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HOW kWh/kWp MODELLING AND MEASUREMENT COMPARISONS DEPEND ON UNCERTAINTY AND VARIABILITY

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ABSTRACT

Most PV simulation programs (PVSP) use similar algorithm sequences [1] to predict system kWh/kWp and ¢/kWh from weather, PV performance and BOS databases with users' best guesses for dirt, shading etc. PVSPs usually estimate PV performance vs. irradiance and temperature from a 1-diode model of either a manufacturer's datasheet or from an indoor or outdoor characterisation of one (or a small number) of samples and often won't consider the variability or uncertainty of module measurements. When modelling kWh/kWp there are a very large number of uncertainties, variabilities and unknowns which dominate the predicted or measured energy yield. Levelized cost of electricity (LCOE) [2] calculations have been performed on the modelled performance data. Important factors are analysed and quantified for locations and suggestions made as to how to improve modelling and performance claims.

VARIABILITY AND UNCERTAINTYAFFECT kWh/kWp

Inconsistencies have been found in the way the 1-diode model fits IV curves [1][3], leading to disagreements with the manufacturers measured low light level efficiency and temperature coefficients (measured to IEC standards) giving kWh/kWp errors.
Hourly weather data averaging results in short term high irradiance peaks being averaged together with low irradiance conditions meaning that an incorrect insolation vs. irradiance curve is used which also affects predicted energy yields [4].
It has also been found in several independent outdoor tests that there may be more variation of kWh/kWp between modules of the same type than between modules of different technologies.
Many parameters that have an effect on the energy yield of a PV system are subject to variability (i.e. changes from the expected design value) and uncertainty (of measurement accuracies, algorithms or user defined estimations). Table 1 lists some of the main parameters and shows what the variability and uncertainty associated with each parameter can be – some uncertainty values shown are taken from product data sheets.

Table 1: Variability and uncertainty of some kWh/kWp determining effects

	Variability and uncertainty	
Effective plane of array insolation YR kWh/m²/y	Yearly site insolation variability (±4% ?NREL); Microclimate differences vs. nearest measurement site; Ground albedo (which affects front row differently); Reference sensor calibration (± 2% typical).	Tilted plane calculations (rely on modelled diffuse factor and anisotropic sky distribution); Reference sensor type and stability (± 0.5 to 1%/y ?)
PV performance	Module P_{MAX} actual/nominal (e.g. 210-220Wp bins); Changes with time of P_{MAX}, I_{SC}, V_{OC}, FF, R_{SH} (→Low Light Efficiency Change), R_S(→high light I²R loss); Loss of output (various dc failure mechanisms)	Reference module calibration factor (>± 2.5% ?); Seasonal thermal annealing (e.g. of thin films <±5% ?); AOI and spectral response differences vs. reference cell; Multijunction matching (e.g. blue, green or red limited); Correlations between different weather parameters; Corrections needed for bad or missing data.
Near shading Self shading Horizon shading	Varies across arrays due to trees, lampposts etc. Stops direct irradiance on some parts of the modules Affects whole array but only at certain times	Pmax vs. shading depends on sun position, beam fraction, bypass diodes, stringing arrangement etc.
Cell temperature	Varies across large arrays with wind direction – (upwind may be coolest) and across module (e.g. hotter where a junction box/mounting structure is behind cell)	NOCT dependency vs. standoff, ventilation unknown; Temperature depends on wind direction e.g. parallel or orthogonal to tilt azimuth.
Dirt/soiling	How to estimate the average value ? Amount depends on pollen, pollution etc. Composition/"stickiness" of dirt determines wash off rate	Dirt accumulation rate %/day (may change if ARC) Depends on tilt angle and frame type (run off) Random rain has less averaged dirt loss than seasonal
Stringing	Current mismatch - depend on lowest current module	Are modules sorted by current or not ?
Inverter Performance	Inverter efficiency varies with P_{IN} (and V_{IN}) MPPT of commoned strings of varying performance Inverter downtime	AC measurement accuracy ±0.5% ?

MODULE P_{MAX} BIN VARIABILITY

"Identically produced" modules on a production line will have varying P_{MAX}, I_{SC}, and V_{OC} etc. due to process and material variabilities. Manufacturers don't quote these performance distributions but the minimum possible variability of PV parameters per power bin can be ascertained by studying the values of parameters for each P_{MAX} bin from a 3^{rd} party manufacturer's datasheet as plotted in figure 1 (this is from a typical example thin film module). The change in P_{MAX} from bin to bin will depend on how the other values change in equations {1} and {2}.

$$\Delta \mathbf{P_{MAX}} \sim \Delta \mathbf{V_{MPP}} + \Delta \mathbf{I_{MPP}} \qquad \{1\}$$

$$\Delta \mathbf{P_{MAX}} \sim \Delta \mathbf{V_{OC}} + \Delta \mathbf{FF} + \Delta \mathbf{I_{SC}} \qquad \{2\}$$

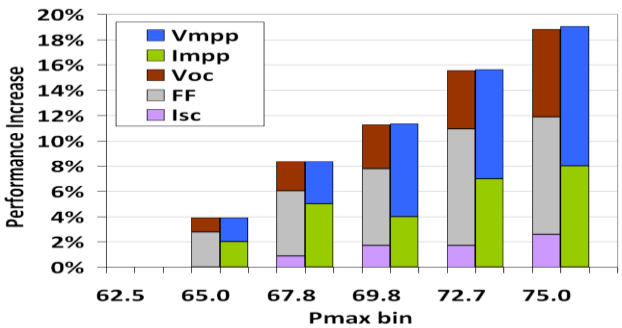


Figure 1: Proportions of changes in P_{MAX} due to changes in I_{SC}, V_{OC}, FF, I_{MPP} and V_{MPP}

Figure 1 allows the minimum parameter variation within a range of modules to be estimated, e.g. this thin film has ~4% P_{MAX} bins and its P_{MAX} variation will be due to (~45% V_{MPP}+ ~55% I_{MPP}) or (~30% V_{OC} + 55% FF + ~15% I_{SC}). In reality the variabilities will be greater than this as there can be higher than average I_{SC} devices with lower than expected V_{OC} in the same P_{MAX} bin.

Figure 2 illustrates the IV curves at STC taken from a PVSP database for a commonly used 3^{rd} party module; note the general improvement in I_{SC}, V_{OC} and FF as the P_{MAX} rises but not linearly as can be seen on the zoomed in regions of I_{SC} and V_{OC} as well as the P_{MAX} points.

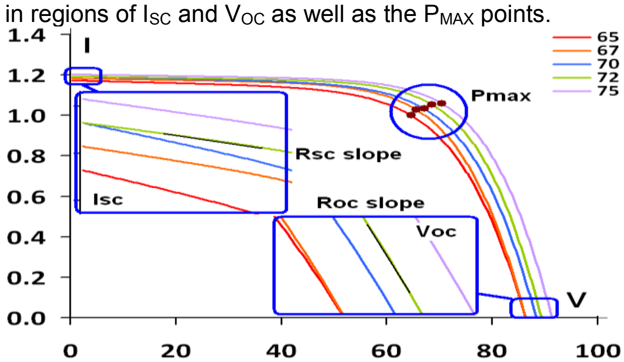


Figure 2: IV curves (colours) and zoomed in I_{SC} and V_{OC} regions as modelled by a thin film manufacturer's datasheet values at 1000 and 200W/m².

The PVSPs ought to allow for variability of modules performance but this rarely seems to be done as they are based on one datasheet or one characterised module output only.

UNCERTAINTY IN kWh/kWp

The final energy yield YF is defined as the AC kWh produced per year divided by a nominal value for kWp {3} (IEC 61724) [5].

$$\mathbf{YF} = \frac{\mathbf{kWh_{AC}}}{\mathbf{kW_P}} \qquad \{3\}$$

kWh_{AC} will depend on the actual insolation at the site and should be normalised by some reference value (as in a year year with lower insolation the actual energy yield will be necessarily less than from a normal insolation year). There will also be some correction needed for downtime (if part or all of the array is not producing) and the output will change due to long term degradation, dirt, seasonal annealing and BOS performance, the expected kWh value will be a product of several uncertain functions {4} :-

$$\mathbf{kWh_{AC}} = \mathbf{kWh_{AC.OPTIMAL}} * \left(\frac{\mathbf{Insolation\ yearly}}{\mathbf{Insolation\ nominal}}\right) * \mathbf{f_{DOWNTIME}} * \mathbf{f_{DEGRADATION}} * \mathbf{f_{DIRT}} * \mathbf{f_{SEASONAL}} * \mathbf{f_{SHADING}} * \mathbf{f_{BOS}} \qquad \{4\}$$

kWp {5} is the nominal value of STC power. The uncertainties here are from the reference module calibration, uncertainty in the flash tester, the actual/nominal power from the module due to module P_{MAX} binning and the allowance by the manufacturer for degradation to satisfy the end of lifetime power guarantee (for example a manufacturer might choose to measure 110Wp initially for every 100Wp it stamps on the nameplate).

$$\mathbf{kW_P} = \mathbf{kW_{P.ACTUAL}} * \mathbf{f_{REFERENCE.MODULE.CALIBRATION}} * \mathbf{f_{FLASH.TEST.UNCERTAINTY}} * \mathbf{f_{MODULE.BINNING}} * \mathbf{f_{MANUFACTURER.DECLARATION}} \qquad \{5\}$$

Corrections will usually be done to the irradiance from a calibrated reference cell which may not be of the same technology but with the smallest spectral mismatch (particularly for thin film). The reference cell may also have angle of incidence and other effects (such as dirt build up) that will differ from the array and should be corrected for.

The modelling of PV modules is usually calculated on just one set of non-degraded "nominal" values. However degradation may happen and the kWh/kWp will differ depending on how the module degrades. Table 2 lists some PV properties that can change and their effect on performance.

Table 2: Possible PV degradation cause and effect

Type	Likely causes	Effects
Falling I_{SC} and I_{MPP}	Recombination, delamination	Increased I_{MPP} variability and/or mismatch
Falling R_{SH}	Shunting, mismatch	Worse and more variable low light performance.
Falling FF	Junction properties, R_S	Higher P_{MAX} variability
Rising R_S	Contact resistance.	Worse and more variable high light performance ($\rightarrow I^2.R_S$)
Falling V_{OC} and V_{MP}	Junction Io	Higher V_{MP} variability

WEATHER CORRELATIONS

All weather parameters are correlated with each other as has been shown previously [6] – this does not appear to be modelled perfectly by simulation programs.

P_{MAX} performance and seven weather parameters listed in table 3 are plotted in figures 3 and 4-8 clockwise from the top. "Poor weather" (i.e. low irradiance) values are plotted towards the centre of the graphs and "good weather" values to the outside of the graphs.

Table 3: Correlation weather parameters

	Parameter (Unit)	"poor weather" (inner limit)	"good weather" (outer limit)
1	DC yield YA (W/Wp)	0 low	1.2 high
2	Irradiance Gi (kW/m²)	0 dull	1.2 bright
3	T_{MODULE} (C)	0 cold	80 hot
4	$T_{AMBIENT}$ (C)	-20 cold	60 hot
5	Angle of Incidence (°)	100	0 normal
6a	"Blue fraction" {6}	0.3 redder	0.6 bluer
6b	Air Mass (solar height)	5 redder	1 bluer
7	Season (#)	-1 winter	+1 summer
8	Beam Fraction (#)	0 all diffuse	1 all direct

Note that two different options "blue fraction" {6} and "Air Mass" are used for spectrum depending on whether site spectral measurements exist or not, for details see [9].

$$\textbf{Blue Fraction} = \frac{G(350nm-650nm)}{G(350nm-1050nm)} \qquad \{6\}$$

In figure 3 the yellow circles mark the values corresponding to STC, note there is no "Season" for STC and the ambient temperature for STC would be ~-9C as calculated in equation {7} (ignoring wind speed).

$$T_{AMBIENT} \sim T_{MODULE} - G_I/0.8 * (NOCT - 20) \qquad \{7\}$$

IEC 61853 [7] lists other weather conditions to be used to measure PV modules – these are shown in figure 3 with green diamonds as different irradiances and module temperatures plus the ambient temperatures from equation {7}. No variations are made in AOI, spectrum or beam fraction. (For both STC and the IEC 61853 conditions Blue Fraction is ~52% and Air Mass = 1.5)

The blue line in figure 3 shows one measurement made of a c-Si module at 1 sun irradiance conditions at an Oerlikon test site in Arizona – clear differences can be seen vs. STC temperatures, AOI and Beam Fraction.

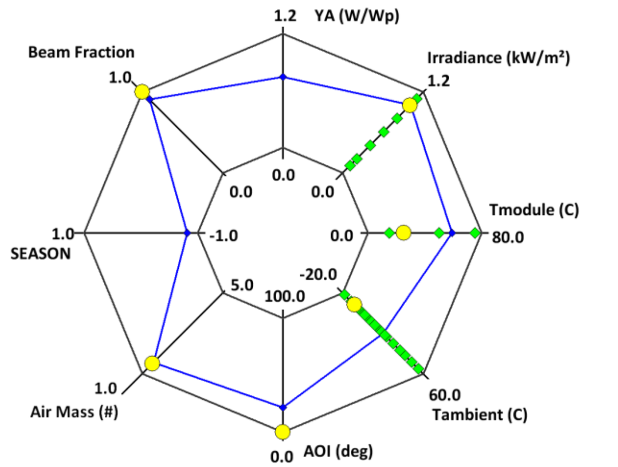


Figure 3: DC P_{MAX} performance vs. 7 weather parameters defining Standard Test Conditions vs. IEC 61853-1 and one c-Si measured at 1 sun conditions at an Oerlikon test site in Arizona

Figure 4 and table 4 show how different weather has been separated into "types" for further analysis plotted in figures 5 to 8.

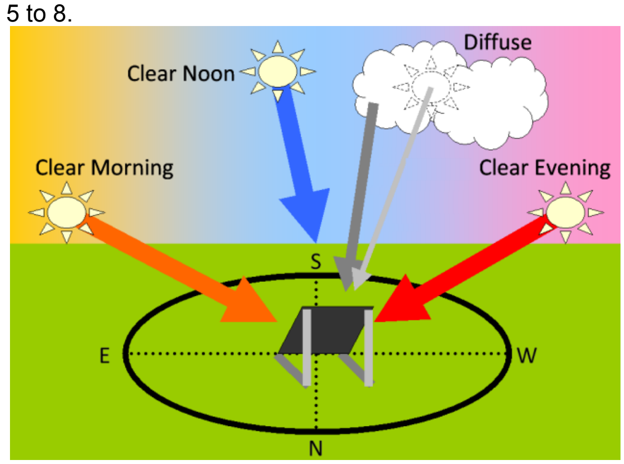


Figure 4: Illustration of different "weather types"

Table 4: Definitions of "weather types"

Weather type	Graph colour	Irradiance Gi kW/m²	Clear-ness kTh	Time (h)
Clear Morning	Orange	0.1-0.4	>0.5	<12
Clear Noon	Blue	>0.7	>0.7	10-14
Diffuse sky	Grey	0.1- 0.4	<0.5	any
Clear Evening	Red	0.1-0.4	>0.5	>12
"Other"	Green	Everything else		

Positive correlations between adjacent parameters will be seen by "parallel lines of constant radius", non correlated data will be seen by scattered lines criss-crossing each other.

Twenty measurements were chosen at randomly selected data for each weather type from 1 minute measurements on a c-Si module at an Oerlikon Solar outdoor test facility (OTF) in Arizona [8][9].
The highest irradiances (red, figure 5) correlate with high temperatures, clear blue skies, low angle of incidence etc. (they are usually around the outside of the graph although there can still be some in mid winter). Low irradiances due to dull weather (red, figure 7) can occur at any time of the day and are nearer the centre of the graph for irradiance, temperatures, AOI and beam fraction but have slightly higher blue fraction and can occur at any season. Low irradiances can also occur because of "clear skies and high angles of incidence" in the morning (red, figure 6) or evening (red, figure 8). This weather is correlated differently to the clear noon or diffuse; there are more medium ambient and module temperatures, off axis AOI, a more variable blue fraction plus any season and high beam fraction.

Twenty measurements were similarly chosen at random from a commercial simulation program for the c-Si module modelled at the same site in Arizona in (blue in figures 5 to 8) although the lower left axis is now air mass (calculated from solar height) for the model rather than blue fraction for the measurements as spectral data doesn't exist and can't be compared exactly with the red curves (it has been hidden by a grey stripe).

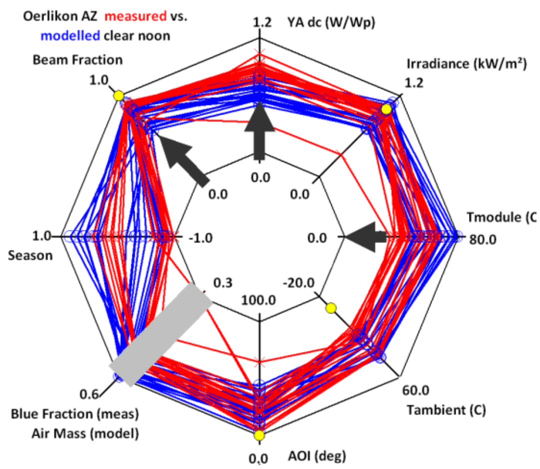


Figure 5: Measured vs. modelled clear noon in Arizona

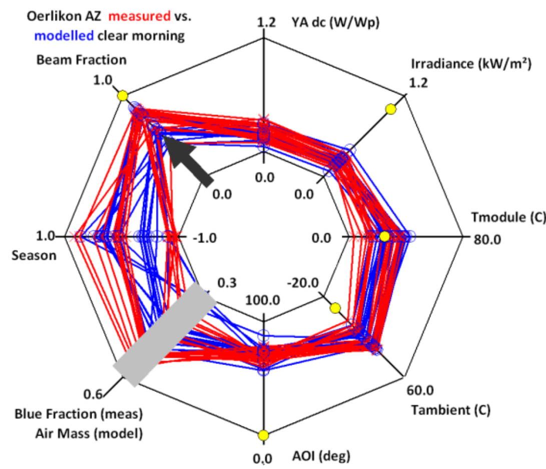


Figure 6: Measured vs. modelled clear morning

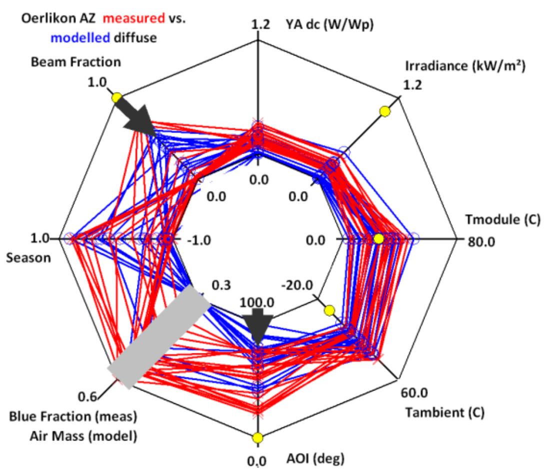


Figure 7: Measured vs. modelled diffuse

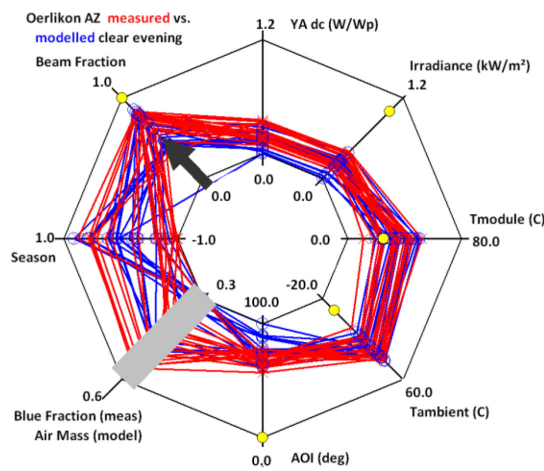


Figure 8: Measured vs. modelled clear evening

Many differences can be seen between the measured and modelled predictions (the direction of the black arrows point from mean modelled to mean measured) and some are summarised in table 5.
These findings show that the modelled module has a worse low light level performance and the high temperatures are more extreme than measured. It also appears that there is more low light distribution predicted than measured – both these facts will mean that a higher variability in energy yield will be predicted than measured as found in previous papers

Table 5: Differences between Oerlikon measured and simulation program modelled data.

Weather	Measured (compared with modelled)
Clear Noon	Higher Pmax; Higher beam fraction; Lower Tmodule
Diffuse sky	Lower beam fraction, Lower AOI
Clear morning/ evening	Higher beam fraction than measured correlated with season (even more high beam in summer)

UNCERTAINTY IN ¢/kWh (LCOE)

A simple program was developed to estimate the relative levelized cost of energy LCOE [4] at different sites and to use it to determine the sensitivity in ¢/kWh to the variability and uncertainty in the various electrical, thermal, mechanical and cost inputs.
Table 6 describes the current status of the modelling for many parameters – it is hoped to be able to add many others to the analysis soon.

Table 6: Present status of this LCOE modelling

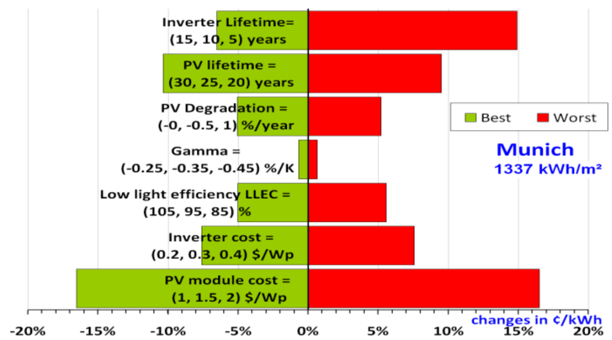
Effect	Modelled?
Plane of array kWh/m² vs. light level and module temperature	Y
PV Efficiency vs. light level (LLEC)	Y
PV Efficiency vs. Temperature (gamma)	Y
Absolute PV efficiency (area costs)	Y
Cost depreciation of replacements	N
Repair if cheaper than replacement	N
Thermal annealing (autumn vs. spring)	N
Spectral response (poor red - some thin film)	N
Multi junction red-blue current matching	N

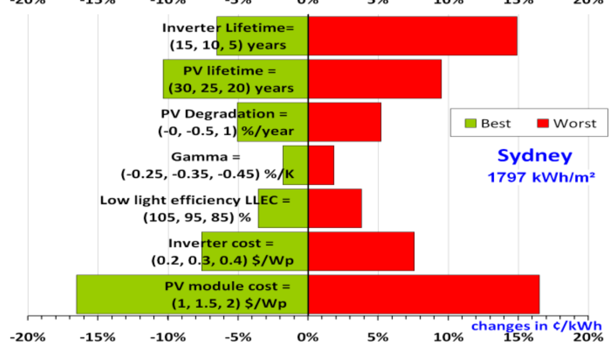
Many of the defaults will be site and time specific but estimates were obtained and compared with published data for the default “fixed values”[4][10][11][12] which are listed in table 7. Other “changing values” are used to estimate the sensitivity of ¢/kWh to defined “best, default and worst” limits.

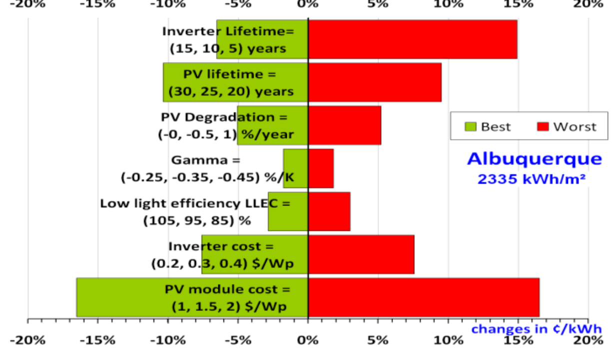
Table 7: Default values used in this LCOE study

Fixed values	Default Value	Unit
BOS cost	0.25	$/Wp
Install cost	0.25	$/Wp
Area cost (structure, land)	50	$/m²
Dirt ratio	98%	%
Inverter Efficiency	95%	%
Changing values	**Best, Mid, Worst**	**Unit**
Inverter lifetime to failure	15, 10, 5	y
PV lifetime to failure	30, 25, 20	y
PV degradation linear	0, -0.5, -1	%/y
Gamma (1/P*dP/dT)	-0.25, -0.35, -0.45	%/K
LLEC(eff@200W/m²/ STC)	105, 95, 85	%
Inverter cost	0.2, 0.3, 0.4	$/Wp
PV module cost	1.0, 1.5, 2.0	$/Wp

Figures 9-11 show the changes in ¢/kWh from the default sets obtained by using the fixed values in Table 7 and then the decrease and increase in ¢/kWh obtained by altering the changing values to the best and worst amounts listed for Munich 1337kWh/m², Sydney 1797 kWh/m² and Albuquerque 2335 kWh/m² (low, medium and high yearly insolation respectively).
Note that the absolute default value of ¢/kWh will be approximately inversely proportional to the plane of array insolation at the site.
The graphs show that variations of ¢/kWh due to Gamma and LLEC (low light efficiency) are all relatively small (<5%). The highest LLEC (~ 5% ¢/kWh per 10% LLEC) is at the worst insolation site (Munich). The highest gamma (approximately 2% ¢/kWh per 0.1%/K) occurs at the highest insolation site (Albuquerque) as expected.
The changes for ¢/kWh are larger due to 5 year variations in inverter and PV lifetime to failure and also PV degradation of ±0.5%/y. Large variations in ¢/kWh are due to cost changes for the Inverter and PV $/Wp.
The Gamma and LLEC values are site dependent but the inverter and PV cost, lifetime and degradation rates are determined by the default relative proportions of cost for PV, inverter and the rest of the BOS.







Figures 9-11: Relative changes in ¢/kWh in Munich, Sydney and Albuquerque

CONCLUSIONS

- Simulation programs may merely coincide with measured data and cannot predict kWh/kWp or ¢/kWh precisely – there are far too many variabilities and uncertainties.
- All weather parameters are correlated making outdoor and indoor corrections more difficult. The indoor matrix of measurements in IEC 61853-1 only uses all direct light at 0° AOI and AM1.5, which is not found in the field.
- A simple LCOE model shows that LLEC improvements of modules benefit mostly poor insolation climates whereas Gamma improvements for modules work best for high insolation climates. However both of these values are smaller than the cost benefits in reducing annual degradation by -0.5%/y or by improving the PV and inverter lifetimes of 5y before replacement.
- Large improvements are found in ¢/kWh by cost reductions in PV and inverter $/Wp, (although presently cheaper components may have worse degradation and/or shorter lifetimes – this correlation which will be studied in future work).

ACKNOWLEDGEMENTS

Oerlikon solar for outdoor test facility data in Arizona for figures 3 and 5-8

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SOME DEFINITIONS USED IN THIS WORK

	Parameter names	**Previous or other name**
PF = YA/YR	Performance factor	Module Factor ; PR_{DC}
(eff@200W/m² / eff@1000W/m²)	Low Light Efficiency Change	LLEC
Global.horiz/ Extraterrest.horiz	Clearness index	kTh
$1/P_{MAX} * dP_{MAX}/dT$	Power temperature coefficient.	Gamma