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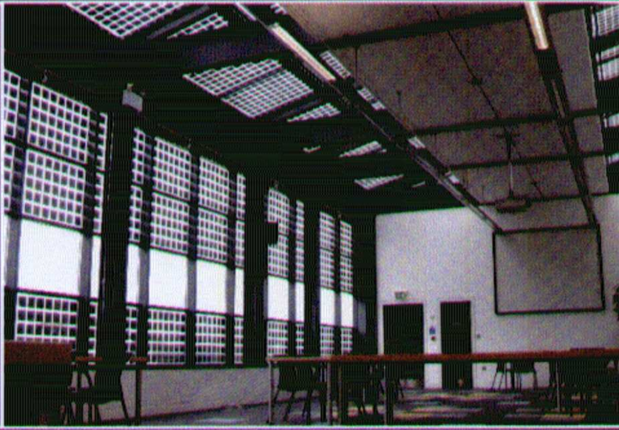

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Performance of two photovoltaic arrays in the UK

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There are numerous conflicting reports into the economic and embodied energy return of photovoltaic (PV) arrays installed in the UK. Using actual performance data measured on two PV arrays installed on the ZICER building at the University of East Anglia, this paper attempts to resolve some of the issues arising from earlier predictions made using theoretical test bed performance data. A PV model using the monitored data, in combination with solar radiation and geometry data from across the UK, was used to predict the average annual electricity output from the installations over a range of tilt angles, orientations and geographical locations. Six separate capital cost scenarios are considered and the predictions of the unit cost for electricity range from £0.10 (€0.14) per kWh under the most favourable conditions to £2.68 (€3.83) per kWh. At a mean solar radiation of 1000 kWh/m^2 per year, typical of many locations in the UK, the energy yield ratio (EYR) ranges from 4.3 to 5.1 depending on whether the cells are mono-crystalline or poly-crystalline and the assumptions made in the scenarios. Even on a vertical west-facing face, an EYR of over 2.5 is achieved.

1. INTRODUCTION

Photovoltaic (PV) economic and energy studies seek to identify the cost and environmental sustainability of PV power. Several economic methods exist, including evaluation of the net present value (NPV) and estimation of the projected unit cost of electricity generated over the lifetime of the facility. Similarly, in terms of embodied energy, the energy payback time indicates how long it takes before the energy investments during manufacture, construction and installation are recovered during operation, whereas the energy yield ratio (EYR) defines the number of times that the energy invested in the technology is returned or paid back by the system over its entire life.

Economic and embodied energy studies of PVs are prevalent in today's literature from across the globe, but conflicting views are reported on PV costs and their sustainability. Some studies investigating the economic potential of PVs make the future prospects seem rather promising,[1,2] with the value of crystalline silicon PV grid-connected electricity as little as £0.08 (€0.11) per unit. Less favourable economics have been reported by Oliver and Jackson[3] and Omer *et al*[4]. who calculated the unit cost of crystalline silicon PV systems to be £0.75 (€1.05) and £3 .69 (€5.17) per kWh respectively. Likewise, some embodied energy studies report that PVs receive many times their energy input required fabricating the modules with energy paybacks in the region of 2-7 years.[5-9] Yet other studies suggest that carbon dioxide abatement by the introduction of PV is not a promising candidate[10] with energy payback times in some cases as high as 22 years,[11] significantly above competing technologies.

The inconsistencies between the results can mostly be explained by three main issues.

(a) *Methodological issues*. For example, in an economic analysis, the chosen discount rate and system lifetime can bias the results towards the desired outcome; in an embodied energy analysis, the results depend upon the scope and the adopted boundaries of the study. In addition, some studies have explored future prices and the uncertainties they bring,[1,2] whereas others consider actual performance at the present time.[3,4] Batteries are included in some studies of PV applications, which adversely affects the energy payback. However, even removing such items for comparison with the building studied in this research, the energy payback time would still be in excess of 10 years.

(b) *Input data on which PV calculations are based.* For example, the chosen module efficiency and the solar irradiance level received by the surface of the PV cells used in the study. These in turn will affect the derived income and the energy return values.

(c) *Timescale of the research*. For example, the economics associated with production, the energy investment and cell efficiencies of PVs are constantly evolving. Hence, the time period in which the research is undertaken will influence the results.

This PV research develops economic and embodied energy return assessments of building-integrated crystalline PVs in the UK, taking into account these three issues.

2. CASE STUDY DETAILS

The module efficiency and inverter efficiency required to calculate PV electricity output were based on the actual performance of two building-integrated crystalline PV installations on the Zuckerman Institute for Connective Environmental Research (ZICER) building at the University of East Anglia, which was built during 2002-2003 (Fig. 1). The building houses approximately 120 occupants—faculty, staff, researchers and post-graduate students.

Fig. 1. The ZICER building

The building is an energy-efficient educational office that incorporates high thermal mass hollow-core concrete slabs for heating and cooling, combined with excellent air tightness and insulation standards that exceed current UK building regulations. Tovey and Turner describe the thermal performance of the building[12] and in 2005 the ZICER building won the Low-Energy Building of the Year award from the Carbon Trust. The 'top floor of the building is light in construction. As part of a demonstration project, the southern facade and roof are almost entirely glazed by grid-connected building-integrated PV modules, creating a light, airy, naturally conditioned exhibition area and seminar room (Fig. 2). These modules are embedded in double-glazed units that have an impact on performance due to increased cell temperatures.

The PV facade consists of 3360 polycrystalline cells (covering an area of 84.8 m^2) having a rated output of 6.7 kW_p and connected in three separate arrays (each having 28 modules). The cells are square in shape, making them more costly, but were chosen for aesthetic architectural reasons. The PV roof consists of 12 320 mono-crystalline octagonal PV cells covering an area of 264.9 m^2, a rated output of 27.2 kW_p and connected as ten separate arrays (each having 14 modules). All modules are laminated between two sheets of glass and were supplied by BP Solar. There are thirteen Fronius IG20 inverters, one for each array, that transform the DC electricity produced into AC electricity (Fig. 3) giving a combined output of 33 .9 kW_n.

Fig. 2. PV cells integrated into the construction of the top floor of the ZICER building

Fig. 3. The ZICER Fronius inverters

3. METHODOLOGY

The electrical performance of a PV system depends on the cell and inverter efficiencies, and the orientation, tilt and geographical location of the array. The last three parameters affect the solar radiation that reaches the surface of the PV modules. In particular, it is the radiation perpendicular to the cell surface that is of importance. A comprehensive PV monitoring programme was established to monitor the actual physical behaviour of the PV modules under varying solar radiation and climatic conditions, providing a realistic assessment of their performance.

Figure 4 shows the apparent mono-crystalline and polycrystalline module efficiency as a function of solar radiation. The module efficiencies were derived by measuring the DC output off the Fronius inverters, but also backed up by more accurate independent monitoring. A correction was applied to the readings taken using the Fronius inverters as they were shown to be underestimating the DC power by 7-9%. The module efficiency is affected by the temperature of the PV cells and this explains the scatter in Fig. 4. In actual conditions, PV cells can reach temperatures as high as 708C; for each one degree variation in temperature from the standard test condition (STC) temperature of 258C, the efficiency changes by approximately 0 .4%,[13,14] representing a potential reduction in efficiency of 18% at 708C. This variation is consistent with the scatter shown in Fig. 4 of approximately ±16%. The maximum hourly apparent module efficiency for the mono-crystalline PVs is _14 0%, close to the test bed efficiencies measured under STC, but the overall annual average module efficiency of PV electricity generated is lower

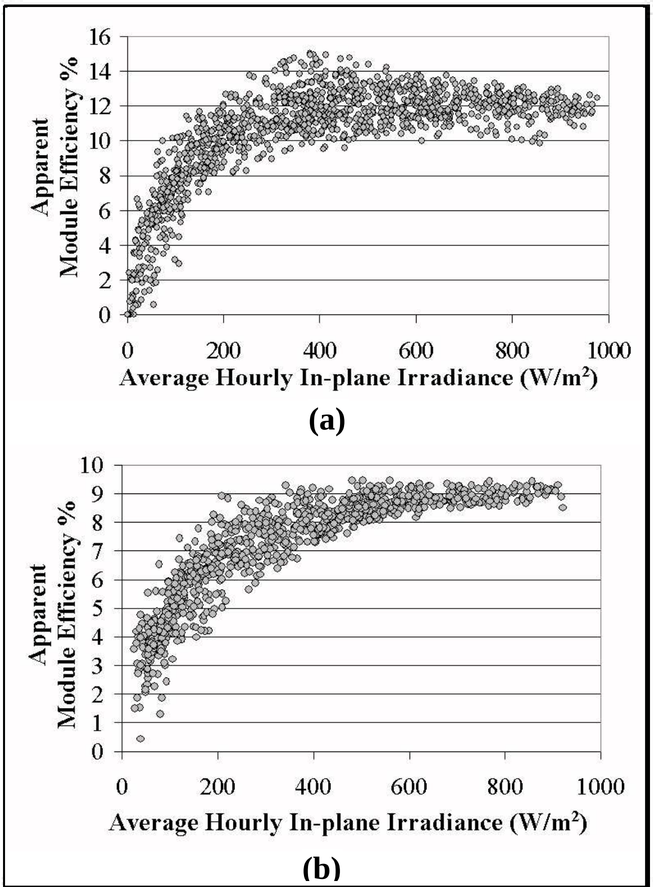

Fig. 4. Effect of average hourly solar radiation on (a) monocrystalline and (b) polycrystalline cell efficiencies

at 11.1%. The corresponding maximum hourly module efficiency for the polycrystalline PVs is ~9.5%, again with a lower annual average module efficiency of PV electricity generation of 7.5%.

Many previous studies, such as those of Richards and Watt [9] and Alsema and Nieuwlaar,[6] use cell efficiencies of 13-14% for mono-crystalline PVs, which are close to those measured under STCs when determining the energy output. Using such cell efficiencies will tend to overestimate the actual energy output from present mono-crystalline PV technology installed in the UK and thus underestimate the unit energy costs and energy payback time.

The conversion efficiency of the Fronius inverters is a function of DC power level (Fig. 5); the maximum inverter efficiency of ~94% is reached at high DC electricity generation levels. The sizing ratio of PV array output to inverter capacity is important, particularly in countries with a climate similar to that of the UK. Mondol[15] showed that the optimum ratio for the UK varied between 1.2 and 1.5; the sizing ratio of the two arrays in this study, based on peak PV output, was 1.25-1.5. The measurement of inverter efficiency was based on the DC and AC outputs as measured over specific periods for two separate inverters with the measurements cross-checked with independent meters. The weighted annual average inverter efficiencies are 89.7% and 91.0% for the arrays on the facade and roof respectively. The average overall system efficiency (including both module efficiency and inverter efficiency) for the mono-crystalline PVs is 10.1%, with a maximum actual

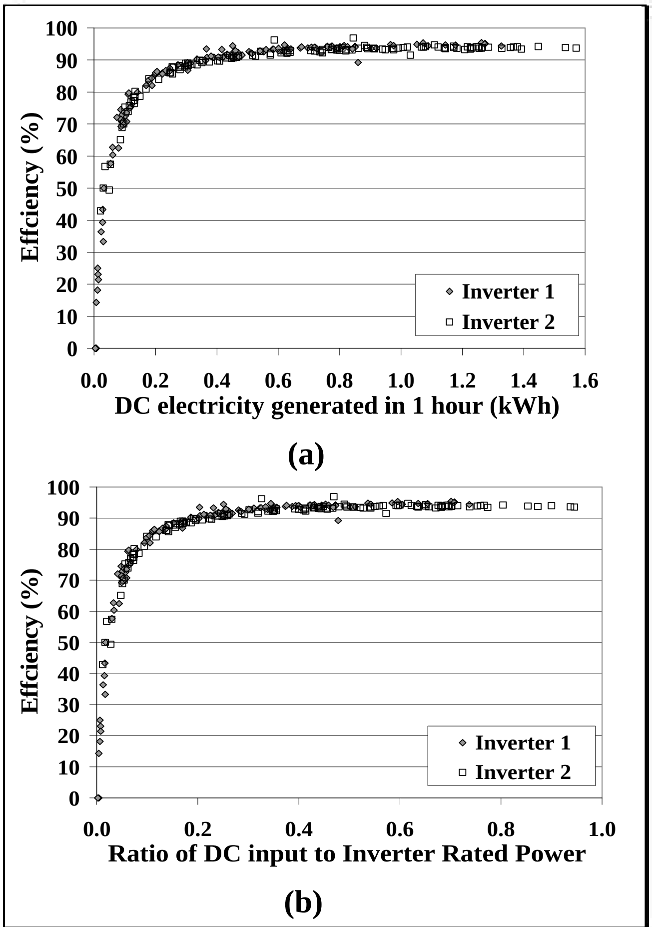

Fig. 5. Conversion efficiency of two PV inverters from DC to AC electricity. The measurements were supported by independent metering. (a) Efficiency with input power. (b) Efficiency as a function of input power to power rating of inverter. The inverters had sizing ratios of 1.24 and 1.5 respectively

value of around 12.7%. The average monocrystalline system efficiency compares favourably with corresponding efficiencies for other systems reported in the UK (Table 1[4,16-21]).

In the modelling discussed in this paper, the actual physical characteristics of the PV modules and inverters as defined in Figs 4 and 5 were used in conjunction with 10-year hourly solar radiation data for (a) the area specific to the location of the ZICER PV cells and (b) other UK locations. In more northerly areas, the cell efficiency will be higher as the ambient temperatures are generally lower, but the purpose of this modelling is not to give definite predicted outputs, but rather values sufficient for a basic economic analysis. Indeed, for an accurate analysis, full modelling of all temperature and weather conditions for each site would be needed, which is beyond the scope of this paper. As indicated earlier, the maximum error in this approximation would be ±18% (as shown in Fig. 4) and in most cases very much less.

Solar radiation datasets used for the PV model came from the Met Office MIDAS land surface station database.[22] The most suitable solar radiation dataset for the location of the ZICER building came from a weather station at Hemsby, approximately 40 km to the east. The global and diffuse horizontal solar radiations for Hemsby were recorded from 1981-1999 for every hour of every month for every year. In addition to the

Location	Monitoring period	System efficiency: %	Ref.
Northumberland Building, University of Northumbria, Newcastle-Upon-Tyne, UK	1995-1997	8 1.	16
Solar Office Doxford International, Sunderland, UK	Mar 1998-May 2000	7.5-8.0	17
Jubilee Campus, Nottingham University, Nottingham, UK	Sept 2000-Aug 2001	8	18
Eco Energy House, Nottingham University, Nottingham, UK	Sept 2000-May 2002	3 6.	4
Gaia Energy Centre, Delabole, Cornwall, UK	Jan 2003-June 2003	9-10	19
PV Domestic Installations, UK (average of six systems)	12-25 months	8.2 (6 .5-10 .4)	20
ECOS Millennium Environmental Centre, Ballymena, Northern Ireland	Dec 2000-Dec 2003	7 7.	21

Table 1. Actual recorded crystalline PV system efficiencies in the UK

Hemsby data, similar data were also obtained from five other locations across the UK (Table 2).

3.1. The model

Daily global and diffuse horizontal solar radiation values (and, by difference, direct solar radiation) were averaged to produce representative hourly values for an average day of each month in an average year. These values, together with the known positions of the sun in the sky for each of the given locations, permitted calculation of the average hourly total solar irradiance for any particular month on a tilted surface for any given orientation and location using equations from Duffie and Beckman[23,24] and Muneer *et al*[25].

From predicted values of solar radiation it was possible to estimate the hourly DC electrical generation using the module efficiency performance data in Fig. 4 and the corresponding AC generation using the appropriate inverter efficiency as described by Fig. 5. Aggregating the hourly AC electricity generation figures for each day allowed the annual predicted output to be estimated for the different geographic locations for a range of tilt and azimuth angles. In addition, the predictions specific to the tilt and azimuth of the ZICER building were compared with actual recorded data to validate the model.

The predicted average annual electricity generation based on the 10-year data from Hemsby for the actual location, tilt angle and orientation of the ZICER building (assuming no shading and no downtime) is 2860 kWh (427 kWh/kWp) for the facade installation and 22 300 kWh (820 kWh/kWp) for the roof installation: the monthly values are shown in Fig. 6. There are three reasons why these figures must be corrected before a comparison is made with the actual data.

(a) For the specific location of the ZICER building, shading from neighbouring buildings affects the facade and theoretically reduces output by 4 .0%, giving a predicted output of 2770 kWh. However, this shading effect assumed that only the actual cells affected by shading produced no electricity. In reality, since the cells were connected as horizontal arrays, the output from all cells in a module drops to zero when just one cell is shaded. Allowing for this effect reduces the predicted facade electricity output to 2660 kWh per annum.

(b) Although the data from Hemsby were used for modelling purposes, a complete set of detailed actual solar data at 5-min intervals for the location of the ZICER PVs was only available for four separate months in 2005 towards the end of the intensive monitoring period. These data indicated that the solar radiation received at the ZICER building in 2005 was 3.7% less than the corresponding average solar radiation from the 10-yr Hemsby database. This gives a corrected predicted output of 2706 kWh.

(c) The PV arrays are covered by G59 compliance requirements[26] and often trip during bad weather, e.g. thunderstorms, leading to cell downtime. Tripping of the PVs is not a problem if an automatic reset function is installed, thus leading to minimal downtime and hence minimal electricity loss. However, the ZICER arrays do not have this automatic function and it can often take several days to rectify if a trip occurs over a weekend or holiday period. During the study period, there were no fewer than 26 days when no electricity was generated; these incidents were estimated to have caused a loss of a further 100 kWh/yr of potential generation. Thus the final predicted solar radiation on the facade is estimated at 2560 kWh per annum, which compares very favourably with the mean actual electricity generated (2570 kWh).

On the roof, the effects of tripping and reduction in solar radiation due to shading of the PVs from the neighbouring teaching wall and the cleaning gantry reduce the predicted PV electricity output from 22 300 kWh to 20 280 kWh per annum—comparable to the measured value of 19 600 kWh per annum.

Location	Longitude: °	Latitude: °	Period of recorded data	Solar radiation: kWh/m^2 per yr
Aviemore, Inverness	3 .827 (W)	57.206 (N)	1987-1998	845
Aughton, Lancashire	2.917 (W)	53.549 (N)	1985-1995	955
Finningley, South Yorkshire	1.006 (W)	53.482 (N)	1983-1994	926
Hemsby, Norfolk	1.690 (E)	52.65 (N)	1989-1999	1060
Crawley, West Sussex	0.209 (W)	51.082 (N)	1981-1991	1001
Jersey Airport, Jersey	2.200 (W)	49.217 (N)	1984-1993	1164

Table 2. Location of solar radiation data stations used in modelling

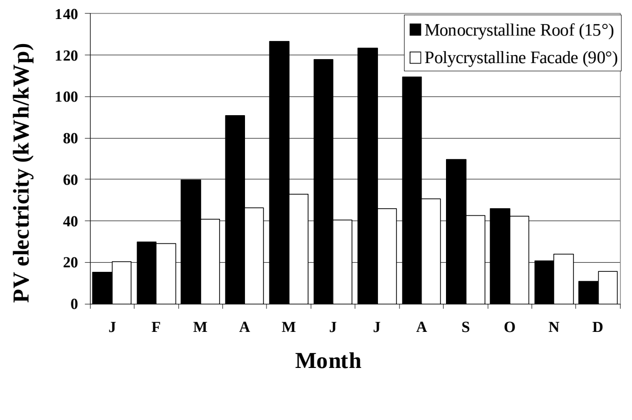

Fig. 6. Monthly average predicted ZICER PV electricity generation

Orientation	Proportion of maximum electricity generation: %						
	Tilt angle: °						
	0	15	30	45	60	75	90
East	87	84	80	73	65	55	45
Southeast	87	92	93	90	83	72	58
South	87	96	100	98	91	80	63
Southwest	87	94	97	95	89	78	64
West	87	87	84	79	73	64	53

Table 3. Percentage output of maximum electricity generation for PV arrays with different tilt angles and azimuths

The close agreement between predicted and actual measurements provides confidence in the model prediction for other locations.

The geographic location strongly affects PV electricity output. Fig. 7 shows the predicted unshaded average annual electricity output of the two PV arrays on the ZICER building had it been located in different areas of the UK at the same roof tilt angle and azimuth. The bars show the maximum range of error from using the apparent module efficiency.

As might be expected, the optimum location among the six areas investigated is Jersey in the Channel Islands. This location has the greatest annual solar radiation out of the six UK locations and it also generates the greatest PV electricity—3257 kWh on the facade and 24 664 kWh on the roof. These values should be compared with the theoretical unshaded values of 2860 kWh and 22 300 kWh for the ZICER location in Norwich. The worst location for the arrays would be Aviemore, which receives the lowest annual solar radiation out of the six locations and also generates the lowest PV electricity with 2353 kWh on the facade and 17 049 kWh on the roof. The Aviemore figures are 35% and 31% less than the PV output for equivalent polycrystalline and monocrystalline PV arrays in Jersey. It should be noted that the difference arises primarily from the difference in cloud cover at the two locations and not the difference in latitude. Aviemore receives 90% of the diffuse radiation of Jersey but only 55% of the direct beam radiation.

In addition to the effects of geographic location, the azimuth and tilt angle of the arrays can be significant. Predictions of the actual electricity generated by the ZICER PV arrays at different azimuth angles and tilt angles were calculated as a percentage of the maximum value (Table 3). The table shows that there are many combinations of tilt angle and orientation that will achieve 80% or more of the maximum electricity output. However, if the PVs are unfavourably positioned, electricity generation falls to low levels; for example, less than 50% of maximum electricity generation occurs if the PV arrays have an orientation of 908 (east) and a tilt angle of 90°.

3.2. Economic analysis

The economic viability of PV power can be determined by its ability to produce electricity at a unit cost that can compete with other sources to make adoption of the technology worthwhile. This unit cost has two components. The first is regular maintenance, which is assumed to be a fixed percentage (m) of the capital costs each year; the second represents the payback of the initial capital cost taking due allowance for an assumed discount factor. This latter factor is a composite factor

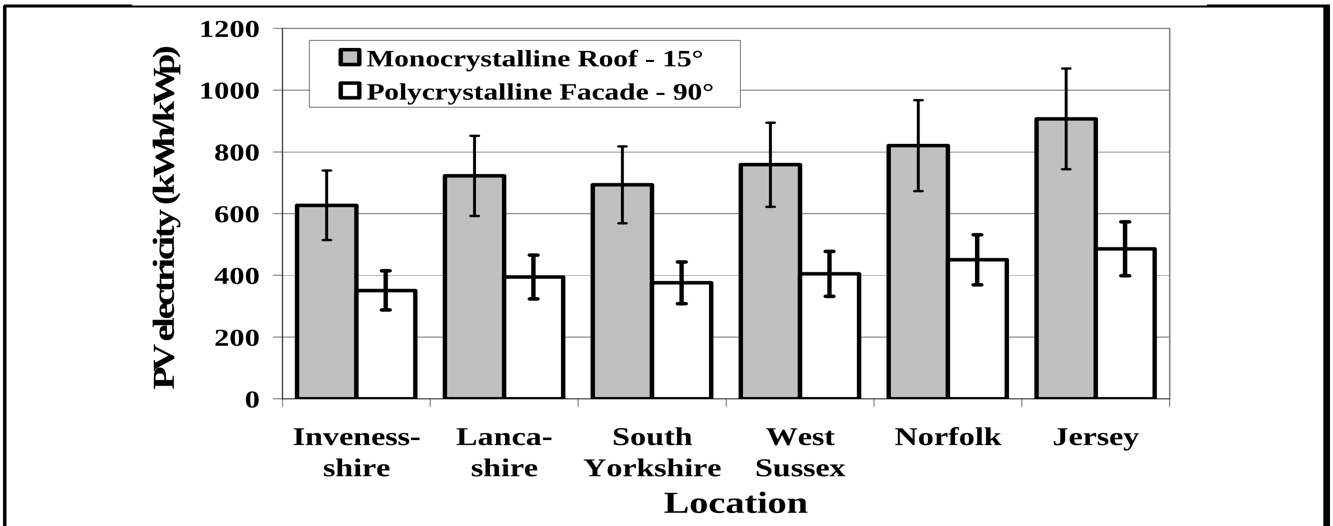

Fig. 7. Average annual electricity output for the PV facade and PV roof for different locations across the UK. The error bars show the maximum range of values arising from variations in cell temperature

Scenario	Description	Net capital cost of PV system: £ (€)	Capital cost per peak Watt: £ (€)
A	Actual ZICER PV cost including installation, ancillary equipment and design fees	482 350 (675 000)	1 .20 (1.88)
B	As (A) but including UK Government and European grants totalling £172 200 towards the cost of the ZICER PV installations	310 150 (435 000)	9.15 (12.81)
C	An avoided cost technique based on actual ZICER PV system to illustrate the cost benefits of integrating PVs directly into buildings. The total material and building cost of the top floor would have been £209 000 cheaper had the PV units been omitted from the design and replaced with traditional standard glazing units	209 000 (293 000)	6.20 (8.68)
D	As (C) including actual PV grant towards the ZICER PV installations	36 800 (51 520)	1.09 (1.53)
E	Average European cost of PV power in 2006[27] including installation/design fees	Not applicable	8.00 (11.00)
F	As (E) including a 50% governmental PV grant		4.00 (5.50)

Table 4. Scenarios used in the analysis (£1 = €1.40 assumed)

incorporating both the assumed discount rate and annual degradation of the PV cells. A lifetime of 25 years was assumed, this being a typical value for the current generation of cells.

Income from generation in the nth year of operation when discounted back to the present value is

$$I_n = Eu_c\,(1+r)^{-n} \tag{1}$$

where E is the expected energy generated each year, u_c is the unit cost of electricity to cover capital costs and r is the discount factor. The cumulative income I over all n years of the expected lifetime must equal the capital cost C and is given by

$$I = C = Eu_c \sum_{x=1}^{n} (1+r)^{-x} \tag{2}$$

Equation (2) is a geometric series and can be simplified and rearranged to give

$$u_c = \frac{C}{E}\left[\frac{r}{1-(1+r)^{-n}}\right] \tag{3}$$

Incorporating the maintenance element gives an over unit cost u of

$$u = \frac{C}{E}\left[m + \frac{r}{1+(1+r)^{-n}}\right] \tag{4}$$

In this study, the capital cost of the PV systems includes both module costs and 'balance of system' costs, which represent all other system component costs such as inverters, electrical installation, design fees, etc. A variety of economic scenarios associated with the capital investment was considered to provide a range of cost scenarios (Table 4). Scenarios A to D relate to the actual economics of the ZICER PVs, while scenarios E[27] and F relate to the present average costs of PVs in Europe.

The total capital cost of the PV installation was provided by quantity surveyors Northcotts as £482 350 (€675 290). There were two grants under scenarios B and D—the first was provided by the DTI Large Scale Building Integrated Field Trials Programme and amounted to £104 400 (€146 160); the second was provided from European funding and amounted to €107 989 (£67 800). In scenario C, where allowance was made for avoided costs, the estimated additional costs according to the quantity surveyors for the PV arrays would have amounted to £209 000 (€292 600).

The system has no moving parts and maintenance costs of PVs are minimal. Previous PV studies have used annual operation and maintenance figures ranging from 0.5-2.0% of initial capital costs.[1,2,4] To date, there have been no maintenance costs of the ZICER PVs incurred at the expense of the University. Future maintenance costs are likely to include electrical faults associated with the replacement of inverters; these have been estimated at 0 .4% of the total capital cost (~£1900 (€2650) per annum). Discount rates of 3, 5 and 7% were used in this study, together with a typical average annual degradation rate of 0.7% for the crystalline silicon PV cells as reported by several studies.[28-30]

To allow comparisons between different parts of the UK, the output was based on the PV modelling described in this paper relating to long-term averages for the solar radiation data. This model was validated against actual data as discussed earlier.

Figure 8 shows the unit cost of PV electricity using a discount rate of 5% for each of the six economic scenarios outlined in Table 4. To cover all possible solar radiation values falling normal to surfaces orientated at different angles and located in different parts of the UK, the values in the graph range from 500 to 1400 kWh/yr. The results show that increasing the solar radiation received by the PV surface can more than halve the cost per unit of PV electricity. This reduction is largely due to the increased solar radiation, but the module efficiency also has an effect, as demonstrated by Fig. 4.

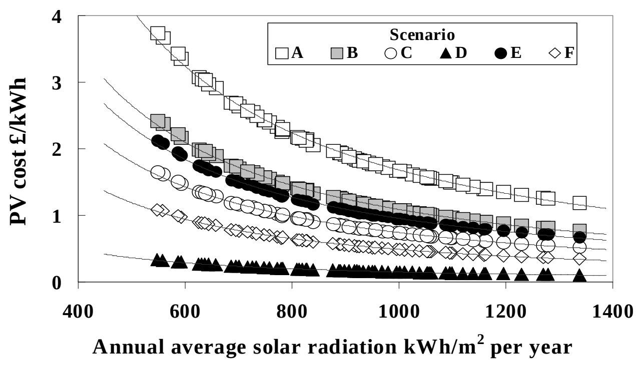

Fig. 8. Unit cost of PV electricity in six economic scenarios (Table 4) as a function of solar radiation

At a typical mean solar radiation intensity of 1000 kWh/m^2 per yr (see Table 2), the cost of PV electricity generation equates to £1.67 (€2.30) per kWh under scenario A, but reduces to £1.11 (€1.55) per kWh when the PV grant is included in scenario B. As the PVs are integrated into the structure of the building, scenarios C and D consider the actual ZICER PV costs using the avoided cost methodology. The corresponding electricity generation costs are then £0.72 (€1.00) per kWh and £0.16 (€0.22) per kWh under scenarios C and D respectively. Scenarios E and F, which explore the situation using current European costs, produce unit costs of £0.94 (€1.30) per kWh and £0.50 (€0.70) per kWh respectively.

Table 5 summarises the key information for each of the scenarios for three different discount factors and for three different solar radiation values.

3.3. Embodied energy analysis

The energy yield ratio is calculated by dividing lifetime PV electricity generation (accounting for annual degradation of the PV cells) by the embodied energy required in manufacture, construction and installation

$$EYR_{system} = \frac{\text{Lifetime PV electricity generation}}{\text{Input embodied energy}} \quad (5)$$

The EYR was used in this study (rather than energy payback time) as it incorporates the predicted life of the PV system and is thus beneficial when comparing such systems against other generation methods that have very different life spans. Equation (5) can also readily be adapted to include any embodied energy arising from maintenance or replacement over the life of the system. The system boundaries for this EYR assessment include the embodied energy of direct materials (i.e. materials that make up part of the finished product, e.g. silicon) and indirect materials (i.e. materials that are used in the process but do not end up in the product, e.g. solvents), manufacturing/ processing, embodied energy of ancillary components, transportation from the factory to the site and on-site installation.

The most comprehensive and relevant source for PV embodied energy for both monocrystalline and polycrystalline modules came from a study by De Wild-Scholten and Alsema.[31] Their PV life cycle inventory data are representative of the technology status in 2004 and, unlike many studies, cover all processes from silicon feedstock production to cell and module manufacturing. The module embodied energy input values amount to 3230 kWhe/kW_p associated with monocrystalline PV cells and 2750 kWhe/kW_p for polycrystalline PV cells.

Energy is also needed in the production of ancillary equipment such as support materials and inverters; this was derived from an earlier study by Alsema and De Wild-Scholten.[32] The embodied energy for array support and cabling is equivalent to approximately 100 kWhe/kW_p while the embodied energy for

Discount factor: %	Solar radiation: kWh/m^2 per yr	Cost: £/kWh (€/kWh) Scenario A	B	C	D	E	F
3	800	1.75 (2.44)	1.16 (1.62)	0.76 (1.05)	0 .17 (0.24)	0.98 (1.37)	0.52 (0.73)
	1000	1.37 (1.91)	0.91 (1.27)	0.59 (0.83)	0.14 (0.19)	0.77 (1.07)	0.41 (0.57)
	1200	1.13 (1.58)	0.75 (1.05)	0.49 (0.68)	0.11 (0.15)	0.63 (0.88)	0.34 (0.47)
5	800	2.13 (2.98)	1.41 (1.97)	0.92 (1.29)	0 20 (0.28)	1. 20 (1.67)	0.63 (0.88)
	1000	1.67 (2.34)	1.11 (1.55)	0.72 (1.01)	0.16 (0.22)	0.94 (1.31)	0.50 (0.69)
	1200	1.38 (1.92)	0.91 (1.27)	0 60 (0.83)	0.13 (0.18)	0.77 (1.08)	0.41 (0.57)
7	800	2.55 (3.57)	1.68 (2.35)	1.11 (1.54)	0.24 (0.32)	1.44 (2.00)	0.75 (1.04)
	1000	2.00 (2.80)	1.32 (1.84)	0.87 (1.21)	0.18 (0.25)	1.13 (1.57)	0.59 (0.82)
	1200	1.65 (2.31)	1.09 (1.52)	0.72 (1.00)	0.15 (0.21)	0.93 (1.29)	0.48 (0.67)

Table 5. Unit costs of energy generated by PV for different discount factors, solar radiation and scenario (£1 = €1 .40 assumed)

the inverters (including one replacement half way through the system life) is equivalent to approximately 185 kWhe/ kWp.

The energy used during installation of the PV arrays was based on that measured on the site during construction and is equivalent to 131.4 kWhe/kWp. The energy consumed during transportation of the units was based on the actual journey that the cells took to the site. This included transportation of the PVs from the manufacturing plant in Spain, via Germany where the PV cells were encapsulated between glass, to the final site location, i.e. Norwich. An estimated 11 250 vehicle-km were involved in this transportation, equivalent to 453.2 kWhe/kWp.

The overall embodied energy representing the sum of these components is 4.1 MWhe/kWp for monocrystalline PVs and 3 4.MWhe/kWp for polycrystalline PV systems.

A scenario similar to the 'avoided costs scenario' used in the economic analysis was also used to explore the environmental benefits of integrating PVs directly into buildings rather than as additions (thereby saving the requirement for cladding materials). This scenario, known as the 'avoided energy scenario', considered that on-site construction energy was treated as zero and the embodied energy from the replaced conventional cladding materials was subtracted from the PV material embodied energy. Net resulting embodied energy values of 3.7 MWhe/kWp and 3.0 MWhe/kWp were derived for the monocrystalline and polycrystalline PV system respectively.

Though there is a small amount of degradation in performance over time, it is much less than the reduction in income from energy generated in the future from the discount rates assumed in the economic analyses. As a result, the effect of choice of lifetime will have a more significant effect on the EYR than for an economic analysis. Table 6 illustrates the variation for a range of lifetime values (20-30 years) for monocrystalline cells at a typical solar radiation of 1000 kWh/m^2 per year. Two embodied energy scenarios are considered

(a) the PV arrays are considered as stand-alone and the full impacts of PV construction are taken into account
(b) allowance is made for the avoided energy requirements when the arrays are incorporated into the fabric of the building.

For the polycrystalline cells, the corresponding EYR values at a lifetime of 30 yr are 4.3 and 4.9 respectively.

	Energy yield ratio					
	MC cell lifetime: years			PC cell lifetime: years		
	20	25	30	20	25	30
Standard analysis	3 2.	3 8.	4 6.	2 9.	3 6.	4 3.
Avoided energy analysis	3 5.	4 2.	5 1.	3 3.	4 1.	4 9.

Table 6. Energy yield ratios for monocrystalline (MC) and polycrystalline (PC) cells at a typical solar radiation intensity of 1000 kWh/m^2 per year

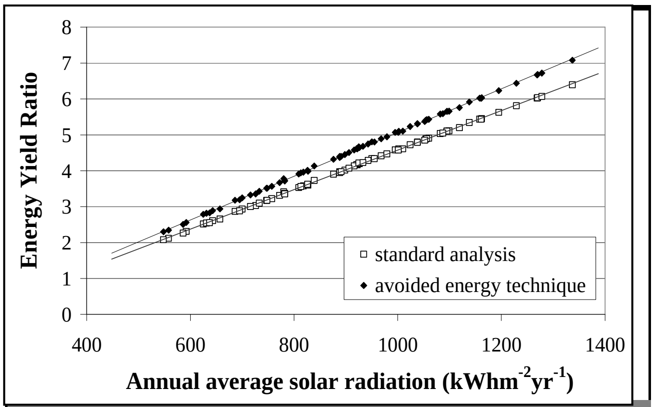

Fig. 9. Energy yield ratio for monocrystalline PVs as a function of solar radiation

As was the case with the economic analysis, the EYR varies significantly with solar radiation as demonstrated by Fig. 9.

Despite the annual average monocrystalline module efficiency being approximately 3.0 - 3.5% higher than that of polycrystalline modules, there was very little difference between the monocrystalline and polycrystalline EYR results under the current situation. This is because, although the monocrystalline PV arrays have higher cell efficiencies than polycrystalline arrays, they utilise more process energy during the crystallisation process.

4. DISCUSSION

Both the economic results and the EYR are highly dependent on PV tilt angle, orientation of the installation and location in the UK. The PV economics and EYR become more favourable as the solar radiation received by the system increases. In the case of building-integrated PV arrays, the angle and tilt are determined by the design of the building, but there are still many combinations of angles and tilts that achieve 80% or more of the maximum electricity generation as demonstrated in Table 2. However, for a vertically mounted PV system installed on an easterly or westerly orientation, the unit cost of PV power will be more than double and the EYR will be less than half that of a south-facing installation tilted at a more optimum angle of 30^o.

Even with grants and using the avoided cost analysis method, the unit costs compare unfavourably with conventional generation. Significant advances in PV technical development and further reductions in cost are required if PVs are to become a competitive source of energy.

To achieve this goal, the UK Government intervened in promoting the use of PV technology and, since 2002, has subsidised PV installations through a number of demonstration projects and field trials. However, as shown, these grants by themselves are insufficient to make the technology competitive. Other measures are now also in place—such as the promotion of renewable energy through the Renewables Obligation (RO) and the partial internalising of external environmental costs from fossil fuel combustion under the European Union Emission Trading System (EU-ETS)—which will further improve the situation.

Since April 2002, all UK electricity suppliers have been bound by the RO, which requires them to deliver a growing percentage

Period	Buy-out price: £/MWh (€/MWh)	Effective value: £/MWh (€/MWh)
2003-2004	30.51 (42.71)	53.43 (74.80)
2004-2005	31.39 (43.95)	45.04 (63.06)
2005-2006	32.33 (45.26)	42.54 (59.56)
2006-2007	33.24 (46.54)	49.28 (68.99)

Table 7. Value of the 'buy-out' price and effective premium value of RO certificates. [33] (A figure of £33.24 (€46.50) per MWh is equivalent to 3.324p (¢4.65) per kWh)

of their power from renewable technologies, increasing their proportion of supply from 3.0% in 2002/2003 to reach 10.4% by 2010/2011. Compliance failure results in a 'buy-out' fine that is index linked on an annual basis as shown in Table 7.[33] As there is currently a shortfall in renewable generation, RO certificates are trading at a premium price and this potentially reduces the unit cost of PV generation by a further 4-5 pence per kWh. However, though such benefits are theoretically present, few PV arrays have yet achieved such benefits as the number of RO certificates generated even by such a large array as the ZICER is considered to be too small by the majority of suppliers. Though there are companies offering an aggregation service, the administration costs in achieving additional income are disproportionate to the benefits received.

In theory, EU-ETS should provide further incentive. However, because of a significant over allocation of free allowances, the cost of carbon emitted fell to just a 3-4 cents per tonne (2-3p per tonne) at the end of the first phase in December 2007. This was so low that it only represented an additional cost for coal generation and consequential benefit for PV generation of only 0.0025p (¢0.0035) per kWh. Very recently, the value in the second phase (January 2008) has been just over €20 per tonne (£15.30/t) representing improved financial benefits with a figure over 1p/kWh. Predicting the cost effectiveness of a particular technology is also affected by the wholesale price of electricity, which has been as high as 5.5p (¢7.7) per kWh and as low as 3.0p (¢4 .00) per kWh over the last 12 months. Any general future increases in conventional electricity costs will also make the economics of PVs more attractive.

The EYR figures encountered in this study are lower than typical European values largely due to the lower solar radiation levels in the UK compared to some studies reporting results from southern Europe. The analyses described here also incorporate aspects that are often ignored in similar studies such as

(a) the degradation of modules over time
(b) the use of actual PV cell efficiencies to provide a realistic assessment of the performance of PVs (rather than the use of cell efficiencies in STCs)
(c) the incorporation of embodied energy associated with transportation.

Even in unfavourable locations in the UK, the EYR is around 2.5 for a vertically mounted PV system installed on an easterly or westerly orientation. This figure approaches 3 when the avoided energy technique is taken into account, i.e. the use of PVs integrated into the building structure displaces the use of conventional building cladding materials. EYRs greater than 6 occur when a PV system is located in the south/southeast of the UK and optimally positioned with a south-facing orientation and a tilt angle around 30^{o}.

The location of the PV manufacturing plant in relation to the final destination of the PV installation is an important matter to consider, although it is often overlooked. In this study, this transportation embodied energy of 450 kWh of delivered energy per kW_p increases the payback time by 1.4 yr for a vertically mounted polycrystalline PV installation and by 0.8 yr for a monocrystalline PV installation. If a PV manufacturer closer to the UK had been chosen, the transportation embodied energy could have potentially reduced by more than half. On the other hand, the carbon emission factor for electricity generated in Spain (the location of the PV manufacturer) is significantly lower than that in the UK; thus carbon reductions achieved through less transportation are likely to be lost through increased carbon emissions associated with electricity use from a UK manufacturer.

It is inevitable that commercial PV module efficiencies will increase in the future beyond typical values recorded in this study. If, for example, the overall average monocrystalline PV cell efficiency increases to 13.5%, the polycrystalline increases to 10% and the lifetime increases to 30 yr, then an EYR of 6.5 for an integrated PV system will be achieved at an annual average solar radiation intensity of 1000 kWh/m^2 per year.

5. CONCLUSIONS

Monitoring results from two crystalline PV installations were used to create an objective predictive tool to ascertain the annual average PV electricity generation over a range of orientations, tilts and locations across the UK. The model was used to predict the unit costs and EYRs under several different scenarios.

The unit price of PV electricity and the EYR for a PV installation in the UK is highly dependent on the location of the PV array within the UK and the chosen tilt angle and orientation of the installation. Integration of PV cells into the structure of a building avoids the use of conventional building cladding materials, thus reducing both costs and embodied energy. While optimum performance is achieved with near south-facing arrays at a tilt angle of approximately 308, there are still many combinations of angles and tilts that achieve 80% or more of the maximum electricity generation. In the particular case study, even with grants, the unit cost of £0.15 (€0.21) per kWh is still well above conventional generation costs, although there is potential to reduce these costs by £0.040 (€0 .055) to £0.045 (€0.063) when additional factors such as RO certificates, embedded generation benefits, climatic change levy exemption, etc. are taken into account.

With the module efficiencies reported here, EYRs approaching 6 occur when a crystalline PV system is located in the south/southeast of the UK and optimally positioned with a south-facing orientation and a tilt angle around 30^{o}, however, in unfavourable locations and orientations the EYR can fall to below 2. In the future, these values are likely to increase with improvements in module efficiency.

Attention to detail in design is important. Automatic reset facilities should be provided on inverters to minimise losses as a result of tripping due to electrical faults.

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