Australian PV Association

Development of a Strategic Planning Model for ASI to assist further development of the Australian PV Sector

The Australian PV Association
for
The Australian Solar Institute

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Acknowledgements

This model 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.

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EXECUTIVE SUMMARY

In the mid 1990's the Australia PV market comprised 13% of the market in IEA countries and Australia was the 4th largest world manufacturer of PV cells. By 2009, the Australian market accounted for 1% of the world market and, after stopping production altogether, a small cell and module plant is now in operation by Silex Solar.

It is clear that, although Australia leads the world in many areas of PV technology development and application, it has become less significant as a manufacturer and exporter of photovoltaic products and has not played a major role in development of the new grid-connected markets which have seen significant system cost reductions and the rise of a global industry worth US$50 Billion a year and growing.

Understanding and communicating the economic and technical barriers to increased commercial deployment of PV in Australia is critical to the success of R&D programs, market deployment policy and industry collaboration efforts. In order to support the re-emergence of an innovative and globally competitive PV sector in Australia, industry and policy makers require tools with the ability to test the impact of technical, financial, commercial and policy changes on both the operation of the PV industry as a whole, as well as on system cost, design and performance. These can suggest where efforts to improve efficiency or reduce costs should be focussed, inform the design of incentives to accelerate commercial deployment and maximise macroeconomic benefits to Australia.

This project involved the development of a techno-economic simulation model with a range of input sub-models which can be independently modified. They allow the impacts on the levelised cost of electricity (LCOE) of changes to the characteristics of PV technology, deployment, financing and incentive policies to be assessed. This in turn allows an assessment to be made of the 'feasibility gap' between the PV LCOE and end-user grid electricity prices or investment returns, and also identifies the key factors which can reduce this gap. Model outputs include the net present value (NPV) of total installed cost (including interest expenses), the Levelised Cost of Electricity, the NPV of offset electricity, the NPV Return on Equity (ROE) and the Internal Rate of Return (IRR) for a range of PV systems, under a range of input conditions.

Separate models were developed to reflect a higher level of detail for each of the residential, commercial and large-scale central power station sectors. Key findings are summarised below.

Key Results

Sensitivity Analyses of LCOE

For all three models, mono-crystalline was found to provide the lowest LCOE, followed by polycrystalline then thin film then high efficiency.

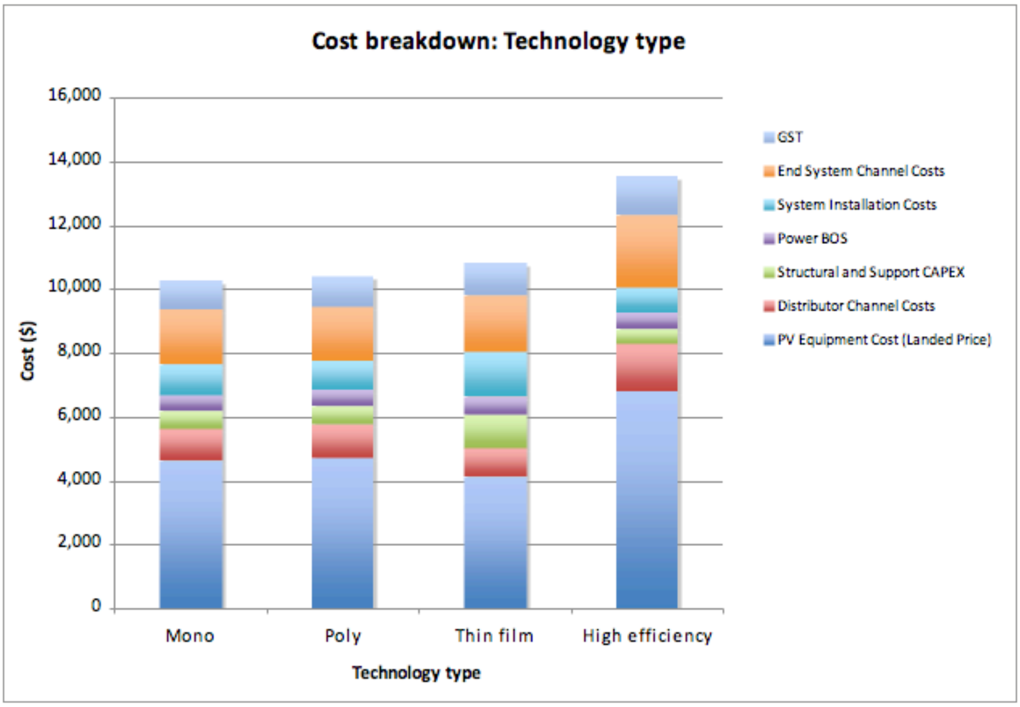
For the residential model, use of the bulk deployment approach, which is currently widespread in Australia and gaining in popularity, was found to reduce LCOE by 10.7%. The equivalent strategy for the commercial model (bypassing the distributor), reduced LCOE by 7.8%. Sensitivity analysis that varied the distributor and installer channel costs showed that reductions in the installer costs have slightly greater impacts on LCOE than reductions in the distributor costs.

For all three models, sensitivity analysis was conducted on the following parameters: system size, module efficiency, module cost, inverter cost and debt finance rate. Of these, increased system size is the only parameter that can be applied to the market now. The increase in LCOE when going from the commercial to the large-scale model (from 500kW to 1MW) is because the loan term is 15 years instead of 25 years, and because of slightly higher equipment and structural support costs as well as O&M costs.

Summary of impacts on PV LCOEs of different system sizes

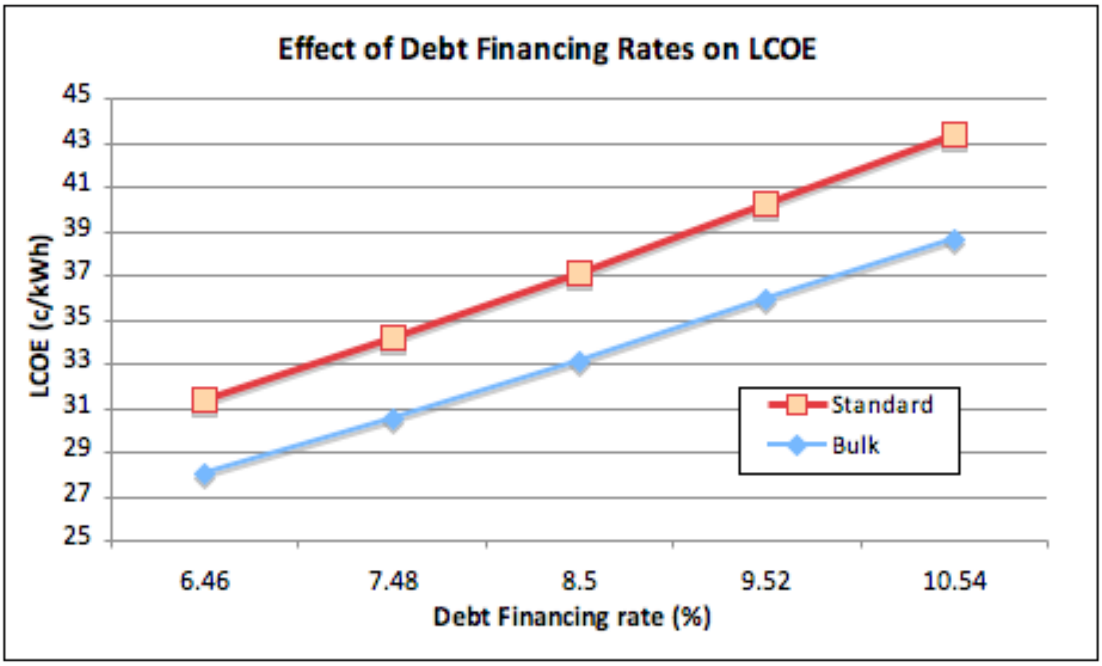
Model	PV System size	Standard (c/kWh)	Bulk (c/kWh)
Residential	1.5kW	37.16	33.16
	5kW	33.22	30.39
	10kW	30.2	28.34
Commercial	100kW	33.69	31.07
	250kW	33.24	30.7
	500kW	32.91	30.44
Large-scale	1MW	35.15	NA
	10MW	31.47	NA
	50MW	30.35	NA

For all three models, increasing the module efficiency by 25% (from 13.32% to 16.51%, which would occur in 2020 with just over a 2% per annum increase between 2010 and 2020) decreases LCOE by around 13% to 16%. Decreasing the module cost by 25% decreases LCOE by around 12.5% to 16.5%. Given that decreases in module costs can result from module efficiency increases as well as improvements in other aspects of the market, it is likely that a 25% decrease in module cost will occur before a 25% increase in module efficiency. Decreasing the inverter cost by 25% decreases LCOE by around 2.5% to 4.5%.



Effect of Technology Type on Capital Cost Breakdown

Changes to debt finance costs (which could occur either because of changes to financial markets but also through government policy) also had a significant impact on LCOE, with a 1% increase resulting in around 2-3% (commercial and large-scale) to 8.5% (residential) increase in LCOE, and vice versa.



Effect of Debt Finance Rates on LCOE

For the commercial and large-scale models, changes to the corporate tax rate had very little impact on the LCOE, with reduction from 30% to 27.6% decreasing LCOE by 1% (commercial) and 1.6% (large-scale).

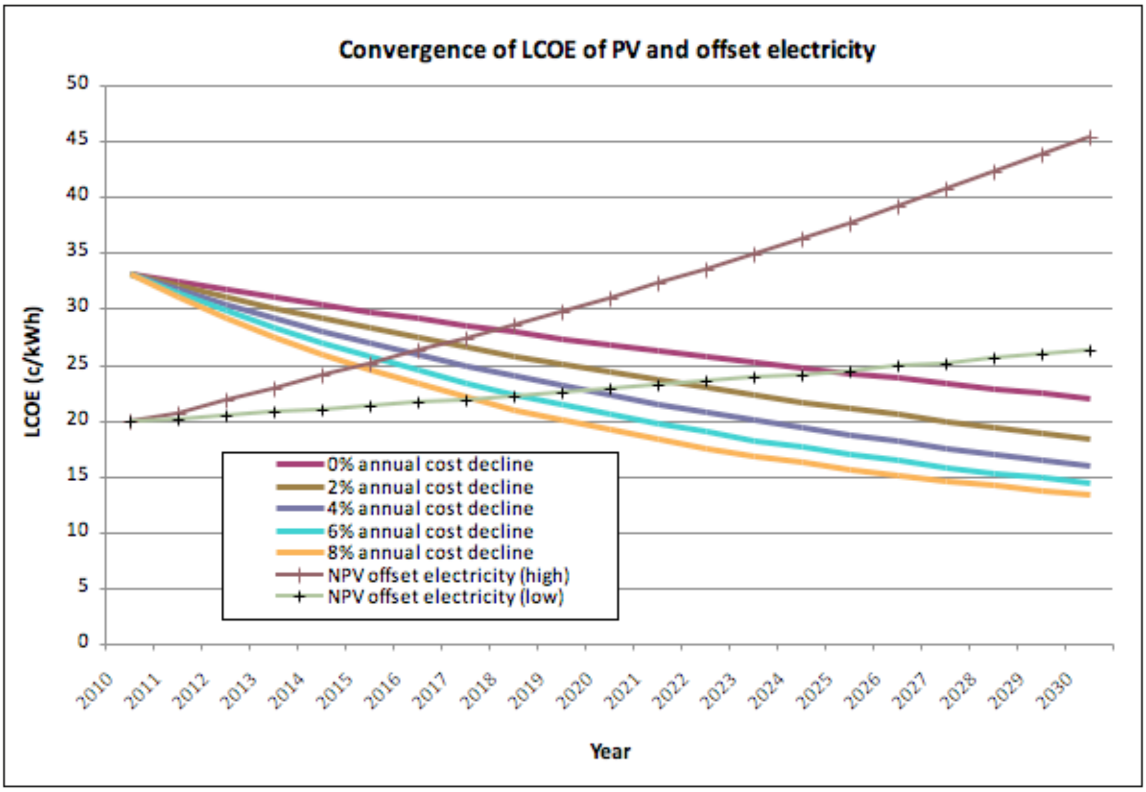
For the large-scale model, sensitivity analysis was conducted around the use of tracking. It was found that single axis tracking increased LCOE by around 0.7% while two-axis tracking decreased LCOE by around 3.1%. However, these results should be viewed with caution and would benefit from better real world data on the costs of tracking in Australia.

LCOE Projections

Projections of the LCOE for systems installed in the years 2010 to 2030 were compared to projections on the LCOE of offset electricity (for the residential and commercial models) and the LCOE of electricity sold wholesale (large-scale). In all 'mid-point' scenarios, for the residential and commercial models, intersection occurred before 2022, and in some cases by 2014-15. Increased module efficiency, decreased module price, increased system size and reduced rates of debt brought the intersection year forward. For systems installed in successive years, the module efficiency is assumed to increase by 2% each year, the module costs decrease by 4% each year, while the cost of inverters as well as the importer/distributor and installer margins are each assumed to decrease by 2% each year. Note that not all PV arrays will be north-facing at latitude angle (as assumed by the model), in which case they will have higher LCOEs.

Summary of impacts on intersect of PV and grid electricity LCOEs for residential and commercial models – different system sizes

		Electricity price growth projections	
Model	**PV System size**	**Low**	**High**
Residential	1.5kW	2021	2017
	5kW	2019	2015-16
	10kW	2017	2014-15
Commercial	100kW	2020-21	2016-17
	250kW	2020	2016-17
	500kW	2019-20	2016-17



Projections of the Impact of Module Cost on LCOE: 2010 to 2030 – bulk installation model

For the large-scale model, in none of the scenarios did the PV LCOE reduce to be equal to or below that of wholesale electricity. Assuming the above default rates of cost and efficiency improvements, then where there is either a 4% annual efficiency increase, an 8% annual module cost reduction or less than a 4.49% cost of debt, then by 2030 the LCOE of PV electricity is only slightly more than the LCOE of wholesale electricity. Thus, it seems that out to 2030, in the absence of significant breakthroughs of some kind that reduce costs, large-scale PV will struggle to be cheaper than wholesale prices in Australia.

Cost breakdowns

For all three models, the upfront cost breakdowns show that the PV equipment cost is the greatest cost, being between half and two thirds the total. The end system channel/developer costs are the next greatest component. The most significant savings for the bulk purchase model are from reduced distributor channel costs as well as end system channel costs, with the former providing a greater saving in the residential model and the latter in the commercial model. Although thin film has lower PV equipment costs it also greater power equipment costs (because of increased cabling), structural and support costs and civils (because of land preparation and foundations) – all because the modules are lower efficiency and hence the system takes up a larger area. Finance costs differ depending on the relative levels of debt to equity, the interest rates at which these are available, whether tax benefits can accrue and whether depreciation can be applied.

Future work

More detailed collection of real world data would be useful, especially for large-scale systems, as no multi-MW scale systems have yet been built in Australia. In general, prices are changing rapidly, and so they will need to be updated each year regardless, possibly more often. This includes wholesale and retail electricity prices (including carbon prices), which, as discussed in the detailed methodology, need to be extended annually for the model to calculate cost projections.

The large-scale model has, in effect, assumed that the PV systems are 'unscheduled' and so have no restrictions placed on their output. Further work in this area could include:

- Assessing the degree to which a large-scale PV system might be curtailed (likely to be site specific) and the impact this has on LCOE.
- Incorporation of the avoidance of such losses into the financial analysis of storage, although related financial benefits are unlikely to be significant compared to extending output regularly to take advantage of higher prices
- Including the capability to add in annual costs that are unrelated to output that are related to: submitting offers, providing the information required for the UIGF, complying with FCAS cost requirements and responding to potential voltage and reactive power instructions from NEMMCO.

The model currently has limited ability to assess the impact of different types of support policies. These could include feed-in tariffs, capital grants, low interest loans and tax breaks. Being able to assess the impacts of different types of policies would be particularly useful for future development of commercial and large-scale systems.

1 INTRODUCTION

In the mid 1990's the Australia PV market comprised 13% of the market in IEA countries and Australia was the 4th largest world manufacturer of PV cells. By 2009, the Australian market accounted for 1% of the world market and, after stopping production altogether, a small cell and module plant is now in operation by Silex Solar.

It is clear that, although Australia leads the world in many areas of PV technology development and application, it has become less significant as a manufacturer and exporter of photovoltaic products and has not played a major role in development of the new grid-connected markets which have seen significant system cost reductions and the rise of a global industry worth US$50 Billion a year and growing.

Internationally, Germany is installing around 3 GW of PV a year, the European PV Industry Association has a target of meeting 12% of Europe's electricity from PV by 2020, China has a booming manufacturing industry, China and India are now embarking on large internal deployment programs (~20GW each by 2020) and the US is developing a 2030 Solar Vision to evaluate the technical, economic, and environmental feasibility of meeting 10-20% of electricity demand from solar energy technologies by 2030. The latter will identify technology research, development, demonstration, deployment and policy options.

Understanding and communicating the economic and technical barriers to increased commercial deployment of PV in Australia is critical to the success of R&D programs, market deployment policy and industry collaboration efforts. In order to support the re-emergence of an innovative and globally competitive PV sector in Australia, industry and policy makers require tools with the ability to test the impact of technical, financial, commercial and policy changes on both the operation of the PV industry as a whole, as well as on system cost, design and performance. These can suggest where efforts to improve efficiency or reduce costs should be focussed, inform the design of incentives to accelerate commercial deployment and maximise macroeconomic benefits to Australia.

A range of models has been developed internationally and in Australia to examine different aspects of PV development and cost-effectiveness. The 2004 Australian PV Roadmap developed a PV grid parity cost model, based on international PV learning curve price reductions and local electricity rates; APVA members have developed electricity price models by State, PV project cost models, manufacturing cost models and more. NREL has recently published results of modelling residential sector PV break-even costs for all US States, using local solar resources, electricity tariff structures, and PV cost projections.

This project involved the development of a techno-economic simulation model with a range of input sub-models which can be independently modified. They allow the impacts of changes to the characteristics of PV technology, deployment, financing and incentive policies to be assessed. This will also enable the ASI to review proposals for likely cost impacts and macroeconomic benefits.

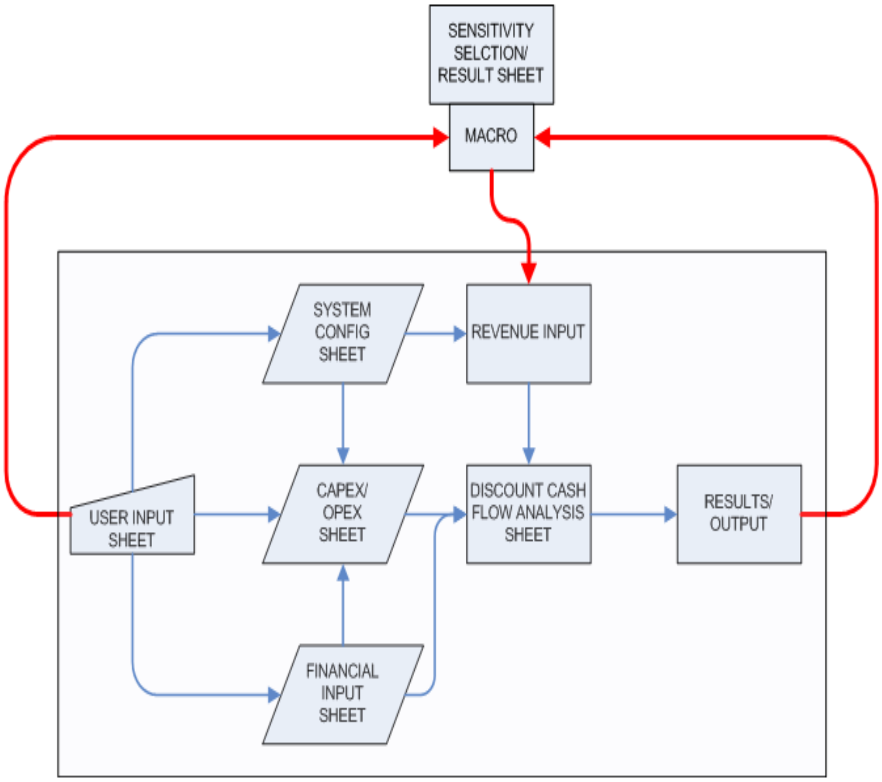
2 SCOPE OF WORK

The scope of work is as defined in the original APVA proposal to the ASI:

- Develop a model structure which allows calculation of the Levelised Cost of Electricity (LCOE) using a range of inputs from sub-models of the PV and BOS technologies, the site, the system, the cost of finance, the return on investment required by the project developers etc.
    - Collect a range of data to test the model sensitivities and ensure reasonable outputs
- For the three different markets: wholesale, commercial, and residential, use the LCOE to identify the 'feasibility' gap between the current LCOE and either grid parity for end-user applications, or an acceptable IRR for a wholesale system.
- Once the feasibility gap is known, identify which areas will reduce that gap in the quickest manner with the maximum degree of benefit to Australia through a sensitivity analysis.

3 METHODOLOGY

Models were developed to calculate a variety of financial outcomes including the net present value (NPV) of total installed cost (including interest expenses), the Levelised Cost of Electricity (LCOE), the NPV of offset electricity, the NPV Return on Equity (ROE) and the IRR for a range of PV systems, under a range of input conditions. A schematic structure of the model is shown below:



Separate models were developed to reflect a higher level of detail for each of the sectors to be studied: residential, commercial and central power station.

Generic and sector-specific data were collected via email and phone surveys of APVA members and the wider PV industry, as well as from in-house information available to personnel working on the project. Cross-checking was undertaken to ensure consistency and validity of data and outputs.

The model assumptions and logic were cross-checked within the project staff, as well as via external checks by APVA members with appropriate expertise (Suntech, SunWiz, IT Power, Kenneth Kong, CSIRO)

4 MODEL SPECIFICATION

The following summarises the points most relevant to the operation of the three models: residential, commercial and large-scale. Significantly more detail is in Appendix 1: Detailed Methodology.

4.1 Input specification

The model operates via user definition of a scenario. It is then possible to conduct sensitivity analyses by varying specified parameters around a 'present day' default value. Sensitivity analyses can also be conducted around projected outcomes by altering how selected parameters change over time.

4.1.1 Scenario parameters

Variables are selected from a drop down table which provides choice of:

- Technology type: thin film, polycrystalline, monocrystalline and high efficiency[1]
- Nominal system size: 1.5kW, 5kW or 10kW (residential), 100kW, 250kW or 500kW (commercial), and 1MW, 10MW or 50MW (large-scale)
- Location: Brisbane, Sydney or Melbourne[2]
- Financing: (See Table 1 for how these differ)
    - Residential: 100% Mortgage, 100% Savings, 50/50 Mortgage/Savings
    - Commercial: 100% Debt Risk Free, 100% Debt Including Risk Premium, 100% Equity Self Finance, 50% Equity 50% Debt
    - Large-scale: Utility WACC, 100% Debt Risk Free, 100% Debt Market Risk, 100% Equity, 50% Equity 50% Debt.
- Development model:
    - Residential: Standard household retail, Bulk purchase[3] or Commercial investor
    - Commercial: Retail, Bulk purchase
    - Large-scale: Utility developer, Operator developer, Utility – avoided network augmentation
- Tracking: the large-scale model can also select whether the panels are fixed, or have single axis or dual axis tracking

[1] These differ in terms of efficiency, cost, area, open circuit voltage (Voc) and weight.

2 These differ in the annual average insolation and the performance ratio.

[3] The operation of the 'bulk purchase' or 'bulk supply' model is explained in Section 0.

Table 1 Parameters of different financing options

Financing option	% Debt Financing	Cost of Debt	Cost of Equity
Residential			
100% Mortgage Rate	100%	8.5%	6.5%
100% Savings Term Deposit	0%	8.5%	6.5%
50% Mortgage 50% Savings	50%	8.5%	6.5%
Commercial			
100% Debt, Risk Free	100%	5.34%	11.64%
100% Debt, Including Risk Premium	100%	8.63%	11.64%
100% Equity, Self Finance	0%	0.00%	11.64%
50% Equity, 50% Debt	50%	8.63%	11.64%
Large-scale			
Utility WACC	60%	8.63%	11.64%
100% Debt, Risk Free	100%	5.34%	11.64%
100% Debt, Market Risk	100%	8.63%	11.64%
100% Equity	0%	8.63%	11.64%
50% Equity, 50% Debt	50%	8.63%	11.64%

Once the technology type 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). Note that all models assume north-facing PV arrays at latitude angle.[4]

4.1.2 Present day parameters

The following parameters can also then be specified, with their values varied from zero to double a default value. Some of the default values are determined by the chosen scenario, while some are fixed.

- Cost of equity
- Cost of debt
- CPI
- Module costs
- Inverter costs
- Importer/Distributor margin (termed 'Logistics' in the Large-scale model)
- Installer margin
- Module efficiency

The commercial and large-scale models can also have the following varied

- Corporate tax rate
- Depreciation period

[4] 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.

4.1.3 Projected parameters

The same parameters can have the percentage rate at which they change over time defined by the user. A default value is available.

4.1.4 Calculated input data

The model calculates the following PV equipment input data according to the technology type:

- module power
- cable length per series string
- modules per series string
- power per series string
- number of modules
- number of series strings
- number if inverters
- total module or land area
- actual output power
- cable length
- total module weight

The models also calculate the related financial input data according to the technology type and the particular model used (residential, commercial, large-scale).

4.1.5 Electricity price projections

For the residential and commercial models, two projections have been made of electricity prices – low and high. The residential tariff is taken to be flat while the commercial tariff is derived from the interaction between a TOU tariff and a PV output profile, and includes a 25% discount to account for the discount likely to be available to large commercial customers. They take into account current price determinations and are discounted back to present day values. The large-scale model, uses a reference wholesale price projection as well as projections assuming a 0%, a 5%, a 15% and a 25% CPRS by 2020. They allow for the impact of a 10% 'solar premium' due to the correlation between PV output and wholesale price.

4.1.6 DUOS and TUOS charges

Distribution Use of System (DUOS) charges are charges payable to the Distribution Network Service Provider (DNSP) by customers connected to the distribution network that pay for the costs of constructing, maintaining and operating the distribution network. Transmission Use of System (TUOS) charges are the equivalent charges payable to the Transmission network Service provider (TSNP).

For the model, no avoided DUOS is assumed – since DG is using the distribution network. Given the small payment currently available for avoided TUOS, and the likely variation between jurisdictions, no TUOS repayment has been included. DG connected to the transmission network assumes no avoided DUOS reward, as well as no avoided TUOS reward – since they are using the transmission network. For more detail see Appendix 2: DUOS and TUOS .

4.1.7 Network Losses

Line losses occur in both the transmission and distribution networks. DG will reduce such losses and so, in theory, result in savings to retailers. However, in the retailer price determinations, the losses, as well as the reductions in losses due to DG, are taken into account when working out what prices retailers can charge (the higher the losses the more they can charge end users). Thus, DG does not provide benefits directly to the retailer.

Instead, the benefits of DG are distributed throughout the population through lower tariffs. Therefore retailers are unlikely to reward DG for reducing line losses, so there is no need to account for reduced losses in the model. For a more detailed discussion of this and the use of Marginal Loss Factors (MLFs, also called Transmission Loss Factors) and Distribution Loss Factors (DLFs), see Appendix 3: Loss Factors.

4.2 Outputs

The models automatically calculate the following values for the present day, as well as for each year out to 2030. So for example, they calculate the LCOE for a system installed now, as well as the LCOE for systems installed in each year out to 2030.

- Total installed cost (as both $/W and $), which consists of:
    - PV equipment cost (landed price)
    - Importer/Distributor margin
    - Structural CAPEX
    - BOS costs
    - Installation costs
    - Installer margin
    - GST
    - Interest expenses (present value terms)
- Levelised Cost of PV Electricity (LCOE), as both $ and c/kWh
- Net present value Return on Equity (ROE) of the system including offset electricity, as $

The residential and commercial models also calculate:

- Net present value of offset electricity, as both $ and c/kWh
- Internal Rate of Return (IRR) of the investment

5 RESIDENTIAL SECTOR

Summary: The 'feasibility gap' between the LCOE's of PV and grid electricity can best be reduced by (i) promoting the installation of larger systems, (ii) promoting the use of the 'bulk installation' model, where the importer/distributor and installer margins are reduced and (iii) reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes. Finance costs have a large impact on LCOE, but are currently ameliorated by up-front capital assistance through Solar Credits.

5.1 Residential-specific issues

5.1.1 Bulk supply models

An increasing number of residential systems are being installed under 'bulk supply' models. There are two main types of such models – company-based and council or community group-based. Company-based models seem to be the first to have been used widely and initially involved signing on 50 or so households willing to buy a system, then a rapid roll out while the next 50 were signed on. Council or community group-based schemes are better described as 'preferred supplier' models. In this case, a council or community group requests quotes from installers, then selects preferred suppliers that it then advertises to the community. Based on currently available prices through such schemes, these impacts have been incorporated into the model by reducing the import/distribution channel costs from 20% to 10% in the residential model and from 10% to zero in the commercial model.

Note that in the market there are various combinations of these models in operation. Some 'standard' installers also purchase container loads of PV modules direct from manufacturers, thus removing the distributor cost. For more information of these models, including prices available under both company and community-based schemes, see Appendix 4: Bulk Supply Models.

5.1.2 Treatment of debt

In all three models, where debt is used to purchase the PV system, the loan is assumed to be discrete from all other loans the system owner may have. While this assumption is likely to be justified for the commercial and large-scale models, the residential situation may be more complex. For the commercial and large-scale models, once the system has 'paid itself off' the loan will still exist and so repayments will still be based on the cost of debt, while the system's revenue will now produce returns that can be approximated from the cost of equity. For the residential PV system, the cost of purchase may simply draw down on the owners home loan, and so once the system has 'paid itself off', the PV system component of the loan will no longer exist. The system's revenue may now be used for a variety of things: to help repay any remaining home loan (so producing returns based on the cost of debt), it may be invested in some way (possibly producing returns based on the cost of equity), or it could even increase expenditure by, for example, increasing electricity use (I have a PV system so my electricity is 'free') or contributing to a general feeling of financial well being. Given this variety of alternatives, treatment of the residential debt in the same manner as the commercial and large-scale debt was considered reasonable.

5.2 Results

5.2.1 Sensitivity analysis of LCOE

The following charts indicate some of the types of sensitivity analysis possible with the residential model – comparing the standard retail installation model and the bulk installation model. Sensitivity analysis was conducted on:

- Module technology (Figure 1)
- System size (Figure 2)
- Module efficiency (Figure 3)
- Module costs (Figure 4)
- Inverter costs (Figure 5)
- Debt financing rates (Figure 6)
- Importer/distributor margin (Figure 7)
- Installer margin (Figure 8)

Except where specified, the model runs assumed a 1.5kW polycrystalline system in Sydney on a 100% debt repayment. The most notable outcomes were:

a) System size has a significant impact, with the LCOE of a 10kW system being just over 80% that of a 1.5kW system. Note, however, that the bulk installation model, and hence the price reductions available through them, may be more difficult to apply to larger system sizes.

b) Increasing the module efficiency by 25% (from 13.30% to 16.49%, which would occur in 2020 with just over a 2% per annum increase between 2010 and 2020) decreases LCOE by 13.2%.

c) Decreasing the module costs[5] by 25% (from $2.31/W to $1.76/W) decreases LCOE by about 12.5%.

d) Decreasing the inverter costs by 25% (from $0.70/W to $0.53/W) decreases LCOE by about 4.5%.

e) Each percentage increase in debt finance costs (eg. from 6.5% p.a. to 7.5%), increases LCOE by about 8.5%.

f) Probably the most significant recent innovation in the Australian PV market, the use of the bulk installation model (which here is emulated by reducing the importer/distributor margin from 20% to 10%), results in a 10.75% drop in LCOE. Figure 7 and Figure 8 show the impact of more incremental changes, with reductions in the installer margin having slightly greater impacts than reductions in the importer/distributor margin.

[5] Decreases in module costs can result from module efficiency increases as well as improvements in other aspects of the market, such as manufacturing. For module purchasers, module costs can also be a function of volume purchase and of the strength of the global PV demand.

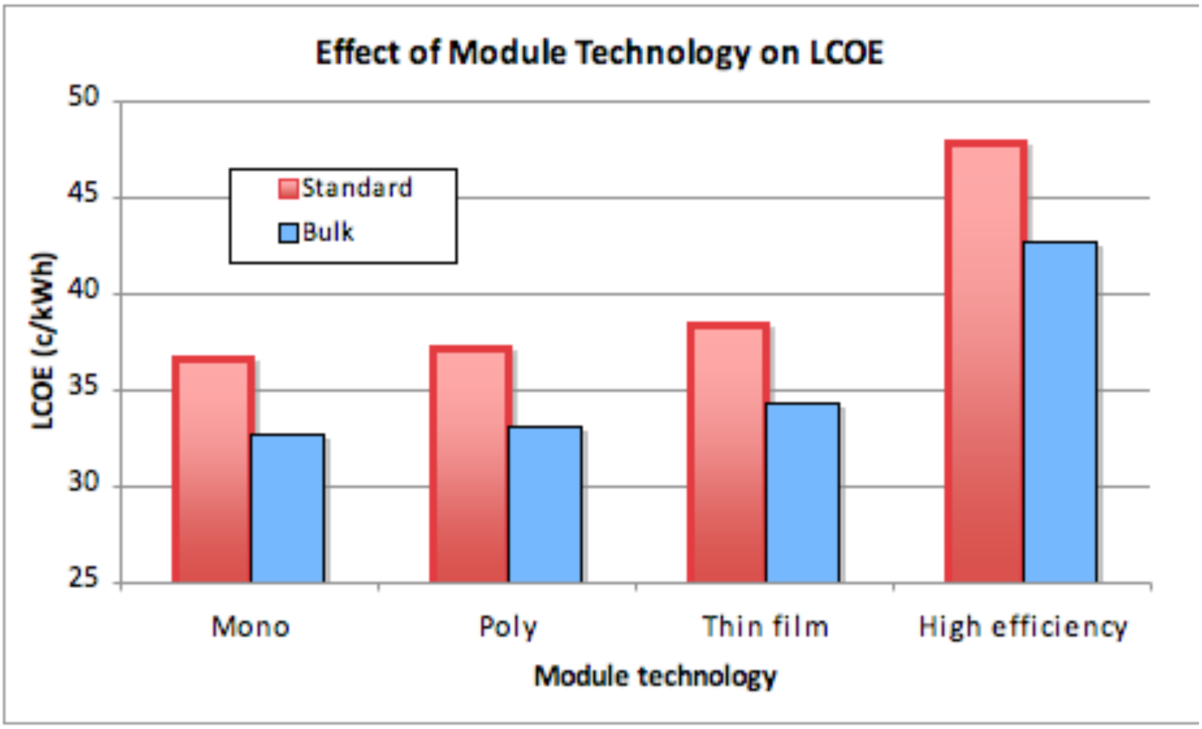


Figure 1 Effect of Module Technology on LCOE using the 'standard' supply and installation model, and the 'bulk' supply and installation model

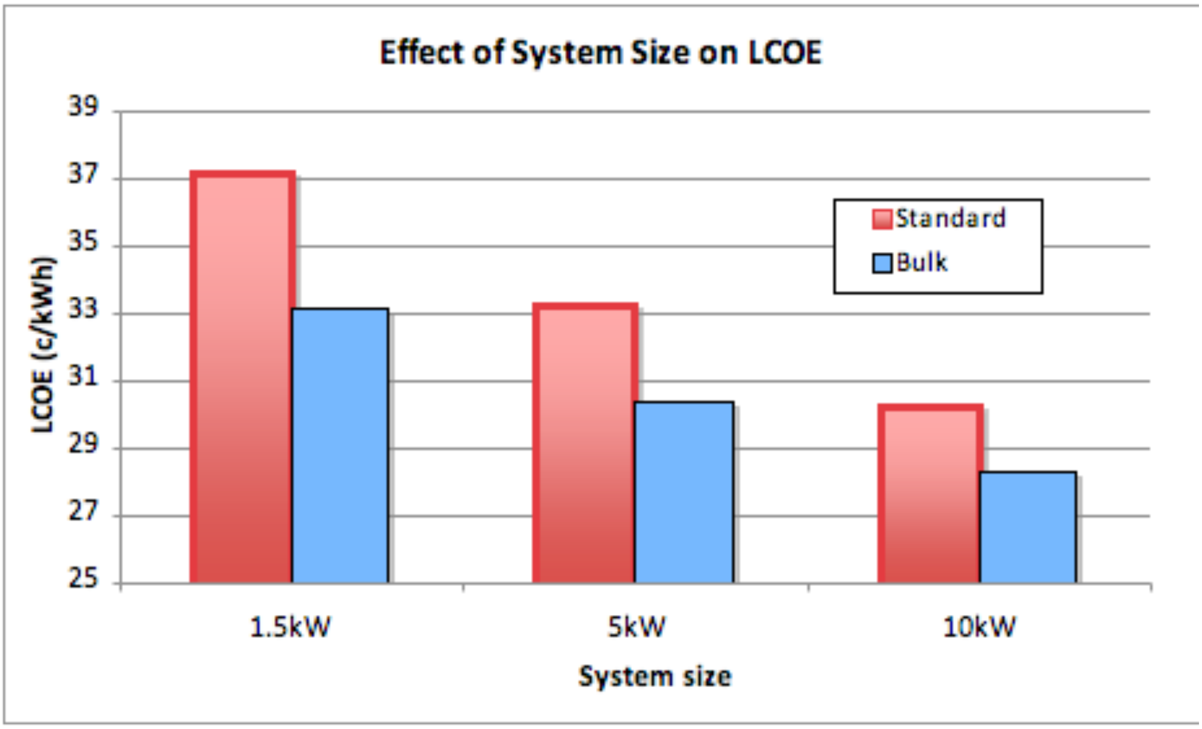


Figure 2 Effect of System Size on LCOE

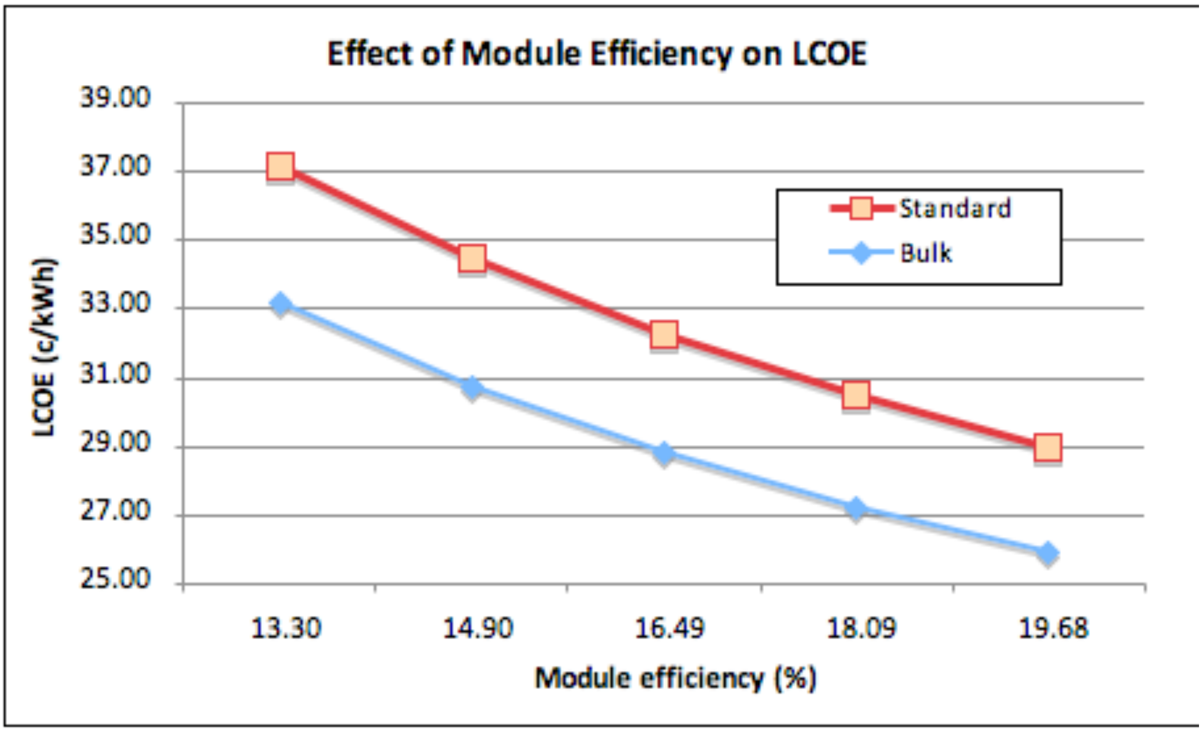


Figure 3 Effect of Module Efficiency on LCOE

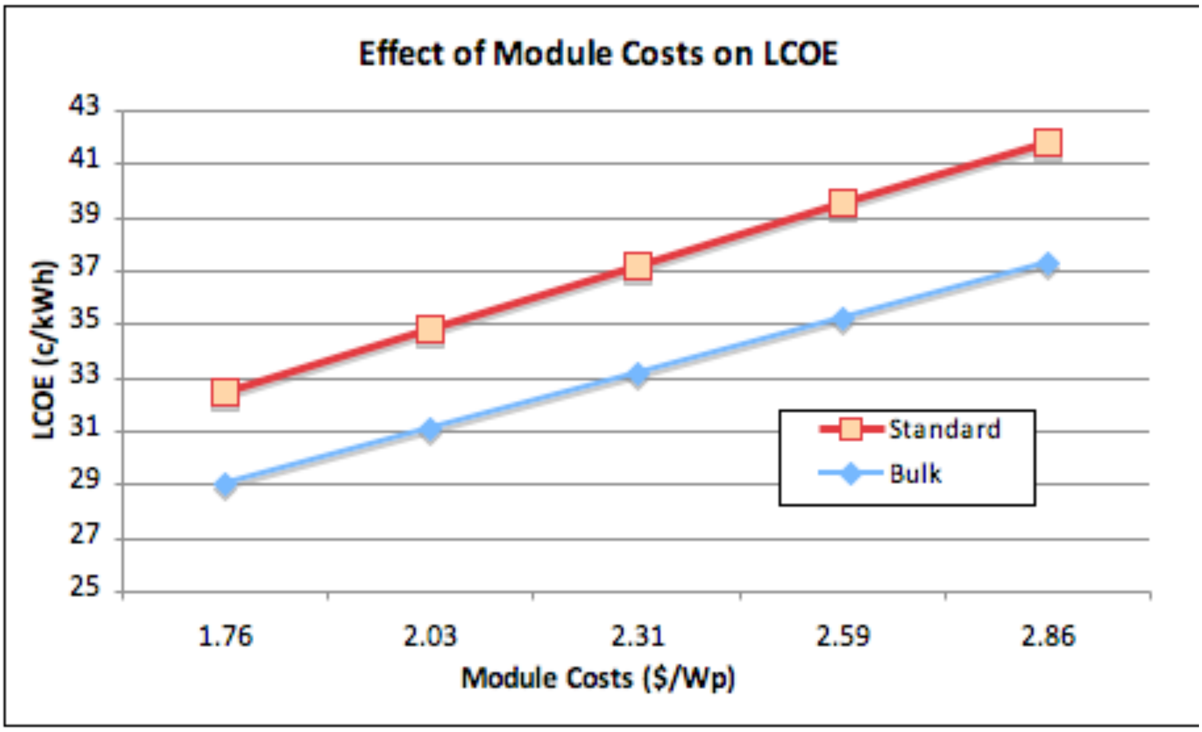


Figure 4 Effect of Module Costs on LCOE

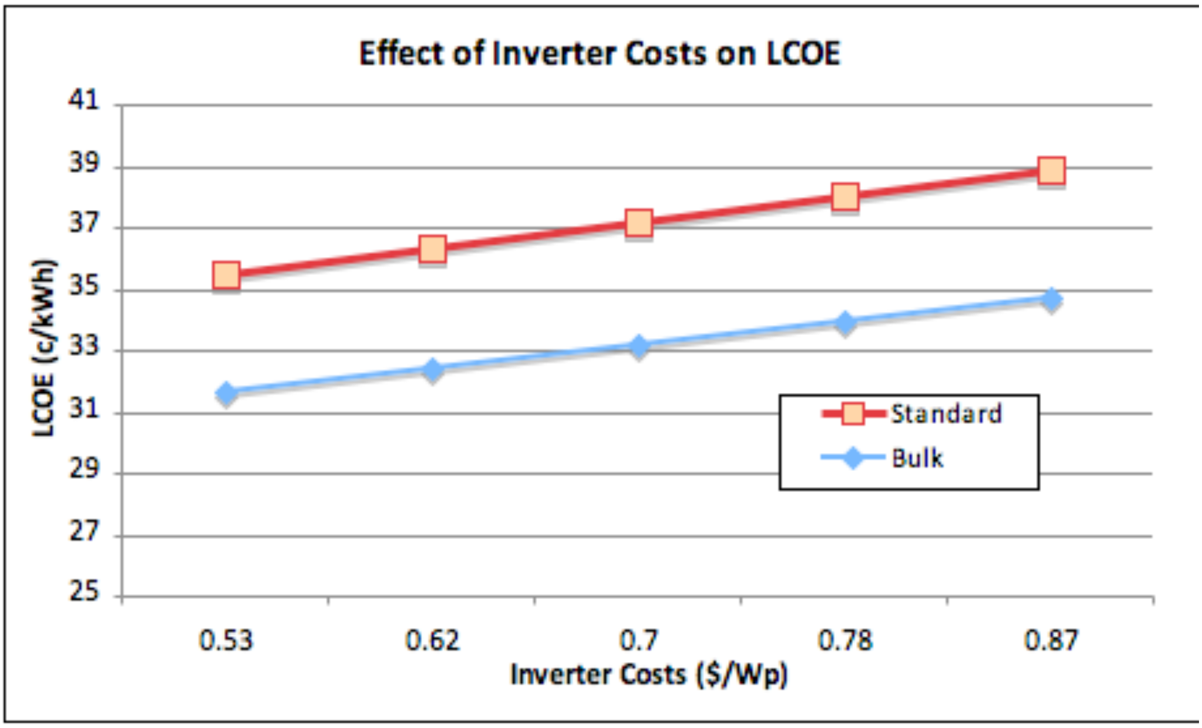


Figure 5 Effect of Inverter Costs on LCOE

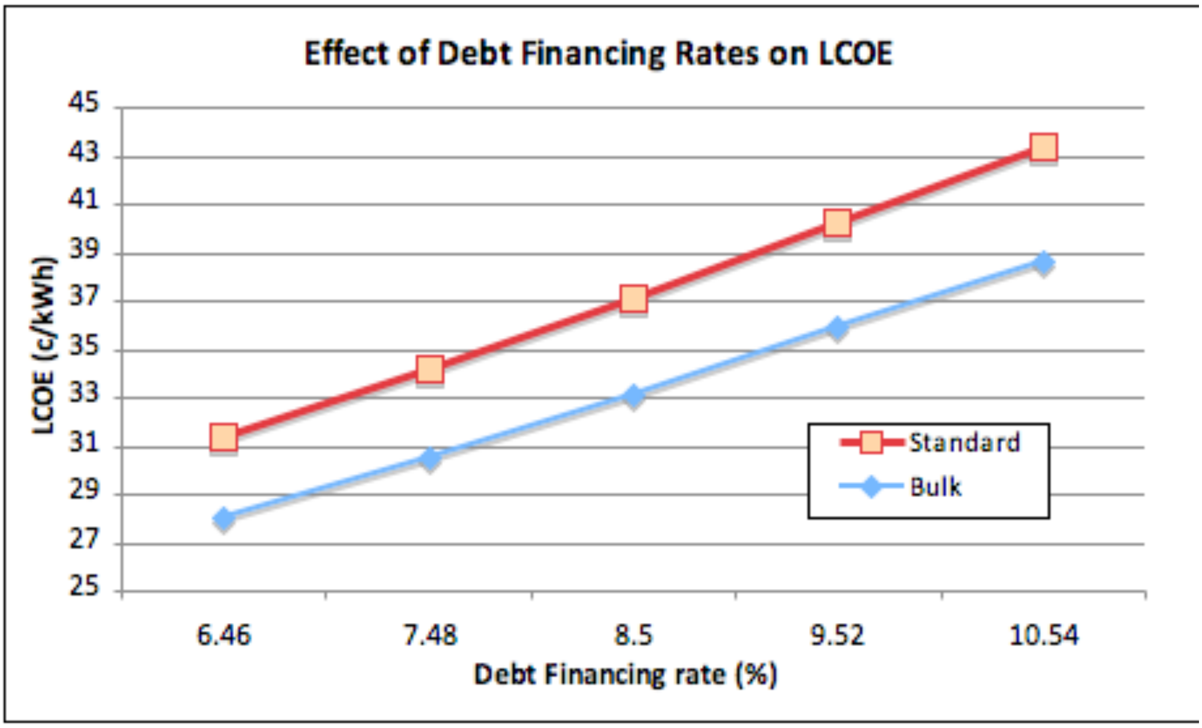


Figure 6 Effect of Debt Finance Rates on LCOE

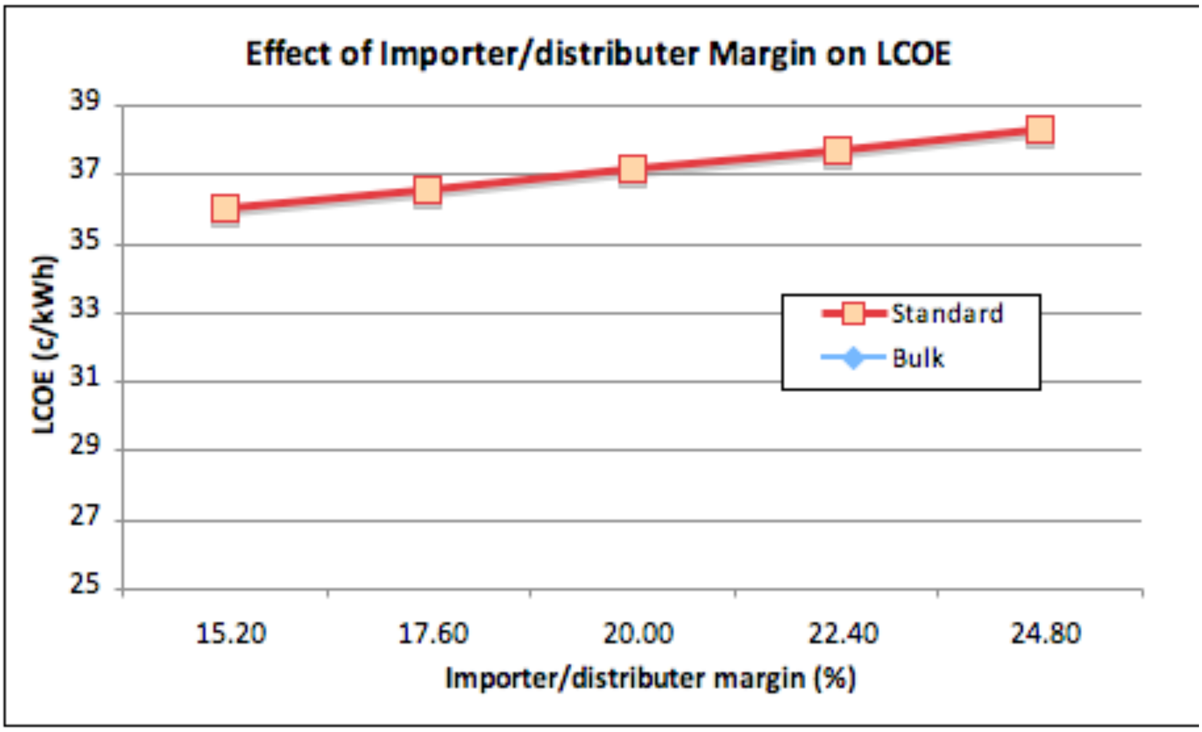


Figure 7 Effect of Importer/distributor Margin on LCOE

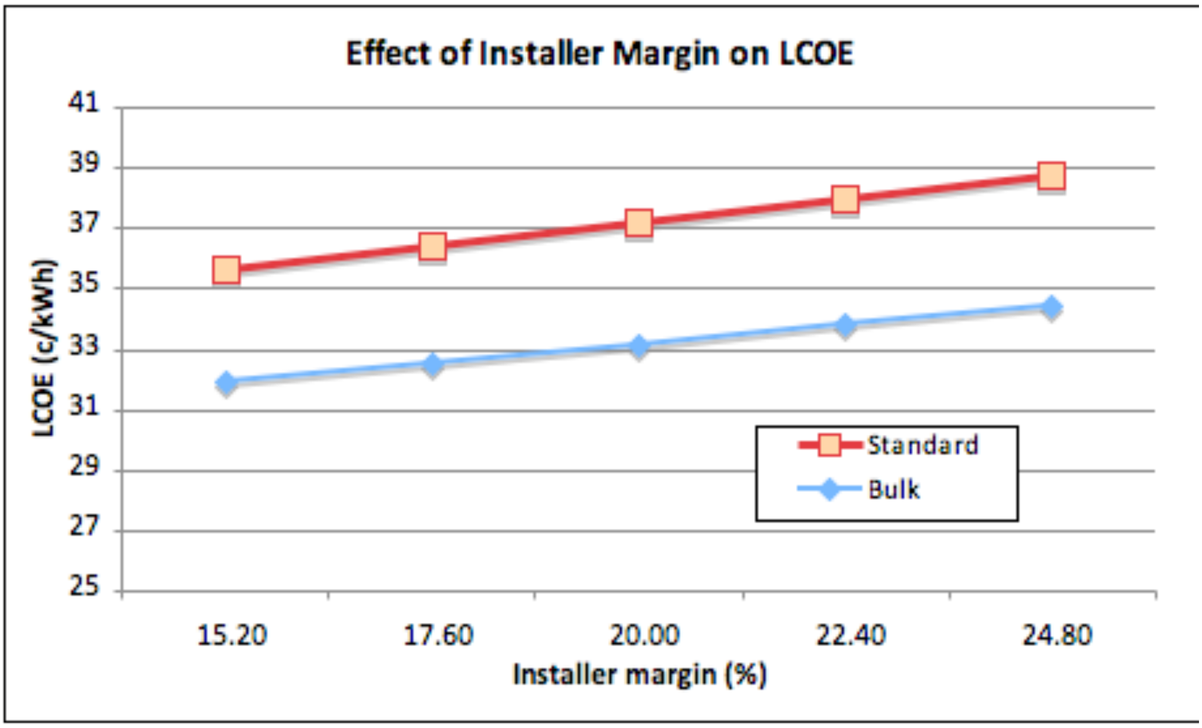


Figure 8 Effect of Installer Margin on LCOE

5.2.2 LCOE projections

The following charts show projections of the LCOE for systems installed in the years 2010 to 2030. Unless otherwise indicated, they assume a 1.5kW monocrystalline system installed in Sydney on a 100% debt repayment. For systems installed in successive years, the module efficiency increases by 2% each year, the module costs decrease by 4% each year, while the cost of inverters as well as the importer/distributor and installer margins are each assumed to decrease by 2% each year. Note that not all PV arrays will be north-facing at latitude angle (as assumed by the model), in which case they will have higher LCOEs.

The sensitivities from the standard case show the impacts of:

- Module efficiency increasing annually by 0%, 1%, 2%, 3% or 4% (standard installation model, Figure 9) and (bulk installation model, Figure 10)
- Module cost decreasing annually by 0%, 2%, 4%, 6% or 8% (standard installation model, Figure 11) and (bulk installation model, Figure 12)
- Increased system size (standard installation model, Figure 13)
- Reduced debt finance costs (standard installation model, 1.5kW, Figure 14)

Changes to both efficiency and cost of modules changes the year that the PV LCOE intersects with the grid electricity LCOEs. Table 2 summarises these impacts for low and high price projections of grid electricity LCOEs. For simplicity, the mid points of the rates of efficiency increases (2%) and cost decreases (4%) have been used.

Table 2 Summary of impacts on intersect of PV and grid electricity LCOEs

	Electricity price growth projections	
PV Projection	**Low**	**High**
Module efficiency increases, standard installation	2021	2017
Module efficiency increases, bulk installation	2019	2016
Module cost decreases, standard installation	2021	2017
Module cost decreases, bulk installation	2019	2016

As shown in Table 3, increasing the system size has a significant impact on the intersection point, highlighting the importance of promoting the deployment of larger systems.

Table 3 Summary of impacts on intersect of PV and grid electricity LCOEs – different system sizes

	Electricity price growth projections	
PV System size	**Low**	**High**
1.5kW	2021	2017
5kW	2019	2015-16
10kW	2017	2014-15

As shown in Table 4, decreasing the debt rate, as could be achieved through low interest loans, also has a significant impact on the intersection point.

Table 4 Summary of impacts on intersect of PV and grid electricity LCOEs – different debt rates

	Electricity price growth projections	
Debt rate	**Low**	**High**
8.50%	2021-22	2017
7.48%	2020	2016
6.46%	2018	2015
5.44%	2016	2014
4.42%	2015	2013

In summary the 'feasibility gap' between the LCOE's of PV and grid electricity can best be reduced by the following, which are given in order of effectiveness:

- promoting the installation of larger systems (that are still small enough to connect to the distribution network)
- promoting the use of the 'bulk installation' model, where the importer/distributor and installer margins are reduced
- reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes.
- As shown in Section 5.2.1, likely reductions in inverter costs have a relatively small effect, but of course should not be overlooked as part of overall cost reductions. As PV module prices reduce, balance of system costs will become relatively more significant.

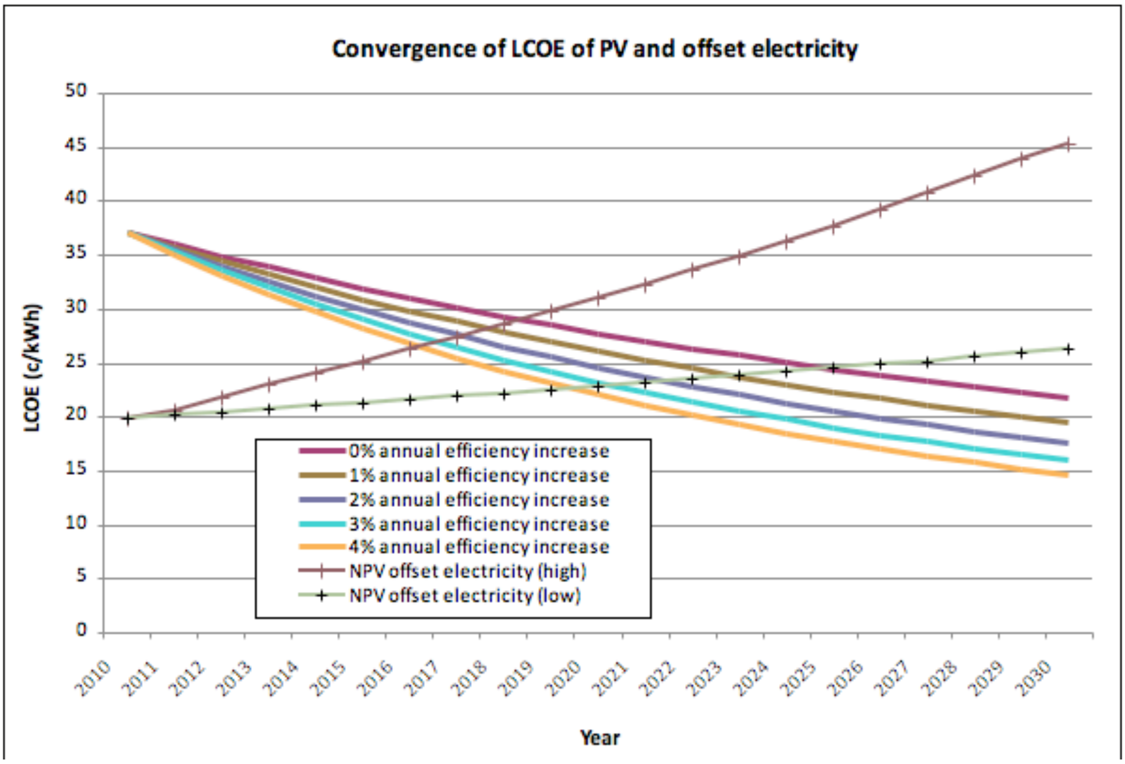


Figure 9 Projections of the Impact of Module Efficiency on LCOE: 2010 to 2030 – standard installation model

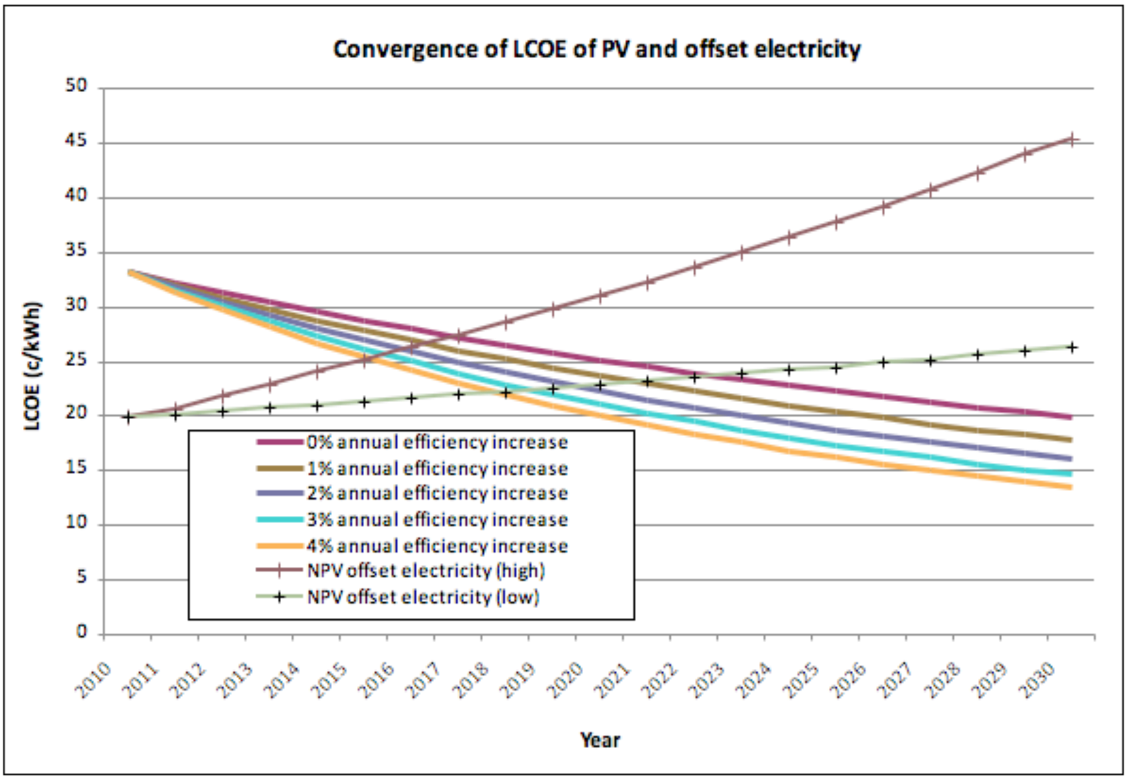


Figure 10 Projections of the Impact of Module Efficiency on LCOE: 2010 to 2030 – bulk installation model

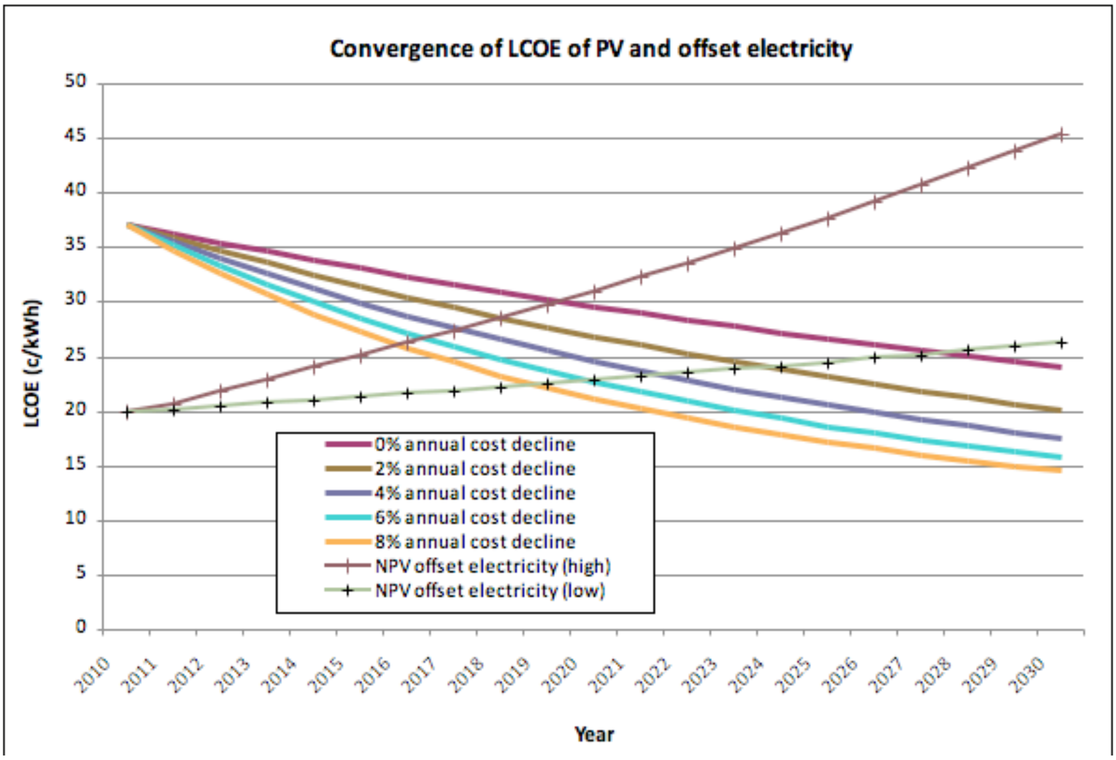


Figure 11 Projections of the Impact of Module Cost on LCOE: 2010 to 2030 – standard installation model

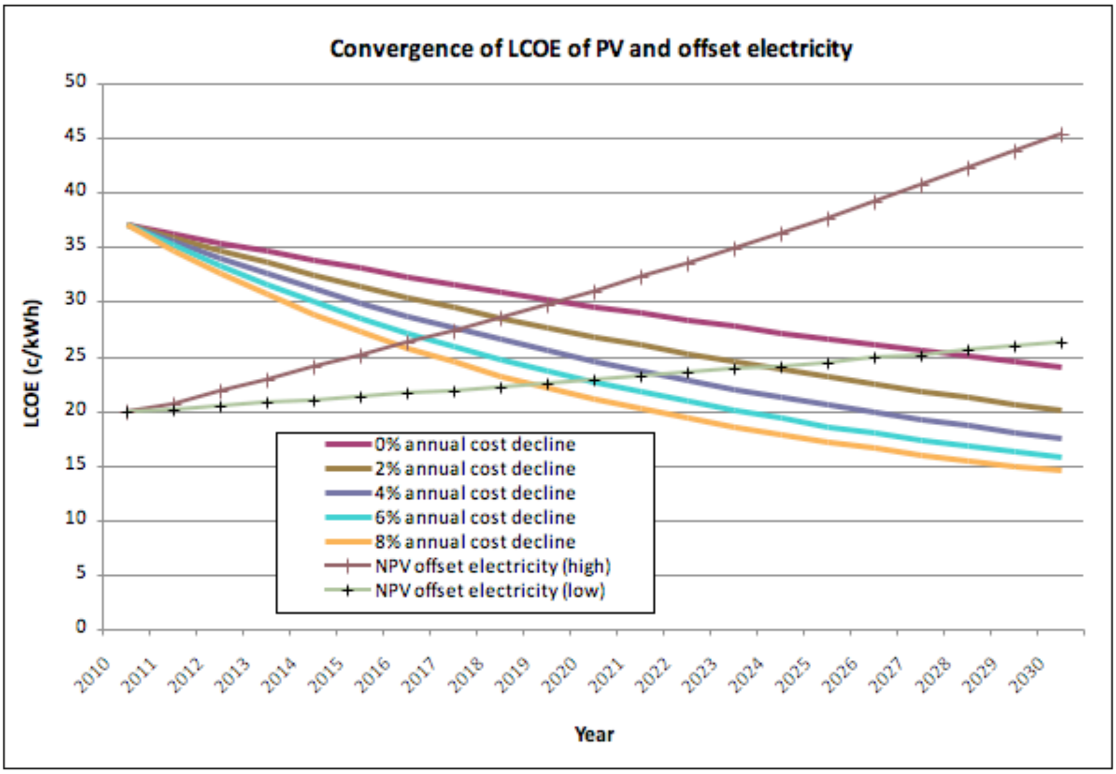


Figure 12 Projections of the Impact of Module Cost on LCOE: 2010 to 2030 – bulk installation model

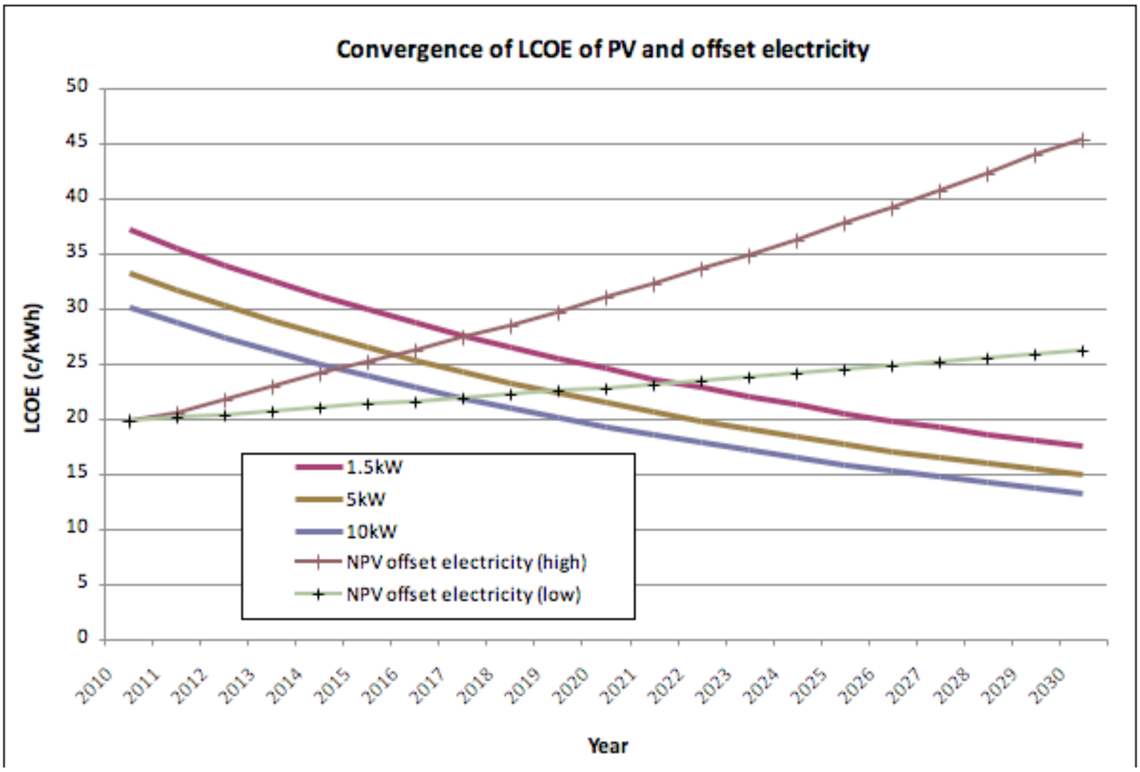


Figure 13 Projections of the Impact of System Size on LCOE: 2010 to 2030 – standard installation model

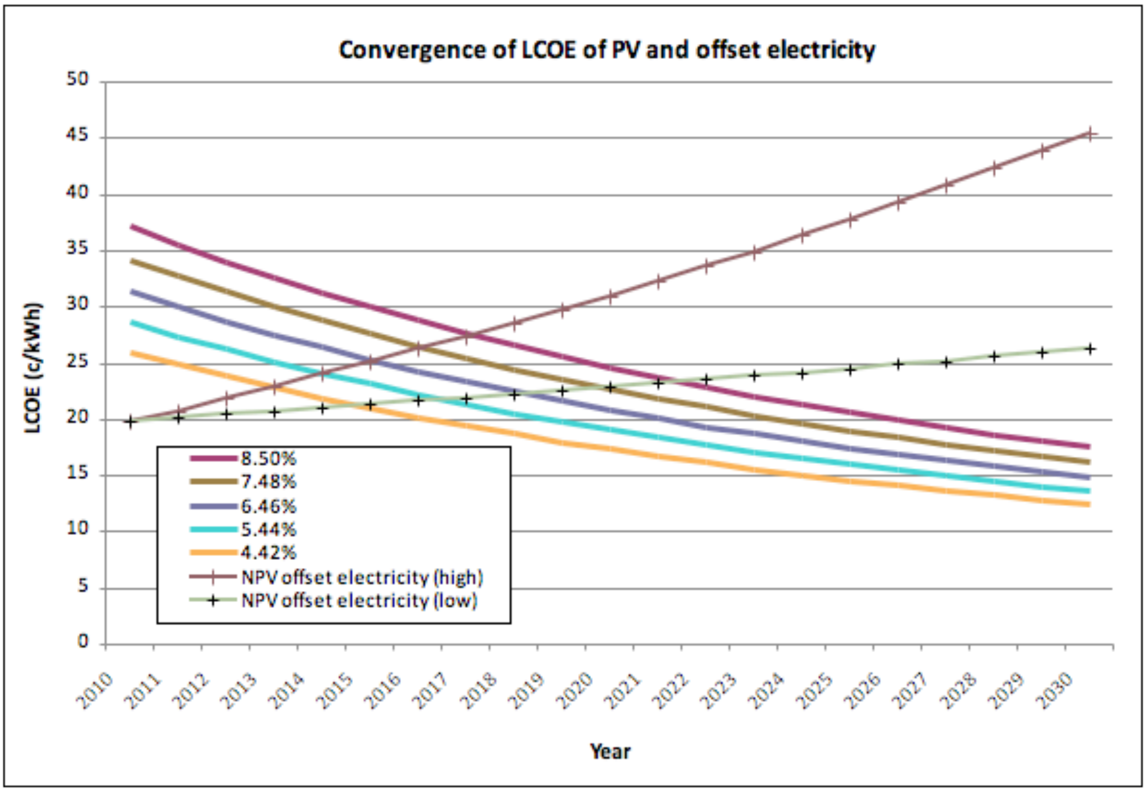


Figure 14 Projections of the Impact of Different Debt Rates on LCOE: 2010 to 2030 – standard installation model

5.2.3 Cost breakdowns

The following charts show the breakdowns of the upfront costs, and how they are affected by varying:

- the technology type (Figure 15)
- the development model (standard retail, bulk installation and commercial investor) (Figure 16)

The next chart shows the system lifetime costs for different development models, including the standard retail model with 50% equity and 50% debt financing (Figure 17)

Except where specified, the model runs assumed a 1.5kW polycrystalline system in Sydney on a 100% debt repayment, installed under the standard retail model.

The most notable outcomes were:

a) The PV equipment cost is the greatest cost, being up to half the total.

b) The end system channel costs are the next greatest component. These are the business costs and profit margin of the system developer which is additional to the installer costs (components and labor).

c) The most significant savings for the 'bulk purchase' and 'commercial investor' models come from reduced distributor channel costs, but reduced end system channel costs also play a role.

d) In terms of total lifetime finance costs, the bulk purchase model saves on financing costs (principal and interest paid on loans) derived from lower channel costs, the commercial investor's debt repayments are tax deductible and it receives a depreciation benefit, and the standard retail model with 50% debt / 50% equity saves through the lower return on equity (which is effectively further reduced by the tax it would have had to pay on earnings).

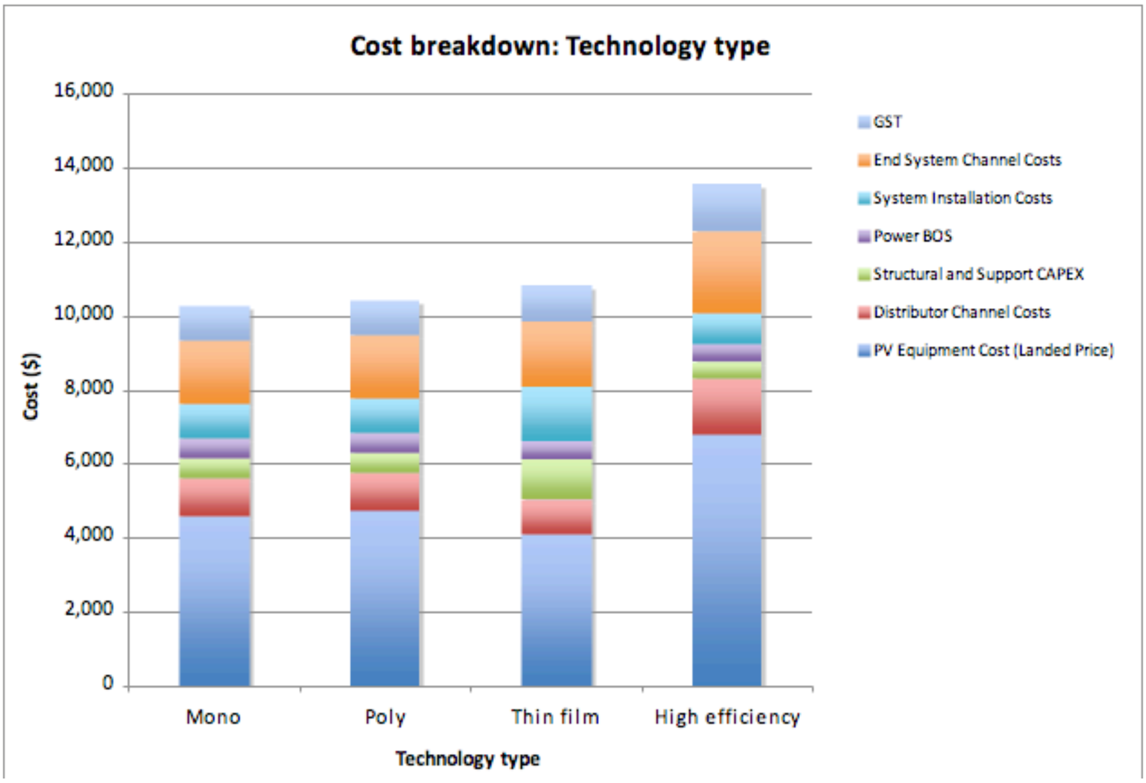


Figure 15 Effect of Technology Type on Capital Cost Breakdown

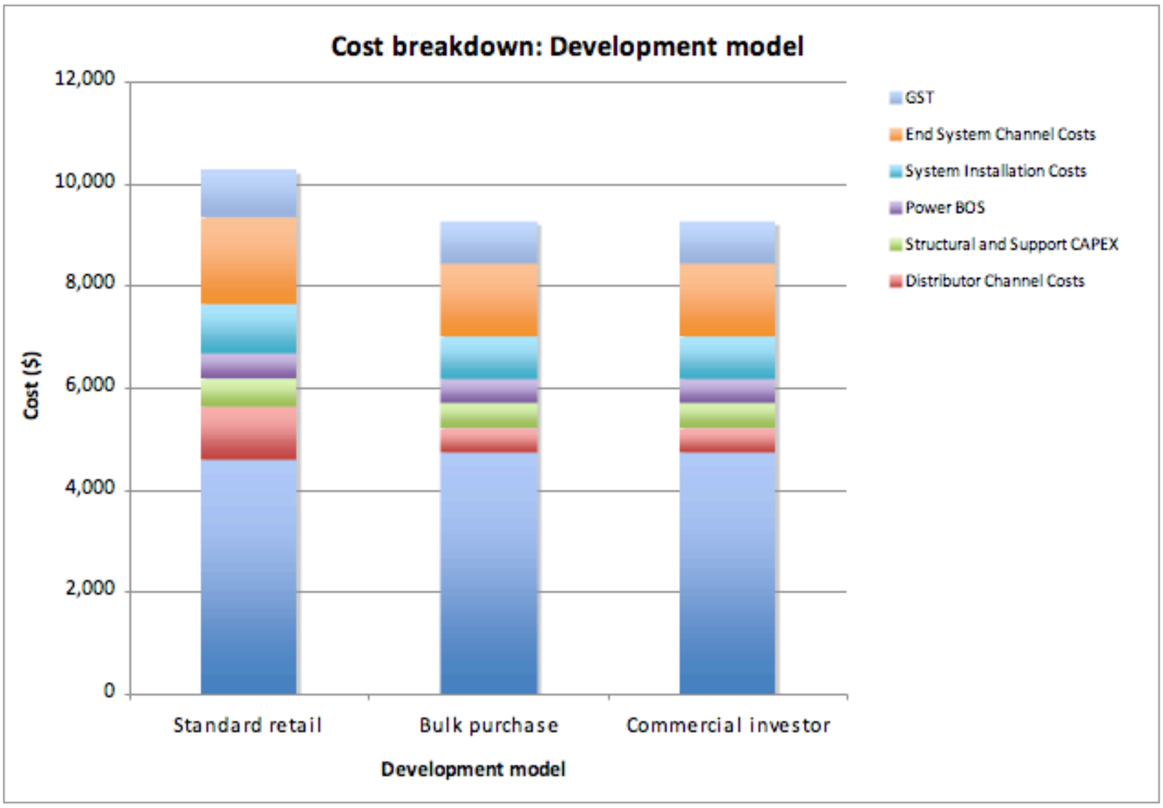


Figure 16 Effect of Development Model on Capital Cost Breakdown

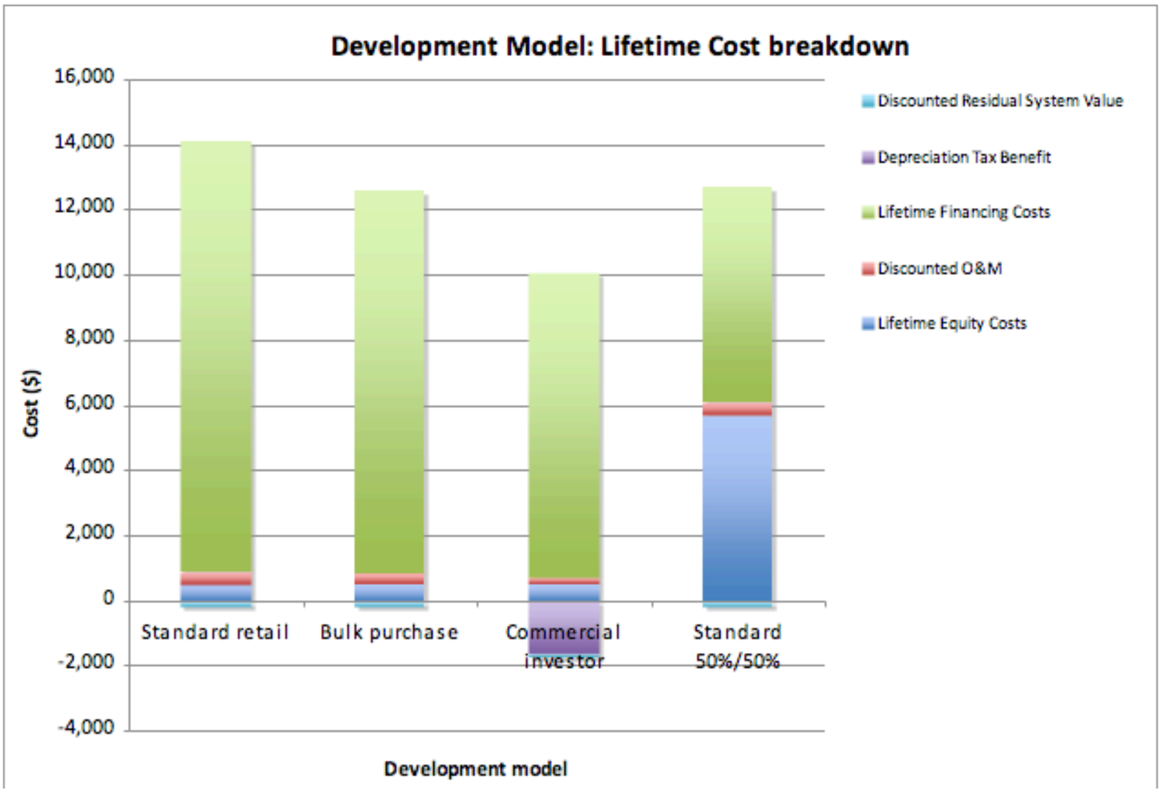


Figure 17 Effect of Development Model on Lifetime Cost Breakdown

6 COMMERCIAL SECTOR

Summary: As for the residential model, the 'feasibility gap' between the LCOE's of PV and grid electricity can best be reduced by (i) promoting the installation of larger systems, (ii) promoting the use of the 'bulk installation' model, where the importer/distributor and installer margins are reduced and (iii) reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes. Likely reductions in inverter costs have a relatively small effect, but of course should not be overlooked as part of overall cost reductions.

6.1 Commercial-specific issues

6.1.1 Bulk supply models

The commercial market is not developed to any extent in Australia, with current, relatively small, commercial installations typically following similar paths to residential ones. Hence, although, in the longer term, the commercial sector would not necessarily use the same type of bulk supply model as the residential sector, it has been used here to illustrate the impact of bypassing the importer/distributor.

6.1.2 Corporate tax rate

The corporate tax rate in the model is set at 30%, reducing to 29% in 2013 and 28% in 2014.

6.2 Results

6.2.1 Sensitivity analysis of LCOE

The following charts indicate some of the types of sensitivity analyses possible with the commercial model – comparing the standard retail installation model and the bulk installation model. Sensitivity analyses was conducted on:

- Module technology (Figure 18)
- System size (Figure 19)
- Module efficiency (Figure 20)
- Module costs (Figure 21)
- Inverter costs (Figure 22)
- Debt financing rates (Figure 23)
- Distributor channel costs (Figure 24)
- System delivery channel costs (Figure 25)
- Corporate tax rate (Figure 26)

Except where specified, the model runs assumed a 100kW polycrystalline system in Sydney on a 50% Equity 50% Debt basis. The most notable outcomes were:

a) Changes to system size have much less of an impact than in the smaller system sizes of the residential model, with the LCOE of a 500kW system being 98% of that of a 100kW system.

b) Increasing the module efficiency by 25% (from 13.30% to 16.49%, which would occur in 2020 with just over a 2% per annum increase between 2010 and 2020) decreases LCOE by 15.5%, slightly more than for the residential model.

c) Decreasing the module costs[6] by 25% (from $2.31/W to $1.7/W) decreases LCOE by about 16.5%, more than for the residential model.

d) Decreasing the inverter costs by 25% (from $0.45/W to $0.34/W) decreases LCOE by about 4.1%, slightly less than for the residential model.

e) Each percentage increase in debt finance costs increases LCOE by about 2.9%, much less than for the residential model, primarily because it is only 50% debt financed.

f) Reducing the distributor channel costs from 10% to 5% and the end system channel costs from 20% to 15%, results in a 7.8% decrease in LCOE, less than the 10.75% drop seen with the residential model bulk purchase scheme. Figure 24 and Figure 25 show the impact of more incremental changes to the system delivery channel costs and the distributor channel costs respectively, with reductions in the former having slightly greater impacts than reductions in the latter.

g) Changes to the corporate tax rate had very little impact on the LCOE, with reduction from 30% to 27.6% increasing LCOE by 1.0%.

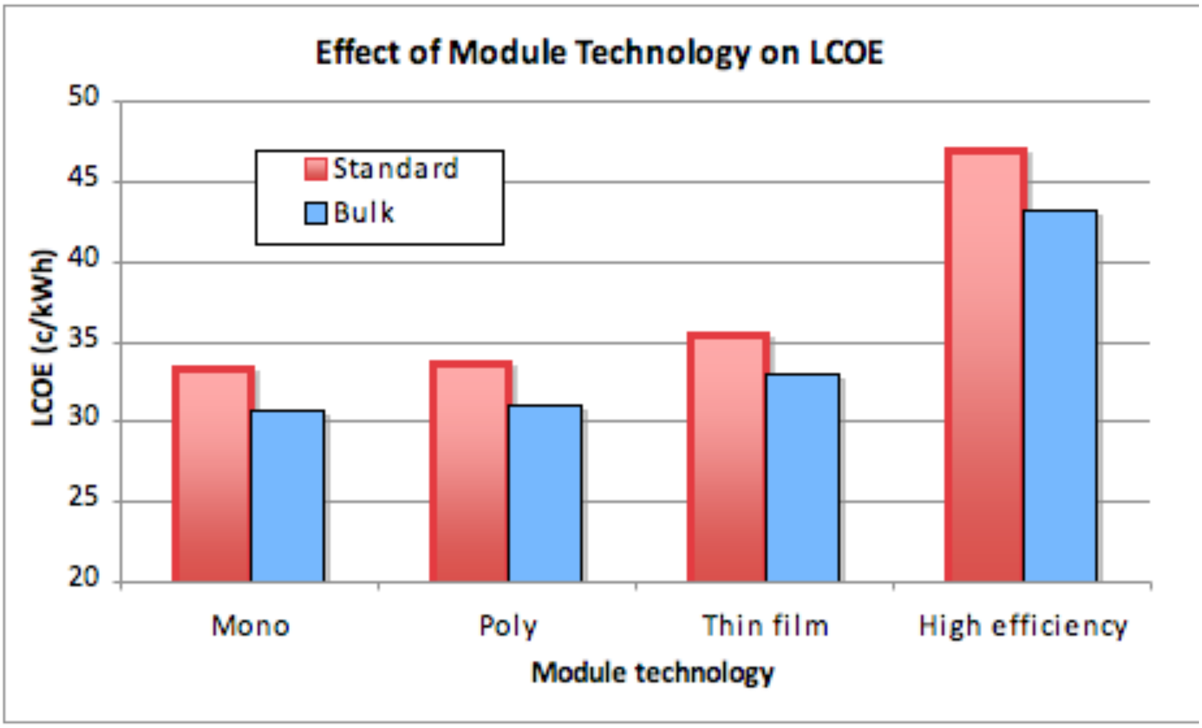


Figure 18 Effect of Module Technology on LCOE

[6] Decreases in module costs can result from module efficiency increases as well as improvements in other aspects of the market, such as manufacturing.

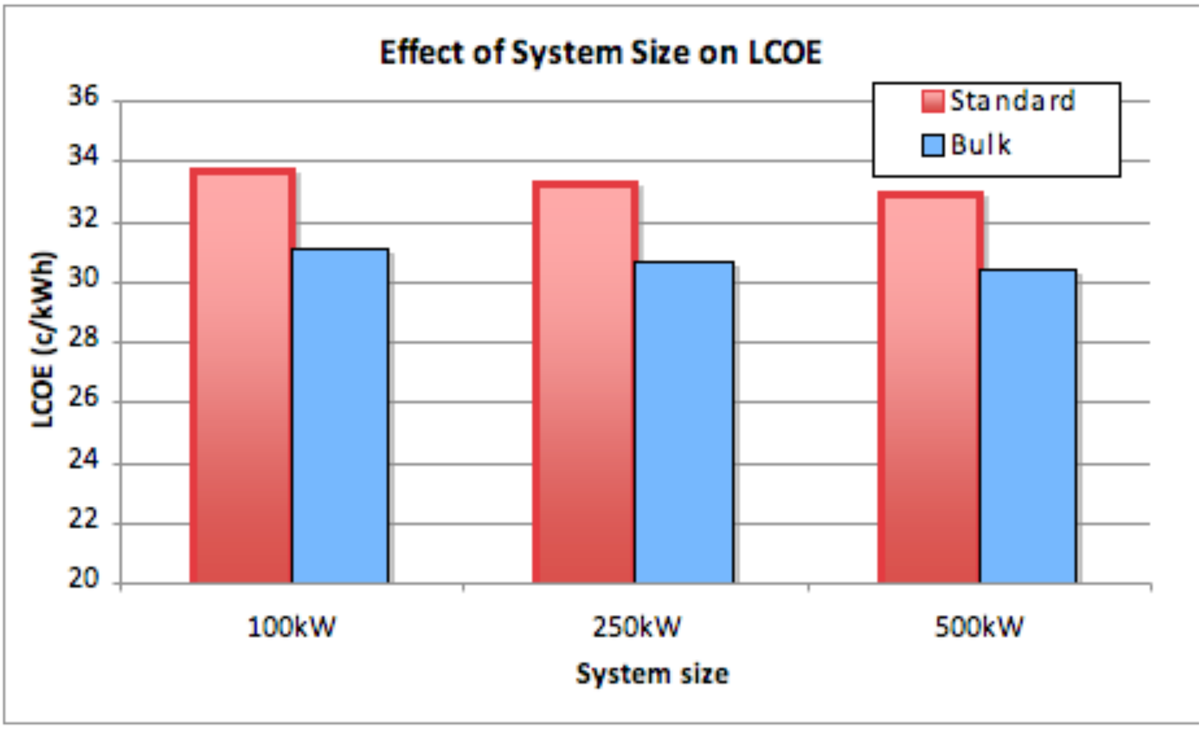


Figure 19 Effect of System Size on LCOE

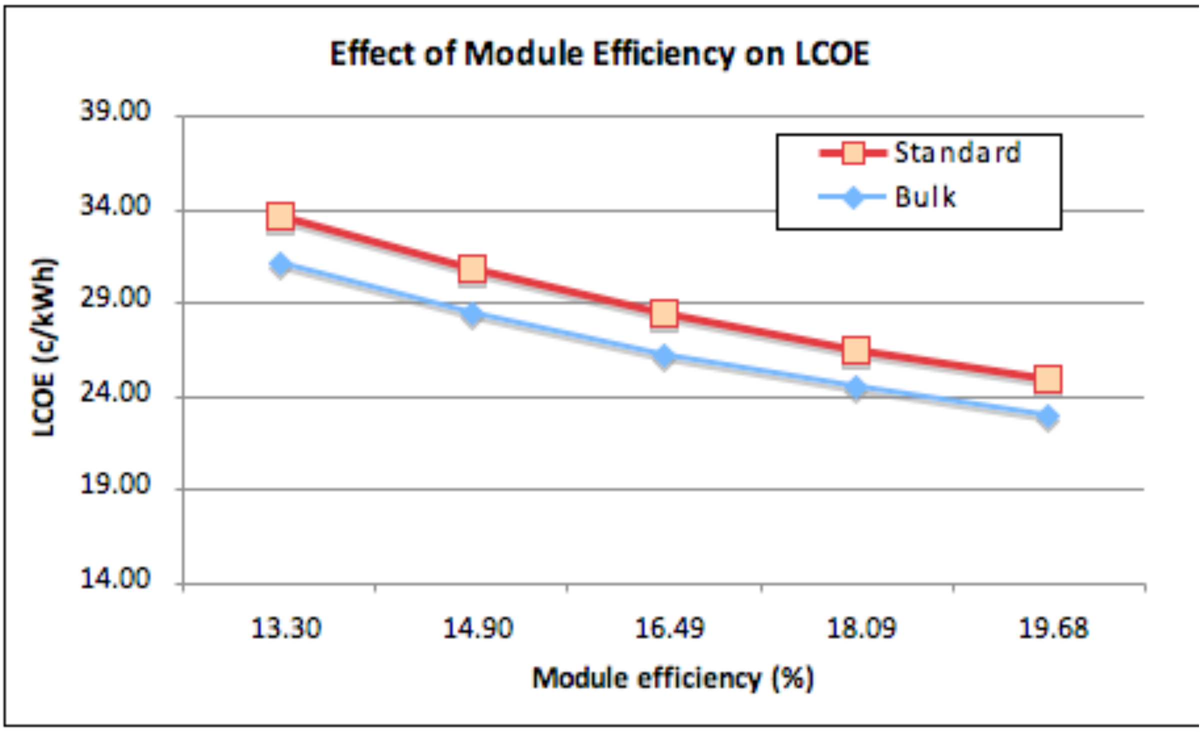


Figure 20 Effect of Module Efficiency on LCOE

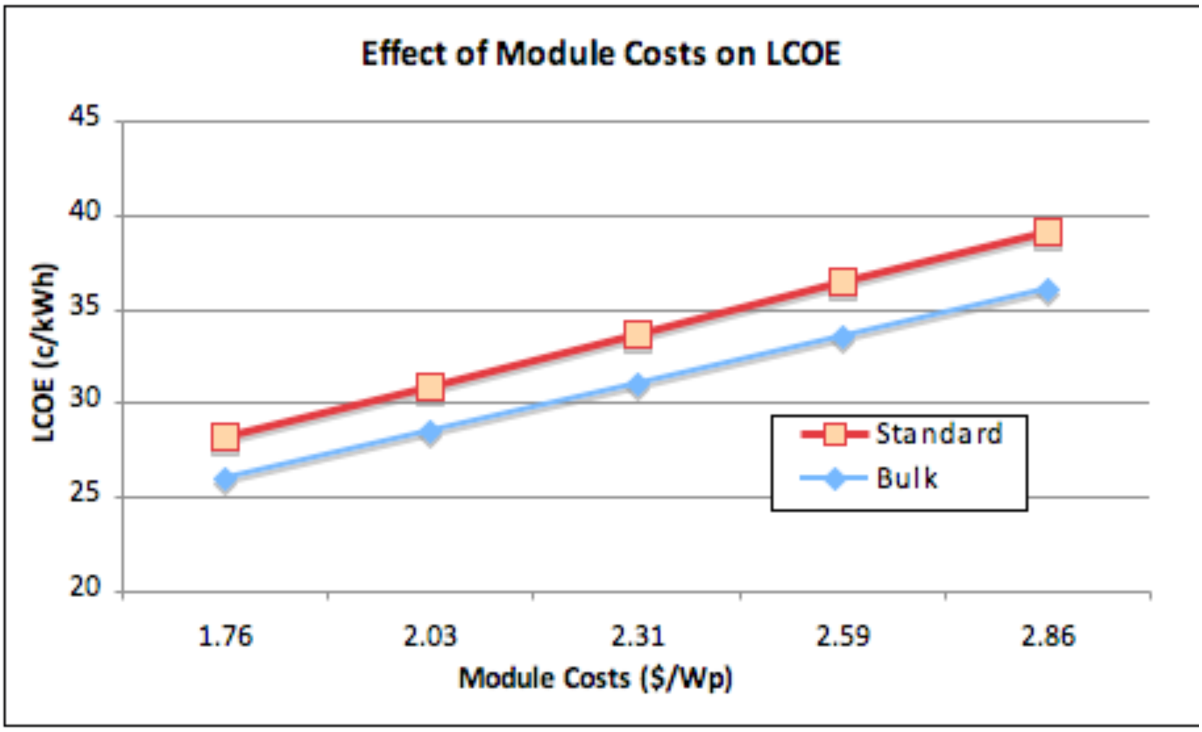


Figure 21 Effect of Module Costs on LCOE

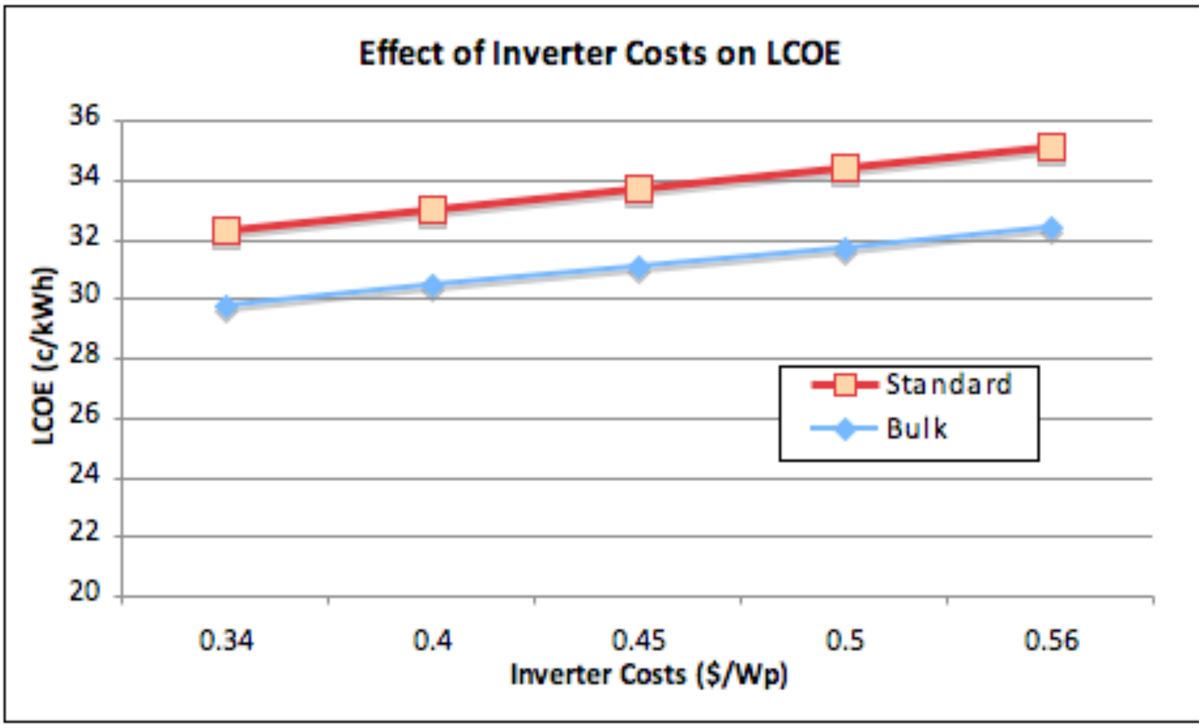


Figure 22 Effect of Inverter Costs on LCOE

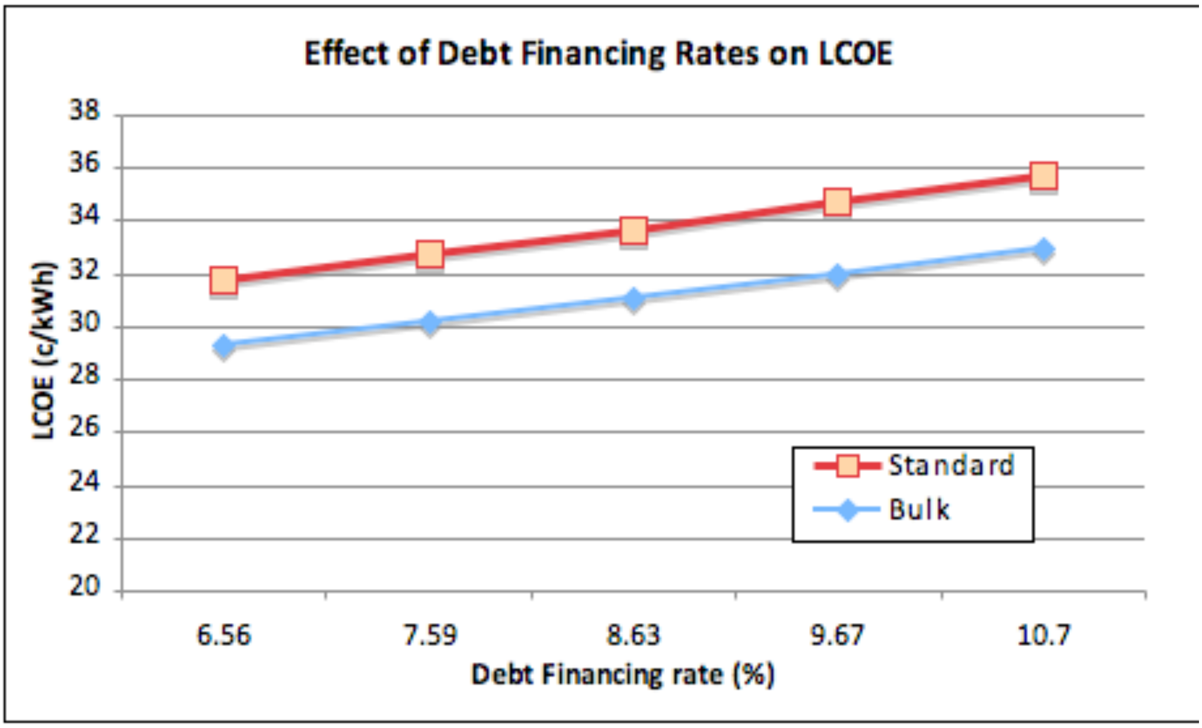


Figure 23 Effect of Debt Finance Rates on LCOE

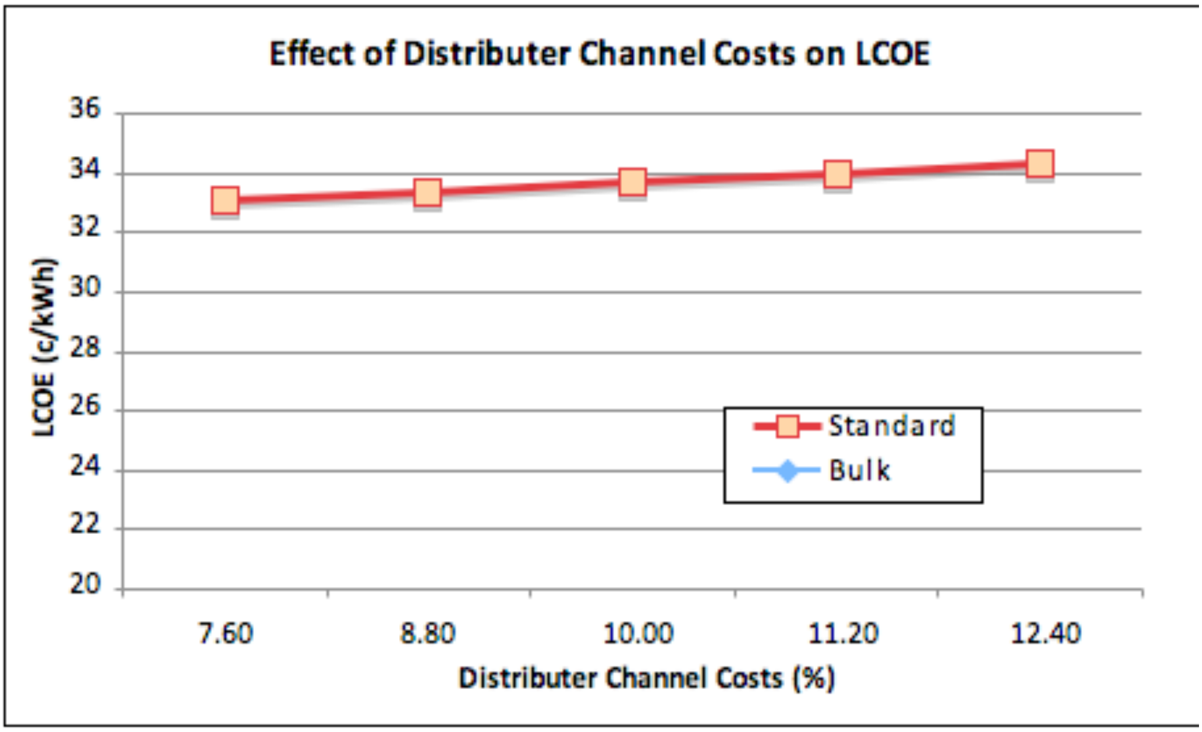


Figure 24 Effect of Distributor Channel Costs on LCOE

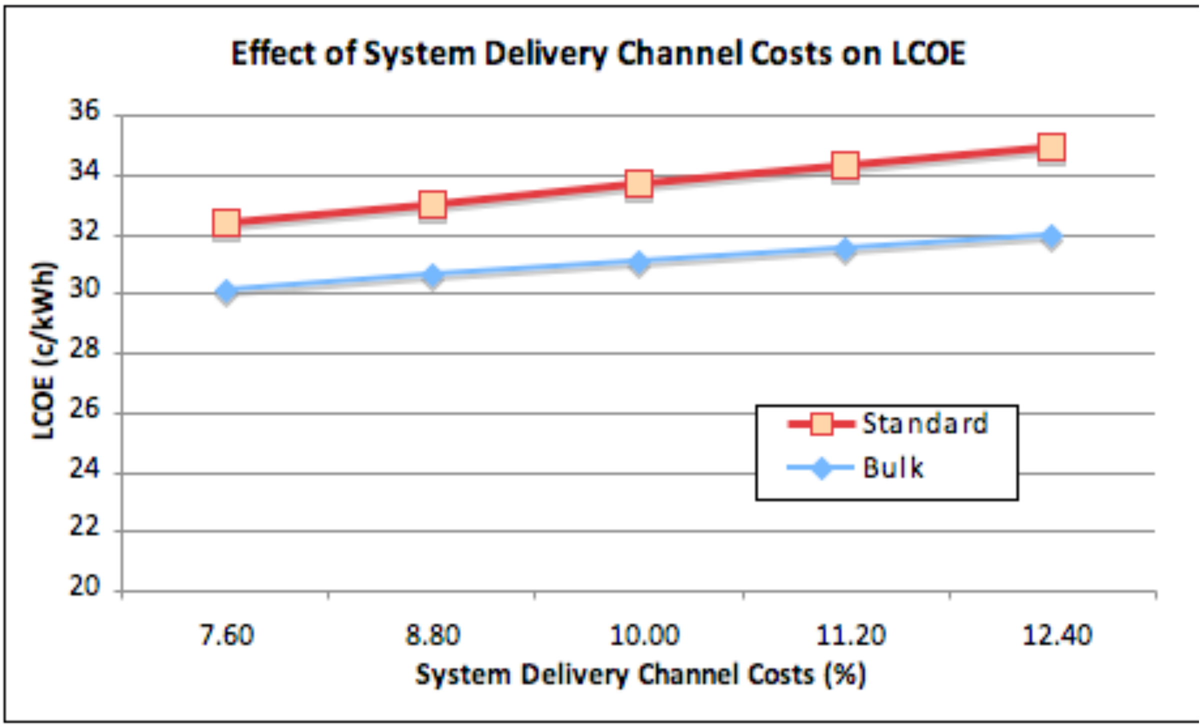


Figure 25 Effect of System Delivery Channel Costs on LCOE

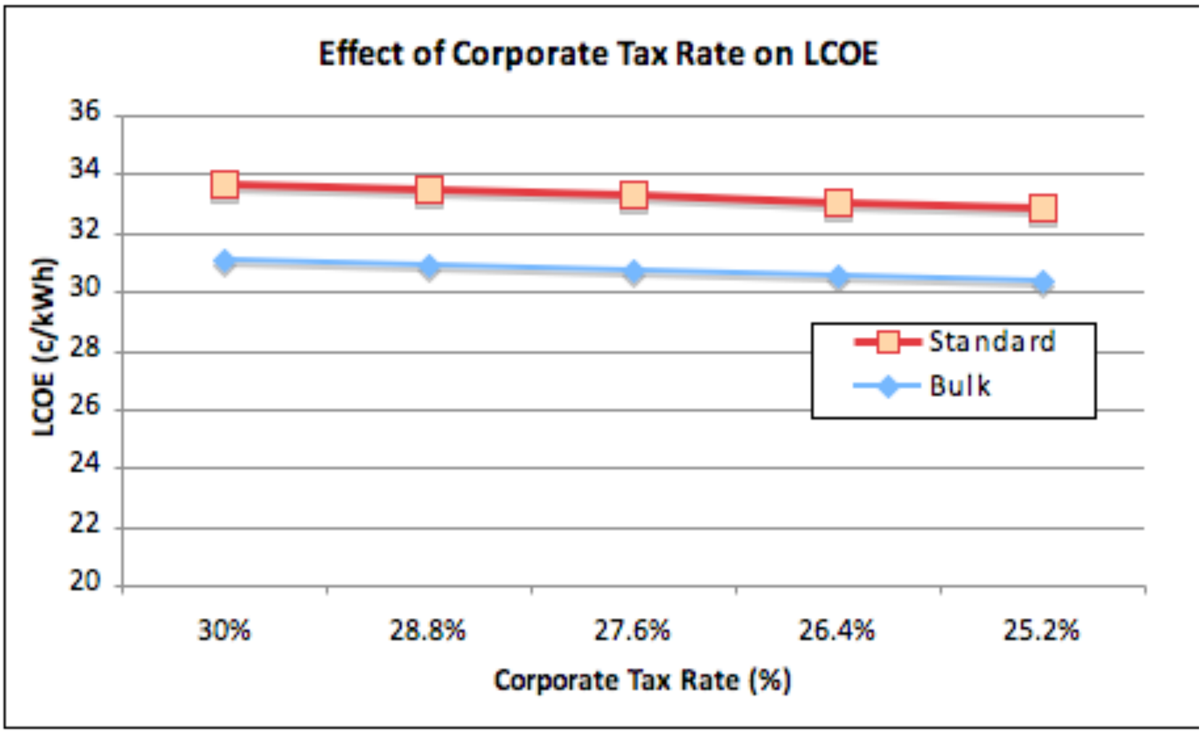


Figure 26 Effect of Corporate Tax Rate on LCOE

6.2.2 LCOE projections

The following charts show projections of the LCOE for systems installed in the years 2010 to 2030. Unless otherwise indicated, they assume a 100kW mono-crystalline system installed in Sydney on a 50% Equity 50% Debt basis. For systems installed in successive years, the module efficiency increases by 2% each year, the module costs decrease by 4% each year, while the cost of inverters as well as the importer/distributor and installer margins are each assumed to decrease by 2% each year. Note that not all PV arrays will be north-facing at latitude angle (as assumed by the model), in which case they will have higher LCOEs.

The sensitivity analyses show the impacts of:

- Module efficiency increasing annually by 0%, 1%, 2%, 3% or 4% (standard installation model, Figure 27) and (bulk installation model, Figure 28)
- Module cost decreasing annually by 0%, 2%, 4%, 6% or 8% (standard installation model, Figure 29) and (bulk installation model, Figure 30)
- Increased system size (standard installation model, Figure 31)
- Reduced debt finance costs (standard installation model, 100kW, Figure 32).

Changes to both efficiency and cost of modules changes the year that the PV LCOE intersects with the grid electricity LCOEs. Table 5 summarises these impacts for low, high and average price projections of grid electricity LCOEs. For simplicity's sake, the mid points of the rates of efficiency increases (2%) and cost decreases (4%) have been used.

Table 5 Summary of impacts on intersect of PV and grid electricity LCOEs

	Electricity price growth projections	
Projection	**Low**	**High**
Module efficiency increases, standard installation	2020	2017
Module efficiency increases, bulk installation	2019	2016
Module cost decreases, standard installation	2020	2017
Module cost decreases, bulk installation	2019	2016

As shown in Table 6, increasing the system size has an impact on the intersection point (although not as significant as for the residential model), again highlighting the importance of promoting the deployment of larger systems.

Table 6 Summary of impacts on intersect of PV and grid electricity LCOEs – different system sizes

	Electricity price growth projections	
System size	**Low**	**High**
100kW	2020-21	2016-17

250kW	2020	2016-17
500kW	2019-20	2016-17

As shown in Table 7, decreasing the debt rate, as could be achieved through low interest loans, also has a significant impact on the intersection point.

Table 7 Summary of impacts on intersect of PV and grid electricity LCOEs – different debt rates

	Electricity price growth projections	
Debt rate	**Low**	**High**
8.50%	2020-21	2016-17
7.48%	2020	2016-17
6.46%	2019-20	2016
5.44%	2019	2015-16
4.42%	2018-19	2015-16

In summary the 'feasibility gap' between the LCOE's of PV and grid electricity can best be reduced in the same ways as for the residential model, that is by the following, which are given in order of effectiveness and feasibility:

- promoting the installation of larger systems (that are still small enough to connect to the distribution network)
- promoting the use of the 'bulk installation' model, where the importer/distributor and installer margins are reduced
- reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes.
- As shown in Section 6.2.1, likely reductions in inverter costs have a relatively small effect, but of course should not be overlooked as part of overall cost reductions.

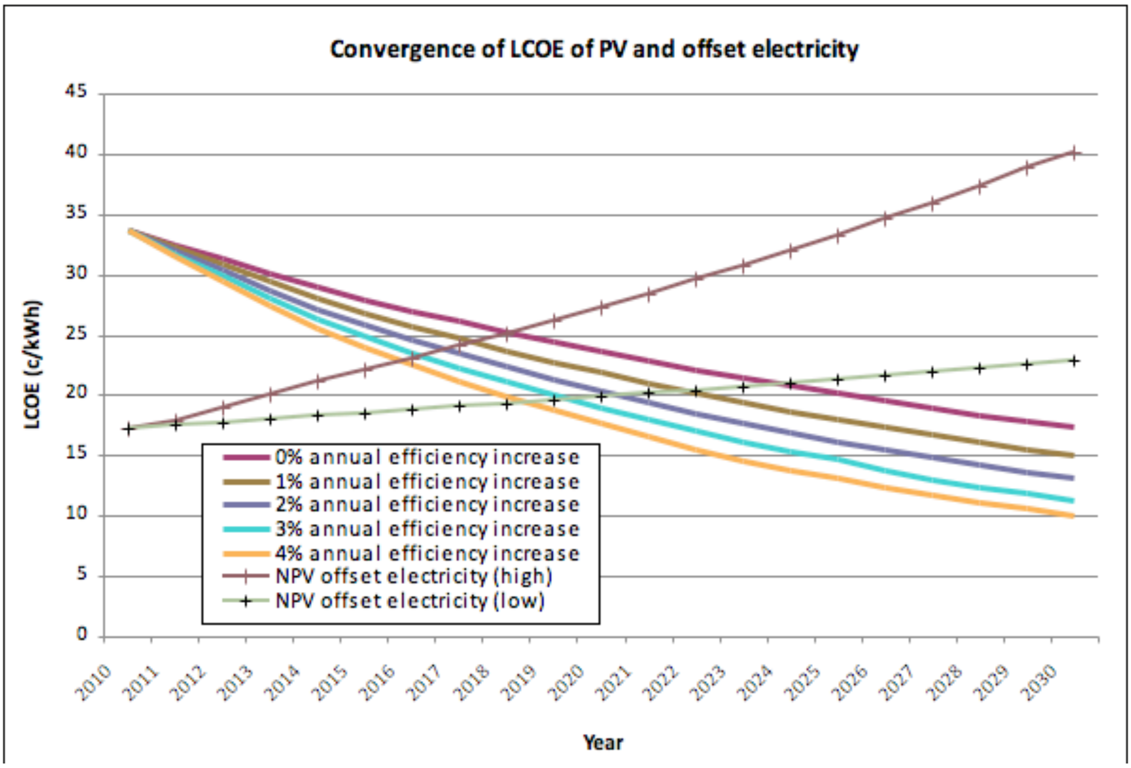


Figure 27 Projections of the Impact of Module Efficiency on LCOE: 2010 to 2030 – standard installation model

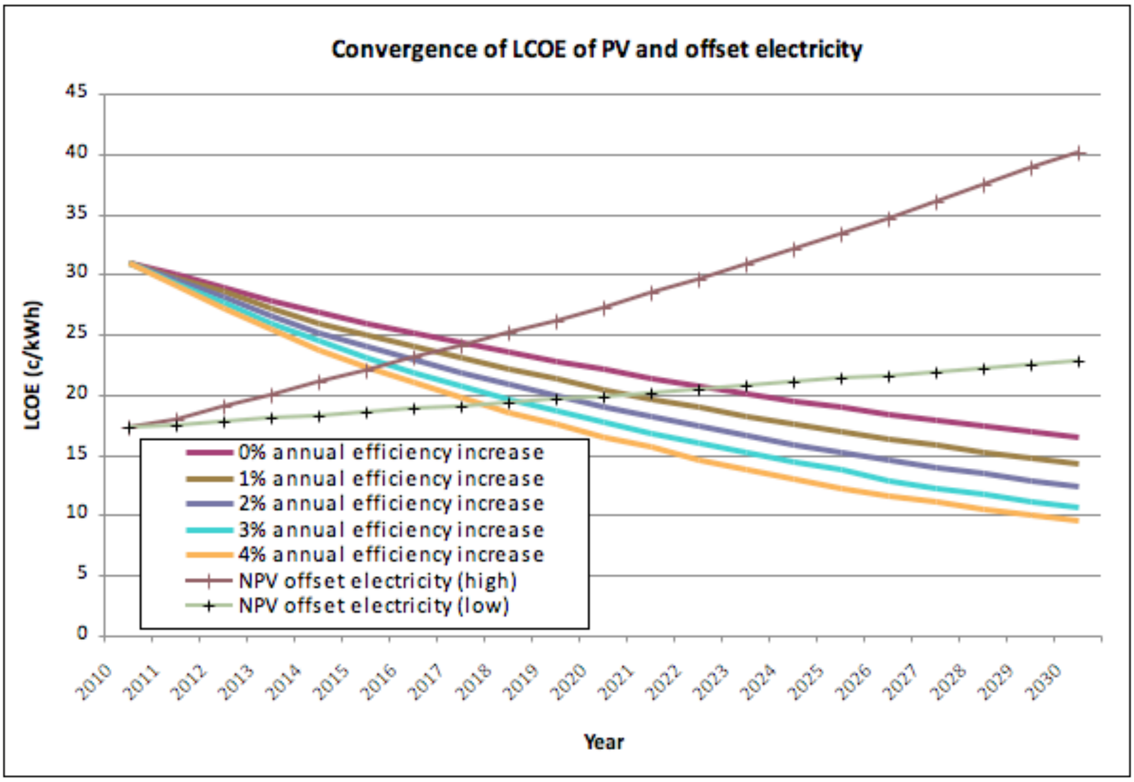


Figure 28 Projections of the Impact of Module Efficiency on LCOE: 2010 to 2030 – bulk installation model

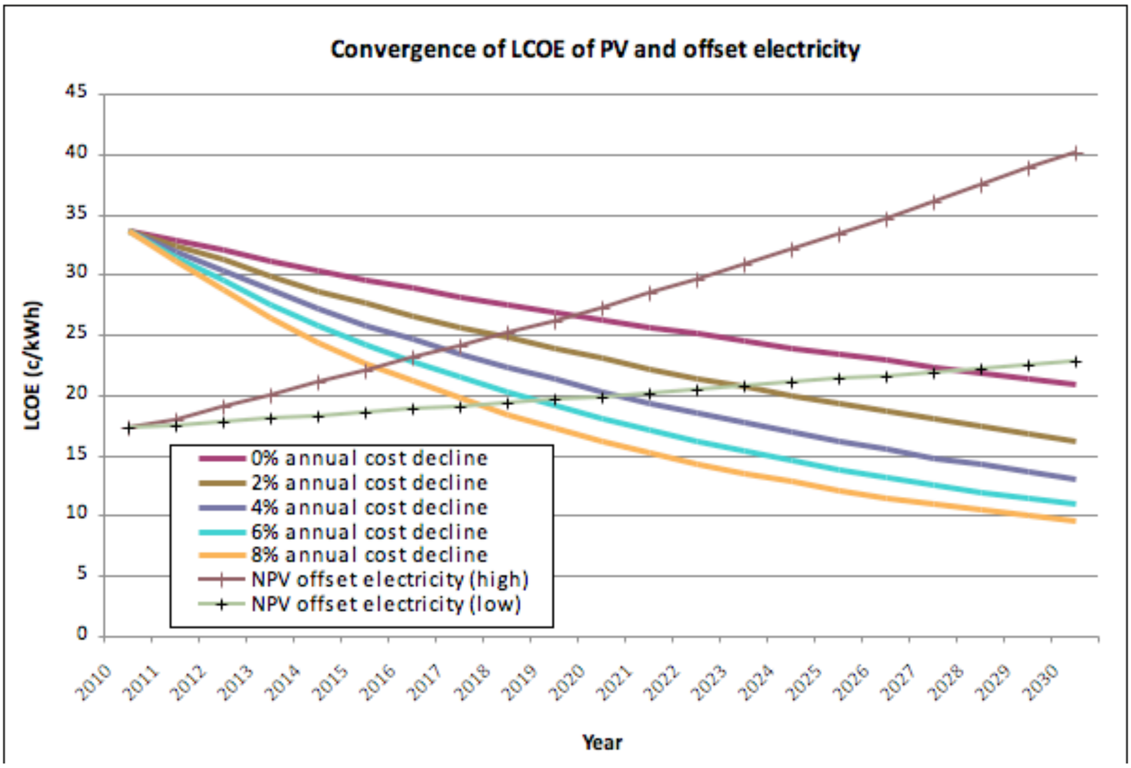


Figure 29 Projections of the Impact of Module Cost on LCOE: 2010 to 2030 – standard installation model

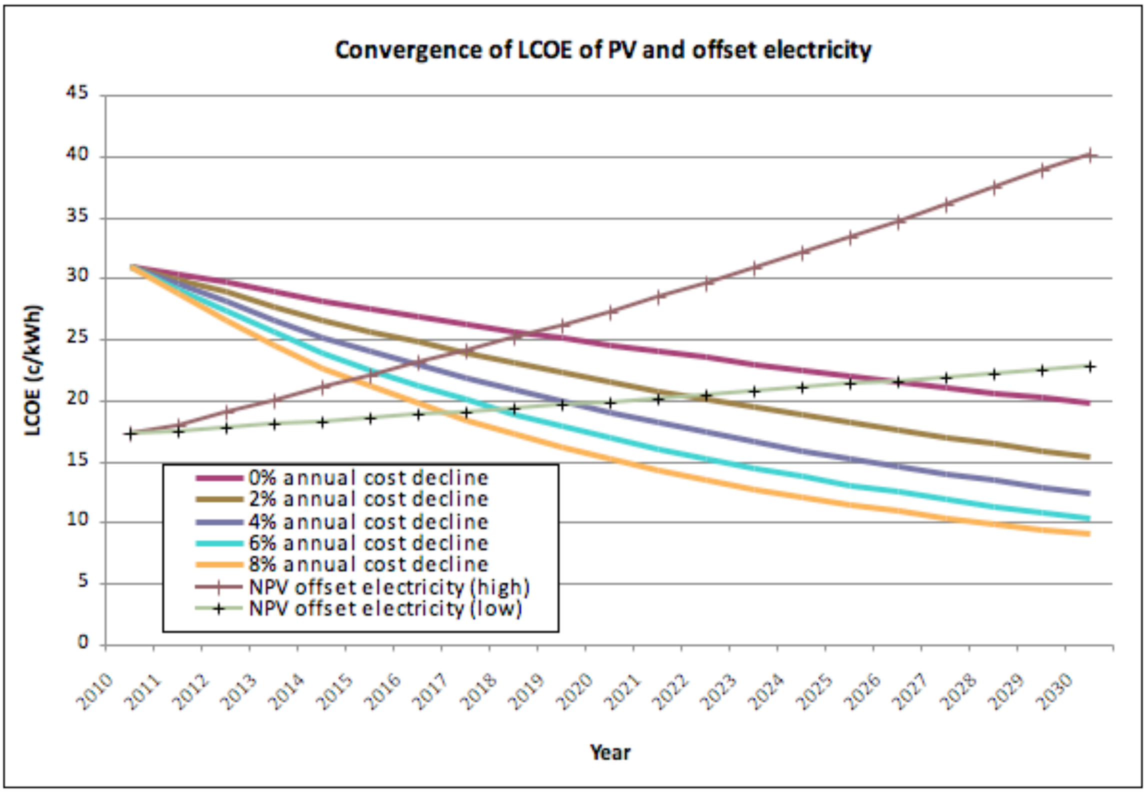


Figure 30 Projections of the Impact of Module Cost on LCOE: 2010 to 2030 – bulk installation model

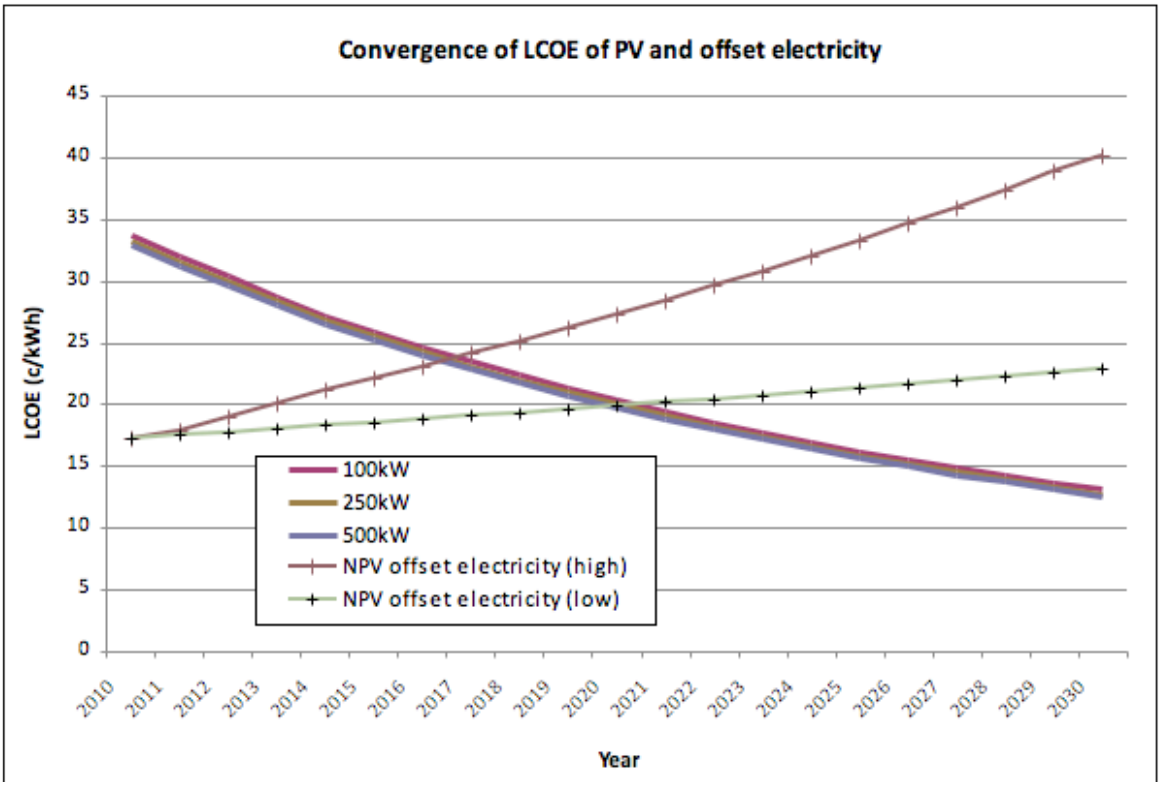


Figure 31 Projections of the Impact of System Size on LCOE: 2010 to 2030 – standard installation model

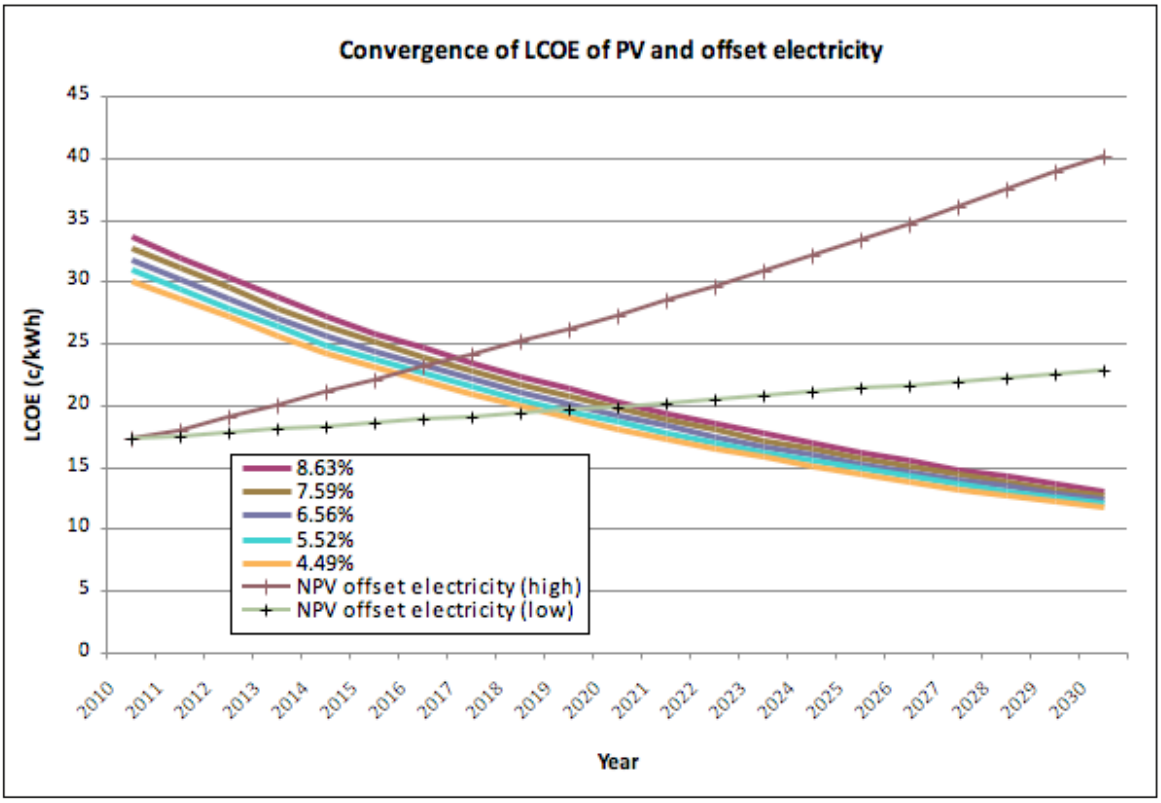


Figure 32 Projections of the Impact of Different Debt Rates on LCOE: 2010 to 2030 – standard installation model

6.2.3 Cost breakdowns

The following charts show the breakdowns of the upfront costs, and how they are affected by varying:

- the technology type (Figure 33)
- the development model (standard retail and bulk installation) (Figure 34)

The next chart shows the system lifetime costs for different development models, including the standard retail model with 100% debt financing which is considered 'risk free' and so has a much lower interest rate (here 5.34% instead of 8.63%) and the standard retail model with 100% equity financing (at 11.64%) (Figure 35).

Except where specified, the model runs assumed a 100kW polycrystalline system in Sydney on a 50% equity and 50% debt financing basis.

The most notable outcomes were:

a) The PV equipment cost is by far the greatest cost, being up to two thirds the total, a greater proportion than for the residential model.

b) The end system developer margin is the next greatest component.

c) The most significant savings for the 'bulk purchase' model come mainly from reduced end system developer margin but also from reduced distributor margin.

d) In terms of total lifetime finance costs, the three models assessed benefited from depreciation tax benefits, the bulk installation model saved mostly from reduced equity costs, the 100% debt risk free is less than the 100% Equity simply because the debt interest rate (5.34%) is less than the rate of return on equity (11.64%).

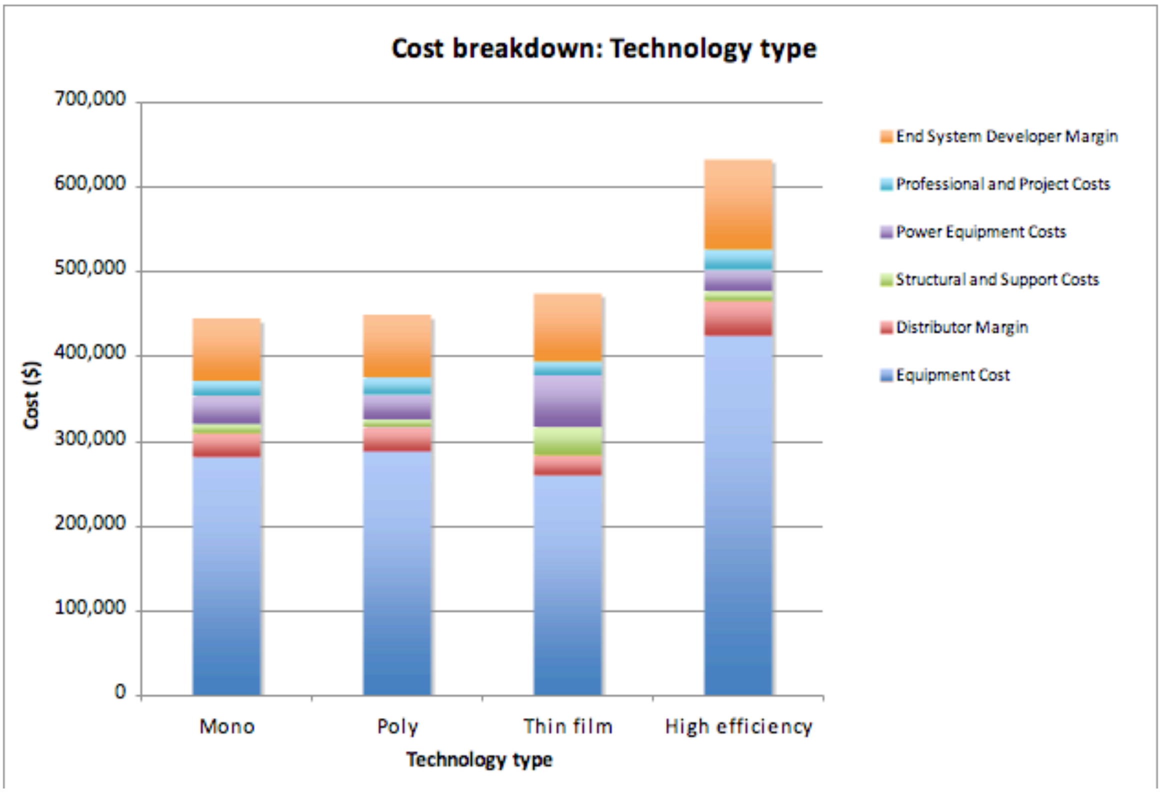


Figure 33 Effect of Technology Type on Capital Cost Breakdown

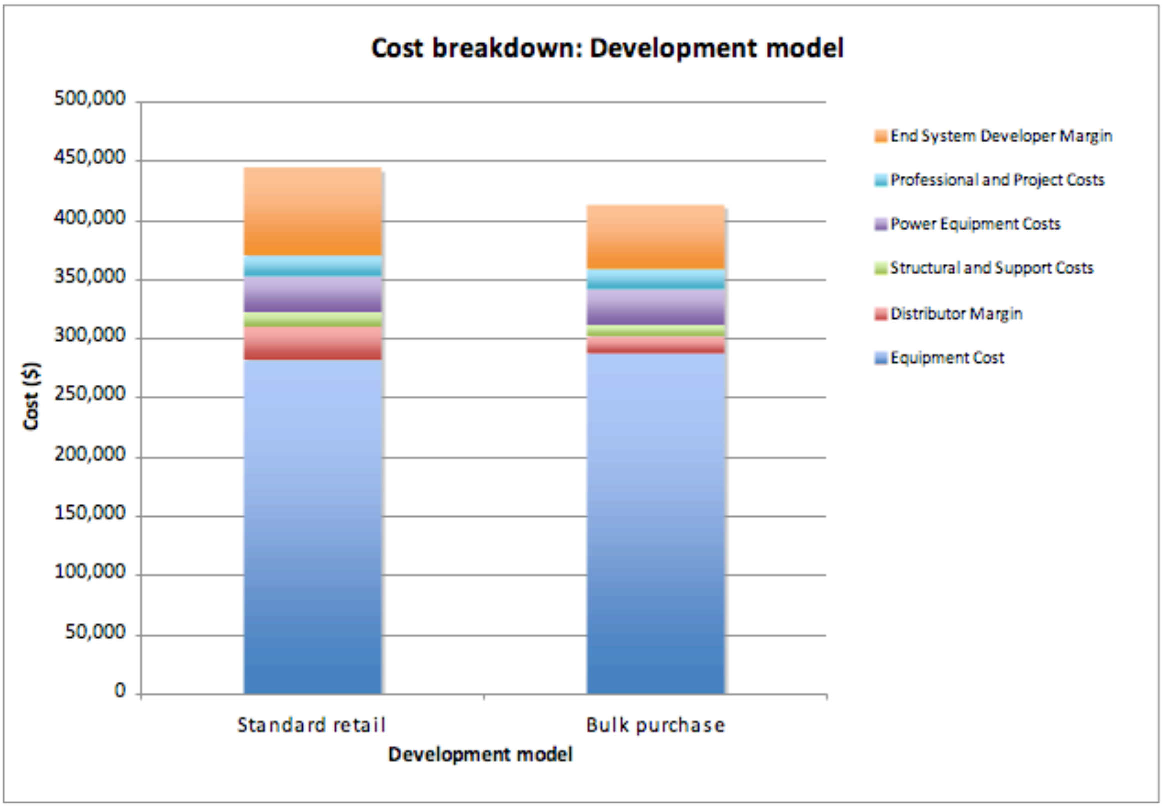


Figure 34 Effect of Development Model on Capital Cost Breakdown

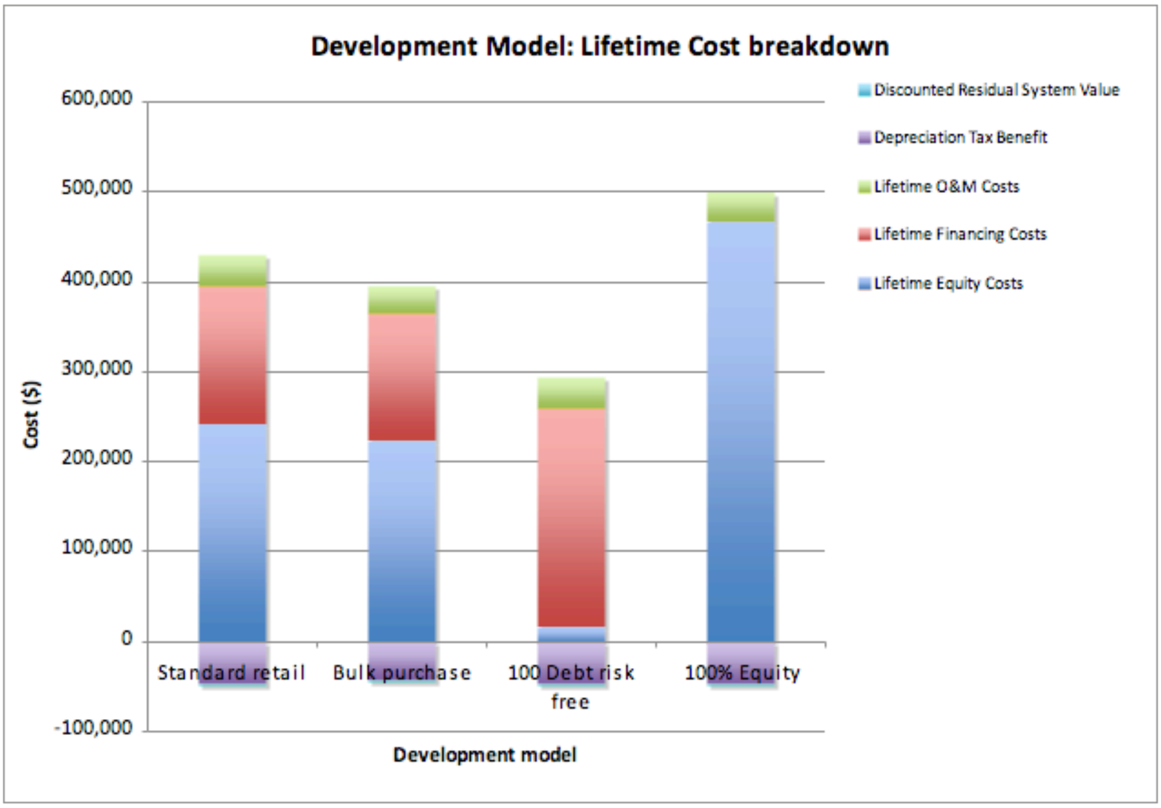


Figure 35 Effect of Development Model on Lifetime Cost Breakdown

7 CENTRAL POWER PLANTS

Summary: As for the residential and commercial models, the 'feasibility gap' between the LCOE's of PV and wholesale electricity can best be reduced by (i) promoting the installation of larger systems, and (ii) reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes.

However, it seems that out to 2030, in the absence of significant breakthroughs of some kind that reduce costs faster than currently projected, large-scale PV will struggle to be cheaper than wholesale prices in Australia, even in the presence of a carbon price.

7.1 Large-scale-specific issues

7.1.1 Semi-scheduled requirements:

Large-scale PV systems (≥30MW) are classified as semi-scheduled generators. This means:

- they have to submit forecasts of their output
- at times they will be 'semi-dispatched' which means they may have to constrain their output to below their forecast
- at all other times they will have no constraints on their output.

The main consequences of this are

- some loss of revenue when their output is curtailed
- storage may become financially viable if curtailment occurs often (to reduce the amount of output lost)
- some costs will be incurred to participate in this process, as well as other processes, such as frequency control ancillary service (FCAS).

See Appendix 5: Semi-scheduled Requirements for relevant background information.

7.2 Results

7.2.1 Sensitivity analysis of LCOE

The following charts indicate some of the types of sensitivity analyses possible with the central power station model. Sensitivity analyses was conducted on:

- Module technology (Figure 36)
- System size (Figure 37)
- Module efficiency (Figure 38)
- Module costs (Figure 39)
- Inverter costs (Figure 40)
- Tracking (Figure 41)
- Debt financing rates (Figure 42)
- Developer margin (Figure 43)
- Corporate tax rate (Figure 44).

Except where specified, the model runs assumed a 50MW polycrystalline system in an area with the same insolation as Sydney on a 50% Debt 50% Equity basis. The most notable outcomes were:

a) The LCOE of a 1MW system is slightly greater than that of a 500kW system in the commercial model. This is because the loan term is 15 years instead of 25 years, and because of slightly higher equipment and structural support costs as well as O&M costs.

b) Changes to system size have a slightly greater impact than in the commercial model, with the LCOE of a 50MW system being 96.5% of that of a 10MW system. The equivalent increase in the commercial model, from 100kW to 500kW, reduced LCOE by 2.5%.

c) Increasing the module efficiency by 25% (from 13.30% to 16.49%, which would occur in 2020 with just over a 2% per annum increase between 2010 and 2020) decreases LCOE by 16.2% (15.5% in the commercial model).

d) Decreasing the module costs[7] by 25% (from $2.31/W to $1.7/W) decreases LCOE by about 15% (16.5% in the commercial model).

e) Decreasing the inverter costs by 25% (from $0.40/W to $0.3/W) decreases LCOE by about 2.6% (4.1% in the commercial model).

f) The use of single axis tracking increased LCOE by around 0.7% while two-axis tracking decreased LCOE by around 3.1%. However, these results should be viewed with caution and would benefit from better real world data on the costs of tracking, which has not been widely used for larger systems in Australia to date.

g) Each percentage increase in debt finance costs increases LCOE by about 2.2% (2.9% in the commercial model).

h) Increasing the end system delivery margin by 25% (from 5% to 6.2%) had an insignificant effect on the LCOE.

i) Changes to the corporate tax rate had very little impact on the LCOE, with reduction from 30% to 27.6% decreasing LCOE by 1.65% (1.0% in the commercial model).

[7] Decreases in module costs can result from module efficiency increases as well as improvements in other aspects of the market, such as manufacturing.

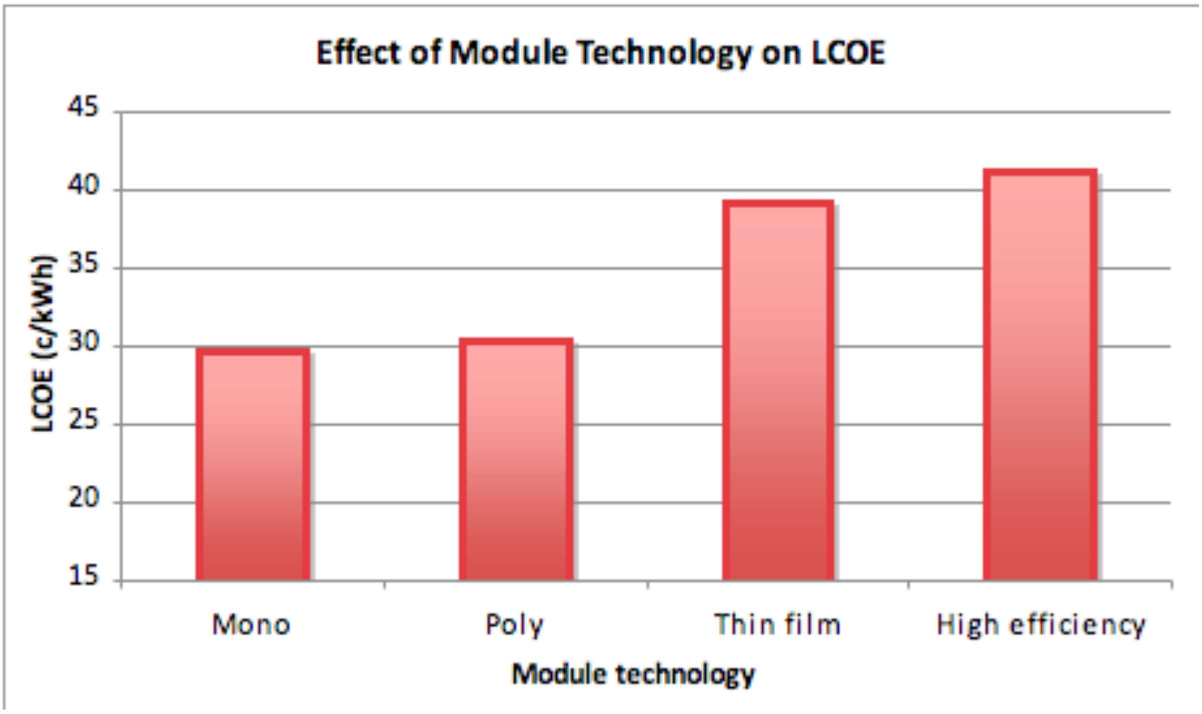


Figure 36 Effect of Module Technology on LCOE

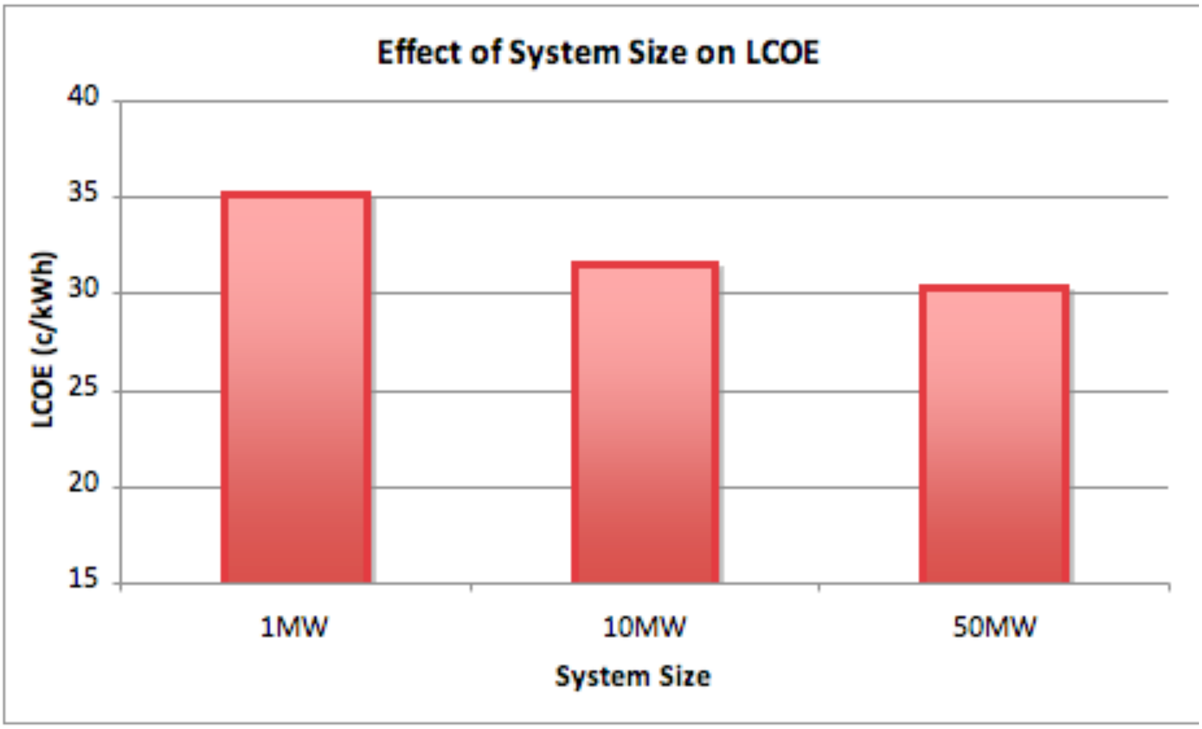


Figure 37 Effect of System Size on LCOE

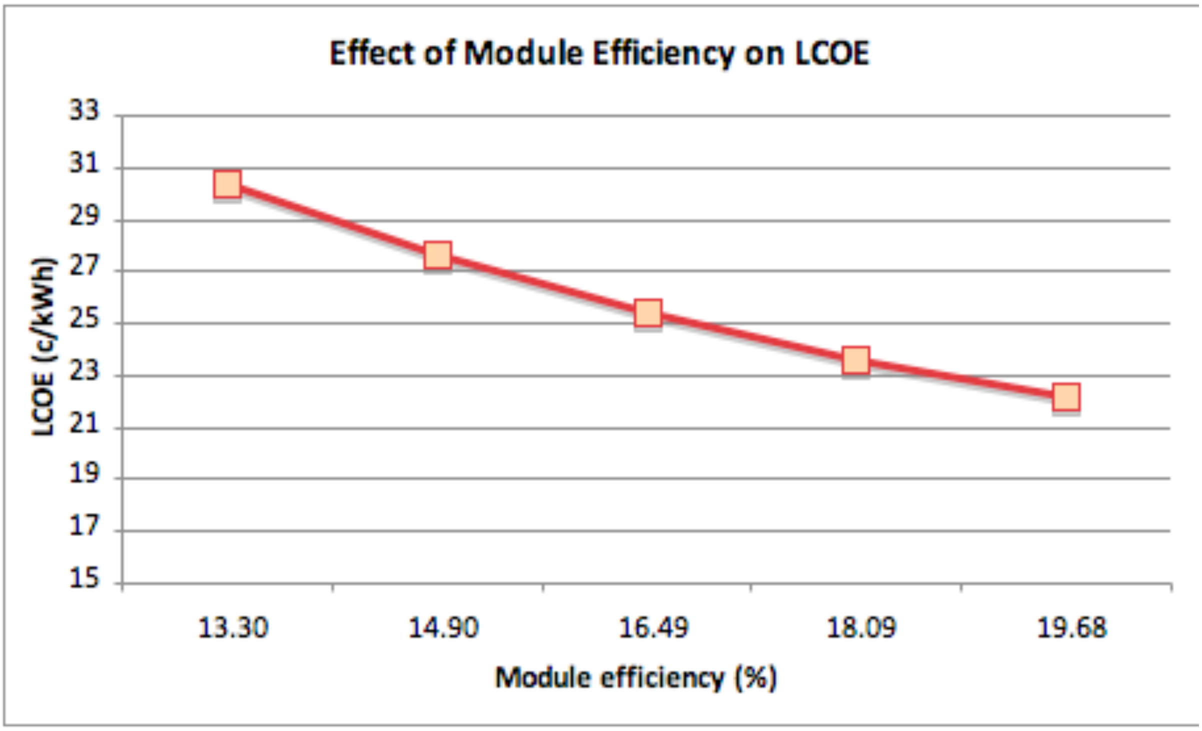


Figure 38 Effect of Module Efficiency on LCOE

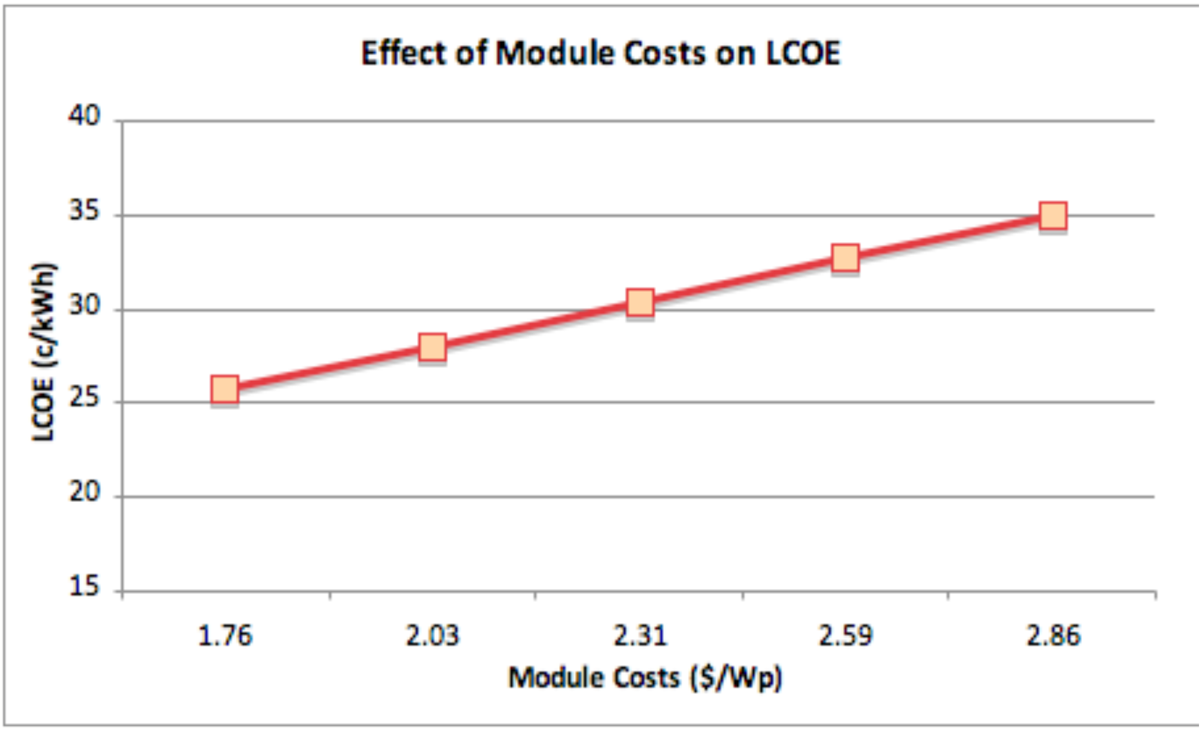


Figure 39 Effect of Module Costs on LCOE

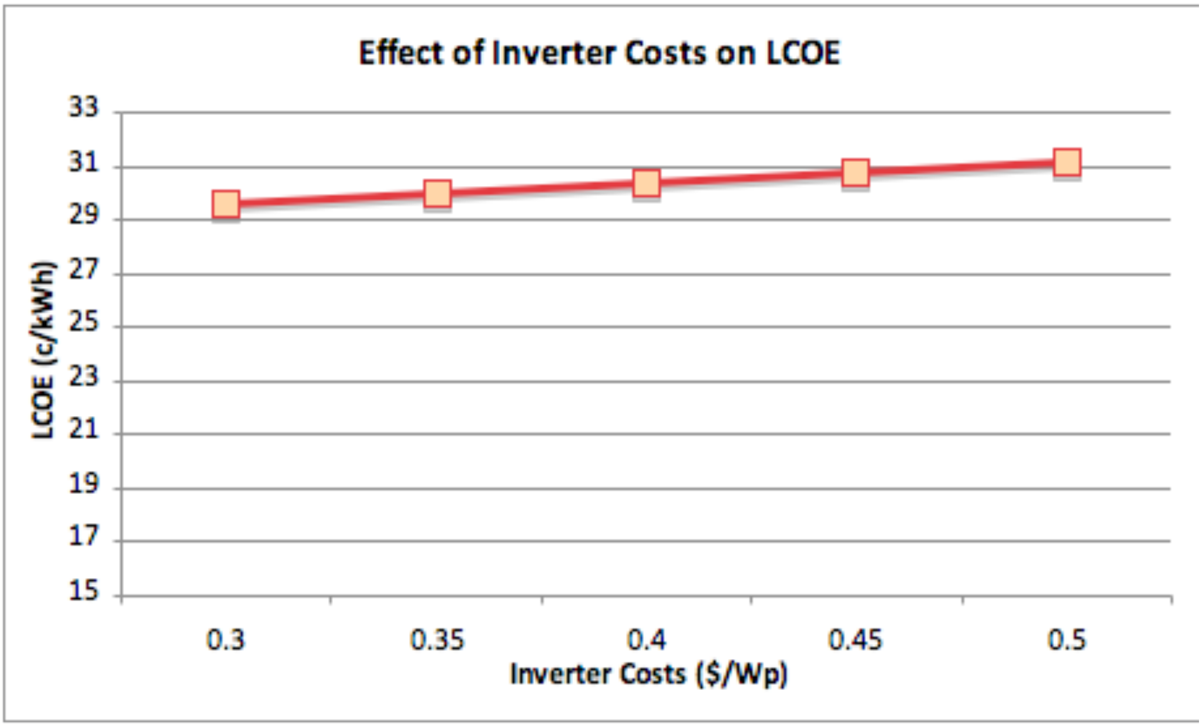


Figure 40 Effect of Inverter Costs on LCOE

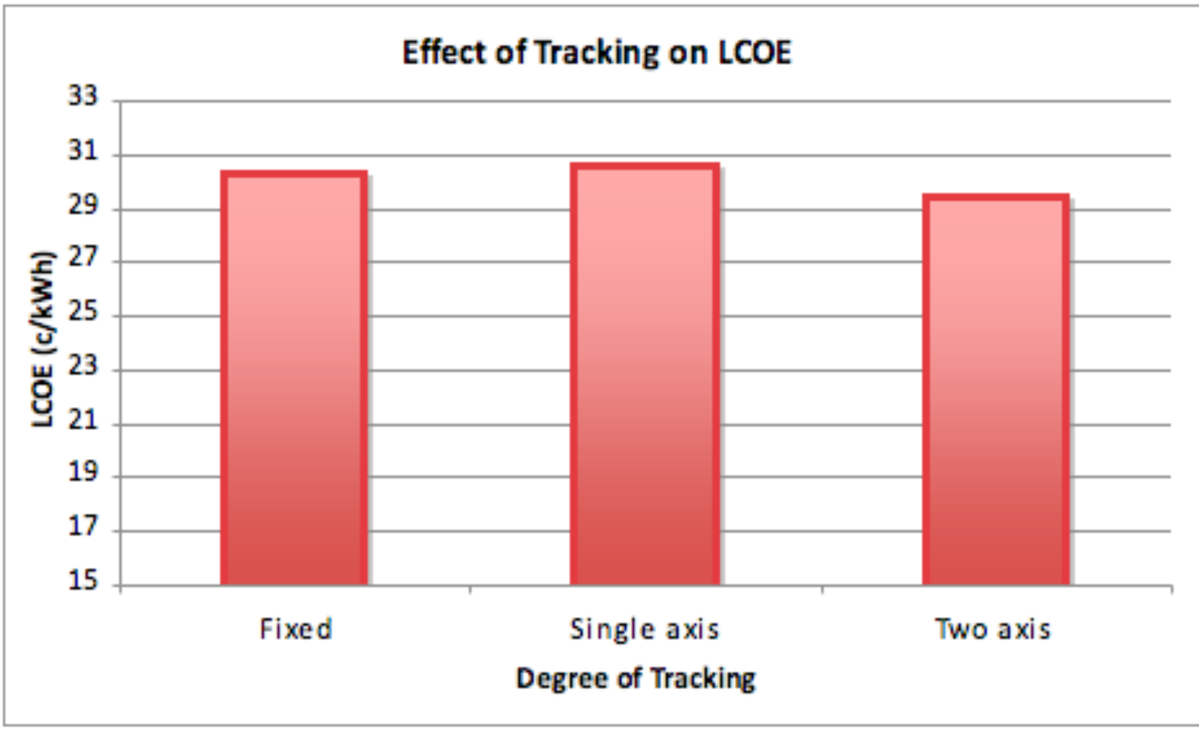


Figure 41 Effect of Tracking on LCOE

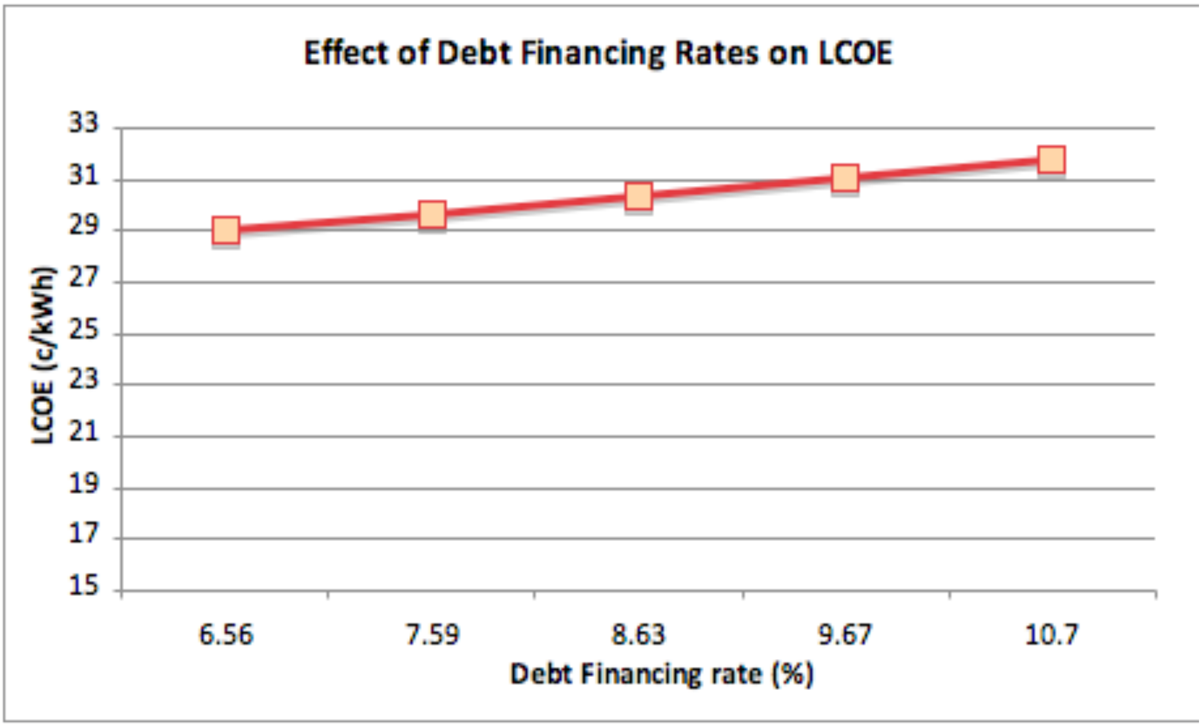


Figure 42 Effect of Debt Finance Rates on LCOE

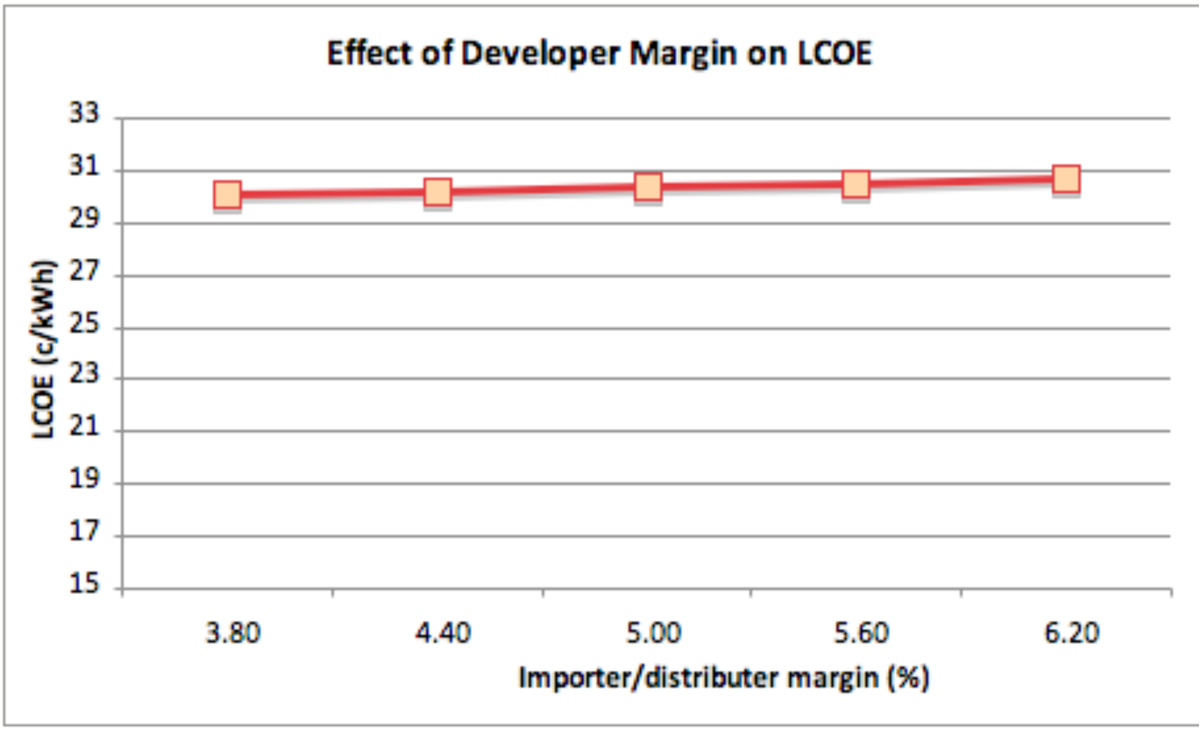


Figure 43 Effect of Developer Margin on LCOE

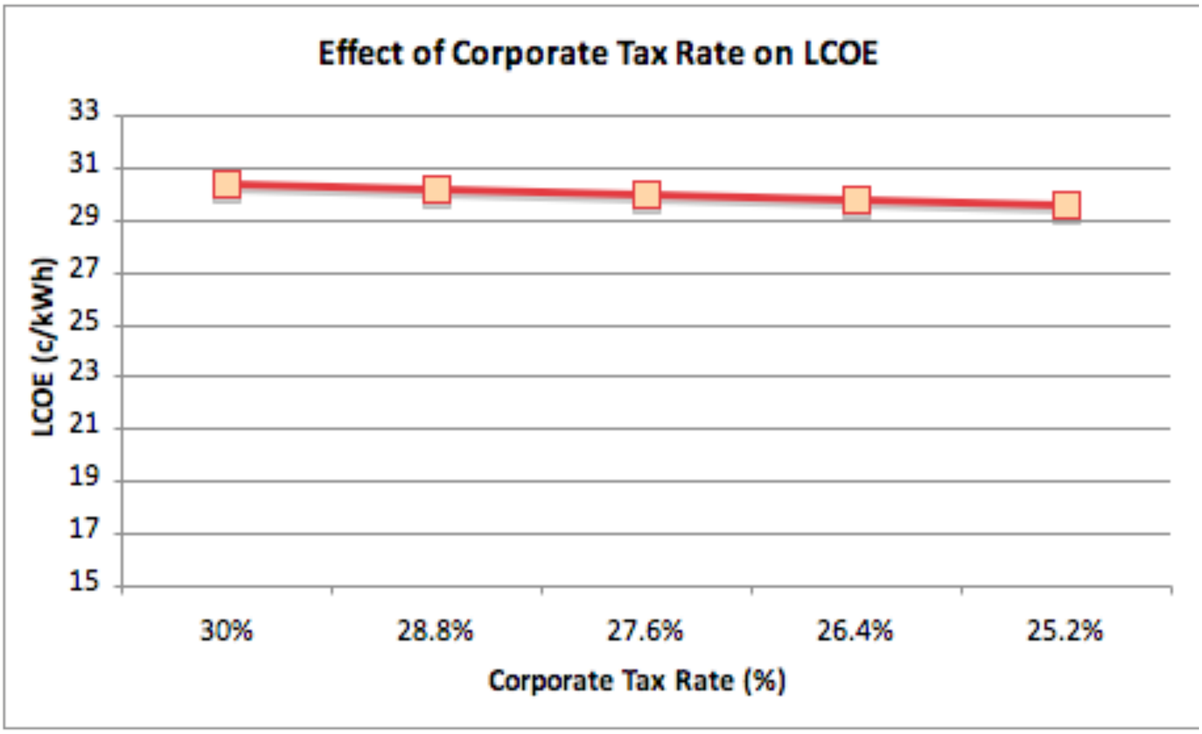


Figure 44 Effect of Corporate Tax Rate on LCOE

7.2.2 LCOE projections

The following charts show projections of the LCOE for systems installed in the years 2010 to 2030. Unless otherwise indicated, they assume a 50MW mono-crystalline system in an area with the same insolation as Sydney on a 50% Equity 50% Debt basis. For systems installed in successive years, the module efficiency increases by 2% each year, the module costs decrease by 4% each year, while the cost of inverters as well as the importer/distributor and installer margins are each assumed to decrease by 2% each year. Note that not all PV arrays will be north-facing at latitude angle (as assumed by the model), in which case they will have higher LCOEs.

The sensitivities show the impacts of:

- Module efficiency increasing annually by 0%, 1%, 2%, 3% or 4% (Figure 45)
- Module cost decreasing annually by 0%, 2%, 4%, 6% or 8% (Figure 46)
- Increased system size (Figure 47)
- Reduced debt finance costs (Figure 48)

In none of the scenarios does the PV LCOE reduce to be equal to or below that of wholesale electricity. Assuming the above default rates of cost and efficiency improvements, then where there is either a 4% annual efficiency increase, a 8% annual module cost reduction or less than a 4.49% cost of debt, then by 2030 the LCOE of PV electricity is only slightly more than the LCOE of wholesale electricity.

In summary the 'feasibility gap' between the LCOE's of PV and wholesale electricity can best be reduced by the following, which also apply to the residential and commercial models, and which are given in order of effectiveness and feasibility:

- promoting the installation of larger systems
- reducing module cost, which can occur through module efficiency improvements as well as through other activities such as improvements to manufacturing processes.

However, it seems that out to 2030, in the absence of significant breakthroughs of some kind that reduce costs faster than currently projected, large-scale PV will struggle to be cheaper than wholesale prices in Australia.

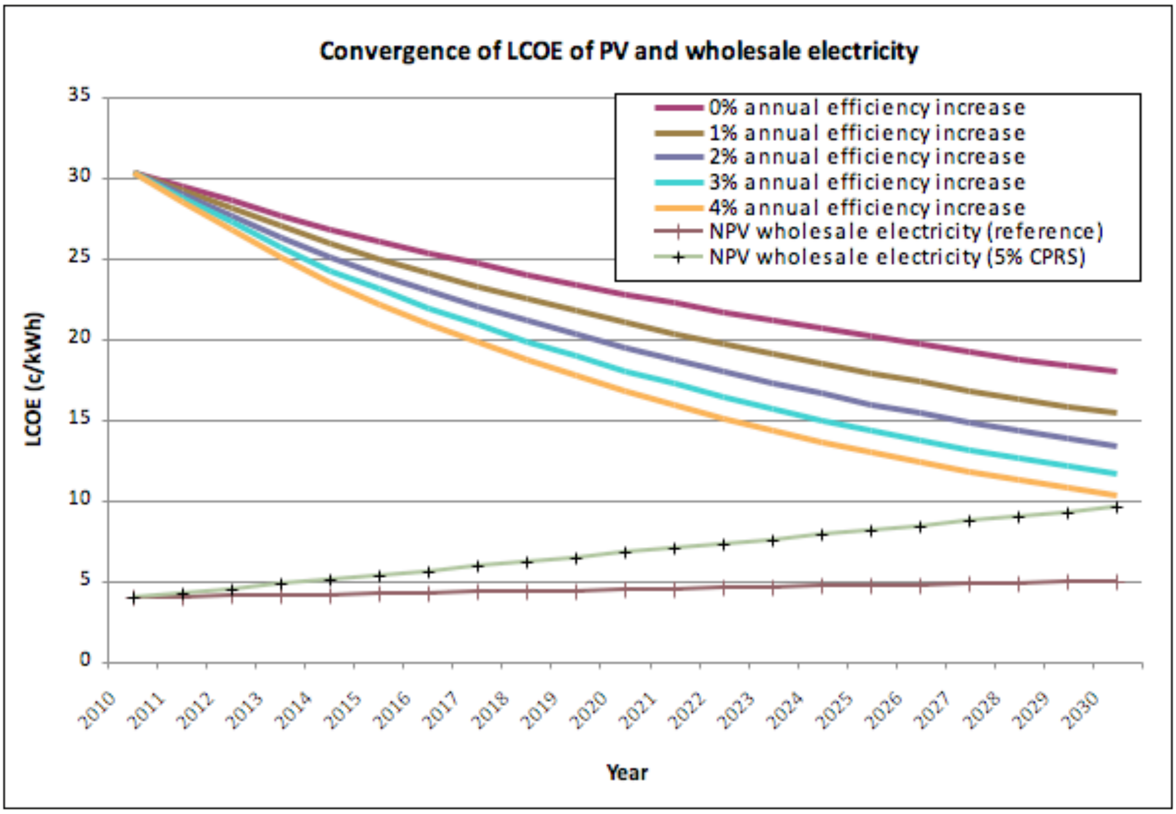


Figure 45 Projections of the Impact of Module Efficiency on LCOE: 2010 to 2030

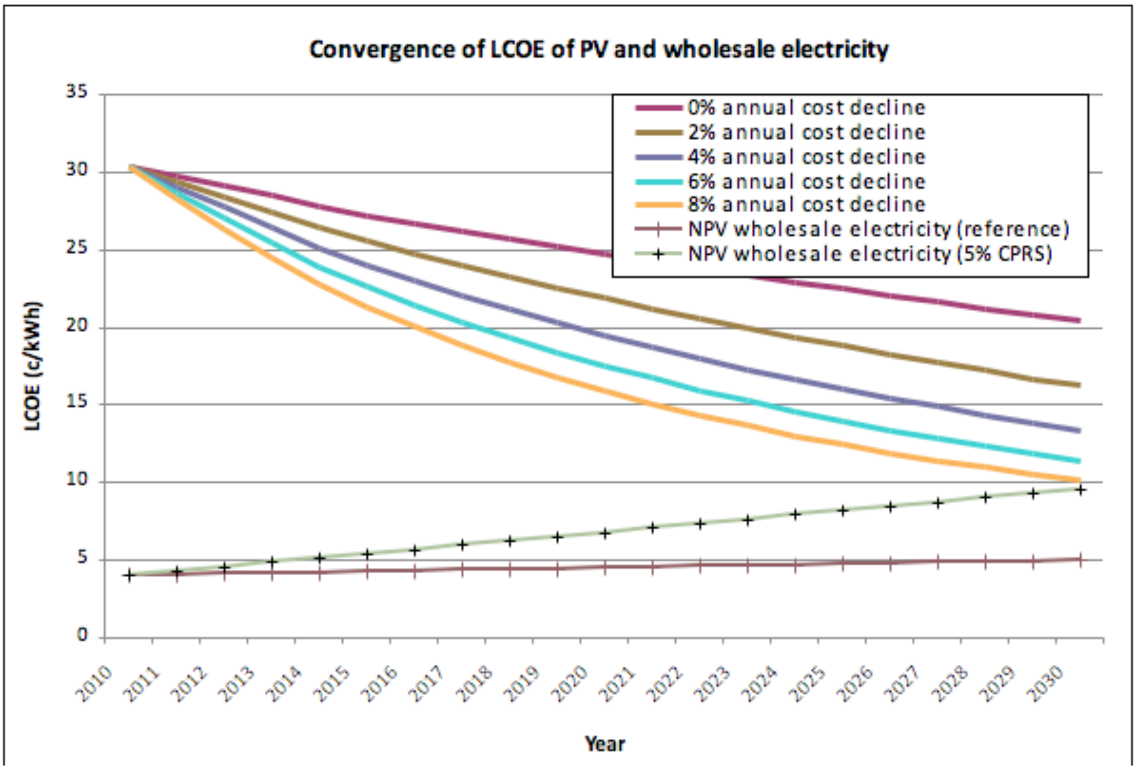


Figure 46 Projections of the Impact of Module Cost on LCOE: 2010 to 2030

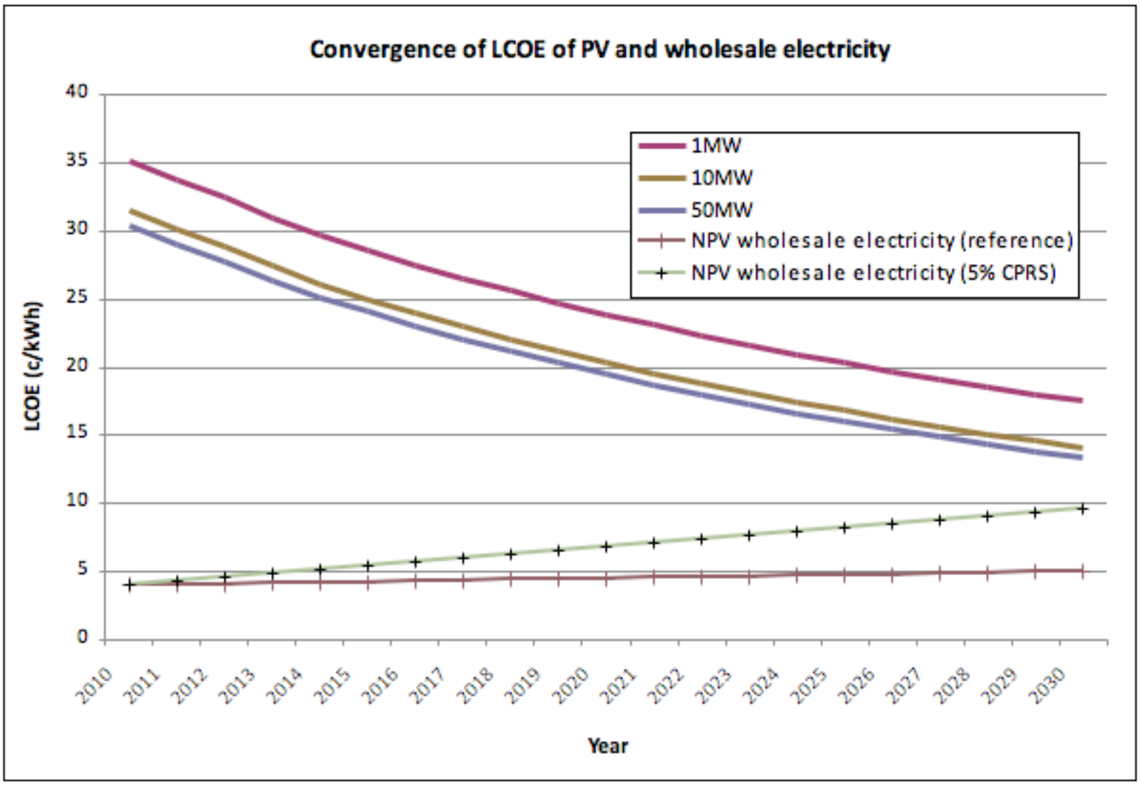


Figure 47 Projections of the Impact of System Size on LCOE: 2010 to 2030

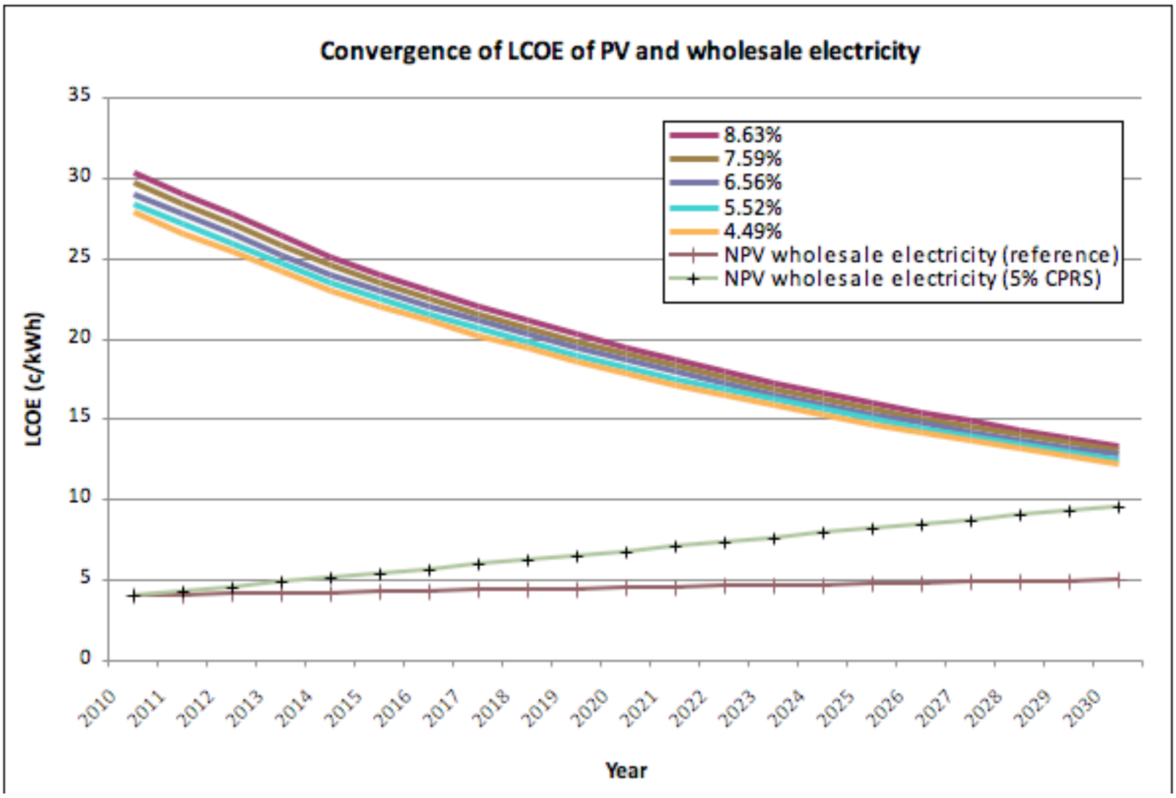


Figure 48 Projections of the Impact of Different Debt Rates on LCOE: 2010 to 2030 – standard installation model

7.2.3 Cost breakdowns

The following charts show the capital cost breakdowns in present day values, and how they are affected by varying:

- the technology type (Figure 49)
- the types of financing (Figure 50), where the types of financing are as for the commercial model: 50% equity and 50% debt financing, 100% debt financing risk free and 100% equity financing.

Except where specified, the model runs assumed a 50MW mono-crystalline system in an area with the same insolation as Sydney on a 50% Equity 50% Debt financing basis.

The most notable outcomes were:

a) Again the PV equipment cost is by far the greatest cost, being up to two thirds the total. The developer channel costs and power equipment costs are about equal and make up another 25%.

b) Although thin film has lower PV equipment costs it also has significantly greater power equipment costs (because of increased cabling), structural and support costs and civils (because of land preparation and foundations) – all because the modules are lower efficiency and hence the system takes up a larger area.

c) In terms of total lifetime finance costs, the three models assessed benefited from depreciation tax benefits, and options with higher levels of debt financing were cheaper than those with higher levels of equity financing – because of the higher interest rates of the latter.

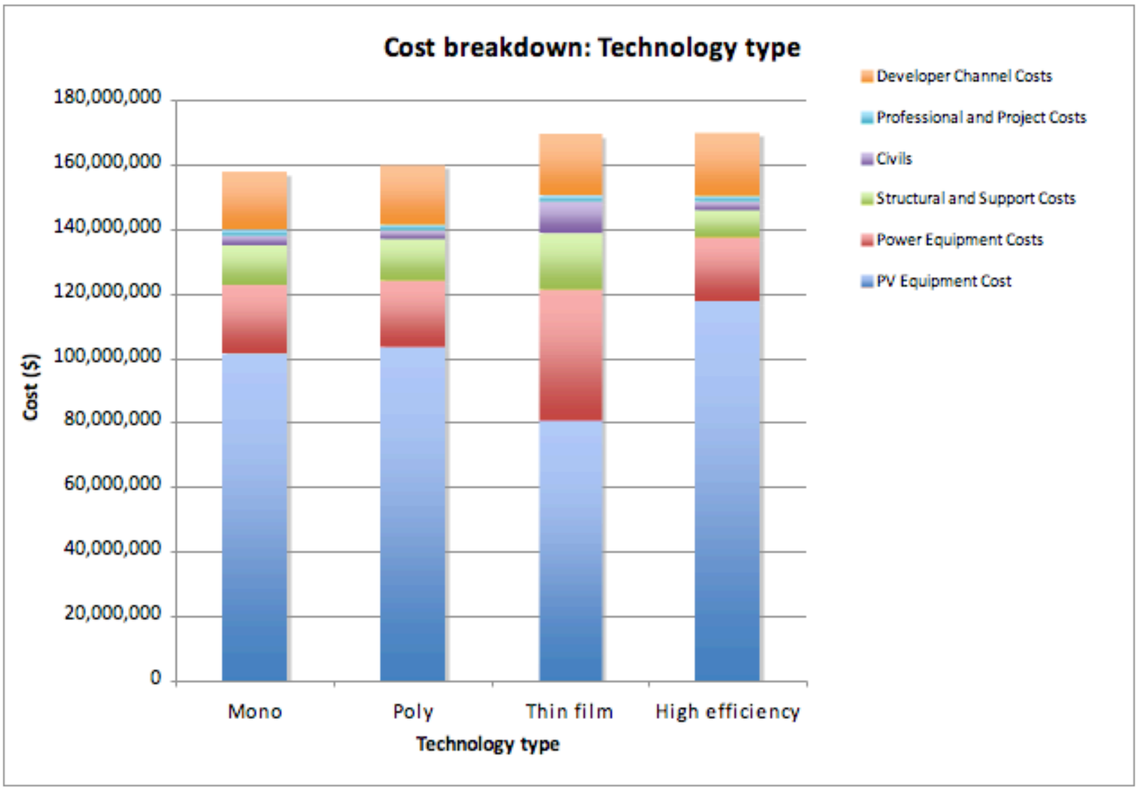


Figure 49 Effect of Technology Type on Capital Cost Breakdown

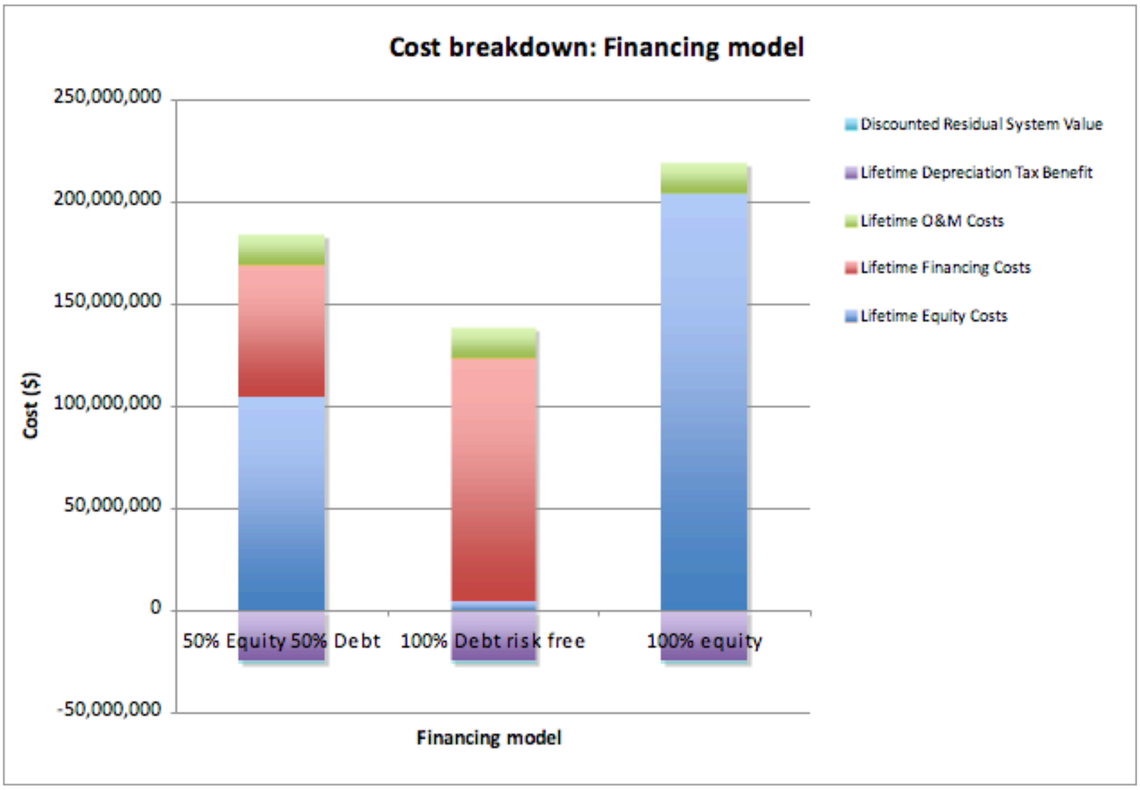


Figure 50 Effect of Types of Financing on Lifetime Cost Breakdown

8 DISCUSSION

8.1 Sensitivity Analyses of LCOE

For all three models, mono-crystalline was found to provide the lowest LCOE, followed by polycrystalline then thin film then high efficiency.

For the residential model, use of the bulk deployment approach, which is currently widespread in Australia and gaining in popularity, was found to reduce LCOE by 10.7%. The equivalent strategy for the commercial model (bypassing the distributor), reduced LCOE by 7.8%. Sensitivity analysis that varied the distributor and installer channel costs showed that reductions in the installer costs have slightly greater impacts on LCOE than reductions in the distributor costs.

For all three models, sensitivity analysis was conducted on the following parameters: system size, module efficiency, module cost, inverter cost and debt finance rate. Of these, increased system size is the only parameter that can be applied to the market now, and it was also shown to have the greatest impact on LCOE – see Table 8 for a compilation of the three models. As discussed above, the increase in LCOE when going from the commercial to the large-scale model (from 500kW to 1MW) is because the loan term is 15 years instead of 25 years, and because of slightly higher equipment and structural support costs as well as O&M costs.

Table 8 Summary of impacts on PV LCOEs of different system sizes

Model	PV System size	Standard (c/kWh)	Bulk (c/kWh)
Residential	1.5kW	37.16	33.16
	5kW	33.22	30.39
	10kW	30.2	28.34
Commercial	100kW	33.69	31.07
	250kW	33.24	30.7
	500kW	32.91	30.44
Large-scale	1MW	35.15	NA
	10MW	31.47	NA
	50MW	30.35	NA

For all three models, increasing the module efficiency by 25% (from 13.32% to 16.51%, which would occur in 2020 with just over a 2% per annum increase between 2010 and 2020) decreases LCOE by around 13% to 16%. Decreasing the module cost by 25% decreases LCOE by around 12.5% to 16.5%. Given that decreases in module costs can result from module efficiency increases as well as improvements in other aspects of the market, it is likely that a 25% decrease in module cost will occur before a 25% increase in module efficiency. Decreasing the inverter cost by 25% decreases LCOE by around 2.5% to 4.5%. Changes to debt finance costs (which could occur either because of changes to financial markets but also through government policy) also had a significant impact on LCOE, with a 1% increase resulting in around 2-3% (commercial and Large-scale) to 8.5% (residential) decrease in LCOE, and vice versa.

For the commercial and large-scale models, changes to the corporate tax rate had very little impact on the LCOE, with reduction from 30% to 27.6% decreasing LCOE by 1.0% (commercial) and 1.6% (large-scale).

For the large-scale model, sensitivity analysis was conducted around the use of tracking. It was found that single axis tracking increased LCOE by around 0.7% while two-axis tracking decreased LCOE by around 3.1%. However, these results should be viewed with caution and would benefit from better real world data on the costs of tracking in Australia.

8.2 LCOE Projections

Projections of the LCOE for systems installed in the years 2010 to 2030 were compared to projections on the LCOE of offset electricity (for the residential and commercial models) and the LCOE of electricity sold wholesale (large-scale). In all 'mid-point' scenarios, for the residential and commercial models, intersection occurred before 2022, and in some cases by 2014-15. Increased module efficiency, decreased module price, increased system size and reduced rates of debt brought the intersection year forward. Table 9 shows the intersection year for the residential and commercial models for different system sizes assuming a polycrystalline system installed in Sydney under the standard installation model (not bulk installation). For systems installed in successive years, the module efficiency increases by 2% each year, the module costs decrease by 4% each year, while the cost of inverters as well as the importer/distributor and installer margins are each assumed to decrease by 2% each year. Note that not all PV arrays will be north-facing at latitude angle (as assumed by the model), in which case they will have higher LCOEs.

Table 9 Summary of impacts on intersect of PV and grid electricity LCOEs for residential and commercial models – different system sizes

		Electricity price growth projections	
Model	**PV System size**	**Low**	**High**
Residential	1.5kW	2021	2017
	5kW	2019	2015-16
	10kW	2017	2014-15
Commercial	100kW	2020-21	2016-17
	250kW	2020	2016-17
	500kW	2019-20	2016-17

For the large-scale model, in none of the scenarios did the PV LCOE reduce to be equal to or below that of wholesale electricity. Assuming the above default rates of cost and efficiency improvements, then where there is either a 4% annual efficiency increase, an 8% annual module cost reduction or less than a 4.49% cost of debt, then by 2030 the LCOE of PV electricity is only slightly more than the LCOE of wholesale electricity. Thus, it seems that out to 2030, in the absence of significant breakthroughs of some kind that reduce costs, large-scale PV will struggle to be cheaper than wholesale prices in Australia.

8.3 Cost breakdowns

For all three models, the upfront cost breakdowns show that the PV equipment cost is the greatest cost, being between half and two thirds the total. The end system channel/developer costs are the next greatest component. The most significant savings for the bulk purchase model are from reduced distributor channel costs as well as end system channel costs, with the former providing a greater saving in the residential model and the latter in the commercial model. Although thin film has lower PV equipment costs it also greater power equipment costs (because of increased cabling), structural and support costs and civils (because of land preparation and foundations) – all because the modules are lower efficiency and hence the system takes up a larger area. Finance costs differ depending on the relative levels of debt to equity, the interest rates at which these are available, whether tax benefits can accrue and whether depreciation can be applied.

8.4 Future work

More detailed collection of real world data would be useful, especially for large-scale systems, as no multi-MW scale systems have yet been built in Australia. In general, prices are changing rapidly, and so they will need to be updated each year regardless, possibly more often. This includes wholesale and retail electricity prices (including carbon prices), which, as discussed in the detailed methodology, need to be extended annually for the model to calculate cost projections.

The large-scale model has, in effect, assumed that the PV systems are 'unscheduled' and so have no restrictions placed on their output. Further work in this area could include:

- Assessing the degree to which a large-scale PV system might be curtailed (likely to be site specific) and the impact this has on LCOE.
- Incorporation of the avoidance of such losses into the financial analysis of storage, although related financial benefits are unlikely to be significant compared to extending output regularly to take advantage of higher prices
- Including the capability to add in annual costs that are unrelated to output that are related to: submitting offers, providing the information required for the UIGF, complying with FCAS cost requirements and responding to potential voltage and reactive power instructions from NEMMCO.

The model currently has limited ability to assess the impact of different types of support policies. These could include feed-in tariffs, capital grants, low interest loans and tax breaks. Being able to assess the impacts of different types of policies would be particularly useful for commercial and large-scale systems.

9 APPENDICES

9.1 Appendix 1: Detailed Methodology: The Three System Category Tools

Given the diversity of PV applications, in order to represent the range of system costs, it was necessary to break the PV system market into the following broad PV System Categories: Residential; Commercial Building Systems; and Large-Scale free-standing systems with a different PV calculation tool implemented in respect of each category.

Each of these three calculation tools implements a different internal system model to represent the differences between the cost structures of each of the three system categories.

9.1.1 The Internal System Models

The internal system model is the generic PV system to which the key parameters selected by the user are applied. The internal system models for each of the PV system categories are introduced below.

9.1.1.1 Residential System

The internal residential system model is taken to be a PV system of between 1.5kWp and 10kWp north facing and inclined at latitude angle installed on a household roof. As such, there is no land related/structural support cost components beyond the roof mounting frames. The System is grid-connected and no energy storage is assumed.

A single inverter is assumed with the inverter capacity equalling the peak capacity of the installed system.

Investment returns are calculated on the basis of the value of grid electricity offset by the PV System and does not include consideration of tax liabilities or policy incentives (RECs, Feed-in Tariffs).

9.1.1.2 Commercial Building System

The internal commercial building system model is a PV System between 100kWp and 500kWp north facing and inclined at latitude angle, and is installed on a roof area of a commercial building (warehouse/hospital/office/civic building). The system is not integrated into the building structure instead being installed as a standard module-support structure arrangement.

It is assumed that the system is grid-connected and the space upon which the system sits does not have other beneficial use. The system is made up of 50kW inverters with no energy storage included.

Investment returns are calculated on the basis of the value of the electricity offset with the end system owner being a commercial entity, considering tax obligations including depreciation. No policy incentives (RECs, Feed-in Tariffs) are modelled.

9.1.1.3 Large Scale System

The large scale system is between 1MWp and 50MWp and is a freestanding system located on rural land. The system cost structure includes: foundation costs; land preparation costs; fencing costs; full structural support costs; conduit and cabling costs; high voltage grid connection and power equipment costs; and 5 km of high voltage transmission line.

The system is assumed to feed directly into a transmission system which is part of the National Electricity Market. The system is assumed to be treated as an unscheduled system in the NEM for the purpose of this model. No energy storage is modelled with the system.

Investment returns are calculated on the basis of a commercial entity by considering tax obligations including depreciation. No policy incentives (RECs, Feed-in Tariffs) are modelled.

9.1.2 Model Functionality and User Interface

In normal operation, the user does not have the flexibility to change the internal system models. The user, however, can 'set up' the internal model by selecting a different set of parameters to reflect the characteristics of the particular system of interest.

The user selects a set of parameters to apply to the internal system model through the Define New Scenario User Form. The Define New Scenario Form provides the user with each of the system parameter options available within the model.

Once the System Scenario has been defined, the model provides three primary functionalities for assessing the cost and investment return: Reference (default) system modelling; Sensitivity to the reference system; and Price Projection modelling.

9.1.2.1 Reference (default) system modelling

The reference (default) system modelling capabilities are executed through the user setting the system scenario via the Define New Scenario User Form. Once defined, the output of the model will immediately reflect the system scenario of interest to the user.

The reference (default) system modelling capability is the base capability of the model and can give an indication of the static differences which are a result of variation in system type, location, financing, system tracking, and development model.

9.1.2.2 Sensitivity modelling ("Sliders")

The sensitivity of the system cost and investment output parameters to variation in a range of inputs can be assessed using the Sliders which are present on the User Input page. The Sliders allow the user to 'dial' the desired model input parameter value from the reference system default parameters.

For the purpose of the sensitivity modelling functionality, each of the model inputs are assumed to be independent.

9.1.2.3 Price Projection Modelling

The third functionality of the model is the ability to calculate the present value (current year dollar) reference system cost and investment return for each of the following 20 years (eg. currently to 2030) based on the present value model input parameters defined by the user for each of those years.

When the user presses the 'Execute Price Projection' button on the user input page, the controlling Macro activates a loop. When this loop is executed, the values specified by the user for each year are, in turn, entered into the model input cells, the model then calculates the cost and investment return parameters for the particular year of interest with the output parameter values (in current year dollars) being extracted from the model and inserted into an output results sheet created (and named) for the defined System Scenario.

A fundamental assumption is that those variables which are not presented to the user on the User Input Page retain their real (current year dollar) value.

When specifying the input parameters for each of the following 20 years, the user input values must be specified in real terms (current year dollars) with all outputs calculated in real terms (current year dollar).

9.1.3 Electricity Price Projections

Because the investment return from the System Scenario defined by the user is calculated on the basis of the value of the electricity either offset or sold back to the grid at standard electricity prices, a projection of residential, commercial, and wholesale electricity prices is included as a set input to the relevant calculation tool.

In each year of the system price projection period, electricity prices for each of the following 25 years (starting in the year of interest) are loaded from the User Input page into the model. It is from these values that the lifetime electricity revenue associated with the investment decision made in that year of interest is assessed. All electricity price projections are in real current year dollars (having been corrected for the impact of inflation).

The model calculates outputs until 2030 and the electricity price projections currently incorporated into the model only go until 2055. This means that in order to run the model in 2011, another year of electricity prices will need to be incorporated.

No policy support mechanisms were modelled as part of this study. The potential financial benefit available through Renewable Energy Credits, state based Feed-in Tariffs, and other subsidies are excluded to provide clarity on the investment return from the underlying generation investment.

9.1.3.1 Residential Electricity Tariffs

Single value retail tariffs were surveyed throughout Queensland, Victoria, New South Wales, and South Australia for 2010 electricity price determinations, pricing comparators, and other publicly available information.

In order to estimate future electricity prices (in real 2010 dollars), an assessment was performed of the growth in historic electricity prices. From this assessment, in order to account for uncertainty, a high and low electricity price growth scenario was devised using the following assumptions:

- The high electricity price growth scenario was based on the average across all states of the last 10 years real terms electricity price growth from the ABS Consumer Price Data.

- The low electricity price growth scenario reflects the last 20 years electricity price growth in real terms from ABS Consumer Price Data.

9.1.3.2 Commercial Building System

As electricity prices paid by commercial building owners are more variable than those paid by individual householders, and generally established through negotiated agreements, investment returns from commercial building systems are estimated by reducing time of use (TOU) electricity prices available to small commercial customers by 25% to account for the likely discount available to larger commercial property owners.

An average single price of electricity is then established by applying a Sydney solar profile for each month of the year and averaging the resulting revenue across the amount of electricity generated to produce a single average annual figure in c/kWh.

The electricity price projection then assumes that on average, prices paid by commercial building owners grow in real terms at the same rate as residential prices. As such, a high and low electricity price growth scenario is established using the growth rates described above.

9.1.3.3 Large-Scale System

The large-scale system model is assumed to participate as an uncontracted party in the NEM with revenues reflecting the NEM spot price.

In order to model the benefit likely to be enjoyed by a large-scale PV system participating in the NEM, able to capture the wholesale market prices associated with peak and extreme price events occurring during summer, a study of the price premium enjoyed by PV as a result of the correlation between the solar profile and NEM high/extreme price events was conducted for each year between 1999 and 2009 in NSW. The average premium enjoyed by PV over this period is included in the large-scale system model as a multiplying factor applied to the NEM spot price projections.

The average NEM spot price over the period 2010 to 2055 was taken from economic modelling of the impact of the CPRS performed by Commonwealth Treasury/MMA. Incorporated into the model was the anticipated impact of the following CPRS scenarios: No Scheme; 5% abatement to 2020; 15% abatement in 2020; and 25% abatement in 2020. All spot price input projections are in real 2010 dollars.

9.1.4 The 'Tables' Default Value Worksheet

The 'Tables' worksheet contains the default values which are loaded into the model and correspond to the selections made by the user in the Define New Scenario User Form when specifying the reference (default) system scenario. These values are then loaded into the User Input sheet as well as the respective model Calculation Sheets by the controlling Macro in setting up the reference system model.

9.1.4.1 Cell Technology Type

The Cell Technology Type information for Module Efficiency (%); Landed Module Cost ($/Wp); Module Area (m^2); Open Circuit Voltage (Voc); Module Weight (kg); Average Performance Degradation (%p.a.) was supplied by APVA members participating in the study.

9.1.4.2 System Size Options

Representative cost information was obtained from APVA members in respect of the following variables which are a function of System Size: Inverter Cost ($/Wp); Power BOS ($/Wp); and Scale Factor.

9.1.4.3 System Tracking Options

While the internal system model for residential and commercial building systems assumes that modules are fixed and inclined at latitude angle, the Large-Scale System model is set up with the capability to model the additional energy generated and cost associated with single axis and twin axis tracking.

The factors contained in the Tables spreadsheet assume that the additional cost of tracking (relative to fixed plate) is in proportion to the additional electricity generated through each tracking option. This was assessed from the output of PV Syst modelling.

9.1.4.4 Location Options

Variables which are a function of System Location include: Annual Solar Radiation (kWh/m^2 annum); and Performance Ratio (%).

The System Performance Ratio includes the efficiency of the inverter and the change in the module efficiency as a function of the ambient temperatures in each of the different locations. Annual Solar Radiation is assessed for fixed plate inclined at latitude angle.

9.1.4.5 Financing Option List

The impact of financing on the investment return from a PV system is assessed through considering the separate cost of equity and debt and the proportion of equity and debt making up the financing of the system.

The cost of equity, the cost of debt, and the proportion of project financing from debt are used to calculate the interest payable on debt financing and also the effective return in each year required by an equity investor.

The 'Tables' sheet provides these parameters in respect of a number of different financing options available to the user.

9.1.4.6 Development 'Channel' Costs

The cost of the system to the end user not only includes the cost of the individual physical components making up the system but also the: profit margin and business costs of the component importer/distributor; profit margin and business costs of the end system developer. The magnitude of these 'Channel' costs is a function of the number of parties through which each system component passes as well as the business models of those parties.

So as to account for these Delivery Channel costs within the model, the Development Channel Costs Table includes an aggregate % cost factor for the business channel costs of: the importer/distributor; and the End System Installer. The model applies the Importer/distributor margin to the cost of the Modules and Inverters while the End System Margin is applied to the entire cost of the final system ex GST.

Development channel costs used in this modelling are nominal figures which are considered to be representative of standard profit and business margins of efficient businesses.

9.1.5 Investment Periods

The following is a list of the periods which are applied in calculating the investment outcome from the PV system being modelled.

- System Lifetime is assumed to be a fixed 25 year period for all system types and sizes
- Projection Period is the 20 year period between the start and finish years (eg. 2010 and 2030).
- The depreciation period is taken to be 20 years as the Tax effective life of the PV system
- Finance period is taken to be a fixed 25 year period (residential and commercial models) and a 15 year period (large-scale model) for debt financing.
- Levelisation Period is taken to be the lifetime of the investment decision which is the lifetime of the system.

9.1.6 Taxes

Investment returns are evaluated after consideration of the following Taxes:

- Goods and Services tax of 10% (householders only)
- Corporate Taxation (30% of taxable profits, reducing to 29% in 2013 and 28% in 2014)

The Goods and Services Tax is applied to the end value of systems for householders. GST is not modelled as payable for Commercial entities which are able to claim GST input credits in respect of business investments.

Return on Equity is calculated after corporate tax for all system types except for residential systems purchased by householders. The amount of corporate tax is calculated after depreciation, expenses, interest costs.

All tax calculations and deductions are performed in Nominal Terms for each year over the system lifetime through the Discount Cash Flow Analysis.

Depreciation Tax deductions for systems in which the system developer is a commercial entity is calculated on a straight line basis according to the following formula:

$$D_n = \frac{Co}{N}$$

Where:

- Dn is the nominal depreciation allowance in year n
- Co is the original capital cost of the system
- N is the depreciation period (Taken to be 20 years)

No residual value is accounted for as part of the depreciation calculation as the system lifetime of 25 years exceeds the depreciation period of 20 years.

9.1.7 Relationship between module efficiency and $/W module costs

The cost of a system is initially modelled using a default module cost according to the technology of interest. Changes in the efficiency of the module are assumed to change the input $/W module costs.

As the module efficiency increases relative to the default efficiency, the input $/W decreases and vice versa according to the following formula:

$$\$/W_{final} = \$/W_{default}\left(\frac{default\,efficiency}{final\,efficiency}\right)$$

9.2 Model Results and Output Calculations

9.2.1 NREL Manual for the Economic Evaluation of Renewable Energy

The principal reference used in developing the economic analysis included in the modelling tools has been taken from the NREL Manual for the Economic Evaluation of Renewable Energy (March 1995 NREL/TP-462-5173, Walter Short, Daniel J Packey, and Thomas Holt).

9.2.2 Present Value and Calculation Base Year

The base year for the analysis is taken to be the current year (eg. 2010), and all dollar value inputs and outputs are presented in real (current year dollar) terms. Present value (base year) dollar values are related to nominal dollar values (those values which are the actual dollar values, inclusive of inflation, which occur in each year of the system lifetime) through the following formula:

$$PV = PVIF_n * F_n$$

$$PVIF_n = \frac{1}{(1+d)^n}$$

- PV is the dollar value in base year (current year dollar) terms
- Fn is the nominal dollar value received in year n (in year n dollars)
- PVIF is the present value inflation factor for year n
- D is the discount rate

The choice of discount value depends on whether the future year cash flows are in nominal (inclusive of inflation) or real terms (current year dollars). The choice and calculation of the discount rates used in the models is presented in the following section.

9.2.3 Discount Rates and Cost of Capital

Three discount rates are used in the economic evaluation conducted by the model tools developed for this study.

- Inflation rate which is taken to be CPI of 2.5%. The 2.5% CPI represents the middle of the desired inflation band used by the Reserve Bank of Australia when setting monetary policy. On this basis it is considered to be representative of likely long term CPI.

- Cost of Equity. Return on Equity is evaluated through discounting the after tax, debt finance, and expenses cash flow to (or from) the equity holder by the desired nominal return on equity. The desired return on equity represents the opportunity cost associated with the equity capital.

The cost of debt is accounted for in the calculation of interest payments made on loans obtained for the purpose of financing the system under consideration. These interest payments are accounted for in the cash flows generated by the system and as such are not included in the discount factor used.

Financing factors including the costs of debt and equity have been obtained from the parameters used by the Australian Energy Regulator in its Draft NSW Distribution Network Determination of 21 November 2008 which are presented in the table below:

Table 26: AER's conclusion on WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	5.34%	5.34%	5.34%
Risk–free rate (real)	2.72%	2.72%	2.72%
Expected inflation rate	2.55%	2.55%	2.55%
Debt risk premium	3.29%	3.29%	3.29%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	8.63%	8.63%	8.63%
Nominal post–tax return on equity	11.34%	11.34%	11.34%
Nominal vanilla WACC	9.72%	9.72%	9.72%

9.2.4 Real and Nominal Discount Rates

The nominal discount rate is related to the real discount rate through the following formula which corrects for inflation. The real discount rate is used to discount future values which are expressed in real current year dollar terms while a nominal discount rate is used to discount future values which are expressed in nominal dollar terms.

$$d_r = \left[\frac{1+d_n}{1+e}\right] - 1$$

Where

- dr is the real discount rate
- dn is the nominal discount rate
- e is inflation rate CPI

9.2.5 Net Present Return on Equity

The Net Present Return on Equity (NPV ROE) is evaluated to give the user a sense of whether a particular investment, in a particular year, will provide the owner of the system (the equity holder) with a return which exceeds their threshold requirements (as determined from the cost of equity). As cash flows over the system life are calculated in nominal terms, a nominal discount rate is used.

The NPV Return on Equity is calculated according to the following equation:

$$NPV\ ROE = \sum_{n=0}^{N-1} \frac{F_n}{(1+d)^n}$$

Where

- Fn is the nominal cash flow to equity in year n (calculated after tax, expenses, depreciation, and debt financing)

- dn is the discount rate which is the nominal Cost of Equity
- N is the system lifetime

9.2.6 Total Life Cycle Cost Breakdown (TLCC)

The TLCC is presented so the user can understand the breakdown between the different components of cost over the lifetime of the system in real value dollar terms and is calculated according to the following relationship:

$$TLCC = \sum_{n=0}^{N-1} \frac{C_n}{(1+d)^n}$$

Where

- Cn is the cost in period n (capital costs, financing costs, residual system value, O&M, depreciation tax benefits)
- dn is the discount rate which is the nominal Cost of Equity
- N is the system lifetime

9.2.7 Levelised Cost of Electricity (LCOE)

The Levelised cost of the electricity generated by a PV system over its lifetime provides the present value c/kWh cost which equals the total present value TLCC according to the following formula:

$$TLCC = \sum_{n=0}^{N-1} \frac{Q_n * LCOE}{(1+d)^n}$$

The LCOE can then be calculated as follows:

$$LCOE = \frac{TLCC}{\sum_{n=0}^{N-1} \frac{Q_n}{(1+d)^n}}$$

Where

- d is the discount rate which is the nominal cost of equity
- Qn is the sent out generation (kWh) produced in year n

9.2.8 Levelised Cost of Grid Electricity (LCGE)

The LCGE is an analogous concept to the LCOE in that it calculates the average real current year dollar value of each kWh of electricity offset by the electricity produced by the PV system over its life.

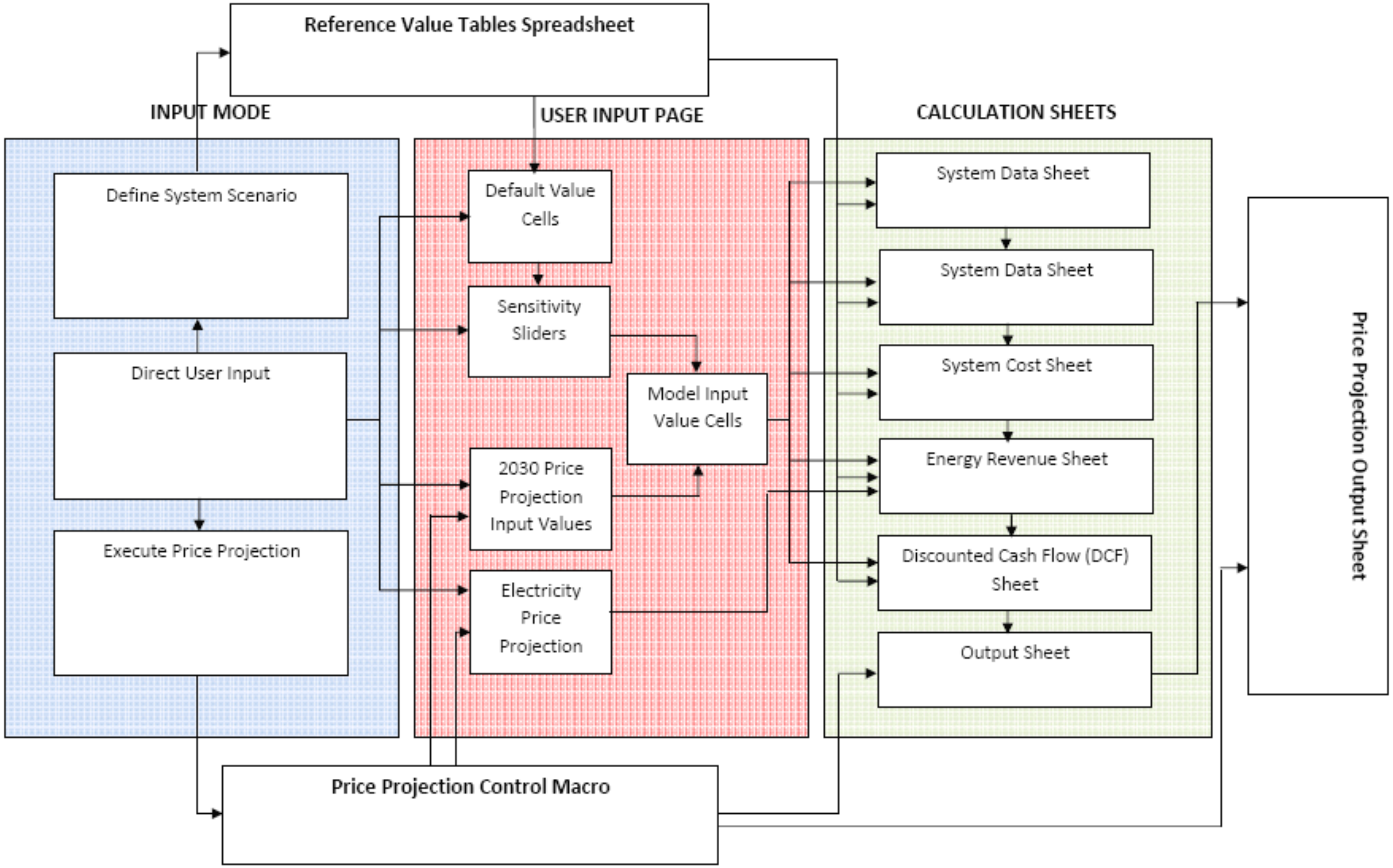
The LCGE is then compared with the LCOE used to calculate the point at which an investment in PV reaches 'grid parity' when compared on a lifetime basis.

$$LAGE = \frac{\sum_{n=0}^{N-1} QC_n}{\sum_{n=0}^{N-1} \frac{Q_n}{(1+d)^n}}$$

Where

- QCn is the total real value (current year dollar) revenue achieved by the system after degradation in year n.
- Qn is the total amount of energy in kWh produced by the system in year n
- D is the discount rate which is the real cost of equity

As all electricity price inputs are in real value current year dollars, a real (inflation adjusted) discount rate is used.


Reference Value Tables Spreadsheet
INPUT MODE
USER INPUT PAGE
CALCULATION SHEETS
Define System Scenario
Direct User Input
Execute Price Projection
Default Value Cells
Sensitivity Sliders
Model Input Value Cells
2030 Price Projection Input Values
Electricity Price Projection
System Data Sheet
System Data Sheet
System Cost Sheet
Energy Revenue Sheet
Discounted Cash Flow (DCF) Sheet
Output Sheet
Price Projection Output Sheet
Price Projection Control Macro

9.3 Appendix 2: DUOS and TUOS

Distribution Use of System (DUOS) charges are charges payable to the Distribution Network Service Provider (DNSP) by customers connected to the distribution network that pay for the costs of constructing, maintaining and operating the distribution network. Transmission Use of System (TUOS) charges are the equivalent charges payable to the Transmission network Service provider (TSNP).

In the National Electricity Rules (the Rules) Version 35 (25 March 2010), there appears to be no allowance for reduced DUOS charges to be passed through to DG. Presumably because DG still uses the distribution network to export it's electricity to consumers. However, network service providers are not allowed to charge DG DUOS charges for electricity they export.

The Rules requirements for passing on TUOS costs to embedded generation on the distribution network are given below. In summary, it outlines a basic methodology for calculating the avoided TUOS charges, which are essentially the difference between what the DNSP would have paid if the DG hadn't been operating and what the DNSP actually pays with the DG in place. The precise methodology is not specified.

Country Energy has stated it will pay residential DG 0.812 c/kWh for avoided TUOS but only up to 10kW. EnergyAustralia pays in arrears each financial year according to the methodology specified in the Rules. It is likely that Country Energy follows the same procedure for systems greater than 10kW.

Extract from National Electricity Rules (the Rules) Version 35 regarding TUOS charges.

"(h) A Distribution Network Service Provider must pass through to a Connection Applicant the amount calculated in accordance with paragraph (i) for the locational component of prescribed TUOS services that would have been payable by the Distribution Network Service Provider to a Transmission Network Service Provider had the Connection Applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUOS services').

(i) To calculate the amount to be passed through to a Connection Applicant in accordance with paragraph (h), a Distribution Network Service Provider must, if prices for the locational component of prescribed TUOS services were in force at the relevant transmission network connection point throughout the relevant financial year:

> (1) determine the charges for the locational component of prescribed TUOS services that would have been payable by the Distribution Network Service Provider for the relevant financial year:
>
> > (i) where the Connection Applicant is an Embedded Generator, if that Embedded Generator had not injected any energy at its connection point during that financial year;
> >
> > (ii) where the Connection Applicant is a Market Network Service Provider, if the Market Network Service Provider had not been connected to the Distribution Network Service Provider's distribution network during that financial year; and
>
> (2) determine the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the Distribution Network Service Provider, which amount will be

the relevant amount for the purposes of paragraph (h).

(j) Where prices for the locational component of prescribed TUOS services were not in force at the relevant distribution network connection point throughout the relevant financial year, as referred to in paragraph (i), the Distribution Network Service Provider must apply an equivalent procedure to that referred to in paragraph (i) in relation to that component of its transmission use of system service charges which is deemed by the relevant Transmission Network Service Provider to represent the marginal cost of transmission, less an allowance for locational signals present in the spot market, to determine the relevant amount for the purposes of paragraph (h)."

9.4 Appendix 3: Loss Factors

Distribution Loss Factors (DLFs)

DLFs account for electricity losses in the distribution network.

They are calculated for connection points (where loads or generators connect to the distribution network) according to methodologies provided by the Australian Energy Market Operator (AEMO) (National Electricity Rule 3.6.3):

- If a generator is greater than 10MW, or a load is greater than 10MW or 40GWh/yr, then the DLF is calculated specifically for that point.
- Otherwise, the DLF is calculated as a volume weighted average of the average electrical energy loss between the transmission network connection point (where the distribution network connects to the transmission network) or virtual transmission node to which it is assigned and each distribution network connection point in the relevant voltage class assigned to that transmission network connection point or virtual transmission node, for all connection points on a distribution network not of greater than 10MW or 40GWh.

DLFs are published on the AEMO website for each financial year. Each retailer has a list of site-specific DLFs as well as DLFs for each class of load (which can be based on eg low or high voltage, or even TOU etc).

The adjusted gross energy (AGE) is the energy that would need to be supplied at the transmission network connection point (where the distribution network connects to the transmission network) to meet all the loads connected to the distribution network after taking into account the distribution losses ie.

- AGE = ME x DLF
    - AGE = adjusted gross energy in MWh at the TN connection point
    - ME = MWh at the DN connection point (where the load connects to the DN) in that trading interval
    - DLF = distribution loss factor for that DN connection point
    - thus, AGE is increased to adjust for electricity lost in the distribution network
    - DG most likely reduces a connection point's DLF and so the AGE is either increased by less or decreased by more
    - DG also decreases the ME with the same results.

Marginal Loss Factor (MLFs)

MLFs (also called Transmission LFs) account for electricity losses in the transmission network.

They differ depending on whether the connection point is a net load (MLF more than 1) or a net generator (MLF less than one)[8].

- TA = (transmission) AGE[9] x TLF x RRP
- TA = trading amount paid to centralised generator
- (transmission) AGE = AGE for that transmission connection point or virtual transmission node
- TLF = intra-regional loss factor
- RRP = regional reference price for the regional reference node to which the connection point or virtual transmission node is assigned ($/MWh)
- DG decreases both the TLF (since it is calculated based on total load flow) and the AGE and so reduces the TA paid to the centralised generator

MLFs are published on the AEMO website for each financial year.

If a generator connects directly to the transmission network:

- (transmission) AGE = ME – AAGE
- AAGE = aggregated AGEs for all the connection points connected to that transmission network connection point
- ME = energy supplied by a generator at that transmission network connection point
- meaning that less energy has to be supplied to that connection point from 'upstream'

If the transmission network connection point is virtual (meaning that no generation or load connects there):

- (transmission) AGE = - AAGE.

Summary:

- **DLFs** are used to 'increase' the amount of energy that passes through a transmission connection point in order to allow for losses in the distribution system.
- **MLFs** are used to increase the value of energy that passes through a connection point to allow for transmission losses
- **DG** will, in theory, reduce the DLF as well as the ME, which means the AGE is increased by less or decreased by more at the distribution connection point It also reduces the TLF, and this combined with the reduced AGE reduces the Trading Amount the retailer has to pay for.
- However, in the retailer's price determinations, the DLF and MLF are taken into account when working out what prices retailers can charge, (the higher the losses

[8] Note that where a PV system is connected at that node, it could be a net load at night and a net generator during the day - complicating calculation of the MLF.

[9] This is the aggregated AGE's of downstream distribution connection points

the more they can charge end users), and so embedded generation (by reducing DLFs and MLFs) reduces what the retailer can charge.

- In this way, the benefits of embedded generation are distributed throughout the population through lower tariffs, rather than as benefits to the retailer.
- On a consumer network (where DG feeds directly into a load), the benefits of DG go to the party responsible for the load
- Therefore retailers are unlikely to reward DG for reducing line losses, so no need to account for this in the model.
- However, in a purely competitive market, where prices aren't regulated, would the downward pressure on prices due to competition have the same effect?

Conclusion for the model:

- No need to include the benefits of reduced line losses in the model
- Note that DLFs and MLFs can still be used to calculate the benefits of reduced line losses to society in general ie. (i) for PV connected to the DN, just multiply the existing DLF by the energy produced then by the MLF then by the Regional Reference Price; (ii) for PV connected to the TN, just multiply the energy produced by the MLF then by the Regional Reference Price

9.5 Appendix 4: Bulk Supply Models

There are two main types of 'bulk supply' models – company-based and council or community group-based. Company-based seems to be the first to have been used widely and initially involved signing on 50 or so households willing to buy a system, then a rapid roll out while the next 50 were signed on. For the more successful companies, this seems to have morphed into an ongoing process where households are signed on rapidly enough for the process to be continuous and so batches are not required. Note that at least one company, Energy Matters, still offers a bulk purchase discount, with additional savings of up to $1,500 on a 1kW system for 50 systems or more.[10] A sample of company-based schemes is given in Table 10.

Council or community group-based schemes are better described as 'preferred supplier' models. In this case, a council or community group requests quotes from installers, then selects preferred suppliers that it then advertises to the community. Selection is not only based on price but also on ability to deliver and quality of systems. In both company and council or community group-based models, all rebates etc are transferred to the installer. A sample of council and community-based schemes is given in Table 13.

A combined bulk installation and preferred supplier model was investigated by the Moreland Energy Foundation in early 2009. Installers were asked for both their base offer price as a preferred supplier as well as a bulk installation price. They were also asked for their costs for additional work such as different roof types, two storey houses and metering. This information is given in Table 14.

The prices according to the Climate Clever Shop (Table 13) show both the standard or recommended retail prices for a range of system sizes as at August 2009, as well as the discounted price available through the scheme. The Climate Clever Shop has recently asked the installers to update their prices in line with recent price decreases. These new prices will provide an indication of how things have changed over the last 9 months. The coordinators of the Climate Clever Shop said they have confirmed that the RRP prices are genuine. Apart from Suntech, the discount ranges from around 9% to 13% (Suntech's discount is much higher but their RRP is also higher, and so as a result, their discounted price is no lower than the others, and is generally higher). Note that there isn't any correlation between discount and system size.

The prices according to the Moreland Energy Foundation (MEFL) show the impact of guaranteed bulk supply in addition to being a preferred supplier – see Table 14. The 'single installation' prices are higher than those given in Table 13 most likely because they were obtained in late 2008. There is quite a large variation in the bulk supply discount, with some installers offering no discount even for 100 installations, and others offering up to 16%. Higher single installation prices do generally result in greater discounts, with $10,500 appearing to be a baseline price for 100 installations (except for one which reached $9,821).

Unfortunately it is unclear at which stage in the value chain the savings are made. Presumably the costs of attracting customers would be reduced, but according to the Moreland Energy Foundation, one installer said that there was little savings to be made, as

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[10] http://www.energymatters.com.au/renewable-energy/solar-power/grid-connected-systems/solar-buyers-group.php

the coordination and reporting requirements often offset any savings gained. One significant source of savings does seem to be the purchase of panels direct from an overseas manufacturer, rather than through an importer, thereby avoiding the intermediary costs. Another potential source of savings may simply be that with guaranteed and large numbers of sales, taking on more employees is less risky and a company may be able to obtain better terms of finance. Savings therefore occur through a combination of economies of scale as well as higher throughput.

Based on currently available prices through such schemes, these impacts have been incorporated into the model by reducing the import/distribution channel costs from 20% to 10% in the residential model and from 10% to zero in the commercial model.

Table 10 Company-based schemes

Company	System (kW)	Cost (incl GST)
Beyond Building, http://www.beyondbuildingenergy.com, NSW	1.5	$2,995
	2	$4,995
	3	$9,995
	4	$14,995
	5	$19,995
	10	$42,995
Solar Online, http://www.solaronline.com.au, NSW		See Table 11
Aussie Solar, http://www.aussiesolar.com.au, NSW		See Table 12
Braemac, http://www.braemacenergy.com.au	1.44	$3,480 (NSW, $5,510 RECs)
		$4,248 (Vic, $4,750 RECs)
Solar Save, http://www.solarsave.com.au/, NSW	1.5	$4,995
Yes Solar, http://www.yessolar.com.au/, NSW	1	$3,999
Nu Energy, http://www.nuenergy.com.au/, NSW	1.5	$2,500 (special, normally $2,999 and $5,499 for 2kW)

Table 11 Solar Online Prices

Installed Size	kWh per day	No. of Panels	Installed Price	Solar Credits (RECS) Discount	After Solar Credits (RECS) Discount
1530W	6.3	9 x 170W	$9,267	$5,772	$3,495
2040W	8.4	12 x 170W	$11,140	$6,142	$4,998
2720W	11.0	16 x 170W	$15,730	$6,660	$9,070
3060W	12.8	18 x 170W	$17,010	$6,920	$10,090
4080W	17.0	24 x 170W	$22,650	$7,696	$14,954
4725W	19.0	27 x 175W	$25,320	$8,177	$17,143
6300W	25.5	36 x 175W	$33,350	$9,398	$23,952
7350W	30.0	42 x 175W	$38,120	$10,212	$27,908
9990W	40.0	54 x 185W	$54,737	$12,247	$42,490

The prices are indicative and assume $37 per REC.

Table 12 Aussie Solar Prices

Package	System	Rebate Abvailable	Cost to you
1kw	1020W	n/a	n/a
1.5kw	1530W	**$6200**	**$2995**
2kw	2040W	**$6640**	**$4995**
3kw	3060W	**$7440**	**$11995**
4kw	4080W	**$8300**	**$15995**
5kw	5100W	**$9200**	**$19995**

Table 13 Council or community group-based 'preferred supplier' schemes

Organisation/Company	**System (kW)**	**Price (incl GST)**		
Alice Solar City http://www.alicesolarcity.com.au/solarpvbulkpurchase				
Conergy	1.05	$2,795		
	1.58	$3,306		
	2.1	$5,489		
Eco-Kinetics	1.02	$1,990		
	1.53	$2,490		
	2.04	$4,490		
NT Darwin Bulk Buying Scheme http://www.eco-kinetics.com/nt-bbp.html				
Eco-Kinetics	2.5	$6,990		
	3	$8,490		
	3.5	$9,990		
	4	$12,490		
	4.5	$14,990		
	5	$16,990		
Climate Clever Shop [a] (all prices exclude RECs) as at Aug 2009 [b] http://www.climateclevershop.com.au/solar-pv-panels.php		Price	RRP	Discount (%)
Conergy	1.05	$9,100	$10,500	13.3
	1.54	$13,600	$15,500	12.3
	1.76	$15,000	$16,700	10.2
	2.64	$21,500	$24,000	10.4
	3.08	$25,000	$29,000	13.8
	3.96	$32,500	$36,000	9.7
Kaneka	1	$8,500	$9,350	9.1
	1.44	$11,500	$13,220	13
	1.9	$14,950	$16,350	8.6
	3	$22,950	$24,880	7.8
Sanyo	4.1	$34,950	$37,350	6.4
	5.5	$45,390	$48,500	6.4
Suntech	1.08	$10,890	$13,890	21.6
	1.44	$13,990	$17,990	22.2
	1.8	$16,990	$22,490	24.5
	2.88	$26,990	$34,490	21.7

a) Willoughby Council conducted this tender process on behalf of Hunters Hill, Ku-ring-gai, Lane Cove, North Sydney and Willoughby City Councils.
b) These prices are soon to be updated so will give us an indication of how things have changed over the last 9 months.

Table 14 Moreland Energy Foundation preferred supplier & bulk supply prices (late 2008)

Company	Package	Price (incl GST)	Price (no SHCP or RECs)	Discount (%)
Clear Solar	PS	$1,500	$10,121	
	10	$1,200	$9,821	3%
	50	$1,200	$9,821	3%
	100	$1,200	$9,821	3%
Eco-Kinetics	PS	$2,505	$11,126	
	10	$2,505	$11,126	0%
	50	$2,505	$11,126	0%
	100	$2,505	$11,126	0%
Energy Matters	PS	$4,000	$12,621	
	10	$3,500	$12,121	4%
	50	$3,000	$11,621	8%
	100	$2,800	$11,421	10%
Environment Shop	PS	$3,795	$12,416	
	10	$2,995	$11,616	6%
	50	$2,495	$11,116	10%
	100	$1,995	$10,616	14%
Green Energy Australia	PS	$2,300	$10,921	
	10	$2,200	$10,821	1%
	50	$2,100	$10,721	2%
	100	$1,900	$10,521	4%
Rezeko	PS	$2,495	$11,116	
	10	$2,295	$10,916	2%
	50	$1,895	$10,516	5%
	100	$1,895	$10,516	5%
Sustainability in our Suburbs	PS	$2,850	$11,471	
	10	$2,850	$11,471	0%
	50	$2,850	$11,471	0%
	100	$2,790	$11,411	1%
Solar Shop	PS	$3,990	$12,611	
	10	$2,570	$11,191	11%
	50	$2,280	$10,901	14%
	100	$2,000	$10,621	16%
Braemic Energy	PS	$1,996	$10,617	
	10	$1,996	$10,617	0%
	50	$1,996	$10,617	0%
	100	$1,996	$10,617	0%

a) Assumes $8,000 PVRP/SHCP rebate and 17.75 RECs at $35 each ($621.25) = $8,621

b) PS; Preferred supplier single installation.

9.6 Appendix 5: Semi-scheduled Requirements

The following is derived from *Semi-Dispatch of Significant intermittent Generation, Proposed Market Arrangements* prepared by the Australian Energy Market Operator (AEMO) in May 2007, and from the *Final Rule Determination: National Electricity Amendment (Central Dispatch and Integration of Wind and Other Intermittent Generation) Rule 2008* prepared by the Australian Energy Market Commission (AEMC) in May 2008.

- Under the National Electricity Rules, as of 31 March 2009, all intermittent generators with a nameplate rating of greater than or equal to 30MW[11] must register as a semi-scheduled generator
- Under the Semi-Dispatch Arrangements all significant intermittent generation would be required to participate in Central Dispatch (NEMDE[12]) and PASA[13], and must comply with dispatch instructions to control its output below a dispatch cap[14] at times when that output would otherwise violate secure network limits.
- Prior to the Semi-Dispatch Arrangements a generating unit could only be classified as either scheduled or non-scheduled, with NEMMCO required under Clause 2.2.3(b)(3) to automatically approve a non-scheduled classification if the output from the generating unit was intermittent. All non-scheduled generation is exempt from participating in Central Dispatch (which covers both the Dispatch and Pre-dispatch processes) and PASA.
- Central Dispatch
    - Submit valid daily energy market offers ("dispatch offers") to NEMMCO for each semischeduled generating unit (including band MW, band prices and unit availability)
    - Allow dispatch instructions for each semi-scheduled generating unit to be centrally determined by NEMDE.
    - Electronically receive dispatch instructions for each semi-scheduled generating unit in the form of a dispatch cap (which represents a maximum generation limit) and an associated new "semi-dispatch compliance" flag
    - Comply with dispatch instructions only during dispatch intervals where the semischeduled generating unit is subject to a "semi-dispatch compliance" requirement
- PASA
    - Submit valid inputs for use in NEMMCO's STPASA and MTPASA processes respectively, including PASA Availability and (optionally) any daily or weekly energy constraints.

The Semi-Dispatch Arrangements rely on the regular provision of "unconstrained intermittent generation forecast" (UIGF) data for each semi-scheduled generating unit,

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[11] Or a collection of generators connected to a common connection point with a combined output of greater than pr equal to 30MW

[12] NEM Dispatch Engine

[13] Projected Assessment of System Adequacy, can be Short Term or Medium Term

[14] The cap only applies at the end of the dispatch interval ie. it must constrain its output at the end of that dispatch interval to less than or equal to the value of its dispatch cap for that dispatch interval.

profiled across all dispatch intervals for use as input to the Dispatch, Pre-dispatch and PASA processes. The UIGF is the equivalent forecast of electrical power output from an intermittent generating unit based on the forecast amount of raw energy available for conversion into electrical power.[15] The UIGF is not produced by the generators but they do have to provide some of the information required to make the forecasts.

For the Dispatch and Pre-dispatch processes the UIGF is determined based on the most probable forecasts (that is, 50% probability of exceedance). The PASA processes would use both 10% and 50% probability of exceedance forecasts for UIGF, in the same way that demand forecasts are currently provided for input to those processes.

For the Dispatch and Pre-dispatch processes the UIGF for each semi-scheduled generating unit would be automatically applied as an inviolable or "hard" upper limit on the value of the dispatch cap calculated by NEMDE for that generating unit. Hence the calculated dispatch cap for a semi-scheduled generating unit would never be constrained to above its UIGF through the action of any network constraint equation.[16]

Similarly in the STPASA and MTPASA processes the unit UIGF would be automatically applied as an upper limit on the amount of generating capacity dispatched from each semi-scheduled generating unit to meet the PASA demand plus minimum reserve requirements.

The current Dispatch process determines a dispatch target for each scheduled unit for every dispatch interval, and electronically reports this confidentially to the relevant participant. Under the Semi-Dispatch Arrangements the Dispatch process would also determine for each semi-scheduled generating unit both a dispatch cap and an associated "semi-dispatch compliance" requirement flag, and electronically issue these quantities confidentially to the relevant Semi-Scheduled Generator. A semi-scheduled generating unit would only need to comply with its dispatch cap (as a maximum generation limit) for dispatch intervals where the "semi-dispatch compliance" requirement flag for that dispatch interval is also set eg. due to network constraints. Where it does need to comply with its dispatch cap, it is 'semi-dispatched', otherwise, it is 'non-semi-dispatched'.

For all "non-semi-dispatch intervals" (that is, all intervals that are not "semi-dispatch intervals") a semi-scheduled generating unit would not be required to comply with its dispatch instruction for that dispatch interval, can ignore the dispatch cap and operate at any generating output level over that dispatch interval, subject to any direction or Clause 4.8.9 instruction issued by NEMMCO to do otherwise.

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[15] This generation forecast is "unconstrained" in the sense that it is based on the raw energy input to the unit's power conversion process and ignores overriding factors that are external to the power conversion process, such as the impact of any network constraint on that output or any economic requirement (as signalled through their dispatch offer) to otherwise operate at reduced levels.

[16] However if the Semi-Scheduled Generator were to (optionally) submit a maximum loading level inflexibility (in accordance with new Clause 3.8.19(a1) of the Semi-Dispatch Rules) then that value would override the UIGF and set the dispatch cap. This is analogous to the situation where a scheduled generating unit could not normally be constrained-on above its bid availability unless overridden by a submitted fixed loading level.