THE UNIVERSITY OF QUEENSLAND
AUSTRALIA

gciQ Global Change Institute

Oct 2016
DISCUSSION
PAPER #4

Levelised Cost of Energy (LCOE) of Three Solar PV Technologies Installed at UQ Gatton Campus

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Version 5 – 13 Oct 2016

Abstract

Economic assessment of the viability of different types of solar PV tracking technologies centres on assessment of whether the annual production of the different tracking technologies is increased enough relative to a benchmark Fixed Tilt system to compensate for the higher cost of installation and operation incurred by the tracking systems. To investigate this issue, we calculated the LCOE of three representative solar PV systems. These calculations depend crucially on assumptions made about ($/kW) construction costs as well as annual capacity factors of the three solar technologies considered. A key finding was that the Single Axis Tracking technology was the most cost competitive, followed by a Fixed Tilt system. A Dual Axis Tracking system was the least cost competitive technology of those considered. We also considered how LCOE could underpin a 'Contract-for-Difference' feed-in tariff scheme.

1. Introduction

The economics of solar PV has changed significantly over the last decade with installation costs declining significantly following the marked take-up of solar PV systems. This has occurred on the back of generous Government feed-in tariff support particularly in Europe. In Australia more recently, a marked increase in the up-take of roof-top solar PV occurred on the back of generous state-based feed-in tariffs and the Federal Government's small-scale renewable energy target (RMI, 2014).

To-date, investment in utility scale solar PV projects has proceeded largely on the basis of support from two particular programs: (1) Australian Capital Territory (ACT) reverse auction for solar PV projects (ACT, 2016); and (2) Government support from the Australian Renewable Energy Agency (ARENA, 2016a) and Clean Energy Finance Corporation (CEFC, 2016). This has occurred against a backdrop of a concerted attack on renewable energy in Australia, particularly since late 2013. Accompanying this attack and the resulting regulatory uncertainty, a general drying up of investment in large-scale renewable energy projects occurred with major retail electricity companies appearing unwilling to under-write the financing of large projects through Power Purchase Agreements (PPA). This has led to the situation whereby the required capacity to meet the 2017 Large-Scale Renewable Energy Target (LRET) now appears to be in excess of 3000 MW's in arrears [Green Energy Markets (2015) and CER (2016)].

A measure commonly used to assess the feasibility of a renewable energy project is the Levelised Cost of Energy (LCOE). This variable is used to ascertain what return on average would be needed over the lifetime of the project to cover costs associated with its construction and operation. As part of these calculations, a required return on invested capital is also incorporated into the analysis. The conventional LCOE is usually expressed as a dollar per megawatt-hour ($/MWh) amount that represents the average price needed over the project's lifetime. Project feasibility has typically been ensured by setting ($/MWh) strike prices in PPA's to the project's LCOE. The other advantage with LCOE is that it is not technology specific and provides a benchmark for assessing the feasibility or cost competitiveness of a wide assortment of different generation technologies.

Two factors typically produce higher LCOE estimates for renewable energy projects involving wind and solar PV when compared with thermal generation technologies. The first is a relatively lower annual capacity factor (ACF) and the second is a significantly higher ($/kW) construction costs. Furthermore, utility scale wind projects will typically have lower LCOE compared with utility scale solar PV projects because wind farms generally have higher ACF's.

The production profile and ACF of a solar PV array will also be influenced by whether sun tracking technologies have been incorporated into the array's design. Wild (2016) demonstrated that the production of a Single Axis Tracking (SAT) array was between 17.7 and 17.9 per cent above the output of a Fixed Tilt (FT) array. Moreover, the output of a

Dual Axis Tracking (DAT) array was between 36.5 and 36.7 per cent higher than the output from the FT array. Therefore, for similarly sized arrays, the ACF's of DAT and SAT arrays will be significantly above that of an FT array.

However, in assessing economic feasibility, account also needs to be taken of the capital and operational costs of the different solar array technologies. These costs are typically higher for DAT and SAT arrays than for FT arrays. Therefore, in this paper, we will conduct a comparative assessment of the LCOE of three representative 630 kW FT, SAT and DAT arrays, calculated from simulated solar PV yields over the years 2007–2015, for representative arrays installed at The University of Queensland (UQ) Gatton Campus.

The structure of this paper is as follows. The next section will give a brief description of the solar array at UQ Gatton Campus that underpins the modelling performed for this paper. This modelling draws heavily on the work on solar PV yields reported in Wild (2016). Section (3) contains a description of the model and assumptions that are used to calculate LCOE estimates. Section (4) provides a brief discussion of the ACF values used in the LCOE modelling. Section (5) documents the main findings. Section (6) discusses the link between LCOE and the determination of feed-in tariff support for renewable energy projects, including the 'Contract for Difference' (CfD) approach to feed-in tariff support. Finally, Section (7) contains conclusions.

2. The University of Queensland Solar Research Facility (GSRF)

The GSRF was part of a large ARENA funded project involving investment by Australian Gas and Light Pty Ltd (AGL) in the Nyngan and Broken Hill Solar farms (AGL, 2015). As part of the successful AGL bid, the GSRF received a grant of $40.7 million from the Education Investment Fund (EIF) program in the Commonwealth Department of Education (UQ, 2015a). The objective of the EIF Project was to act as a pilot for the utility-scale plants – proofing technology and establishing supply chains.

The solar array installed at Gatton is a 3.275 megawatt pilot plant that comprises three different solar array technologies: (1) a FT array comprising three identical 630 kW systems

(UQ, 2015b); (2) a 630 kW Horizontal SAT Array utilising First Solar's SAT system (UQ, 2015c); and (3) a 630 kW DAT utilising the Degertraker 5000 HD system (UQ, 2015d).

An overhead picture of the Gatton array is contained in Figure 1. The three FT arrays can be located at the top right hand side (termed the 'top' FT array) and with the main FT array being located just below the buildings and line of trees but above the road in Figure 1. The SAT array can be located in Figure 1 immediately below the top FT array, adjacent to the main FT array and above the road. The DAT array is located underneath the main FT array and below the road.

Figure 1. Overhead Picture of the UQ Gatton Solar Array

The representative SAT and DAT arrays used in the modelling correspond to the SAT and DAT arrays identified in Figure 1.The representative FT array used in the modelling is the left most FT array observed in Figure 1.

3. LCOE Model.

Economic assessment of the viability of different types of solar PV tracking technologies typically centres on assessment of whether the annual production of the different tracking technologies is lifted enough relative to the benchmark FT system to compensate for the higher cost of installation and operational expenditures incurred by tracking systems. The installation costs refer to the 'overnight' ($/Wp) or equivalently ($/kW) installation costs that would be incurred if the whole solar PV plant could be constructed overnight. This expenditure category would include costs associated with purchase of modules and inverters as well as various categories of balance of plant costs.

The second cost component is operational costs, in particular, Operational and Maintenance (O&M) expenditures associated with keeping modules and inverters operating efficiently. For tracking systems, additional O&M costs would have to be incurred against the need to also keep the tracking infrastructure working efficiently. In general, O&M expenses are likely to be directly proportional to the complexity of the tracking system employed. As such, O&M provisions associated with more complex two axis trackers such as the DAT system are likely to be of a higher magnitude because the tracking infrastructure is more complex, of larger scale, and more prone to mechanical faults or break-downs.

(3.1) Assumptions

To derive LCOE estimates, a number of key cost and technical assumptions need to be made for each of the three representative GSRF solar array technologies. These assumptions are illustrated in Table 1, Panels (A)-(C):

Table 1. Generation Technology Cost Assumptions

Panel (A): Capital cost, unit size, useful life, and auxillary load assumptions

Generation Technology	Capital Cost ($/kW)	Unit Size (MW)	Useful Life (Years)	Auxillary Load (%)
Fixed Tilt	2,151	0.63	25	0.5
Single Axis Tracker	2,204	0.63	25	0.5
Dual Axis Tracker	3,089	0.63	25	0.5

Cost of capital: *11.0%* *Annual Inflation:* *2.5%*

Panel (B): O&M Rates ($/kW/Year)

Generation Technology	Fixed O&M ($/kW/Year) WP	Fixed O&M ($/kW/Year) PC	Fixed O&M ($/kW/Year) PC_low

Fixed Tilt	25.00	20.00	17.00
Single Axis Tracker	30.00	26.00	25.00
Dual Axis Tracker	39.00	33.00	32.00

Panel (C): O&M Cost ($m pa)

Generation Technology	Fixed O&M ($m pa) WP	Fixed O&M ($m pa) PC	Fixed O&M ($m pa) PC_low
Fixed Tilt	0.0158	0.0126	0.0107
Single Axis Tracker	0.0189	0.0164	0.0158
Dual Axis Tracker	0.0246	0.0208	0.0202

The parameters listed in Table 1, Panels (A)-(C) provide cost estimates of key components of the three representative solar PV technologies. The ($/kW) Overnight Capital Cost (OCC) estimates listed in column 2 of Panel (A) were determined from data cited in Table 3.5.2 of BREE (2012). Specifically, the following OCC estimates for the three solar PV technologies were listed in that table as:

- FT: $3380/kW;
- SAT: $3860/kW; and
- DAT: $5410/kW.

These (BREE, 2012) estimates were then rebased to an average of the updated FT and SAT ($/kW) results linked to published information from ARENA about the capital costs and MW capacity of successful projects listed in the most recent large-scale competitive Solar PV round (ARENA, 2016c). This was combined with private information sought from project proponents about the solar PV array technology intended to be used. The DAT estimate was determined by applying the original BREE cost shares between the SAT and DAT technologies listed above and pro-rating to the current SAT ($/kW) cost estimate. This led to the following ($/kW) estimates:

- FT: $2151/kW;
- SAT: $2204/kW; and

- DAT: $3089/kW = (5410/3860)*2204,

which are listed in column 2 of Panel (A), of Table 1.

The unit sizes of each representative solar PV technology corresponds to a capacity limit of 630 kW determined by the capacity limits currently applied to each inverter at GSRF. We also assume auxiliary load factors of half a percent for each solar PV array, representing the amount of electricity consumed internally during the production of electricity. Finally, in Panel (A), we also assume a useful life for each technology of 25 years.

To gauge sensitivity of LCOE to variations in O&M expenditure, three particular O&M estimates are used. These estimates are compiled from data cited in Table 11 of BREE (2013). Note that we have adopted the same methodology as adopted in BREE (2012, 2013) and assumed that all O&M expenditures applicable to solar PV arrays are classified as Fixed O&M (FOM) expenditure. Unlike the case with thermal based generation, there are no fuel costs or Variable O&M (VOM) expenses.

Panel (B) of Table 1 contains the ($/kW/year) FOM estimates used in the LCOE modelling. The first set, denoted by the 'WP' column header, denotes the Worley Parsons 2013 updated values reported in Table 11 of BREE (2013). The second set of FOM cost estimates represent the average of the private O&M service provider estimates cited in Table 11 of BREE (2013). These estimates are denoted by the 'PC' column header. The third set of estimates correspond to the lower range values of the private O&M service provider cost estimates reported in Table 11 of BREE (2013). These estimates are denoted by the 'PC_low' column header.

In Panel (B) of Table 1, the FT array has the lowest FOM cost estimates, in the range $17/kW/Year to $25/kw/Year. The SAT array has the next lowest FOM estimates, in the range $25/kW/Year to $30/kW/Year. The DAT array has the highest FOM estimates of between $32/kW/Year and $39/kW/Year. The other feature is that the WP estimates are consistently the highest FOM estimates whilst the private O&M service provider estimates are lower. The WP estimates were derived from a broad based assessment of the literature, including overseas studies, while the private O&M service provider estimates were sourced directly from private sector contractors.

The values reported in Panel (C) of Table 1 were derived by multiplying each ($/kW/year) estimate in Panel (B) of Table 1 by 630, representing the 630 kW energy sent-out capacity limit to give the annual dollar FOM cost and then dividing this by one million to convert to the equivalent ($m pa) estimate listed in Panel (C) of Table 1.

The cost of capital on a weighted basis is assumed to be 11.0% (nominal, pre-tax) and long run inflation is assumed to be 2.5%. The basis upon which inflation is applied to all subsequent modelling is at full CPI against (non-finance) operating cost streams, and only ¾CPI against revenue streams. This reflects real-world trends in power generation, and the CPI disconnect follows because financing costs tend to be fixed up-front and form the dominant cost of power applications. The time profile of the 'inflation stream' escalation rates are calculated as

$$\inf l(t)_R = \left\{\left[1+\left(\frac{2.5}{100}\right)\right]*\alpha_R\right\}^t, \tag{1}$$

and

$$\inf l(t)_C = \left\{\left[1+\left(\frac{2.5}{100}\right)\right]*\alpha_C\right\}^t, \tag{2}$$

where subscripts 'R' and 'C' denote revenue and cost streams and we assume that $\alpha_R = 0.75$ and $\alpha_C = 1.0$. Variable 't' represents a discrete time index starting in the first period of the projection horizon and containing 'N' time periods $(i.e.\ t = 1,\ldots,N)$. Parameter 'N' corresponds to the useful life assumptions reported in Panel (A) of Table 1.

(3.2) Calculating LCOE

We now outline the calculation of the 'levelised cost' of each representative solar PV technology. In broad terms, this involves calculating the present value of the time profile of annualised plant costs less revenue streams from the sale of large-scale renewable energy certificates (LGC) and sale of merchant electricity, deflated by the nominal time profile of energy production of the solar array over its lifespan. Note that the LGC and sale of merchant electricity revenue streams are treated as negative cost entries in the LCOE calculation.

Energy generated gives a measure of the output of each representative solar PV array and can be represented as

$$ES(t)_j = US_j * ACF_j * 8.76 * ESF(t)_j \tag{3}$$

where $ES(t)_j$ denotes energy generated by representative array 'j'. US_j is the constant unit size for each representative array described in Panel (A) of Table 1. ACF_j is the constant annual capacity factor assumed for each representative solar array and 8.76 is the number of hours in a year divided by 1000. Finally $ESF(t)_j$ is an energy scale factor for each representative array that captures the loss in output over time. This output deflation factor is assumed to be an annual deflation rate equal to $(0.8)^{\frac{1}{n}} = 0.9911$. Variable $'n'$ is the number of years of useful life reported in Panel (A) of Table 1 and 0.8 represents the guarantee of First Solar that 80% of the nameplate capacity of the modules installed at GSRF will be available after 25 years of operation.

The nominal production of each solar array over its lifetime is calculated by escalating the energy generated of each array by the assumed revenue 'inflation escalation rate'. This is given by

$$RS(t)_j = ES(t)_j * \inf l(t)_R, \tag{4}$$

where $RS(t)_j$ is the production stream of each representative solar PV array 'j'. $ES(t)_j$ is the energy generated by each solar array calculated in (3), and $\inf l(t)_R$ is the 'inflation escalation rate' applied to generator revenue outlined in (1).

In defining annualized plant costs, aggregate fixed operating costs can be split into operations, maintenance and depreciation cost components. The FOM cost component can be calculated as

$$FARC(t)_j = FIXC_j * 1000 * \inf l(t)_C, \tag{5}$$

where $FARC(t)_j$ is the FOM cost of array 'j'. $FIXC_j$ is the constant FOM \$m pa cost for each representative solar array listed in Panel (C) of Table 1 and $\inf l(t)_C$ is the 'inflation escalation rate' applied to generator costs defined in (2).

The other fixed cost component is the maintenance capital expenditure allowance allocated by solar array 'j'. This expense item is given by

$$MCAP(t)_j = MCAPEX_j * CAPEX_j * \inf l(t)_C , \quad (6)$$

where $MCAP(t)_j$ is the nominal depreciation allowance for each solar PV array 'j', $MCAPEX_j$ is the constant capital maintenance rate for each array type and $CAPEX_j$ is the nominal amount of 'upfront' capital expenditure associated with building each solar PV array.[1] Variable $MCAPEX_j$ can be interpreted as giving the annual amount of capital expenditure (as a percentage of upfront capital expenditure $CAPEX_j$) required for ongoing capital maintenance to ensure that existing units continue to operate in working order. In this paper, we have set $MCAPEX_j = 0.10\%$ for each solar PV array type.

Total operating costs by array type $(TGC(t)_j)$ equals FOM costs $FARC(t)_j$ and maintenance capital expenditure $MCAP(t)_j$, producing

$$TGC(t)_j = FARC(t)_j + MCAP(t)_j . \quad (7)$$

It should be noted that $TGC(t)_j$ does not incorporate returns on the capital stock employed at the marginal efficiency of capital, which has been defined in Table 1 as 11.0% (weighted average).[2]

Recall that revenue streams are treated as negative cost entries and subtracted from total operating costs. These revenue streams relate to revenue earnt from the sale of renewable energy (LGC) certificates and from the merchant sale of electricity. These two revenue items are clearly linked to the amount of electricity generated $ES(t)_j$ as calculated in (3). For LGC revenue, the crucial component is the ($/MWh) strike price received for each MWh of eligible renewable energy produced by the representative solar PV arrays which is assumed to be the same for each solar PV technology considered. Revenue earnt from the merchant sale of electricity depends crucially on the ($/MWh) electricity tariff rate received

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[1] The capital stock employed, denoted $CAPEX_j$, can be calculated by multiplying the unit capital cost ($/kW) by the unit size which are both listed in Panel (A) of Table 1.

[2] The 11.0% pre-tax marginal efficiency of capital is applied to ungeared cash flows, with the implication being that the solar PV project would be financed with 70% debt and 30% equity. The equivalent post-tax weighted average cost of capital is approximately 8.3%.

for this electricity. We assume that this rate is also the same across the three solar PV technologies.

When we include both LGC and merchant sale of electricity revenue streams in the LCOE calculation, the resulting LCOE estimate gives the required ($/MWh) return needed for project viability after meeting the projects long run operational and capital costs, required return to equity and netting off returns from the sale of eligible renewable energy certificates and merchant electricity. However, if we set the ($/MWh) strike prices for the LGC certificates and merchant sale of electricity to zero, we ignore these two revenue based cost-offset components, thus obtaining the more conventional LCOE estimate.

These two revenue streams can be formally calculated as

$$TGR(t)_{LGC,j} = SP_{LGC} * ES(t)_j * \inf l(t)_R, \tag{8}$$

and

$$TGR(t)_{MES,j} = SP_{MES} * ES(t)_j * \inf l(t)_R. \tag{9}$$

$TGR(t)_{LGC,j}$ and $TGR(t)_{MES,j}$ denote revenue from the sale of eligible LGC certificates and merchant sale of electricity by solar PV array 'j'. Variables SP_{LGC} and SP_{MES} represent the ($/MWh) strike prices received for the sale of renewable energy (LGC) certificates and merchant electricity sales by each solar array 'j'. $ES(t)_j$ is the energy generated as defined in (3) and $\inf l(t)_R$ is the 'inflation escalation rate' applied to revenue streams outlined in (1). Total revenue $\left(TGR(t)_j\right)$ for solar array 'j' is given by

$$TGR(t)_j = TGR(t)_{LGC,j} + TGR(t)_{MES,j}. \tag{10}$$

The measure of real unit cost (including capital costs) is given by calculating the Present Value (PV) of the total net cost stream $TCPV_j$ and deflating this by the present value of the output stream $TRPV_j$ of array 'j'. This is then adjusted by the amount of power that is expected to be consumed internally, referred to as 'auxilliary load' and given by the expense weighting factor in the last column of Panel (A) of Table 1 to covert to an energy sent-out basis.[3] This gives

$$TCPV_j = PV\left(TGC(t)_j - TGR(t)_j\right) + CAPEX_j, \tag{11}$$

$$TRPV_j = PV(RS(t)_j)\,. \tag{12}$$

LCOE (or equivalently long run marginal cost) is calculated as

$$LRMC_j = TCPV_j \,/\, TRPV_j \,/ \left(1 - AUX_j\right). \tag{13}$$

The cost of debt and equity emerge from the PV calculation in (11) via the process of discounting the cash flows at a discount rate of 11.0% which represents the nominal weighted average cost of debt and equity capital. Furthermore, the discount rate can also be interpreted as a pre-tax marginal efficiency of capital so we do not have to explicitly account for any implied tax liability which is, instead, implied in the discounting process underpinning the PV calculation in (11). Therefore, the pre-tax cost of capital can be determined as the difference between the LRMC and the sum of operational costs which reflect aggregate O&M expenses.

(3.3) Calculation of Annual Capacity Factors

In Wild (2016), the PVSyst software (Mermoud and Wittmer, 2014, PVsyst, 2016) was used to simulate electricity production of the three representative solar PV systems at GSRF over 2007 to 2015. To run simulations in PVSyst, user supplied inputs relating to: (1) hourly solar and weather data; (2) technical information about modules, inverters, array sizing and design; (3) soiling effects; (4) near-object and mutual shading effects; and (5) DC and AC electrical losses are required. In the modelling conducted in Wild (2016), it was also assumed that all modules, inverters and tracking infrastructure were in working order.

Once annual production outcomes were determined for the three representative arrays at GSRF from the PVSyst simulations, the ACF's for each representative solar PV array was calculated as

[3] We assume that each representative solar array consumes 0.5% of its nameplate capacity. In equation (13) the 'weighting' given to power sent out is represented by the last '(1-AUXj)' term which equates to 99.5 percent of total power produced in the case of an auxiliary load factor of 0.5 per cent, being available to service demand.

$$ACF = \left[\frac{Annual\_\Pr od}{(8760 \times System\_Capacity)} \right], \tag{14}$$

where ‘8760’ represents the number of hours in a year assuming a 365 day year.[4] Furthermore, in the denominator of (14), the kW system capacity concept used was the sent-out capacity linked to the kW maximum capacity of each of the inverters connected to the three representative solar PV arrays at GSRF. The average of the ACF outcomes cited in Wild (2016) for years 2007-2015 and for three module soiling scenarios considered in Wild (2016), relating to the ‘low’, ‘medium’ and ‘high’, are reported in Table 2. These ACF results will be used in the LCOE modelling. Thus, this analysis will produce sets of LCOE results according to module soiling scenarios and the ‘WP’ ‘PC’ and PC_low’ FOM cost scenarios indicated in Panels (B) and (C) of Table 1. These results will permit investigation of the sensitivity of LCOE estimates to differences in module soiling and FOM costs.

Table2. Average Energy Sent-out ACF’s by Representative Array Type and Soiling Scenario

Soiling	FT	SAT	DAT
Low	20.5	24.2	28.0
Medium	20.2	23.8	27.6
High	19.7	23.3	27.0

Table 2 points to two key conclusions: (1) average ACF outcomes decline as the level of module soiling increases; and (2) average ACF outcomes increase with the degree of sun tracking. Specifically, the DAT array secures the highest average ACF values in the range of 27.0 to 28.0 per cent. This is followed by the SAT array with results between 23.3 to 24.2 per cent. Finally, the FT array has the lowest average ACF results, in the range of 19.7 to 20.5 per cent.

[4] Note that for the leap years 2008 and 2012, the additional day corresponding to 29 February implied a 366 day year and 8784 hours in a year that was used in (14) instead of ‘8760’ for these two particular years.

4. LCOE Results

(5.1) Conventional LCOE results

Conventional LCOE results are reported in Table 3. Recall that these LCOE estimates are calculated ignoring the cost-offsets associated with renewable energy certificate and merchant electricity sale revenue streams.

In Table 3, the LCOE estimates increase in magnitude as the rate of module soiling increases which produces reductions in the ACF estimates as indicated in row 6 of Table 3, thereby increasing the LCOE estimates. The lowest LCOE estimates are recorded for the low soiling scenario. These estimates are in the range $142.70/MWh to $147.76/MWh for the representative FT array, $128.25/MWh to $130.93/MWh for the representative SAT array and $153.53/MWh to $156.77/MWh for the representative DAT array. In contrast, the highest LCOE estimates are associated with the high soiling scenario, in the range $148.57/MWh to $153.83/MWh for the FT array, $133.26/MWh to $136.05/MWh for the SAT array and $159.62/MWh to $162.99/MWh for the DAT array. These outcomes, more generally, point to average percentage increases in LCOE estimates associated with medium soiling relative to low soiling of 1.5, 1.4 and 1.4 per cent for the representative FT, SAT and DAT arrays, respectively. Similarly, the average percentage increase in LCOE with high module soiling relative to the low soiling is 4.1, 3.9 and 4.0 per cent, respectively.

Table 3 also indicates that the SAT array is the most competitive technology with lowest LCOE in the range $128.25/MWh to $136.05/MWh across module soiling scenarios. The next most competitive technology is the FT array with LCOE estimates in the range $142.70/MWh to $153.83/MWh. This represents an increase in relative terms in LCOE of between 11.3 and 13.1 per cent relative to the lower SAT estimates. Finally, the least competitive technology is the DAT array, with LCOE estimates in the range $153.53/MWh to $162.99/MWh. These latter LCOE estimates represents, in relative term, increases of between 19.7 and 19.8 per cent over the lower cost estimates of the SAT array, again taken across the module soiling scenarios.

The potential role that different FOM costs might play can be discerned from the observed decline in LCOE estimates with lower FOM costs. This can be seen by comparing the higher LCOE estimates associated with the higher cost 'WP' FOM scenario with the lower LCOE estimates associated with the lower cost 'PC' and 'PC_low' scenarios, respectively. In average terms and across the different soiling scenarios, the *reduction* in LCOE for the 'PC' scenario relative to the higher cost 'WP' scenario are approximately 2.1, 1.6 and 1.8 per cent for the representative FT, SAT and DAT arrays. Similarly, the average *reduction* in LCOE for the lowest cost 'PC_low' scenario relative to the highest 'WP' cost scenario is approximately 3.4, 2.1 and 2.1 per cent, respectively. Thus, the biggest reduction in LCOE flows to the representative FT array when compared with the other two solar PV technologies considered.

Table 3 Conventional ($/MWh) LCOE Estimates

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	147.76	130.93	156.77	149.95	132.80	159.04	153.83	136.05	162.99
PC	144.60	128.78	153.99	146.74	130.62	156.22	150.54	133.82	160.10
PC_low	142.70	128.25	153.53	144.82	130.07	155.75	148.57	133.26	159.62
ACF(%)	20.5	24.2	28.0	20.2	23.8	27.6	19.7	23.3	27.0

(5.2) LCOE with revenue from renewable energy certificates included

In this sub-section we investigate impacts on LCOE after including revenue from the sale of eligible large-scale renewable energy (e.g. LGC) certificates. Every MWh of electricity produced by the GSRF is eligible under the Large-Scale Renewable Energy Target (LRET) scheme and revenue is calculated by multiplying this output by the assumed LGC ($/MWh) strike price.

In this paper we assume LRET non-compliance given the significant capacity deficit now existing in relation to the capacity required to meet the LRET target in forward years [Green Energy Markets (2015, 2016)]. In this situation, two LGC prices are relevant. The first is a LGC strike price of $65.00/MWh which corresponds to the nominal shortfall LGC penalty price payable by eligible but non-compliant entities which do not have a tax liability. The second is a LGC strike price of $92.86/MWh which equates to the tax-effective level of the shortfall LGC penalty price payable by non-compliant entities having a tax liability [Green Energy Markets (2016)].

LCOE associated with LGC revenue streams for these two particular LGC strike prices are reported in Panels (A)-(B) of Table 4. For the higher LGC price of $92.86/MWh, Panel (A) of Table 4 shows LCOE estimates in the range $48.91/MWh to $60.03/MWh for representative FT array, $34.45/MWh to $42.26/MWh for the representative SAT array, and $59.73/MWh to $69.19/MWh for the representative DAT array. In the case of the lower LGC price of $65.00/MWh, the LCOE results reported in Panel (B) shows a slightly higher range of $77.05/MWh to $88.18/MWh for the FT array, $62.59/MWh to $70.40/MWh for the SAT array, and $87.87/MWh to $97.33/MWh for the DAT array. Observe that both of these sets of results are significantly lower than the equivalent ranges of $142.70/MWh to $153.83/MWh, $128.25/MWh to $136.05/MWh and $153.53/MWh to $162.99/MWh recorded in Table 3 for the conventional LCOE results.

Table 4 Required ($/MWh) Return for Lower and Upper Range LGC Strike Prices

Panel (A): LGC strike price of ($92.86/MWh)

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	53.97	37.13	62.97	56.16	39.00	65.24	60.03	42.26	69.19
PC	50.80	34.99	60.20	52.95	36.82	62.42	56.74	40.02	66.30
PC_low	48.91	34.45	59.73	51.02	36.28	61.95	54.77	39.47	65.82

Panel (B): LGC strike price of ($65.00/MWh)

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	82.11	65.27	91.11	84.30	67.14	93.38	88.18	70.40	97.33
PC	78.95	63.13	88.34	81.09	64.96	90.56	84.88	68.17	94.45
PC_low	77.05	62.59	87.87	79.16	64.42	90.10	82.91	67.61	93.96

Comparison of results in Table 3 with those in Panel (A) of Table 4 indicates that the latter LCOE outcomes represent *reductions* relative to the Table 3 results of between 61.0 to 65.7 per cent for the FT array, 68.9 to 73.1 per cent for the SAT array and between 57.5 and 61.1 per cent for the DAT array. For the results reported in Panel (B) of Table 4, the equivalent reduction rates are between 42.7 and 46.0 per cent, 48.3 and 51.2 per cent and 40.3 and 42.8 per cent.

These results indicate that accounting for revenue from LGC certificates serves to reduce LCOE (or required return) needed to cover capital and operational costs while earning an economic return on invested capital, thereby making the project feasible. Furthermore, the extent of the reduction in LCOE is also directly related to the magnitude of the LGC price – higher LGC prices reduce LCOE to a larger extent than do lower LGC prices.

More generally, other conclusions made in the previous sub-section continue to hold. Specifically, the SAT array continues to remain the most competitive technology, followed by the FT array and then the DAT array. LCOE also increases with the level of module soiling reflecting the deterioration in the ACF associated with increased soiling. Moreover, LCOE continues to decline as FOM costs decline, as seen with the lower LCOE results associated with the 'PC_low' and 'PC' FOM cost scenarios relative to the higher LCOE results associated with the highest 'WP' FOM cost scenario.

(5.3) LCOE estimates with revenue from renewable energy certificates and merchant electricity sales included

In this sub-section we investigate impacts on LCOE after including another revenue stream relating to the merchant sale of electricity to the wholesale electricity market, in addition to revenue earnt from the sale of renewable energy certificates. Merchant sale of electricity revenue is calculated by multiplying the MWh output of the GSRF by the Queensland (QLD) ($/MWh) average wholesale price, corrected for marginal loss and distribution loss factors to account for the location of GSRF within the electricity network.

The wholesale price concepts utilised in the modelling relate to annual volume weighted average wholesale electricity prices calculated for QLD over 2007–2015. The volume weighted prices for 2007–2015 were compiled from half-hourly demand and price data contained in AEMO (2016) for the Queensland 'QLD1' regional wholesale market. Three particular volume weighted average prices are used in the modelling. The first is an average wholesale price of $28.00/MWh which is the lowest QLD volume weighted average wholesale price calculated for the period 2007-2015. The second is an average wholesale price of $72.57/MWh which is the highest QLD volume weighted average wholesale price calculated over 2007-2015. The third is $57.83/MWh which is the 2015 QLD volume weighted average wholesale electricity price.

It should be noted that the three above volume weighted average prices cited are the values obtained after adjusting the calculated volume weighted average prices for transmission and distribution loss factors.[5] Adjustments to the calculated volume weighted average wholesale prices for transmission and distribution losses was made using a marginal loss factor of 0.9723 and distribution loss factor of 1.0262. These values were determined as averages of the published values for these loss factors over the time period 2011/12 to 2015/16. Multiplying these two factors together produces a value of 0.9979 that was multiplied by each respective volume weighted average price calculated from the source AEMO data. This produced a slight downward revision in the average wholesale price used in the analysis and reported above.

The LCOE results associated with LGC revenue streams for the two LGC prices considered in the previous sub-section and for the lowest average wholesale spot price of $28.00/MWh are reported in Table 5, Panels (A)-(B). For the case of the higher LGC price of $92.86/MWh listed in Panel (A) of Table 5, LCOE results are in the range $20.77/MWh to $31.90/MWh for the representative FT array, $6.31/MWh to $14.12/MWh for the representative SAT array, and between $31.60/MWh and $41.06/MWh for the representative DAT array. In the case of the lower LGC price of $65.00/MWh, the LCOE results reported in Panel (B) of Table 5 indicate values in the higher range of $48.91/MWh to $60.04/MWh for the FT array, $34.45/MWh to $42.26/MWh for the SAT array, and $59.74/MWh to $69.20/MWh for the DAT array. These sets of results can again be compared with the much higher conventional LCOE results cited in Table 3 which were in the range of $142.70/MWh to $153.83/MWh, $128.25/MWh to $136.05/MWh and $153.53/MWh to $162.99/MWh, respectively.

[5] The three volume weighted average prices calculated from the source AEMO data were $28.06/MWh, $72.72/MWh and $57.95/MWh.

Table 5 Required ($/MWh) Feed-in Tariff: Lowest average wholesale price ($28.00/MWh)

Panel (A): LGC strike price of ($92.86/MWh)

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	25.83	9.00	34.84	28.02	10.87	37.10	31.90	14.12	41.06
PC	22.67	6.85	32.06	24.81	8.69	34.29	28.61	11.89	38.17
PC_low	20.77	6.31	31.60	22.89	8.14	33.82	26.63	11.33	37.69

Panel (B): LGC strike price of ($65.00/MWh)

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	53.97	37.14	62.98	56.16	39.01	65.25	60.04	42.26	69.20
PC	50.81	34.99	60.20	52.95	36.83	62.43	56.75	40.03	66.31
PC_low	48.91	34.45	59.74	51.03	36.28	61.96	54.77	39.47	65.83

Comparison of results in Table 3 with those in Panel (A) of Table 5 indicates that the latter LCOE results represent *reductions* relative to the Table 3 of between 79.3 to 85.4 per cent for the FT array, between 89.6 and 95.1 per cent for the SAT array and between 74.8 and 79.4 per cent for the DAT array. In the case of the results in Panel (B) of Table 5, the equivalent rates of reductions are between 61.0 and 65.7 per cent, 68.9 and 73.1 per cent and 57.5 and 61.1 per cent, respectively.

The LCOE results associated with LGC revenue streams of the two LGC strike prices and the highest average wholesale spot price of $72.57/MWh are reported in Panels (A)-(B) of Table 6. For the higher LGC strike price of $92.86/MWh, the LCOE results in Panel (A) of Table 6 indicate LCOE in the range of $(-24.02)/MWh to $(-12.90)/MWh for the FT array, $(-38.48)/MWh to $(-30.67)/MWh for the SAT array, and $(-13.20)/MWh to $(-3.74)/MWh for the DAT array. Furthermore, in the case of the results associated with the lower $65.00/MWh LGC price listed in Panel (B) of Table 6, the LCOE outcomes fall in the slightly higher range of $4.12/MWh to $15.24/MWh, $(-10.34)/MWh to $(-2.53)/MWh, and $14.94/MWh to $24.40/MWh, respectively. Note again that these results are much lower than the equivalent results associated with the conventional LCOE results reported in Table 3.

It should be recognised that the negative LCOE outcomes reported in Panels (A) and (B) of Table 6 (e.g. in parentheses in red font) indicates that at the specific LGC and average wholesale electricity price levels, the revenue earnt is ***more than*** sufficient, on average, to cover the capital and operational costs of the project over its lifespan while earning an economic return on invested capital, thus ensuring project viability. This outcome would also point to supernormal economic profits being made by the project.

Table 6 Required ($/MWh) Feed-in Tariff: Highest average wholesale price ($72.57/MWh)

Panel (A): LGC strike price of ($92.86/MWh)

	Low soiling			Medium soiling			High soiling		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	(-18.97)	(-35.80)	(-9.96)	(-16.77)	(-33.93)	(-7.69)	(-12.90)	(-30.67)	(-3.74)
PC	(-22.13)	(-37.95)	(-12.74)	(-19.98)	(-36.11)	(-10.51)	(-16.19)	(-32.91)	(-6.63)
PC_low	(-24.02)	(-38.48)	(-13.20)	(-21.91)	(-36.65)	(-10.98)	(-18.16)	(-33.46)	(-7.11)

Panel (B): LGC strike price of ($65.00/MWh)

	Low soiling			Medium soiling			High soiling		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	9.17	(-7.66)	18.18	11.37	(-5.79)	20.45	15.24	(-2.53)	24.40
PC	6.01	(-9.80)	15.40	8.16	(-7.97)	17.63	11.95	(-4.77)	21.51
PC_low	4.12	(-10.34)	14.94	6.23	(-8.51)	17.16	9.98	(-5.32)	21.03

Comparison of results in Table 3 with those in Panel (A) of Table 6 indicates that the latter LCOE outcomes represent *reductions* relative to the results in Table 3 of between 108.4 and 116.8 per cent for the FT array, 122.5 and 130.0 per cent for the SAT array and between 102.3 and 108.6 per cent for the DAT array. The fact that the percentage change values exceed 100 per cent reflects the fact that all the LCOE estimates in Panel (A) of Table 6 are negative. Moreover for the results in Panel (B) of Table 6, the equivalent reduction rates fall between 90.1 and 97.1 per cent, 101.9 and 108.1 per cent and 85.0 and 90.3 per cent, respectively. Once again, percentage change values exceeding 100 per cent for the SAT array follows because all corresponding LCOE estimates in Panel (B) of Table 6 for this array are negative.

These results show that incorporating revenue from the merchant sale of electricity also serves to reduce the LCOE or required return needed to make the project feasible. Moreover, the extent of the reduction in the required return is, once again, directly related to the magnitude of the average wholesale electricity price level. Higher average wholesale electricity prices reduce LCOE to a much greater extent than do lower average wholesale electricity prices. Furthermore, we also saw that if LGC and average wholesale electricity prices are high enough, we can obtain negative LCOE values. This means that the revenue earnt is more than sufficient to cover the capital and operational costs of the project over its lifespan, thereby ensuring project viability and supernormal economic profit in that particulat circumstance.

5. Policy Implications: Linking LCOE to Required Feed-in Tariff Support Rates

(6.1) Constructing 'Contract for Difference' (CfD) feed-in tariff support based upon LCOE

The LCOE results in the last two sub-sections can be used to illustrate how the required level of feed-in tariff support can be determined from LCOE calculations after accounting for revenue streams associated with the sale of renewable energy certificates and merchant sale of electricity. Recall that the level of feed-in tariff support required to ensure project feasibility is the level necessary to cover capital costs, operational costs and achieve a required return on invested capital over the lifespan of the project after accounting for renewable energy and sale of merchant electricity revenue streams. These latter revenue streams are treated as cost-offsets in the LCOE calculation. The required tariff level, therefore, will correspond to the LCOE estimates reported in Tables 5 and 6 for the range of different LGC and average wholesale electricity strike prices considered in that analysis.

We also saw in the previous section that the LCOE estimates (e.g. required feed-in tariff levels) can fluctuate significantly with changes in both the LGC and average wholesale electricity strike prices. Specifically, increases in both LGC and average wholesale electricity price would *lower* the LCOE (and required level of feed-in tariff support) necessary to ensure project feasibility. In contrast, reductions in LGC or average wholesale electricity price would *increase* the required level of feed-in tariff support (LCOE) needed to ensure project feasibility.

It is emphasised that the LCOE results cited in Tables 5 and 6 are significantly lower than the LCOE results associated with the conventional definition of LCOE reported in Table 3 which underpin feed-in tariff support based upon a conventional fixed price feed-in tariff scheme [Cory *et al.* (2009) and Couture *et al.* (2010)]. The reason for this is that cost-offsets associated with revenue streams from the sale of renewable energy certificates and merchant electricity is ignored when calculating the LCOE estimates cited in Table 3 and in implementation of fixed price feed-in tariff schemes.

These considerations raise a number of important policy implications. First, the magnitude of feed-in tariff levels and resulting size of Government expenditure on the tariff scheme associated with the results in Tables 5 and 6 will be significantly lower than Government feed-in tariff support geared towards the implied support levels associated with conventional LCOE outcomes in Table 3. Note that Government expenditure, in this context, refers to the implied cost of the feed-in tariff scheme linked to Government payments to owners of successful renewable energy projects under the scheme. In principle, this could be financed from consolidated revenue or as a special levy applied to industrial, commercial and residential electricity customers.

Second, feed-in tariff support levels can be tailored to reflect changes in market conditions, particularly in relation to changes in LGC and average wholesale electricity market prices over time. Heuristically, the feed-in tariff scheme would be similar to the Spot Market Gap Sliding Premium-Price FIT model [Cory *et al.* (2009, pp. 5-6) and Couture *et al.* (2010, Section 4.3.2.3)]. If both LGC and average wholesale electricity prices increase over time, the required feed-in tariff support level and implied expenditure outlay by Government would decline. On the other hand, if these two prices decline over time, then the required feed-in tariff support and implied spending by Government would increase. However, to the extent that LGC and average wholesale prices move in different directions, then the impact on the required feed-in tariff support and implied Government outlay would be ambiguous and would need to be explicitly determined.

Third, the potential role of learning and economies of scale and scope in PV component manufacturing and logistics over time would be expected to reduce both capital (installation) costs and operational costs. These trends would exert downward pressure on the LCOE over time, reducing the required level of feed-in tariff support needed until grid parity is achieved and no additional Government support would be required. This trend has been termed 'predetermined tariff degression' in the literature, for example, see Couture *et al.* (2010, pp. 36-42).

Fourth, the LCOE of a project still plays a key role in determining the required feed-in tariff support ensuring that a key policy objective of renewable energy project viability is achieved. This goal would be central to any broader policy objectives associated with promoting an innovative and viable renewable energy industry more broadly within the economy while contributing towards decarbonising the economy.

Fifth, least cost principles could be entrained in the design and implementation of the feed-in tariff scheme by: (1) choosing eligible projects on the basis of a competitive reverse auction process; and (2) allocating capacity segments of the scheme to be rolled out in parcels over time to ensure that competitive cost advantages associated with technological innovation and economies of scale and scope are built into the bids by participants.

Sixth, the feed-in tariff scheme that is generally envisaged by the above mechanisms most closely approximates the 'Contract for Difference (CfD)' feed-in tariff scheme adopted recently in Great Britain (UK Government, 2015). In this context, the 'strike' price would correspond to the conventional LCOE estimate identified in Table 3. The 'reference' price would correspond to an aggregate price calculated from both the average wholesale price and LGC prices. Finally, the *size* and *sign* of the required return would indicate the nature of payments to and from the owners of the solar PV array. If the required return (e.g. LCOE) is positive, this would indicate payments *from* Government to the owner of the solar PV project. However, a negative required return would indicate payments *from* the owner of the solar PV project to the Government.

A key implication of the CfD feed-in tariff scheme is that it can be easily applied as a 'top-up' mechanism to other existing schemes such as a national carbon pricing mechanism or renewable energy certificate scheme based on some renewable energy obligation or target. An example of the latter would be the current LRET scheme operating at the Commonwealth level in Australia (CER, 2016). In this context, the carbon pricing mechanism would work to increase average wholesale electricity prices while the tradeable price on eligible renewable energy certificates would provide an equivalent LGC-type revenue stream. By drawing on the revenue available from both of these mechanisms, the required feed-in tariff level needed to secure project feasibility would be reduced as would be the additional level of Government expenditure needed to support the scheme. As such, the feed-in tariff scheme could easily be implemented in conjunction with existing Commonwealth Government policies in Australia to help secure State based renewable energy targets. Moreover, the scheme's implementation would not depend upon the availability of PPA instruments or the willingness of electricity retailers to underwrite projects with PPA instruments. However, it could also be constructed to act as a 'top-up' mechanism around commercially available PPA instruments. More generally, the feed-in tariff scheme itself would provide a guaranteed and bankable revenue stream for the project.

Finally, Governmental costs associated with administering and monitoring the scheme are likely to be significant and care would be needed to protect the revenue base of the Government while pursuing the policy objective of decarbonising the economy and promoting investment in renewable energy. Useful lessons can be drawn from European experience of such feed-in tariff schemes. Comprehensive surveys can be found in Cory *et al.* (2009) and especially Couture *et al.* (2010).

(6.2) Assessment of contemporaneously required feed-in tariff support

In this sub-section we determine the contemporaneous value of required feed-in tariff support for the three representative solar arrays based upon recently available LGC spot price information and the most recent volume weighted loss adjusted wholesale electricity price. An LGC closing spot price of $89.15/MWh was adopted, being sourced as the mid-point of the 'ask' and 'bid' range of the LGC spot price values listed by Mercari (2016) on 10/10/2016.[6] The wholesale price utilised is the analysis is the 2015 loss adjusted volume weighted average wholesale price of $57.83/MWh.

[6] The bid and ask spot rates were $88.70/MWh and $89.60/MWh, respectively.

The LCOE results associated with these two price settings are reported in Table 7. It should be noted that the same model that was used to calculate the ($/MWh) LCOE estimates reported in Tables 3 to 6 was also used to generate an equivalent set of ($/MWh) LCOE estimates for the two price settings mentioned above. However, given that the discussion of feed-in tariff support is typically expressed in terms of a cents per kilowatt-hour (c/kWh), we converted these ($/MWh) LCOE values into equivalent (c/kWh) values using the conversion factor of 0.1, that is, $1/MWh = 0.1 c/kWh.

Table 7 indicates that the lowest required feed-in tariff rates are associated with the low soiling scenario. These estimates are in the range (-0.55) to (-0.04) c/kWh for the representative FT array, between (-1.99) and (-1.72) c/kWh in the case of representative SAT array and between 0.54 and 0.86 c/kWh for the representative DAT array. In comparison, the highest contemporaneous feed-in tariff rates are associated with the high soiling scenario, and are in range 0.04 to 0.57 c/kWh, (-1.49) to (-1.21) c/kWh and 1.15 to 1.48 c/kWh, respectively.

It is apparent that of the three technologies considered, the SAT array continues to have the lowest required feed-in tariff support, in the range of (-1.99) to (-1.21) c/kWh, depending upon soiling and FOM cost scenarios. This is followed by the FT array with required feed-in tariff support levels between (-0.55) to 0.57 c/kWh. Finally, the required level of feed-in tariff support is highest for the DAT array, in the range of 0.54 to 1.48 c/kWh.

Table 7 Required (c/kWh) Feed-in Tariff Rates ($57.83/MWh average price and $89.15/MWh LGC price)

	Low soiling			**Medium soiling**			**High soiling**		
O&M Cost Scenario	FT	SAT	DAT	FT	SAT	DAT	FT	SAT	DAT
WP	(-0.04)	(-1.72)	0.86	0.18	(-1.54)	1.09	0.57	(-1.21)	1.48
PC	(-0.36)	(-1.94)	0.58	(-0.14)	(-1.75)	0.81	0.24	(-1.43)	1.19
PC_low	(-0.55)	(-1.99)	0.54	(-0.33)	(-1.81)	0.76	0.04	(-1.49)	1.15

It should again be recognised that the negative values included in parentheses and shaded in red font in Table 7 signify the (c/kWh) amount that project proponents would have to pay back to the Government under a 'CfD' feed-in tariff scheme, given the LGC and average wholesale prices used in the above analysis. More generally:

- the SAT array is commercially viable at all soiling rate and FOM cost scenarios at the assumed LGC and wholesale electricity strike prices;
- the FT array is commercially viable at low and medium soiling rates (for the two lower FOM based cost scenarios in the latter case) but still needs some additional support at high soiling rates and across all three FOM cost scenarios;
- the required feed-in tariff support rates for the FT array in the latter case are significantly less than 1c/kWh;
- the DAT array needs additional support at all soiling and FOM cost scenarios; and
- the required feed-in tariff support rates for the DAT array is between 0.5c/kWh and 1.5c/kWh.

6. Conclusions

Studies of the economic viability of different types of solar PV tracking technologies centres on assessment of whether the annual production of the different tracking technologies is increased enough relative to the benchmark FT system to compensate for the higher cost of installation and operation incurred by the tracking systems. In this paper we have investigated this issue from the perspective of the LCOE of the three individual FT, SAT and DAT arrays located at GSRF.

Of crucial importance to the results in this paper are the assumptions made about the ($/kW) construction costs of the three different arrays technologies installed at the GSRF.

Another crucial parameter affecting LCOE is the ACF of each representative array. The PVSyst software was used to simulate electricity production of the three representative solar PV systems at GSRF. The ACF's were calculated from these production profiles assuming that each array had an energy sent-out capacity limit of 630 kW. Three broad module soiling scenarios were also incorporated into the PVsyst modelling. These were a low, medium and high module soiling scenario. The sensitivity of LCOE estimates to different FOM cost scenarios was also investigated.

A number of broad conclusions follow from analysis of our results. First, of the three technologies considered, the SAT array is the most competitive consistently having the lowest LCOE. This is followed by the FT array and then the DAT array which is the least competitive technology (e.g. having the highest LCOE). LCOE estimates also increase with the level of module soiling reflecting the deterioration in the ACF associated with increased soiling. Depending upon solar array type, analysis pointed to average percentage increases in LCOE associated with medium module soiling relative to low soiling of between 1.4 and 1.5 per cent. Similarly, we found average percentage increases in LCOE associated with high soiling relative to low soiling of between 3.9 and 4.1 per cent.

LCOE results were also shown to decline with reductions in FOM costs. Depending upon the extent of module soiling and the solar PV array type being considered, typical reductions in LCOE attributable to reductions in FOM costs were found to be between 11.3 and 19.8 per cent.

From the perspective of project feasibility, the appropriate level of feed-in tariff support was the rate needed to cover capital costs, operational costs and achieve a required return on invested capital over the lifespan of the project after accounting for renewable energy certificate and merchant electricity sales revenue streams. These latter revenue streams were treated as cost-offsets in the LCOE calculation.

A direct link was established between the LCOE value and the required feed-in tariff rate needed to ensure project feasibility. LCOE estimates were also shown to decline significantly when revenue from the sale of renewable energy certificates and merchant sale of electricity to the wholesale electricity market were incorporated in the LCOE modelling. Moreover, feed-in tariff support levels according to this methodology could be tailored to reflect changes in market conditions, particularly changes in LGC and average wholesale electricity market prices over time. Technological innovation and economies of scale and scope in solar PV component manufacturing and logistics could also be accommodated over time through lower costs trends flowing through into lower LCOE estimates.

The type of feed-in tariff scheme most closely aligned to the methodology developed in this paper would be a ‘Contract for Difference’ Feed-in Tariff scheme. Finally, the feed-in tariff scheme could be easily applied as a ‘top-up’ mechanism to other existing schemes such as a national carbon pricing mechanism or renewable energy certificate scheme based upon a renewable energy obligation or target. In particular, it could be easily implemented in conjunction with existing Commonwealth Government policies in Australia to help secure State based renewable energy targets. While it does not depend upon the willingness of electricity retailers to underwrite projects with PPA instruments, it could also be developed as a 'top-up' mechanism around commercially available PPA instruments.

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