Modelling of Large-Scale PV Systems in Australia

By

The Australian PV Association

November 2011

AUTHORS:
Graham Mills (APVA); Simon Franklin, Rob Passey & Muriel Watt (IT Power Australia); Anna Bruce (UNSW); Warwick Johnson (SunWiz)

With support from

ACKNOWLEDGEMENTS

The model used to prepare the analyses for this report was developed with funding assistance predominantly from the Australian Solar Institute but also from the Australian PV Association, and with data sourced from APVA members and literature sources.

The model was initially developed in early 2010 and updated in mid 2011. However, since PV costs and performance continue to improve, values in the graphs should be read from the relevant current date.

About the Australian PV Association

The APVA is an Association of companies, government agencies, individuals, university and other research groups with an interest in photovoltaic solar electricity research, technology, manufacturing, systems, policies, programs and projects. In addition to Australian activities, we provide the structure through which Australia participates in the International Energy Agency (IEA) Photovoltaic Power Systems program (PVPS).

Our work is intended to be apolitical and of use, not only to our members, but also to the general community. We are not a traditional lobby group, but instead focus on data analysis, independent and balanced information and collaborative research, both nationally and internationally.

Our reports, media releases and newsletters etc can be found at www.apva.org.au.

COPYRIGHT *This report is copyright of the Australian PV Association and the Australian Solar Institute. The information contained therein may freely be used but all such use should cite the source as "**Modelling of Large Scale PV Systems in Australia, 2011**".*

Contents

Large Scale PV in Australia

The APVA has developed a set of techno-economic projection models to inform stakeholders as to likely changes in the cost of electricity generated by PV, compared to prevailing grid electricity prices. Three models were developed, one for residential systems, one for systems on commercial buildings, and another for systems designed for generation on a large scale. The residential and commercial systems are compared to the prices of grid electricity under standard electricity supply arrangements, whereas the large-scale model compares the cost of PV-electricity to wholesale electricity market prices.

Each of these three models has the same functionality, but is structured to reflect the differing cost arrangements for each application. The models exclude government subsidies, such as Renewable Energy Certificates or grants, so as to model the underlying economic case for current and future investments in PV.

PV remains a relatively new technology, with much research and development still required. Nevertheless, it is one of the most versatile and promising of the renewable energy technologies now available. The results presented herein provide an indication of its prospects for large-scale system deployment in Australia. The underlying data were sourced from APVA members and publically available information. The amount of information available to assess the costs associated with large-scale PV systems is far more limited than the information available to assess costs in residential and commercial PV applications, because this sector has not yet been developed in Australia. While the APVA has endeavored to provide as accurate an estimate of costs as possible, the results presented in this study should be taken as indicative only.

The results presented are for the purposes of informing stakeholders and the interested public. They are general in nature and subject to a number of underlying assumptions. As such, readers should not take these results as representing financial or investment advice.

Background

Australia's National Electricity Market (NEM) is an energy only, single settlement wholesale electricity market covering Queensland, New South Wales, Victoria, Tasmania, and South Australia. The NEM supplies electricity to over nine million end customers and, in 2009, 206 terawatt hours valued at A$9.6 billion was traded in the wholesale market[1]. Generators sell electricity to electricity retailers, and other direct market participants, with prices being determined in real time by supply and demand.

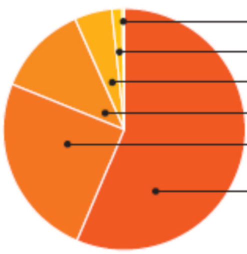

Figure 1: Key sources of generation in the Australian National Electricity Market[2]

[1] Australian Energy Regulator, *State of the Energy Market 2010*, p. 19,

[2] The Australian Energy Market Operator, An Introduction to Australia's National Electricity Market, July 2010, page 4.

Prices in each region of the NEM (South Australia, Victoria, Tasmania, NSW, and Queensland) are determined on a half hourly basis by the bids of the marginal generators dispatched by the Australian Electricity Market Operator (AEMO). NEM prices are volatile and can range between -$1,000 per MWh and $12,500 per MWh. As such, when demand is high and there are unplanned transmission interconnector or generator outages, very high prices can occur. Very high price events have been observed in summer due to high levels of air-conditioning load.

From Figure 1 it can be seen that the majority (over 93%) of the generation capacity in the NEM is large-scale fossil fuelled generation. This generation is referred to as scheduled generation as it generates according to dispatch instructions issued by AEMO. By contrast, renewable generation (which is intermittent and not 100% controllable) participates in the NEM as unscheduled generation or semi-scheduled generation, depending on its size. Un-scheduled generation is not subject to dispatch instructions while semi-scheduled generation is subject to instructions from AEMO to curtail generation in certain circumstances.

While large-scale wind generation has been participating in the NEM for a number of years, PV systems installed in Australia to date generally interact with the electricity system at end user level rather than participating in the NEM's wholesale market. However, the Commonwealth Government's Solar Flagships program will see a number of large-scale systems begin to participate in the near future.

Description of the model

The results presented herein were obtained from the APVA's large system cost projection model which is an integrated system cost and discount cash flow model implemented in Excel and controlled by VBA Macros. For detailed information regarding the methodology used, interested readers should consult *"A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies"* published by the US National Renewable Energy Laboratory[3].

The model calculates its results based only on an assessment of energy value and assumes that the PV system will participate in the NEM as an unscheduled generator.

Model Inputs

System Scenario

The model operates via user definition of a system scenario. The variables selected by the user for this system then define the default cost, energy, and financial parameters from which the model produces its results. The user selects from a drop down table which provides the following choices for this purpose:

- Technology type: thin film, polycrystalline, monocrystalline and high efficiency silicon[4]
- Nominal system size: 1MW, 10MW or 50MW
- Location(radiation): Brisbane, Sydney or Melbourne[5]
- System Tracking: Fixed, Single Axis Tracking, Two Axis Tracking
- Financing: 100% debt (risk free), 100% debt, 100% equity, 50% debt / 50% equity

[3] Short W, Packey D, Holt T, *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*, National Renewable Energy Laboratory, 1995. www.nrel.gov/docs/legosti/old/5173.pdf
[4] These differ in terms of efficiency, cost, area, open circuit voltage (Voc) and weight.
[5] These differ in the annual average insolation and the performance ratio.

Once the system scenario has been specified, the model selects the relevant PV equipment data (module efficiency, module area, Voc, Module weight and average annual performance degradation) and financial data (landed module cost, inverter cost and BOS costs) from a set of default pre-programmed values contained within the model. Note that all models assume north-facing PV arrays at latitude angle.[6]

Key Cost / Financial Parameters

In addition to the system scenario, the model requires the user to define key financial and other input parameters which allow returns from the system to be calculated. These parameters (listed below) are specified by the user for present day (2011) and calculated by the model each of the next 20 years to 2031.

- Key financial parameters (cost of equity, cost of debt, CPI)
- Module Costs, Inverter Costs (factory gate / landed costs)
- Importer / Distributor system margins
- End system delivery margin
- Corporate Tax Rate
- Depreciation Period
- Module Efficiency

Calculating investment returns relies on parameters which determine the value of money in future years. While the model provides the user with the flexibility to vary all parameters, the following are applied for the modelling presented in this study:

- Inflation is taken at be 2.5% (the middle of the RBA target inflation band); and
- The cost of equity and cost of debt are taken from the Australian Energy Regulator's final decision on the NSW Distribution Determination 2009[7] and are as follows:
  - Nominal pre tax return on equity: 10.29%
  - Nominal pre tax return on debt: 7.78%.

While the model provides the ability to test the impact of a number of different financing options, the base case herein uses a 50% debt to 50% equity split with all results calculated on a return to equity basis. As such, the return on equity is used as the discount rate for the purpose of calculating the net present values including the LCOE.

Civil Works and Land Costs

The cost structure of a large scale PV system differs from commercial and residential systems in that there are additional cost items in the following areas:

- Land Costs were assessed using an average of a survey of rural land costs located around Dubbo in NSW.
- Representative Civil Works costs were established from a system cost model developed from data listed in Rawlinson's Construction Handbook[8]

NEM Wholesale Price Projections

The APVA has used three wholesale electricity market price projections published by Commonwealth Treasury with respect to the modelling of its carbon pricing policies[9]:

- *Reference Projection:* The average of the three wholesale price projections (ROAM, MMA-SKM, and Treasury) presented by Treasury as business as usual cases in the absence of a carbon price;

[6] Note that this model does not attempt to duplicate what detailed PV performance models such as PVSyst offer. It is envisaged that data from such models can readily be inserted at the front end of this model if required.
[7] Australian Energy Regulator, Final Decision - NSW Distribution Determination (Table 11.8), April 2009
[8] Rawlinsons Publishing, Rawlinsons Australian Construction Handbook and Construction Cost Guide 2010.
[9] Commonwealth of Australia, Strong Growth Low Pollution – Modelling a Carbon Price, 2011 (page 87)

- *Core Policy:* Assumes an Australian emission target of a 5 per cent cut on 2000 levels by 2020 and an 80 per cent cut by 2050. Assumes a nominal domestic starting price of A$20/t CO_2-e in 2012-13, rising 5 per cent per year, plus inflation, before moving to a flexible world price in 2015-16, projected to be around A$29/t CO_2-e;
- *High Price:* Assumes an Australian emission target of a 25 per cent cut on 2000 levels by 2020 and an 80 per cent cut by 2050. Assumes a nominal domestic starting price of A$30/t CO_2-e in 2012-13, rising 5 per cent per year, plus inflation, before moving to a flexible world price in 2015-16, projected to be around A$61/t CO_2-e.

As previously stated, no account has been taken of the value of large-scale generation certificates (LGCs) created under the Large-scale Renewable Energy Target. At present, and until 2030, LGCs may effectively increase the wholesale market price by 2 to 4 c/kWh, which will serve to bring the breakeven point forward by 2 to 3 years.

Time of Day Premium Factor

The revenue made by a PV system selling into the wholesale market is a function of the market price at the time of day during which electricity is being generated by the system. While peak market prices are well correlated with PV generation during summer, this correlation is weaker during winter. To determine the average premium enjoyed by PV over and above average wholesale market prices, the APVA conducted an analysis of prices in NSW between 1999 and 2009 from which it was found that over this period PV would have received an average price of 120% of the average annual wholesale market price.

This Time of Day Premium Factor has been applied to the NEM wholesale price projections to model the additional revenue associated with the correlation of PV generation and high electricity market price events. Note, however, that experience with wind has shown the potential for renewable energy generators, which have zero marginal cost of generation, to reduce the market price when conditions are favourable (high wind or high solar insolation), so that in future if there are large numbers of solar generators on the NEM, prices may not remain higher than average.

Model Outputs

Once the system scenario has been defined and all key inputs specified by the user, the model automatically calculates the following values for the present day as well as for an investment made in PV in each year out to 2031. To emphasise the impacts over the next 10 years, the following graphs only cover the period to 2021.

- Total installed cost (as both 2011 A$/W and 2011 A$), which consists of:
    - PV equipment cost (landed price)
    - Power Equipment Costs
    - Structural and Support Costs
    - Civils
    - Professional and Project Costs
    - Importer/Distributor margin
    - End system delivery costs
    - End system delivery margin
- Levelised Cost of PV Electricity (LCOE), in 2011 c/kWh
- Net present value Return on Equity (ROE) of the system including offset electricity, as 2011 $
- Net present value of offset electricity, as both 2011 $ and 2011 c/kWh
- Internal Rate of Return (IRR) of the investment

Results

The Levelised Cost of Energy (LCOE) from a PV system is a metric used to understand the per unit cost of the electricity generated by that system. It is the cost that, if assigned to every unit of energy produced by the system over its lifetime, will equal the net present value of the total lifetime system cost at the point of implementation[10].

In the results presented below, the LCOE is compared to projected wholesale electricity market prices to establish the range of years over which system breakeven costs may occur. The wholesale electricity market price projections are adjusted by the Time of Day Premium Factor in each case.

Base Case System

The following configuration is taken as the base case system for the purpose of this modelling:

- Technology type: polycrystalline
- Nominal system size: 50MW
- Location (solar radiation levels): Sydney
- System Tracking: North facing fixed plate inclined at latitude angle
- Financing: 50% equity, 50% debt
- Development model: Owner-Developer

Table 1 shows the key input parameters used in this case study. It also shows the annual changes in these parameters the purpose of establishing future year system costs.

Table 1: Base Case Input Parameters

Input Parameter	2011 Value	Base Case – Annual % Change
System lifetime	25 years	
Depreciation period	20 years	
Loan term	15 years	
Sydney generation	1,522 kWh/kW	
Brisbane generation	1,606 kWh/kW	
Melbourne generation	1,401 kWh/kW	
Financing	50% debt/ 50% equity	
Cost of equity (discount rate)	10.29%	
Cost of debt	7.78%	
Inflation	2.5%	
Annual performance degradation	0.8% p.a.	
Module Cost (factory gate / landed)	1.30 ($/Wp)	-4% p.a.
Inverter Cost (factory gate / landed)	0.40 ($/Wp)	-2% p.a.
Importer / distributor margin	5%	-2% p.a.
End System installation margin(s)	5%	-2% p.a.
Module Efficiency	13.5%	2% p.a.

[10] Short W, Packey D, Holt T, p. 47, *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies,* National Renewable Energy Laboratory, 1995.

Base Case System Capital Cost Breakdown

The system delivery model for the base case system under investigation is an owner-developer model which assumes that the system developer purchases PV equipment directly from the manufacturer and covers business costs with a 5% logistics margin and 5% end system delivery margin. Figure 2 shows total system CAPEX in the order of $140 million dollars, leading to an installed cost of 2.85 $/Wp for a base case 50 MW system delivered via such an owner-developer model.

By contrast, a final system CAPEX of $160 million, leading to an installed cost of 3.20 $/Wp, would be expected if the system were to be delivered by a third party system developer with a 20% end system development margin, which not only covers business costs but also provides for a commercial return on system delivery.

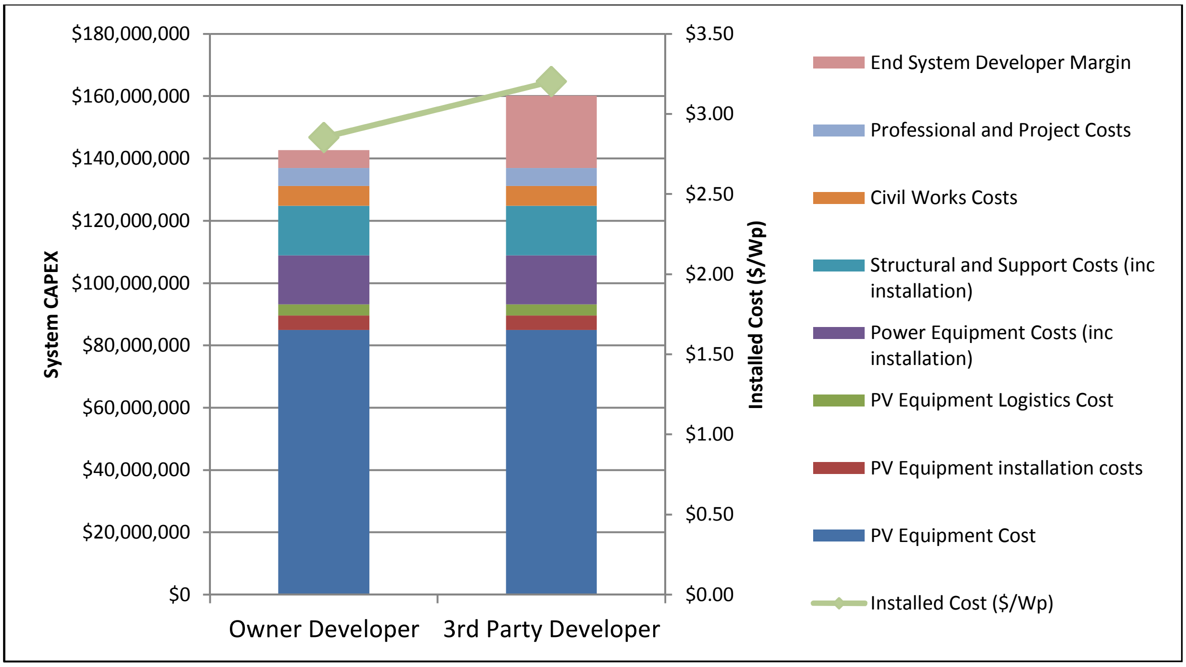

Figure 2: Base case system capital cost breakdown for a 50MW PV system under the owner developer and 3rd party developer models – excludes LGCs

System Break Even

System break-even is taken to be the range of years over which LCOE falls below each of the different wholesale electricity market price projections. The bounds of this range are established for each wholesale electricity market price projection (reference, core policy, and high price) from the following:

- The point at which the LCOE falls below the average wholesale electricity price in the year of system installation; and
- The point at which the LCOE falls below the net present value of each kWh sold into the wholesale electricity market over system life.

These two bounds may reflect different appetites for risk on the part of investors making a decision to invest in a base case PV system. Risk adverse investors may not invest until the LCOE has fallen below the average wholesale electricity market price in the year of system installation while investors with a greater appetite for risk may choose to invest on the basis of anticipated positive returns over system life.

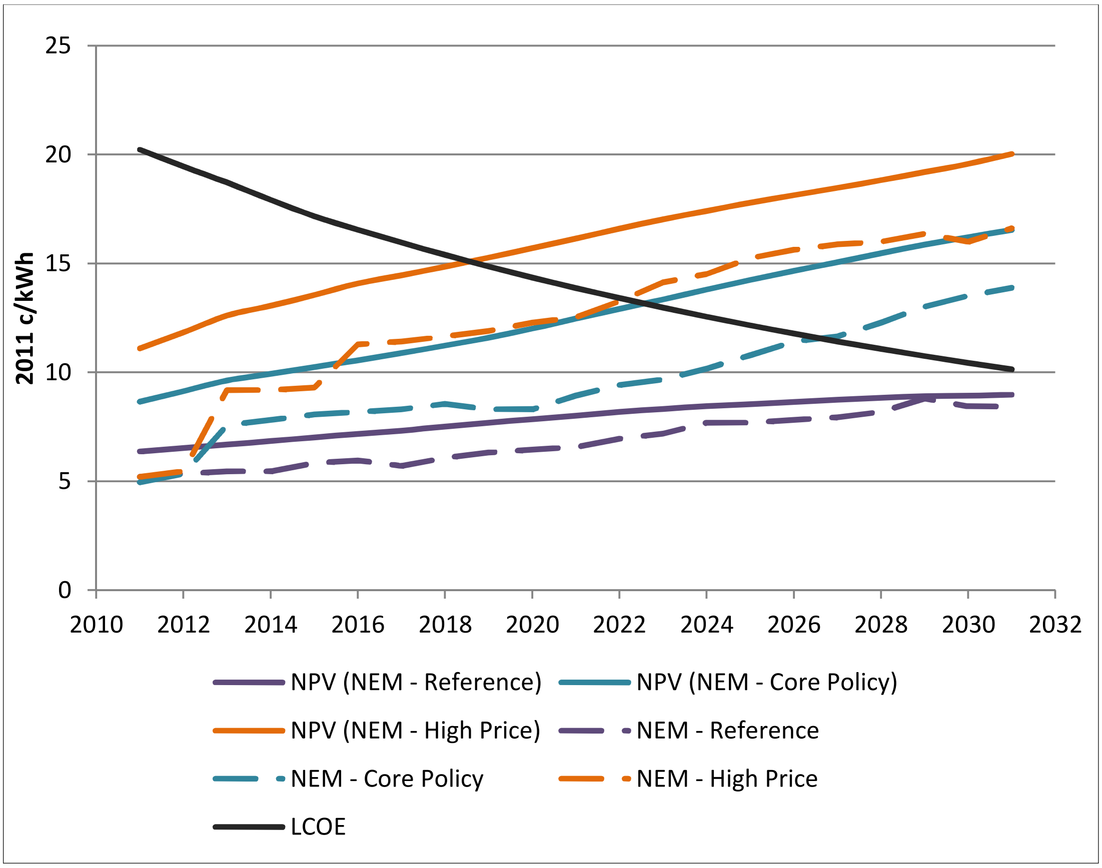

Figure 3: Projected base case system LCOE projection and the NPV of offset wholesale electricity price projections – excludes LGCs

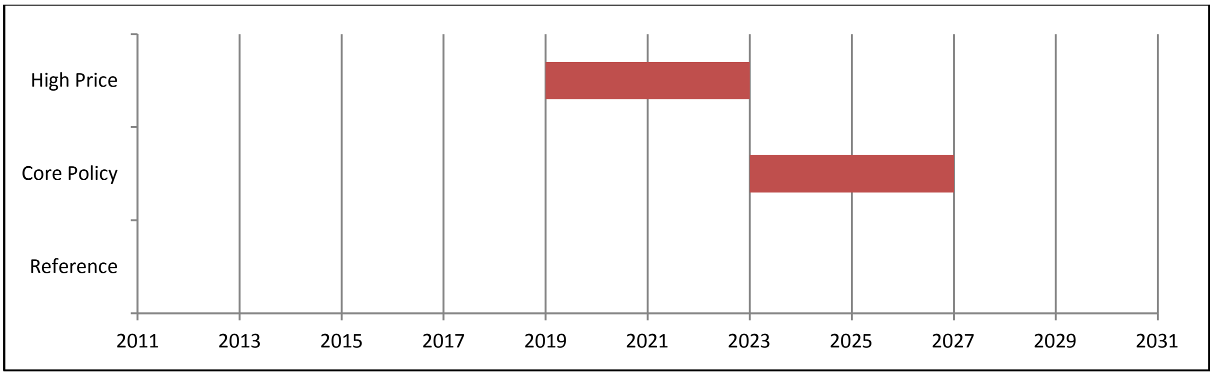

Figure 4: Years over which break-even is expected to occur for each wholesale market price projection – excludes LGCs

Figure 3 shows the LCOE of the base case system along with the Reference, Core Policy, and High Price wholesale electricity price projections on both an annual basis and a net present value of electricity sold over system life basis. Correspondingly, Figure 4 shows the range of years over which breakeven is expected to occur, from which it is observed that a base case PV system will breakeven between 2019 and 2023 under the High Price wholesale electricity price projection, and between 2023 and 2027 for the Core Policy projection. Base case system LCOE does not break even for the reference case prior to 2031. Note again that this does not include LGC value, which if included would serve to bring forward the breakeven point by 2 to 3 years for each scenario.

Sensitivity Analysis

The model allows for the variation of key parameters to establish the resulting impact on the LCOE and range of years over which breakeven is expected. Figure 5 shows the results of a sensitivity analysis undertaken by varying a selection of key input parameters by ± 25%.

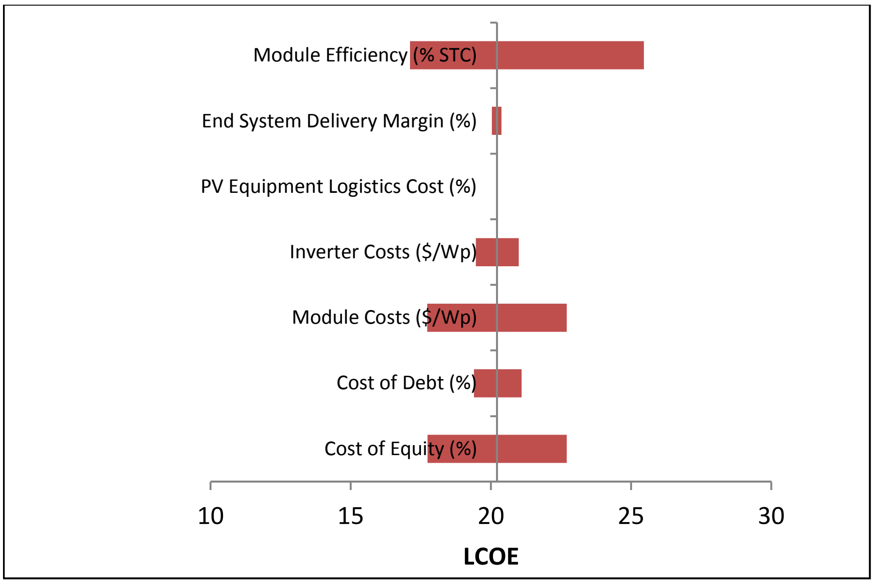

Figure 5: Impact on LCOE associated with variation of key parameters ± 25% – excludes LGCs

The results above show that module efficiency, module costs and the cost of equity are identified as those parameters to which the LCOE is most sensitive. The effect of varying each of these parameters is investigated in more detail below.

Module Efficiency

Improvements in module efficiency, without a corresponding increase in module costs, are observed to significantly reduce the LCOE of the electricity generated by the base case PV system. In particular, increasing module efficiency by 25% (from 13.3% to 16.65%) is observed to reduce the base case LCOE by approximately 12% (from 20.22 c/kWh to 17.74 c/kWh)[11].

Figure 6 shows the reduction in base case system LCOE corresponding to annual module efficiency improvements of 0%, 2% (base case), and 4% respectively; while Figure 7 shows the range of years over which breakeven is expected, corresponding to each of these module efficiency improvement and wholesale electricity price projection scenarios.

From these figures, it can be seen that breakeven is expected to occur between 2018 and 2025 for the High Price wholesale electricity market price projection and between 2021 and 2031 for the Core Policy wholesale electricity market price projection. The range of years over which breakeven is expected in the Reference wholesale electricity price projection case however, commences in 2029 and only for a 4% annual improvement in module efficiency over the period to 2031.

[11] It should be noted that LCOE change with improvements in module efficiency is non-linear

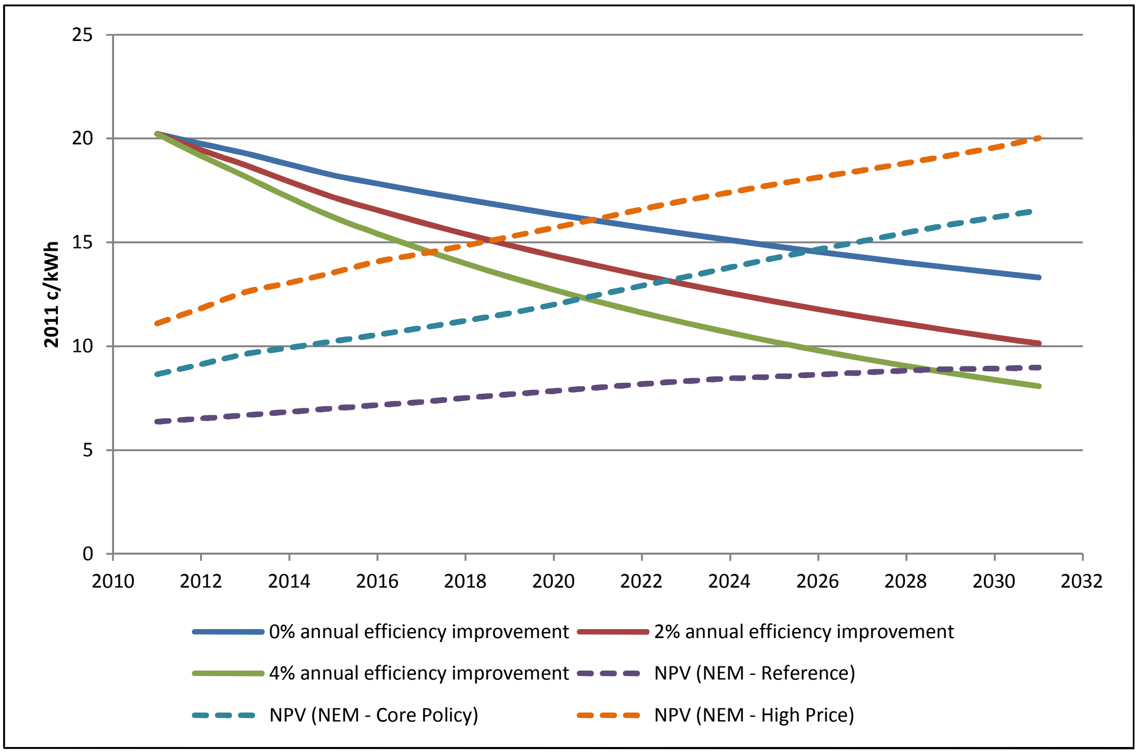

Figure 6: Impact of annual module efficiency improvement on base case system LCOE over the period to 2031 – excludes LGCs

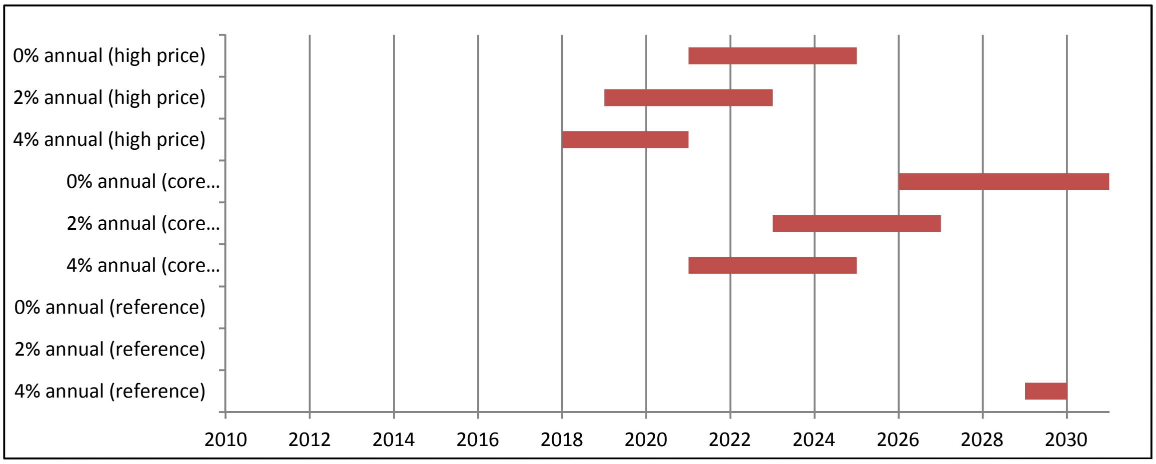

Figure 7: Years over which breakeven is expected for each wholesale electricity price projection and module efficiency improvement case – excludes LGCs

PV Module Costs

PV modules represent the largest single cost in the base case PV system. Variation in module costs therefore is observed to significantly impact base case LCOE. Specifically, a 25% reduction in module cost (from 1.30 $/Wp to 0.975 $/Wp) results in an improvement in LCOE of 12.3% (from 20.22 c/kWh to 17.73 c/kWh) when all other parameters are held constant.

Figure 8 shows the impact on base case LCOE as a result of annual module cost reductions of 0%, 4% (base case), and 8% respectively; while Figure 9 shows the range of years over which breakeven is expected, corresponding to each module cost improvement and wholesale electricity price projection case.

From these figures, it can be seen that breakeven is expected to occur between 2018 and 2026 for the High Price wholesale electricity market price projection, between 2021 and 2031 for the Core Policy wholesale electricity market price projection. The range of years over which breakeven is expected under the Reference wholesale electricity market price projection only commences in 2030 and only for the 8% annual improvement in module efficiency case.

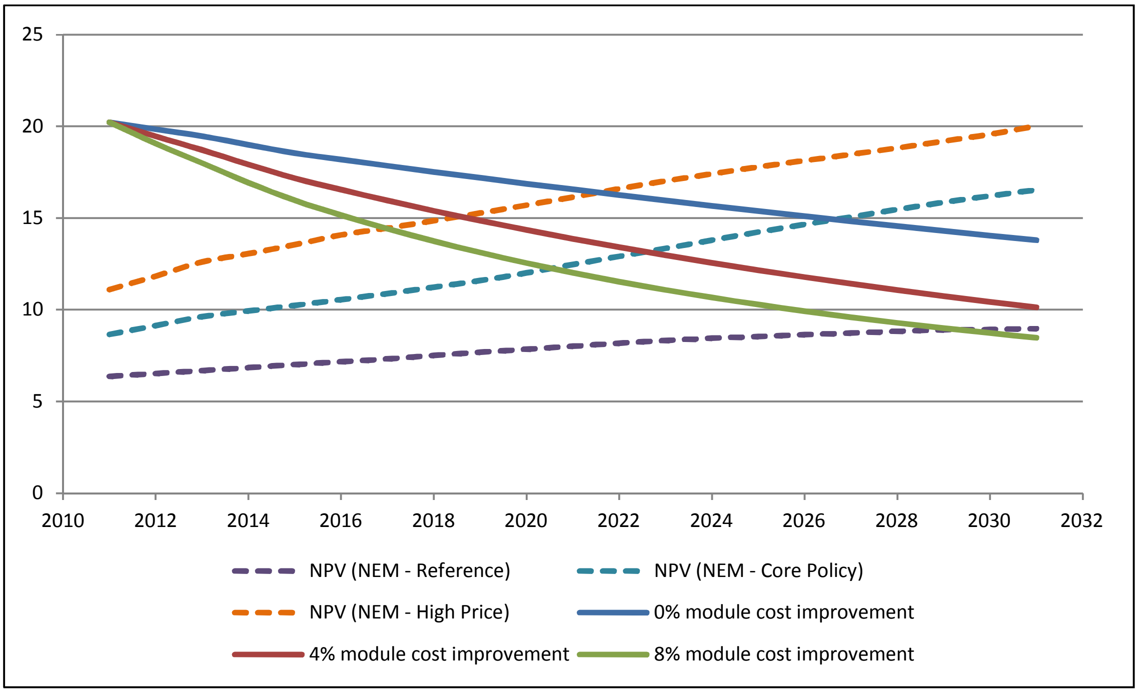

Figure 8: Effect of module cost improvements on the LCOE and the NPV of offset wholesale electricity price projections over the period to 2031 – excludes LGCs

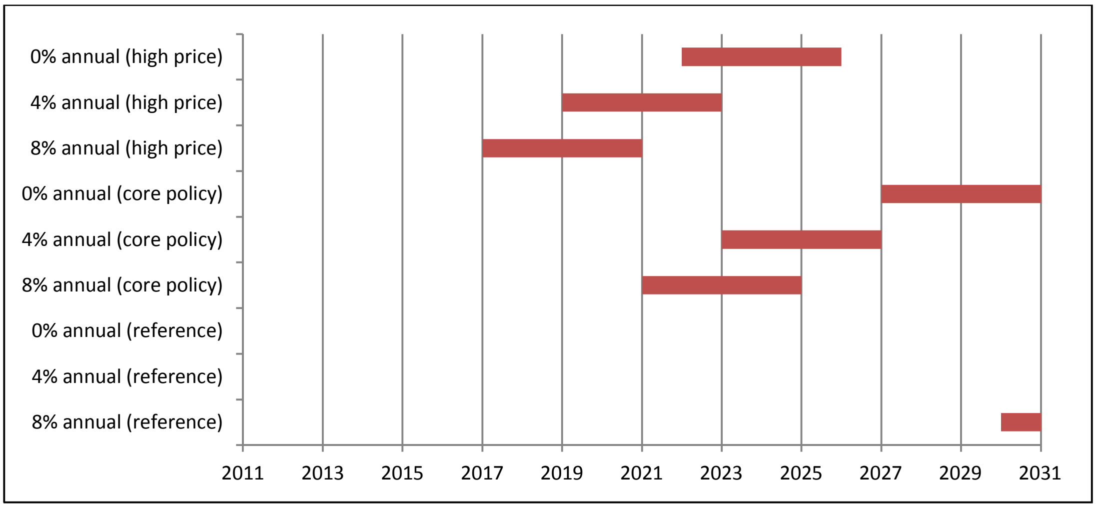

Figure 9: Years over which breakeven is expected for each electricity price projection and module cost reduction case – excludes LGCs

Financing Structure

The split between debt and equity financing has an impact on LCOE because interest on debt is tax deductable, in addition to debt generally being cheaper than equity funding. As such, the greater the proportion of debt to equity the lower the resulting LCOE. The ability to fund a large scale PV system development through debt, and the corresponding cost of both debt and equity, are observed to have a significant impact on the range of years over which system breakeven in expected.

Figure 10 illustrates this point by showing the total gross lifecycle costs for the base case system under four different debt / equity structures:

- 100% equity;
- 50% debt to equity split;
- 100% debt; and
- 100% debt financed at the risk free rate (10 year Commonwealth bond rate)

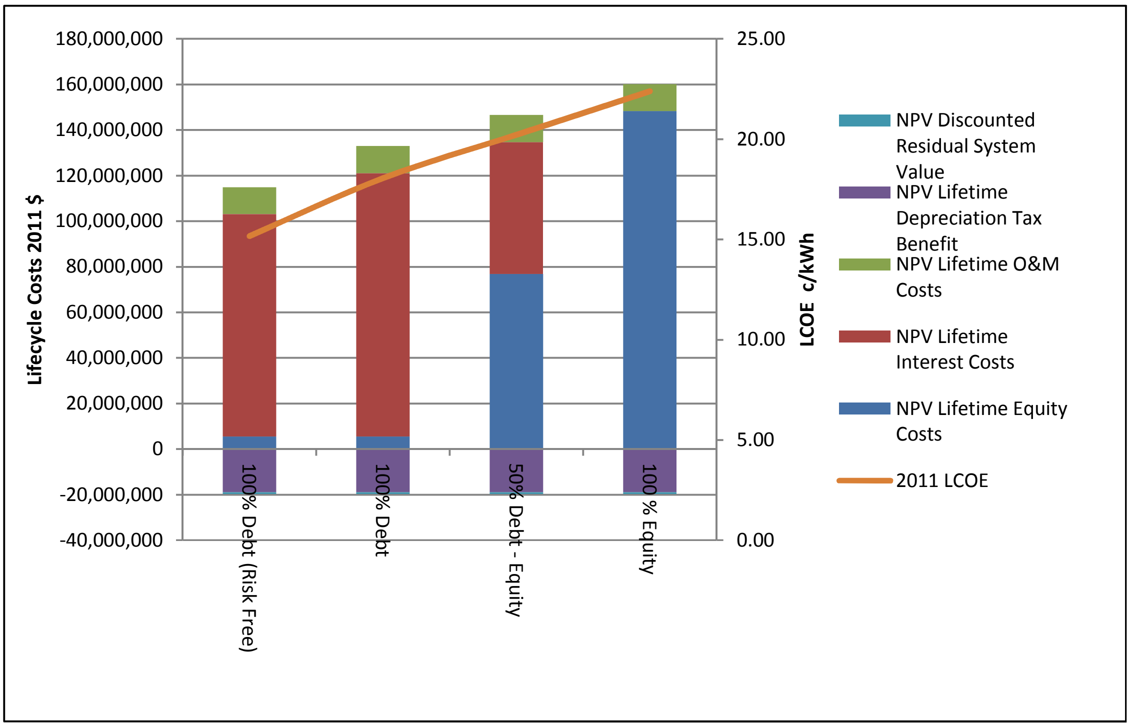

Figure 10: Effect of a selection of equity and debt splits on gross lifecycle costs and base case LCOE – excludes LGCs

100% debt financing at the risk free rate is observed to be the cheapest option, resulting in the lowest LCOE. 100% debt financing at the same nominal interest rate available to the Commonwealth of 4.29%[12] is seen to result in an LCOE of 15.17 c/kWh, which is 25% below the 20.22 c/kWh resulting from the base case 50% debt (at a nominal market interest rate of 7.78%) and 50% equity at a nominal rate of 10.29%[12]. The ability to finance a base case PV system development at the 10 year Commonwealth bond rate may be an outcome possible in the context of Commonwealth loan guarantees, although it would also be expected that any such guarantees would be accompanied by a 'guarantee fee' which has not been considered here.

A full investigation of finance options for large scale PV systems is very complex, with the results presented here acting simply to illustrate the impact of different structures on the LCOE and range of years over which breakeven is expected to occur. Figure 11 presents the change in the base case LCOE over the period to 2031 for each of the finance structures, with Figure 12 presenting the range of years over which breakeven would be expected, corresponding to each debt-equity split and wholesale electricity market projection.

[12] Australian Energy Regulator, Final Decision - NSW Distribution Determination (Table 11.8), April 2009

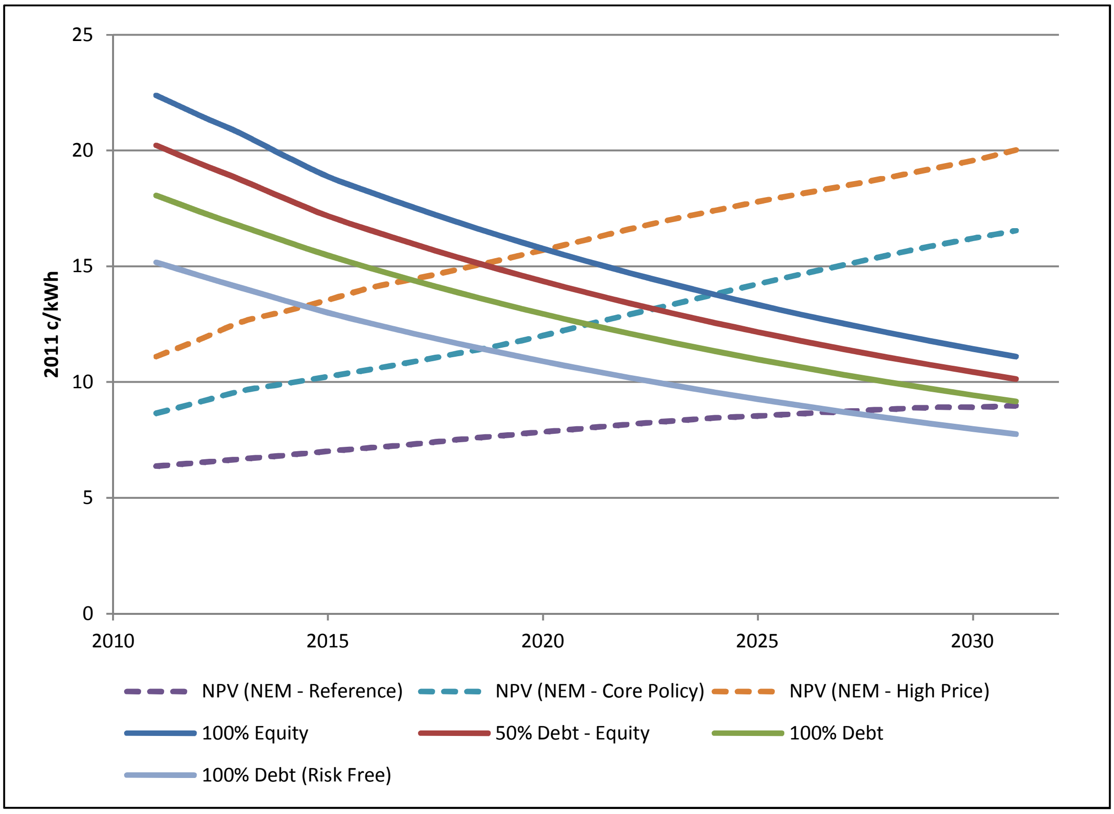

Figure 11: Effect of debt-equity splits and cost on the LCOE and the NPV of offset wholesale electricity price projections over the period to 2031 – excludes LGCs

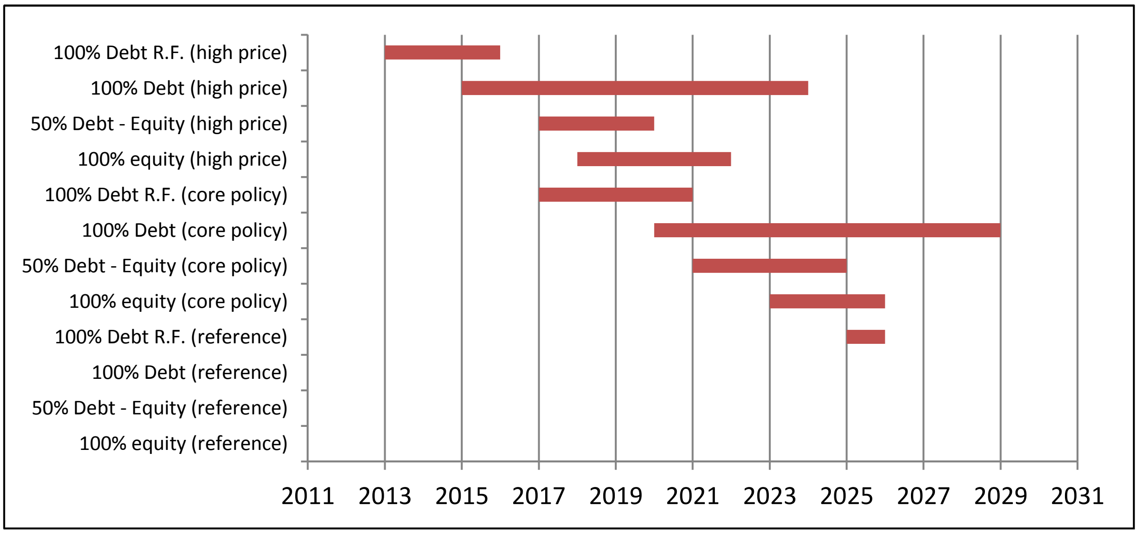

Figure 12: Years over which breakeven is expected for each investigated finance structure – excludes LGCs

Figure 12 shows that break even for the base case PV system can occur anywhere between 2013 and 2031 depending on outcomes in the wholesale electricity market and the financing cost and structure available to, and adopted by, the system developer. It is however clear that, regardless of the financing option chosen, breakeven is not expected to occur under the Reference case wholesale electricity market price case prior to 2031.

Conclusions

PV system costs in the residential and commercial sectors compete against retail electricity prices which include retail margins and network costs, in addition to the value of the electricity itself. Network costs make up approximately half current 2011 NSW regulated small user tariffs[13]. In contrast, large scale PV systems of the type investigated herein compete in a single settlement, energy only, wholesale market where the price is set by the costs of the marginal generator. As such, daytime wholesale electricity market prices are generally in the order of 4 c/kWh compared to prices more than 20 c/kWh at residential and commercial end user level.

This situation is a challenging one for large scale PV applications. While residential and commercial PV applications may be approaching, or at, the point of grid parity, a significant feasibility gap remains for large scale PV. The results presented herein illustrate that there is no single cost of electricity generated by a large scale PV system, nor is there a single point at which a PV system selling into the wholesale electricity market will become cost competitive. Instead there is a range of possible costs and a range of years over which a system may breakeven. In particular:

- A base case system financed via a 50% debt-equity split can be expected to breakeven at some point between 2019 and 2027, if the Commonwealth's current carbon pricing policies are enacted. In the absence of such policies, expected wholesale electricity market prices are such that large scale PV may not become competitive without government subsidy until after 2031;
- The LCOE is most sensitive to module efficiency, module cost, and financing (cost of debt and equity):
    - A 4% annual module efficiency improvement will see break even occurring at some point between 2018 and 2025; and
    - An 8% annual module cost improvement will see break even occurring at some point 2017 and 2025;

  Both of these outcomes rely on the Commonwealth's current carbon pricing policies being enacted.
- The LCOE is very sensitive to the cost of money and the structure used to finance the system. In particular, the availability of low cost debt finance could bring break-even forward to as soon as 2013.

From the results obtained, the importance of carbon pricing is clearly established. However, even with carbon pricing, additional government assistance will still be required over the next decade or so. Government debt guarantees which provide large scale PV project developers with access to 100% debt financing at government rates would be especially useful.

The results presented in this study represent a partial examination of the economics of establishing a large scale PV system, as revenue streams from LGCs and certain costs associated with participating in the wholesale market have been excluded from the analysis. The exclusion of LGC revenue is deliberate in that the APVA wish to assess the underlying investment proposition; however it is also clear that the costs and practicalities of a large scale PV system participating in the NEM require further assessment and understanding with a view to inclusion in future work.

[13] NSW IPART, Changes in regulated electricity retail prices from 1 July 2011 – Final Report, June 2011 (Figure 1.2)