The Economics of Solar PV in Singapore

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August 2011 • Discussion Paper EE/11-01
JEL Classification Codes: O38, Q82, Q48, Q47, Q58, R15, R38

Energy Economics Division

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Executive Summary

Benchmarked to 2010 data, it is clear that solar photovoltaics (PV) is an expensive proposition when compared to conventional fossil fuel-based power generation technologies. With reported data on an Housing Development Board (HDB) pilot project and Singapore operating conditions, it is found that the estimated solar PV break-even price at a 5% discount rate ranges about 25 – 41% more than the average 2010 Singapore tariff rate (depending on the value of the ‘derating factor’ adopted). Using first principles for our constructed Singapore Model, an estimated solar PV module cost of US$2.50 per Watt, a discount rate of 5%, and base case assumptions for module efficiency, derating factor, module cost to investment cost ratio and annual degradation rate, the calculated Levelized Cost of Electricity (LCOE) of Singapore 41.45 cents per kilowatt hour (S41.41¢/kWh), which is about 76% more than the average Singapore 2010 tariff rate.

While solar PV is currently much more expensive than technologies such as the combined cycle gas turbine (CCGT), technological progress and manufacturing in increased scale will drive down costs. Grid parity, however, is not imminent: our best estimates under base case assumptions suggest that grid parity may be achievable around 2018, comparable to the findings of the International Energy Agency (IEA). The variability of the projected time when grid parity will occur, as a function of a number of key technological and economic parameters, behooves us to handle forecasts of grid parity with caution.

“Grid parity,” furthermore, is not a straightforward concept: measures of LCOE do not include systemic effects such as the costs incurred for providing back-up for intermittent (non-dispatchable) sources of electricity such as solar PV. To further add to this complication, it is not easy to calculate the investments required to enhance system flexibility to absorb large shares of fluctuating renewable energy sources (such as solar PV or wind). There is no single, straightforward solution towards such a calculation; no standard “reduced-form” algorithms exist for assessing the required system flexibility enhancement of any particular grid system and its associated costs. For Singapore grid-specific estimates, this remains a critical area of further research.

The data suggests that investment costs imposed by the need to integrate intermittent sources of power beyond a very limited penetration threshold in any grid system are not insubstantial; any full assessment of the costs of solar power needs to take these into account. If costs of such investments on the power grid necessitated by the induction of new
intermittent technologies into the power generation mix are funded by a general electricity tariff rate increase, then this would effectively be an implicit subsidy of the intermittent power generation technology financed, in the first instance, by electricity rate-payers (prior to general equilibrium effects which would distribute ultimate costs across various firms and households over time). If the investment costs are borne by the general government budget, the costs of this implicit subsidy would fall in the first instance on tax payers (firms and households). To the extent that electricity bills account for a larger share of the budget of poorer households, this implicit subsidy whether paid for by power tariffs or general taxes would tend to have a regressive impact on household incomes (unless the progressivity of tax incidence is increased to compensate such households, for instance).

The promise of environmentally-benign sources of energy and the need to abate greenhouse gas emissions with a backdrop of global warming has led many countries to support public finance or regulations that provide subsidies for technologies such as solar PV and other renewable energy sources. These include not only OECD countries such as Germany or Spain, but also developing countries such as Thailand and Malaysia more recently. Is promoting solar PV technology a cost-effective means of mitigating climate change? We have shown, along with several other studies cited in the literature, that solar PV is extremely expensive relative to conventional fossil fuel-based power generation technologies, under current conditions and for some time to come. As a result, it is not surprising that solar PV is not a cost-effective means of carbon emission mitigation. In fact, solar PV is among the most expensive options in abating greenhouse gases.

At a CO$_2$ price of US$30/ton and a discount rate of 5%, the LCOE for fossil fuel-based technologies such CCGT and coal increase but still remain far lower than solar PV and diesel genset technologies. Under current conditions, solar PV in the Singapore model becomes competitive to conventional coal plants when the carbon price is US$341/ton of CO$_2$. It only becomes competitive with CCGT, the mainstay technology for power generation in Singapore, at US$677/ton of CO$_2$. These estimates are likely to be conservative; two well-cited studies derive break-even CO$_2$ prices of between US$750 – 1,000/ton. It is well established in the mainstream literature that market-based policy instruments such as the carbon tax or tradable emission permit regimes offer much more effective and efficient means to mitigate carbon emissions.
Under conditions of uncertainty, there is an option value in delaying inherently irreversible investment decisions. In the case of solar PV installations, given the expected drop in module prices, it may be rational to delay investment and getting cheaper modules for system installations in the future. Significant savings may result from the decision to delay investments. The recommendation to “buy from overseas later” may well be the optimal policy approach for those countries which do not have a comparative advantage in the manufacture of solar PV panels.

To the extent that there are “learning-by-doing” and informational externality effects in the installation, use, and integration of solar PV systems into the national grid, there is a case for publicly-financed test-beds and controlled experiments in the installation and use of such systems in Singapore, in preparation for the potential mass adoption of the technology as it improves and costs come down to the point where solar PV truly becomes competitive.
1. Introduction

Renewable energy technologies have been receiving much attention in the past few years. High fossil fuel prices and concerns of global climate change have motivated policy makers and ordinary citizens, in developed and developing countries. Proponents of renewable energy advocate policy and regulatory changes to promote non-fossil fuel-based electricity generation. With additional purported benefits to energy security and the creation of “green” jobs, several governments have legislated subsidies or other forms of policy and regulatory support for renewable technologies.

A renewable energy technology that may be relevant to Singapore is solar photovoltaics (PV), which directly transforms solar radiation into electrical energy. Solar PV systems are seen as a viable source of renewable energy for Singapore in particular, given the country’s equatorial location and the lack of other renewable energy resources such as hydro, geothermal, wind, or tidal energy due to meteorological, geographical, or space availability constraints. Indeed, Singapore has set up several initiatives that include solar test bedding by statutory authorities such as the Housing and Development Board (HDB).

This paper presents an economic and technical analysis of the feasibility of solar PV in the local context. Section 2 describes the prevalent solar PV technologies, the evolution of costs, and the efficiency of solar PV systems and the process of electricity generation from solar PV. Section 3 evaluates the cost of generating electricity from solar PV and calculates the likely cost trajectory estimates of solar PV electricity generation under Singapore conditions. Section 4 offers preliminary conclusions.
2. Overview of the Solar Industry

The basic building block of a PV system is a solar cell. A solar cell is a semiconductor device that converts sunlight into direct-current (DC) electricity. Solar cells can be constructed from several materials that have different efficiencies and costs. Efficiency refers to the percentage of useful electricity output per unit of solar energy input. Solar cells are connected to form a module that generates power in the range of 50W to 250W. A solar PV system consists of an array of modules and installation structures depending on the system configuration, which include inverters, connecting wires, etc.

Figure 1 below gives the International Energy Agency’s (IEA) findings in their Technology Roadmap study for module efficiency in Watts per m² (lower horizontal axis), module price in 2008 US$ per m² (upper horizontal axis), and module price in 2008 US$ per Watt peak\(^1\)(vertical axis) for the extant range of solar PV technologies. It also gives estimates of market share for the identified technologies. Wafer-based crystalline silicon dominates the industry, accounting for 85 – 90% of the market for solar PV systems.

Crystalline silicon has been the dominant PV technology till date and is expected to be the mainstay up until 2020.\(^2\) Crystalline silicon is generally categorized into two types: mono-crystalline (sc-Si) and multi-crystalline (mc-Si). Thin film technologies account for a market share of approximately 10 – 15%. The semiconductor materials used for thin film technologies include amorphous (a-Si) and micromorph Silicon (µc-Si), Cadmium-Telluride (CdTe), and Copper-Indium-Diselenide (CIS) and Copper-Indium-Gallium-Diselenide (CIGS). Concentrating PVs and organic solar cells are technologies that are expected to see greater adoption in the future. The IEA predicts that by 2050 more than 50% of the market share will go to these novel solar PV technologies.\(^3\)

\(^1\)In photovoltaics, the maximum possible output of a solar module operating under standard conditions is defined as its peak output, which is measured as either Wp (watt peak) or kWp (kilowatt peak).
\(^2\) IEA, “Energy Technology Perspectives” (2008), pg. 372.
\(^3\) Loc. cit.
Figure 1

Module price, module efficiency and market share of different PV technologies in 2008

Note: * refers to market shares


Figure 2 shows the annual PV module shipments for crystalline and thin film technologies from 1982 to 2009. The market share of thin film peaked in 1988 at 32% and it has stayed well below 20% for most of the past decade. However, the IEA predicts that the market share of thin film will supersede that of crystalline technology by 2030.4

4 Loc. cit.
2.1 Module Efficiency

According to the estimates given by the IEA in Figure 1, crystalline silicon technologies exhibit efficiencies of around 15 – 20% or about 150 – 200 W/m². This range is higher than the efficiencies recorded for thin film technologies which lie in the 10 – 15% range or 100 – 150 W/m². Crystalline silicon technologies cost more than thin film technologies, at between US$2 – 3/Wp or US$400 – 500/m² compared to the latter’s US$1 – 1.5/Wp or US$250 – 350/m². Concentrating PV technologies are the costliest, at about US$4/Wp or US$600/m². Their efficiencies are also significantly higher, at around 25% or 250 W/m². Organic solar cells are at the lowest end of the IEA scale in efficiencies at less than 5% or 50 W/m².

According to the US Department of Energy’s (DOE) market report on solar technologies,5 both crystalline and thin film technologies have experienced improvements in efficiency, although crystalline silicon technologies have consistently outperformed thin film on this metric over the past decade (see Figure 3). Monocrystalline technology has improved in efficiency from just over 13% to over 19% by 2008; multicrystalline technologies also improved, though more slowly, achieving efficiencies of about 17% by the end of the period. Among the thin film technologies, Cadmium-Telluride (CdTe) has achieved efficiencies at about the 11% level.

Figure 3

*Best-in-class commercial module efficiencies by PV technology*

Note: a-Si, CdTe and CIS are thin film technologies; Monocrystalline and Multicrystalline are crystalline silicon technologies; HIT stands for Heterojunction with Intrinsic Thin layer is a hybrid technology composed of a thin monocrystalline wafer surrounded by ultra-thin layers of amorphous silicon (a-Si).


2.2 Module Cost

The solar PV industry has experienced rapid growth in the past decade (see Figure 4). Over 1990 to 2009, the compounded annual growth rate (CAGR) of cumulative installed capacity was 33.2%. During this period, the average module price fell from approximately US$10/Wp in 1990 to US$2.8/Wp in 2009, a decline of nearly 72% in real terms (see Figure 5). Several studies using different sets of data reach similar conclusions with regard to the overall trend in the fall in module prices. The decline in costs is reflective of several factors such as learning-by-doing, economies of scale, and technological breakthroughs.

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Figure 4

Global installed capacity of solar PV (MWp), 1990 – 2009


Figure 5

Global average module prices, all PV technologies, 1990 – 2009


The price decline has not been continuous. Prices began to increase from 2003 to 2006 as European demand, primarily from Germany and Spain, experienced high growth.
rates after feed-in tariffs and other generous government incentives were adopted. Also contributing to the price increases was an imbalance between polysilicon supply and demand from around 2004 to mid-2008. Polysilicon production facilities entail high capital costs and long construction times. Given these constraints, the polysilicon industry was unable to respond quickly to the spike in polysilicon demand driven by the PV industry. This resulted in the average polysilicon contract prices between 2003 and 2007 nearly doubling. The polysilicon spot price reached a high of US$475/kg in February 2008 and then steeply declined to the US$50 – 75/kg range from May 2009 (see Figure 6). The high price was sustained until the third quarter of 2008 when the global recession reduced demand, polysilicon supply constraints eased and module production capacity was added.

Figure 6


*Source: Bloomberg Professional Service*

From an estimated average $2.50/Wp for multi-crystalline silicon modules in 2010, prices have fallen dramatically in 2011. A recent manufacturer survey found one fifth of retailers quoting prices below $2.00/Wp, with the lowest retailed price quoted at $1.31/Wp in

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the US and $1.28/Wp in Asia. A large inventory overhang and a glut of new solar panel production capacity, with China emerging as the world’s low-cost producer, have coincided with reduced expected demand growth, as subsidies in European markets have been curtailed in the aftermath of the financial crisis and constrained public budgets. It is difficult to rigorously determine the extent to which current solar PV module prices are due to inherent technological progress on the one hand, and to unsustainable pricing pressures arising out of short and medium term market disequilibrium on the other. The evidence however suggests that the price falls of the past year have been a reflection of a global solar industry that has been subject to falling rates of demand growth (in Europe in particular) relative to global export capacity expansion, compression of gross margins, net losses among many solar panel producers, several major manufacturer bankruptcies, predatory pricing and market consolidation among a smaller group of global manufacturers.

2.3 Generating Solar PV Electricity

When light falls on a photovoltaic semi-conductor device, electricity is generated. The amount of electricity generated depends on the intensity and the duration for which sunlight is available at a given location and the conversion efficiency of the solar PV system.

The intensity of incident sunlight, i.e. solar irradiation, is expressed in terms of kW per unit area (kW/m²). Irradiation fluctuates throughout the day and exhibits seasonal trends. Its minimum value is 0 kW/m² when there is no sunlight and its maximum is 1 kW/m² at noon (in summer). If it is plotted against time as illustrated in Figure 7, the area under the curve indicates the total amount of solar energy received during that period. This is referred to as solar insolation, which is expressed in kWh/m². Insolation may be more conveniently expressed as peak sun hours. This refers to the number of hours that the sun shines at its maximum intensity at a particular location. The shaded areas in the two graphs in Figure 7 are identical by construction.

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10 “Module Pricing – Retail Price Summary November 2011 Update”, accessed at www.solarbuzz.com. In assessing price surveys, it should be noted that other non-price attributes such as manufacturers’ standards, brand names, product certification and performance standard guarantees are also critical.

Located near the equator, Singapore is regarded as a favourable site for solar installations. Its annual average solar insolation is 1,663 kWh/m², which is equivalent to receiving 4.55 peak sun hours/day. Figure 8 shows the distribution of peak sun hours for various regions in the world. Singapore’s solar potential lies roughly in the middle of the scale, at 4.55 peak sun hours. Locations such as South and Southwest Asia, north and southern parts of Africa, the US West Coast and Australia have higher insolation rates.

Source: World Resources Institute, NASA Surface Meteorology and Solar Energy

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12 Insolation data is provided by the Atmospheric Science Data Center of National Aeronautics and Space Administration (NASA). The insolation data for any particular location can be looked up by specifying its latitude and longitude, accessed at http://eosweb.larc.nasa.gov/sse/.
Actual solar PV system conversion efficiencies, the second determinant of solar power generated from PV systems, are lower than the rated efficiencies of solar modules which are measured under the Standard Test Conditions (STC) where solar irradiation is maintained at its maximum value of 1 kW/m², temperature is kept at 25°C, and the air mass coefficient, which is used to characterize the solar spectrum after solar radiation has travelled through the atmosphere, is AM 1.5. Due to the variability of meteorological factors and technical performance of solar PV systems under real conditions, system efficiency can only attain a proportion of rated module efficiency. The ratio of actual system efficiency to rated module efficiency is defined as the “derating factor.”

These above factors determine the system output at the completion of installation. It should be noted that climatic exposure degrades module performance. Degradation usually occurs in two stages: the initial stage occurs due to a chemical process within the cell upon exposure to the UV rays, the second stage is a result of the gradual weathering and aging of the module. The literature reports a range of values for the degradation exhibited at each stage; the initial stage degradation is reported to range between 1 – 3% while the second stage of degradation lies within the range of 0.5 – 1.0% per annum. In our report, we assume that the initial degradation is captured in the derating factor and only explicitly account for the second stage (annual) degradation. Annual electricity generated from a solar PV system is thus, a function of the area of the solar module array, average insolation, module conversion efficiency, derating factors, and degradation rate as follows in Equation 1:

\[
E_i = (1 - d)^i \cdot \sum_{day=1}^{365} E_{day}
\]

\[
= (1 - d)^i \cdot \sum_{day=1}^{365} Area \cdot \sum_{j=0700}^{1900} SI_j \cdot CE_{system}
\]

---


\[ \text{PV Energy} = (1 - d)^i \sum_{day=1}^{365} \text{Area} \sum_{j=0}^{1900} S_{I_j} \times \text{CE}_{\text{module}} \times \text{TDF} \times \prod \text{Other derating factors} \]  

where

E\text{\textsubscript{i}} \text{ is the average PV electricity generated in year i (kWh/year);}  
d \text{ is the annual degradation rate (%);}  
E_{\text{day}} \text{ is the average PV electricity generated in a day (kWh/day);}  
Area \text{ is the area of the solar PV module array (m}^2\text{);}  
S_{I_i} \text{ is the average solar insolation in Singapore at time } i \text{ (kWh/m}^2\text{);}  
\text{CE}_{\text{system}} \text{ is the conversion efficiency of the system (%);}  
\text{CE}_{\text{module}} \text{ is the rated conversion efficiency of the module (%);}  
\text{TDF} \text{ is the temperature derating factor (%);}  
\text{Other derating factors refer to the loss of efficiency due to BOS components (inverters, wiring) and other effects such as soiling, etc.}\textsuperscript{16}  

\textsuperscript{16} \text{Table A1 in Appendix A provides NREL’s description of the components of the derating factor. Table A2 in Appendix A gives the values for various components of the derating factor based on simulations run under Singapore meteorological conditions using PVSyst Version 5.50. It should be noted that derating factors for actual operating conditions will be significantly lower.}
3. The Economics of Solar PV

As with other innovative technologies early in their development cycle, solar PV is subject to a wide range of expert views on its commercial feasibility. Actual system performance is determined by a range of varying economic and technical conditions operating at any point in time and place. Furthermore, continued technical progress in a range of scientific disciplines such as materials sciences and manufacturing process engineering will continue to lead to improvements in the technology. With these caveats in mind, it is nevertheless possible to derive reasonable estimates of the range of costs of solar power relative to other extant power generating technologies; likewise, one can derive reasonable estimates of the likely trajectories of solar power generation costs over time. In the following sections, we discuss the basic assumptions used to derive realistic economic assessments of solar PV systems under Singapore conditions with “most likely” estimates of the technical and environmental parameters drawn from the available literature.17

3.1 Levelized Cost of Electricity (LCOE)

The Levelized Costs of Electricity (LCOE) is the metric widely used to evaluate the cost of electricity generation of different technologies over their economic life.18 The LCOE provides an economic assessment of the costs of generating electricity over the plants lifetime, including initial construction costs, costs of operation and maintenance, cost of fuel, and the (opportunity) cost of capital. If electricity is priced equal to the LCOE over the lifetime of the generating plant, the plant would “break even,” i.e., the streams of its discounted revenues and costs would be equal.

\[
LCOE = \frac{\sum_t(\text{Investment}_t + \text{O&M}_t + \text{carbon cost}_t + \text{decommissioning}_t)(1+r)^{-t}}{\sum_t(\text{Electricity}_t(1+r)^{-t})}
\]  

(2)

The LCOE is calculated as shown in Equation 2. The numerator sums the discounted costs of electricity generated over the lifetime of the plant. The denominator is the sum of discounted electricity produced over the lifetime of the plant, assuming that the electricity

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17 As with any other innovative technology where the scientific literature is in contested terrain among interested constituencies with differing agendas, it is particularly important to be explicitly aware of the provenance of the particular research results that one cites or uses.

price is level in real terms through the life of the plant.\textsuperscript{19} The life cycle cost of a power plant consists of capital investment costs and variable costs such as operation and maintenance (O&M) costs, fuel costs, and decommissioning costs. For solar PV technologies, of course, there are no fuel costs. Included in upfront investment costs are contingency costs set aside for any technical or regulatory difficulties which may arise through the life of the plant or system.

For solar PV systems, the upfront investment cost constitutes the largest share of the cost of the plant, reflecting the capital intensity of the technology (i.e. capital costs are large relative to lifetime variable costs). Solar PV modules contribute approximately 60\% of the upfront investment cost.\textsuperscript{20} The remainder of the cost comes from the inverters, supporting structures, electrical cabling, and installation labor cost, namely Balance of System (BOS) costs. This report adopts the 60-40 ratio in investment cost between modules and BOS.

As with any power plant, regular operations and maintenance (O&M) expenditure is required for a solar installation, to remove dust and dirt collected on the panels, replacing the inverter, etc. Generally, O&M expenditure is correlated with system size. It is estimated to be 0.5 to 1\% of the initial investment cost.\textsuperscript{21} With current crystalline silicon technology, modules are durable and can last for around 25 years.\textsuperscript{22} At the end of this period, a decommissioning cost is incurred. This is assumed to be 5\% of the initial investment cost.\textsuperscript{23} The LCOE results in this report are calculated for discount rates of 5\% and 10\%. It is important to note that the LCOE analysis in this paper does \textit{not} take into consideration taxes, subsidies, and transfers with respect to solar electricity generation.

3.2 An Illustrative Case from Singapore

The Housing and Development Board (HDB) has been testing the viability of rooftop solar PV electricity by launching a series of solar PV test-beds in HDB precincts across

\textsuperscript{19} It should be noted that the denominator shows the discounting of the physical flow of electricity produced over the lifetime of the plant, and there is no direct sense in which one can discount physical flows (as against financial values). However, the output of the plant in effect gives rise to a (flat) revenue stream that does pay interest over the lifetime of a plant; it is only the mathematical transformation that seems to discount a physical quantity. See IEA (2010), op. cit., pg. 33 – 35.

\textsuperscript{20} The authoritative Lawrence Berkeley National Laboratory study reports a range from 54\% to 58\% (see “Tracking the Sun II,” pg. 17). The IEA uses a 60\% ratio in its report “Energy Technology Perspectives” (2008), pg. 373 and 70\% in “Trends in Photovoltaic Applications” (2010), pg. 27.


\textsuperscript{22} IEA, “Projected Costs of Generating Electricity” (2010), pg. 43.

\textsuperscript{23} \textit{Loc. cit.}
Singapore starting from 2008. Serangoon and Wellington were the first HDB precincts to be installed with solar PV panels in 2008. Each precinct is able to generate about 220 kWh per day. In 2009, HDB announced that it would conduct a wider-scale test bedding of 3.1 MWp of solar PV installations over a 5-year period. This test bed was to be funded from the Inter-Ministerial Committee for Sustainable Development’s (IMCSD) budget of S$31 million. Various incentive schemes have been put in place to assist in financing solar installations such as the Market Development Fund (MDF) by the Energy Market Authority (EMA), the Solar Capability Scheme (SCS), and the Clean Energy Research and Test-bedding (CERT) platform by the Economic Development Board (EDB). As of 2010, the total installed capacity of residential and non-residential PV systems in Singapore stood at 2.8 MWp.

In July 2010, a batch of 4,348 PV modules was procured by HDB from Renewable Energy Corporation (REC). These panels will be installed in 6 HDB precincts and are capable of generating 1 MWp of solar power; total cost for the modules is S$2.3 million. This translates to a unit module cost of S$2.3/Wp and a capacity of 230 Wp per module. According to REC product factsheets, the module efficiency is 13.9%.

We use the data for annual electricity output and module costs reported in the referenced Business Times article while the other model inputs are calculated from assumptions based on literature surveys (see Table 1). As discussed earlier, the literature commonly estimates module costs to contribute 60% of total investment cost. We thus obtain a total investment cost of S$3.8 million, given the reported module costs of S$2.3 million. Contingency costs similarly are assumed to be 5% of the investment cost. O&M costs are annualized to 1% of investment cost, again in keeping with literature-based estimates. A degradation rate of 0.75% per annum is assumed given the range of 0.5 – 1% found in literature.

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26 Tan, M., “HDB makes $2.3m solar panel purchase,” The Business Times, 13 July 2010.
27 Please refer to Appendix B, Table B1 for a list of module efficiencies by solar PV manufacturer.
Table 1
Singapre illustrative case model inputs

<table>
<thead>
<tr>
<th>Item</th>
<th>Data source/Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual electricity output (MWh)</td>
<td>1,020 BT article (See footnote 24)</td>
</tr>
<tr>
<td>Total module cost (S$)</td>
<td>2,300,000 BT article (See footnote 24)</td>
</tr>
<tr>
<td>Total investment cost (S$)</td>
<td>3,833,333 @ 60/40 ratio for module cost/BOS cost</td>
</tr>
<tr>
<td>Contingency cost (S$)</td>
<td>191,667 @ 5% of total investment cost</td>
</tr>
<tr>
<td>O&amp;M cost (S$/year)</td>
<td>38,333 @ 1% of total investment cost</td>
</tr>
<tr>
<td>Decommissioning cost (S$)</td>
<td>191,667 @ 5% of total investment cost</td>
</tr>
</tbody>
</table>

Note: Ratios for total investment costs, contingency costs, O&M costs, and decommissioning costs are based on assumptions adopted by IEA as discussed on page 13 of this report.

An indicator of the actual performance of a solar PV system as opposed to its performance under ideal laboratory conditions (rated capacity) is given by the solar yield, which indicates the actual number of hours that a solar PV system produces at its rated output over a period of time, usually a year. It is defined as follows

\[
\text{Annual solar yield} = \frac{\text{Annual electricity output}}{\text{Rated capacity}}
\]

\[
= \frac{\eta_{\text{system}} \times \text{Insolation} \times \text{Area}}{\eta_{\text{module}} \times \text{Irradiation}_{\text{STC}} \times \text{Area}}
\]

\[
= \left(\frac{\eta_{\text{system}}}{\eta_{\text{module}}}\right) \times \left(\frac{\text{Insolation}}{\text{Irradiation}_{\text{STC}}}\right)
\]

\[
= \text{Derating factor} \times \text{Peak sun hours}
\]

where \(\eta_{\text{system}}\) is the system efficiency and \(\eta_{\text{module}}\) is the module efficiency.

The estimated annual electricity output for each of the 6 precincts is 170 MWh which gives a total output of 1,020 MWh.\(^{29}\) Given the rated capacity of 1 MWp, the annual solar

\(^{29}\) Tan, op. cit.
yield can be calculated from Equation 3 to be 1,020 kWh/kWp. According to the EMA, the average annual solar yield of Singapore is slightly higher at 1,150 kWh/kWp.\textsuperscript{30}

Given the annual solar yield and the number of annual peak sun hours, we can use Equation 3 to calculate the derating factor. The Illustrative Case gives a derating factor of 61.4% while the reported EMA average solar yield gives a derating factor of 69.2%.

**Results for the Illustrative Case**

Figure 9 illustrates the LCOE estimates for generating solar PV electricity in Singapore for both derating factors of 61.4% (Illustrative Case) and 69.2% (EMA). At a 5% discount rate and using Equation 1 and 2, the lower derating factor derived for the Illustrative Case yields an LCOE of Singapore $33.06¢/kWh. This is more expensive than the LCOE derived from EMA’s estimated derating factor estimate, at $29.33¢/kWh. The average Singapore electricity tariff in 2010 was $23.48¢/kWh.\textsuperscript{31} In other words, if the derived derating factor from the Illustrative Case is used, break-even prices for solar PV are 1.41 times the tariff; if EMA’s estimated derating factor is used then the break-even price is 1.25 times the tariff. At a 10% discount rate, the LCOE is significantly higher for both derating factors. The predominance of investment costs in the break-even (LCOE) price is also apparent in Figure 9, typically accounting for 85% to 90% of the total LCOE. On the other hand, decommissioning cost constitutes a minuscule proportion of the total LCOE, ranging from 0.2 to 0.7 cents. Its effect is therefore negligible.


3.3 Estimates of Available HDB Rooftop Area

There has not been any rigorous study to date on the area available for solar PV system installations in Singapore. Land is a scarce resource in Singapore, a highly urbanized island of approximately 700 km² with among the highest rental rates for built up areas in the world. The area available for installing solar PV systems which has no alternative use, and hence no opportunity cost, will be some subset of total rooftop area in commercial, industrial, and public sector residential buildings as well as private residential homes. We assume that non-built up areas such as nature reserves and reservoirs are not available for PV system installations, since these have amenity value, and hence an opportunity cost for alternative uses.  

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32 It should be noted that there are initiatives by the Agri-food and Veterinary Authority for instance to assess the viability for farming techniques where “the rooftops of thousands of HDB blocks can potentially be turned into urban farmland” (see Kassim, Y. R., “HDB rooftops as farmland,” The Straits Times, 24 August, 2011). In this context, it may be argued that HDB rooftops have an opportunity cost, in that there are competing uses for the open area (rooftop farming as against space for solar panel arrays), and this would need to be incorporated into the LCOE calculations for solar PV.
Using Geographic Information Systems (GIS) and sampling techniques, the Singapore Land Authority (SLA) estimated the potential area available for installing PV systems in public housing (HDB) rooftops in Singapore. HDB blocks constitute a significant proportion of Singapore’s building stock and the government has already engaged in extensive test-bedding of solar PV installations on HDB block rooftops.

Based on SLA’s analysis, the total rooftop area available for solar PV installations ranges from 6,337,360 m² to 7,779,890 m². This range accounts for potential shading cast by obstructions on the rooftops such as lift shafts and water tanks. It represents the minimum and maximum theoretically available HDB rooftop area in the case of maximum shading and no shading respectively. Covering this area, total installed solar capacity would range from 856 MW to 1,050 MW, accounting for 8.5% to 10.5% of Singapore’s total installed power generating capacity as of 31st March 2011.

3.4 A Singapore Model Based on First Principles

In this section, irradiation factors that reflect Singapore conditions and estimates from the literature for key model parameters are used to derive the LCOE for Singapore-located solar PV systems from first principles. To get an idea of the range of break-even solar PV electricity prices (i.e. LCOE) as a function of key parameters for efficiency, derating factors and module costs as a proportion of total investments costs, we set up three cases: the high LCOE case, the base LCOE case, and the low LCOE case. The low LCOE case assumes higher efficiency, a better derating factor, and module costs accounting for a larger portion of total investment costs. The high LCOE case assumes the converse, i.e. module efficiency is lower, the derating factor is more unfavorable, and module costs account for a smaller proportion of total costs. The base case reflects an intermediate set of assumed parameter values. We consider the power output of a 1 m² multi-crystalline solar module in all three cases.

Table 2

| Parameters | Low | Base | High |

33 A brief description of the methodology used in SLA’s analysis can be found in Appendix C.
35 This last assumption effectively makes BOS costs lower, as a proportion of total investment costs.
Table 2 gives the assumptions for key parameters in the high, base, and low LCOE cases. For the Singapore Model, we use an estimated average multi-crystalline silicon module cost of US$2.50/Wp in 2010. For module efficiency (multi-crystalline silicon technology), a survey of product factsheets from various solar PV manufacturers indicates a range from 12% to 15%. A mid-point value of 13.5% module efficiency is utilized for the base case.

With respect to the derating factor, a value of 69.2% is chosen for the base case LCOE, which is derived from the reported annual solar yield by EMA (as discussed above). For the high LCOE case, we use a value of 61.4% which is derived from the illustrative HDB test-bed example (as discussed above). For the low LCOE case, we use a high derating factor of 77%, estimated by NASA. The IEA estimate for the module cost/investment cost ratio of 60% is used for the base LCOE case, and is varied by 10% down or up for the high and low case respectively. The degradation rate ranges from 0.5% to 1% for crystalline silicon.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>LCOE</th>
<th>LCOE</th>
<th>LCOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Module efficiency (%)</td>
<td>15</td>
<td>13.5</td>
<td>12</td>
</tr>
<tr>
<td>Derating factor (%)</td>
<td>77</td>
<td>69.2</td>
<td>61.4</td>
</tr>
<tr>
<td>Module cost/Investment cost ratio (%)</td>
<td>70</td>
<td>60</td>
<td>50</td>
</tr>
<tr>
<td>Degradation rate (%)</td>
<td>0.5</td>
<td>0.75</td>
<td>1</td>
</tr>
</tbody>
</table>

---


37 Refer to Appendix B, Table B1 for a list of module efficiency by manufacturer.

modules, reflecting extant literature estimates.\textsuperscript{39} A lower degradation rate slows down the rate at which module annual electricity output is declining and increases lifetime total energy output, effectively making solar PV more competitive.

**Results for the Singapore model**

Figure 10 gives the LCOE for the three cases at 5% and 10% discount rates. We see a wide range in the LCOE with the value in the high case being nearly double that in the low case. In all the cases (at both discount rates) the LCOE exceeds the average retail price of electricity in Singapore for 2010, which was S$23.48¢/kWh. In the base case at 5% discount rate, the LCOE is S$41.41¢/kWh or about 76% above the 2010 Singapore tariff rate. In the most optimistic low LCOE case (at a 5% discount rate), the break-even price is S$31.17¢/kWh or about 33% more than the average 2010 Singapore tariff.\textsuperscript{40} At the higher 10% discount rate, the LCOE results are significantly higher, with the base case LCOE of S$57.52¢/kWh being nearly 40% higher than the base case LCOE at the 5% discount rate.


\textsuperscript{40} It should be noted that the high derating factor utilized in the low LCOE case is based on NASA estimates for temperate regions with high peak sun hours, and hence is not applicable to Singapore conditions. In other words, the low LCOE case is illustrative and very unlikely to be attainable under Singapore’s meteorological conditions. See Appendix A for a more detailed explanation on derating factors.
Figure 10

LCOE for the low, base, and high case (@ 5% and 10% discount rate)

Note: Base case assumptions are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% annual degradation rate. Low case assumptions are 15% for module efficiency, 77% for derating factor, 70% for module cost/investment cost ratio, 0.5% annual degradation rate. High case assumptions are 12% for module efficiency, 61.4% for derating factor, 50% for module cost/investment cost ratio, 1% annual degradation rate. Module cost is assumed to be US$2.5/Wp in 2010.
Sensitivity Analysis for the Singapore model

The chart in Figure 11 shows the results of a uniform ± 30% change in the base case parameter values for the degradation rate, discount rate, module cost, and derating factors on LCOE. This allows for a ranking of the parameters according to their relative importance in determining the LCOE.

The LCOE exhibits a high sensitivity to derating factor variations and module costs and to a lesser extent to the discount rate. It exhibits the least sensitivity to the degradation rate. Faster degradation of the panels (+30%) increases LCOE marginally by 2.1% as compared to the range of 11% to 30% seen for the impact of varying the other parameters. The impact of variations in the derating factor is also markedly skewed to the right, meaning that plants are particularly sensitive to decreases in the derating factor (i.e. less efficient BOS). A 30% decrease in the derating factor increases the median case LCOE by 43% whereas a 30% increase results in a 23% decrease in the LCOE.

As the major component of upfront investment expenditure, module cost is an important parameter affecting the competitiveness of solar PV systems. Substantial cost reductions in PV module costs are expected over time, as a result of “learning rates,” manufacturing cost reductions, and technology improvements.41

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41 IEA, “Projected Costs of Generating Electricity” (2010), pg. 111.
Degradation Rates

Solar PV modules are relatively durable, and reputable suppliers of crystalline silicon modules typically give product warranties for 20 – 25 years. Nonetheless, studies have shown that solar PV modules deployed outdoors experience steady declines in power output over time.\(^{42}\) This highlights the importance of factoring degradation into the LCOE calculations to arrive at the true cost of solar PV. Constant climate exposure and weathering can cause significant wear and tear to the modules, resulting in either power degradation or failures, with the latter being less frequently observed. In some cases, depending on the settings, modules can experience up to nearly 5% annual degradation. That implies 90% initial power only after 2 years of deployment, as compared to 10-12 years usually guaranteed by the manufacturers.

According to a study done by the Sandia National Laboratories and the National Renewable Energy Laboratory on fielded PV modules, degradation is grouped into 5 categories, namely: degradation of packaging materials, loss of adhesion, degradation of cell/module interconnects, degradation caused by moisture intrusion, and degradation of the

semiconductor device. However, the lack of consensus measurement techniques and analytical methods makes it difficult to assign a single degradation rate. Studies have reported findings for modules installed in different years, for a varied period of investigation, at different locations and of different sizes. However, most studies typically report an annual degradation rate in the range of 0.5% to 1%. For our base case assumptions, we use a degradation rate of 0.75%.

Assuming no degradation, the base case LCOE is measured at S38.60¢/kWh and S54.44¢/kWh at 5% and 10% discount rate respectively (see Figure 12), still well exceeding the 2010 current electricity tariff. At a degradation rate of 0.5% p.a., the LCOE at a 5% discount rate increases to S40.46¢/kWh, a 4.8% increase from the case where degradation is not factored in. At a 1% degradation rate, the LCOE increases to S42.37¢/kWh, a 9.8% increase, assuming a 5% discount rate.

43 M.A Quitana et. al. (2000), “Commonly observed degradation in field-aged photovoltaic modules”
Figure 12

Sensitivity of base case LCOE to a change in the degradation rate

Note: Base case assumptions are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% annual degradation rate.

Discount Rates

Although capital costs account for a large share of total net present costs (i.e. variable costs are low relative to capital costs), solar PV systems are relatively less sensitive to variations in discount rates than to other parameters such as module costs and the derating factor. Nevertheless, as can be seen in Figure 13 below, discount rate assumptions still make a significant difference to the resulting LCOE (assuming other parameters at base case levels). If a 10% discount rate is adopted, the break-even price for solar PV electricity is S57.52¢/kWh while if a 5% discount rate is adopted, the break-even price is reduced to S41.41¢/kWh, a fall of almost 40%. All else equal, the discount rate has to fall below 1% for the base case LCOE to break even with the current electricity tariff.
Figure 13

Sensitivity of base case LCOE to a change in the discount rate

Note: Base case assumptions are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% annual degradation rate.

The appropriate discount rate to use in deriving LCOE depends on the purpose of analysis: as the interest rate for a personal loan, for household installation decisions; as the cost of capital for a business investment by a (profit-maximizing) private utility company; or as the social discount rate imputed by government policy incorporating social cost-benefit calculus.

Personal loans at a real interest rate of 3 – 5% are available for households to pay for installation of solar PV systems.\textsuperscript{44} As a personal loan, the decision choice facing a household is whether it pays the household to borrow the principal to install a solar PV system (and hence reduce expected grid-supplied electricity bills over the life of the system) or not. That is, will the household investment in solar PV installation have a positive rate of return?

For business investments, the appropriate real discount rate would be determined by the weighted average cost of capital (WACC) for the investing firm adjusted for the market risk of the segment of industry in which the investment is being made relative to the market-wide risk index and a risk-free real rate of return.\textsuperscript{45} While results in this study are reported

\textsuperscript{44} For instance, the OCBC Renovation Loan provides a loan at nominal interest rates of 5.3% to 6.25% depending on the amount and payback period. See http://www.ocbc.com.sg/personal-banking/loans/Lns_Prl_RenovationLoanRates.shtml

for discounts rates of 5% and 10%, the “hurdle” rates of return for private utility investments in relatively stable OECD markets with predictable regulations may be higher than this range due to the higher levels of uncertainty (including future electricity tariffs) faced by investors in liberalized markets.\footnote{See, for instance, IEA, “Executive Summary”, pg. 12, accessed at: \url{http://www.iea.org/textbase/npsum/ElecCostSUM.pdf}}

Government policy may incorporate social measures of costs and benefits that differ from market rates due to the presence of externalities or other market failures. Sensitivity of LCOE of various electric power generation technologies to carbon price scenarios gives measurable indicators for the social value of solar PV in reducing carbon emissions. Whether solar PV offers an effective means of carbon emission abatement relative to other power generation technologies is discussed in a later section of this paper on LCOE comparisons across extant generating technologies. Nevertheless, it is well established in the literature that the first best policy option for internalizing externalities is to utilize market-based instruments (MBIs) such as the (Pigouvian) carbon tax or cap-and-trade regimes for carbon emissions.\footnote{See for instance, Stavins, R. N., “Experience with Market-Based Environment Policy Instruments,” in \textit{Handbook of Environmental Economics: Volume 2}, edited by Karl-Göran Mäler and Jeffrey R. Vincent (Elsevier, 2005)} Discretionary policies such as a lower imputed interest rate for public investments or other instruments such as “feed-in-tariffs” based on technology specifications cannot approximate the efficiency characteristics of MBIs to internalize environmental externalities.

\textit{Module Costs}

The sensitivity of the LCOE to variations in module costs is shown in the Figure 14 below. Given base case values for all other parameters, the chart gives LCOE values in Singapore (S) €/kWh for module costs measured in 2010 US$/Wp. At a 5% discount rate, and given the estimated price range of solar modules of US$2.50 – 3.00/Wp in 2010,\footnote{See for instance, Solarbuzz “Module Pricing Trends,” accessed at \url{www.solarbuzz.com/facts-and-figures/retail-price-environment/module-prices}.} the LCOE lies in the range of S41.41 – 49.69€/kWh, or between 76% to 111% above the average electricity tariff for 2010 in Singapore. At the higher 10% discount rate, the LCOE goes up to between S57.52 – 69.03€/kWh. If module cost falls to around US$1.50/Wp (in real 2010$ terms), the implied LCOE drops to about S24.85€/kWh, approaching the average Singapore tariff rates for 2010 (at S23.48€/kWh).
Figure 14

Sensitivity of base case LCOE to a change in the module cost

Note: Base case assumptions are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% annual degradation rate.

Investment decisions, such as the decision to install a solar PV system, are inherently irreversible. Given the presence of uncertainty, there is an incentive to wait before acting until the uncertainty is resolved or reduced. Thus, the option to wait has value.49 In the case of solar installations, given the expected drop in module prices, it may be rational to delay investment as there is value to doing so and getting cheaper modules for installations in the future.

Hence, a recent report by the United Kingdom’s Committee on Climate Change (CCC) recommended that in light of the high current costs of solar PV, it would be more prudent to defer deployment of solar PV to a later date and buy the technology from abroad as and when cost reductions were achieved. 50 In the same vein, the Minister Mentor (MM) Lee Kuan Yew remarked recently that, given the subsidies that China’s government is devoting to solar PV panel production, it would make more sense for Singapore to buy cheaper panels from China when they become economical. 51 In a context where prices are expected to fall, and there is significant uncertainty as to how specific energy technologies will evolve, the recommendation to “buy from overseas later” may well be the optimal policy

approach for those countries which do not have a comparative advantage in the mass manufacture of solar PV panels.\textsuperscript{52}

\textit{Derating Factor}

Figure 15 below shows the sensitivity of the LCOE to variations in the derating factor at 5\% and 10\% discount rates. Given base case values for all other parameters, the chart gives LCOE values in S\$/kWh for a range of derating factors. At a 5\% discount rate and for a derating factor of 69.2\% (the average derating factor for Singapore based on the EMA reported solar yield, as derived above), the LCOE is S41.41\$/kWh. This value is approximately 63\% above the average electricity tariff for 2010 in Singapore. As discussed above, derating factors cited in the literature range from 60\% to over 75\%. At a high derating factor of 75\%, the LCOE is S38.21\$/kWh at a 5\% discount rate. For a less favorable derating factor of 60\%, the LCOE is S47.76\$/kWh, an increase of approximately 40\%.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure15.png}
\caption*{Sensitivity of base case LCOE to a change in the derating factor}
\end{figure}

\textit{Note: Base case assumptions are 13.5\% for module efficiency, 69.2\% for derating factor, 60\% for module cost/investment cost ratio, 0.75\% annual degradation rate.}

The derating factor is a function of the temperature, among other variables, at which a solar PV module operates. This operating temperature depends on several factors which

\textsuperscript{52} Appendix D gives an illustrative example of the value of delaying investments in solar PV capacity.
include ambient temperature, thermal and physical characteristics of the solar module, incident irradiation, weather conditions, and heat transfer coefficient due to wind speed at the solar installation.\textsuperscript{53} Considerable research has gone into quantifying the effect of these factors on the solar module operating temperature.\textsuperscript{54} An example of the relationship is\textsuperscript{55}

\[ T_c = T_a + \frac{G_T}{G_{NOCT}} (T_{NOCT} - T_{a,NOCT}) \]  

where

\( T_c \) is the module operating temperature (K)

\( T_a \) is the ambient temperature (K)

\( G_T \) is the solar irradiation on the module plane (W/m\(^2\))

\( G_{NOCT} \) is the solar irradiation on the module plane at the nominal operating cell temperature (W/m\(^2\)), which is defined as the temperature of a solar module that is freely mounted and perpendicular to solar noon receiving an irradiance of 800 W/m\(^2\) at an ambient temperature of 20°C, an average wind speed of 1 m/s, and zero electrical load.\textsuperscript{56}

We can see from Equation 4 above that the solar module operating temperature is linearly related to the ambient temperature. This linear relationship is robust and has been replicated in several studies.\textsuperscript{57} Therefore, the greater the ambient temperature of a solar module, the greater will be its operating temperature. Given Singapore’s equatorial climate and the degradation of solar module output with increasing operating temperatures, the temperature effect is substantive in the Singapore context.

As discussed in Appendix A (Table A2), the temperature derating factor is the single largest contributor to total system loss. In the case of Singapore, the temperatures at which PV cells operate are quite high. For instance, a study on a flat rooftop PV installation in


\textsuperscript{54} \textit{Ibid.}, pg. 25, Table 2.


\textsuperscript{57} Skoplaki, \textit{op. cit.}, pg. 25.
Singapore found that the PV cells can attain temperatures as high as 60°C to 70°C. At a temperature of 60°C, the voltage of a PV module can drop by as much as 83.94% according to Equation 5 below. As the module power output is found to be proportional to its terminal voltage, this implies a 83.94% drop in module output at 60°C. The drop in voltage can be calculated using the following equation:

\[
\frac{V_{mpp-T_c}}{V_{mpp-25°C}}(\%) = [1 - \alpha \times (T_c - 25)] \times 100% 
\]

\(V_{mpp-T_c}\) is the voltage of the module at the operating temperature (V)

\(V_{mpp-25°C}\) is the voltage of the module at 25°C (V)

\(T_c\) is the module operating temperature (K)

\(\alpha\) is the coefficient of the module.

### 3.5 LCOE across Technologies

Table 3 below gives the IEA’s projected electricity generation costs for a range of technologies expected to be commissioned by 2015, except for some advanced plants with innovative designs (such as coal plants with CCS) which might reach commercial viability by 2020. The projections are given for median specifications based on data on generating costs for almost 200 plants in 17 OECD countries and 4 non-OECD countries. Included for comparison are the LCOE values for solar PV power generation for the Singapore model (base case) and ESI estimates for diesel generation sets.

At a discount rate of 5% and with no price being put on carbon emissions, the LCOE for electricity generated from super critical (SC) and ultra-super critical (USC) coal plants is the lowest amongst the technologies considered, at just over US4¢/kWh. The LCOE for nuclear and coal with carbon capture and sequestration (CCS) technologies are comparable, at US5.9¢/kWh. Nuclear power is more competitive than combined cycle gas turbine (CCGT).

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technology (which has an LCOE of US7.5¢/kWh), even with higher contingency costs. Only diesel is more expensive than solar PV.

At a carbon price of US$30/ton CO₂ and a discount rate of 5%, the LCOE for fossil fuel-based technologies, such as CCGT and coal, increase but still remain far lower than solar PV and diesel genset technologies. The LCOE for coal technologies increases by almost 60%, from US4.1¢/kWh to US6.5¢/kWh. The LCOE for CCGT technology increases more moderately by about 15%, from US7.5¢/kWh to US8.6¢/kWh, reflecting the lower emission intensity for natural gas relative to coal. The newer technology for coal with 90% carbon capture and sequestration (CCS) becomes competitive relative to conventional coal plants (SC/USC) with a carbon price of US$ 30/ton of CO₂.

Table 3

<table>
<thead>
<tr>
<th>LCOE across Technologies, 2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>Capacity (MW)</td>
</tr>
<tr>
<td>Investment cost (US$/kW)</td>
</tr>
<tr>
<td>O&amp;M (US¢/kWh)</td>
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<td>Fuel cost (US¢/kWh)</td>
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<td>CO2 cost (US¢/kWh) @ US$30</td>
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<td>Efficiency (net, LHV)</td>
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<tr>
<td>Load factor (%)</td>
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<tr>
<td>Lead time (years)</td>
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<tr>
<td>Expected lifetime (years)</td>
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<tr>
<td>LCOE at 5% discount rate (US¢/kWh)</td>
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<td>Zero carbon price</td>
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<tr>
<td>US$30/ton carbon price</td>
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<td>LCOE at 10% discount rate (US¢/kWh)</td>
</tr>
<tr>
<td>Zero carbon price</td>
</tr>
<tr>
<td>US$30/ton carbon price</td>
</tr>
</tbody>
</table>

Notes: (1) LCOE calculations for Nuclear, CCGT, SC/USC coal, and Coal with 90% CCS are median case estimates from IEA, “Projected Costs of Generating Electricity” (2010), pg. 103. (2) Solar PV and Diesel Genset are ESI estimates. (3) Fuel costs for hard coal (OECD) – US$90/ton; natural gas (Europe) – $10.3/MMBTU, natural gas (Asia) US$11.7/MMBTU; diesel price – US$238/bbl (see IEA for full dataset on prices utilized at http://www.iea.org/stats/surveys/mps.pdf). Prices are in 2008US$. (4) Base case assumptions for ESI’s solar PV LCOE calculations are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% for degradation rate, at a module cost of US$2.5/Wp. (5) Values for ESI solar PV are base case LCOE values of US31.45¢/kWh and US43.69¢/kWh at 5% and 10% discount rate respectively (in 2010$) with an assumed exchange rate of SGD/USD = 1.3. The values are then adjusted for inflation to 2008$ so as to facilitate comparison with the LCOE for the other technologies, which are expressed in 2008$. A deflator of 1.013 is used.

60 Under IEA’s assumptions, nuclear is assigned a higher contingency costs factor (15% of total investment costs) relative to all other technologies which have a contingency cost factor of 5% of total investment costs.
When calculating LCOE, the cost of carbon can be incorporated, as an operating cost, to assess the impact of taking economic externalities into account. Figure 15 illustrates the sensitivity of the LCOE for several technologies to the carbon price. The data for the technologies other than solar PV and diesel genset was obtained from the IEA. The LCOE for carbon-producing electricity generating technologies such as combined cycle gas turbines (CCGTs) and diesel gensets are affected by increases in the carbon price. The LCOE for nuclear power and solar PV are obviously invariant to the carbon price, since neither give rise to carbon emissions. Diesel generation is most expensive over the carbon price range. As the carbon price rises to US$341/ton (of CO₂), the LCOE for coal-based power generation approaches the US31.45¢/kWh level calculated for solar PV under the Singapore model base case assumptions. For solar PV to be competitive against CCGT technology, an even higher carbon price of approximately US$677/ton is needed. The LCOE for nuclear and coal with 90% CCS is lower than solar PV LCOE through the whole range of carbon prices (i.e. from 0 to US$1,000/ton of CO₂) shown in Figure 16.

Figure 16

Sensitivity of LCOE to the carbon price

These high break-even carbon prices for solar PV are consistent with other authoritative studies. For instance, in reviewing Germany’s energy policies in 2007, the IEA found the abatement cost at around €1,000/ton of CO₂ abated given that solar PV displaces

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gas-fired power. A more recent study that examines Germany’s renewables policies estimates the abatement costs to be €716/ton of CO₂ assuming that solar PV displaces power produced from a mixture of natural gas and hard coal power plants. The price of emission certificates in the European Union Emissions Trading Scheme (ETS) has never exceeded €32/ton of CO₂ since its inception in 2005. Using solar PV to mitigate CO₂ emissions is thus an extremely expensive GHG abatement option and is highly inefficient relative to market-based policy regimes such as the EU’s ETS.

3.6 LCOE Projections and Grid Parity

While solar PV is currently more expensive than fossil fuel alternatives, much of the promise of the technology lies in expected cost reductions as solar PV is deployed and manufactured in increasing scale. Grid parity, in common usage in the literature, is said to occur when the cost of generating PV solar electricity, and supplied as AC at an AC-point, equals the retail grid-supplied electricity price. In this parlance, solar PV technology as a source of electricity will achieve commercial feasibility when grid parity occurs, subject to important caveats which are discussed in later sections of this paper. The occurrence of grid parity depends on several factors. Parameter values such as learning rates lead to module cost reductions over time while the price trajectory of grid-supplied electricity depends on, among other factors, projected future fuel price costs. The intersection of the LCOE curves with projected grid-supplied electricity price paths determines when “grid parity” would be achievable.

64 Frondel, M., N. Ritter, C. M. Schmidt, C. Vance, “Economic Impacts from the Promotion of Renewable Energy Technologies: The German Experience,” (2009) Ruhr Economic Papers, Number 156; the emission factor for coal is assumed to be 0.584 kg CO₂/kWh.
65 See US DOE, “2008 Solar Technologies Market Report,” (2010), pg. 31 which uses this specific notion of grid parity. Note that the costs of connecting solar PV systems to the grid do not arise in this concept of grid parity. In some electricity markets, such as Singapore, a “grid” or “use of system” charge has to be paid to the grid operator. As per EMA’s “Review of Policy on Generation with Less Than 1MW in Installed Capacity” – EMA’s Assessment and Decision (2011), page 3, paragraph 5.1, a renewables installation up to a capacity of 1 MW (or 1MWP in the case of solar) that exports electricity into the grid will be compensated on the basis of the difference between the low tension tariff rate (T) and the grid charge (G). SP Power Grid, which manages Singapore’s electricity transmission and distribution networks, levies a grid charge (G) of 4.78 cents per kWh (4Q2011), a value that has been relatively stable over the years (SP Power Grid, “Transmission Service Rate Schedule,” page 7, http://www.sppowergrid.com.sg/cms/admin/contentfiles/tsrs.pdf). The grid charge lowers the revenue stream of a solar installation. The impact of grid charges in the case of solar PV installations on building rooftops will be minimal as in most instances buildings would be net importers of electricity. However, for solar installations on landed properties that can potentially export to the grid, the revenue loss on account of the grid charges is pertinent.
66 Most importantly, “grid parity” here disregards the costs of investments in grid system stability required once intermittent sources of electricity constitute more than a particular share of generating capacity.
In general, new technologies gradually become cheaper with increasing cumulative deployment. This phenomenon has been observed across many technologies and can provide insight into future price trajectories. In describing technological change and projected cost reductions in solar PV technologies, the literature uses “experience curves” to track the fall in module costs as a function of global cumulative installed capacity. Of the many functional forms proposed to represent the experience curve, the power function is most commonly used in the literature.  

The experience curve is expressed as:

\[
P_t = P_0 \cdot X^{-E}
\]  

Where

- \(P_t\) is the real module price at time \(t\),
- \(P_0\) is a constant,
- \(X\) is the cumulative installed capacity, and
- \(E\) is the experience parameter.

Using this equation, the progress ratio (PR), which is the price reduction that comes from a doubling of capacity, can be arrived at.

\[
PR = \frac{P_0 \cdot 2X^{-E}}{P_0 \cdot X^{-E}} = 2^{-E}
\]

The learning rate (LR) can then be calculated as:

\[
LR = 1 - PR
\]

The learning rate thus gives the rate of fall in module prices with a doubling of cumulative capacity. For instance, a learning rate of 20% corresponds to a 20% reduction in cost for each doubling of cumulative installed capacity. It should be noted that the learning rate is highly sensitive to the choice of period over which the data is collated and the number of data points. Data in earlier years suggest a range of values between 18% and 20%.  


dataset illustrated in Figure 17 yields a fitted trend line with a rather low learning rate of 13%.

**Figure 17**

*Experience curve based on global average solar PV module price and cumulative installed capacity 1990 – 2009*

The IEA provides projections for global cumulative installed capacity for solar PV (see Table 4 below). We use these projections and the learning rate parameter to derive solar PV module cost projections. Projected reductions in LCOE will be overstated to the extent that deployment forecasts may overstate future cumulative capacity growth. In a context where investments in solar PV capacity are primarily driven by government incentives and regulations (such as feed-in tariffs for example), there is an added element of regulatory uncertainty. As demand for solar panel investments is a function of government policy support, there is added uncertainty about the durability of such policies in the current context of tightly constrained OECD public budgets. For instance, solar power subsidies in countries

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*IEA, “Technology Roadmap: Solar PV Energy” (2010), pg. 18. The IEA’s solar PV capacity projections are based on the “BLUE Map” scenario which has CO₂ emissions being mitigated to a steady state of 450ppm of CO₂e by 2050, required for global warming not to exceed 2°C. This scenario represents the IEA’s view of “successful climate change policies” being enacted and where enough solar PV installations are developed accordingly.*
such as Germany, France, the United Kingdom, Slovakia, and Spain were cut back in 2011 and have resulted in the European Photovoltaic Industry Association (EPIA) forecasting a slow-down in capacity additions in 2011.\textsuperscript{71}

\begin{table}[h]
\centering
\caption{IEA’s solar PV cumulative installed capacity to 2050}
\begin{tabular}{|c|c|c|c|c|c|}
\hline
\textbf{PV capacity (GW)} & \textbf{2010} & \textbf{2020} & \textbf{2030} & \textbf{2040} & \textbf{2050} \\
\hline
Residential & 17 & 118 & 447 & 957 & 1380 \\
Commercial & 3 & 22 & 99 & 243 & 404 \\
Utility & 5 & 49 & 223 & 551 & 908 \\
Off-grid & 2 & 21 & 103 & 267 & 463 \\
Total & 27 & 210 & 872 & 2019 & 3155 \\
\hline
\end{tabular}
\end{table}


In Figure 18 below, we plot the LCOE trajectories with high and low learning rates for base case values in module efficiency, module cost/investment costs ratio, and derating factors at a 5\% discount rate from 2010-2050.\textsuperscript{72} We consider a range of learning rates in constructing our three cases: values of 13\%, 15\%, and 18\% were assigned for the high (projected) LCOE case (i.e. a lower learning rate keeps the LCOE trajectory at a high level), the base case, and the low case respectively.

We consider two compound annual rates of growth for grid-supplied electricity prices: 1\% and 3\%. To put these price projections in context, the IEA’s most aggressive long run crude oil price projection, which puts crude oil price at US$136/barrel in 2035 (in 2009$), shows an annual compound average growth rate of oil prices to be 3.4\%.\textsuperscript{73} For the foreseeable future, Singapore’s cost of fuel for power generation is likely to be primarily a function of oil and natural gas prices, with natural gas prices in turn being largely a function


\textsuperscript{72} We assume the solar PV costs continued to fall according to historical trends. Given a learning rate of 13\% (see Figure 16) and an approximate cumulative installed capacity of 37.7 GWp in 2010, the average module cost in 2010 is estimated to be US$2.5/Wp.

of oil prices to which most natural gas term contracts, delivered via pipeline or in LNG vessels, are indexed.74

Figure 18

Grid parity projections (Base case with different learning rates @ 5% discount rate)

![Grid parity projections](image)

Note: Base case assumptions are 13.5% for module efficiency, 69.2% for derating factor, 60% for module cost/investment cost ratio, 0.75% degradation rate, at a 2010 module cost of US$2.50/Wp.

Figure 18 illustrates the LCOE trajectory for the base case with different learning rates. It highlights the uncertainties with predicting when grid parity will occur. Given base case assumptions, the most aggressive learning rate of 18% combined with the steeper grid electricity price path with a compound annual growth rate of 3% (as a function of crude oil price increase) results in grid parity at 27.61¢/kWh occurring as early as 2018. At the other extreme, again under base case assumptions for all other parameters, a slow learning rate of 13% together with a more moderate grid electricity price increase at 1% CAGR leads to a delay of about 5 years (relative to the aggressive case) before grid parity is achieved.

74 While LNG prices for Japan (the largest buyer of natural gas in Asia) are largely based on the Japan import price of crude oil (the “JCC” index), Singapore’s pipeline natural gas imports are indexed to an index of heavy fuel oil prices. Heavy fuel oil prices, in turn are highly correlated to the crude oil price.
S26.16¢/kWh around 2023. This is in line with the IEA’s forecasts. The 5-year variability to learning rate and fossil fuel price path assumptions illustrates how the many forecasts of “grid parity” in industry journals need to be handled with sufficient care and due diligence.

Figure 19 highlights even more dramatically the uncertainties of predicted grid parity. This figure traces model results which vary all parameters according to whether one is uniformly “pessimistic” or “optimistic”. To put this alternatively, we have grouped the most extreme values for all parameters available in the literature to illustrate diverging scenarios on grid parity. Given the assumptions in the high and the low cases, grid parity could be achieved as early as 2014 or as late as 2031. It should be noted however that the uniformly optimistic or pessimistic cases are unlikely to hold in entirety, and are better seen as extreme cases purely for an illustration of the theoretically possible range.

**Figure 19**

*Grid parity projections (pessimistic case and optimistic case @ 5% discount rate)*

Note: Optimistic case assumptions are 15% for module efficiency, 77% for derating factor, 70% for module cost/investment cost ratio, 0.5% for degradation rate, 18% for learning rate. Pessimistic case assumptions are 12% for module efficiency, 61.4% for derating factor, 50% for module cost/investment cost ratio, 1% for degradation rate, 13% for learning rate.

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3.7 Grid Parity and “Intermittency” Costs

In the broadest sense, grid parity implies cost competitiveness of solar PV with conventional sources of electricity generation. However, the exact definition of grid parity differs according to whether the reference is to electricity spot market price parity, parity with peaking electricity generation such as diesel generators, or retail electricity price parity. Complicating matters is the assignment of the cost of investments at the system level due to the intermittency of electricity from renewable technologies such as solar PV or wind power.

For intermittent electricity generation technologies such as solar PV, costs imposed on the system for grid stability can be substantial. In an electricity system, demand must equal supply at any given point of time in order to ensure system stability, since grid electricity cannot be “stored.” The intermittency of renewable electricity technologies such as wind or solar PV makes balancing of the grid system a more complicated task. Forecasting techniques and optimal distribution of intermittent sources might help alleviate the issues that arise; however, they do not eliminate them. Hence, system balancing considerations necessitate additional investment in backup generation and ramp-up capability. The ability to rapidly ramp up/down generation is crucial when intermittent sources are connected to the system.

The amount of investment needed to handle the impact of intermittency on the electricity grid depends on a host of variables including the size and configuration of the electricity system and the share of intermittent sources as a proportion of total electricity capacity (i.e. “penetration” level). While there have been a number of studies done on estimating costs of integrating intermittent sources of renewable energy, these studies are specific to the power systems studied, and there is no reliable means of generalizing the results. There is evidence, for example, to suggest that the link between penetration of intermittent power sources and balancing costs could be non-linear. In a study done for

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77 In particular, an appreciably larger penetration by intermittent source of power such as solar or wind would make unrealistically high ramping demands on the grid system (see Parsons, B.E. Ela, H. Holttinen, P. Meibom, A. Orths, M. O’Malley, B. C. Ummels, J. O. Tande, A. Estanqueiro, E. Gomez, J. C. Smith, “Impacts of large amounts of wind power design and operation of power systems” (2008) Results of IEA Collaboration. AWEA Wind Power 2008, Houston, Texas). Technology might help mitigate the technical constraints imposed by intermittency. For instance, new gas turbines designed by General Electric allow for rapid ramp up at the rate of more than 50 MW/minute which is twice the ramp-rate of today’s industry benchmarks (see “MetCap Energy selects GE’s New FlexEfficiency Technology”, The Wall Street Journal, June 7, 2011, accessed at http://online.wsj.com/article/PR-CO-20110607-904935.html). However, these flexible power plants would require greater upfront costs than conventional plants. Hence, the point remains that the addition of intermittent sources of electricity raises system costs.

California, it was estimated that 3,000 MW of “regulation” reserves and 4,000 MW of “ramping” reserves from “fast” resources would be required if penetration rates of 33% by intermittent sources were to be achieved by 2020.\textsuperscript{79} This constitutes approximately 10% of California’s current installed capacity, a cost which would have a non-trivial impact on the state’s average power tariffs if rate-payers are to foot the bill.

The California study considers wind and solar installations in the renewable technology mix. A combination of these two intermittent sources is able to better ‘average-out’ the variability. For dependence on a single resource such as solar PV, system costs would be higher due to higher intermittency rates. According to the EMA, the Singapore grid can handle up to 350 MW of solar PV power or about 3.5% of total generating capacity; above this threshold, additional investments are needed to stabilize the grid.\textsuperscript{80} The LCOE derivations presented in this study do not account for grid-system stability costs imposed by the use of intermittent technologies beyond the relatively low threshold (as a proportion of total electricity produced by the grid). The LCOE derivations reported in this report, therefore, understate the full cost of generating electricity from intermittent technologies.

Given the need for continuous balancing of load, an electricity generating unit whose output can be controlled so as to match variations in load will be more valuable to the electricity system than an intermittent electricity generating source. This applies to countries, such as Singapore, that have wholesale electricity markets with real-time pricing. In such markets, wholesale electricity prices are prone to considerable fluctuations throughout the day. Intermittent sources, such as solar power, cannot dispatch power supplies into the grid when wholesale prices are high as they are not controlled by an operator as in a conventional electricity plant but depend on the weather, cloud cover and daily solar cycles. As a result, intermittent sources tend to produce output that has a lower value than output from conventional sources of electricity generation, a matter which would naturally be of key

\textsuperscript{79} KEMA “Research Evaluation of Wind and Solar Generation, Storage Impact, and Demand Response on the California Grid” (2010) (prepared for the California Energy Commission. CEC-500-2010-010); the power system must match aggregate generation and load instantaneously and continuously. The regulation reserve is employed to achieve this generation/load balance in order to maintain the system frequency. For Singapore, the system frequency is 50Hz with an allowable deviation of ±0.2Hz. Intermittent sources of electricity generation are prone to large fluctuations in output, which is referred to as ramp up or ramp down of output. Ramping reserves are required to manage these large fluctuations.

concern to power generating companies. The LCOE methodology thus further understates the costs of electricity generated from intermittent sources in a context of variable real time pricing of output.

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4. Conclusions

Renewable energy technologies have been receiving much attention in policy circles as well as the mass media. High fossil fuel prices and concerns of global climate change have motivated interest in renewable energy among policy makers and ordinary citizens. Proponents of renewable energy advocate strong government support for non-fossil fuel-based electricity generation. With additional purported benefits to energy security and the creation of “green” jobs, several governments have legislated subsidies or other forms of policy support such as Feed-In-Tariffs (FITs) to compensate renewable energy producers with guaranteed higher rates. These include not only several OECD countries, but also developing countries such as Thailand and Malaysia more recently.

Solar PV systems are seen as a viable source of renewable energy for Singapore in particular, given the country’s equatorial location and the lack of other renewable energy resources such as hydro, geothermal, wind or tidal energy due to meteorological and geographical constraints. Indeed, Singapore has set up several R&D initiatives that include solar test bedding by the Housing and Development Board (HDB).

The economic and technical analysis of the feasibility of solar power in the local context was examined in this paper. The results were not surprising. Other comparable studies done by bodies such as International Energy Agency (IEA) or the US Department of Energy’s Energy Information Administration (EIA) were broadly consistent with results obtained here.

It is clear that solar PV is an expensive proposition when compared to conventional fossil fuel-based power generation technologies. Using reasonable estimates for key factors such as solar power system efficiencies, local peak sunshine hours and operating conditions, and average solar module costs in 2010, the model calculated the break-even price – the price at which the costs of solar power are just balanced by its revenues over the life of the equipment – to be 25 – 40% more than the average Singapore 2010 tariff rate.

While solar power is currently more expensive than technologies such as the combined cycle gas turbine (CCGT), renewable energy advocates rightly point out that technological progress and increased production scale will drive down module costs. However, if costs are expected to come down, then this is an argument in favour of delay, not immediate action. It makes more sense to invest later, at a lower cost. “Grid parity”, when solar power costs come down to levels which make it competitive to conventional fuels, is
also not imminent. Our best estimates suggest that grid parity may be achievable around 2020, comparable to the findings of the IEA. Uncertainty as to when grid parity will occur, as a function of key technological and economic parameters, as well as the outlook for fossil fuel prices, behooves us to handle forecasts of the economic competitiveness of solar power with caution.

Grid parity, furthermore, is not a straightforward concept: break-even cost measures of solar power do not include systemic effects such as the costs incurred for providing back-up for intermittent sources of electricity such as solar power. Available data suggests that investment costs imposed by the need to integrate fluctuating sources of power into an electricity grid are substantial. Any full assessment of the costs of solar power needs to take these necessary investments into account.

If these costs are funded by a tariff rate increase, then it would effectively be an implicit subsidy of the intermittent power generation technology. The subsidy would be financed, in the first instance, by electricity rate-payers (prior to feedback effects which would distribute ultimate costs across various firms and households over time). To the extent that electricity bills account for a larger share of the budget of poorer households, this implicit subsidy would tend to have an inequitable impact on household incomes.

The analysis also showed that solar power is not a cost-effective means of carbon emission mitigation. In fact, it is among the most expensive options in abating greenhouse gases. At a CO₂ price of US$30/ton, the break-even prices for fossil fuel-based technologies such as gas turbines and coal-based power generation increase but still remain far lower than solar power. Solar power in the Singapore model becomes competitive to conventional coal plants only when the CO₂ price is US$341/ton. It becomes competitive with cleaner gas turbines, the mainstay technology for power generation in Singapore, at US$677/ton of CO₂. These estimates are likely to be conservative; two well-cited studies on Germany derive break-even CO₂ prices of between US$750 – 1,000/ton. Market-based policy instruments such as the carbon tax or tradable CO₂ emission permit regimes, initially pricing CO₂ at around the US$30/ton level, offer much more effective and efficient means to mitigate carbon emissions, as they improve incentives to reduce emissions evenly across all technologies and economic sectors.

To the extent that there are informational and “learning by doing” benefits in installing and integrating solar power systems in Singapore, there is a case for publicly
financed test-beds and local experiments in the adoption of an uncertain and costly technology. A premature transition in our power supply technologies, however, will not only be a costly option bought at the tax payer’s expense; it also means that we have not learnt lessons from the policy reversals in countries such as Germany and Spain where generous FITs have been an unnecessary burden on public finance.
### APPENDIX A

**Derating Factors**

Table A1 List of components of derating factors

<table>
<thead>
<tr>
<th>Component Derating Factors</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV module nameplate DC rating</td>
<td>Accounts for the accuracy of the manufacturer’s nameplate rating. Field measurements of a representative sample of PV modules may show that the PV module wattages are different than the nameplate rating or that they experienced light-induced degradation upon exposure (even crystalline silicon PV modules typically lose 2% of their initial power before power stabilizes after the first few hours of exposure to sunlight).</td>
</tr>
<tr>
<td>Inverter and Transformer</td>
<td>Combined efficiency in converting DC power to AC power. These inverter efficiencies include transformer related losses when a transformer is used or required by the manufacturer.</td>
</tr>
<tr>
<td>Module mismatch</td>
<td>Accounts for manufacturing tolerances that yield PV modules with slightly different current-voltage characteristics. Consequently, when connected together electrically they do not operate at their respective peak efficiencies.</td>
</tr>
<tr>
<td>Diodes and connections</td>
<td>Accounts for losses from voltage drops across diodes used to block the reverse flow of current and from resistive losses in electrical connections.</td>
</tr>
<tr>
<td>DC wiring</td>
<td>Accounts for resistive losses in the wiring between modules and the wiring connecting the PV array to the inverter.</td>
</tr>
<tr>
<td>AC wiring</td>
<td>Accounts for resistive losses in the wiring between the inverter and the connection to the local utility service.</td>
</tr>
<tr>
<td>Soiling</td>
<td>Accounts for dirt or other foreign matter on the front surface of the PV module that reduces the amount of solar radiation reaching the solar cells of the PV module. Dirt accumulation on the PV module surface is location and weather dependent, with greater soiling losses for high-traffic, high-pollution areas with infrequent rain.</td>
</tr>
<tr>
<td>System availability</td>
<td>Accounts for times when the system is off due to maintenance and inverter and utility outages. The default value of 0.98 represents the system being off for 2% of the year.</td>
</tr>
<tr>
<td>Shading</td>
<td>Accounts for situations when PV modules are shaded by nearby buildings, objects, or other PV modules and array structure.</td>
</tr>
<tr>
<td>Sun-tracking</td>
<td>Accounts for losses for one- and two-axis tracking systems when the tracking mechanisms do not keep the PV arrays at the optimum orientation with respect to the sun's position.</td>
</tr>
</tbody>
</table>

Simulating Losses of Solar PV Systems

To have a better idea as to the contribution of the component derating factors to the total losses, PVsyst Version 5.50\(^{82}\) was used to simulate the behavior of a polycrystalline solar installation under Singapore meteorological conditions. This software consists of a large database of PV components, locations, and meteorological data and can be used to design standalone, grid-tied, and PV irrigation pumping systems. Given detailed parameter values for parameters such as thermal behavior, wiring and mismatch losses, real module quality losses, incident angle losses, and electrical losses, PVsyst allows for accurate simulation of a solar PV system. Several studies have employed PVsyst to simulate the electricity generated from solar PV systems under different sorts of conditions and locations.\(^{83}\)

In the PVsyst simulations for Singapore, the losses due to the temperature effect dominate (see Table A2). Approximately 50% of the system loss is attributable to temperature. Operating temperature losses are especially important in the Singapore context given its year-round warm equatorial climate. Since the simulations in PVsyst are run under the assumption that the system is operating at standard test conditions (STC), the derating factor we obtained (75.8%) in this simulation is much higher than the Singapore model base case derating factor of 69.2%. Under actual operating conditions, the derating factor will be significantly lower than 75.8% as evidenced by the derating factor of 61.4% derived for the Singapore Illustrative Case. The derating factor from this simulation should therefore be seen as the theoretical upper bound under ideal operating conditions.

---


Table A2 Simulated component derating factors for Singapore

(Poly Crystalline Silicon Module)

<table>
<thead>
<tr>
<th>Derating Factor</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV loss due to irradiance level</td>
<td>2.1</td>
</tr>
<tr>
<td>PV loss due to temperature</td>
<td>12.3</td>
</tr>
<tr>
<td>Module quality loss</td>
<td>0.1</td>
</tr>
<tr>
<td>Module array mismatch loss</td>
<td>2.1</td>
</tr>
<tr>
<td>Ohmic wiring loss</td>
<td>0.9</td>
</tr>
<tr>
<td>Inverter loss during operation (Efficiency)</td>
<td>6.7</td>
</tr>
<tr>
<td><strong>Total loss</strong></td>
<td><strong>24.2</strong></td>
</tr>
</tbody>
</table>

Note: Given the total loss of 24.2%, the derating factor is calculated as 100 – Total Loss = 75.8%.
### Table B1 Multi-crystalline Silicon Module Efficiency

<table>
<thead>
<tr>
<th>Manufacturers</th>
<th>Module capacity</th>
<th>Material</th>
<th>Module efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>BP solar</td>
<td>230</td>
<td>mc-Si</td>
<td>13.8%</td>
</tr>
<tr>
<td>BP solar</td>
<td>225</td>
<td>mc-Si</td>
<td>13.5%</td>
</tr>
<tr>
<td>BP solar</td>
<td>220</td>
<td>mc-Si</td>
<td>13.2%</td>
</tr>
<tr>
<td>BP solar</td>
<td>215</td>
<td>mc-Si</td>
<td>12.9%</td>
</tr>
<tr>
<td>BP solar</td>
<td>170</td>
<td>mc-Si</td>
<td>13.6%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>200</td>
<td>mc-Si</td>
<td>12.2%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>205</td>
<td>mc-Si</td>
<td>12.5%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>210</td>
<td>mc-Si</td>
<td>12.8%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>215</td>
<td>mc-Si</td>
<td>13.1%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>220</td>
<td>mc-Si</td>
<td>13.4%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>225</td>
<td>mc-Si</td>
<td>13.7%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>230</td>
<td>mc-Si</td>
<td>14.0%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>235</td>
<td>mc-Si</td>
<td>14.3%</td>
</tr>
<tr>
<td>ecoSolargy</td>
<td>225</td>
<td>mc-Si</td>
<td>13.7%</td>
</tr>
<tr>
<td>Canadian solar</td>
<td>190</td>
<td>mc-Si</td>
<td>11.8%</td>
</tr>
<tr>
<td>Canadian solar</td>
<td>220</td>
<td>mc-Si</td>
<td>13.7%</td>
</tr>
<tr>
<td>Canadian solar</td>
<td>230</td>
<td>mc-Si</td>
<td>14.3%</td>
</tr>
<tr>
<td>Canadian solar</td>
<td>235</td>
<td>mc-Si</td>
<td>14.6%</td>
</tr>
<tr>
<td>Evergreen solar</td>
<td>200</td>
<td>mc-Si</td>
<td>14.0%</td>
</tr>
<tr>
<td>Evergreen solar</td>
<td>200</td>
<td>mc-Si</td>
<td>14.0%</td>
</tr>
<tr>
<td>Evergreen solar</td>
<td>210</td>
<td>mc-Si</td>
<td>14.7%</td>
</tr>
<tr>
<td>Hyundai</td>
<td>230</td>
<td>mc-Si</td>
<td>14.2%</td>
</tr>
<tr>
<td>Kyocera</td>
<td>215</td>
<td>mc-Si</td>
<td>14.5%</td>
</tr>
<tr>
<td>Kyocera</td>
<td>225</td>
<td>mc-Si</td>
<td>15.0%</td>
</tr>
<tr>
<td>Mitsubishi</td>
<td>125</td>
<td>mc-Si</td>
<td>12.4%</td>
</tr>
<tr>
<td>Mitsubishi</td>
<td>185</td>
<td>mc-Si</td>
<td>13.4%</td>
</tr>
<tr>
<td>REC</td>
<td>205</td>
<td>mc-Si</td>
<td>12.4%</td>
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<td>210</td>
<td>mc-Si</td>
<td>12.7%</td>
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<tr>
<td>REC</td>
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<td>13.0%</td>
</tr>
<tr>
<td>REC</td>
<td>220</td>
<td>mc-Si</td>
<td>13.3%</td>
</tr>
<tr>
<td>REC</td>
<td>225</td>
<td>mc-Si</td>
<td>13.6%</td>
</tr>
<tr>
<td>REC</td>
<td>230</td>
<td>mc-Si</td>
<td>13.9%</td>
</tr>
<tr>
<td>Ritek</td>
<td>230</td>
<td>mc-Si</td>
<td>13.9%</td>
</tr>
<tr>
<td>Manufacturers</td>
<td>Module capacity</td>
<td>Material</td>
<td>Module efficiency</td>
</tr>
<tr>
<td>---------------</td>
<td>-----------------</td>
<td>----------</td>
<td>-------------------</td>
</tr>
<tr>
<td>Sharp</td>
<td>170</td>
<td>mc-Si</td>
<td>13.1%</td>
</tr>
<tr>
<td>Sharp</td>
<td>224</td>
<td>mc-Si</td>
<td>13.7%</td>
</tr>
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<td>Solon</td>
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<td>mc-Si</td>
<td>13.4%</td>
</tr>
<tr>
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</tr>
<tr>
<td>trinasolar</td>
<td>225</td>
<td>mc-Si</td>
<td>13.7%</td>
</tr>
<tr>
<td>trinasolar</td>
<td>230</td>
<td>mc-Si</td>
<td>14.1%</td>
</tr>
<tr>
<td>trinasolar</td>
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<td>mc-Si</td>
<td>14.4%</td>
</tr>
<tr>
<td>Yingli</td>
<td>230</td>
<td>mc-Si</td>
<td>14.1%</td>
</tr>
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**Average module efficiency** 13.3%

Source: Company Product Factsheets
APPENDIX C

SLA Study on HDB Rooftop Solar Potential using GIS

The Singapore Land Authority (SLA) had conducted a study\textsuperscript{84} to examine the solar potential of rooftops in Singapore using Geographic Information System (GIS). The results of the study were used in this report to determine the theoretical limits to solar installation capacity (MW) on Housing Development Board (HDB) rooftops (see Section 3.3).

HDB blocks were investigated given that they constitute a substantial portion of Singapore’s building stock. Manual digitization of roof features from satellite images was used to derive the maximum possible installed capacity and the expected annual electricity output. We outline the methodology used in the SLA study to arrive at the total available rooftop area for solar PV in Singapore below.

Satellite imagery from SLA could be accessed for this study for a period of 6 weeks between 1st December 2010 and 14th January 2011. Cadastral data with footprints of all buildings in Singapore was also available from SLA. The footprint data consisted of the outline of all buildings in Singapore.

Singapore’s total land area was divided into a grid whose cells measured 250m x 250m. Using the footprint data, those cells that had HDB blocks lying within them were selected (see Figure C1). The proportion of area occupied by the blocks in a cell was then used to calculate the building density in each cell.

\textsuperscript{84} Wong, R. “Using GIS to aid the assessment of the economic viability of solar photovoltaic investments in Singapore,” SLA (2011).
The cells were then segregated by density. Three categories were chosen: yellow (with a building density of 1-6%), orange (with a building density of 7-18%) and red (with a building density of >18%). Jenk’s optimization method was used to determine the categories. Figure C2 plots the distribution of building density on a cell basis and Figure C3 shows the building density by category.

Figure C2

*Distribution of cell building intensity*


Figure C3

*Mapping of building density by category*

Stratified sampling was used to obtain a representative sample – 10% of the cells from each category were chosen randomly (see Figure C4). For each cell, a software (ARCMAP) was used to identify the roof and the obstruction(s) (water tank and lift shaft) on the roof. A 1.5 m buffer was subtracted from the roof area to account for parapets and safety margins. Two cases were considered: where the rooftop obstructions cast no shadow and where the rooftop obstructions cast (the longest) shadow. The first case gives the maximum available rooftop area and the second case gives the minimum available rooftop area (see Figure C5).

Figure C4

*Stratified sampling of cells with HDB blocks*

Figure C5

Arriving at the total rooftop area

APPENDIX D

Illustration of the Value of Delaying Investments in Solar PV Capacity

To illustrate the value of delaying investment, we compare the net present value of investments in solar PV installations under two scenarios (see Figure D1). In the first scenario, investments are made to ramp up solar PV capacity by 800 MW over a 10-year period beginning in 2010 (an addition of 80 MW per year for 10 years). In the second scenario, similar investments are made to increase PV capacity by 800 MW over a 10-year period beginning in 2015. The learning rate is assumed to be 18% and the electricity price is assumed to increase by 3% per annum.

In the first scenario, the NPV is negative at about −S$725.6 million (2010$) while in the second scenario, the NPV is approximately S$134.6 million (2010$). This result is driven by the assumptions that electricity prices are increasing at a high 3% per annum and module costs are falling rapidly with a high learning rate of 18%. For instance, the cost of investing in 800 MW beginning in 2010, which is contingent on module costs, is about S$3,360 million (2010$) whereas deferring the investments to 2015 results in a cost of S$2,034 million (2010$). Thus delaying investments reduces costs by about S$1.3 billion (2010$). As can be seen in this illustrative example, the benefits of delayed investments in a context of falling prices and improving technologies can be substantial indeed.

Figure D1

Comparison of the Net Present Value of Investing in 2010 and 2015