13 to 2037/38, using a real discount rate of 4% under both the A1B and the LES scenarios - see Fig. 4[7]. This figure also compares the cumulative SPVV (a societal economic benefit) to the net present cost of the system (as noted earlier, a private financial cost). It can be seen that the time taken for the societal benefit to exceed the financial cost varies greatly between PV systems. For a total of 3 systems (5%) and 31 systems (50%), under the A1B scenario and the LES respectively, this does not occur within the assumed life of the system. Fig.5 shows each system's social payback period (the time taken for its economic benefit to equal the financial cost), with the average and shortest payback periods being 19 and 15 years under the A1B scenario, and 26 and 21 years under the LES.

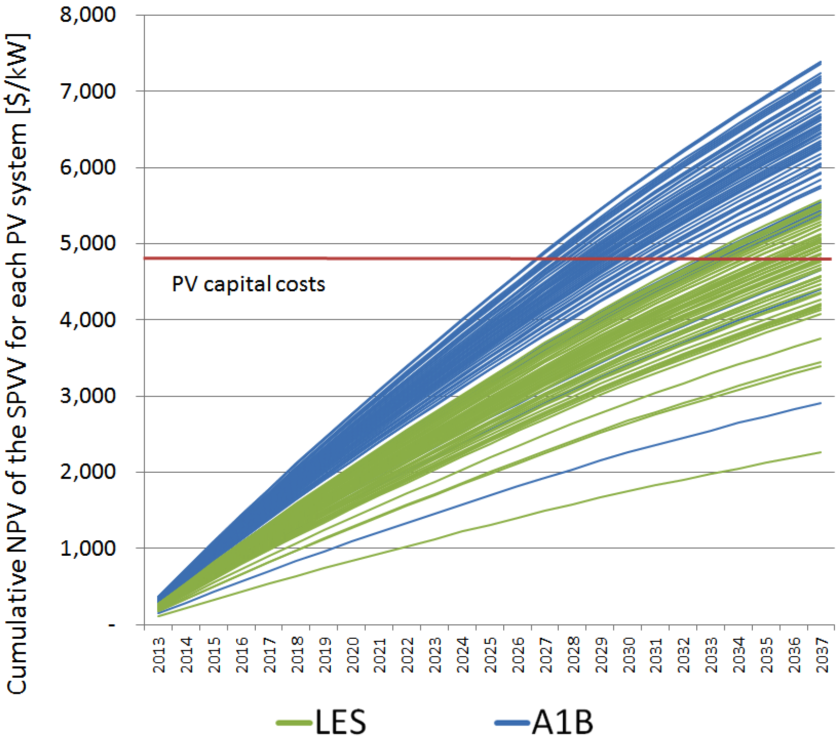

Fig. 4. Cumulative NPV of the SPVV for 61 household PV systems.

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[7] We present these values in 2012 Australian dollars.

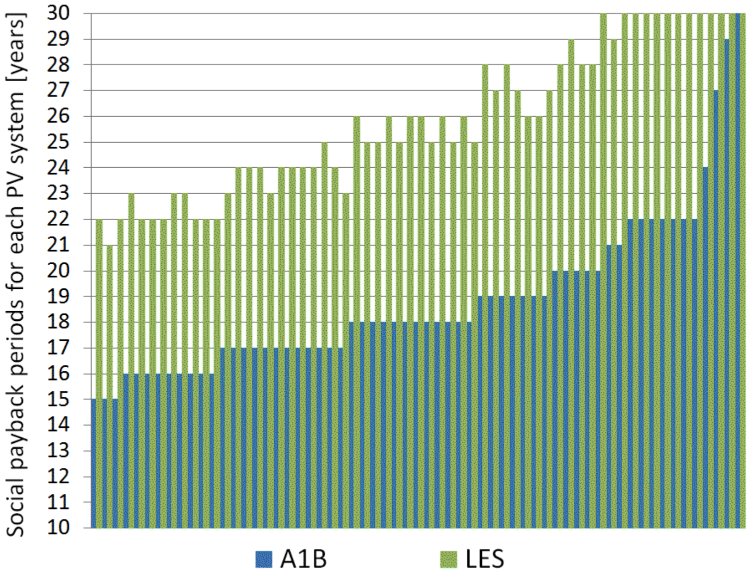

Fig. 5. Chart of social payback periods for 61 household PV systems.

5.3 Sensitivity Analysis

We undertook sensitivity analysis of these findings for the following parameters: loss factors, emission intensity of displaced generation, discount rates and the SCC.

Avoided losses were re calculated using average loss factors rather than the quadratic approach of Eq. (2). This variation allows us to see how well PV generation matches with peak demand and losses.

The emission intensity of displaced generation was calculated assuming that an open cycle gas turbine (OCGT) was operating on the margin at all times, and so an emissions intensity of 0.76 tCO2/MWh (ACIL Tasman, 2009) was assumed.

As discussed above, there is significant variation in the literature regarding the optimal social discount rate. We assessed discount rates of 3% and 5%, where the former was used by Borenstein (2012) and Harrison (2010) in similar sensitivity analysis, and is more aligned with values obtained from the Ramsey formula (Harrison, 2010). The latter rate is close to the SRPT proposed in Evans (2004) for Australia.

There is also significant variation in the literature regarding the SCC. As noted earlier, if one assumes that abatement achieved by a policy mechanism such as an emissions trading scheme results in optimal economic outcomes for society and that the policy mechanism efficiently achieves this price, the scheme's carbon price will be equal to the SCC (Defra, 2007). We use carbon price projections according to the Australian government's High Price Scenario (HPS), which starts at just under $30/tCO2-e, which aims to be in line with a world CO2 atmospheric concentration target of 450 ppm (Treasury, 2011).
Table 3 summarises the different sensitivity analyses conducted and Fig. 6 shows the results.

Name	***Change relative to the base case***
Approach Base A1B	*As described in the methodology. SCC = $143/tCO2 in 2012*
Approach Base A1B - 3%	*Social discount rate is 3% instead of 4%.*
Approach Base A1B - 5%	*Social discount rate is 5% instead of 4%.*
Approach Base LES	*As described in the methodology. SCC = $74/tCO2 in 2012*
Average losses approach	*Instead of using the quadratic losses to estimate avoided losses we use the average loss factor only. i.e. $2\alpha G_t$ is replaced by LF*
NEM marginal emission intensity (OCGT)	*Instead of using average intensity emissions in NSW we use the intensity emission of an OCGT. i.e. 0.76 tCO_2/MWh*
SCC equal to carbon price	*Instead of using a SCC equal to the value for the A1B or LES scenarios we use the HPS value. i.e. a SCC of $30/tCO2 in 2012 and projections in line with HPS modelling*

Table 3. Summary of Sensitivity Analysis scenarios.

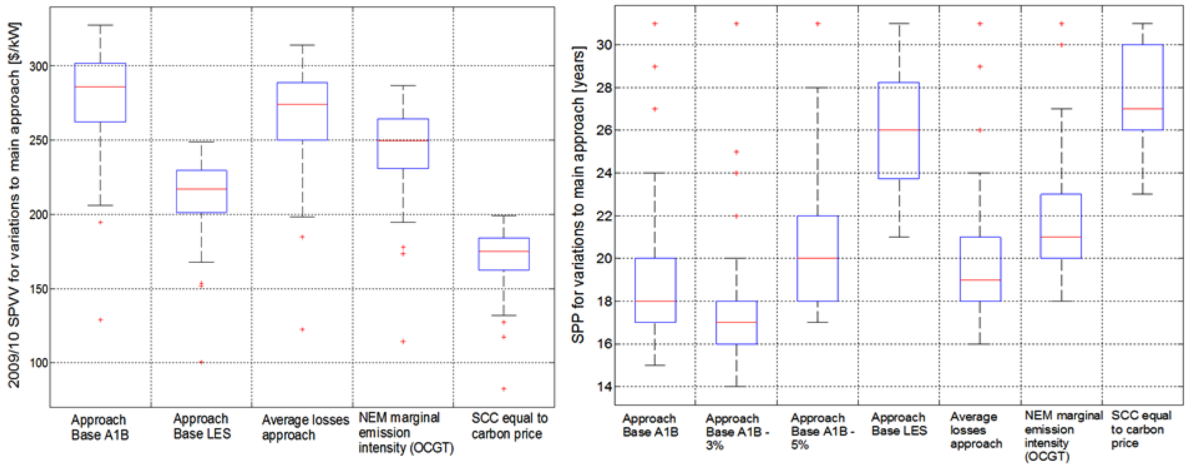

Fig.6. Distribution of SPVVs and SPPs for the different sensitivity scenarios outlined in Table 3. In each box, the central mark is the median, the edges of the box are the 25th and 75th percentiles, the whiskers extend to the most extreme data points not considered outliers, and outliers are plotted individually.

As expected, the results change significantly for each variation to the base case, particularly when we change the SCC. Using a SCC equal to the value of the carbon price under the Australian government's HPS, results in the cumulative SPVV being less than the capital cost of the system during the system's lifetime in almost all cases.

6 Conclusions

In this paper we have presented a methodology for estimating the net marginal societal value of distributed residential PV systems within the Australian NEM. The chosen methodology considers only a subset of potential societal costs and benefits and requires a range of simplifying assumptions. The focus is on PV's potential direct energy value (including avoided losses) and environmental value (including not only greenhouse gas emissions but also regional air pollutants). Such evaluations are challenging yet can play a valuable role in policy development in highlighting the societal value of supporting such deployment within an existing set of electricity market and commercial arrangements that don't actually reflect actual underlying economic costs and benefits. This is a particular issue for residential PV systems that are physically limited within the distribution system and commercially located in retail electricity markets.

We applied this methodology for the example of 61 domestic rooftop PV systems located in Western Sydney using a year of actual system performance data and associated NEM outcomes over that period. Domestic systems of this general type make up almost all of the approximately 2GW of PV currently installed in Australia. Our results highlighted that the better performing residential PV systems offer net marginal societal benefits under reasonable assumptions of marginal energy and environmental values and social discount rates. Much depends, however, on the quality of PV system equipment, maintenance and installation – including system orientation and tilt, and possible adverse impacts such as shading.

There would seem to be some important implications for policy making in these findings. The first is that widespread deployment of residential PV systems seems likely to have societal value and is, hence, potentially worthy of policy support should the current commercial arrangements faced by households not provide sufficient incentive. Any such support, however, should also focus on ensuring high PV system performance that maximises its societal value. An example of such support are feed-in tariffs which reward good system performance with higher financial flows to system owners. By comparison, capital cost subsidies provide less incentive to ensure systems are installed in appropriate locales and maintained. There may also be opportunities to focus PV policy support in areas where PV offers potential network value, and to design complementary policies that increase PV value such as shifting deferrable household loads to times of high PV penetration to increase self-consumption (Elliston et al, 2010).

There are many possible directions for future work in both refining the existing methodology, adding further societal costs and benefits (for example, land-use and water environmental impacts associated with fossil fuels) and applying it to different contexts including different jurisdictions, and commercial and industrial scale PV systems. Further investigation of how well or badly current commercial arrangements in these different contexts reflect underlying PV societal costs and benefits would have particular value for policy makers looking to better align societal and private incentives. Consideration of PV's societal costs and benefits beyond the margin could also contribute usefully to policy development towards the major large-scale electricity industry transformation that appears to be required to effectively address our climate change challenges.

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