

Retrospective modeling of the merit-order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market

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HIGHLIGHTS

- We model the impact of photovoltaic generation on the Australian electricity market.
- Photovoltaic generation depresses electricity prices, particularly in summer peaks.
- Over the course of a year, the depression in wholesale prices has significant value.
- 5 GW of solar generation would have saved \$1.8 billion in the market over two years.
- The depression of wholesale prices offsets the cost of support mechanisms.

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ABSTRACT

In electricity markets that use a merit order dispatch system, generation capacity is ranked by the price that it is bid into the market. Demand is then met by dispatching electricity according to this rank, from the lowest to the highest bid. The last capacity dispatched sets the price received by all generation, ensuring the lowest cost provision of electricity. A consequence of this system is that significant deployments of low marginal cost electricity generators, including renewables, can reduce the spot price of electricity. In Australia, this prospect has been recognized in concern expressed by some coal-fired generators that delivering too much renewable generation would reduce wholesale electricity prices. In this analysis we calculate the likely reduction of wholesale prices through this merit order effect on the Australian National Electricity Market. We calculate that for 5 GW of capacity, comparable to the present per capita installation of photovoltaics in Germany, the reduction in wholesale prices would have been worth in excess of A\$1.8 billion over 2009 and 2010, all other factors being equal. We explore the implications of our findings for feed-in tariff policies, and find that they could deliver savings to consumers, contrary to prevailing criticisms that they are a regressive form of taxation.

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1. Introduction

The design of policies to assist the transition to low emission electric power production presents significant challenges. Any new generation necessarily incurs significant up-front cost, and this is particularly the case for renewables such as solar photovoltaic (PV). On a levelised cost basis, solar PV is currently an expensive way to produce electricity. However, solar PV has a

well-established and demonstrated learning curve that is producing significant cost reductions, reducing at about 22% for each doubling in deployment (Breyer and Gerlach, 2010). Many analysts anticipate that solar PV will reach retail grid parity in this decade (Breyer and Gerlach, 2010; EPIA, 2011; Gerardi and Stevens, 2011), at which time it will become cost competitive with residential electricity tariffs. An objective of policy measures, such as guaranteed feed-in tariffs, is to help realize grid-parity in the near-term.

However, policies such as feed-in tariffs that are designed to accelerate deployment of renewable energy remain controversial. They have been criticized for the impact they have on consumer

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electricity prices, as well as the method by which such costs are distributed across the consumer base. In Australia, the NSW Independent Pricing and Regulatory Tribunal (IPART) has suggested that the State and Federal Government renewable energy schemes added 6% to retail prices in 2010/11 (IPART, 2011). Nelson et al. (2011) argued that current NSW feed-in tariffs cost consumers 0.5 cents per kWh, and that the costs are unequally distributed amongst different sectors of the community. There is particular concern amongst the welfare sector that the costs associated with feed-in tariffs have been unfairly borne by households unable to participate in the scheme, such as renters. Because these costs are likely to impact disproportionately on low income groups, some have argued that feed-in tariffs may constitute an unwelcome form of regressive taxation (Nelson et al., 2011).

However, there are other mechanisms by which renewables can potentially impact electricity prices which may offset the feed-in tariff impost levied across consumers. For example, the low marginal cost of renewables means that they can significantly impact the “merit order”, which plays a crucial role in the determination of the wholesale electricity spot price. Furthermore, distributed renewable energy generation may potentially mitigate network expansion and upgrades by alleviating loads that need to be carried through the transmission and distribution networks. With generation typically accounting for about only 30% of retail electricity costs in the Australian market, there may be hidden benefits of renewable generation that offsets the costs of feed-in tariffs. There may also be hidden network cost, should

excessive localized generation required grid augmentation for export, or two way flow.

The key offset for renewable generation addressed in this paper is through the so-called merit order effect. The addition of significant levels of renewable generating capacity into electricity grids has been shown internationally to markedly reduce wholesale spot prices for electricity (Ray et al., 2010).

In Germany, Sensfuss et al. (2008) estimated that the savings from the merit order effect from renewable generation in 2006 were about €5 billion, while the money spent on feed-in tariffs was €5.69 billion. This gave a net total cost of €0.69 billion for 52 TWh of renewable electricity, which would have otherwise had a wholesale market value of €2.5 billion, representing a net saving to consumers. The merit order effect has also been quantified specifically for wind power in Germany (Weigt, 2009), Denmark (Munksgaard and Morthorst, 2008; Jónsson et al., 2010), Spain (Sáenz de Miera et al., 2008) and a combination of European countries (Ray et al., 2010).

In Australia, renewable generation is demonstrably impacting wholesale spot prices in jurisdictions such as South Australia where wind accounts for some 24% of generation capacity (AEMO, 2011). In South Australia, negative wholesale spot price events are increasingly common during periods of high wind power generation (Boerema et al., 2010; Cutler et al. 2009), and now account for about 1% of market time. The potential of renewables to impact via the merit order effect has been recognized in the purported concerns of some coal-fired generators about the rate of introduction of renewable generation. For example, in 2011,

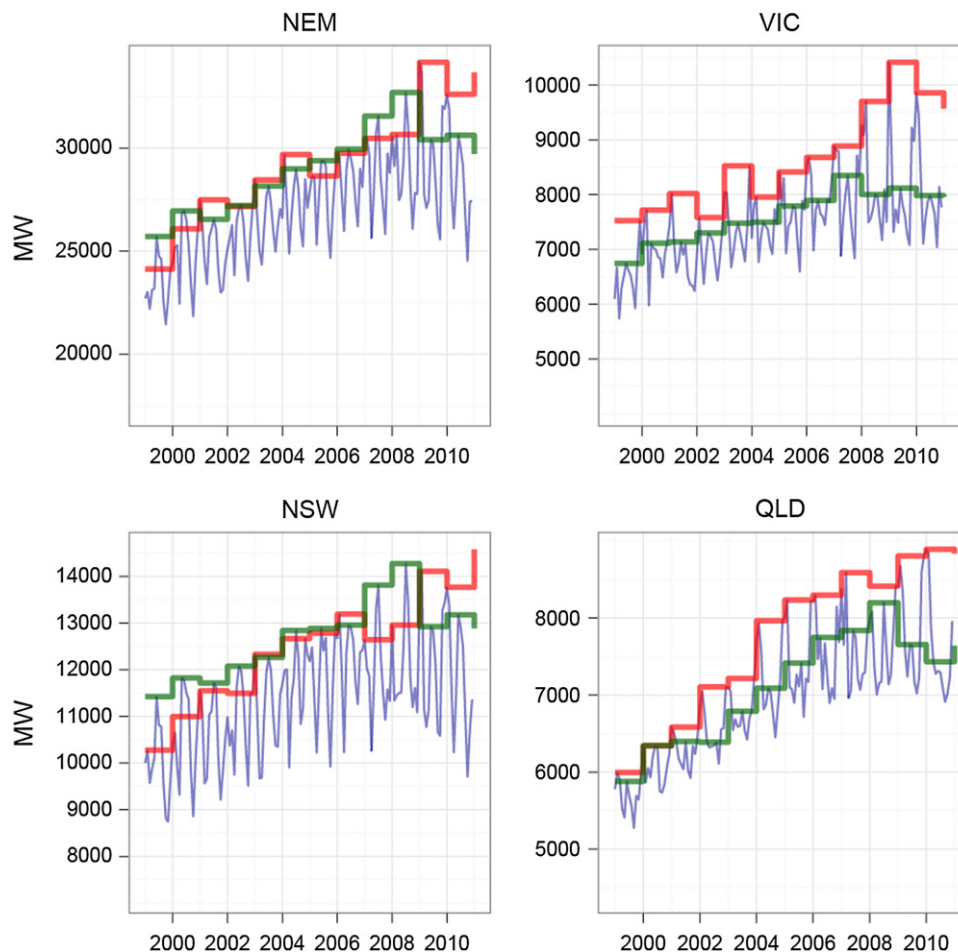


Fig. 1. Annual summer (red) and winter (green) peak demands and monthly (blue) peaks in each of the three main National Electricity Market (NEM) regional jurisdictions (VIC—Victoria, NSW—New South Wales, QLD—Queensland) and the entire NEM, for years 1999–2011 (up to and including August 2011). Data from AEMO. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

the Victorian Auditor-General reported (Pearson, 2011) on the reasons behind relaxation of mandates for introduction of renewable capacity in 2007, when the time frame for increasing the share of Victoria electricity consumption from renewable energy sources to 10% was extended from 2010 to 2016. The Auditor-General concluded that this extension occurred “primarily to alleviate the concerns of brown coal generators that the 10% target would deliver too much renewable energy too quickly which would reduce wholesale electricity prices and adversely affect existing generators”.

PV is expected to impact wholesale electricity spot prices more than wind power (Bode and Groscurth, 2010), per unit of electricity generated in the Australian National Electricity Market (NEM). This is because power production from PV generally correlates more strongly with electricity demand than wind. In markets such as the NEM in which peak demand has recently been dominated by summer peaks (Fig. 1), when PV will be generating the most power, the impact of PV on the merit order may be anticipated to be particularly effective.

In this paper we investigate the potential impact of PV on the wholesale electricity spot price in the Australian NEM over the 2009 and 2010 calendar years, as a preliminary investigation into assessing the extent to which the merit order effect may offset the costs associated with PV incentives. Our primary objective is to estimate the value of the purported concern of coal-fired generators, as expressed in the Victorian Auditors-General's report (Pearson, 2011), that meeting renewable energy targets too quickly would depress wholesale prices. This concern motivates the method of our analysis. Over time we expect the market to adapt to any new generation capacity, adjusting via changes in the amount of capacity overhang, for example. However, in the short term there is little capacity for the market to respond in such ways. We are therefore motivated to calculate the “static” response of the market as if PV generation were instantaneously added. We begin with an outline of some of the relevant characteristics of the Australian NEM, followed by an outline of the models we use for solar generation and price demand dispatch to evaluate the potential impact of PV generation on the NEM wholesale spot prices.

2. The Australian National Electricity Market

The Australian NEM spans the eastern states of Queensland, New South Wales, Victoria, Tasmania and South Australia, and is broadly divided into those 5 regions, with interconnectors between. All electricity in the NEM is traded through a central pool, and the NEM is currently largely dominated by fossil fuel energy sources, particularly black coal (Queensland and New South Wales) and brown coal (Victoria). The NEM peak demand is around 35 GW, with a mean annual demand of 23 GW.

Peak demand is typically in January or February in the Austral Summer, in each of the main jurisdictions (Table 1), as illustrated in Fig. 2. Summer peaks now typically exceed winter peaks by

more than 1 GW in each of the three main regional jurisdictions of the NEM (New South Wales, Queensland and Victoria), and the current trend is for more rapid growth in the summer peak compared to the winter peak demand. Summer demand tends to peak in periods during the afternoon when PV is able to supply some load.

In the normal operation of the NEM, enough generation capacity is scheduled to meet the demand. This demand is met by starting at the lowest price offer and then additional capacity is added in order from the lowest to the highest price. That is, electricity is scheduled on an economic basis in order of merit (AEMO, 2010).

The dispatch price of electricity is determined every 5 min on the basis of bids by the participating generators. The dispatch price is set at the value where the most economic combination of competitive bids meets the demand. All electricity generated within a region receives that price for the 5 min period, and the 5 min prices are averaged over each half an hour period to produce the half-hourly spot price (AEMO, 2010).

With a total generating capacity in excess of 45 GW and a peak demand of 35 GW, the NEM is characterized by a significant “capacity overhang” of almost 30%. One consequence is that volume weighted spot prices are typically below that of long run marginal costs, even for the cheapest generation. In the financial year 2010–11, the volume weighted wholesale price was ~3.2 c/kWh, compared to average retail prices in the range of 16–24 c/kWh.

At the end of 2009, there was about 121 MW of PV capacity installed in Australia, which increased to 385 MW by the end of 2010 (ORER, 2011). As such, over the period we analyzed, installed PV would already have an impact on the NEM. We consider the impact of adding additional capacity over and above this existing deployment. The ‘0 GW’ and ‘5 GW’ scenarios referenced in the following discussion therefore refer to additional installation over and above this existing installed PV base.

3. Solar PV power generation model

To attribute the value of PV generation we consider a scenario in which PV generation is confined to the capitals of the four largest NEM regions, Brisbane (QLD), Sydney (NSW), Melbourne (VIC) and Adelaide (SA), where the bulk of the population is located. The model assumes a PV panel oriented at 30° slope facing directly north, in each of the cities. We consider that the number of PV installations is equally partitioned in these locations. While we could consider distributions more aligned to the population distribution, the absence of interconnect constraints in our model, as discussed below, means that the actual partitioning of PV distribution will have relatively little price impact. Furthermore the range in PV annual capacity factors for the four capital cities is small, with Adelaide having the highest at around 19.5% for 2010 and Sydney having the lowest at around 17.1% for 2010.

Our solar generation model calculates the solar radiation received by a solar panel on an hourly time-step using basic inputs of longitude and latitude, measured Global Horizontal Irradiation (GHI) from 2009 and 2010, measured local air temperature and solar panel orientation.

We use hourly GHI Solar data from the Geostationary Meteorological Satellite and MTSAT series operated by the Japan Meteorological Agency sourced from the Australian Bureau of Meteorology (BOM, 2011), and local ambient temperature data taken from Australian Bureau of Meteorology station readings from within the cities. Temperature data was averaged over relevant stations on an hourly basis.

Table 1
Summer maximum demand and winter maximum demand (MW). Data from AEMO.

	Winter max demand		Summer max demand	
	2009	2010	2009	2010
NSW	12,922	13,176	14,106	13,765
QLD	7655	7313	8804	8891
SA	2362	2505	3331	3121
TAS	1679	1694	1358	1300
VIC	8119	7981	10,415	9858

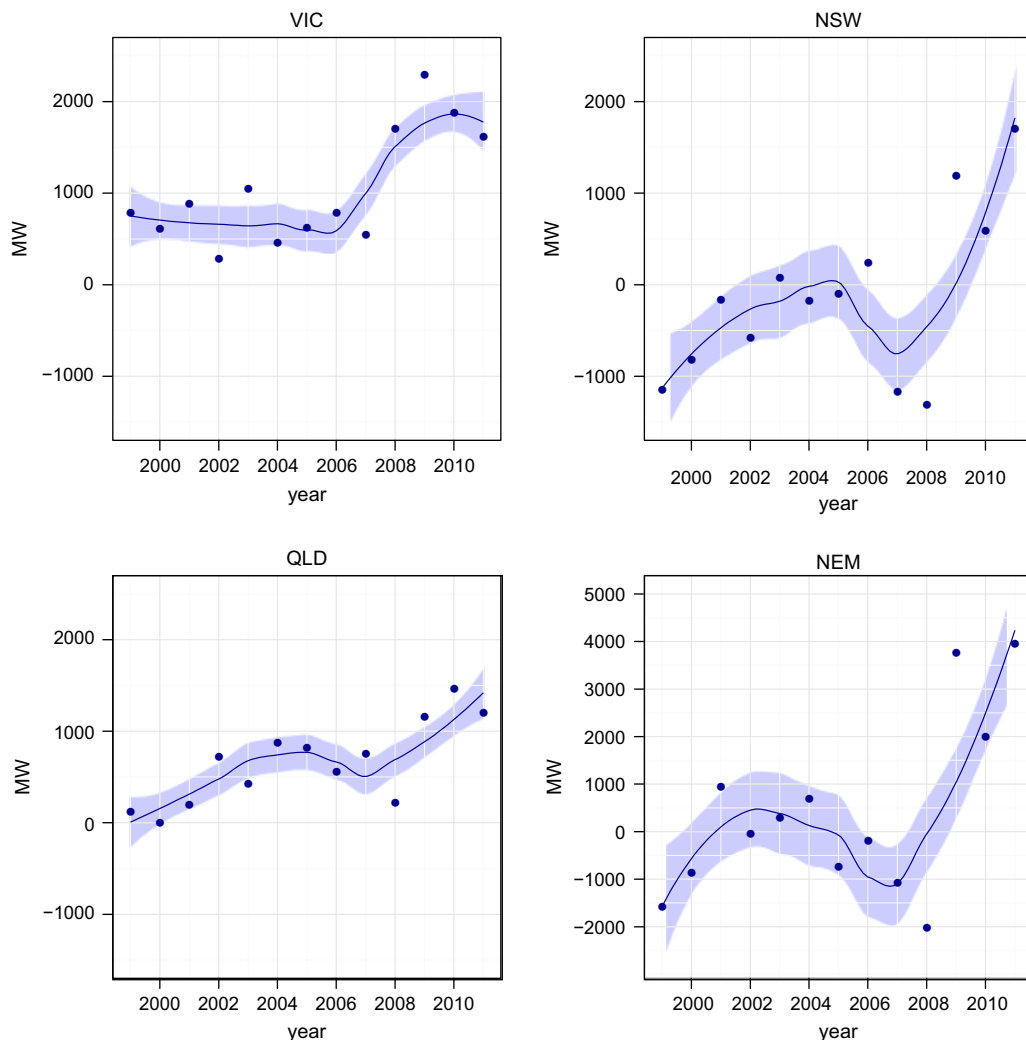


Fig. 2. Difference in Annual summer peak and annual winter peak consumption in each of the three main NEM regional jurisdictions (VIC—Victoria, NSW—new South Wales, QLD—Queensland) and the entire NEM, for years 1999–2011 (up to and including August 2011). Positive values imply summer peak demand exceeds winter peak demand while negative values imply the reverse. Data from AEMO.

Photovoltaic conversion efficiency is strongly affected by the magnitude of received radiation, and by cell temperature. We use the technical specifications of a supplier solar panel (Silex SL270 solar panel) to calculate the power output and capacity factor at each time-step, accounting for efficiency losses due to temperature and received radiation.

Constant conversion loss factors including inverter losses (2.8%), ohmic wiring losses (2%), array mismatch losses (2.2%) and module quality losses (1.6%) are taken from the University of Geneva's "PVSyst" model (PVSYST, 2011).

We use the standard approach from Duffie and Beckman (1991) to calculate the clear-sky radiation on a solar PV panel for any orientation for any geographic location. The Extraterrestrial Horizontal Radiation (instantaneous) is calculated as a function of latitude, longitude and time, correcting for solar time and the Equation of Time. The angle of incidence is calculated based on assumed panel orientation.

We calculate the clearness index (the ratio of measured Global Horizontal Irradiation to Extraterrestrial Horizontal Irradiation) using the Erbs et al. (1982) correlation, to calculate diffuse and beam components of the incident radiation. The 'HDKR model' of solar radiation, which assumes anisotropic sky conditions and takes into account horizon brightening effects, is used to calculate

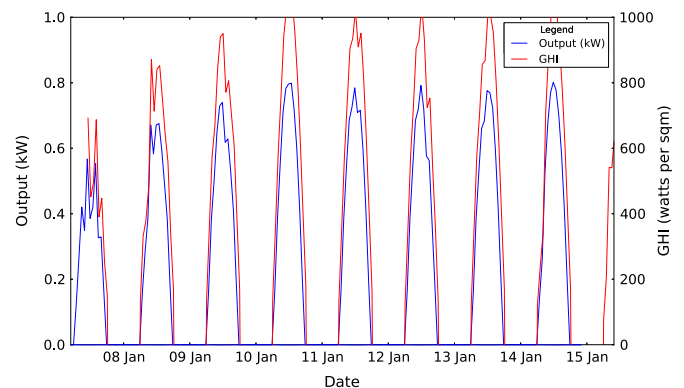


Fig. 3. Solar PV model results for a 1 kW north-facing PV installation at 30° slope in Brisbane, January 2010.

total global horizontal radiation on the panel surface as per equation 2.16.4 from Duffie and Beckman (1991).

From the calculations of incident radiation and PV panel output described above, the hourly capacity factor (the ratio of instantaneous power output to rated peak power output) is determined, and then used to calculate the output of larger

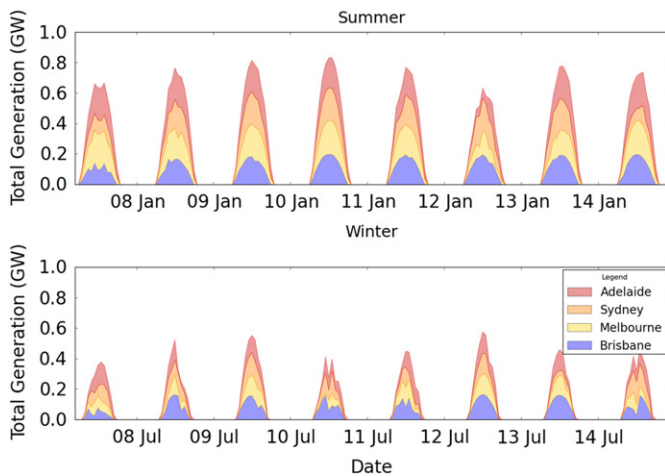


Fig. 4. Cumulative output for 1 GW of PV, distributed throughout eastern seaboard in summer and winter 2010.

Table 2

Annual capacity factors generated from the solar PV model.

City	Calculated annual capacity factor (2009) (%)	Calculated annual capacity factor (2010) (%)
Brisbane	19.0	18.1
Sydney	17.1	18.1
Melbourne	17.6	17.7
Adelaide	18.7	19.5

installations. The calculated solar output for a 1 kW PV system for a week in January 2010 for Brisbane is shown in Fig. 3. Fig. 4 illustrates the cumulative output over all regions for a 1 GW distribution, in summer and winter. Table 2 shows the annual capacity factors (the ratio of actual output to potential output if operated at full capacity) for 2009 and 2010 for the major cities based on the solar model.

It should be noted that no solar dataset is available for November 11 or the period November 15–26, 2009. No attempt was made to estimate placeholder values in this period, which effectively means that no solar output was modeled over this period. As this period contains a number of relatively high wholesale spot price events, the consequence is for the model to underestimate the total market impact of PV by an estimated 3–5% in 2009.

4. Price–demand model

There are thousands of constraints and constraint equations that govern the NEM dispatch process. These constraints include (but are not limited to) interconnector capacities and generating constraints. These are required in order to ensure reliable and safe provision of electricity, but also impact wholesale spot pricing. To simplify the evaluation of the approximate value of the merit order effect of a given PV installation, all other factors being equal, we have made use of the following assumptions in modeling the NEM dispatch process:

- We consider the NEM as a single region. This is equivalent to assuming the Marginal Loss Factor's (MLF) between the NEM

regions to be 1, and that there are no capacity constraints between the 5 different regions.

- We ignore other generation constraints, such as generation constrained on or off.
- We assume that PV generation cannot produce negative spot prices in the model.
- We assume bidding behavior of existing generation is static and does not respond to increased PV generation.

The impact of each of these assumptions is discussed below.

Considering the NEM as a single region significantly simplifies the process of estimation of wholesale spot prices, as only one total demand is considered and one price needs to be resolved. A consequence is that throughout the entire NEM, the cheapest electricity (at a given Regional Reference Price, RRP) is available to satisfy all demand on the NEM; i.e., the cheapest electricity anywhere in the NEM is preferentially dispatched. This assumption yields a lower value for electricity prices, relative to the actual operation of the NEM where transmission capacity constraints and MLF's do apply. Our calculated 'NEM wide' price is typically lower than, and sometimes much lower than, the actual volume weighted average price for high price events within a particular region when interconnectors are constrained (AEMO, 2010), as typically happens in peak demand summer heat wave events in south-eastern Australia (see Table 4 in Section 5).

Due to technical realities of operating the power system, other constraints arise to ensure security of supply, including constraining generation off or on. Generation that has been 'constrained off' is dispatching at a level below what would otherwise be expected from the merit order, or the market determined schedule. In order to balance supply, generation which is higher in the merit order (and would otherwise not be dispatching) must be 'constrained on'. Constrained on generation is, by definition, higher in the merit curve. Whilst under normal operation this generator would receive at least the price it is bid into the market, when constrained on, the compensation or price received is the prevailing regional reference price in the market at the time. Thus 'constrained on' generation has no price impact, and ignoring this constraint does not impact the determination of the price.

It is feasible that significant penetration of PV could induce negative prices events, analogous to the negative price high wind events in SA (Boerema et al., 2010; Cutler et al. 2009). However, unlike large-scale wind which is contracted or hedged, PV generators could be considered fully merchant traders with no start up and shutdown costs. As such, PV generators could be expected to curtail production instead of paying to export to the grid. That is, we assume that production (and hence bidding behavior) is not price independent. It is unlikely that PV owners would pay to feed electricity into the grid.

As outlined earlier bidding behavior in the market would eventually be affected and change as a result of the addition of significant installations of PV. However, as our motivation is to estimate the near-term price impact of large-scale renewable penetration a partial equilibrium (*ceteris paribus*) approach is sufficient. The manner in which bidding behavior would change is unknown. It could be argued that, for example, price would be more volatile as generators (especially 'peakers') would have less opportunity to make their expected income, thus affecting pipeline capacity and gas contracts. However, it could equally be argued that in a fully competitive market, generators would have limited ability to raise (and may even lower) bids, to ensure they are dispatched at all and that their asset is utilized.

In combination, these assumptions allow for the development of a simplified model of the NEM dispatch process, which tends to underestimate the wholesale spot price. We compare the modeled wholesale spot price with PV installations against the

modeled wholesale spot price without PV when determining the merit order effect.

Historic bid data is publicly available from the Australian Energy Market Operator (AEMO), and details information about the dispatch offers including the amount of energy a generator will sell at a certain price. For the purposes of this analysis, third party software NemSight (Creative Analytics, 2011) was used to extract the bidding data and dispatch data for all generators in the NEM for each 5 min period since 2009. This data included the generator identification, the region, the dispatch quantity offer, the dispatch price offer and the actual electricity dispatched in the 5 min period. Each dispatch price offer is tied to a quantity offer for a particular generator, and the price has been adjusted to include Transmission Loss Factors (TLF's). The actual dispatch captures the fact that during a particular trading period, the generation may be constrained (on or off) due to the many different constraint equations to ensure reliable supply of electricity. Table 3 shows a sample bid stack from a 5 min period in August 2011.

The PV generation is assumed to occur on a residential scale, and acts to reduce demand. That is, the PV generated electricity is not bid into the market itself. In reality, not all electricity will be used onsite, and at different times of the day a proportion of the energy will be exported to the grid. We assume any electricity returned to the grid is used locally and thus acts to reduce demand for the large-scale generators participating in the wholesale electricity market.

In order to calculate a wholesale spot price that incorporated the impact of PV using the model described above, a new demand profile input (that also incorporates the impact of PV) is required. PV generating capacity from 0 to 5 GW was used with the solar model in conjunction with the historical demand profile to produce this modified demand profile. The historical 5 min demand was calculated by summing the actual dispatched electricity in a 5 min period. The modified demand (including the impact of PV generation) was calculated by subtracting solar output (MW) from this historical underlying demand. As the instantaneous GHI solar data was available in one hour increments, we have used a linear interpolation to obtain relevant 5 min solar output. The new demand profile was then used in conjunction with the historical bid stacks from a 5 min period to determine a new dispatch price for that 5 min period, using the static bid model described above. The calculated price (at the end of each 5 min period) was averaged over the half hour trading interval to yield the spot price for the interval.

Table 3
Sample bidstacks for 10 August 2011 at 2 pm. Data from NemSight.

Rank	Unit name	Region	Price (AU\$/MWh)	Quantity (MW)	Dispatched (MW)
1	BDL01	VIC	−1052.79	20	20
2	REDBANK1	NSW	−1001.2	76	76
3	CPP_4	QLD	−1000	200	200
4	STAN-3	QLD	−1000	220	220
...
178	TARONG#1	QLD	24.53	20	20
179	TARONG#4	QLD	24.53	20	20
180	TARONG#3	QLD	24.53	20	20
181	LD04	NSW	24.93	140	140
182	LD02	NSW	24.93	140	140
183	LD01	NSW	24.93	170	170
184	ER03	NSW	25.05	140	140
...
353	CG1	NSW	12,500	175	0
354	STAN-1	QLD	12,500	130	0
355	STAN-3	QLD	12,500	85	0
356	BDL02	VIC	13159.86	44	0

5. Results

Our price demand dispatch model has been validated by running a simulation with a 0 GW installation of PV. Figs. 5 and 6 directly compare the model output with the actual regional prices (volume weighted to a national price) in a winter and summer week. The model results generally approximate historical wholesale spot prices well, but underestimate the historical prices during short duration price spikes, as suggested in Section 4.

The model output can be further compared with the real price data by contrasting and analyzing cumulative value plots; plots that illustrate the cumulative value traded through the NEM over a period of time. The accumulation of the traded value (\$) allows the model result and performance to be compared over an extended time period, without losing granularity. Comparing monthly or even weekly values would mask finer detail. Comparing hourly or even daily values over extended time periods (e.g. a year) would convolute the analysis, also obscuring detail.

The cumulative value plot illustrates detail that may occur on very fine timescales (e.g. extreme price events), whilst also showing the value aggregated over longer time periods.

For example, extreme price events can be identified (as near vertical sections in the plot), a detail that would be lost with aggregation over a large time scale. Similarly, by accumulating the value, longer term revenue trends can also be identified (with, for example, the gradient in non-extreme price events representing a more typical value traded per time period). This detail would be obscured if comparing only the value on short timescale, with daily values fluctuating by more than an order of

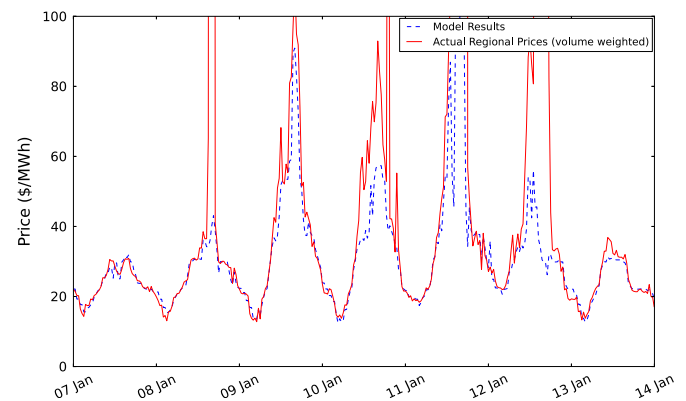


Fig. 5. Comparison of model results (blue, dashed) and actual prices (red, solid) in summer 2010.

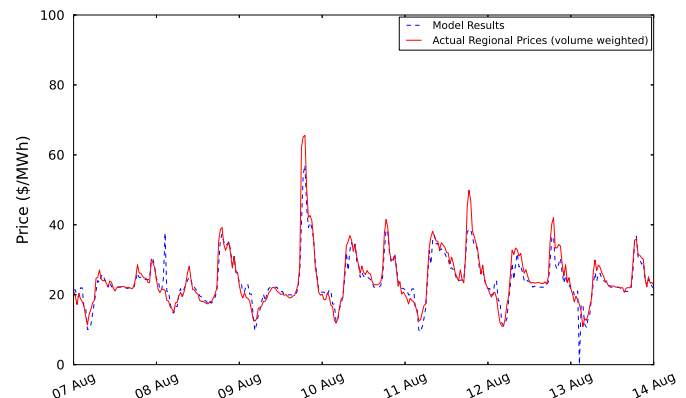


Fig. 6. Comparison of model results (blue, dashed) and actual prices (red, solid) in winter 2009.

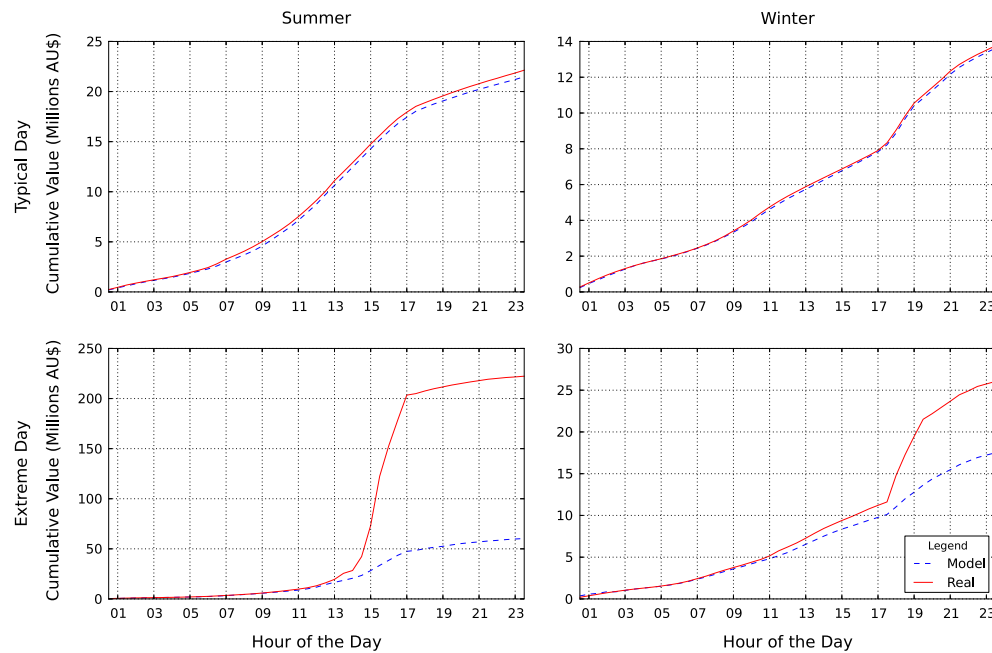


Fig. 7. Performance of dispatch model (blue, dashed) compared to market (red, solid) in cumulative value on typical days (top panel) and extreme days (bottom panel) in summer and winter.

magnitude (and hourly price values fluctuation by up to four orders of magnitude).

Fig. 7 illustrates the performance of the model and shows a representative daily volume weighted spot price revenue for typical summer and winter days, compared to actual revenue. Fig. 7 also shows extreme days, including January 29, 2009, when spot prices yielded one of the largest 'revenues' on the NEM.

Fig. 7 shows that our dispatch model does not capture extreme price events, which occur as a consequence of high demand and severe constraints. For example, the January 29, 2009, high price event in Victoria (with a spot-market value of ~\$550 million) resulted from a combination of near record demand and failure of the Basslink interconnector linking Victoria and Tasmania, as well as other transmission failures (NEMMCO, 2009). In treating the NEM as a single market in our model, interconnect failure constraints are not captured.

Fig. 8 illustrates the cumulative value plots of modeled results and the real price data for 2010, and Fig. 9 shows the plot for 2009.

As can be seen in Fig. 8, the modeled traded value over 2010 was \$4.8 billion AUD, compared to actual traded value of \$7.2 billion AUD. For 2009, the modeled traded value was over \$6 billion compared to the actual value of almost \$10 billion (Fig. 9). The near vertical line segments in the real data plot represent peak periods of extreme high prices and value. The absence of these price extremes from the modeled results reflects the fact that the model significantly underestimates the peak price periods and their corresponding value. Table 4 compares the annual volume weighted prices and the peak prices for the modeled and actual regional wholesale electricity prices (volume weighted to a national average). Individual regional prices could (and did) go as high as \$10000/MWh (the market cap price) in 2009 and 2010.

Comparing the mean absolute error (MAE) and mean signed difference (MSD) also confirms the underestimation of the model, particularly during extreme price events. Table 5 shows the MAE and MSD for the modeled spot prices, and the modeled spot price excluding the top 1% of actual extreme events. This analysis indicates that the model generally underestimates spot prices, and in particular, significantly underestimates spot prices in high price events.

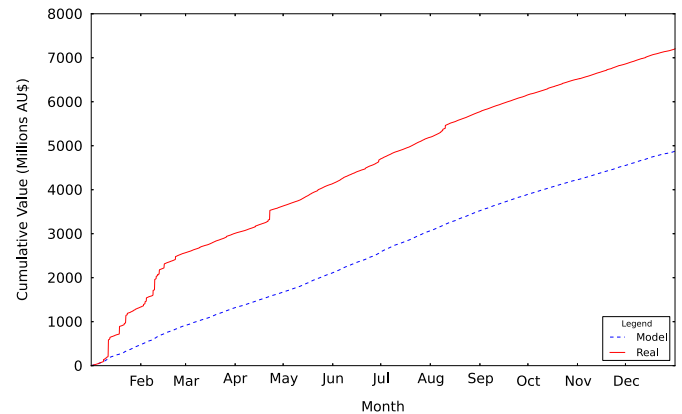


Fig. 8. Dispatch model (blue, dashed) and real market (red, solid) performance for year 2010.

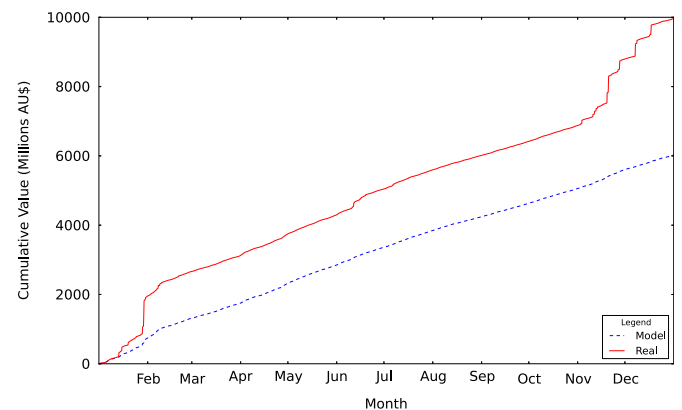


Fig. 9. Dispatch model (blue, dashed) and real market (red, solid) performance for year 2009.

The wholesale spot price savings indicated in this paper are calculated compared to the model scenario with 0 GW of

Table 4
Model and actual annual volume weighted prices (VWP) and peak prices for 2009 and 2010.

2009			2010	
Price	Modeled	Actual regional price (volume weighted)	Modeled	Actual regional price (volume weighted)
Annual VWP	29.52	48.6	23.91	35.2
Peak	521.25	5800.5	118.94	3598.15

Table 5
Mean absolute error and mean signed difference for the modeled wholesale spot prices.

	Mean absolute error (\$/MWh)	Mean signed difference (\$/MWh)
Modeled spot prices	10.05	−8.9
Modeled spot prices, excluding top 1% of extreme price events	1.86	−1.07

additional PV capacity installed. As our baseline model underestimates prices during peak period, the estimated value of the merit order effect presented in this paper is also likely to be underestimated.

Simulations were run from 0 to 5 GW installations of PV capacity in 1 GW increments, with 5 GW representing an equivalent installation capacity to Germany on a per capita basis, of around 250 W per capita. As of September 2011, Germany had an installed capacity of 20.6 GW (BNetzA, 2011) and population of around 81 million. Figs. 10 and 11 illustrate the impact of varying installation capacities on both prices and demand. The three shaded areas in the demand graphs indicate the cumulative decrease in demand due to local power generation by hypothetical PV installations. Similarly, the three shaded areas in the price graphs indicate the cumulative wholesale electricity price savings with 1–5 GW of PV installed, compared to the modeled prices with no additional PV capacity.

It can be seen from our analysis that for only minor productions of solar electricity, a significant depression in the spot price can occur, representing significant value. This is particularly evident in summer, with the summer peak demand and high price events better correlated with the solar production as shown in Fig. 10.

The total value of the merit order effect was evaluated for solar installations from 1 to 5 GW. This was evaluated by taking the difference between the total cumulative value modeled for a given solar installation and the modeled value for no installation. In 2010 the value of a 5 GW installation due to the merit order effect could have been \$628 million. The value, realized through the depression of the wholesale spot price (and the volume weighted price), represents 8.6% of the total value traded value in 2010. In 2009 the value of 5 GW due to the merit order effect could have been \$1.2 billion, representing over 12% of the total value traded value in that year. Table 6 shows the potential value of the merit order effect in 2009 and 2010, as a function of installation capacity. The lower merit order effect in 2010 is reflective of the lower price volatility and the general lower amount traded through the pool in that year.

The total value of the merit order effect will increase with increasing installations of PV (Table 6). However, as can be seen in Fig. 12, the marginal merit order value of each additional unit of capacity decreases due to the remaining peak price events becoming smaller in magnitude. As solar capacity increases, peak

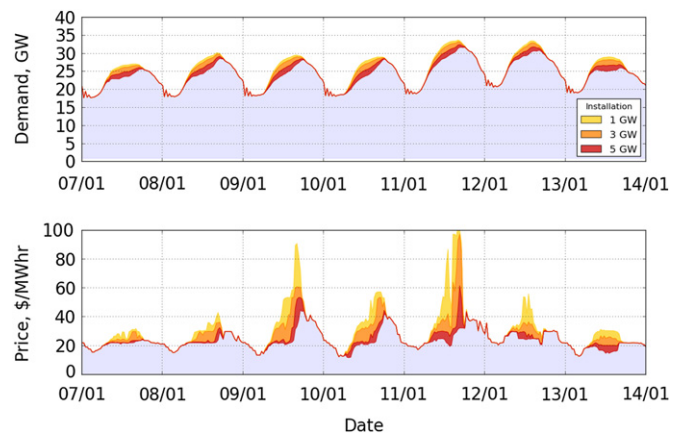


Fig. 10. Modeled impact of PV on demand and price in summer 2010.

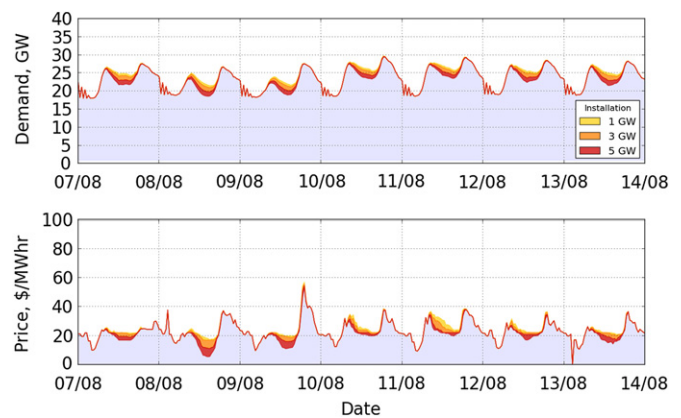


Fig. 11. Modeled impact of PV on demand and price in winter 2009.

Table 6
Potential value of the merit order effect as a function of installed capacity for 2009 and 2010.

PV installed capacity, GW	Merit order effect (million AU\$)	
	2009	2010
1	390	169
2	670	302
3	893	412
4	1073	520
5	1229	628

demand periods reduce in magnitude and frequency, and solar begins displacing cheaper baseload generation, rather than higher cost peak generation.

It should be noted that exported PV electricity also has a primary value: the wholesale value of the energy. Previous studies (Gerardi and Stevens, 2011) have estimated this value by assessing the time and volume weighted wholesale value of the electricity produced by solar. This approach allows the value to be captured based on the time of generation (i.e. during the day, at typically higher than average prices) and the volume produced. Specifically, Gerardi and Stevens (2011) concluded that in NSW, the electricity produced by solar had a weighted wholesale value of 7.8 c/kWh.

A similar approach was used to determine this value in our analysis. However, the impact of the merit order effect (the

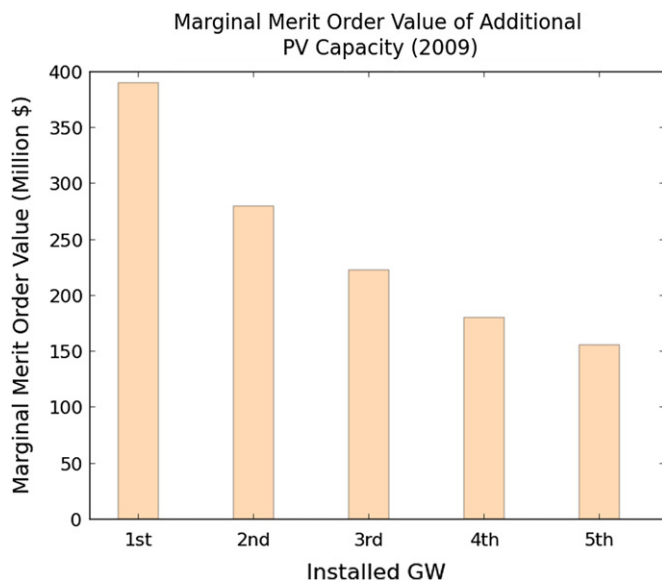


Fig. 12. Marginal merit order value of additional PV capacity for 2009.

Table 7

Impact of PV generation on the wholesale weighted price, in solar production times.

PV installation (GW)	Average wholesale value (c/kWh)
1	5.3
2	4.9
3	4.7
4	4.6
5	4.4

depression of electricity prices during times of solar production) was included. As solar penetration and production increases, this depression in spot price becomes more prominent and the value of the wholesale electricity decreases. Table 7 above illustrates the average wholesale value of electricity as a function of PV installation.

6. Policy implications

Currently in Australia there are two financial incentives for PV system installation: state-based feed-in-tariffs; and revenue from the sale of Small-scale Technology Certificates (STCs), as part of the Federal Small-scale Renewable Energy Scheme (SRES). Feed-in tariff schemes provide revenue over and above the market price of electricity and the STCs provide an upfront subsidy, nominally to recognize the value of electricity generated with zero emissions, and to allow industry development (and cost reductions through learning effects and economies of scale).

These schemes invariably impart a cost on the consumer (typically passed through to consumers through electricity bills), which is often criticized and has been described as an “unjustifiable burden on electricity consumers” (DRET, 2011) or a “regressive form of taxation” (Nelson et al., 2011). However, considering these costs in isolation misrepresents the overall cost of the scheme. These costs are counter-acted by offsets such as that created by the merit order effect. In an efficient market one would expect lower electricity spot prices, with the resulting downward pressure on contract prices, to flow through to customers by reduction in the wholesale component of electricity bills. In effect

this should result in a wealth transfer from generators to consumers. By not considering this value, the cost of both feed-in tariffs and STCs to consumers is somewhat exaggerated. The German Federal Ministry for the Environment (BMU) does consider the merit order effect in its evaluation of the overall cost of the various German renewable energy policy schemes (BMU, 2011).

The following analysis considers the impact of the merit order analysis on a hypothetical feed-in tariff scheme that operates independently to other support mechanisms (e.g. the SRES scheme). Consideration of the merit order effect allows determination of the ‘overall’ cost of feed-in tariff schemes, and the determination of a ‘breakeven point’. Since the PV output is considered as demand reduction, and to avoid double counting, no value (e.g. sport market value) is given to the in electricity fed into the grid from PV installations. The ‘breakeven point’ can be considered as the feed-in tariff rate at which the cost of the feed-in tariff scheme is equal to the value of the merit order effect or the value saved in the wholesale spot market, assuming an efficient market in which such reductions are passed through to consumers. Tariffs above the ‘breakeven point’ will impose a net cost on consumers, while tariffs below this point will create a net saving to consumers. The overall cost of the schemes will depend on the type of scheme and export rates.

Currently in Australia the majority of feed-in-tariffs offered by the state governments are net feed-in tariffs. These tariff schemes pay PV electricity generators only for the energy that is exported to the electricity grid or in other words, the energy that is not used locally at the PV generation site. The amount of energy exported from a system is quantified by the export rate, a percentage of the total energy generated that is exported into the electricity grid. Based on the export rates recently tabled from systems in NSW (Balding and Kua, 2010), export rates range from as low as 17% for 1.5 kW systems in predominantly metropolitan NSW, to as high as 84% for 10 kW systems in regional NSW. The average size of new connections between January and June 2010 was found to be 2.1 kW, with 1.8 kW being the total average system size. The export rate for 2 kW systems ranged from around 30% (predominantly metropolitan NSW) to 40% (regional NSW), with a trend towards larger systems and thus larger export rates.

In this study export rates of 40%, 50% and 60% were used to estimate the breakeven point at which the cost of a net scheme would be offset by the merit order effect. Fig. 12 illustrates this breakeven point, as a function of total installation capacity and export rate.

For example if the average export rate was 60%, then for an installed capacity of 2 GW, a net tariff of 35 cents would not impose any additional cost or burden on the electricity consumer base, assuming grid augmentations and associated costs are not required. A tariff less than 35 cents would deliver a net saving to the wider consumer base (providing sufficient PV was actually installed). Moreover, if the merit order effect delivered a saving greater than the cost of the scheme, a tariff below the breakeven value, could be considered a progressive measure, with those that install capacity creating a benefit for those that cannot (i.e. a wealth transfer from generators to consumers, as opposed to from consumers to PV system owners).

It is also of interest to note that the tariff required for the breakeven point in Fig. 13 decreases as the installed capacity increases. This is commensurate with the decrease in marginal merit order value shown in Fig. 12 as additional PV capacity is added to the grid. Similar ‘breakeven’ analysis could be undertaken for different mechanisms. For example, a level of upfront support from the SRES (which is passed through to consumers in electricity bills) that ‘breaks even’ when included merit order effects could also be determined.

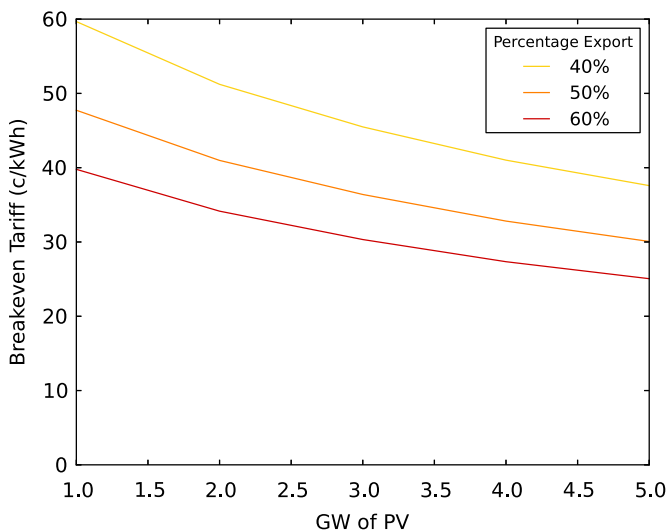


Fig. 13. Breakeven tariff as function of installed capacity and percentage exports.

7. Discussion and avenues for future work

At the market level our price demand model is limited by ignoring several key constraints within the system. In particular, not including the constraints placed on the inter-regional inter-connectors means our model misses several of the key high price events that impact significantly on annual spot market revenue, resulting in the value of the merit order effect being underestimated. Including these constraints would allow regional analysis to be conducted and allow the analysis to capture more of the high price events (some of which occur because of inter-regional connector constraints), and determine if PV has the potential to relax or alleviate these constraints. Further work would be needed to incorporate the marginal loss factors and capacity constraints and provisions for the generation constraints.

To further improve the analysis the impact of PV installations on the grid investment needs could be quantified. As mentioned, network costs may be deferred due to PV helping mitigate peak loads. A highly distributed generation system may also reduce loss factors throughout the network. Alternatively, network costs may be increased due to the need for improved transmission and distribution infrastructure, to accommodate stability issues. There may be a need to curtail PV generation to ensure a stable grid, or a requirement for more ancillary services.

It is recognized that in reality not all rooftop panels installed would be at a 30° angle. Remodeling and analysis could be performed to find the most appropriate average angle. This could also involve changing orientations, for example to north-west or directly west to generate more power during afternoon electricity peaks. More geographically diverse PV installations could also be considered and would likely reduce the variation in the solar output model. Variations in the distribution of PV throughout the NEM (based on population and solar resource) should also be investigated. Higher PV penetrations could also be considered, especially taking into account the likelihood of solar PV reaching retail grid parity. Germany's 2030 target of 66 GW would be equivalent to over 17 GW in Australia on a per capita basis, if emulated here.

The manner in which the merit order effect would impact the long term functioning of the National Electricity Market could also be investigated. The long term effects on the system will have implications for the operation and development of the grid, generation mix and overall system reliability. For the market to create the right signals to encourage construction of new capacity and deliver new investment in large scale energy projects, market dynamics may have to adapt to the impact of the a large penetration of renewable

generation and the merit order effect. Consideration of the likely change in bidding behavior could also be investigated.

8. Conclusion

As demonstrated in our analysis and other studies, significant photovoltaic energy generation has real and substantial economic value, as demonstrated by the reduction of wholesale electricity prices through the merit order effect. Our modeling shows that in 2010 the value of a 5 GW installation due to the merit order effect could have been \$628 million, or 8.6% of the total value traded through the electricity pool in 2010. In 2009 the value of 5 GW due to the merit order effect could have been \$1.2 billion, representing over 12% of the total value traded in that year. The smaller saving in 2010 is due to less volatile prices in that year.

These results indicate that policy incentives such as feed-in tariffs actually produce an economic benefit—savings in wholesale electricity prices via the merit order effect. The cost of such policy schemes should not be considered in isolation from their benefits. Incentives can be set slightly below the breakeven point, such that a net transfer of wealth to consumers occurs.

As the overall reported cost of the scheme does not reflect the merit order value it remains an externalized benefit of PV generation; a benefit not recognized by the wider public.

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