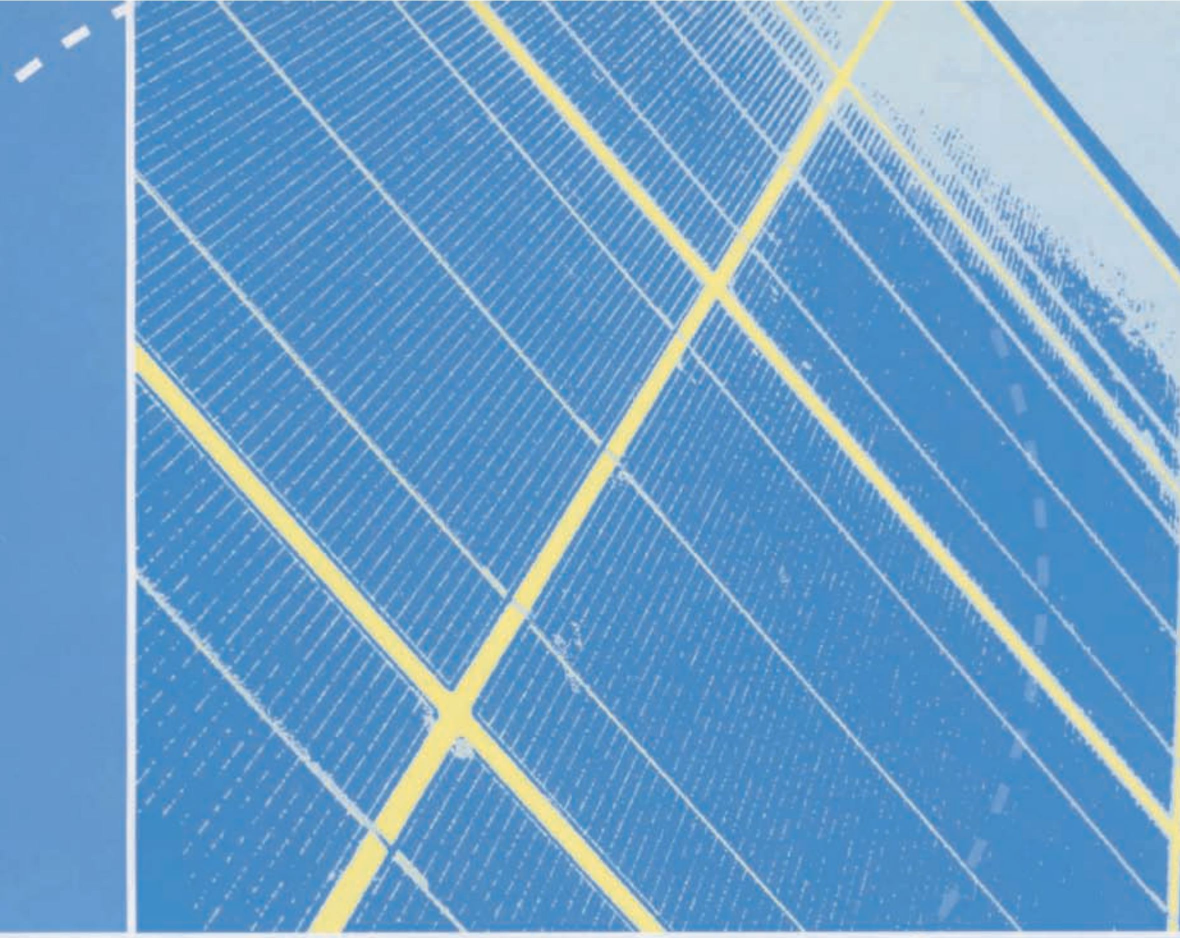

applied PHOTOVOLTAICS

Stuart R. Wenham, Martin A. Green,
Muriel E. Watt and Richard Corkish

APPLIED PHOTOVOLTAICS

Second Edition

First published by Earthscan in the UK and USA in 2007

ISBN-10: 1-84407-401-3 paperback

ISBN-13: 978-1-84407-401-3 paperback

Typesetting by Roman Balla

Printed and bound in the UK by TJ International Ltd, Padstow, Cornwall

Cover design by Mike Fell

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22883 Quicksilver Drive, Sterling, VA 20166-2012, USA

Earthscan is an imprint of James & James (Science Publishers) Ltd and publishes in association with the International Institute for Environment and Development

A catalogue record for this book is available from the British Library

Library of Congress Cataloguing –in-Publication data has been applied for.

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ACKNOWLEDGEMENTS

In recent years, the undergraduate subject *Applied Photovoltaics*, originally within the School of Electrical Engineering and now within the Centre for Photovoltaic Engineering at the University of New South Wales, has been taught by Dean Travers, Christiana Honsberg, Armin Aberle and Alistair Sproul. Alistair Sproul has provided significant help in the preparation of this edition, especially in proofreading, advising on corrections and supplying data. The feedback from students, advice on content and organisation and the additional course material provided are gratefully acknowledged.

The contributions from numerous members of the Centre for Photovoltaic Engineering at the University of New South Wales, particularly those of Jenny Hansen, Roman Balla, Robert Largent, Matt Edwards and Robert Passey, and from David Roche of Greenwatt Pty Ltd, with regard to typing, formatting, figures and eventually typesetting, have been very valuable and greatly appreciated.

Permission to use or adapt figures is gratefully acknowledged: CSIRO Australia (Fig. 1.11), Dr. Aden and Marjorie Meinel (Fig. 1.12), Australian Bureau of Meteorology (Fig. 1.13), Sandia National Laboratories (Figs. 6.7, 6.8, 7.1, 7.2, 9.3, 11.1, 11.3), IEEE (Figs. 4.14, 5.1, 9.5, 10.4, 10.5, 10.7, 10.8, 10.10, 10.11, 10.13, G.1, G.2), Telecommunications Society of Australia (Figs. 6.2, 6.3, 6.4), Silcar Pty Ltd. Design & Construction (Figure 8.2), Springer Science and Business Media (Figures 8.3, 8.4, 11.12, 11.16, 11.17), Halcrow & Partners (Figs.8.5, 8.6, 8.7, 11.8, 11.9, 11.11, ,11.15, H.4), Regional Energy Resources Information Centre (Fig. 11.2), M. Sahdev (Fig. 11.5), Thomson (Fig. 11.6) and the McGraw-Hill Book Companies (Figs. 1.14, 1.17, 11.10, 11.13, 11.14). ASTM International is acknowledged for the tabulated data of Appendix A, as is the assistance with that table of Daryl Myers and Keith Emery (NREL).

CONTENTS

INTRODUCTION

Photovoltaics is the process of converting sunlight directly into electricity using solar cells. The first photovoltaic device was demonstrated in 1839 by Edmond Becquerel, as a young 19 year old working in his father's laboratory in France. However, the understanding and exploitation of this effect was to depend on some of the most important scientific and technological developments of the 20th century. One is the development of quantum mechanics, one of the major intellectual achievements of the 20th century. Another, dependent on the first, is the development of semiconductor technology, which has been responsible for the pervasive electronics revolution and the photonics revolution now gathering pace. An interesting history of modern photovoltaic developments is given by Loferski (1993) and the early history, reaching back to 1839, is described in more technical detail by Crossley *et al.* (1968).

Fortunately, given its pedigreed background, the simplicity and reliability of use of solar cells is one of the technology's great strengths. In the first few chapters of this book, we explore the properties of the two most important components of this process—sunlight, which provides the primary source of energy, and the solar cells themselves, which convert this sunlight by elegant internal processes into electricity. We then look at the fabrication of cells and modules before examining a range of photovoltaic systems, from specific purpose applications such as solar cars through independent power supplies for households or water pumping to large grid-connected power stations.

This book aims to provide workers in the field with the basic information needed to understand the principles of photovoltaic system operation, to identify appropriate applications and to undertake simple photovoltaic system design. It is based on course material used for undergraduate Photovoltaic and Solar Energy Engineering, Renewable Energy Engineering and Electrical Engineering students at the University of New South Wales, and will continue to be used as a principal text. By increasing the number of graduates who are expert in photovoltaic concepts and applications, we hope to provide engineers qualified to participate in and promote the rapid global growth of the photovoltaics industry.

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Crossley, P.A., Noel, G.T. & Wolf, M. (1968), *Review and Evaluation of Past Solar-Cell Development Efforts*, Report by RCA Astro-Electronics Division for NASA, Contract Number NASW-1427, Washington, DC.

Loferski, J.J., (1993), 'The first forty years: A brief history of the modern photovoltaic age', *Progress in Photovoltaics: Research and Applications*, **1**, pp. 67–78.

Chapter

1

THE CHARACTERISTICS OF SUNLIGHT

1.1 PARTICLE-WAVE DUALITY

Our understanding of the nature of light has changed back and forth over the past few centuries between two apparently conflicting viewpoints. A highly readable account of the evolution of quantum theory is given in Gribben (1984). In the late 1600s, Newton's mechanistic view of light as being made up of small particles prevailed. By the early 1800s, experiments by both Young and Fresnel had shown interference effects in light beams, indicating that light was made up of waves. By the 1860s, Maxwell's theories of electromagnetic radiation were accepted, and light was understood to be part of a wide spectrum of electromagnetic waves with different wavelengths. In 1905, Einstein explained the photoelectric effect by proposing that light is made up of discrete particles or *quanta* of energy. This complementary nature of light is now well accepted. It is referred to as the particle-wave duality, and is summarised by the equation

$$E = hf = hc/\lambda \qquad (1.1)$$

where light, of frequency f or wavelength λ, comes in 'packets' or *photons*, of energy E, h is Planck's constant (6.626×10^{-34} Js) and c is the velocity of light (3.00×10^{8} m/s) (NIST, 2002).

In defining the characteristics of photovoltaic or 'solar' cells, light is sometimes treated as waves, other times as particles or photons.

1.2 BLACKBODY RADIATION

A ‘blackbody’ is an ideal absorber, and emitter, of radiation. As it is heated, it starts to glow; that is, to emit electromagnetic radiation. A common example is when a metal is heated. The hotter it gets, the shorter the wavelength of light emitted and an initial red glow gradually turns white.

Classical physics was unable to describe the wavelength distribution of light emitted from such a heated object. However, in 1900, Max Planck derived a mathematical expression describing this distribution, although the underlying physics was not understood until Einstein’s work on ‘quanta’ five years later. The spectral emissive power of a blackbody is the power emitted per unit area in the wavelength range λ to $\lambda + d\lambda$ and is given by the Planck distribution (Incropera & DeWitt, 2002),

$$E(\lambda, T) = \frac{2\pi hc^2}{\lambda^5\left[\exp\left(hc/(\lambda kT)\right) - 1\right]} \tag{1.2}$$

where k is Boltzmann’s constant and E has dimensions of power per unit area per unit wavelength. The total emissive power, expressed in power per unit area, may be found by integration of Eqn. (1.2) over all possible wavelengths from zero to infinity, yielding $E = \sigma T^4$, where σ is the Stefan-Boltzmann constant (Incropera & DeWitt, 2002).

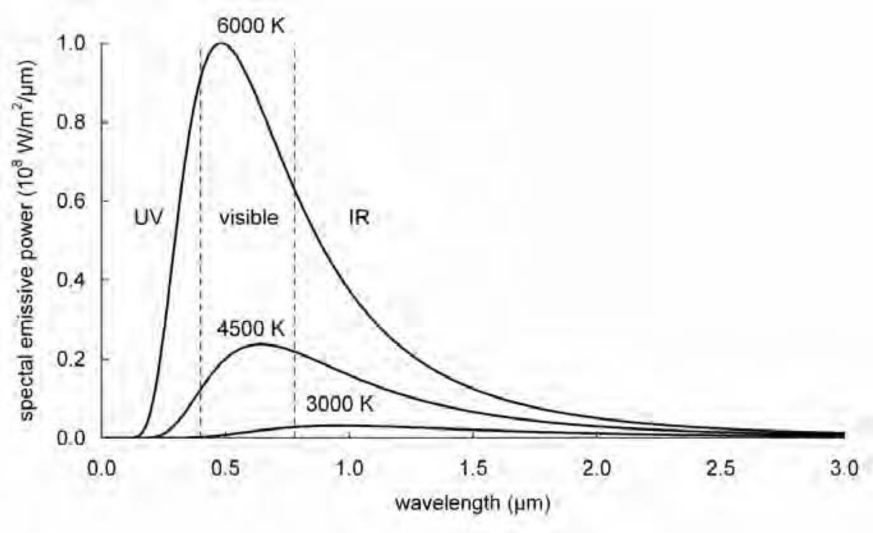


Figure 1.1. Radiation distributions from perfect blackbodies at three different temperatures, as would be observed at the surface of the blackbodies.

Fig. 1.1 illustrates the radiation distribution for different blackbody temperatures, as would be observed at the surface of the blackbody. The lowermost curve is that for a body heated to 3000 K, about the temperature of the tungsten filament in an incandescent lamp. The wavelength of peak energy emission is about 1 µm, in the infrared. Only a small amount of energy is emitted at visible wavelengths (0.4–0.8 µm) in this case, which explains why these lamps are so inefficient. Much higher temperatures, beyond the melting points of most metals, are required to shift the peak emission to this range.

1.3 THE SUN AND ITS RADIATION

The sun is a hot sphere of gas heated by nuclear fusion reactions at its centre (Quaschning, 2003). Internal temperatures reach a very warm 20 million K. As indicated in Fig. 1.2, the intense radiation from the interior is absorbed by a layer of hydrogen ions closer to the sun's surface. Energy is transferred by convection through this optical barrier and then re-radiated from the outer surface of the sun, the *photosphere*. This emits radiation approximating that from a blackbody with a temperature of nearly 6000 K, as shown in Fig. 1.3.

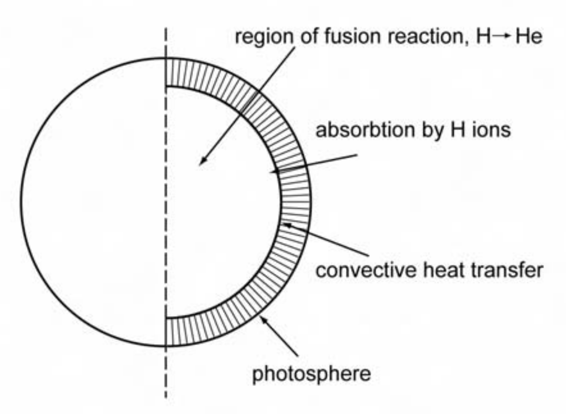


Figure 1.2. Regions in the sun's interior.

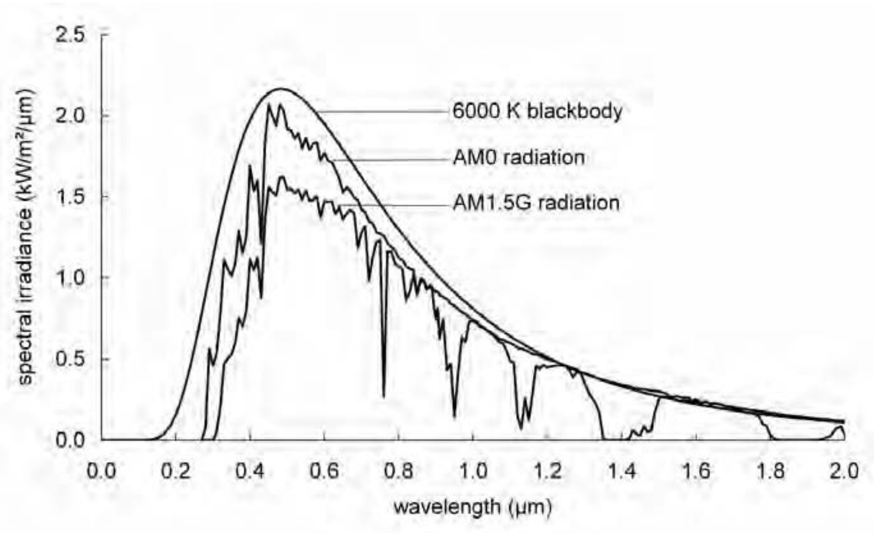


Figure 1.3. The spectral irradiance from a blackbody at 6000 K (at the same apparent diameter as the sun when viewed from earth); from the sun's photosphere as observed just outside earth's atmosphere (AM0); and from the sun's photosphere after having passed through 1.5 times the thickness of earth's atmosphere (AM1.5G).

1.4 SOLAR RADIATION

Although radiation from the sun's surface is reasonably constant (Gueymard, 2004; Willson & Hudson, 1988), by the time it reaches the earth's surface it is highly variable owing to absorption and scattering in the earth's atmosphere.

When skies are clear, the maximum radiation strikes the earth's surface when the sun is directly overhead, and sunlight has the shortest pathlength through the atmosphere. This pathlength can be approximated by $1/\cos\varphi$, where φ is the angle between the sun and the point directly overhead, as shown in Fig. 1.4. This pathlength is usually referred to as the *Air Mass* (AM) through which solar radiation must pass to reach the earth's surface. Therefore

$$AM = 1/\cos\varphi \tag{1.3}$$

This is based on the assumption of a homogeneous, non-refractive atmosphere, which introduces an error of approximately 10% close to the horizon. Iqbal (1983) gives more accurate formulae that take account of the curved path of light through atmosphere where density varies with depth.

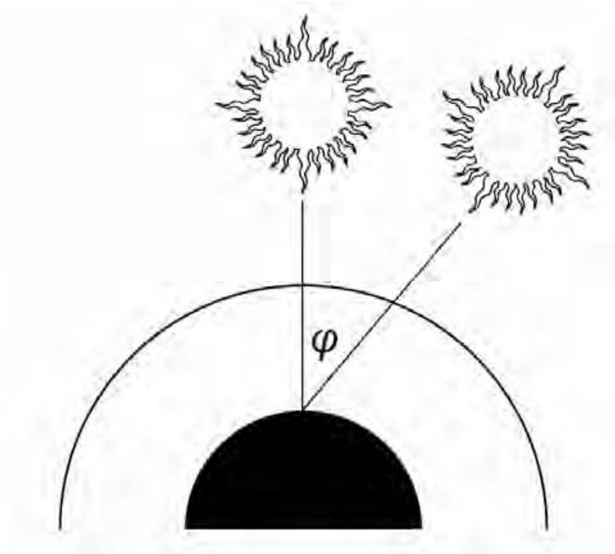


Figure 1.4. The amount of atmosphere (air mass) through which radiation from the sun must pass to reach the earth's surface depends on the sun's position.

When $\varphi = 0$, the Air Mass equals 1 or 'AM1' radiation is being received; when $\varphi = 60°$, the Air Mass equals 2 or 'AM2' conditions prevail. AM1.5 (equivalent to a sun angle of 48.2° from overhead) has become the standard for photovoltaic work.

The Air Mass (AM) can be estimated at any location using the following formula:

$$AM = \sqrt{1 + (s/h)^2} \tag{1.4}$$

where s is the length of the shadow cast by a vertical post of height h, as shown in Fig. 1.5.

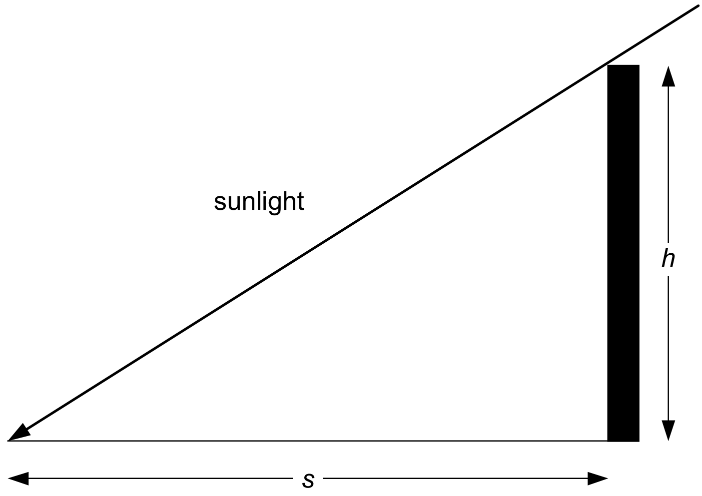


Figure 1.5. Calculation of Air Mass using the shadow of an object of known height.

The spectral distribution of sunlight outside the atmosphere (*Air Mass Zero* or AM0), and at AM1.5 are shown in Fig. 1.6. Air Mass Zero is essentially unvarying and its total power density, integrated over the spectrum, is referred to as the *solar constant*, with a generally accepted value (ASTM, 2000, 2003; Gueymard, 2004) of

$$\gamma = 1.3661\ \mathrm{kW/m^2} \tag{1.5}$$

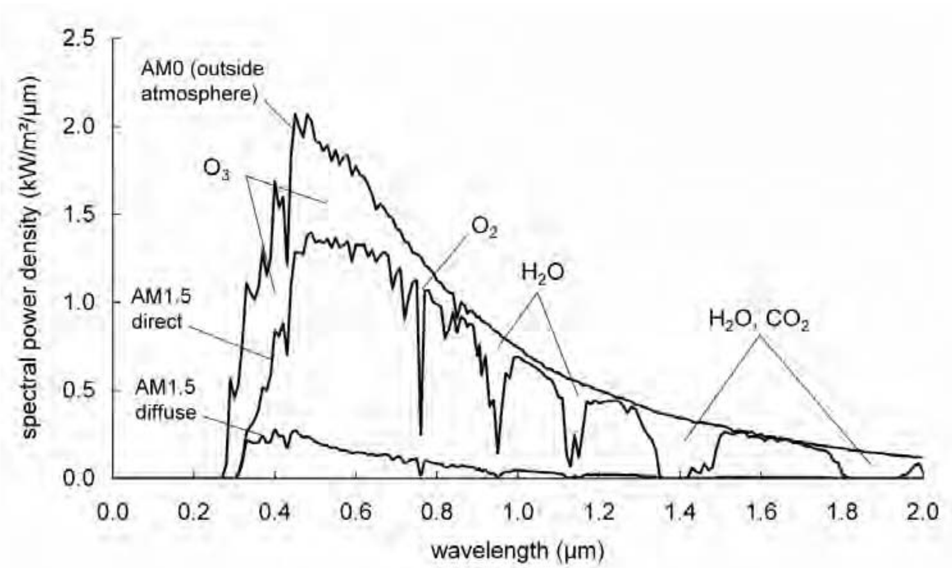


Figure 1.6. The spectral power density of sunlight, outside the atmosphere (AM0) and at the earth's surface (AM1.5), showing absorption from various atmospheric components.

It is common to consider separately the 'direct' (or 'beam') radiation from the solar disk and the 'diffuse' radiation from elsewhere in the sky, with their sum known as 'global' radiation. A table of AM1.5 global (AM1.5G) irradiance versus wavelength for an equator-facing, 37° tilted surface on earth is given in Appendix A. Since different types of photovoltaic cells respond differently to different wavelengths of light, the tables can be used to assess the likely output of different cells.

For the spectrum of Appendix A, the total energy density, i.e. the integral of the power density over the entire wavelength band, is close to 970 W/m^2. This spectrum, or the corresponding 'normalised' spectrum of 1000 W/m^2, is the present standard used for rating photovoltaic products. The latter is close to the maximum power received at the earth's surface. The power and photon flux density components corresponding to the 'normalised' spectrum can be obtained by multiplying the Appendix A values by 1000/970.

To assess the likely performance of a photovoltaic cell or module in a real system, the standard spectra discussed above must be related to the actual solar insolation levels for the site at which the system is to be installed. (Fig. 1.12 illustrates the global and seasonal variation in daily insolation levels.)

1.5 DIRECT AND DIFFUSE RADIATION

Sunlight passing through the earth's atmosphere is attenuated, or reduced, by about 30% by the time it reaches the earth's surface due to such effects as (Gast, 1960; Iqbal, 1983):

1. Rayleigh scattering by molecules in the atmosphere, particularly at short wavelengths (~λ^{-4} dependence)
2. Scattering by aerosols and dust particles.
3. Absorption by atmospheric gases such as oxygen, ozone, water vapour and carbon dioxide (CO_2).

The latter produces the absorption bands apparent in Fig. 1.3. Wavelengths below 0.3 μm are strongly absorbed by ozone. Depletion of ozone from the atmosphere allows more of this short wavelength light to reach the earth, with consequent harmful effects on biological systems. The absorption bands around 1 μm are produced by water vapour absorption, complemented by CO_2 absorption at longer wavelengths. Changing the CO_2 content of the atmosphere also has consequences for the earth's climatic and biological systems.

Fig. 1.7 shows how atmospheric scattering results in a diffuse component of sunlight coming from all directions in the sky. Diffuse radiation is predominantly at the blue end of the spectrum because of more effective scattering at small wavelengths. Hence, the sky appears blue.

AM1 radiation (radiation when the sun is directly overhead), has a diffuse component of about 10% when skies are clear. The percentage increases with increasing air mass or when skies are not clear.

Cloud cover is, of course, a significant cause of radiation attenuation and scattering. *Cumulus* or bulky, low altitude clouds, are very effective in blocking sunlight.

However, about half the direct beam radiation blocked by cumulus clouds is recovered in the form of diffuse radiation. *Cirrus*, or wispy, high altitude clouds, are not as effective in blocking sunlight, and about two thirds of the direct beam radiation blocked is converted to diffuse radiation. On a totally cloudy day, with no sunshine, most radiation reaching the earth's surface will be diffuse (Liu & Jordan, 1960).

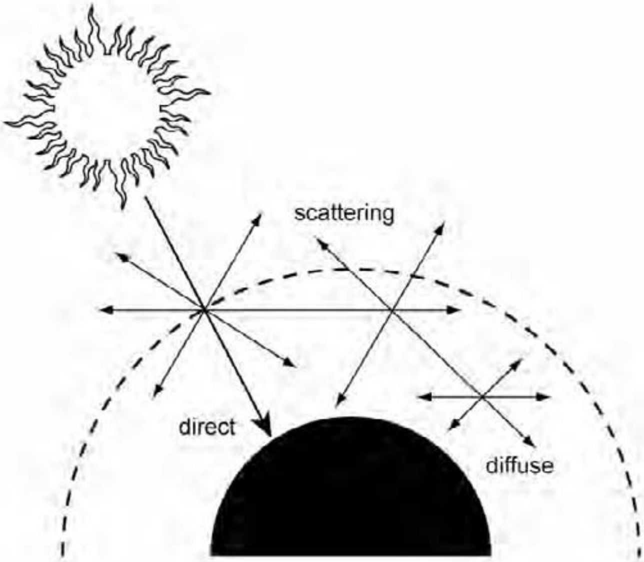


Figure 1.7. Atmospheric scattering leading to diffuse radiation.

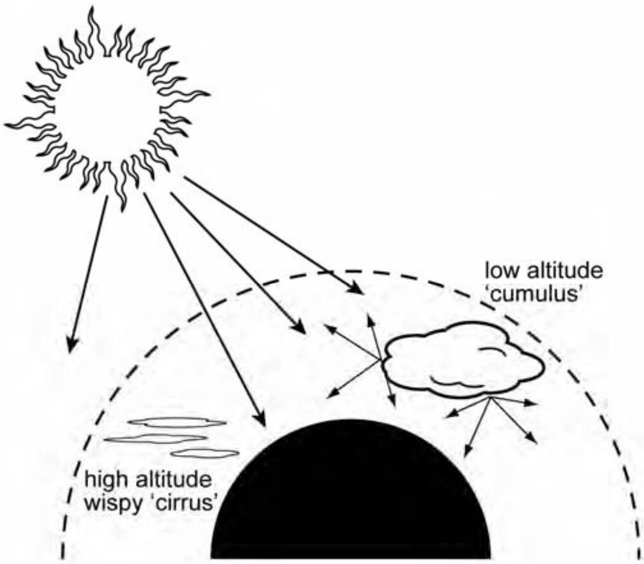


Figure 1.8. The effect of cloud cover on radiation reaching the earth's surface.

1.6 THE GREENHOUSE EFFECT

To maintain the earth's temperature, energy reaching the earth from the sun must equal energy radiated back out from the earth. As with incoming radiation, the atmosphere interferes with outgoing radiation. Water vapour absorbs strongly in the 4–7 µm wavelength band and carbon dioxide in the 13–19 µm wavelength band. Most outgoing radiation (70%) escapes in the 'window' between 7 and 13 µm.

If we had no atmosphere, as on the moon, the average temperature on the earth's surface would be about –18°C. However, a natural background level of 270 ppm CO_2 in the atmosphere causes the earth's temperature to be about 15°C on average, 33°C greater than the moon's. Fig. 1.9 shows the wavelength distribution of incoming and outgoing energy if the earth and the sun were ideal blackbodies.

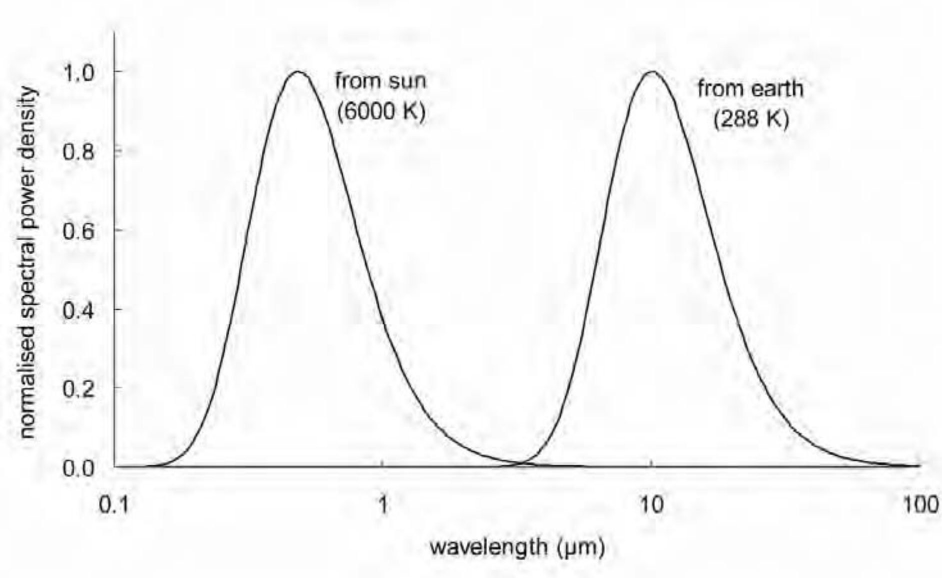


Figure 1.9. Spectral distribution of incoming and outgoing radiation at the earth's surface if both earth and sun are treated as black bodies. (Note that the peaks of the two curves have been normalised and the scale of the horizontal axis is logarithmic.)

Human activities are increasingly releasing 'anthropogenic gases' into the atmosphere, which absorb in the 7–13 µm wavelength range, particularly carbon dioxide, methane, ozone, nitrous oxides and chlorofluorocarbons (CFCs). These gases are preventing the normal escape of energy and are widely accepted to be causing observed increases in average terrestrial temperatures. According to McCarthy *et al.* (2001), 'Globally-averaged surface temperatures have increased by 0.6 ± 0.2°C over the 20th century, and the globally-averaged surface air temperature is projected by models to warm 1.4–5.8°C above 1990 levels by 2100. These projections indicate that the warming would vary by region, and be accompanied by increases and decreases in precipitation. In addition, there would be changes in the variability of climate, and changes in the frequency and intensity of some extreme climate phenomena.' There are already indications of increased floods and droughts, and a wide range of serious impacts on human and natural systems are predicted.

Clearly, human activities have now reached a scale where they are impacting on the planet's self-support systems. The side-effects could be devastating and technologies with low environmental impact and low 'greenhouse gas' emissions will increase in importance over the coming decades. Since the energy sector is the major producer of greenhouse gases via the combustion of fossil fuels, technologies such as photovoltaics, which can be substituted for fossil fuels, should increasingly be used (Blakers *et al.*, 1991).

1.7 APPARENT MOTION OF THE SUN

The apparent motion of the sun (Iqbal, 1983; Sproul, 2002), and its position at solar noon, relative to a fixed observer at latitude 35°S (or N) is shown in Fig. 1.10. The sun's path varies over the year and is shown at its extreme excursions, the summer and winter solstices, as well as at the equinoxes, its mid-season position. At the equinoxes, (around March 21 and September 23), the sun rises due east and sets due west and at solar noon, the altitude equals 90° minus the latitude. At the winter and summer solstices (around June 21 and December 22, respectively, for the southern hemisphere and the opposite for the northern hemisphere), the altitude at solar noon is increased or decreased by the inclination of the earth's axis (23°27'). Equations that allow the sun's position in the sky to be calculated at any point in time are given in Appendix B. The apparent solar trajectory is sometimes indicated in the form of polar (Fig. 1.11) or cylindrical diagrams. The latter are particularly useful for overlaying the shading effects of nearby objects (Duffie & Beckman, 1991; Quaschning & Hanitsch, 1995; Skiba *et al.*, 2000). An online calculator for cylindrical sun charts is available from the University of Oregon Solar Radiation Monitoring Laboratory (University of Oregon, 2003).

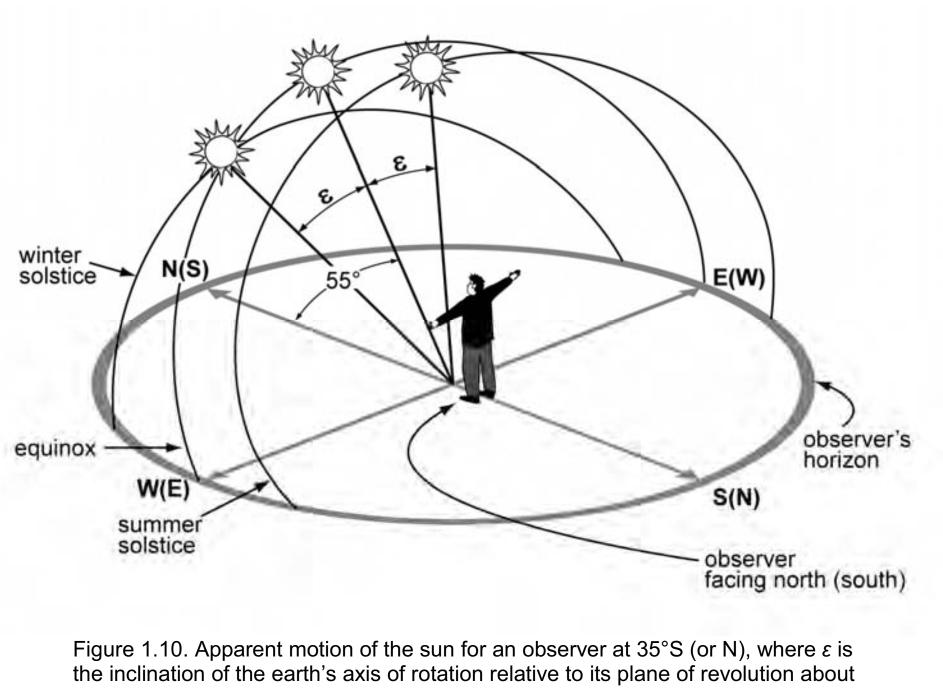


Figure 1.10. Apparent motion of the sun for an observer at 35°S (or N), where ε is the inclination of the earth's axis of rotation relative to its plane of revolution about the sun (= 23°27' = 23.45°).

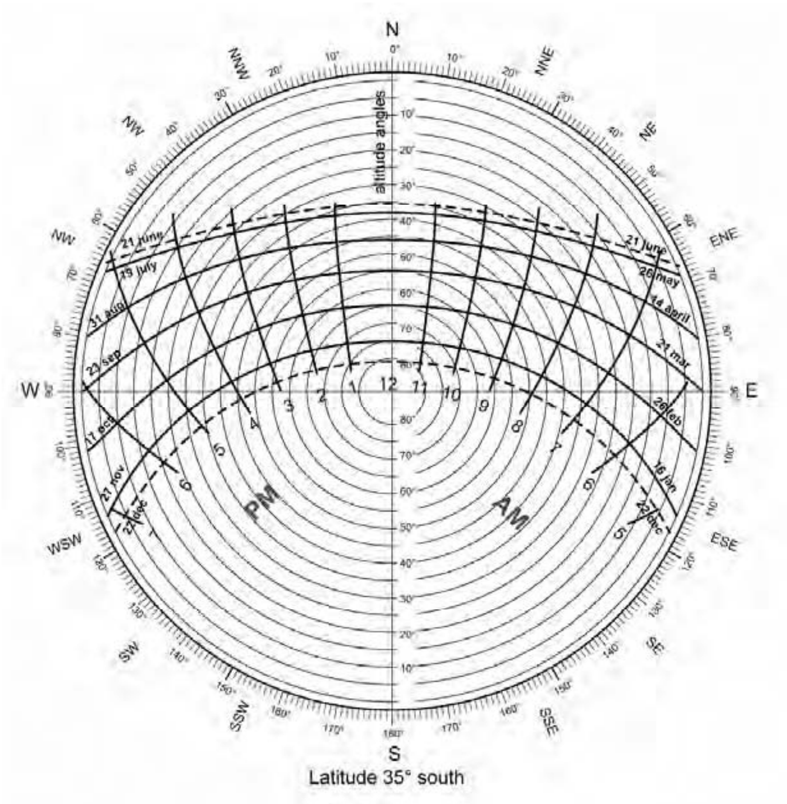


Figure 1.11. Polar chart showing the apparent motion of the sun for an observer at 35°S. ("Copyright © CSIRO 1992, Reproduced by permission of CSIRO PUBLISHING, Melbourne Australia from Sunshine and Shade in Australasia 6th edition (R.O. Phillips) http://www.publish.csiro.au/pid/147.htm)

1.8 SOLAR INSOLATION DATA AND ESTIMATION

Good reviews of this field have been done by, for example, Duffie and Beckman (1991), Iqbal (1983), Reddy (1987), Perez *et al.* (2001) and Lorenzo (1989, 2003). Extraterrestrial irradiation is known from geometry and the solar constant (see Eqn. 1.5) but terrestrial intensities are less well defined.

Photovoltaic system designers often need estimates of the insolation expected to fall on arbitrarily-tilted surfaces. For most purposes, monthly average daily insolation values are sufficient (Lorenzo, 2003) and 'characteristic' days near the middle of each month are often used to define average monthly values (Appendix C). Asterisks are used in this book to denote variables based on characteristic days and overbars indicate monthly averages. Separated direct and diffuse components are usually required for estimation of the effects of module tilt, but these need to be estimated from global values if not separately measured. Hence, there are three basic problems:

1. Evaluating the global radiation on a horizontal surface for a given site from available measured quantities.

2. Evaluating the horizontal direct and diffuse components from the global values.
3. Estimating these components for a tilted plane from the horizontal values.

1.8.1 Extraterrestrial radiation

R_0, the extraterrestrial radiation on a horizontal surface, may be calculated from γ_E, the solar constant expressed as energy incident in one hour

$$\gamma_E = 3.6\gamma \quad \left(\mathrm{kJm^{-2}h^{-1}}\right) \tag{1.6}$$

and the geometry of the sun and earth (Iqbal, 1983, p. 65)

$$R_0 = \left(\frac{24}{\pi}\right)\gamma_E e_0 \cos\varphi \cos\delta\left[\sin\omega_s - \left(\frac{\pi\omega_s}{180}\right)\cos\omega_s\right] \tag{1.7}$$

where

$$e_0 \approx 1 + 0.033\cos\left(\frac{2\pi d}{365}\right) \tag{1.8}$$

is the orbital eccentricity (the reciprocal of the square of the radius vector of the earth) (Iqbal, 1983) (a more accurate expression for the eccentricity is also available in Lorenzo, 1989), ω_s is the sunrise hour angle, defined by

$$\cos\omega_s = \tan\varphi \tan\delta \tag{1.9}$$

d is the day number starting with 1 January as $d = 1$ (February is always assumed to have 28 days, introducing a small error in leap years), and δ is the declination of the sun as given by

$$\delta \approx \sin^{-1}\left\{\sin\varepsilon.\sin\left[\frac{(d-81)360}{365}\right]\right\} \approx \varepsilon \sin\left[\frac{(d-81)360}{365}\right] \tag{1.10}$$

where $\varepsilon = 23.45°$. The declination is the angle between a line joining the earth and sun centres and the earth's equatorial plane and is zero at the equinoxes (Iqbal, 1983). More complicated and accurate expressions are also available (see Appendix B).

The corresponding monthly average of extraterrestrial daily global radiation on a horizontal surface is given by

$$\overline{R}_0 = \left(\frac{24}{\pi}\right)\gamma_E e_0^* \cos\varphi \cos\delta^*\left[\sin\omega_s^* - \left(\frac{\pi\omega_s^*}{180}\right)\cos\omega_s^*\right] \tag{1.11}$$

1.8.2 Terrestrial global radiation on a horizontal surface

Various instruments exist for measuring insolation levels (Iqbal, 1983; Tindell & Weir, 1986). The simplest is a heliograph, which measures the hours of bright sunshine by using focussed light to burn a hole in a rotating chart. Silicon solar cells themselves are used in the next most sophisticated group of equipment. The thermoelectric effect (voltage generated by heat differences across junctions of dissimilar material) forms the basis of the more accurate equipment (pyrometers, pyrheliometers) since this effect is less sensitive to the wavelength of light.

Obtaining accurate solar insolation data in an appropriate form is obviously important for designing photovoltaic systems but it is sometimes a difficult task. One of the most widely available data forms is the average daily, monthly, quarterly or annual total global (direct and diffuse) radiation falling on a horizontal or tilted surface. Examples are shown in Fig. 1.12, which gives the quarterly-average global isoflux contours for each quarter in MJ/m^2 per day. Similar global plots are available from Sandia National Laboratories (1991). Where possible, more exact data for each particular location should be sought, preferably in the form of direct and diffuse components rather than global insolation levels. Some sources of insolation data are listed in Appendix D. Direct and diffuse components have been measured and are available for some locations. Data for several Australian sites have been processed into a range of forms useful to solar energy engineers and architects (Lee *et al.*, 2003).

Peak sun hours data

Average daily insolation values for each month are sometimes presented in the form of 'peak sun hours'. Conceptually, the energy received throughout the day, increasing from low intensity in the morning, peaking at solar noon and declining during the afternoon, is compressed into a reduced duration of noon intensity sunlight (Sandia National Laboratories, 1991). If the intensity of noon insolation (peak sun) is approximated to 1.0 kW/m^2, the number of peak sun hours coincides with the total daily insolation measured in kWh/m^2.

Sunshine hours data

A form in which solar insolation data are commonly available is as 'sunshine hours' (SSH) (Twidell & Weir, 2006). This term indicates the number of daily hours of sunlight above a certain intensity, approximately 210 W/m^2, for a given period (usually a month), but gives no indication of absolute values and applies only to the direct component of sunlight. The measurements of 'sunshine hours' are made on a Campbell-Stokes sunshine hours instrument by concentrating parallel rays of light onto a small area of moving tape, which burns if the sun is shining brightly. Diffuse light cannot be concentrated in the same way and is not recorded by the instrument. The resulting data are not very high quality and are not recommended for use except where they can be reliably correlated with irradiation (Standards Australia, 2002), but are available for many locations where irradiation has not been recorded.

For PV system design, the difficulty is in converting SSH data to a useable form. Here we consider techniques for estimating, from SSH data, the monthly average of daily global radiation incident on a horizontal surface (Iqbal 1983)

$$\overline{R} = \overline{R}_0(a + b\,\overline{n}\,/\,\overline{N}_d) \qquad (1.12)$$

where $\overline{R}_o$ is defined by Eqn. (1.11), $\overline{n}$ is the recorded monthly average of bright sunshine hours per day, as measured by a Campbell-Stokes instrument, *a* and *b* are regression ‘constants’ extracted from measured data at various locations, and $\overline{N}_d$ is the monthly average day length = $2/15\omega_s^*$.

This model was used by Telecom (now Telstra) Australia (Muirhead & Kuhn, 1990), who determined *a* and *b* values as listed in Table 1.1 and ‘averages’ for Australia of

$$a = 0.24 \text{ and } b = 0.48, \tag{1.13}$$

although some dependence on latitude was found.

See Appendix D for some sources of extracted *a* and *b* values for various world locations. Extensive records are available for many sites across Australia as well as some isolated islands and Antarctica.

Table 1.1. Regression data for Australian sites (Muirhead & Kuhn, 1990).

Site	Latitude °	*a*	*b*
Adelaide	34.9	0.24	0.51
Alice Springs	23.8	0.24	0.51
Brisbane	27.5	0.23	0.46
Darwin	12.5	0.28	0.46
Hobart	42.8	0.23	0.47
Laverton	37.9	0.24	0.49
Mt. Gambier	37.8	0.26	0.46
Perth	32.0	0.22	0.49
Sydney	33.9	0.23	0.48
Wagga Wagga	35.2	0.27	0.52

More complicated expressions (Reitveld, 1978)

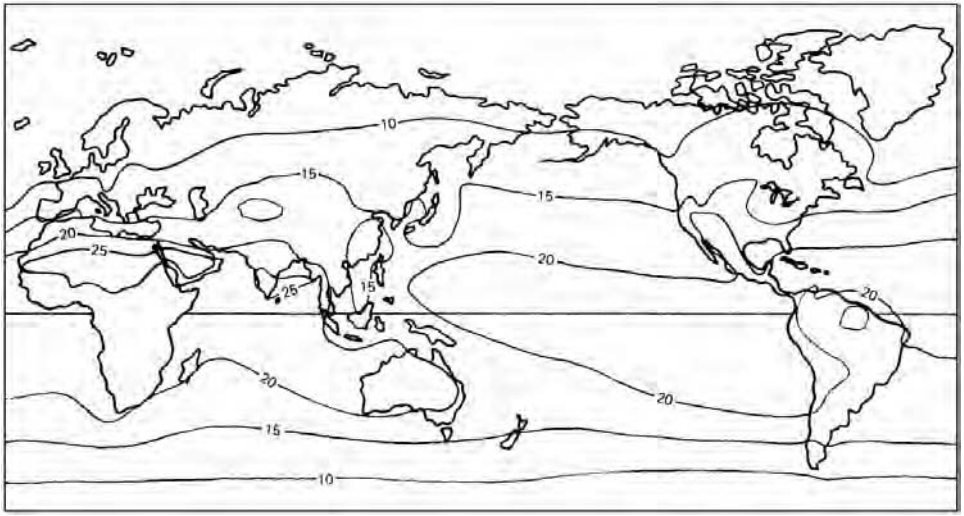
$$a = 0.10 + 0.24\,\overline{n}/\overline{N}_d \text{ and } b = 0.38 + 0.08\,\overline{n}/\overline{N}_d \tag{1.14}$$

have been determined through the use of data generated from sites all around the world. This is supposed to be applicable globally and to be superior to other correlations for cloudy conditions (Iqbal, 1983). Latitude dependence (for latitude $\theta < 60°$) has been introduced by Glover and McCulloch (1958), giving

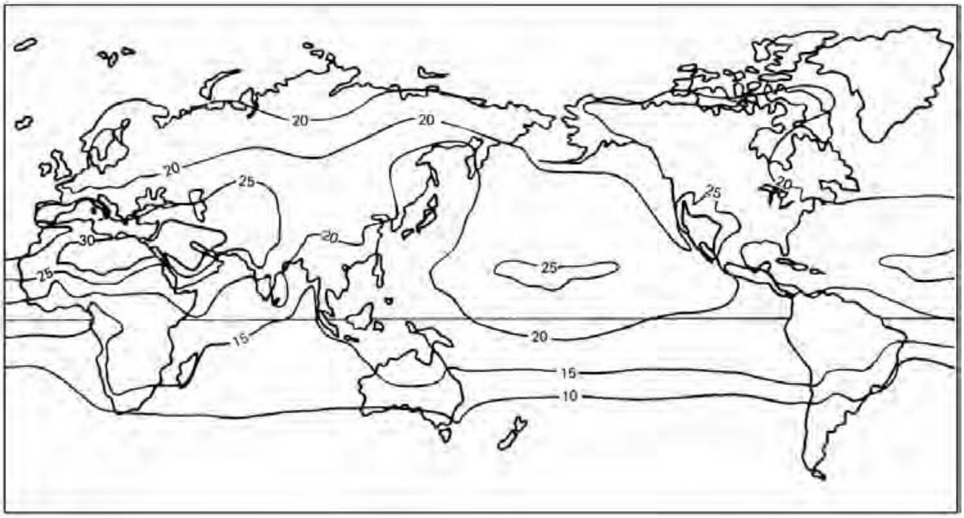
$$\overline{R} = \overline{R}_o\,[0.29\cos\theta + 0.52\,(\overline{n}/\overline{N}_d)] \tag{1.15}$$

There are reasons for caution in using *a* and *b* values from the literature. Various values for geometric and insolation parameters have been used in their derivation, measured data have come from a variety of instruments using a variety of methods, and data obtained in different ways have sometimes been mixed and treated as if of identical form (Iqbal, 1983).

Another way of estimating global radiation from SSH data is to use the value of $\overline{n}/\overline{N}_d$ as an estimate of the percentage of ‘sunny days’, with $(\overline{N}_d - \overline{n})/\overline{N}_d$ being the corresponding percentage of ‘cloudy days’. The air mass values throughout each day for the given latitude and time of year are then used to estimate quite accurately the direct component of insolation via Eqn. (1.20) below. The diffuse component can then be estimated by assuming that 10% of the insolation on a ‘sunny day’ is diffuse and that the average solar intensity on a ‘cloudy day’ is 20% that of a ‘sunny day’.

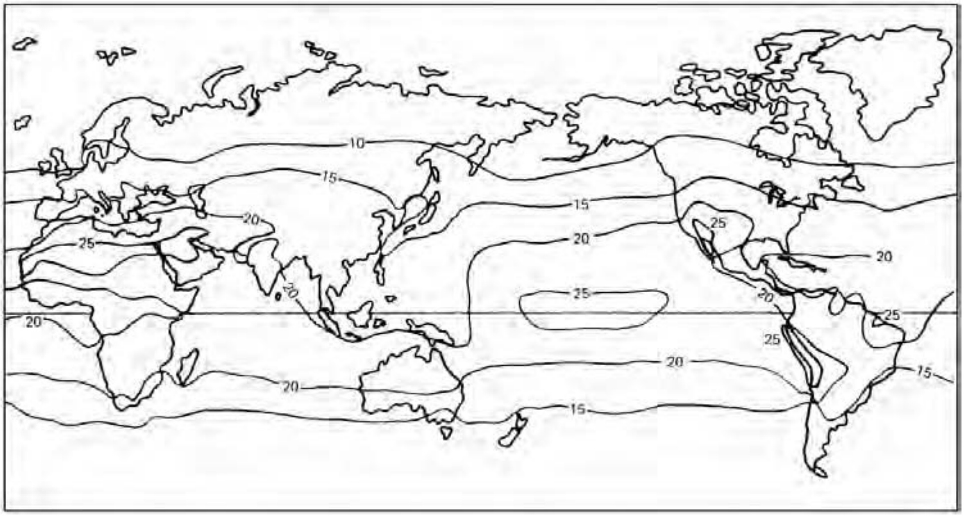


a

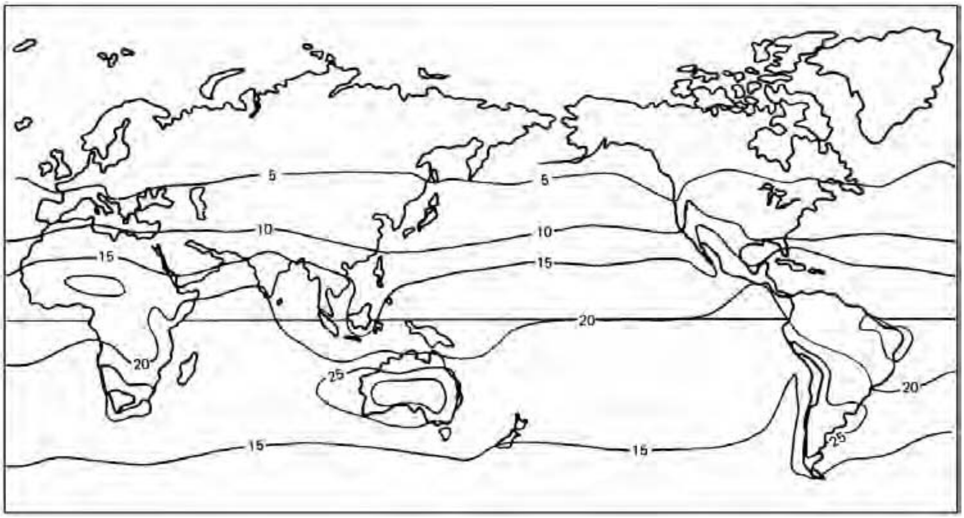


b

Figure 1.12. Average quarterly global isoflux contours of total insolation per day in MJ/m^2 falling on a horizontal surface (1 MJ/m^2 = 0.278 kWh/m^2). (*a*) March quarter, (*b*) June quarter (Used with permission of the authors, Meinel & Meinel, 1976).



c



d

Figure 1.12 (continued). Average quarterly global isoflux contours of total insolation per day in MJ/m^2 falling on a horizontal surface (1 MJ/m^2 = 0.278 kWh/m^2). (*c*) September quarter, (*d*) December quarter (Used with permission of the authors, Meinel & Meinel, 1976).

Typical meteorological year (TMY) data

Insolation data is sometimes available in the form of a 'typical meteorological year' (TMY) data set (Hall, 1978; Perez, 2001; Lorenzo, 2003). This is a full year of data combined from individual months, each of which has been selected from an historical record as being 'typical'. Several selection methods exist and smoothing may be applied to reduce discontinuities that could arise from concatenating months of data from different years (Perez, 2001). Lorenzo (2003) argues at length that although a TMY data set may consist of hourly values, its use in modelling does not necessarily produce results more accurate than those of a set of 12 monthly values.

Satellite cloud cover data

Every hour, satellite cloud cover data are updated at the Australian Bureau of Meteorology (2004). The digitised data corresponding to photographs such as that in Fig. 1.13 are also available and have a resolution of 2.5 km. Such data can be fed directly into a computer for processing and analysis to facilitate very accurate estimates of percentages of cloudy and sunny weather (Beyer *et al.*, 1992). Satellite data, accumulated over many years, can then be used in conjunction with Eqn. (1.19) below, and the equations of Appendix B, to estimate insolation levels.

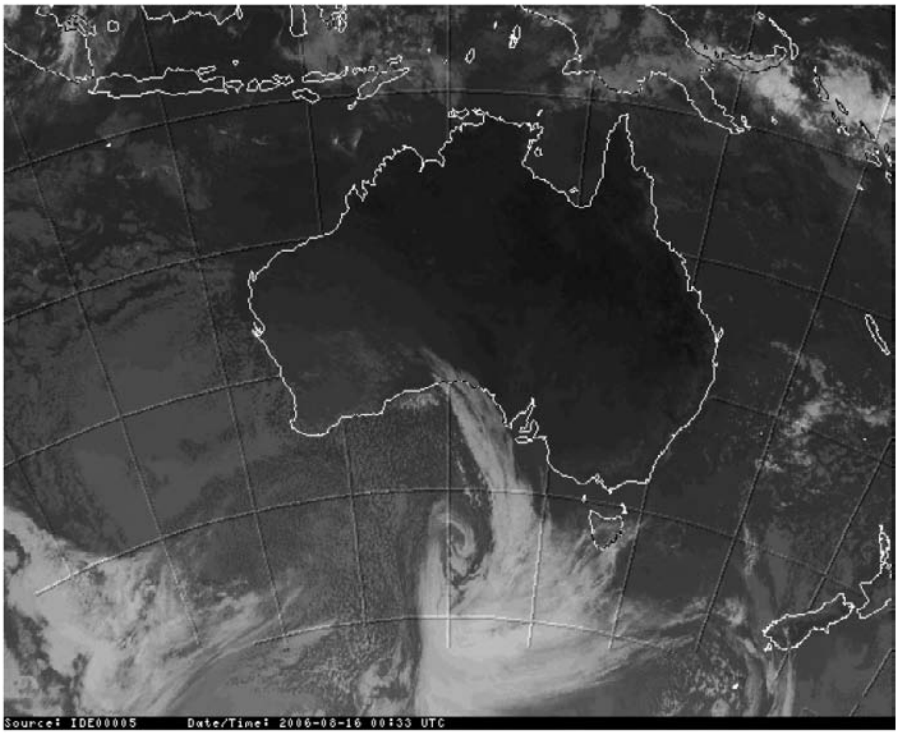


Figure 1.13. Infrared satellite cloud cover photograph, 16 August 2006 (Used with permission of the Bureau of Meteorology , "MTSAT-1R : Satellite image originally processed by the Bureau of Meteorology from the geostationary satellite MTSAT-1R operated by the Japan Meteorological Agency.")

A cloudiness index, corresponding to the fraction of sky blocked by clouds, has been correlated with global radiation (Lorenzo, 1989) and cloud cover (sky cover) data, and is discussed by Iqbal (1983), who considers this form of data to be less reliable than sunshine hour correlations.

Also available for some locations are nephanalysis charts, which portray cloud data by standardised symbols and conventions, showing cloud types, amounts and sizes, the spaces between them and various types of cloud lines and bands. The degrees of coverage are determined by ground-level observations, in conjunction with the satellite picture. Cloud types are usually identified on nephanalyses as stratiform, cumuliform, cirriform and cumulonimbus, with each type able to be characterised in terms of its effects on incident insolation.

Satellite-derived insolation estimates

NASA (2004*a*) makes freely available satellite-derived estimates of global insolation for the world, on a grid of cells, each 1° latitude × 1° longitude. The data are considered to be the average over the area of the cell. The data are not intended to replace ground measurement data but to fill gaps where ground measurements are missing and to complement ground measurements in other areas. The data quality may at least be accurate enough for preliminary feasibility studies.

Various models are applied to estimate diffuse and direct components and global radiation on tilted surfaces, with the applied methods being documented clearly (NASA, 2004*b*).

1.8.3 Global and diffuse components

Diffuse insolation is produced by complex interactions with the atmosphere, which absorbs and scatters, and the earth's surface, which absorbs and reflects. Measurements of diffuse insolation, which require pyranometers fitted with shadow bands to block direct sunlight, are available for far fewer sites than are measurements of global insolation. Hence, methods have been developed to estimate the diffuse fraction from the global value.

Clearness index

Liu and Jordan (1960) estimated the diffuse fraction of sunlight from the monthly average clearness index, $\overline{K}_T$, defined by:

$$\overline{K}_T = \overline{R} \big/ \overline{R}_o \tag{1.16}$$

the ratio of monthly averages of daily diffuse and extraterrestrial global radiation.

The procedure to estimate $\overline{R}_d$, the monthly average daily diffuse radiation on a horizontal surface, from published or measured values of $\overline{R}$ is simply:

1. Calculate $\overline{R}_0$ for each month using Eqn. (1.7), then

$$\overline{K}_d = \overline{R}_d \big/ \overline{R}_o \tag{1.17}$$

where $\overline{R}_d$ is the desired result. The latter expression yields the diffuse component, $\overline{R}_d$, from the more commonly measured $\overline{R}$ if $\overline{K}_d$ and $\overline{K}_T$ can be correlated. There are several such correlations in the literature, with that due to Page (1961) being considered the most reliable for latitudes less than 40° (Lorenzo, 2003)

$$\overline{K}_d = 1 - 1.13\overline{K}_T \tag{1.18}$$

2. Estimate $\overline{K}_T$ for each month using Eqn. (1.16).
3. Estimate $\overline{K}_d$ for each month using Eqn. (1.18).
4. Estimate $\overline{R}_d$ far each month using Eqn. (1.17).

Correlation models, such as that of Eqn. (1.18) are available in the literature for different averaging times from one month down to less than one hour. These models depend strongly on the averaging times and should not be applied for different averaging periods (Perez *et al.*, 2001).

Telecom model

If the separate components for diffuse and direct insolation are not known, a reasonable approximation for both (for most locations) may be obtained by equating the total monthly global insolation with the total insolation theoretically calculated for an appropriate number of 'sunny' and 'cloudy' days. The calculations proceed as follows:

1. '**Sunny' days**—The intensity of the direct component of the sunlight throughout each day can be determined as a function of the air mass from the experimentally-based equation (Meinel & Meinel, 1976)

   $$I = 1.3661 \times 0.7^{(AM)^{0.678}} \text{ kW/m}^2 \tag{1.19}$$

   where the currently accepted value of the solar constant has been inserted in place of the original value, I is the intensity of the direct component incident on a plane perpendicular to the sun's rays and air mass (AM) values are a function of the latitude, the time of year and the time of day, which can be calculated using the algorithms in Appendix B.

   By determining I values throughout a typical day, the daily direct insolation can be calculated. This value is then increased by 10% to account for the diffuse component, the origin of which is indicated in Fig. 1.14. This then gives the expected daily insolation on a sunny day for the given location and time of year.

2. '**Cloudy' days**—All incident light is assumed to be diffuse, with an intensity on a horizontal surface typically 20% of that determined by Eqn. (1.19). Consequently, an approximation to the daily insolation (all diffuse) for a 'cloudy' day can be estimated.

   By assuming that the known average global insolation data can be represented by the sum of an appropriate number of 'sunny' days, estimated as described in Section 1.8.2.1 above with insolation given by (i), and 'cloudy' days with insolation given by (ii), the direct and diffuse components can then be determined.

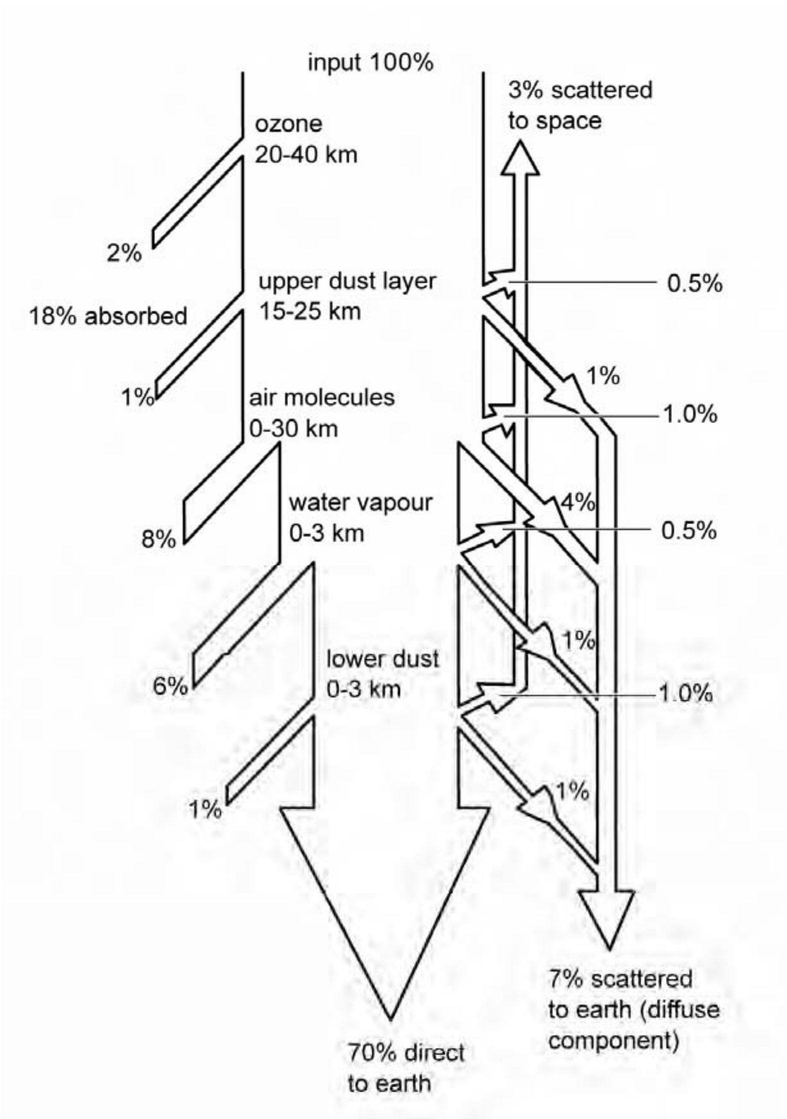


Figure 1.14. Typical AM1 clear sky absorption and scattering of incident sunlight (Used with permission of McGraw-Hill Companies, Hu, C. & White, R.M. (1983), Solar Cells: From Basic to Advanced Systems, McGraw-Hill, New York.).

As an aside, Eqn. (1.19) has been written independently of insolation wavelengths whereas, in reality, different wavelengths are attenuated to different degrees as empirically approximated by the expression (Hu & White, 1983)

$$I_{\mathrm{AM}K}(\lambda) = I_{\mathrm{AM0}}(\lambda)\left|\frac{I_{\mathrm{AM1}}(\lambda)}{I_{\mathrm{AM0}}(\lambda)}\right|^{AM^{0.678}} \qquad (1.20)$$

where λ is the wavelength of light. Changes in spectral content can have a significant effect on the output of a solar cell. However, this effect is often neglected, since silicon solar cells absorb almost no light of wavelength greater than 1.1 μm and module reflections increase at oblique angles of incident light, corresponding to longer wavelengths and increasing air mass.

1.8.4 Radiation on tilted surfaces

Since photovoltaic modules are commonly mounted at a fixed tilt, it is often necessary to estimate insolation on such tilted surfaces from that on the horizontal. This requires separate direct and diffuse components, as discussed above. Various models are available with a range of assumptions about the sky distribution of diffuse radiation (Duffie & Beckman, 1991; NASA, 2004*a*). Simple models are preferred if the input data is itself derived by modelling, such as, for example, from sunshine hours data (Perez *et al.*, 2001). Here, we consider only surfaces tilted towards the equator, although models are presented elsewhere for arbitrary orientations (Lorenzo, 1989).

Telecom method

Where insolation data is available in the form of direct and diffuse components, the following approach can be used to determine the corresponding insolation incident on a solar panel tilted at an angle β to the horizontal (after Mack, 1979).

First, we can assume the diffuse component D is independent of the tilt angle (which is a reasonably close approximation provided tilt angles are not much more than about 45°). Lorenzo (2003) discusses several more comprehensive models considering, for example, the higher intensities close to the solar disk and near the horizon with clear skies.

Secondly, the direct component on the horizontal surface S is to be converted into the direct component S_β incident on a plane tilted at angle β to the horizontal as illustrated in Fig. 1.15.

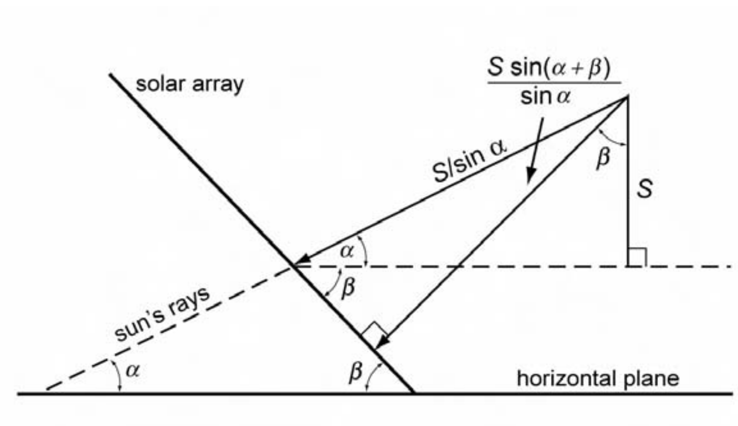


Figure 1.15. Light incident on a surface tilted to the horizontal (after Mack, 1979).

Consequently, we get

$$S_\beta = \frac{S\sin(\alpha+\beta)}{\sin\alpha} \tag{1.21}$$

where α is the altitude of the sun (i.e. the angle between the sun and the horizontal) at noon, and is given by:

$$\alpha = 90^\circ - \theta - \delta \tag{1.22}$$

where θ is the southern latitude.

The above is for solar modules facing north in the southern hemisphere. If facing south in the northern hemisphere, use $\alpha = 90 - \theta + \delta$, where θ is, in this case, the northern latitude.

Eqn. (1.21) is only strictly correct at midday, although it is often used in system sizing to convert the direct component of mean daily solar radiation on a horizontal surface for solar panels at angle β, which introduces a small error.

Fig. 1.16 gives typical daily sunlight intensity profiles for a sunny and a cloudy winter's day. The cloudy day has a light intensity of only about 10% of that of the sunny day, owing to the boosting of the direct component relative to the diffuse component by tilting the array at 60° to the horizontal.

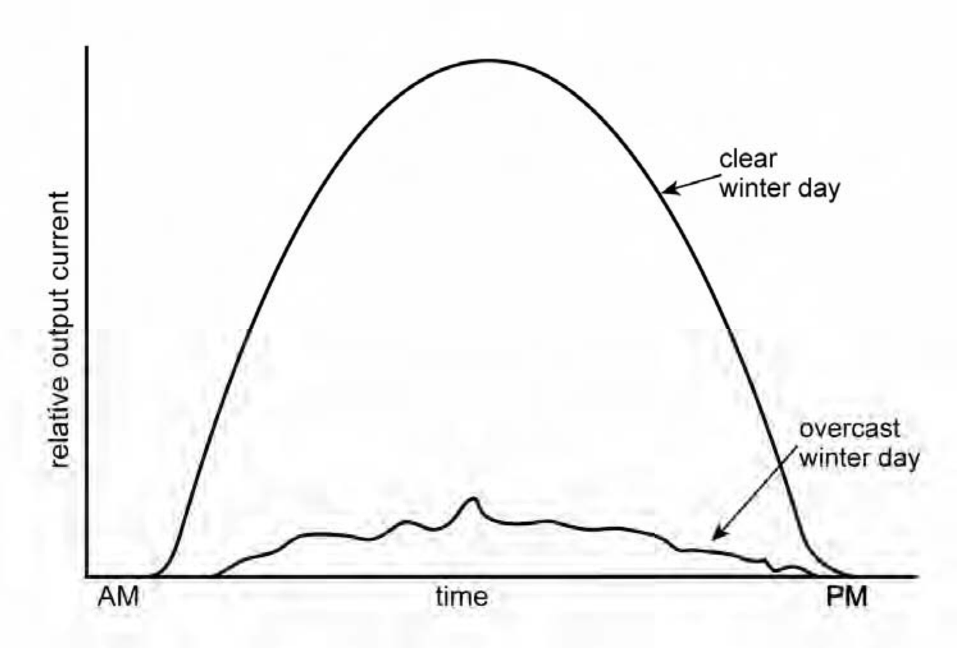


Figure 1.16. Relative output current from a photovoltaic array on a sunny and a cloudy winter's day in Melbourne (38°S) with an array tilt angle of 60° (after Mack, 1979).

Fig. 1.17 shows the effect of array tilting on the daily solar energy incidence for a location at latitude 23.5°N with a clear sky. Meinel and Meinel (1976, p. 108) tabulate the theoretical, clear sky daily energy interception for a range of fixed and tracking orientations at two representative latitudes for summer and winter solstices and the equinoxes.

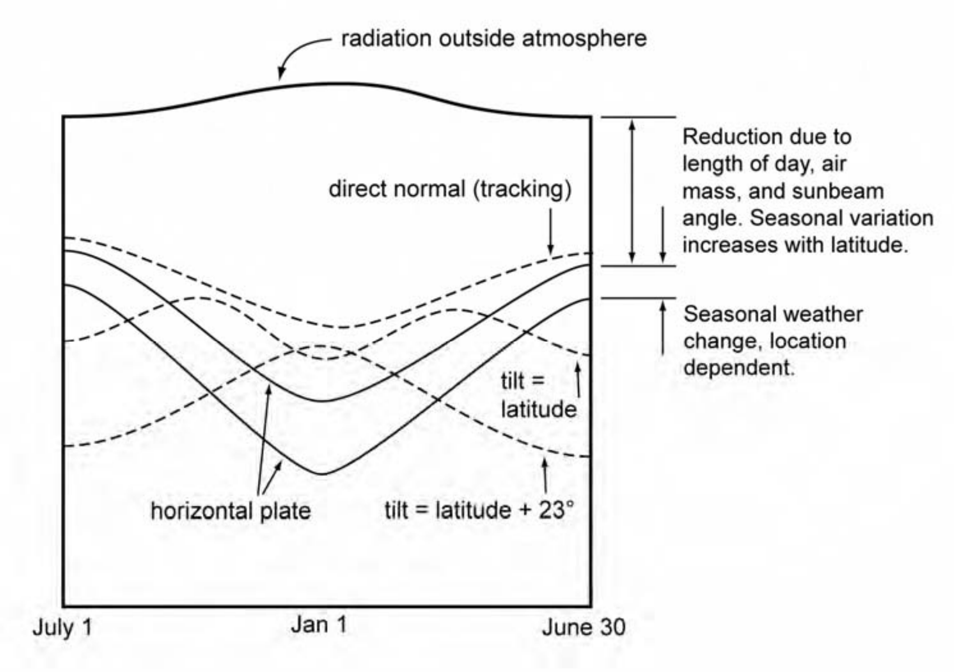


Figure 1.17. The effect of array tilting on the total insolation received each day for a location at latitude 23.4°N (Used with permission of McGraw-Hill Companies, Hu, C. & White, R.M. (1983), Solar Cells: From Basic to Advanced Systems, McGraw-Hill, New York.).

Tilt towards equator

Lorenzo (2003) outlines the general method for converting monthly average daily radiation on the horizontal to monthly average daily radiation on an arbitrarily tilted surface. It requires estimation of hourly horizontal global, direct and diffuse components, their transposition to the tilted surface, and integration over a day. This procedure is computationally intensive and is done by some available PV system sizing computer programs.

However, as noted by Duffie and Beckman (1991, Section 2.19), a method has been devised by Liu and Jordan (1962) and extended by Klein (1977) for the special case of a flat surface tilted towards the horizon, for which a simple approximation may be used; that is

$$\overline{R}(\beta) = \overline{R}_b\left(1 - \frac{\overline{R}_d}{\overline{R}}\right) + \overline{R}_d\,\frac{1+\cos\beta}{2} + \overline{R}\,\frac{1-\cos\beta}{2}\,\rho \qquad (1.23)$$

where ρ is the ground reflectivity, the ratio $\overline{R}_d / \overline{R}_o$ is correlated with $\overline{K}_T$ as discussed in Section 1.8.3.1, and $\overline{R}_b$ is the ratio between the daily direct insolation on the tilted surface to that on the horizontal. The latter ratio is approximated by the same ratio of the corresponding extraterrestrial values. For the southern hemisphere, the ratio is given by

$$\overline{R}_b = \frac{\cos(\varphi+\beta)\cos\delta\sin\omega_{s,\beta}^{*} + \left(\frac{\pi}{180}\right)\omega_{s,\beta}^{*}\sin(\varphi+\beta)\sin\delta}{\cos\varphi\cos\delta\sin\omega_{s,\beta}^{*} + \left(\frac{\pi}{180}\right)\omega_{s,\beta}^{*}\sin\varphi\sin\delta} \tag{1.24a}$$

where

$$\omega_{s,\beta}^{*} = \min\begin{cases} \cos^{-1}(-\tan\varphi\tan\delta) \\ \cos^{-1}(-\tan(\varphi+\beta)\tan\delta) \end{cases} \tag{1.24b}$$

is the sunset hour angle on the tilted surface for the characteristic day of the month. For the northern hemisphere

$$\overline{R}_b = \frac{\cos(\varphi-\beta)\cos\delta\sin\omega_{s,\beta}^{*} + \left(\frac{\pi}{180}\right)\omega_{s,\beta}^{*}\sin(\varphi-\beta)\sin\delta}{\cos\varphi\cos\delta\sin\omega_{s,\beta}^{*} + \left(\frac{\pi}{180}\right)\omega_{s,\beta}^{*}\sin\varphi\sin\delta} \tag{1.24c}$$

where

$$\omega_{s,\beta}^{*} = \min\begin{cases} \cos^{-1}(-\tan\varphi\tan\delta) \\ \cos^{-1}(-\tan(\varphi-\beta)\tan\delta) \end{cases} \tag{1.24d}$$

Duffie and Beckman (1991) tabulate and plot values of $\overline{R}_b$ for various tilt angles.

1.9 SOLAR ENERGY AND PHOTOVOLTAICS

Photovoltaics is inextricably linked with the development of quantum mechanics. Solar cells respond to light particles or *quanta*, although the wave-particle duality of light cannot be overlooked in cell design.

Sunlight itself approximates ideal blackbody radiation outside the earth's atmosphere. The inability to explain such blackbody radiation by classical theory was itself responsible for the development of quantum mechanics, which in turn was needed to understand solar cell operation. As well as reflecting light from the sun, the earth itself emits radiation similar to that of a blackbody, but centred at much greater wavelengths because of its lower temperature.

Absorption and scattering of light by the earth's atmosphere reduce the intensity and wavelength distribution of light reaching the earth's surface. They also interfere with energy being radiated by the earth, resulting in higher terrestrial temperatures than on the moon and a sensitivity of terrestrial temperature to 'anthropogenic' greenhouse gases. Owing to the variability of the intensity and wavelength distribution of terrestrial light, a standard solar spectrum is used to rate photovoltaic products. The present standard for most terrestrial applications is the global Air Mass 1.5 spectrum tabulated in Appendix A.

EXERCISES

1.1 The sun is at an altitude of 30° to the horizontal. What is the corresponding air mass?

1.2 What is the length of the shadow cast by a vertical post with a height of 1 m under AM1.5 illumination?

1.3 Calculate the sun's altitude at solar noon on 21 June in Sydney (latitude 34°S) and in San Francisco (latitude 38°N).

1.4 The direct radiation falling on a surface normal to the sun's direction is 90 mW/cm^2 at solar noon on one summer solstice in Albuquerque, New Mexico (latitude 35°N). Calculate the direct radiation falling on a surface facing south at an angle of 40° to the horizontal.

1.5 To design appropriate photovoltaic systems, good data on the insolation (i.e. amount of sunshine) is essential for each particular location. List the sources and nature of insolation data available for your region (state or country).

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Chapter

2

SEMICONDUCTORS AND *P-N* JUNCTIONS

2.1 SEMICONDUCTORS

In 1839 Becquerel observed that certain materials, when exposed to light, produced an electric current (Becquerel, 1839). This is now known as the photovoltaic effect, and is the basis of the operation of photovoltaic or solar cells.

Solar cells are manufactured from semiconductor materials; that is, materials that act as insulators at low temperatures, but as conductors when energy or heat is available. At present, most solar cells are silicon-based, since this is the most mature technology. However, other materials are under active investigation and may supersede silicon in the long term.

The electrical properties of semiconductors can be explained using two models, the *bond* and the *band* models. These models are described briefly below. (More detailed descriptions are given in Green, 1992 and Neville, 1978.)

2.1.1 The bond model

The bond model uses the covalent bonds joining the silicon atoms to describe semiconductor behaviour. Fig. 2.1 illustrates the bonding and the movement of electrons in a silicon crystal lattice.

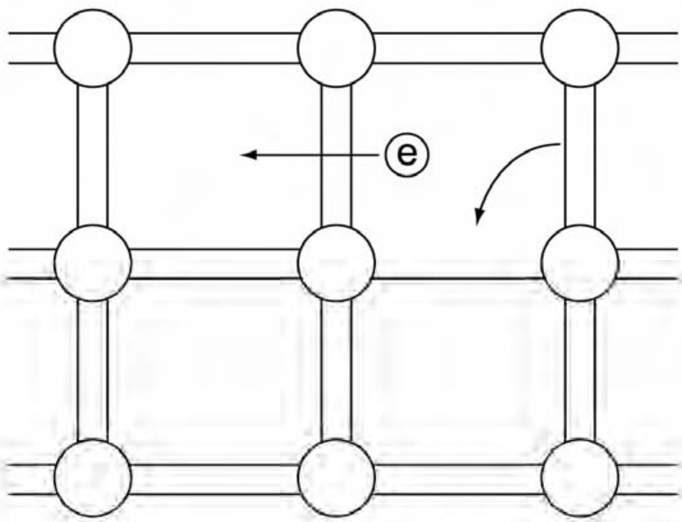

Figure 2.1. Schematic representation of covalent bonds in a silicon crystal lattice.

At low temperatures, the bonds are intact and the silicon behaves as an insulator. At high temperatures, some bonds are broken and conduction can occur by two processes:

1. Electrons from broken bonds are free to move.
2. Electrons from neighbouring bonds can also move into the ‘hole’ created in the broken bond, allowing the broken bond or hole to propagate as if it had a positive charge.

The concept of a moving hole is analogous to that of a bubble in a liquid. Although it is actually the liquid that moves, it is easier to describe the motion of the bubble going in the opposite direction.

2.1.2 The band model

The band model describes semiconductor behaviour in terms of the energy levels between valence and conduction bands. This is illustrated in Fig. 2.2.

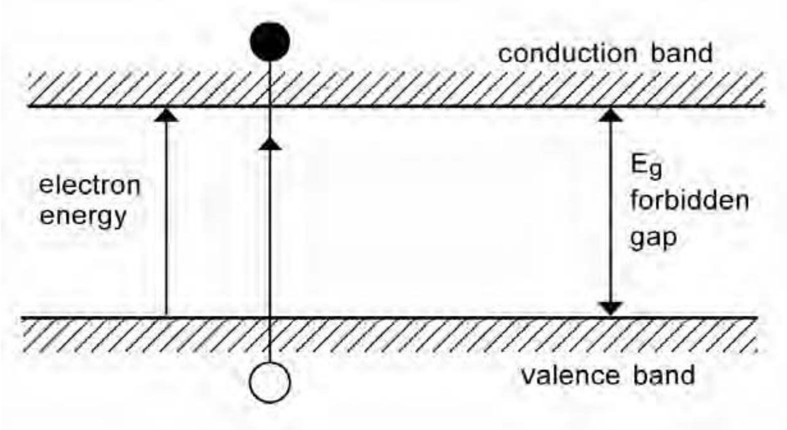

Figure 2.2. Schematic of the energy bands for electrons in a solid.

The electrons in covalent bonds have energies corresponding to those in the *valence band.* In the *conduction band* the electrons are free. The *forbidden gap* corresponds to the minimum energy needed to release an electron from a covalent bond to the conducting band where it can conduct a current. The *holes* remaining conduct in the opposite direction in the valence band, as described for the bond model.

2.1.3 Doping

It is possible to shift the balance of electrons and holes in a silicon crystal lattice by 'doping' it with other atoms. Atoms with one more valence electron than the semiconductor are used to produce '*n*-type' material. Atoms with one less valence electron result in '*p*-type' material. This is illustrated in Fig. 2.3.

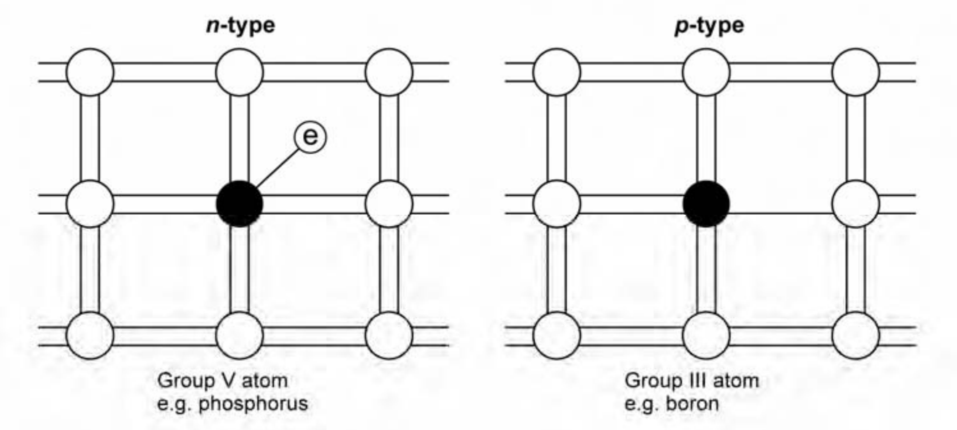

Figure 2.3. Schematic of a silicon crystal lattice doped with impurities to produce *n*-type and *p*-type semiconductor material.

2.2 SEMICONDUCTOR TYPES

Silicon and other semiconductor materials used for solar cells can be crystalline, multicrystalline, polycrystalline, microcrystalline or amorphous. Although usages of these terms vary, we follow the definitions by planar grain size according to Basore (1994). Microcrystalline material has grains smaller than 1 μm, polycrystalline smaller than 1 mm and multicrystalline smaller than 10 cm. The structure of the different material types is illustrated in Fig. 2.4.

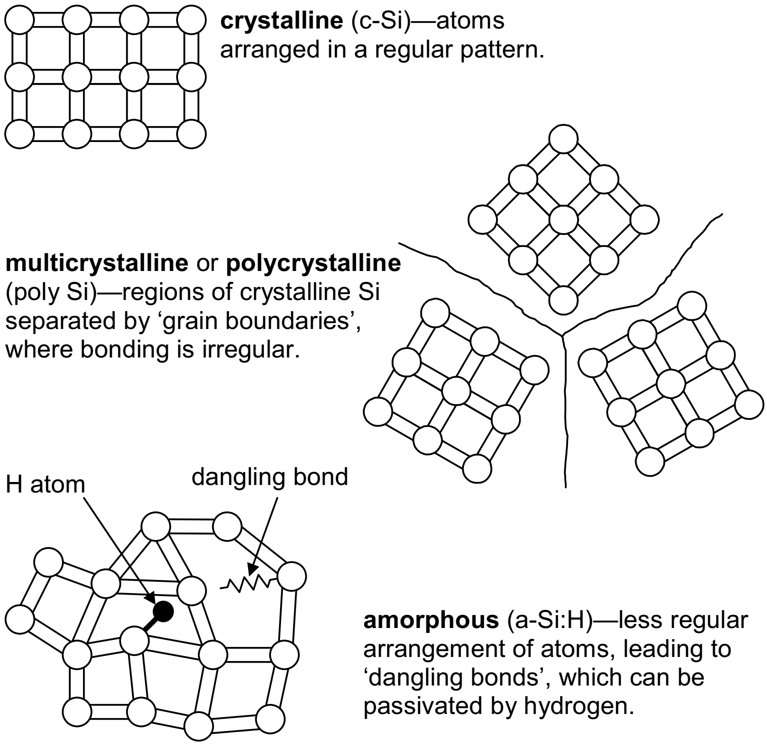

Figure 2.4. The structure of crystalline, multicrystalline and amorphous silicon.

2.2.1 Crystalline silicon

Crystalline silicon has an ordered crystal structure, with each atom ideally lying in a pre-ordained position. It therefore allows ready application of the theories and techniques developed for crystalline material, described in previous sections, and exhibits predictable and uniform behaviour. It is, however, the most expensive type of silicon, because of the careful and slow manufacturing processes required. The cheaper multicrystalline or polycrystalline silicon (poly-silicon), and amorphous silicon are therefore increasingly being used for solar cells, despite their less ideal qualities.

2.2.2 Multicrystalline silicon

The techniques for production of multicystalline or polycrystalline silicon are less critical, and hence cheaper, than those required for single crystal material. The grain boundaries reduce the cell performance by blocking carrier flows, allowing extra energy levels in the forbidden gap, thereby providing effective recombination sites, and providing shunting paths for current flow across the *p-n* junction.

To avoid significant recombination losses at grain boundaries, grain sizes in the order of a few millimetres are required (Card & Yang, 1977). This also allows single grains to extend from the front to the back of a cell, providing less resistance to carrier flow and generally decreasing the length of grain boundaries per unit of cell. Such multicrystalline material is widely used for commercial solar cell production.

2.2.3 Amorphous silicon

Amorphous silicon can be produced, in principle, even more cheaply than poly-silicon. With amorphous silicon, there is no long-range order in the structural arrangement of the atoms, resulting in areas within the material containing unsatisfied, or 'dangling' bonds. These in turn result in extra energy levels within the forbidden gap, making it impossible to dope the semiconductor when pure, or to obtain reasonable current flows in a solar cell configuration.

It has been found that the incorporation of atomic hydrogen in amorphous silicon, to a level of 5–10%, saturates the dangling bonds and improves the quality of the material. It also increases the bandgap (E_g) from 1.1 eV in crystalline silicon to 1.7 eV, making the material much more strongly absorbing for photons of energy above the latter threshold. The thickness of material required to form a functioning solar cell is therefore much smaller.

The minority carrier diffusion lengths in such silicon-hydrogen alloys, (a-Si:H), are much less than 1 μm. The depletion region therefore forms most of the active carrier-collecting volume of the cell. Different design approaches to those discussed above for crystalline silicon are therefore used. In particular, as large a 'depletion region' as possible is created. Fig. 2.5 illustrates the general design of an a-Si:H solar cell.

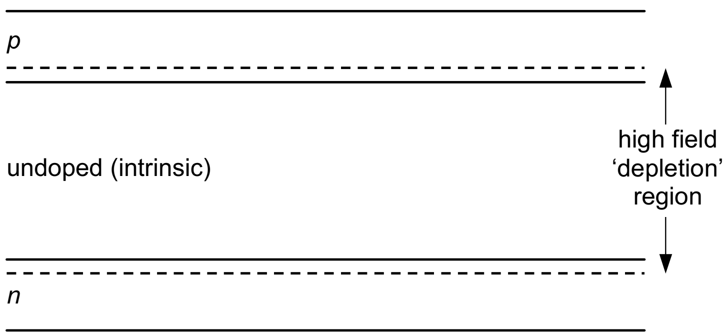

Figure 2.5. Schematic of an a-Si:H solar cell.

Amorphous silicon and other 'thin film' technologies for solar cell manufacture, where films of very thin semiconductor material are deposited onto glass or other substrates, are used in many small consumer products, such as calculators and watches, 'non-critical' outdoor applications and, increasingly also for large scale applications. In principle, thin films provide a very low cost means of cell production, although at present their efficiencies and lifetimes are lower than for crystalline products. Research into thin film and other potentially low cost solar cell materials may see these technologies dominate the solar cell market over coming decades.

2.2.4 Thin film crystalline silicon

A very wide range of methods are being investigated to develop thin film silicon cells deposited on foreign substrates (Green, 2003). If the ratio of hydrogen to silane in the gas from which amorphous silicon is deposited is increased, the resulting material becomes microcrystalline, with columns of crystallites separated by amorphous regions. The optical and electronic properties are similar to those of bulk silicon. Such material has been used as an alternative to silicon-germanium alloys in hybrid structures with amorphous silicon. Particular measures are necessary to allow the amorphous layers to be kept thin enough to avoid light-induced degradation while producing similar current to the microcrystalline cell(s) in series. A microcrystalline/ amorphous tandem design has been developed with an efficiency of about 11% on a laboratory scale.

One company is approaching commercial production with a process in which a thin film silicon cell is formed on a textured glass superstrate. A laser is used to form craters through the active material to contact the *n*-type layer closest to the glass. Low quality material is deposited, then improved by subsequent thermal steps.

2.3 ABSORPTION OF LIGHT

When light falls onto semiconductor material, photons with energy (E_{ph}) less than the bandgap energy (E_g) interact only weakly with the semiconductor, passing through it as if it were transparent. However, photons with energy greater than the bandgap energy ($E_{ph} > E_g$) interact with electrons in covalent bonds, using up their energy to break bonds and create *electron-hole pairs*, which can then wander off independently. This is illustrated in Fig. 2.6.

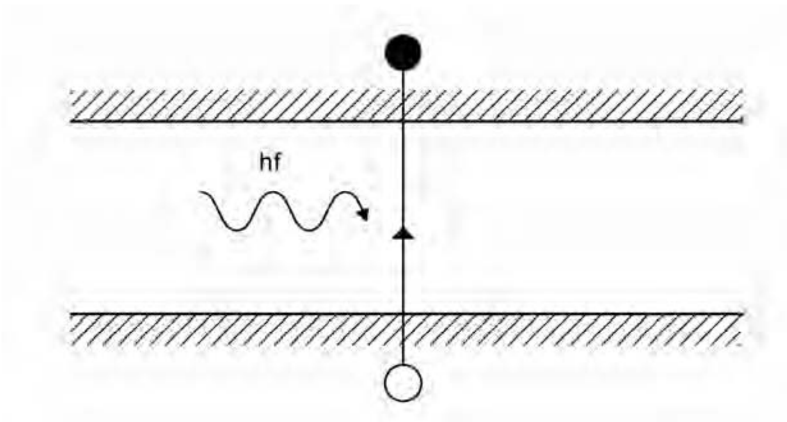

Figure 2.6. The creation of electron-hole pairs when illuminated with light of energy $E_{ph} = hf$, where $E_{ph} > E_g$.

Higher energy photons are absorbed closer to the surface of the semiconductor than lower energy photons, as illustrated in Fig. 2.7.

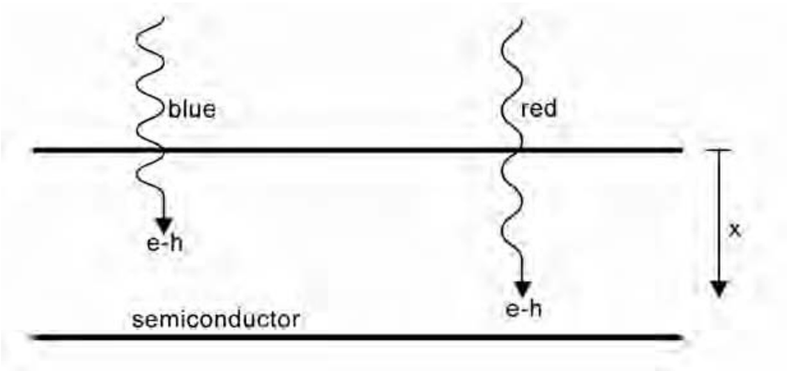

Figure 2.7. The light energy dependency of electron-hole generation.

The generation rate (G) of electron-hole (e-h) pairs per unit volume can be calculated using the formula:

$$G = \alpha N e^{-\alpha x} \tag{2.1}$$

where N is the photon flux (photons per unit area per second), α is the absorption coefficient, and x is the distance from the surface. The value of α as a function of the wavelength of light is illustrated in Fig. 2.8 for silicon at 300 K.

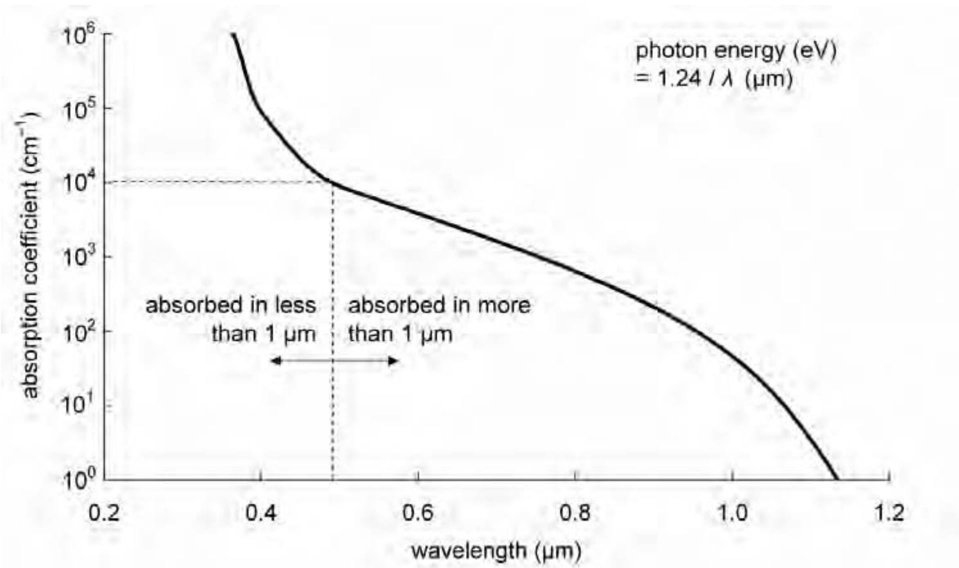

Figure 2.8. The absorption coefficient, α, of silicon at 300 K as a function of the vacuum wavelength of light.

2.4 RECOMBINATION

When the light is switched off, the system must return to a state of equilibrium and the electron-hole pairs generated by the light must disappear. With no external source of energy, the electrons and holes wander around until they meet up and *recombine*.

Any defects or impurities within or at the surface of the semiconductor promote recombination.

The *carrier lifetime* of a material is defined as the average time for recombination to occur after electron-hole generation. For silicon, this is typically 1 µs. Similarly, the *carrier diffusion length* is the average distance a carrier can move from point of generation until it recombines. For silicon, this is typically 100–300 µm. These two parameters give an indication of material quality and suitability for solar cell use. However, no power can be produced from a semiconductor without a means of giving directionality to the moving electrons. Therefore, functional solar cells are typically produced from semiconductor material by the addition of a rectifying *p-n* junction.

2.5 *P-N* JUNCTIONS

A *p-n* junction is formed by joining *n*-type and *p*-type semiconductor materials, as shown in Fig. 2.9.

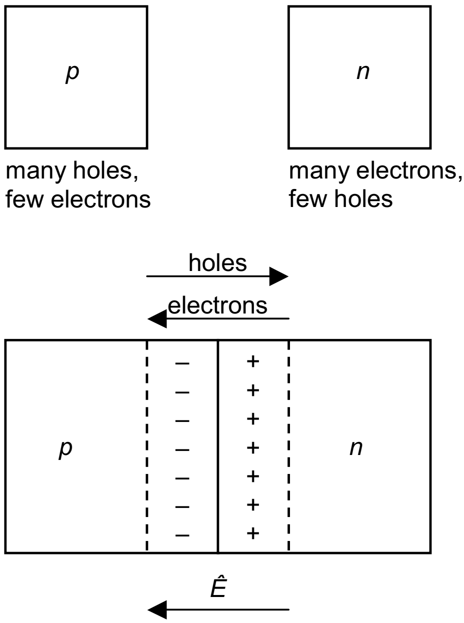

Figure 2.9. Formation of a *p-n* junction.

When joined, the excess holes in the *p*-type material flow by diffusion to the *n*-type material, while electrons flow by diffusion from the *n*-type material to the *p*-type material as a result of the carrier concentration gradients across the junction. The electrons and holes leave behind exposed charges on dopant atom sites, fixed in the crystal lattice. An electric field ($\hat{E}$) therefore builds up in the so-called *depletion region* around the junction to stop the flow. Depending on the materials used, a 'built-in' potential (V_{bi}) owing to $\hat{E}$ will be formed. If a voltage is applied to the junction, as shown in Fig. 2.10, $\hat{E}$ will be reduced.

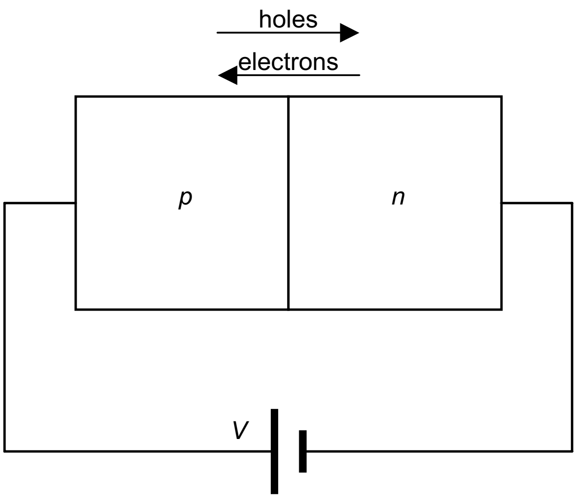

Figure 2.10. Application of a voltage to a *p*-*n* junction.

Once $\hat{E}$ is no longer large enough to stop the flow of electrons and holes, a current is produced. The built in potential reduces to $V_{bi} - V$ and the current flow increases exponentially with the applied voltage. This phenomenon results in the *Ideal Diode Law*, expressed as

$$I = I_0 \left[\exp\left(\frac{qV}{kT} \right) - 1 \right] \tag{2.2}$$

where I is the current, I_0 is the dark saturation current (the diode leakage current density in the absence of light), V is the applied voltage, q is the charge on an electron, k is Boltzmann's constant and T is absolute temperature.

Note that

- I_0 increases as T increases
- I_0 decreases as material quality increases
- at 300 K, kT/q = 25.85 mV, the *thermal voltage*.

For actual diodes, the Eqn. (2.2) becomes

$$I = I_0 \left[\exp\left(\frac{qV}{nkT} \right) - 1 \right] \tag{2.3}$$

where n is the ideality factor, a number between 1 and 2 that typically increases as the current decreases.

The diode law is illustrated for silicon in Fig. 2.11.

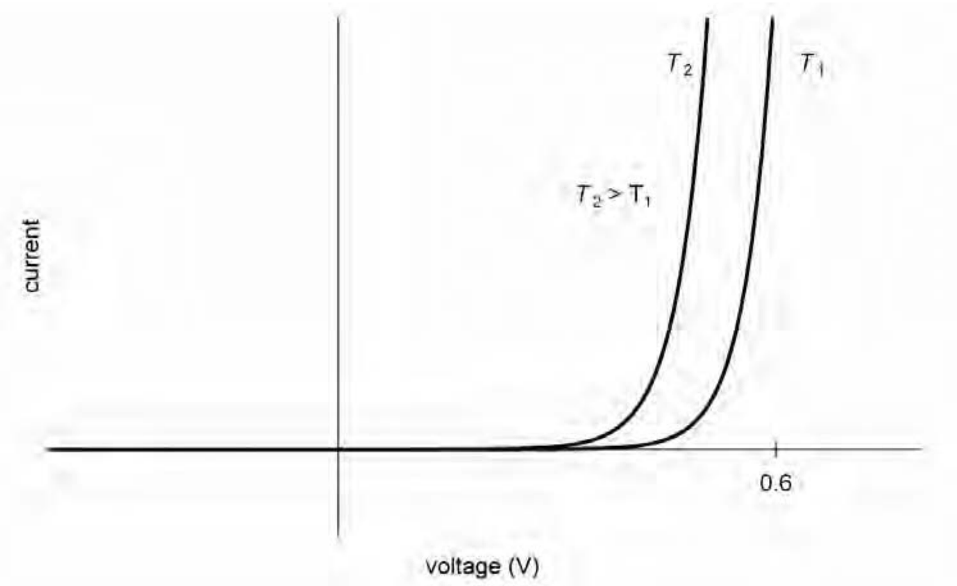

Figure 2.11. The diode law for silicon—current as a function of voltage for temperatures T_1 and T_2 ($T_2 > T_1$). For a given current, the curve shifts by approximately 2 mV/°C.

EXERCISES

2.1. The absorption coefficient of silicon decreases from 1.65×10^6 cm^{-1} at 0.3 μm wavelength, to 4400 cm^{-1} at 0.6 μm and 3.5 cm^{-1} at 1.1 μm. Assuming zero reflection from both front and rear surfaces at each wavelength, calculate and sketch the generation rate of electron-hole pairs, normalised to the surface generation rate, across a silicon cell of 300 μm thickness.

2.2. In terms of the electronic properties of semiconductors, explain why the absorption coefficient increases with increasing photon energy, for energies near the semiconductor bandgap (see Green, 1992 or similar for further information).

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Chapter

3

THE BEHAVIOUR OF SOLAR CELLS

3.1 EFFECT OF LIGHT

A silicon solar cell is a diode formed by joining *p*-type (typically boron doped) and *n*-type (typically phosphorous doped) silicon. Light shining on such a cell can behave in a number of ways, as illustrated in Fig. 3.1. To maximise the power rating of a solar cell, it must be designed so as to maximise desired absorption (3) and absorption after reflection (5).

The electric field $\hat{E}$ at the *p-n* junction sweeps electrons to the *n* side and holes to the *p* side. The ideal flow at short circuit is shown in Fig. 3.2. However, some electron-hole (e-h) pairs get lost before collection, as shown in Fig. 3.3.

In general, the closer the point of e-h generation to the *p-n* junction, the better the chance of 'collection'. 'Collected carriers' are those that generate a finite current when $V = 0$. Chances of collection are particularly good if the e-h pairs are generated within a *diffusion length* of the junction, as discussed in Chapter 2.

The characteristic curves generated by plotting I against V for a diode (I-V curves) were shown in Fig. 2.11 for I_0, with no light falling on the cell. Illumination of a cell merely adds to the normal 'dark' currents in the diode so that the diode law becomes

$$I = I_0\left[\exp\left(\frac{qV}{nkT}\right) - 1\right] - I_L \qquad (3.1)$$

where I_L is the light-generated current.

The light has the effect of shifting the I-V curve down into the fourth quadrant where power can be extracted from the diode, as shown in Fig. 3.4.

The I-V curve characterises the cell, with its power output being equal to the area of the rectangle in the bottom right-hand quadrant of Fig. 3.4*a*. This I-V curve is most often shown reversed, as in Fig. 3.5, with the output curve in the first quadrant, and represented by

$$I = I_L - I_0\left[\exp\left(\frac{qV}{nkT}\right) - 1\right] \qquad (3.2)$$

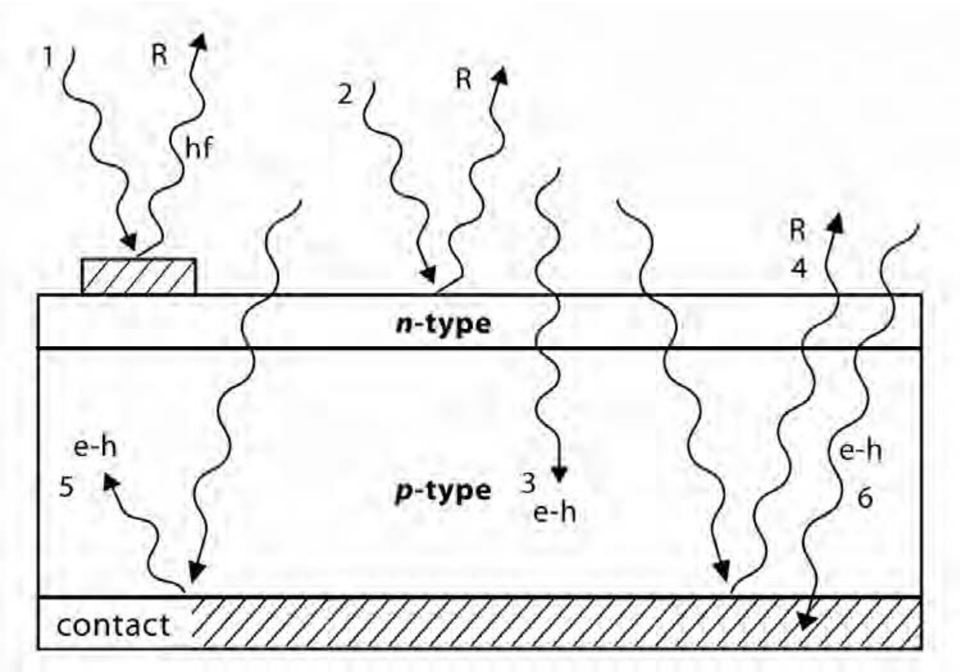


Figure 3.1. Behaviour of light shining on a solar cell. (1) Reflection and absorption at top contact. (2) Reflection at cell surface. (3) Desired absorption. (4) Reflection from rear out of cell—weakly absorbed light only. (5) Absorption after reflection. (6) Absorption in rear contact.

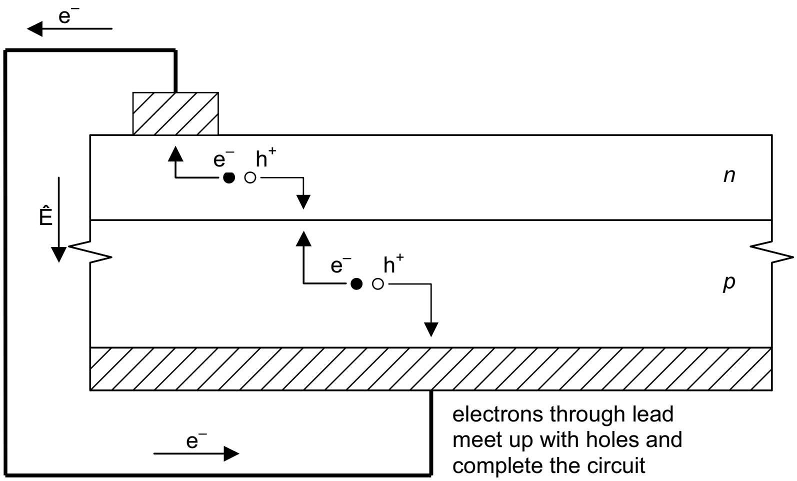


Figure 3.2. The ideal short circuit flow of electrons and holes at a *p*-*n* junction.

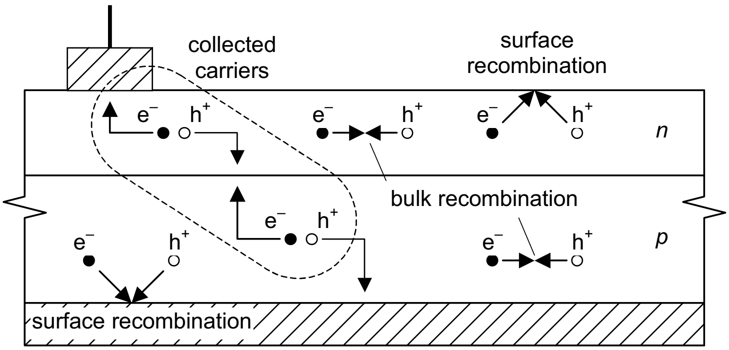
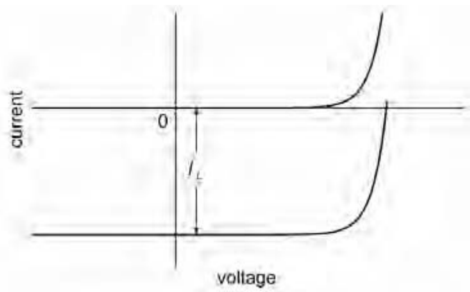
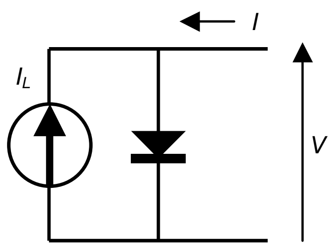


Figure 3.3. Possible modes of recombination of electron-hole pairs, showing 'collection' of carriers that do not recombine.





(*a*) (*b*)

Figure 3.4. The effect of light on the current-voltage characteristics of a *p*-*n* junction.

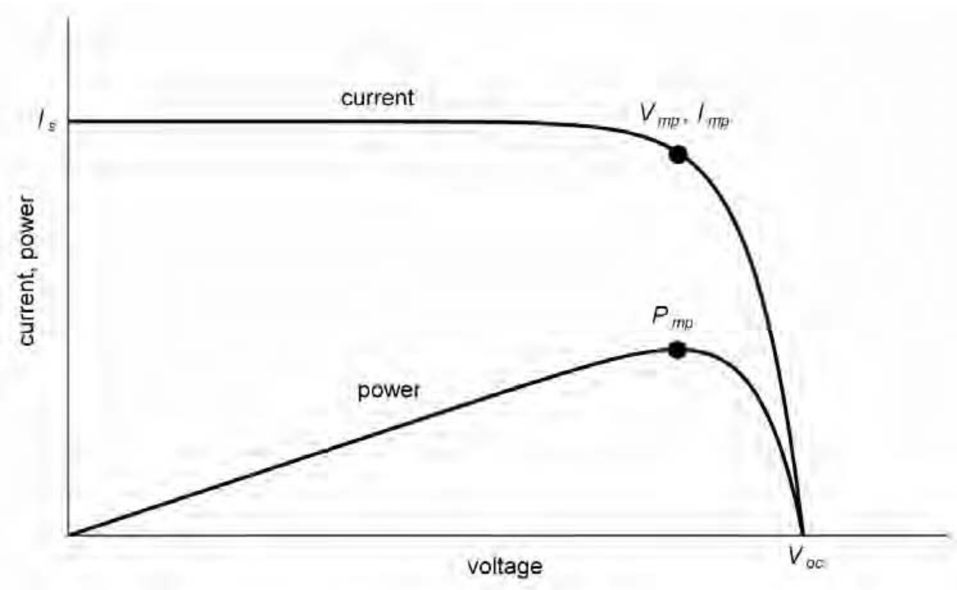


Figure 3.5. Typical representation of an I-V curve, showing short-circuit current (I_{sc} and open-circuit voltage (V_{oc}) points, as well as the maximum power point (V_{mp}, I_{mp}).

The two limiting parameters used to characterise the output of solar cells for given irradiance, operating temperature and area are (Shockley & Queisser, 1961):

1. **Short circuit current** (I_{sc})—the maximum current, at zero voltage. Ideally, if $V = 0$, $I_{sc} = I_L$. Note that I_{sc} is directly proportional to the available sunlight.
2. **Open circuit voltage (**V_{oc})—the maximum voltage, at zero current. The value of V_{oc} increases logarithmically with increased sunlight. This characteristic makes solar cells ideally suited to battery charging.

Note that at $I = 0$,

$$V_{oc} = \frac{nkT}{q} \ln\left(\frac{I_L}{I_0} + 1\right) \tag{3.3}$$

For each point on the I-V curve, the product of the current and voltage represents the power output for that operating condition. A solar cell can also be characterised by its *maximum power point*, when the product $V_{mp} \times I_{mp}$ is at its maximum value. The maximum power output of a cell is graphically given by the largest rectangle that can be fitted under the I-V curve. That is,

$$\frac{d(IV)}{dV} = 0$$

giving

$$V_{mp} = V_{oc} - \frac{nkT}{q} \ln\left(\frac{V_{mp}}{(nkT/q)} + 1 \right) \tag{3.4}$$

For example, if n = 1.3 and V_{oc} = 600 mV, as for a typical silicon cell, V_{mp} is about 93 mV smaller than V_{oc}.

The power output at the maximum power point under strong sunlight (1 kW/m^2) is known as the 'peak power' of the cell. Hence photovoltaic panels are usually rated in terms of their 'peak' watts (W_p).

The *fill factor* (*FF*), is a measure of the junction quality and series resistance of a cell. It is defined as

$$FF = \frac{V_{mp} I_{mp}}{V_{oc} I_{sc}} \tag{3.5}$$

Hence

$$P_{mp} = V_{oc} I_{sc} FF \tag{3.6}$$

Obviously, the nearer the fill factor is to unity, the higher the quality of the cell. Ideally, it is a function only of the open circuit voltage and can be calculated using the approximate empirical expression (Green, 1982)

$$FF = \frac{v_{oc} - \ln(v_{oc} + 0.72)}{v_{oc} + 1} \tag{3.7}$$

where v_{oc} is defined as a 'normalised V_{oc}'; that is

$$v_{oc} = \frac{V_{oc}}{(nkt/q)} \tag{3.8}$$

The above expression applies to *ideal cases* only, with no parasitic resistance losses, and is accurate to about one digit in the fourth decimal place for these cases.

3.2 SPECTRAL RESPONSE

Solar cells respond to individual photons of incident light by absorbing them to produce an electron-hole pair, provided the photon energy (E_{ph}) is greater than the bandgap energy (E_g). Photon energy in excess of E_g is quickly dissipated as heat, as shown in Fig. 3.6.

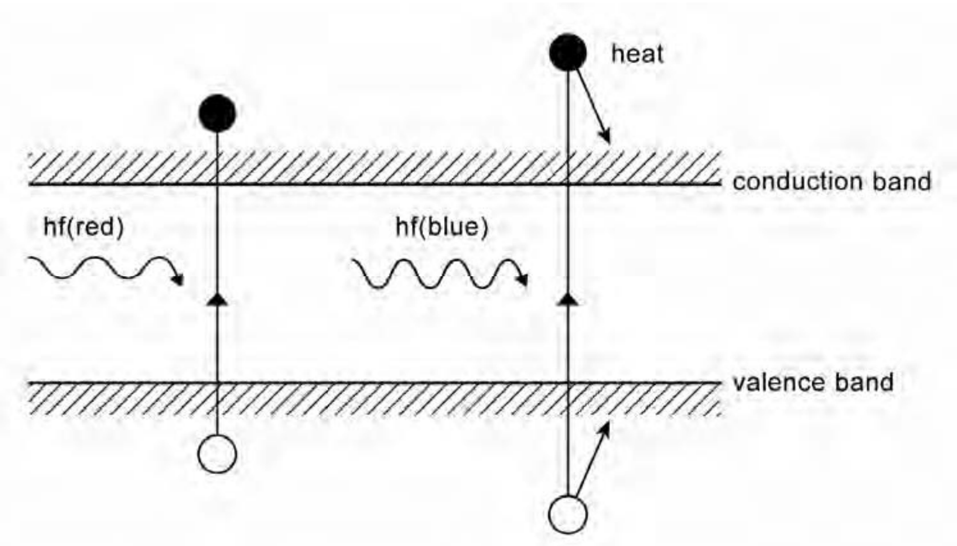


Figure 3.6. The creation of electron-hole pairs and dissipation of energy in excess of E_g.

The quantum efficiency (QE) of a solar cell is defined as the number of electrons moving from the valence band to the conduction band per incident photon. The longest wavelength for which this is finite is limited by its bandgap. Maximum use can only be made of incoming sunlight if the bandgap is in the range 1.0–1.6 eV. This effect alone acts to limit the maximum achievable efficiency of solar cells to 44% (Shockley & Queisser, 1961). The bandgap of silicon, at 1.1 eV, is close to optimum, while that of gallium arsenide, at 1.4 eV, is even better, in principle. Fig. 3.7 illustrates the dependence of ideal quantum efficiency on bandgap.

Also of interest is the spectral responsivity of a solar cell, given by the amperes generated per watt of incident light (Fig. 3.8). Ideally, this increases with wavelength. However, at short wavelengths, cells cannot use all the energy in the photons, whereas at long wavelengths, the weak absorption of light means that most photons are absorbed a long way from the collecting junction and the finite diffusion length in the cell material limits the cell's response.

Spectral responsivity (SR) can be calculated as follows:

$$SR = \frac{I_{sc}}{P_{in}(\lambda)} = \frac{q \times n_e}{\frac{hc}{\lambda} \times n_{ph}} = \frac{q\lambda}{hc} EQE \qquad (3.9)$$

where n_e is the flux of electrons, per unit time, flowing in an external circuit at short circuit conditions and I_{sc} is the short circuit current, n_{ph} is the flux of photons of wavelength λ incident on the cell per unit time, P_{in} is the incident light power and $EQE = (1 - R) \times IQE$ is the external efficiency, which differs from the internal quantum efficiency (IQE) in that the latter excludes the fraction, R, of light reflected from the top surface. $SR \rightarrow 0$ as $\lambda \rightarrow 0$, since there are fewer photons in each watt of incident light.

This strong wavelength dependence of responsivity makes cell performance in turn strongly dependent on the spectral content of sunlight. In addition, optical and recombination losses mean that actual cells can only approach these ideals.

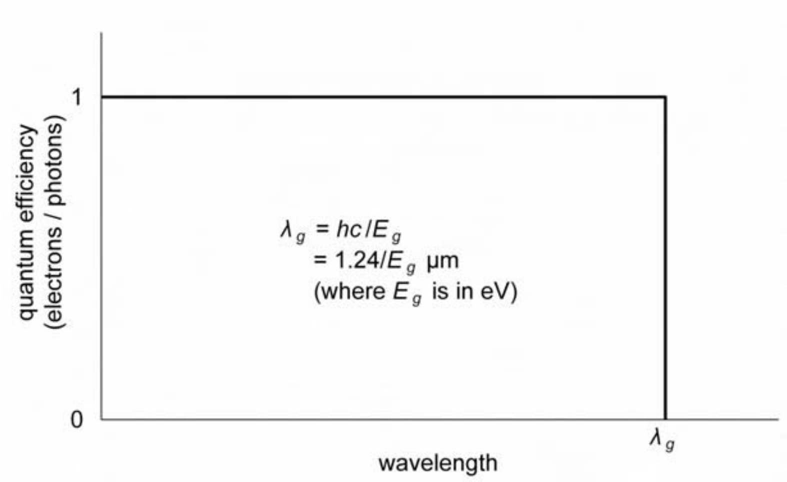


Figure 3.7. Bandgap limitations on the quantum efficiency of silicon solar cells.

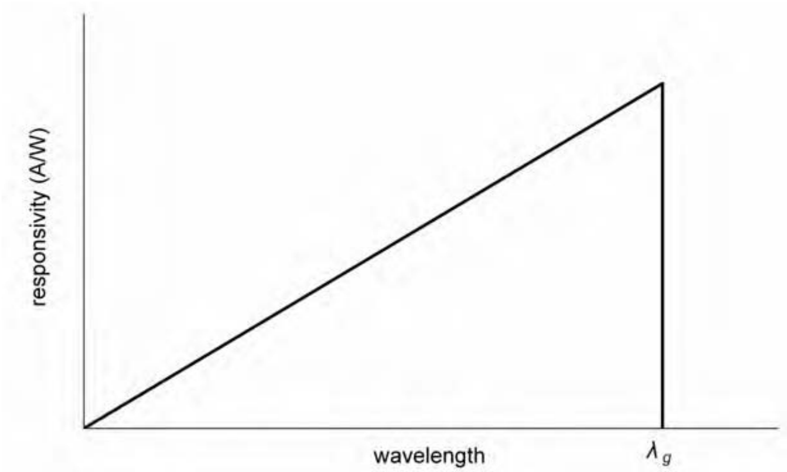


Figure 3.8. The quantum limit of spectral responsivity as a function of wavelength.

3.3 EFFECT OF TEMPERATURE

The operating temperature of a solar cell is determined by the ambient air temperature, by the characteristics of the module in which it is encapsulated (see Section 5.8), by the intensity of sunlight falling on the module, and by other variables such as wind velocity.

The dark saturation current I_0 increases with temperature according to the equation

$$I_0 = BT^{\gamma}\exp\left(\frac{-E_{g0}}{kT}\right) \tag{3.10}$$

where B is independent of temperature, E_{g0} is the linearly extrapolated zero temperature bandgap of the semiconductor making up the cell (Green, 1992) and γ includes the temperature dependencies of the remaining parameters determining I_0.

The short circuit current (I_{sc}) increases with temperature, since the bandgap energy (E_g) decreases and more photons have enough energy to create e-h pairs. However, this is a small effect. For silicon

$$\frac{1}{I_{sc}}\frac{dI_{sc}}{dT} \approx +0.0006\ {}^{\circ}\mathrm{C}^{-1} \tag{3.11}$$

The main effect of increasing temperature for silicon solar cells is a reduction in V_{oc}, the fill factor and hence the cell output. These effects are illustrated in Fig. 3.9.

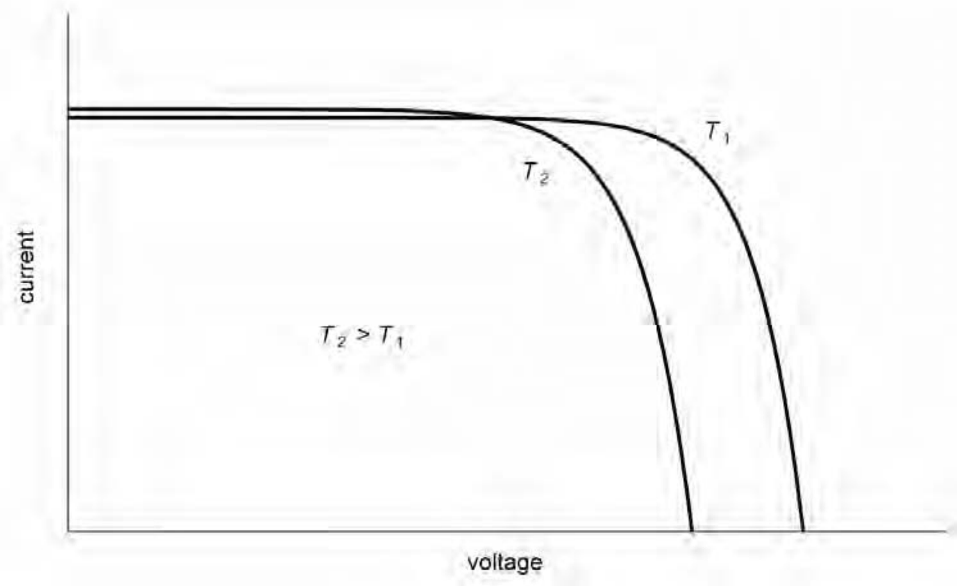


Figure 3.9. The effect of temperature on the I-V characteristics of a solar cell.

The temperature dependency of V_{oc} and FF for silicon is approximated by the following equations:

$$\frac{dV_{oc}}{dT} = \frac{-\left[V_{g0} - V_{oc} + \gamma(kT/q)\right]}{T} \approx -2\ \mathrm{mV/^{\circ}C} \tag{3.12}$$

$$\frac{1}{V_{oc}}\frac{dV_{oc}}{dT} \approx -0.003\ {}^{\circ}\mathrm{C}^{-1} \tag{3.13}$$

$$\frac{1}{FF}\frac{d(FF)}{dT} \approx \frac{1}{6}\left[\frac{1}{V_{oc}}\frac{dV_{oc}}{dT} - \frac{1}{T}\right] \approx -0.0015\,°\mathrm{C}^{-1} \qquad (3.14)$$

For silicon, the effect of temperature on the maximum power output (P_{mp}) is as follows:

$$\frac{1}{P_{mp}}\frac{dP_{mp}}{dT} \approx -(0.004 \sim 0.005)\,°\mathrm{C}^{-1} \qquad (3.15)$$

The higher the value of V_{oc}, the smaller the expected temperature dependence. Temperature effects are discussed in detail by Emery *et al.* (1996), King *et al.* (1997) and Radziemska (2003).

3.4 EFFECT OF PARASITIC RESISTANCES

Solar cells generally have a parasitic series and shunt resistance associated with them, as shown in Fig. 3.10. Both types of parasitic resistance act to reduce the fill-factor.

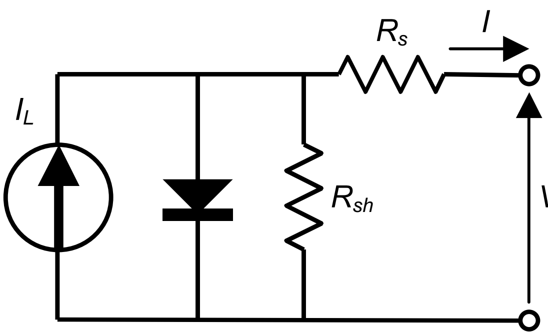


Figure 3.10. Parasitic series and shunt resistances in a solar cell circuit.

The major contributors to the series resistance (R_s) are the bulk resistance of the semiconductor material, the metallic contacts and interconnections, carrier transport through the top diffused layer, and contact resistance between the metallic contacts and the semiconductor. The effect of series resistance is shown in Fig. 3.11.

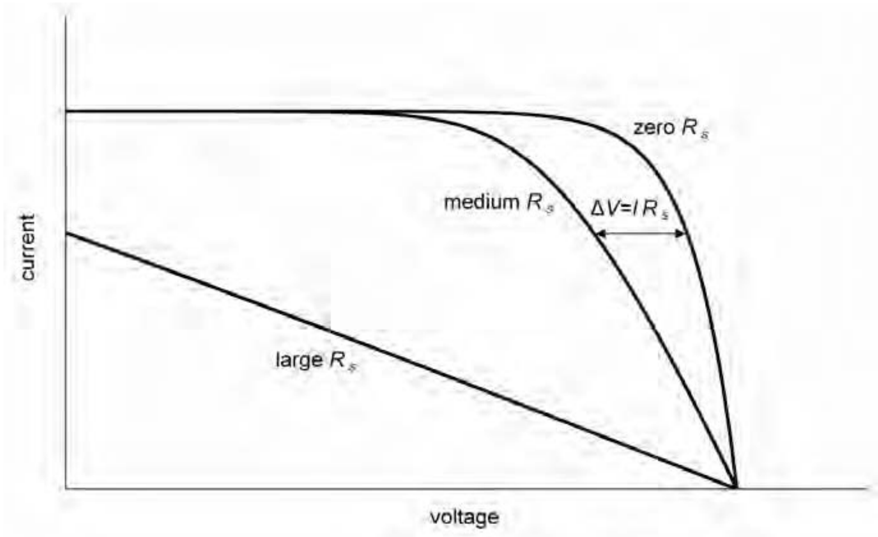


Figure 3.11. The effect of series resistance on fill factor.

The shunt resistance (R_{sh}) is due to *p-n* junction non-idealities and impurities near the junction, which cause partial shorting of the junction, particularly near cell edges. The effect of shunt resistance is shown in Fig. 3.12.

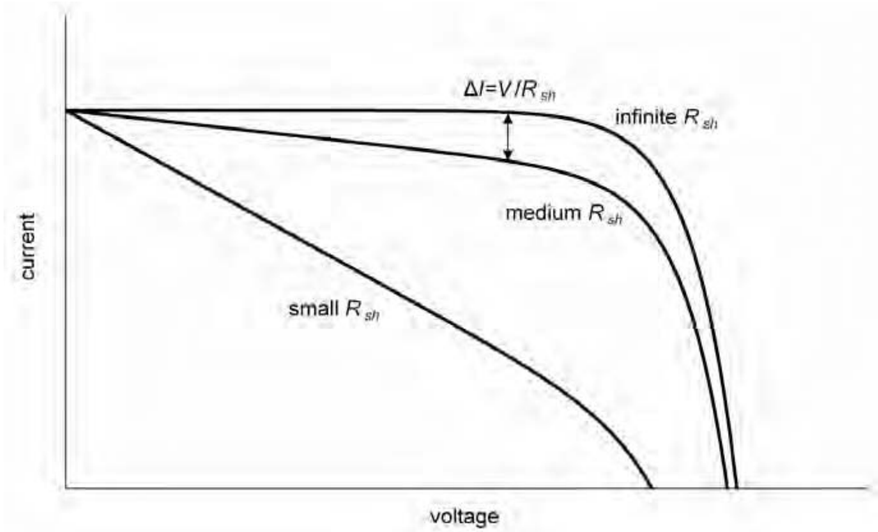


Figure 3.12. The effect of shunt resistance on fill factor in a solar cell.

Since the fill factor determines the power output of the cell, the maximum power output is related to the series resistance, as given approximately by

$$\begin{aligned}P_m &\approx \left(V'_{mp} - I'_{mp}R_s\right)I'_{mp}\\ &\approx P_{mp}\left(1 - \frac{I'_{mp}}{V'_{mp}}R_s\right)\\ &\approx P_{mp}\left(1 - \frac{I_{sc}}{V_{oc}}R_s\right).\end{aligned}$$

If the characteristic resistance of a solar cell is defined as (Green, 1982)

$$R_{ch} = \frac{V_{oc}}{I_{sc}} \tag{3.17}$$

it is possible to define a 'normalised R_s' such that

$$r_s = \frac{R_s}{R_{ch}} \tag{3.18}$$

Hence

$$FF \approx FF_0\left(1 - r_s\right) \tag{3.19}$$

or, empirically but more accurately

$$FF_s \approx FF_0\left(1 - 1.1r_s\right) + \frac{r_s^{\ 2}}{5.4} \tag{3.20}$$

which is valid for $r_s < 0.4$ and $v_{oc} > 10$.

Similarly, for shunt resistance, it is possible to define

$$r_{sh} = \frac{R_{sh}}{R_{ch}} \tag{3.21}$$

Then, as before

$$FF \approx FF_0\left(1 - \frac{1}{r_{sh}}\right) \tag{3.22}$$

or, again more accurately (Green, 1992)

$$FF_{sh} = FF_0\left[1 - \frac{v_{oc} + 0.7}{v_{oc}}\frac{FF_0}{r_{sh}}\right] \tag{3.23}$$

which is valid for $r_{sh} > 0.4$.

In the presence of both series and shunt resistances, the I-V curve of a solar cell is given by

$$I = I_L - I_0\left[\exp\left(\frac{V + IR_s}{(nkT/q)}\right) - 1\right] - \frac{V + IR_s}{R_{sh}} \qquad (3.24)$$

To combine the effect of both series and shunt resistances, the expression for FF_{sh}, derived above, can be used, with FF_0 replaced by FF_s (Green, 1992).

EXERCISES

3.1 (a) Taking the silicon bandgap as 1.12 eV, and assuming unity quantum efficiency as in Figs. 3.7 and 3.8, calculate the upper limit on the short circuit current density of a silicon solar cell at 300 K for the standard 'unnormalised' global AM1.5 spectrum supplied in tabulated form in Appendix B.

(b) Given that, near operating temperatures, the silicon bandgap decreases by 0.273 mV/°C, calculate the normalised temperature coefficient of this current limit at 300 K

$$\frac{1}{I_{sc}}\frac{dI_{sc}}{dT}$$

3.2 (a) A silicon solar cell (bandgap 1.12 eV) is uniformly illuminated by monochromatic light of wavelength 800 nm and intensity 20 mW/cm^2. Given that its quantum efficiency at this wavelength is 0.80, calculate the short circuit current of the cell if its area is 4 cm^2.

(b) For the same quantum efficiency, what would be the value of this current if the cell were made from a semiconductor of bandgap (i) 0.7 eV, (ii) 2.0 eV.

(c) For the silicon cell of part (a), calculate the open circuit voltage, fill factor and energy conversion efficiency, given that its ideality factor is 1.2 and dark saturation current density is 1 ρA/cm^2.

(d) Estimate the range of values of (i) series resistance and (ii) shunt resistance that would cause a relative reduction in the fill factor and energy conversion efficiency of less than 5%.

3.3 (a) When the cell temperature is 300 K, a certain silicon cell of 100 cm^2 area has an open circuit voltage of 600 mV and a short circuit current of 3.3 A under 1 kW/m^2 illumination. Assuming that the cell behaves ideally, what is its energy conversion efficiency at the maximum power point?

(b) What would be its corresponding efficiency if the cell had a series resistance of 0.1 Ω and a shunt resistance of 3 Ω?

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Chapter

4

CELL PROPERTIES AND DESIGN

4.1 EFFICIENCIES

Under laboratory conditions, with current state-of-the-art technology, it is possible to produce single-crystal silicon solar cells with efficiencies in excess of 24%. However, commercially mass-produced cells are typically only 13–14% efficient. There are many reasons for this; the over-riding one being that, while efficiency can be the major aim for laboratory produced cells, irrespective of cost, complexity of processing or throughput, in general, laboratory techniques are unsuited to industry.

Solar cell research continues to improve the efficiency of cells towards the currently accepted theoretical limit of about 30%. Commercial products lag some years behind laboratory results, but commercial module efficiencies of over 20% could be see in coming years. Higher efficiency makes a dramatic difference to the cost of photovoltaics as an electricity source, since fewer modules are required for a given power output. The cost of electricity generated by a photovoltaic system therefore depends on its initial cost, operating life, operating costs and electricity output, as well as the costs of borrowing money and the rate at which current monetary values are discounted over time. These factors can be represented by a standard economic discounted cash flow equation:

$$C = \frac{\sum_t \left[\left(ACC_t + O\&M_t + FUEL_t \right) \left(1 + r \right)^{-t} \right]}{\sum_t \left[E_t \left(1 + r \right)^{-t} \right]} \tag{4.1}$$

where ACC_t is the capital cost in year t, $O\&M_t$ is total operating and maintenance cost in year t, $FUEL_t$ is the fuel cost in year t (if applicable, e.g. for a RAPS system), E_t is the energy produced in year t, and r is the discount rate.

Both increased efficiencies and reduced wafer costs are critical to overall photovoltaic price reductions since, with current single crystal or polycrystalline silicon technology, wafer costs account for about half of the finished module cost per watt, even at production levels of 10 MW per annum (Darkazalli *et al*., 1991). Factors affecting cell efficiency are discussed below.

4.2 OPTICAL LOSSES

Optical and recombination losses reduce the cell output from the ideal values discussed in Chapters 2 and 3. Some of the optical loss processes in a solar cell are illustrated in Fig. 4.1.

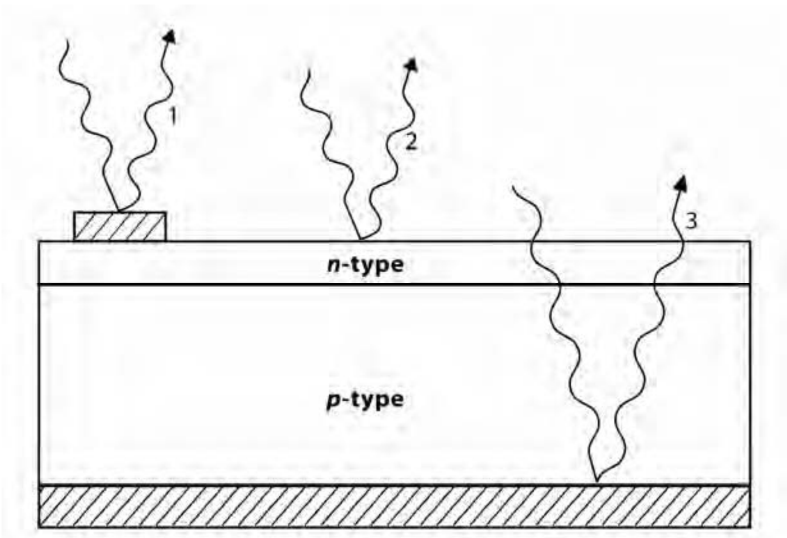

Figure 4.1. Sources of optical loss in a solar cell. (1) Blocking by top contact coverage. (2) Surface reflection. (3) Rear contact reflection.

There are a number of ways to reduce these losses:

1. Top contact coverage of the cell surface can be minimised (although this results in increased series resistance).
2. Antireflection coatings can be used on the top surface of the cell. A *quarter wavelength* antireflection coating; that is, a transparent coating of thickness d_1 and refractive index n_1, such that

$$d_1 = \frac{\lambda_0}{4n_1} \tag{4.2}$$

will, ideally, cancel the light reflected from the top surface by interference effects from the light reflected at the coating-semiconductor interface, which will be 180° out of phase (Heavens, 1955). This is illustrated in Fig. 4.2.

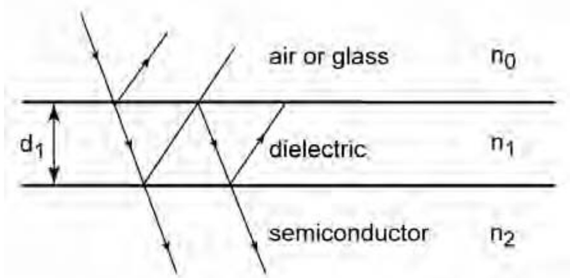

Figure 4.2. Use of a quarter wavelength antireflection coating to counter surface reflection.

Reflection is further minimised if the refractive index of the antireflection coating is the geometric mean of that of the materials on either side—glass (typically) or air, and the semiconductor—that is, if

$$n_1 = \sqrt{n_0 n_2} \tag{4.3}$$

Surface reflection can be reduced in this case to zero, as shown in Fig. 4.3.

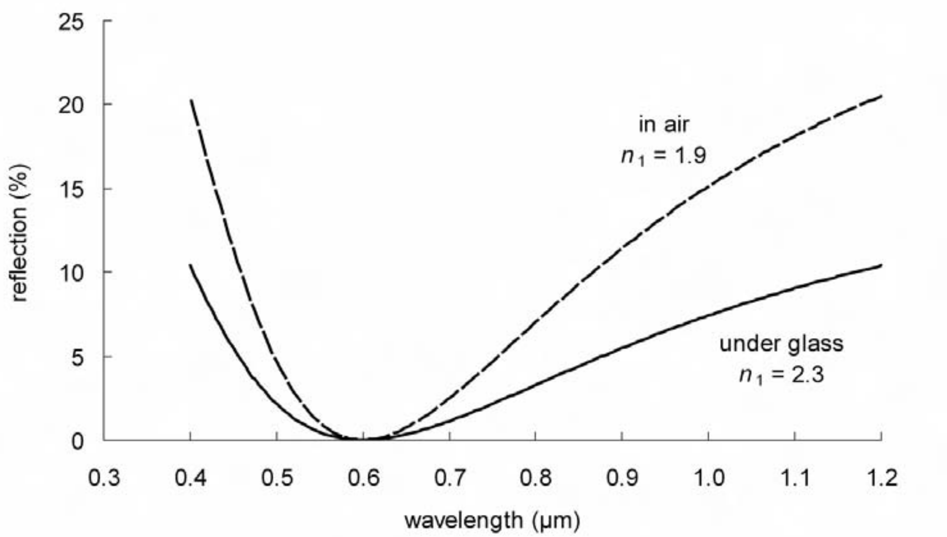

Figure 4.3. Surface reflection from a silicon cell (n_2 = 3.8) in air (n_0 = 1) and under glass (n_0 = 1.5) with an antireflection coating with refractive index and thickness chosen so as to minimise reflection for 0.6 μm wavelength light.

3. Surface texturing can also be used to minimise reflection. Any ‘roughening’ of the surface reduces reflection by increasing the chances of reflected light bouncing back onto the surface, rather than out to the surrounding air.

   The surface of crystalline silicon can be textured uniformly by etching along the faces of the crystal planes. The crystalline structure of silicon results in a surface made up of pyramids, if the surface is appropriately aligned with respect to the internal atoms (Chitre, 1978), as shown in Fig. 4.4. An electron microscope photograph of a textured silicon surface is shown in Fig. 4.5.

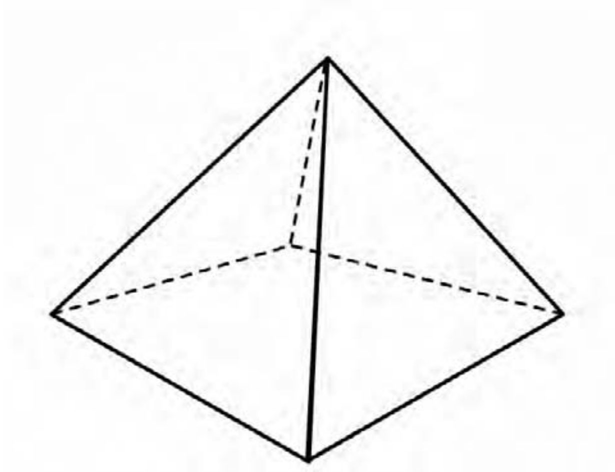

Figure 4.4. A square based pyramid, which forms the surface of an appropriately-textured crystalline silicon solar cell.

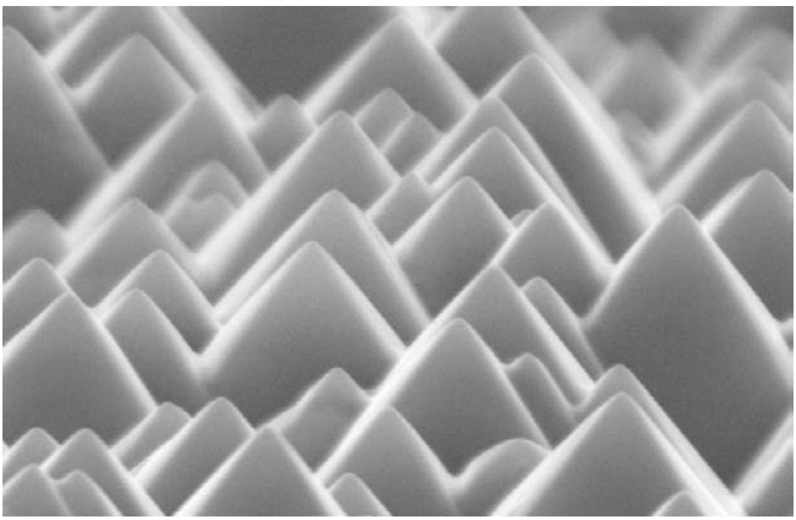

Figure 4.5. Scanning electron microscope image of a textured silicon surface.

An additional benefit of roughened or textured surfaces is that light is obliquely coupled into the silicon in accordance with Snell's law, as given by

$$n_1 \sin\theta_1 = n_2 \sin\theta_2 \qquad (4.4)$$

where θ_1 and θ_2 are the angles for the light incident on the interface relative to the normal plane of the interface within the mediums with refractive indices n_1 and n_2 respectively.

4. High reflection from the rear cell surface reduces absorption in the rear cell contacts, allowing the light to bounce back into the cell for possible absorption. If the back surface reflector can randomise the direction of the reflected light, it can be trapped in the cell by total internal reflection. The possibility of light absorption can be dramatically increased in this way, since the pathlength of the incident light can be enhanced by a factor up to $4n^2$ (~50) by such *light trapping* (Yablonovitch & Cody, 1982). Rear surface reflection is illustrated in Fig. 4.6.

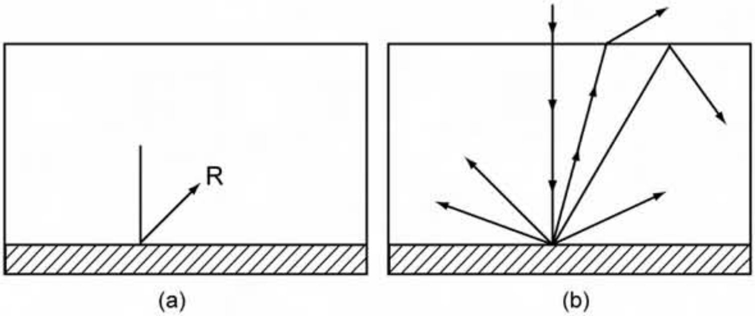

Figure 4.6. (*a*) Reflection from a rear surface. (*b*) Randomised reflection resulting in light trapping.

The efficiency of utilising light of higher wavelengths—the red response—can be improved by adding a *back surface field* (BSF) to the cell, as a means of reducing back surface recombination velocity. This is typically achieved by including a heavily-doped region, such as a screen printed layer of aluminium, at the back of the cell. The interface between this layer and the relatively lightly-doped bulk region of the cell acts as a low recombination velocity surface. A schematic diagram of a BSF is given in Fig. 4.7.

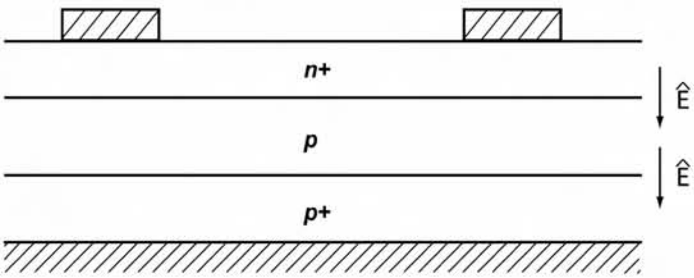

Figure 4.7. Use of a back surface field to reduce rear surface recombination velocities.

4.3 RECOMBINATION LOSSES

The efficiency of a solar cell is also reduced by the recombination of electron-hole pairs before they can be usefully collected (Green, 1986). A number of recombination sites are shown in Fig. 4.8.

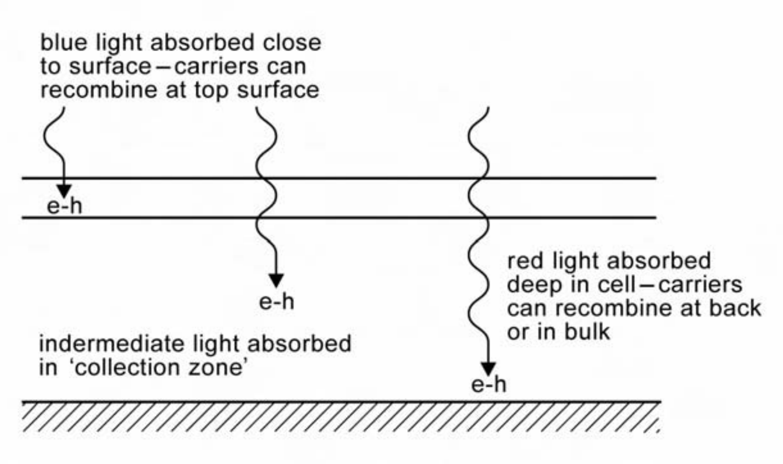

Figure 4.8. Possible sites for recombination of e-h pairs within a PV cell.

Recombination can occur via several mechanisms:

1. **Radiative recombination**—the reverse of absorption. Electrons in a high energy state return to a lower energy state, with the release of light energy. This form of recombination is used for semiconductor lasers and light emitting diodes, but is not particularly significant for silicon solar cells.
2. **Auger recombination**—the reverse of 'impact ionisation' (Hu & White, 1983). An electron recombining with a hole gives up the excess energy to another electron, which then relaxes back to its original energy state, releasing phonons. Auger recombination is particularly effective in relatively highly-doped material, becoming the dominant recombination process when impurity levels exceed 10^{17} cm^{-3}.
3. **Recombination through traps**—This can occur when impurities in the semiconductor or interface traps at the surfaces give rise to allowed energy levels in the otherwise forbidden energy gap. Electrons can thus recombine with holes in a two-stage process, first relaxing to the defect energy level, then to the valence band.

In real cells, the combination of the loss factors described above results in spectral responses similar to those illustrated in Fig 4.9, and the task of the cell designer is to overcome these losses to improve cell performance. The design features used characterise the cells and serve to distinguish the various commercial modules on the market.

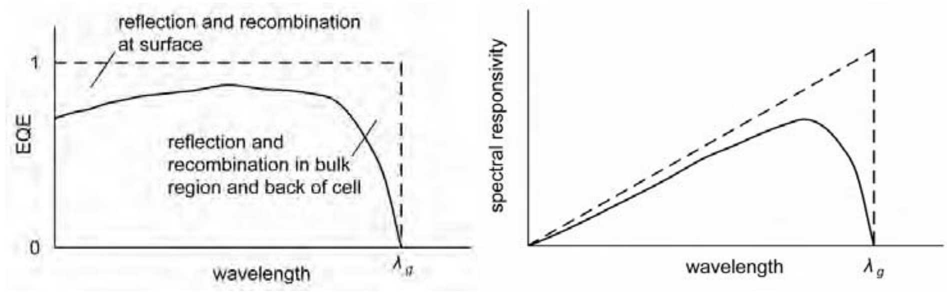

Figure 4.9. Typical external quantum efficiency and responsivity in actual solar cells, illustrating the impact of optical and recombination losses.

4.4 TOP CONTACT DESIGN

Metallic top contacts are necessary to collect the current generated by a solar cell. *Busbars* are connected directly to the external leads, while *fingers* are finer areas of metallisation that collect current for delivery to the busbars. A simple top contact design is shown in Fig. 4.10. Top contact design aims to optimise current collection against losses owing to internal resistances and cell shadowing.

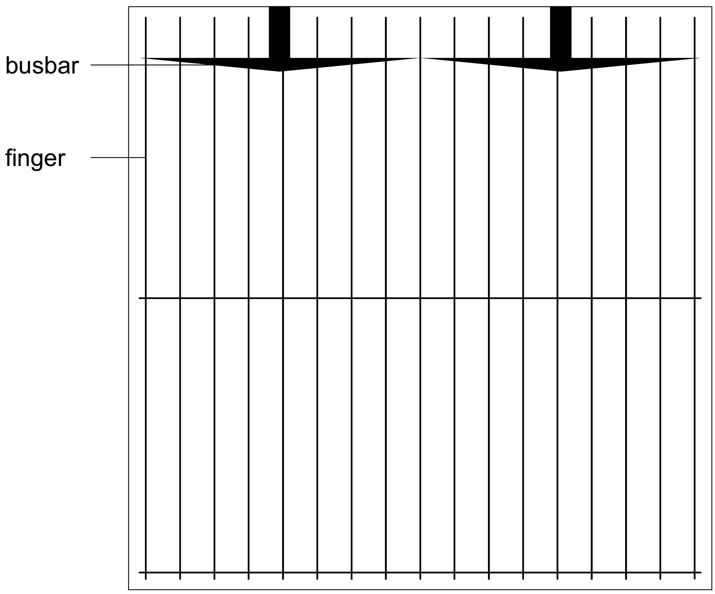

Figure 4.10. Top contact design of a solar cell.

4.4.1 Bulk and sheet resistivities

Generated current typically flows perpendicular to the cell surface from the bulk of the cell and then laterally through the top doped layer until it is collected at a top surface contact, as shown in Fig. 4.11.

The resistance to the current of the bulk component of the cell, or the *bulk resistance* (R_b) is defined as

$$R_b = \frac{\rho l}{A} = \rho_b \frac{w}{A} \tag{4.5}$$

taking into account the thickness of the material, where l is the length of the conducting (resistive) path, ρ_b is the *bulk resistivity* (inverse of conductivity) of the bulk cell material (typically 0.5–5.0 Ω.cm for a silicon solar cell), A is the cell area, and w is the width of the bulk region of cell (see Fig. 4.13).

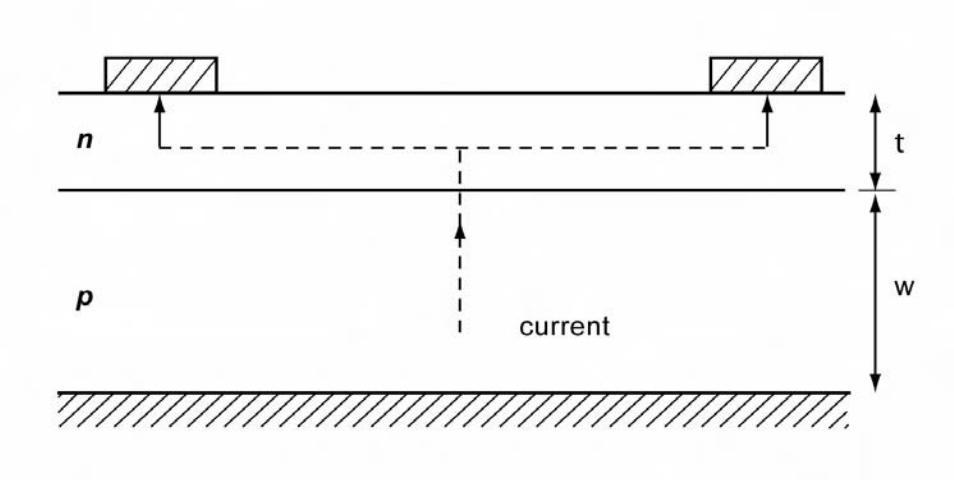

Figure 4.11. Current flow from point of generation to external contact in a solar cell.

Similarly, for the top n-type layer, *sheet resistivity* ($\rho_{\square}$) is defined as

$$\rho_{\square} = \frac{\rho}{t} \tag{4.6}$$

where ρ is the resistivity of this layer. The sheet resistivity is normally expressed as ohms/square or Ω/□.

For non-uniformly doped n-type layers; that is, if ρ is non-uniform

$$\rho_{\square} = \frac{1}{\int_0^t \frac{dx}{\rho(x)}} \tag{4.7}$$

Sheet resistivity is very easy to measure experimentally using a 'four point probe', as shown in Fig. 4.12.

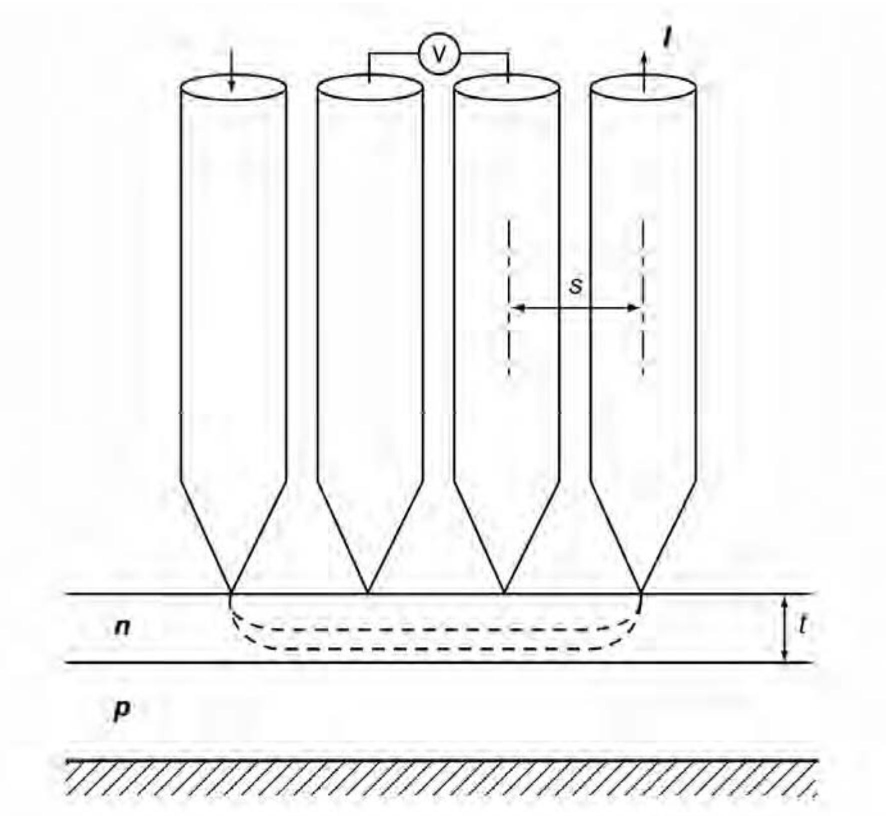

Figure 4.12. Use of a four point probe to measure the sheet resistivity of a solar cell.

Using the voltage and current readings from the probe,

$$\rho_{\square} = \frac{\pi}{\ln 2}\frac{V}{I} \quad (\Omega/\square) \tag{4.7}$$

where $\pi/\ln 2 = 4.53$.

The typical sheet resistivity of silicon solar cells lies in the range 30–100 Ω/□.

4.4.2 Grid spacings

Sheet resistivity is important because it determines the spacing between grid lines of the top contact, as shown in Fig. 4.13.

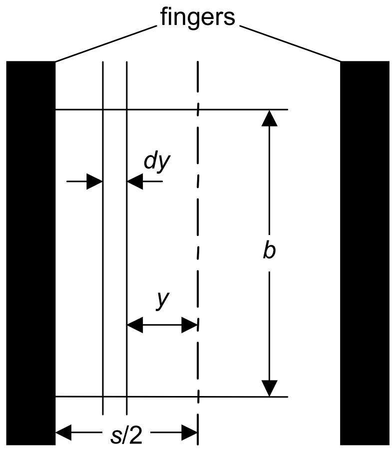

Figure 4.13. Dimensions needed for calculating power loss owing to the lateral resistance of the top layer.

The incremental power loss in the section *dy* of Fig. 4.13 is given by

$$dP = I^2 dR \tag{4.9}$$

where $dR = \rho_\square dy/b$, and $I(y)$ is the lateral current flow, which is zero at the midpoint between grating lines and increases linearly to its maximum at the grating line, under uniform illumination, and hence equals Jby where J is the current density.

The total power loss is therefore

$$\begin{aligned} P_{loss} &= \int I^2 dR \\ &= \int_0^{s/2} \frac{J^2 b^2 y^2 \rho_\square dy}{b} \\ &= \frac{J^2 b \rho_\square s^3}{24} \end{aligned} \tag{4.10}$$

where s is the spacing between grid lines.

At the maximum power point, the generated power is

$$P_{gen} = \frac{V_{mp} J_{mp} bs}{2} \tag{4.11}$$

Therefore the fractional power loss is given by

$$\frac{P_{loss}}{P_{gen}} = \frac{\rho_\square s^2 J_{mp}}{12 V_{mp}} \tag{4.12}$$

Hence, the minimum spacing for the top contact grid can be calculated. For example, for a typical silicon solar cell, if $\rho_\square = 40\ \Omega/\square$, $J_{mp} = 30$ mA/cm^2 and $V_{mp} = 450$ mV, then, for lateral resistance power losses of less than 4%, $s < 4$ mm.

4.4.3 Other losses

The busbars and fingers are the source of a variety of losses, in addition to the lateral current flow losses described previously. These include shading losses, resistive losses and contact resistance losses. A symmetrical contacting scheme, as shown in Fig. 4.14*a*, can be broken down into unit cells, as in Fig. 4.14*b*.

In brief, it can be shown (Serreze, 1978) that:

1. The optimum width of the busbar (W_b) occurs when the resistive loss in the busbar equals its shadowing loss.
2. A tapered busbar has lower losses than a busbar of constant width.
3. The smaller the unit cell, the finger width (W_f) and the finger spacings (s), the lower the losses.

Obviously the third point must be countered by the need to allow light to enter the cell, as well as to allow practical manufacturing. Contact resistance losses at the interface between the grid lines and the semiconductor (see Fig. 4.15) are more important for fingers than busbars. To keep top contact losses low, the top n^+ layer must be as heavily doped as possible. This ensures small sheet resistivities ($\rho_\square$) and hence low contact resistance losses.

However, a high doping level creates other problems. If a high level of phosphorus is diffused into silicon, the excess phosphorus lies at the surface of the cell, creating a 'dead layer', where light-generated carriers have little chance of being collected. Many commercial cells have a poor 'blue' response because of this dead layer.

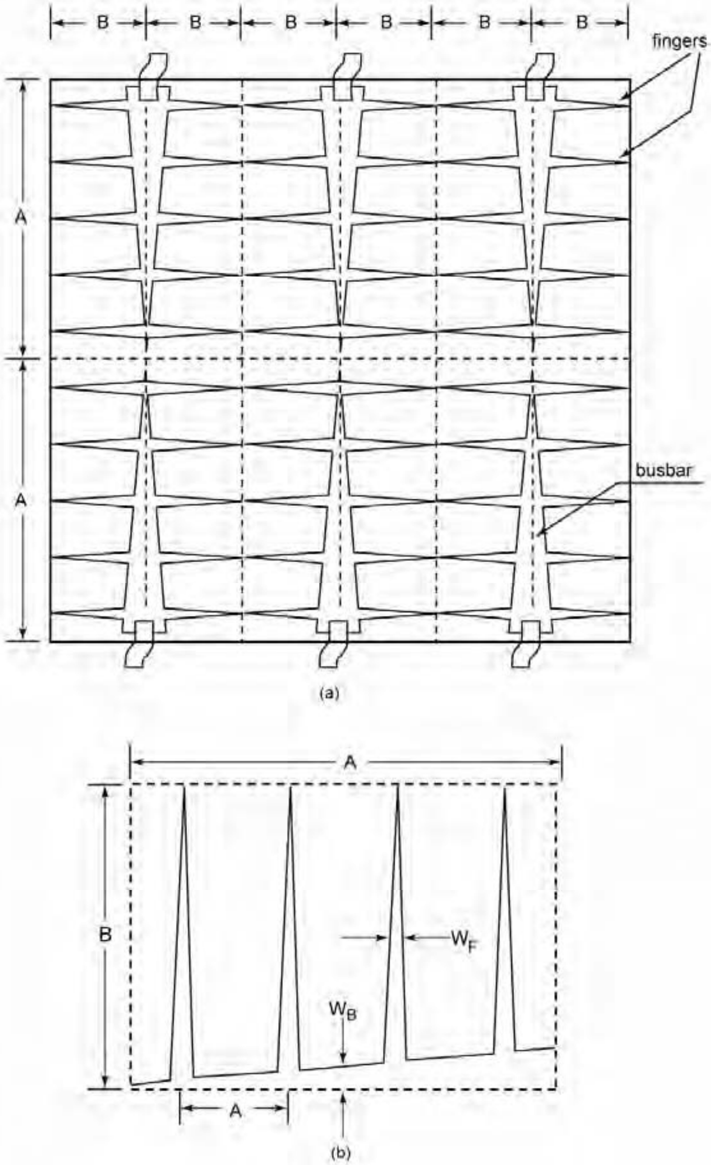

Figure 4.14. (*a*) Schematic of a top contact design showing busbars and fingers. (*b*) Important dimensions of a typical unit cell (©1978 IEEE, Serreze).

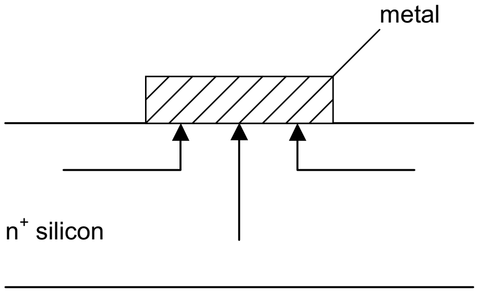

Figure 4.15. Points of contact resistance losses, at interface between grid lines and semiconductor.

4.5 LABORATORY CELLS VERSUS INDUSTRY REQUIREMENTS

Some of the techniques and design features used in the laboratory fabrication of silicon solar cells, to produce the highest possible efficiencies include:

- lightly phosphorus diffused emitters, to minimise recombination losses and avoid the existence of a 'dead layer' at the cell surface
- closely spaced metal lines, to minimise emitter lateral resistive power losses
- very fine metal lines, typically less than 20 μm wide, to minimise shading losses
- polished or lapped surfaces to allow top metal grid patterning via photolithography
- small area devices and good metal conductivities, to minimise resistive losses in the metal grid
- low metal contact areas and heavy doping at the surface of the silicon beneath the metal contact to minimise recombination
- use of elaborate metallisation schemes, such as titanium-palladium-silver, which give very low contact resistances
- good rear surface passivation, to reduce recombination
- use of antireflection coatings, which can reduce surface reflection from 30% to well below 10%.

The extra processing stages required and/or cost generally preclude industry use of the following technologies:

- photolithography
- Ti-Pd-Ag evaporated contacts
- double-layer antireflection coatings
- small area devices
- use of polished or lapped wafers.

To ensure a commercially-viable product, industry requires:

- cheap materials and processes
- simple techniques and processes
- high throughput

- large area devices
- large contact areas
- processes compatible with textured surfaces.

Typical commercially mass-produced solar cells use the following processing sequence:

1. Texturing of surfaces to form pyramids, which decrease the percentage of incident light reflected from the cell from about 33 to 11%, by causing reflected light from the pyramid face to strike at least one other pyramid face before escaping from the surface.
2. Phosphorus diffusion of the top surface, to provide a thin but heavily doped *n*-type layer.
3. Screen-printing and firing of aluminium or aluminium-doped silver paste onto the rear of the cell, to produce a back surface field and a rear metal contact.
4. Chemical cleaning.
5. Screen-printing and firing of front silver metal contact.
6. Edge junction isolation to destroy the conducting path between the front and rear metal contacts.

4.6 THE LASER GROOVED, BURIED CONTACT SOLAR CELL

A novel metallisation scheme, whereby laser grooves define the location and cross-sectional shape of the top surface metal conductors, has been developed at the University of New South Wales' Centre for Photovoltaic Engineering. It is now in large scale commercial production by BP Solar in Spain, and marketed as the 'Saturn' cell. The new cell structure is called a 'Laser Grooved, Buried Contact Solar Cell' (BCSC), and is illustrated in cross section in Fig. 4.16.

The benefits of the BCSC over conventional cell manufacturing processes are:

- large metal aspect ratios (contact thickness / width)
- very fine top contact grid lines (20 μm wide)
- reduction of shading losses on large area devices from 10–15% in screen printed cells to 2–3%
- excellent fill factors owing to low resistive losses in the metallisation and low contact resistance
- increased metal cross-sections, without increasing shading, by increasing groove depth with the same width
- device sizes can be increased without performance loss
- no photolithography, antireflection coatings, polished or lapped surfaces or expensive materials such as Ti-Pd-Ag metallisation are required
- very simple process
- generate electricity at significantly lower cost than standard screen-printed sequence (Jordan & Nagle, 1994)

- 20% efficient large area solar cells and 18% efficient modules have been demonstrated, compared with about 14% and 11% typically achieved using screen printing technology

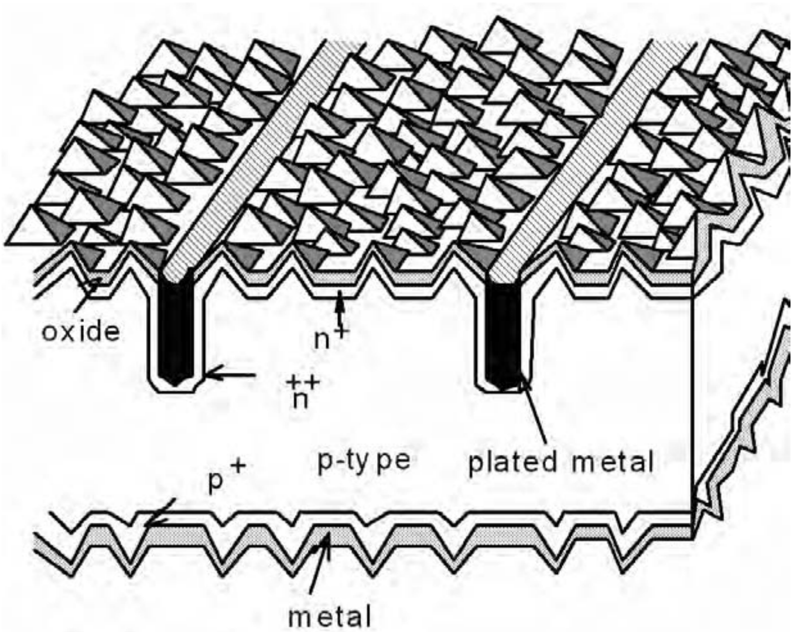

Figure 4.16. Cross-section of Laser Grooved Buried Contact Solar Cell.

Additional advantages for use as concentrator cells include (Wohlgemuth & Narayanan, 1991):

- higher efficiencies achievable on lower cost multicrystalline or single crystal substrates
- lower cost plated nickel-copper metallisation can be used
- process is self-aligning
- deeper diffusion in grooves provides good screening of metal from emitter, while allowing for a lightly-doped, higher efficiency emitter
- avoidance of top surface 'dead layer' through the use of lightly-doped emitter that gives significantly improved response to short wavelength light
- reduced contact resistance resulting from large plated wall area and heavily doped contact region.

The production sequence for laser grooved buried contact solar cells is as follows:

1. Texturing of surfaces.
2. Phosphorus diffusion and oxidation of the surfaces.
3. Laser scribing to form the grooves.
4. Chemical cleaning.
5. Heavy phosphorus diffusion of the groove walls.

6. Application and firing of aluminium onto the rear surface.
7. Electroless plating of front and rear contacts simultaneously (Ni-Cu-Ag).
8. Edge isolation.

An improved process for the BCSC was developed in 1993, which is capable of higher efficiencies at lower cost. The primary differences are the use of boron-diffused grooves at the rear and elimination of the aluminium deposition and firing steps (Honsberg *et al.*, 1993).

EXERCISES

4.1 (a) Give an overview of techniques currently used for silicon substrate formation.

(b) What are the advantages and disadvantages of each?

(c) Do crystalline silicon substrates have a long-term future?

4.2 (a) What substrate materials, other than silicon, can solar cells be made from?

(b) What are the advantages and disadvantages of each?

(c) Are some substrate materials better suited to specific applications or environments compared to others?

4.3 In block diagram form, outline the processing steps required to convert quartzite into a silicon space cell.

4.4 (a) Draw the cross-section of a typical commercial solar cell, marking relevant parts.

(b) Briefly describe how a solar cell operates.

(c) Outline important aspects of solar cell design that affect efficiency.

4.5 Commercially mass-produced solar cells for terrestrial applications have always had significantly lower generating efficiencies than the best laboratory fabricated cells. Discuss the reasons for and the effects of the differences in approaches and processing techniques between the two environments, and explain why these lead to such different levels of performance.

4.6 A certain technology produces 10% efficient solar modules at a cost of \$1 per peak watt output under bright sunshine (1 kW/^{2}). In a particular application, those balance-of-system costs that depend on the area of the array deployed amount to \$80/m^2. Assuming that other costs are identical in each case, at what price would 5% efficient modules produced by a second technology have to sell to give similar overall system costs?

4.7 (a) Derive an expression for the fractional power loss due to lateral current flow in the diffused top layer of a silicon solar cell.

(b) A commercial cell has a top layer sheet resistivity of 35 Ω/☐ and gives its maximum power output at a voltage of 420 mV and a current density of 28 mA/cm^2. If the finger spacing is 3 mm, calculate the fractional power loss owing to lateral current flows in the diffused top layer.

(c) If the bulk substrate resistivity is 1 Ω.cm and the substrate is 350 μm thick, estimate the fractional power loss due to current flow in the substrate.

4.8 Calculate and sketch the upper limit to the spectral sensitivity (short circuit current/power in incident monochromatic light) as a function of wavelength for a silicon solar cell.

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Chapter

5

PV CELL INTERCONNECTION AND MODULE FABRICATION

5.1 MODULE AND CIRCUIT DESIGN

Solar cells are rarely used individually. Rather, cells with similar characteristics are connected and encapsulated to form modules which, in turn, are the basic building blocks of solar arrays.

Since the maximum voltage from a single silicon cell is only about 600 mV, cells are connected in series to obtain the desired voltage (Mack, 1979). Usually about 36 series cells are used for a nominal 12V charging system.

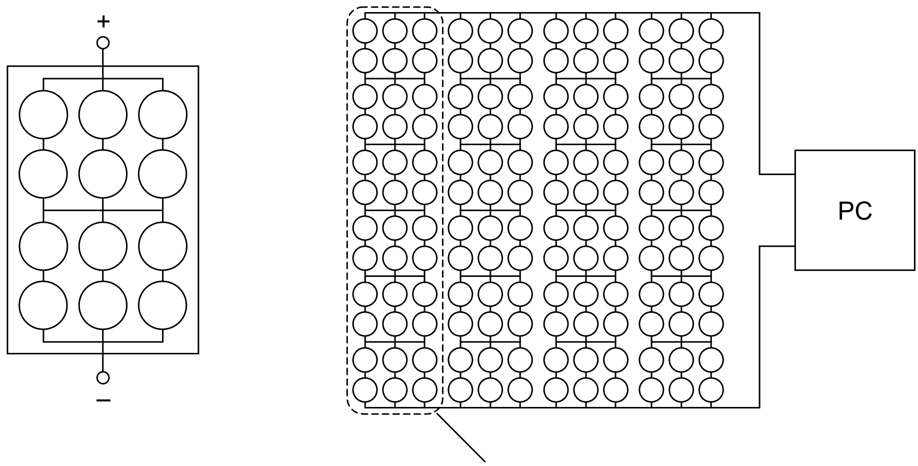
Under peak sunlight (100 mW/cm^2), the maximum current delivered by a cell is approximately 30 mA/cm^2. Cells are therefore paralleled to obtain the desired current. Fig. 5.1 illustrates a typical connection system and the standard terminology used to describe such connections.

A database including the characteristics of 125 commercial modules is available online from Sandia National Laboratories (2002).

5.2 IDENTICAL CELLS

Ideally, the cells in a module would exhibit identical characteristics and the module I-V curve would be the same shape as that of the individual cells, with a change in scale of the axes. Therefore, for N cells in series and M cells in parallel

$$I_{total} = MI_L - MI_0\left[\exp\left(\frac{qV_{total}}{nkTN}\right) - 1\right] \tag{5.1}$$



module
3 parallel strings
2 series blocks
2 cells per substring

branch circuit
3 parallel strings
6 series blocks
2 cells per substring

Figure 5.1. Typical connection systems and terminology used in module circuit design (©1980 IEEE, Ross). PC = power conditioning equipment.

5.3 NON-IDENTICAL CELLS

In practice, all cells have unique characteristics, and the module output is limited by that of the cell with the lowest output. The difference between the maximum output of the component cells and the output actually achieved is called the mismatch loss.

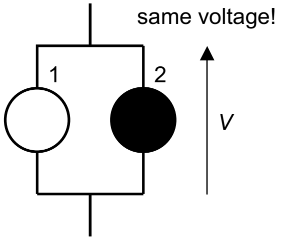
Mismatched cells connected in parallel are shown in Fig. 5.2. Figs. 5.3 and 5.4 illustrate ways of determining the resultant current and open circuit voltage.

Mismatched cells connected in series are shown in Fig. 5.5. Figs. 5.6 and 5.7 illustrate ways of determining the resultant voltage and short circuit current.

5.4 NON-IDENTICAL MODULES

Exactly the same effects and curve shapes occur if cells in the diagrams above are replaced by modules, strings, blocks of cells or source circuits!

Cells or modules with the same current rating, but from different manufacturers, are likely to show different spectral responses and therefore lead to mismatching problems.



cell 2 has lower output caused by:

- manufacturing defects
- degradation (e.g. cracking)
- partial shading (e.g. trees, buildings, leaves, bird droppings, discoloured encapsulant etc.)
- higher temperature

Figure 5.2. Mismatched cells connected in parallel.

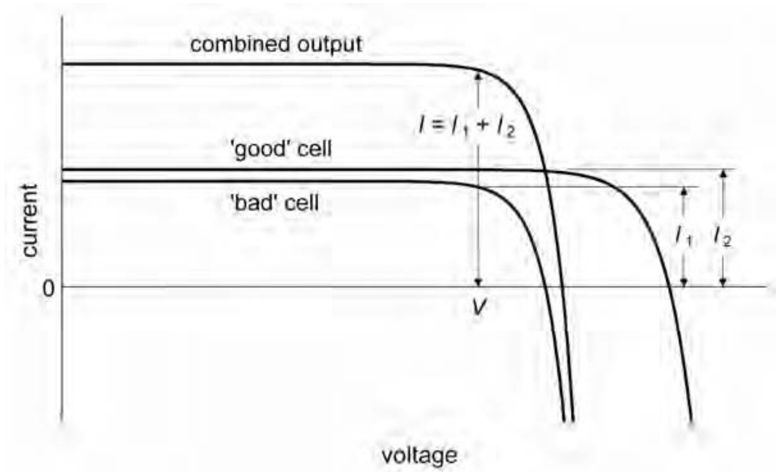


Figure 5.3. Parallel-connected mismatched cells and the effect on current. The combined curve is determined by summing the currents I_1 and I_2 for each voltage V.

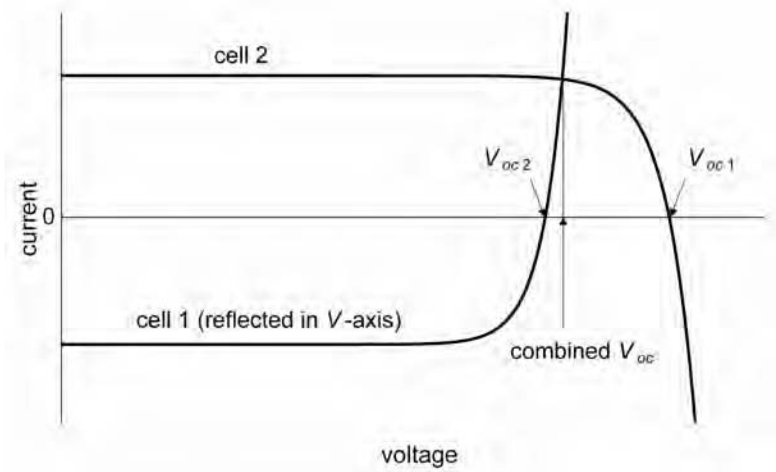


Figure 5.4. An easy method of calculating the combined V_{oc} of mismatched cells in parallel. The curve for one of the cells is reflected in the voltage axis so that the intersection point (where $V_1 + V_2 = 0$) is the V_{oc} of the parallel configuration.

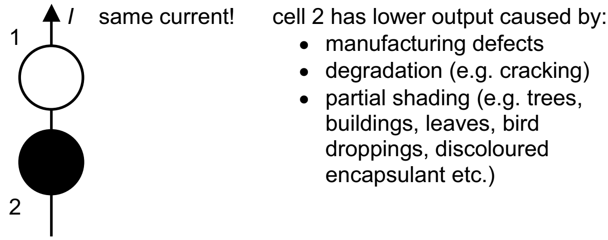


Figure 5.5. Mismatched cells connected in series.

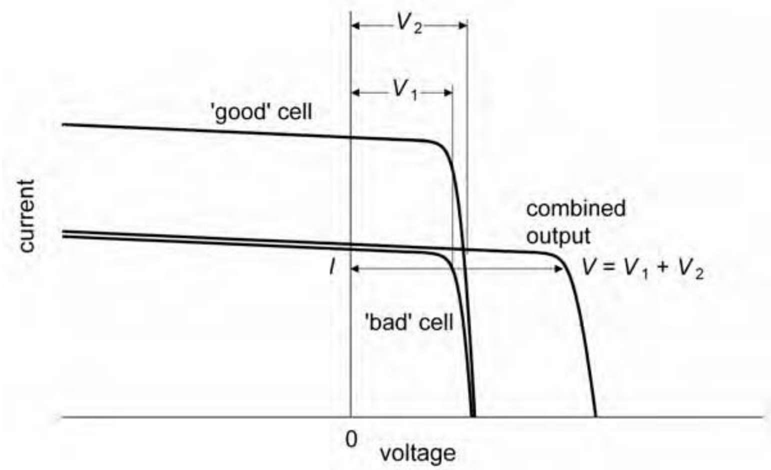


Figure 5.6. Series-connected mismatched cells and the effect on voltage. The combined curve is determined by summing the voltages V_1 and V_2 for each current I.

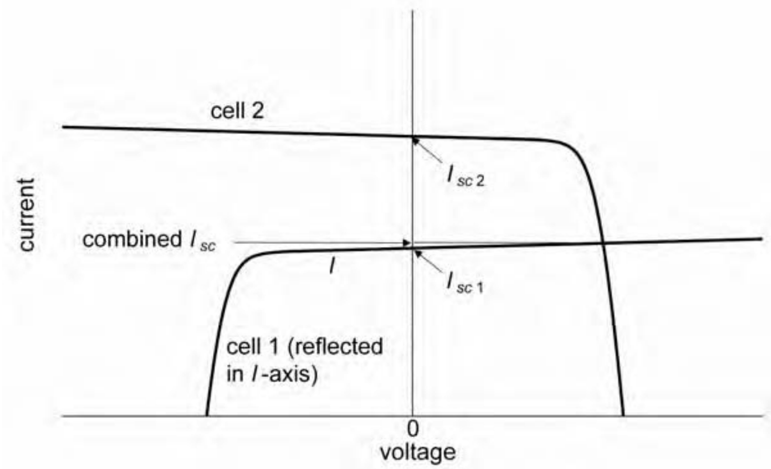


Figure 5.7. An easy method of calculating the combined I_{sc} of series-connected mismatched cells. The current at the point of intersection represents the short circuit current of the series combination (i.e. $V_1 + V_2 = 0$).

5.5 HOT-SPOT HEATING

Mismatched cells within a module can result in some cells generating and some dissipating power. In the worst case, the whole output of the 'good' cells can be dissipated in the 'bad' cell when the module or string of modules is short-circuited. Fig. 5.8 shows a string of cells with one bad cell and Fig. 5.9 shows the impact of the bad cell on module output. The bad cell becomes reverse biased to the voltage-generating capability of the good cells, as shown in Fig. 5.10.

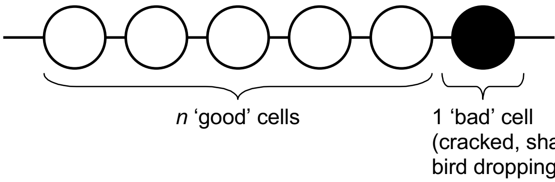


Figure 5.8. One 'bad' cell in a string, which reduces the current through the 'good' cells, leading to them producing higher voltages that can often reverse-bias the bad cell.

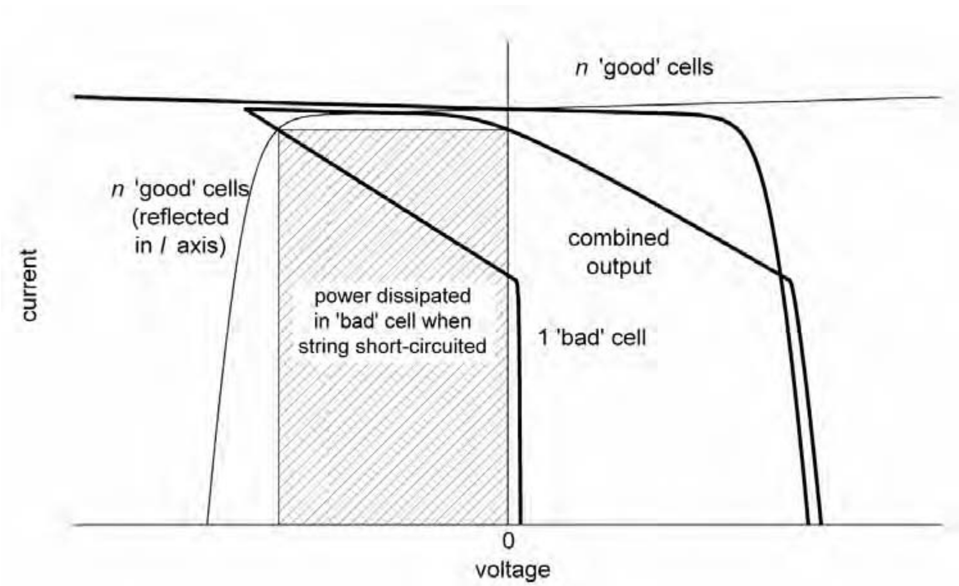


Figure 5.9. The impact on module output of a 'bad' cell in a string of 'good' cells (after Ross & Smokler, 1986).

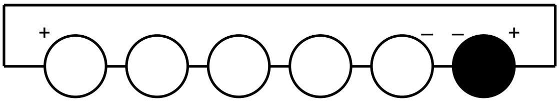


Figure 5.10. Reverse biasing of the 'worst' cell in a string. This occurs as the 'good' cells try to drive a higher current through the 'bad' cell than it can accommodate, even when short-circuited.

Dissipation of power in poor cells leads to breakdown in localised regions of the cell *p-n* junction. An enormous power dissipation can occur in a small area, leading to local overheating, or ‘hot spots’, which in turn leads to destructive effects, such as cell or glass cracking or melting of solder. Similar effects occur with groups of cells, as illustrated in Fig. 5.11.

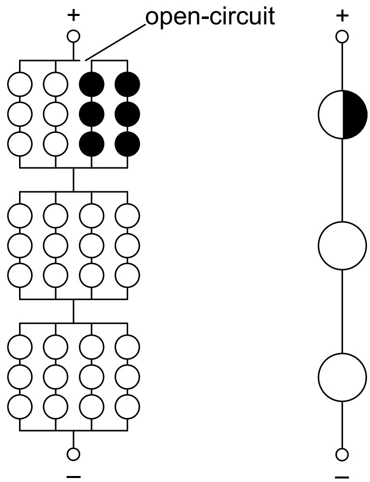


Figure 5.11. Potential source of ‘hot spots’ in groups of cells. The combination of cells on the left acts similarly to three series-connected cells with one ‘bad’ cell, as shown on the right (Ross & Smokler, 1986).

One solution to the problem of mismatched cells and hot spots is to add *bypass diodes* to the circuit (Standards Australia, 2005). Under normal conditions, for example, with no shading, each diode is reverse biased and each cell generates power. When a cell is shaded it ceases to generate, acts as a high resistance and tends to be reverse-biased by the other cells, causing the diode across the cell to conduct, thereby bypassing the shaded cell. Fig. 5.12 shows a bypass diode alone, in a circuit and with a faulty cell. The effect on array output of a faulty cell is shown in Fig. 5.13.

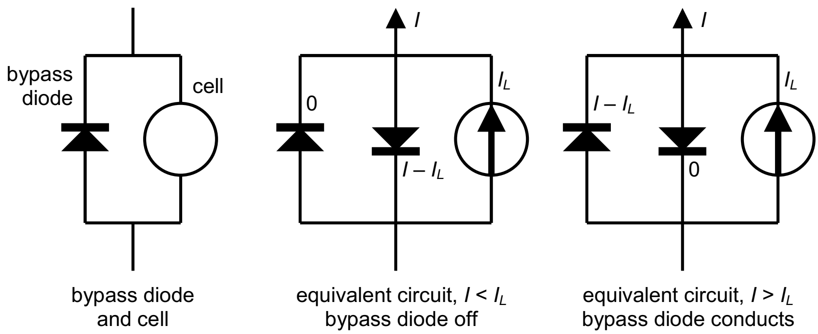


Figure 5.12. A bypass diode in parallel with a cell. When the total current exceeds the I_L of this cell, the bypass diode conducts.

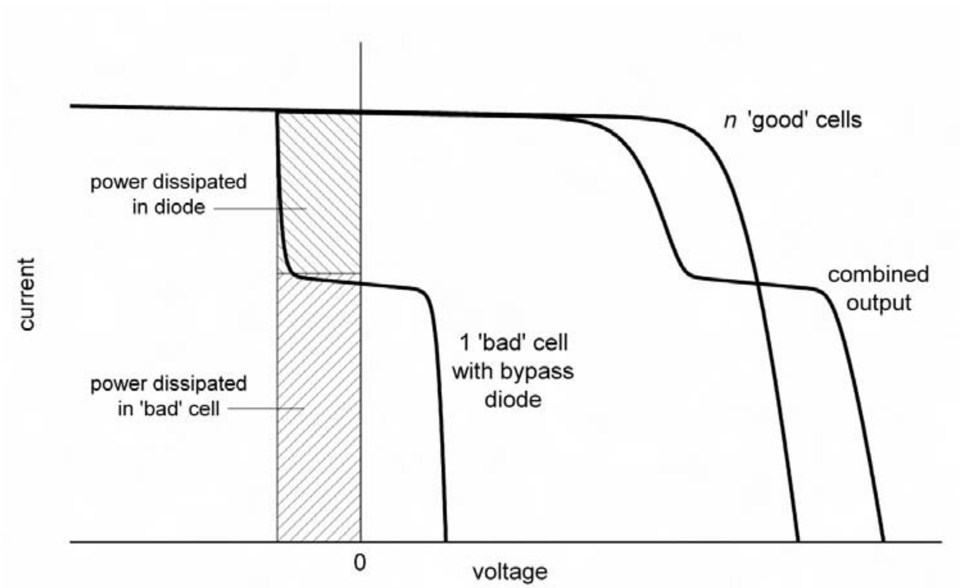


Figure 5.13. Effect on total output of a ‘bad’ cell with a bypass diode. When the combination is short-circuited, the total power dissipated in the bad cell and bypass diode is approximately equal to the output capability of one good cell.

In practice, however, one diode per cell is generally too expensive and diodes are usually placed across groups of cells, as shown in Fig. 5.14. The maximum power dissipation in the shaded cell is then approximately equal to the generating capability of all cells in the group.

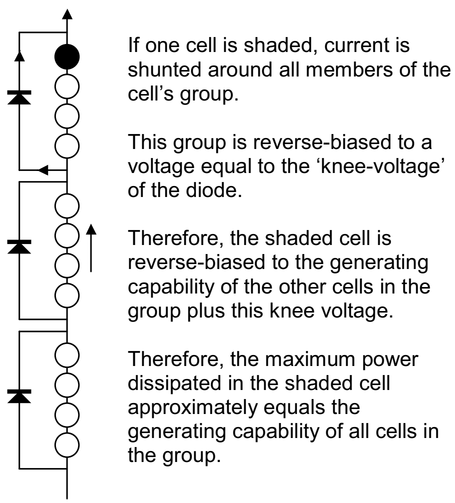


Figure 5.14. Bypass diodes used across groups of cells in a module.

For silicon solar cells, the maximum group size per diode, without causing damage, is about 10–15 cells per bypass diode. Hence for a normal 36 cell module, three bypass diodes are needed to ensure the module will not be vulnerable to hot spot damage.

Not all commercial modules include bypass diodes. If they do not, care must be taken to ensure the modules are not short-circuited for long periods and that parts of the module are not shaded by surrounding structures or adjacent arrays. It is possible for a diode to be integrated into each cell, creating a lower cost means of protecting individual cells (Green, 1980).

For modules in parallel, as shown in Fig. 5.15, an additional problem, thermal runaway, can occur when bypass diodes are used—one string of bypass diodes becomes hotter than the rest, therefore taking up a larger share of the current, hence becoming even hotter and so on. Diodes should therefore be rated to handle the parallel current of the module combination.

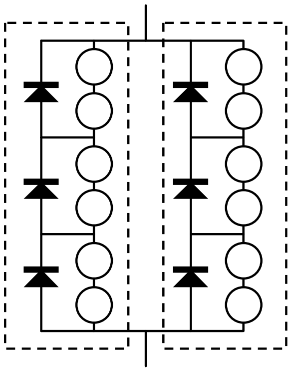


Figure 5.15. Bypass diodes in paralleled modules.

Standards Australia (2005) gives specifications for non-embedded bypass diodes, when used. They should be rated to survive twice the open circuit voltage of the protected module(s) or cell(s) and 1.3 times their short circuit current.

Some modules also include a *blocking diode*, as shown in Fig. 5.16, to ensure current only flows out of the module. This prevents, for instance, a battery from discharging through the module at night.

Blocking diodes in strings are not universally recommended or used because they waste some of the collected energy (Albers, 2004). When blocking diodes are used, as for bypass diodes, they should have a voltage rating at least twice the open circuit array voltage and a current rating 1.3 times the short circuit current at STC of the protected circuit (Standards Australia, 2005).

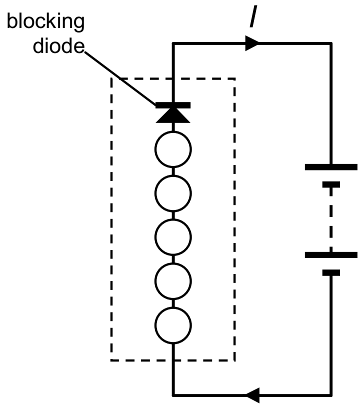


Figure 5.16. Use of a blocking diode to ensure one-way current flow in a module.

5.6 MODULE STRUCTURE

Solar arrays are often used in harsh and remote environments, where supplying power by central grid or fuel-dependent systems is not feasible. Hence, modules must be capable of extended, maintenance-free operation. Module lifetimes of around 20 years are normally quoted by manufacturers, although the industry is seeking 30-year lifetimes. Encapsulation is the main factor affecting solar cell life expectancy (King *et al.*, 2000). A typical encapsulation scheme is shown in Fig. 5.17.

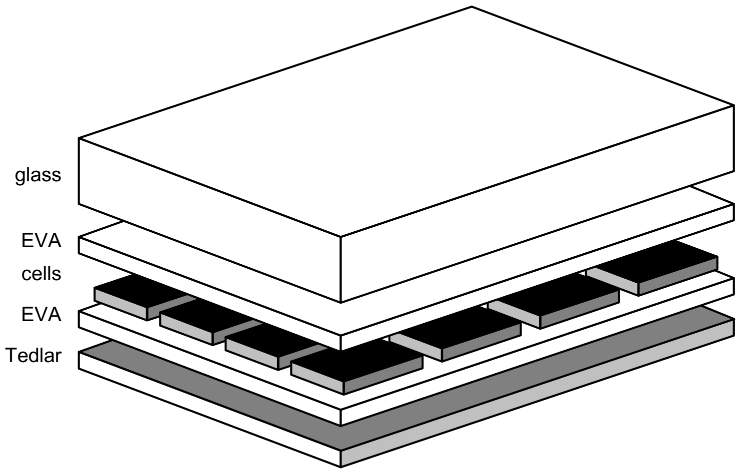


Figure 5.17. A typical laminated module structure.

The Australian Standard for Installation of Photovoltaic (PV) Arrays (Standards Australia, 2005) makes reference to IEC Standard 61215 (IEC, 1993) which is widely used by module manufacturers to ensure that modules continue to perform under extreme, but not unlikely, environments. The IEC 61215 tests require eight modules sampled at random from a production batch that have been subjected to the manufacturer's normal inspection quality control procedures. Each module undergoes a different sequence of tests to check the electrical, optical or mechanical construction of the module type. A module type meets the qualification requirements if each sample meets all of the following criteria:

1. There is no evidence of a major visual defect.
2. The degradation of maximum output power at STC is less than 5% after each test and 8% after the sequence.
3. Insulation resistance and high-voltage tests are passed.
4. No sample exhibits any open circuit or ground fault.

The most important aspects of environmental protection are discussed below.

5.7 ENVIRONMENTAL PROTECTION

(After Treble, 1980; King *et al.*, 2000 and Ecofys BV, 2004.)

The module must be able to withstand such environmental conditions as dust, salt, sand, wind, snow, humidity, rain, hail, birds, condensation and evaporation of moisture, atmospheric gases and pollutants, and diurnal and seasonal temperature variations, as well as maintaining performance under prolonged exposure to UV light.

The top cover must have, and maintain, high transmission in the waveband 350–1200 nm. It must have good impact resistance and a hard, smooth, flat, abrasion-resistant, non-staining surface, which promotes self-cleaning by wind, rain or spray. The entire structure should be free of projections, which could result in the lodgement of water, dust or other matter.

Moisture penetration is responsible for the majority of long-term module failures, with condensation on the cells and circuitry causing shorting or corrosion. Hence, the encapsulation system must be highly resistant to the permeation or ingress of gases, vapours or liquids. The most vulnerable sites are at the interface between the cells and the encapsulating materials, and at all other interfaces between different materials. The materials used for bonding must also be carefully chosen to be able to maintain adhesion under extreme operating conditions. Common encapsulants are ethylene vinyl acetate (EVA), Teflon and casting resin. EVA is commonly used for standard modules and is applied in a vacuum chamber, as is Teflon, which is used for small-scale special modules and which does not require a front cover glass. Resin encapsulation is sometimes used for large modules intended for building integration.

Tempered, low iron content and rolled sheet glass is currently the most favoured choice for the top surface because it is relatively cheap, strong, stable, highly transparent, impervious and has good self-cleaning properties. Tempering helps the glass withstand thermal stress. Low iron glass allows up to 91% of the light to penetrate. A recent development is the availability of glass with anti-reflective coatings applied by caustic processes or dip coating, resulting in up to 96% transmission. Tedlar, Mylar or glass are commonly used for the rear of the module, to act as a moisture barrier, but all polymers are permeable to some degree. Typical short-term loss in performance of modules owing to dust accumulation and soiling in urban and rural environments is shown in Fig. 5.18. Further data on the effects of dust may be found in Hammond *et al.* (1997).

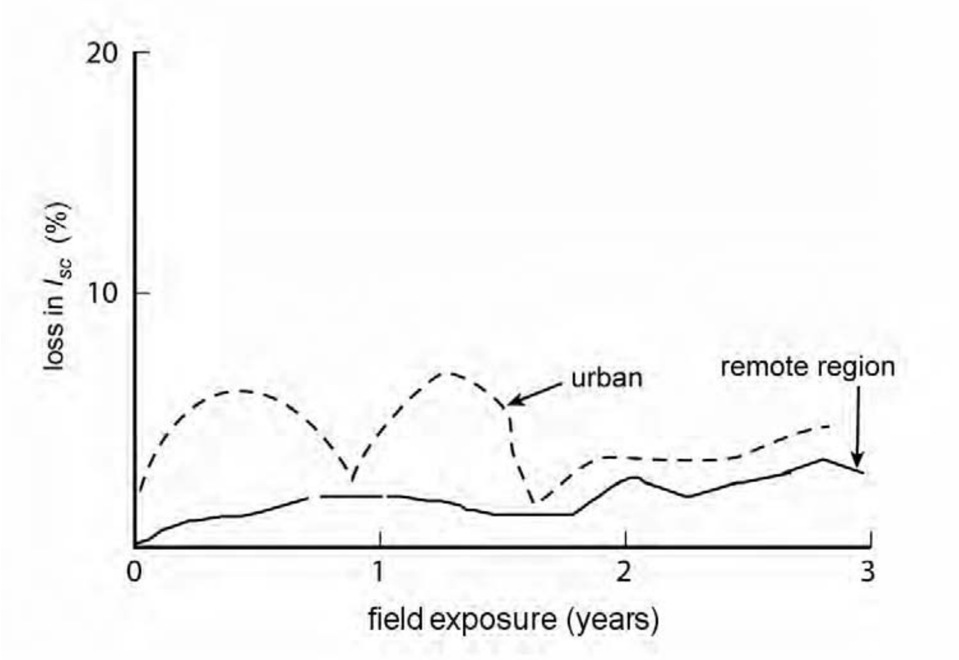


Figure 5.18. Short-term performance degradation in urban and rural environments (after Ross & Smokler, 1986).

5.8 THERMAL CONSIDERATIONS

For crystalline silicon in particular, it is desirable for modules to operate at as low a temperature as possible, since:

- cell output is increased at lower temperatures (see Section 3.3)
- thermal cycles and stress are reduced
- degradation rates approximately double for each 10°C increase in temperature.

To reduce module degradation rates, infrared radiation, the wavelengths of which are too long to be absorbed by the cells, should ideally be rejected; however no cost-effective method has yet been developed for this. The modules and the solar array must therefore take full advantage of radiative, conductive and convective cooling and absorb the minimum of unused radiation. Typically, about half the heat loss from a module is by convection and half by radiation.

Different encapsulation types, giving vastly different thermal properties, have been used by manufacturers to meet different market needs, as illustrated by some of the different modules offered by a typical manufacturer:

- marine module
- injection moulded module
- mini module

- laminated module
- photovoltaic roof tiles
- laminates for building integration.

Fig. 5.19 shows the temperature rise above ambient for a selection of module types. Module temperature rise above ambient is approximately linear with increasing insolation level.

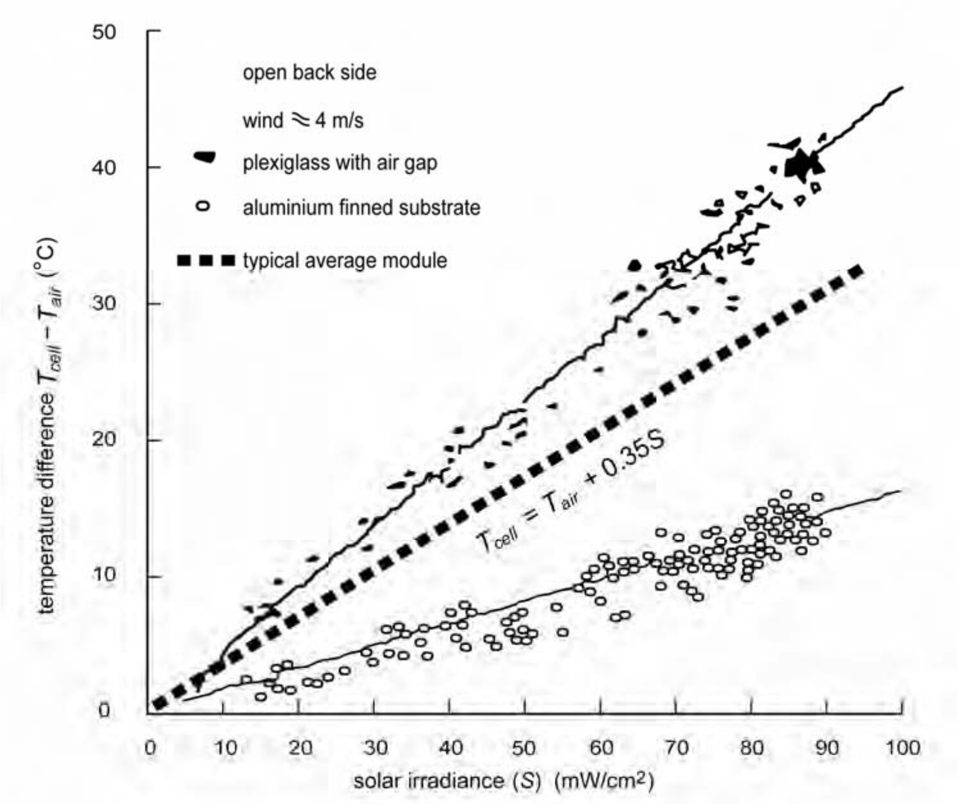


Figure 5.19. Temperature increases, above ambient levels, with increasing solar irradiance for different module types (Ross & Smokler, 1986).

The *nominal operating cell temperature* (NOCT) is defined as the temperature reached by open-circuited cells in a module under the following representative conditions:

irradiance on cell surface	=	800 W/m^2
air temperature	=	20°C
wind velocity	=	1 m/s
mounting	=	open rear surface.

In Fig. 5.19, the best module operated at an NOCT of 33°C, the worst at 58°C and the typical module at 48°C. An approximate expression for calculating the cell temperature is given by (Ross & Smokler, 1986)

$$T_{cell} = T_{air} + \frac{NOCT - 20}{800} \times S \quad (°C) \tag{5.2}$$

where S is the insolation in W/m^2. Module temperature will be lower than this when wind velocity is high, but higher under still conditions. Temperature effects can be particularly important for building-integrated modules, with care needed to ensure as much airflow as possible behind the modules to prevent temperature build-up.

Cell packing density also has a bearing on operating temperature, with sparsely packed cells having a lower NOCT. For example:

- 50% cell packing → 41°C NOCT
- 100% cell packing → 48°C NOCT.

The relative packing density possible with round verses square cells is illustrated in Fig. 5.20.

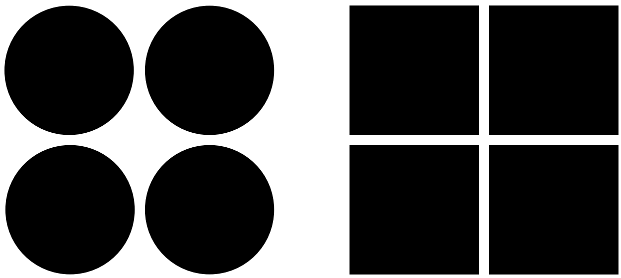


Figure 5.20. The packing density of round and square cells.

Sparsely packed cells in a module with a white rear surface can also provide marginal increases in output via the *zero depth concentrator effect* (SERI, 1984), illustrated in Fig. 5.21. Some of the light striking cell contacts and regions of the module between cells is scattered and channelled to active regions of the module.

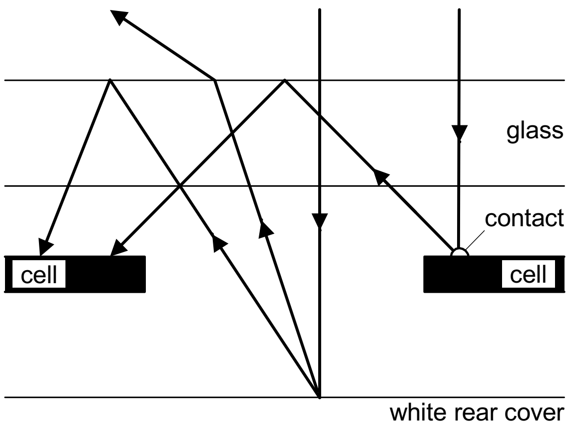


Figure 5.21. The *zero-depth concentration effect* in modules with sparsely packed cells and a white rear surface.

Thermal expansion is another important temperature effect which must be taken into account when modules are designed. Fig. 5.22 illustrates the expansion between cells with temperature increases.

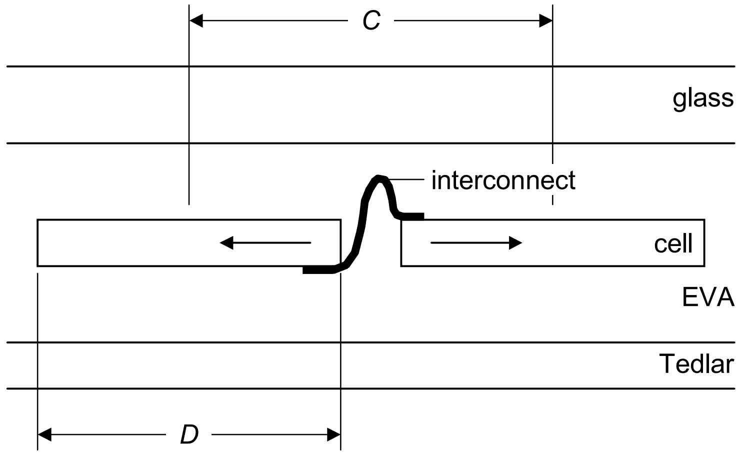


Figure 5.22. Use of stress relief loops to accommodate expansion between cells with increases in temperature.

Referring to Fig. 5.22, the spacing between cells tries to increase an amount δ given by

$$\delta = \left(\alpha_g C - \alpha_c D\right) \Delta T \tag{5.3}$$

where α_g, α_c are the expansion coefficients of the glass and cell, respectively, C is the centre-to-centre distance between cells and D is the cell length.

Typically, interconnections between cells are looped, as shown, to minimise cyclic stress. Double interconnects are used to protect against the probabilistic nature of fatigue failure by such stress.

In addition to interconnect stresses, all module interfaces are subject to temperature-related cyclic stress, which can eventually lead to delamination.

5.9 ELECTRICAL INSULATION

The encapsulation system has to be able to withstand voltage differences at least as large as the system voltages. Metal frames must also be earthed, except in particular special circumstances, as internal and terminal potentials can be well above the earth potential (Standards Australia, 2005). Conditions for which earth leakage safety devices are required are specified by Standards Australia (2005):

1. Array V_{oc} < 50 V—none required.
2. 50 V < Array V_{oc} < 120 V—earth fault protection on DC side required if system earthed and isolated, or DC-sensitive residual current device on AC side if not isolated.

3. Array V_{oc} > 120 V—in addition to the above conditions for arrays exceeding 50 V, an insulation monitor is required for floating, isolated arrays.

5.10 MECHANICAL PROTECTION

Solar modules must have adequate strength and rigidity to allow normal handling before and during installation. If glass is used for the top surface, it must be tempered, since the central areas of the module become hotter than areas near the frame. This places tension at the edges, and can cause cracking. In an array, the modules must be able to accommodate some degree of twisting in the mounting structure, as shown in Fig. 5.23, as well as withstand wind-induced vibrations and the loads imposed by high winds, snow and ice (IEC, 1993).

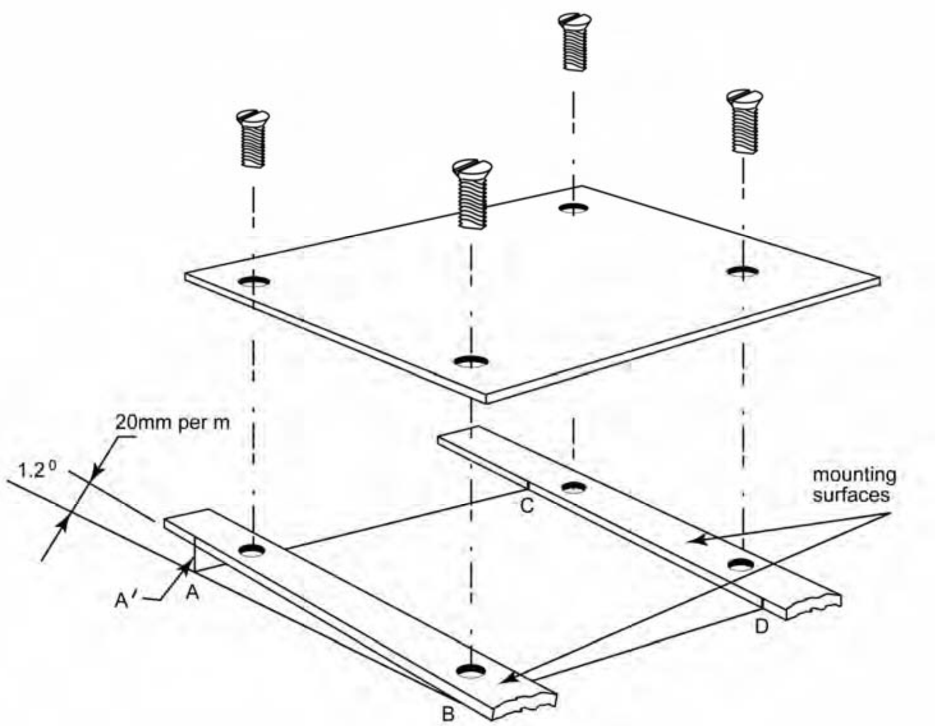


Figure 5.23. Possible module twisting on a distorted mounting frame (JPL, 1981).

The points most sensitive to such mechanical damage are the module corners, edges, cell edges and any substrate supports.

5.11 DEGRADATION AND FAILURE MODES

The operating life of a solar module is primarily determined by the durability of the encapsulation (Czanderna & Pern, 1996), although there are light-induced degradation mechanisms in boron-doped silicon cells (Schmidt & Cuevas, 1999). Field results indicate that, over an anticipated 20–30 year life, solar modules can be expected to fail or to degrade in a number of ways, with long term performance studies indicating typical losses in the range 1–2% per year (King *et al.*, 2000). Ross (1980) gives expected reduction in output due to various degradation modes for each year of operation:

1. **Front surface soiling**—Module performance can be reduced by the accumulation of dirt on the top surface. Self cleaning of glass-surfaced modules by wind and rain keeps these losses under 10%; however they can be much more significant for other surface materials.

2. **Cell degradation—**A gradual degradation in module performance can be caused by:
   - increases in R_s owing to decreased adherence of contacts or corrosion
   - decreases in R_{sh} owing to metal migration through the *p*-*n* junction
   - antireflection coating deterioration
   - degradation of the cell active *p*-type material by the interaction of boron-oxygen complexes (Schmidt & Cuevas, 1999).

3. **Module optical degradation**—Discolouration of the encapsulating materials can result in a gradual drop in performance (Czanderna & Pern, 1996). Yellowing can occur uniformly, because of UV exposure, temperature or humidity, or locally, because of the diffusion of foreign matter from the edge seals, mountings or terminal boxes of the module.

4. **Short circuited cells**—Short circuiting can occur at cell interconnections, as illustrated in Fig. 5.24. This is also a common failure mode for *thin film* cells, since top and rear contacts are much closer together, with more chance of them being shorted together by pin-holes or regions of corroded or damaged cell material.

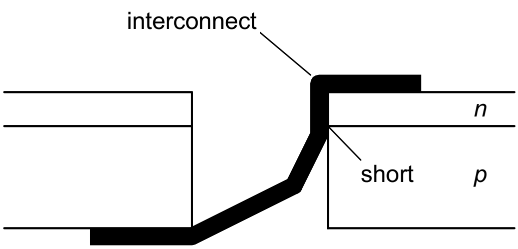


Figure 5.24. Cell failure through interconnect shorting.

5. **Open circuited cells**—This is a common failure mode, although redundant contact points plus *interconnect busbars* allow the cell to continue functioning. A cracked cell, leading to open circuiting, is shown in Fig. 5.25. Cell cracking can be caused by:
   - thermal stress
   - hail or gravel
   - damage during processing and assembly, resulting in ‘latent cracks’, which are not detectable on manufacturing inspection, but appear sometime later.

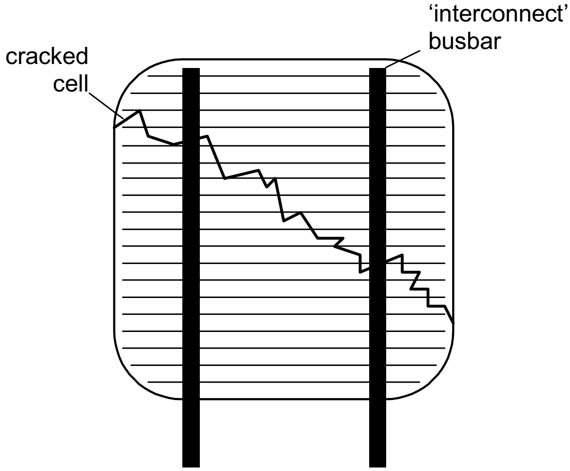


Figure 5.25. Cracked cell indicating how 'interconnect' busbars can help prevent open circuit failure.

6. **Interconnect open circuits and series resistance**—Fatigue owing to cyclic thermal stress and wind loading leads to interconnect open circuit failures and series resistances can gradually increase with age. As tin-lead alloy solder bonds age, the solder becomes brittle and separates into grains of lead and tin with cracks, causing increased resistance.
7. **Module open circuits and series resistance**—Open circuit failures and ageing effects also occur in the module structure, typically in the bus wiring or junction box.
8. **Module short circuits**—Although each module is tested before sale, module short circuits are often the result of manufacturing defects. They occur because of insulation degradation with weathering, resulting in delamination, cracking or electrochemical corrosion.
9. **Module glass breakage**—Shattering of the top glass surface can occur because of vandalism, thermal stress, handling, wind or hail. Roofing gravel has been found to cause fractures in relatively low wind speeds after being blown up the surfaces of tilted roof-mounted modules and then landing on the next row of modules at near normal incidence (King *et al.*, 2000).
10. **Module delamination**—This was a common failure mode in early generations of modules, but is now less of a problem. It is usually caused by reductions in bond strength, either environmentally-induced by moisture or photothermal aging, or stress induced, by differential thermal and humidity expansion. It has been more frequently observed in hot and humid climates. Moisture migration through the encapsulant, sunlight and heat facilitate chemical reactions leading to delamination.
11. **Hot-spot failures**—Mismatched, cracked or shaded cells can lead to hot-spot failures, as discussed in Section 5.5.

12. **Bypass diode failure**—Bypass diodes used to overcome cell mismatching problems can themselves fail, usually due to overheating and often due to undersizing (Durand, 1994). The problem is minimised if junction temperatures are kept below 128°C.
13. **Encapsulant failure**—UV absorbers and other encapsulant stabilisers ensure a long life for module encapsulating materials. However, slow depletion, by leaching and diffusion, does occur and, once concentrations fall below a critical level, rapid degradation of the encapsulant materials occurs. In particular, browning of the EVA layer, accompanied by a build-up of acetic acid, has caused gradual reductions in the output of some arrays, especially those in concentrating systems (Wenger *et al.*, 1991; Czanderna & Pern, 1996; King *et al.*, 2000), although recent improvements in EVA photostability have reduced this problem.

5.12 EMBODIED ENERGY AND LIFE CYCLE ISSUES

Early solar cells required significant levels of material use and processing energy. This raised the issue of net energy production by photovoltaics. Modern commercial products are higher in efficiency than the early cells, production techniques minimise material use and wastage, while energy use has become more efficient, so that there is no longer any question that photovoltaic cells pay back their manufacturing energy in the early years of their operation. Effort is now being directed to developing manufacturing methods that facilitate module recycling (Wambach, 2004; Arai *et al.*, 2004).

A number of methods, including process analyses or input-output techniques, are used to calculate and report on the energy used to manufacture components and modules, which is referred to as the *embodied energy* of manufacture (E_{man}). This is the primary energy requirement during module manufacture, including materials mining.

Life cycle analysis (LCA) techniques (sometimes known as cradle-to-grave analyses) are also used to follow both the materials and the energy flow through manufacturing, operation and end-of-life. Methodologies used are covered under the International Standards Organisation Life Cycle Assessment standard ISO 14040. For energy use, E_{input} can be defined as the sum of primary energy requirements for manufacturing (E_{man}), transport (E_{trans}), installation (E_{inst}), operation (E_{use}) and decommissioning (E_{decomm}) (Kato, 2000)

$$E_{input} = E_{man} + E_{trans} + E_{inst} + E_{use} + E_{decomm} \qquad (5.4)$$

For each year the PV module is in operation, it will displace a certain amount of energy that would otherwise have been used for electricity generation. This is referred to as E_{gen} and will vary with site and fuel displaced. The term *energy payback time* (EPT or EPBT) refers to the time taken for the input energy to be repaid by PV generation. Hence

$$EPT = \frac{E_{input}}{E_{gen}} \qquad (5.5)$$

Using current manufacturing technology, typical crystalline silicon modules have EPTs ranging from 2 to 8 years, while thin film modules have EPTs of 1 to 3 years (Kato, 2000; Alsema, 2000). These are expected to be below 2 years and 1 year, respectively, as newer technologies are installed (Alsema *et al.*, 1998). However, the EPT gives no indication that the life of a PV module (L_{pv}) is likely to be 20—40 years, so that the PV module will generate significantly more energy over its lifetime than was needed in its manufacture. The term *energy yield ratio* (EYR) (Pick, 2002), defined as

$$EYR = \frac{E_{gen} L_{pv}}{E_{input}} \tag{5.5}$$

is used to reflect this. An EYR greater than one indicates the PV module (or system) is a net energy producer. For a module with an EPT of 4 years and a life of 20 years, EYR would be 5, indicating that the module would generate five times the energy used in its manufacture over its lifetime.

EXERCISES

5.1 A hypothetical solar module consists of 40 series-connected identical solar cells, each giving an open circuit voltage of 0.61 V and a short circuit current of 3 A under bright sunshine. The module is short-circuited under bright sunshine and one cell is partly shaded. Assuming that the cells have an ideality factor of unity, and neglecting temperature effects, find the power dissipated in the shaded cell as a function of the fractional shading of the cell.

5.2 (a) Briefly discuss features of a silicon solar cell that affect its spectral response.

(b) When do you need to consider spectral response differences between cells and why?

5.3 (a) Explain how localised ‘hot spots’ can occur in a partially shaded cell connected into a large photovoltaic array.

(b) Explain the steps that can be taken to prevent damage arising from such ‘hot spots’.

5.4 (a) A nominal 12V photovoltaic module contains 36 identical solar cells, each with a short circuit current of 3.0 A, and a fill factor and open circuit voltage typical of those found with commercial solar cells. Draw and label as appropriate the expected current-voltage characteristic of such a module at 25°C.

(b) By mistake, the manufacturer connects one cell in the wrong way (reverse polarity). On the previous diagram, superimpose the corresponding current-voltage characteristic and indicate how it was determined.

(c) What effect will result from shading the wrongly-connected cell and why?

(d) Would it help if the wrongly-connected cell had an integral bypass diode?

5.5 (a) Photovoltaics are renowned for their reliability. However, over the years, many lessons have been learned through failures in the field. List as many of these as possible, giving examples.

(b) Discuss how similar problems have subsequently been avoided.

5.6 Explain what is meant in photovoltaics by the term *nominal operating cell temperature* and why it is important for this parameter to be as low as possible. Indicate how and why this parameter may vary with different module designs.

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Chapter

6

STAND-ALONE PHOTOVOLTAIC SYSTEM COMPONENTS

6.1 INTRODUCTION

Photovoltaic cells and systems have a wide variety of applications, including (see also Rannels, 1991; Sandia National Laboratories, 1991; Preiser, 2003):

- space (e.g. satellites and space stations)
- navigational aids and warning devices (e.g. coded light beacons)
- telecommunications (e.g. microwave repeater stations, remote area radio telephones, emergency call boxes)
- railway crossing, road and emergency signage
- cathodic protection (e.g. corrosion prevention for pipe lines)
- consumer products requiring less than 10 mW (e.g. calculators and watches)
- battery charging (e.g. boats, campervans, lights, power systems of all types and even cars)
- educational (e.g. TV in developing countries)
- refrigeration (e.g. for medicines and vaccines in remote areas)
- water pumping (e.g. for irrigation and domestic water supplies)
- water purification, an increasingly important application in both developing and industrialised countries

- solar powered vehicles (e.g. golf carts, solar cars, boats on reservoirs where petroleum products and noisy motors are restricted)
- lighting (e.g. billboards, street and garden lights, security lighting, emergency warning lights)
- remote monitoring (e.g. weather, pollution, highway conditions, water quality, river heights and flow rates)
- remote meter reading
- gas flow metering
- direct drive applications (e.g. ventilation fans, toys)
- electric fences (e.g. to keep dingos and kangaroos out or stock in)
- remote gates
- remote community power supplies
- remote homestead and household power supplies (usually in a hybrid system)
- power for residential or commercial use where there is grid connection
- power for sectionalising switches along remote sections of electricity grids
- 'distributed photovoltaics'—numerous appropriately-sized arrays feeding into distribution power grids at dispersed sites
- central power plants.

Some of the main applications will be discussed in more detail in the following chapters.

The majority of the above are stand-alone systems, with a wide range of loads, sites and required availabilities, making system design a complex exercise. In some applications, even estimating the load can be quite a difficult task. Grid-connected applications are of increasing interest and have now overtaken stand-alone systems as the main market for photovoltaic modules worldwide. Some options for grid-connected and stand-alone power supply systems are illustrated in Fig. 6.1.

The high cost of extending the electricity grid to customers has meant that many communities, properties and households around the world rely on diesel, petrol or renewable energy-based power supply systems. This applies particularly to countries such as Australia where there are large remote areas and difficult terrain. Photovoltaic systems offer an attractive option or supplement to the older technologies. They are widely used in small systems, and are being used increasingly in larger systems.

The cost-effective region for using a stand-alone system, versus connecting to the grid, varies with load, distance from the grid and the stand-alone system chosen. For instance, in Australia in the 1980s, for a grid-connection cost of A$40,000 the annual load would need to be at least 6000 kWh for the grid to be more cost-effective than a stand-alone system (Harrington, 1986). For smaller loads, say less than 3000 kWh/year, a stand-alone system would have been more cost-effective once grid connection costs exceeded about $A20,000 (*Ibid.*). The Australian Greenhouse Office (2003*a*) indicates that current grid-connection costs are typically A$10,000 per kilometre of line and, although electricity prices have dropped over the last two decades, PV and hybrid system prices have also fallen by up to 40% in real terms (Watt, 2004).

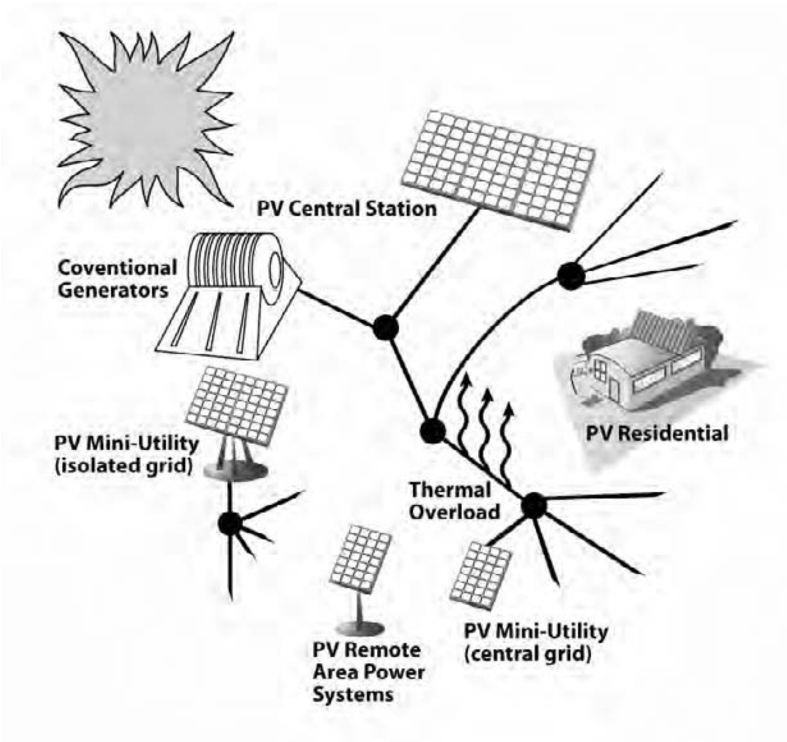

Figure 6.1. Possible uses of photovoltaics on and off the central grid.

In the US in 1991, a PV system could be cost-effective if the grid extension was more than 5 miles and the load was less than 1500 kWh/month, typical of two houses (Rannels, 1991). Smaller 2 kW systems could be cost effective at grid extensions of only one third of a mile (*Ibid.*).

6.2 STAND-ALONE PV SYSTEM DESIGN

The design of a stand-alone PV-based power system is determined by the location, climate, site characteristics and equipment to be used. The selection and interconnection of system components will be discussed in this chapter and design procedures in the next. Unless stated otherwise, the comments on storage refer to lead-acid batteries. Fig. 6.2 shows a schematic of a typical PV-based stand-alone power system.

Many countries and regions have produced standards and/or guidelines for PV systems over the last decade, and the applicable ones should always be understood and followed by designers and installers. Sometimes, compliance is a condition for subsidies or other forms of financial support. In Australia, the primary standards of interest are the AS4509 series of three standards (Standards Australia, 1999–2000*a*, 1999–2000*b*, 2002). Other standards apply to system components and particular aspects, some of which are mentioned below and/or listed in Appendix E.

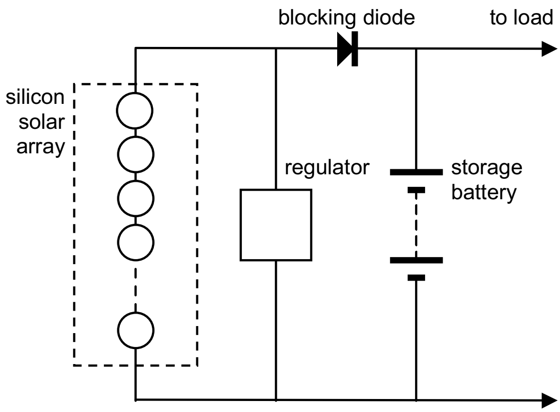

Figure 6.2. Simplified stand-alone PV power system (Mack, 1979, reprinted with permission of the Telecommunication Society of Australia).

6.3 SOLAR MODULES

In a stand-alone system, solar modules are usually used to charge a battery. A typical 36 cell module, based on screen-printed or buried-contact silicon cell technology, has the cells series connected to suit the charging of a 12 V battery. Typical characteristics for each (screen printed) cell would be:

$$\begin{aligned} V_{oc} &= 600 \text{ mV } (25°\text{C}) \\ I_{sc} &= 3.0 \text{ A} \\ FF &= 75\% \\ V_{mp} &= 500 \text{ mV } (25°\text{C}) \\ I_{mp} &= 2.7 \text{ A} \\ Area &= 100 \text{ cm}^2. \end{aligned}$$

Therefore, 36 cells in series give:

$$\begin{aligned} V_{oc} &= 21.6 \text{ V } (25°\text{C}) \\ I_{sc} &= 3.0 \text{ A} \\ FF &= 75\% \\ V_{mp} &= 18 \text{ V } (25°\text{C}) \\ I_{mp} &= 2.7 \text{ A}. \end{aligned}$$

In practice, cells encapsulated in modules usually have lower average efficiencies than unencapsulated cells owing to:

1. Reflection from the glass.
2. Change in reflection from cell-encapsulant interface.
3. Mismatch losses between cells.

4. Resistive losses in interconnects.A module V_{mp} of 18 V is required when charging a 12 V lead-acid battery because:

1. ~2.8 V is lost to temperature rises to 60°C.
2. A drop of ~0.6 V occurs across the blocking diode.
3. A drop of 1.0 V typically occurs across the regulator.
4. There can be some voltage loss with reducing light intensity.
5. The batteries must be charged to 14.0–14.5 V to reach their full state of charge.

In reality, because of the high resistive losses associated with screen printed cells, it is not uncommon for the V_{mp} to actually rise with reduced light intensity in steady state. Although the V_{oc} falls logarithmically with reducing light intensity (constant temperature), the corresponding fall in temperature and reduced voltage loss, owing to the smaller currents flowing through the cell metallisation, can often lead to a small increase in V_{mp}.

The life expectancy of solar cells is determined primarily by the quality of the encapsulation, particularly with regard to protection against ingression of moisture. The most common failure mechanisms were discussed in Chapter 5.

As also discussed previously, module design and the materials used make a significant contribution to cell operating temperature, and hence efficiency. Output is also influenced by aspects such as siting, shading, tilt angle and the self-cleaning properties of the modules.

6.4 BATTERIES

Australian Standard 4086 specifies requirements for storage batteries in stand-alone power supply systems (Standards Australia, 1993, 1997). It applies to all types of batteries, including lead-acid and nickel-cadmium and both vented and valve-regulated cells.

6.4.1 Types

There are many types of batteries potentially available for use in stand-alone PV systems, including lead-acid, nickel-cadmium, nickel-metal-hydride, rechargeable alkaline manganese (RAM), lithium-ion, lithium-polymer and redox batteries (see also Crompton, 1990; Sauer, 2003; Spiers, 2003). At present, the most commonly used is lead-acid. There exist many other battery technologies, such as zinc-bromide, zinc-chloride, magnesium-lithium, sodium-sulphur and nickel-hydrogen, but they are of little relevance for remote PV systems at this stage. Hydrogen-oxygen storage systems are of very low efficiency and are not further considered here (Bossel, 2004).

6.4.2 Applications

Batteries can be used for:

1. Power conditioning (e.g. in water pumping systems, discussed later).
2. Short-term storage, to effectively redistribute the load over a 24 hour period.

3. Longer-term storage, to ensure system availability throughout periods of low insolation.

6.4.3 Requirements

Battery maintenance can be a major limitation for stand-alone PV systems. Typical requirements for a battery system to be used for long term storage are:

- long life
- very low self-discharge
- long duty cycle (long periods of low charge)
- high charge storage efficiency
- low cost
- low maintenance.

6.4.4 Efficiency

There is considerable importance placed on the efficiency of batteries, owing to the relatively high cost of both the batteries and photovoltaic array. Battery efficiency can be characterised as follows:

1. **Coulombic, or charge efficiency**—usually measured at a constant discharge rate, referring to the amount of charge able to be retrieved from the battery, relative to the amount put in during charging. Self-discharge will affect coulombic efficiency.

2. **Voltage efficiency**—also measured at a constant discharge rate and reflecting the fact that charge is retrieved from the battery at a lower voltage than was necessary to put the charge into the battery.

3. **Energy efficiency**—the product of the coulombic and voltage efficiencies.

Typical average charge storage efficiencies are 80–85% for stand-alone PV systems, with winter efficiencies increasing to 90–95%, owing to:

- higher coulombic efficiencies when the battery is at a lower state of charge (85–90%)
- most of the charge going straight to the load, rather than into the batteries (95% coulombic efficiency has been measured experimentally).

6.4.5 Power rating and capacity

The *power rating* of a battery is defined as the maximum rate of charge and discharge, measured in amperes (A).

Battery capacity is the maximum amount of energy that can be extracted from a battery without the battery voltage falling below a prescribed value. The battery capacity is measured in kilowatt-hours (kWh) or ampere-hours (Ah), at a constant discharge rate. The rate of discharge affects capacity. PV systems typically have a 300 hour discharge rate which, for lead-acid batteries, gives them approximately double the capacity specified at a 10 hour rate. Battery capacity is affected by temperature, falling by about 1% per degree below about 20°C. At the other extreme, however, high temperatures accelerate aging, self-discharge and electrolyte use.

6.4.6 Depth-of-discharge

Depth-of-discharge is the percentage of the rated capacity withdrawn from the battery. Shallow cycling batteries should not be discharged more than 25% of rated capacity, while up to 80% of the capacity of deep cycling batteries may be discharged (Ball & Risser, 1988). Since battery life is a function of the average state of charge of the battery, a compromise must be made when designing a system between cycling depth and size of the battery.

6.5 LEAD-ACID BATTERIES

6.5.1 Types

Lead-acid (Pb-acid) batteries are the most commonly used in present stand-alone power systems. They come in a variety of types—deep or shallow cycling, gelled batteries, batteries with captive or liquid electrolyte, sealed or open batteries (Ball & Risser, 1988; Sauer, 2003).

Valve-regulated lead acid (VRLA) or ‘sealed’ batteries allow for evolution of excess hydrogen gas. Catalytic converters are used to convert as much evolved hydrogen and oxygen back to water as possible and gas is vented only in the case of excessive pressure in the battery. They are called ‘sealed’ because electrolyte cannot be added. They require stringent charging controls, but less maintenance than open batteries.

‘Open’ or ‘flooded electrolyte’ batteries contain an excess of electrolyte and gassing is used to reduce electrolyte stratification. The charging regime need not be stringent. However, electrolyte must be replenished frequently and the battery housing must be well ventilated, in accordance with local standards, to prevent the build-up of hydrogen gas.

6.5.2 Plate material

Lead-acid batteries are produced with a variety of plate types.

1. **Pure lead** plates have to be handled extremely carefully since the lead is soft and easily damaged. However, they provide low self-discharge rates and long life expectancy.

2. **Calcium** can be added to the plates (giving lead-calcium plates) to provide strength. Their initial cost is less than that of pure lead batteries, but they are not suitable for repeated deep discharging and have slightly shorter lifetimes. Lead-calcium plates are used in VRLA batteries for low gassing rates.

3. **Antimony** is also often added to lead plates for strength and low contact resistance. Lead-antimony batteries are common in automotive applications. They are substantially cheaper than pure lead or lead-calcium batteries but have shorter lives and much higher self-discharge rates. In addition, they degrade rapidly when deep cycled and need to be kept almost fully charged at all times. They are consequently not ideal for use in stand-alone PV applications. Lead-antimony batteries are usually only available as open batteries, owing to the high rate of electrolyte use and consequent need for topping-up regularly.

6.5.3 Charging regimes

Photovoltaic system batteries are usually operated in either the constant potential (float) or cycling mode. Many PV powered batteries spend long periods at low states of charge, typically over winter, which can cause problems. For instance, crystals of lead sulphate grow on the battery plates during periods of low state-of-charge, reducing the battery efficiency and accessible capacity. This is known as sulphation.

Limiting discharge levels to a maximum of 50% can minimise this effect and keep sulphuric acid concentration high. There is also less chance of the battery freezing if acid concentrations are high. Another means of minimising winter problems is tilting of the array to a steeper angle to fully utilise the winter sun, at some expense to the collection of summer radiation.

Overcharging also has its problems, although it is good for short periods as a means of charge equalisation. It causes gassing, which agitates the electrolyte, hence preventing the more concentrated material from settling in lower regions of the battery. However, over prolonged periods the gassing leads to loss of electrolyte and shedding of active material from the plates.

To prevent overcharging, the voltage of each cell is usually restricted to 2.35 V by using a voltage regulator. This limits the battery voltage to a maximum of about 14 V. The charging characteristics of a typical lead-acid battery used with PV systems is shown in Fig. 6.3, and the discharge characteristics in Fig. 6.4.

The most common method of regulation and control of lead-acid batteries is based on the approximate state of charge, measured via battery voltage. Charging is halted at a specific high voltage disconnect (HVD) point, chosen to allow a limited amount of gassing, charge equalisation and electrolyte agitation, without excessive loss of electrolyte. Similarly, discharge is halted at a specified low voltage disconnect (LVD) point, chosen to maintain a reasonable battery life.

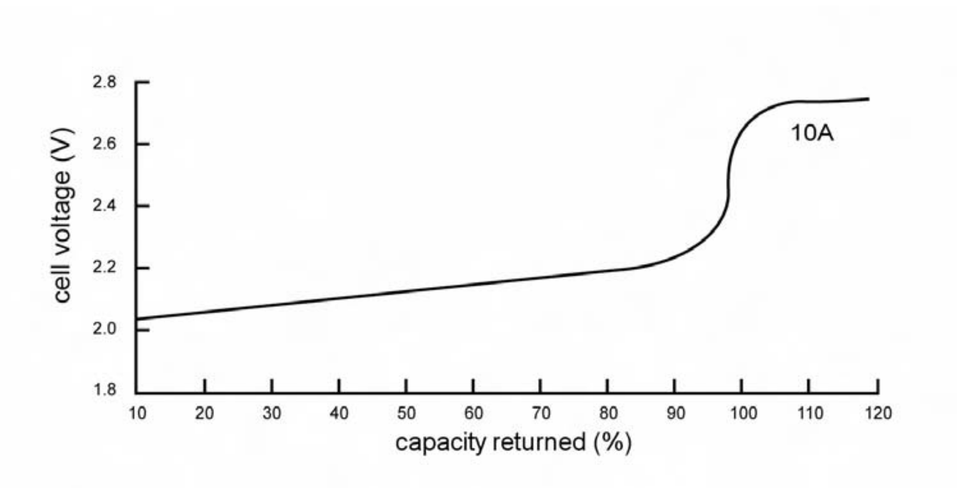

Figure 6.3. Constant-current charging characteristics at 25°C of a 500 Ah lead-acid battery suitable for use in a PV system (Mack, 1979; reprinted with permission of the Telecommunication Society of Australia).

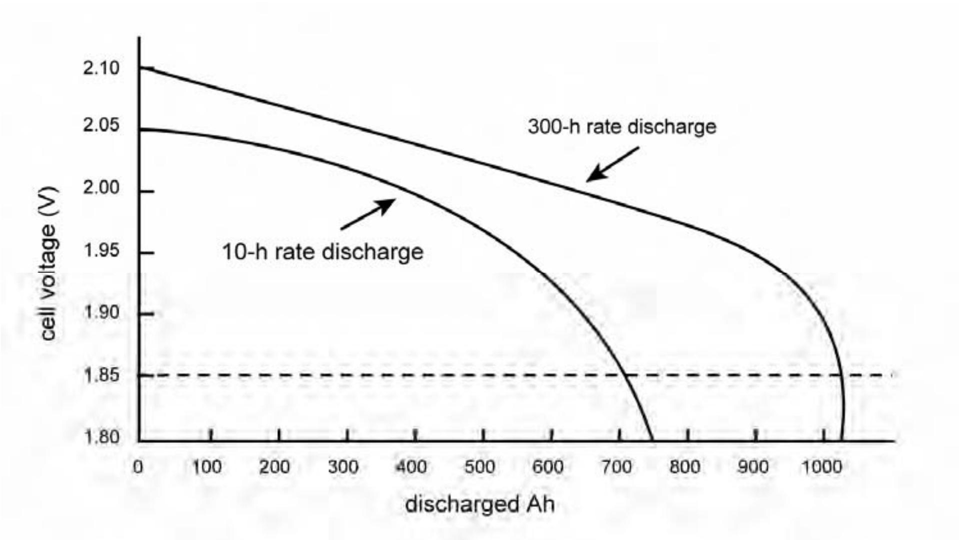

Figure 6.4. Constant-current discharge curves for a 550 Ah lead-acid battery at different discharge rates, with a limiting voltage of 1.85 V per cell (Mack, 1979; reprinted with permission of the Telecommunication Society of Australia).

Manufacturers are continuing to seek more effective methods of battery charge control, as the above method is not ideal, mainly because the battery voltage is not a very reliable indicator of battery state of charge.

6.5.4 Efficiencies

Typical efficiencies of lead-acid batteries are as follows:

- coulombic efficiency—85%
- voltage efficiency—85%
- energy efficiency—72%.

Caution—many battery manufacturers quote the coulombic efficiency as the 'battery efficiency' which is somewhat misleading. In addition, the voltage efficiency can vary quite significantly with variations in the charge/discharge rate.

6.5.5 Benchmarking and categorisation of similar use

A large European Union project has been undertaking a benchmarking and categorisation process to determine the most suitable battery for any possible stand-alone system (Wenzl *et al.*, 2004). The method is based on the standardised evaluation of data from actual systems, defining six categories of similar use. It is associated with an online design tool, *RESDAS*, and design recommendations (Energy Research Centre of the Netherlands, 2004).

6.6 OTHER ELECTRICAL CHARGE STORAGE METHODS

6.6.1 Nickel-cadmium batteries

Nickel-cadmium (NiCd) batteries are commonly used as rechargeable batteries for household appliances and can be suitable for stand-alone PV systems, especially in cold climates. They have a number of advantages over lead-acid batteries. They:

- can be overcharged
- can be fully discharged, eliminating the need for oversizing
- are more rugged
- have excellent low temperature performance and can be frozen without damage to the cells
- have low internal resistances
- can be charged at a much higher rate
- maintain uniform voltage during discharge
- have a longer life
- have low maintenance requirements
- have low discharge rates when not in use.

However, they also have a number of disadvantages. They:

- are typically two to three times more expensive
- have lower charge storage efficiencies (60–70%)
- can require full discharge to prevent 'memory' development, and subsequent inability to deep discharge
- have a much lower capacity increase due to low discharge rates.

Newer designs aim to overcome these disadvantages, and nickel-cadmium batteries are now being designed and manufactured specifically for PV applications. In some cases they are cheaper, on a life-cycle cost basis, than lead-acid batteries (see also Pedals, 1993) although investment costs are around a factor of three higher than for lead-acid batteries (Sauer, 2003).

6.6.2 Nickel-metal-hydride batteries

Nickel-metal-hydride (NiMH) batteries rely on absorption and desorption of hydrogen in a metal alloy during charge and discharge. The electrolyte contains an aqueous solution of potassium hydroxide, most of which is absorbed in the electrodes and separator. Hence, they can be used in any orientation. Their nominal voltage is 1.2 V, like nickel-cadmium. Compared to nickel-cadmium, their energy efficiency is higher, at 80–90%, the maximum power is lower, and the memory effect is less pronounced. Nickel-metal-hydride cells are less tolerant of voltage reversal than nickel-cadmium, so care must be taken to avoid this condition, especially in multiple series connections.

It is not very likely that large nickel-metal-hydride batteries will find wide application in remote PV energy storage due to their high cost, but they are rapidly replacing nickel-cadmium for portable appliances (Sauer, 2003).

6.6.3 Rechargeable alkaline manganese (RAM) batteries

Rechargeable alkaline manganese batteries have been developed from the primary batteries that have been available for decades. They have a nominal cell voltage of 1.5 V and are sealed. They contain no heavy metals and so may be less of an environmental concern than most other battery types, but they are so far available only as small batteries.

Unfortunately, they have a high internal resistance and short cycle life for deep cycling. Limiting the depth-of-discharge to just a few percent is required to achieve long cycle life. These batteries may have applications in photovoltaic systems in special cases such as emergency lighting or where shallow cycling is acceptable (Sauer, 2003).

6.6.4 Lithium-ion and lithium-polymer batteries

Lithium batteries are in common use in portable appliances such as computers, cameras, personal organisers and mobile phones. Since they have a nominal cell voltage (3.6 V) above that required to electrolyse water, water-based electrolytes are forbidden and they use lithium salts in an organic solvent. They are sealed but have a safety vent. The inclusion of highly reactive metallic lithium poses a safety risk of explosion or fire and care needs to be taken to protect against over-charge, over-discharge, over-current, short circuit and high temperatures (Sauer, 2003).

6.6.5 Redox-flow batteries

Redox batteries use reversible reactions to store and discharge electricity in liquid electrolytes. An ion-selective membrane is used to control ion transfer between separate solutions of the active materials as they are pumped through the battery. The electrolytes are stored externally in tanks, where there is no self-discharge. In Australia, both vanadium and zinc-bromine redox batteries are under active development. Compared to lead-acid batteries, they can have high cycle life, high energy density and can be fully discharged.

The capacity of a redox battery is a function of the quantity of active material stored, and the power rating is a function of the battery chamber size. Hence, the capacity and power rating can be independently selected for each application. The efficiencies of redox batteries can be high, as illustrated by the vanadium redox battery (Largent *et al.*, 1993):

- coulombic efficiency—97%
- voltage efficiency—92%
- energy efficiency—87% (including pumping losses).

Problems that may arise with the use of redox batteries in PV applications include the need for maintenance and the contamination of active materials in harsh environments. Cross-contamination problems, such as experienced in iron-chromium redox batteries, are eliminated in the all-vanadium battery.

6.6.6 Super capacitors

In contrast to normal capacitors, these electrostatic storage devices use an ion-conducting membrane between the electrodes, rather than a dielectric. Three of their advantages are long cycle life, low internal resistance, making them suitable for high power applications, and easy determination of the state of charge, which is directly related to the voltage.

Super capacitors are unsuited to long- or medium-term storage because of their high rate of self-discharge. However, they may find application where peak power demand is high, such as during starting of pumps or in smoothing power fluctuations (Sauer, 2003).

6.7 POWER CONDITIONING AND REGULATION

6.7.1 Diodes

Blocking diodes protect the battery from short circuits in the solar array, as well as preventing the batteries from discharging through the solar cells when they are not illuminated. Their function is often satisfied by charge regulators.

Diode voltage droppers can also be used to ensure the batteries do not supply excess voltages to the load.

6.7.2 Regulators

Battery voltage regulators, also known as charge controllers, are needed in PV-based power systems to protect batteries by limiting discharge levels and overcharging (Roberts, 1991; Preiser, 2003; Schmid & Schmidt, 2003; von Aichberger, 2004). Regulators are not specified in detail by any Australian Standard but guidelines for regulators in small solar home systems intended for rural areas (see Section 8.9) are included in the Universal Technical Standard for Solar Home Systems (UPM, 2003) and by Usher and Ross (1998). Four set points are commonly specified (Watts *et al*., 1984), namely:

1. **Regulation set point (VR)**—the maximum allowable voltage. On reaching VR, the controller either discontinues charging or regulates the current delivered to the battery. Temperature compensation is needed for VR unless battery temperatures vary by less than ±5°C.
2. **Regulation hysteresis (VRH)**—the difference between VR and the voltage at which maximum array charging current is restored. If VRH is set too large, there will be long interruptions to charging. If VRH is set too small there will be frequent oscillations, possibly with noise and with the potential to damage the switching elements. The voltage level VR – VRH is called VRR (Usher & Ross, 1998).
3. **Low voltage disconnect (LVD)**—defines the voltage at which the load is disconnected and hence the maximum depth-of-discharge and available battery capacity. LVD prevents over-discharge.
4. **Low voltage disconnect hysteresis (LVDH)**—the voltage span between the LVD and the voltage at which load reconnection is allowable following disconnection. If LVDH is set too small, the load cycles on and off rapidly at low battery state of charge, possibly leading to controller and/or load damage. If it is too high, the load will remain off for extended periods. The voltage

level LVD + LVDH is called the 'low voltage reconnect' (LVR) (Usher & Ross, 1998).

Values for the setpoints depend on battery type, controller type and temperature. This topic is treated in detail by Usher and Ross (1998).

There are two basic charging regulation methods to protect batteries against overcharging, with many available variations (Usher & Ross, 1998).

Interrupting (on/off) regulation—the controller acts as a switch, allowing all available PV current to the battery during charging. On reaching VR, the controller switches off the charging current, by introducing either an open or short circuit. When the voltage falls to VR – VRH, the current is reconnected. An alternative reconnection strategy, aimed at avoiding rapid cycling, is to wait for a certain time following disconnection. If the battery size is small compared to the PV array size, on/off regulation can result in premature cessation of charge on sunny days. Then, the high array current passing through the internal resistance of the battery produces a high terminal voltage and VR can be reached before the battery is fully charged.

Constant voltage (constant potential) regulation. As for on/off regulation, the available charging current is passed to the battery until VR is reached. Then however, the charging current is tapered to ensure that the battery can store all the delivered current. Some controllers modify the VR setpoint by sensing the battery condition or using a low VR to avoid excessive gassing, coupled with provision for an occasional gassing 'equalisation' charge. Several other variations are also used. Linear and pulse width modulation topologies are common. Either of the two general methods can be applied via shunt or series arrangements (Fig. 6.5).

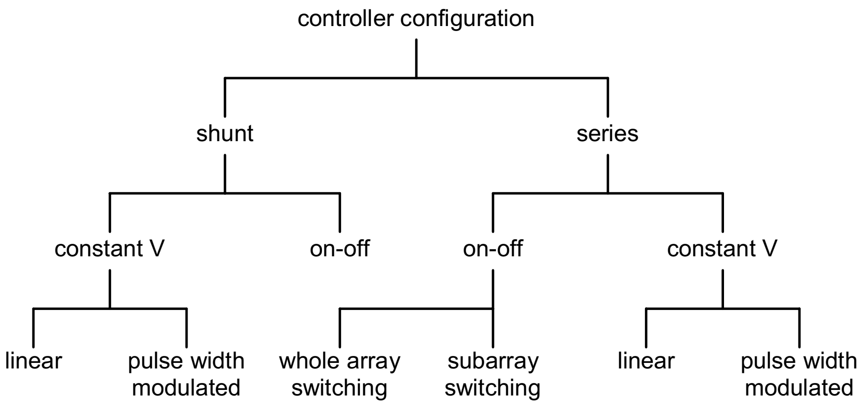

Figure 6.5. Controller families (adapted from Usher & Ross, 1998).

Shunt regulators use a solid state device to clamp the battery voltage at some preset level by dissipating excess array-generated power. A blocking diode is placed in series between the battery and the switch, to prevent battery shorting (Fig. 6.6). Shunt regulators have in the past been suitable only for small systems, typically with PV currents less than 20 A, and could present heating problems in battery enclosures, since the dissipation usually occurs when radiation levels and ambient temperatures are high. They consume little power when the load or battery is using only PV-generated power. However, with the advent of low-resistance semiconductor switching components, that is no longer a serious problem and the losses can be even lower than for shunt regulators (Schmid & Schmidt, 2003). As previously discussed (see Chapter 5), short circuiting can cause hotspots if no bypass diodes have been used.

Series regulators control the array current when a certain preset voltage is reached. The control element is placed in series between the array and the battery with a corresponding voltage drop across the terminals. This can simply open-circuit the array in the on/off configuration or apply a constant voltage as VR is approached by acting as a variable resistor in the linear configuration. In the latter, the control element dissipates power at all times (Fig. 6.6).

The pulse width modulation (PWM) controller applies repetitive pulses of current with a variable duty cycle. It can be either a series or shunt arrangement

The sub-array switching topology is a refinement of the on/off controller. Instead of switching off the whole array, sub-arrays are switched in and out as required (Fig. 6.6). They operate by disconnecting one array section at a time, as charging currents increase towards midday. These are then reconnected as charging currents fall later in the day. They are suitable for use in larger systems, with a number of solar array sections.

Self-regulating systems operate without a regulator, with the array connected directly to the battery, and rely on the natural self-regulating characteristics of the photovoltaic panels. The slope of the current-voltage characteristic curve for a solar cell or module progressively increases when shifting from the maximum power point towards the open circuit condition. This automatic reduction in generating current, with increasing voltage above the maximum power point, appears to be well suited for providing charge regulation to a battery, provided the temperature remains constant. However, due to the large temperature sensitivity of the voltage of a solar cell, the day-to-day temperature variations and wind velocity inconsistencies can make it quite difficult to design a reliable self-regulating system, particularly one suitable for a range of locations. This approach is suitable only where the climate has small seasonal temperature variations and the battery is large relative to the array size.

The other complicating factor regarding the design of self-regulating systems is that different cell technologies are characterised by different effective values of series resistance. The result of this is that the slope of the current-voltage curve between the maximum power point and the open circuit point can vary quite significantly between technologies. This clearly introduces additional complications when trying to design such a system accurately.

The general approach adopted by manufacturers is to remove approximately 10% of the solar cells from the standard modules to reduce the probability of over-charging the batteries. This is because, with a self-regulating system, there is no longer a voltage drop across the voltage regulator, and the excess voltage able to be delivered by the solar panels to ensure batteries can be fully charged under the hottest conditions, can no longer be included without risking over-charging the batteries on cooler days. Consequently, self-regulating systems are substantially cheaper, not only because of the elimination of the battery controller, but also because of the reduced wiring, simpler installation, and the reduced number of solar cells required.

In general, the self-regulating system provides too many compromises in design and runs the risk of over-charging batteries in cooler locations or on cooler days, while under-charging batteries in hot weather. Slight errors in design or product variability can, of course, result in one of these extremes occurring virtually all the time, therefore making such a system quite ineffective and unreliable.

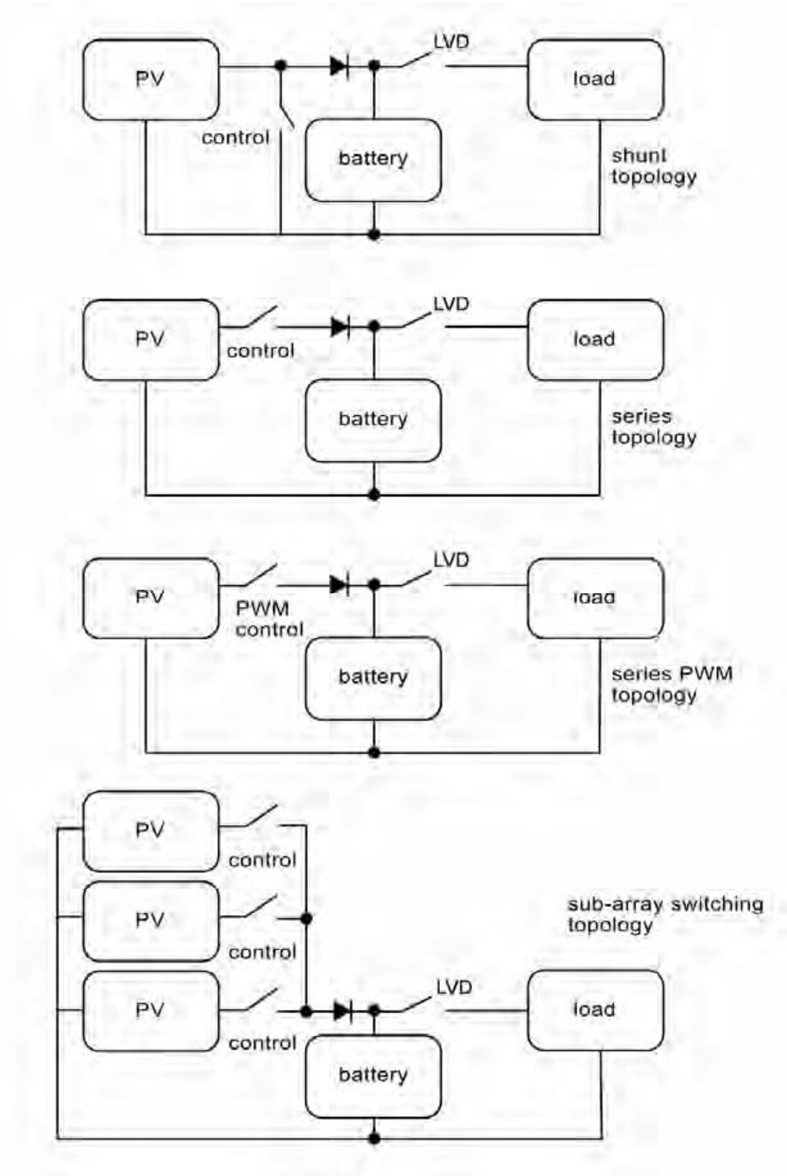

Figure 6.6. Controller topologies (adapted from Usher and Ross, 1998). LVD = low voltage disconnect.

Another problem with a self-regulating system is that the photovoltaic-generating capacity has to be well matched to the load requirements. For instance, during the night the load must partially discharge the batteries so that, on the following morning when the weather is cooler and hence the photovoltaic voltage is higher, the batteries can accept the charge generated. Later in the day, once the solar panels operate closer to the anticipated design temperature, if the batteries are close to full state-of-charge, the same problem will not result as the self-regulation will automatically cause the generating current to fall. This charging scenario has important implications for system maintenance and down-time. Failure to disconnect the batteries from the photovoltaic arrays during periods of no load will result in severe over-charging of the batteries, as they commence each day already at full state-of-charge. Examples of this in the field have led to rapid destruction of the batteries resulting from severe over-heating, over-charging and rapid loss of electrolyte.

Self-regulating systems are best suited to batteries such as nickel-cadmium that can tolerate substantial amounts of over-charging. Lead-acid batteries, on the other hand, should rarely be used in such systems without particular care and monitoring.

Maximum power point trackers seek to transform the array voltage at its instantaneous maximum power point for the pertaining insolation and temperature, to the appropriate voltage required for the charging regime. This allows the array to continually operate at its maximum efficiency except when charging is reduced or suspended to protect the battery. The tracking circuitry is essentially a DC-to-DC converter, commonly using a pulse width modulation topology. Care should be taken when systems are specified to check that the additional expense and complexity is justified by the energy gains. The three main advantages are reduced sensitivity to voltage drops across wires between the array and the battery, reduced sensitivity to the number of cells per module, thereby permitting the use of modules with fewer large-area cells, and the opportunity to use more complex charging current profiles (Schmid & Schmidt, 2003).

Protection against excessive discharge basically requires disconnection of the load at the LVD point and reconnection at the LVR point after sufficient recharge. In a high reliability system, with large array and battery relative to the load, the battery tends to have shallow cycles and the low voltage disconnect protects the battery only under abnormal conditions. In low reliability systems, though, the disconnect frequently protects the battery in normal operation. It has been recommended (Usher & Ross, 1998) that loads be disconnected at 40% depth of charge, even for batteries with higher rated maximum discharges. Some controllers allow the low voltage disconnect to be overridden by the user but this is not recommended (UPM, 2003).

Freeze protection is important in many climates. The freezing temperature of electrolyte depends on its density, which depends on state-of-charge. The load disconnect setpoint should be raised in colder conditions to prevent freezing (Usher & Ross, 1998; Spiers, 2003).

6.7.3 Inverters

Inverters are needed in PV-based power systems when power is required as alternating current (AC), rather than the direct current (DC) produced by the PV array. Inverters use switching devices to convert DC to AC power, at the same time stepping up the voltage, typically from 12, 24 or 48 V_{dc} to 110 or 240 V_{ac} for small systems or higher voltages for larger or grid-connected systems. Inverters in stand-alone systems are required to supply constant voltage and frequency, despite varying load conditions, and need to supply or absorb reactive power in the case of reactive loads. Most inverters for stand-alone PV systems include isolation transformers that separate the DC and AC circuits (Standards Australia, 2005). The inverters most commonly used in stand-alone PV systems are discussed below (Watts *et al.,* 1984; Bower, 2000; Schmid & Schmidt, 2003; Ross, 2003).

1. **Light duty inverters**—typically 100–10,000 W continuous output, with or without frequency control. These are suitable for powering appliances such as computers and television sets, but can be relatively inefficient and can generate both electrical and audible noise.
2. **Medium duty inverters**—typically 500–20,000 W continuous output, some with 'load-demand-start' (automatic start-up and shut-down when a load is turned on or off). These are suitable for use with a wide range of small appliances and power tools, but may not have sufficient surge capacity to operate larger AC induction motors.
3. **Heavy duty inverters**—typically 10,000–60,000 W continuous output, but able to accommodate AC induction motor start-up surge loads of 30,000–200,000 W.

Most of the inverters discussed above have efficiencies of 80–85% with loads in the range 25–100% of the inverter rating, but efficiencies can be very low for smaller loads. Some of the newer inverters are able to accommodate low loads better, offering efficiencies of around 80% (and 90% or more for higher loads) (see Kobayashi & Takigawa, 1993).

Two additional aspects that need to be considered when selecting an inverter are wave shape and standby power draw. The preferred wave shape for AC loads is a sine wave, as is supplied by the electricity grid. However, many small inverters produce square waves, or approximations to sine waves, which can lead to motor starting problems or even appliance burnout, owing to the energy content in the high frequency harmonics. Sine wave inverters are becoming increasingly available, even in small sizes, so that this problem will reduce with time.

If left on, inverters can continue to draw significant power, even with no load. This can rapidly run down solar-charged batteries, so that systems with an inverter must incorporate some means of inverter control, if this is not built-in. Circuit topologies are discussed by Schmid and Schmidt (2003).

Preferred requirements for inverters in stand-alone PV systems are (Preiser, 2003):

- large input voltage range
- voltage waveform close to sinusoidal
- tight control of output voltage (±8%) and frequency (±2%)
- high efficiency for low loads (>90% at 10% load)
- tolerance of short overloads, particularly for motor starting
- good behaviour with reactive loads
- tolerance of loads that use half-wave rectification
- tolerance of short circuits.

6.8 BALANCE OF SYSTEM COMPONENTS

As the above discussion has shown, there are many other costs associated with the establishment of a photovoltaic power supply, other than those directly attributed to the solar modules. Batteries, regulators, inverters and other system components are collectively referred to as the *balance of system*, or BOS. There are also such items as transportation, installation, land (if necessary), site preparation, drainage, electrical wiring, mounting structures and housing. These non-PV costs are expected to dominate, as PV prices fall. Photovoltaic system field downtime is dominated by BOS component problems and failures (Durand, 1994). The necessary increased emphasis on BOS reliability in the future may add to their relative cost, although that cost may be offset by economies of scale as PV systems gain more market acceptance with improved reliability.

Frequently used BOS components to be considered here include constituents of the electrical wiring system, mounting and housing. The emphasis for these components is on reliability and long life, with the aim of providing trouble-free operation for at least 20 years at reasonable initial cost.

Many BOS aspects are now covered by standards in Australia and elsewhere and these should always guide component selection and use (Standards Australia 1999–2000*a*, 2005). Local standards should always be observed or, if no local standard exists, reference may be made to others (Appendix E).

6.8.1 Wiring

Wire costs can become quite substantial, particularly for low voltage, high current applications, or where current must be conducted over long distances. Ideally, copper wire should always be used in PV power systems, although it is more expensive than aluminium wire. However, given the cost difference, aluminium wire may be acceptable for very long runs, provided there is no interconnection with copper wire, and connectors specifically designed for aluminium wire are used.

When designing a system, wire cross-sections should be selected to limit resistive losses to less than 5% between the PV array and the battery and between the DC control board and DC loads, and less than 2% between the battery and the DC control board (Standards Australia, 2002). Exceeding current ratings of wires can lead to overheating, insulation breakdown and potentially to fires. The draft Australian Standard for array installation (Standards Australia, 2005) and an appendix to the System Design Guidelines (Standards Australia, 2002) specify how cable sizes and insulation quality should be chosen, according to system voltage, voltage drop, current-carrying capacity and the trip levels of protection devices. Issues related to low voltage wiring and other aspects of small systems are discussed by Roberts (1991).

Cable size is specified according to its size (in mm^2) and its stranding (number of individual wires and their diameter), with larger cable used as current increases. Wiring should be protected from vermin attack.

6.8.2 Over-current protection

As in all electrical systems, over-current protection devices, such as circuit breakers or fuses, are needed to protect equipment and personnel. They are available in many shapes and sizes. Care must be taken to ensure that devices used within the DC circuit are rated for DC operation and for the potentially high DC currents possible in PV systems. The detailed recommendations are addressed by Standards Australia (2005). The recommendations differ greatly depending on system arrangement and ratings and are not repeated here except as the general rule: “wiring shall be protected from short circuit and overload by high rupturing capacity (HRC) fuses or appropriate type circuit-breakers (AC or DC) sized to limit the current below the maximum current-carrying capacity of any part of the connected circuit” (Standards Australia, 1999–2000*a*). Battery over-current protection devices should be mounted as close as practicable to the battery while avoiding any chance of spark ignition of any evolved hydrogen (Standards Australia, 2002). Each string of cells must be separately protected. Standards Australia (2005) also recommends earth fault protection.

6.8.3 Switches

Switches, which may sometimes take the form of circuit breakers or fuses with removable elements, are installed to isolate the array, battery, controller and load. They should be installed in suitable enclosures for protection against the environment. DC switches are heavy duty and more expensive, and care must be taken that AC switches are not used for DC applications. Switches should be rated for 1.2 times the array open circuit voltage and should interrupt all poles. Specific recommendations, which depend on system arrangement, are given by Standards Australia (2005) and requirements and satisfactory circuit configurations are specified by the design standard (Standards Australia, 2002). Safe isolation must be provided between extra low voltage (up to 50 V_{ac} or 120 V_{dc}) circuits and higher voltages, and provision must be made to de-energise the system in an emergency (Standards Australia, 1999–2000*a*, 2005).

6.8.4 Connectors

Poorly made connections are by far the greatest source of reliability problems in photovoltaic systems. To minimise problems:

1. Ensure the connector and wire sizes are compatible.
2. A ring type connector should always be used in preference to a spade-type connector (it cannot fall off the terminal).
3. Strip about 1 cm of insulation from the wire, clean with solvent if necessary and use a crimp tool to attach the connector to the wire.
4. Make connections between subsystems using terminal strips in weather-resistant boxes. Terminals and connectors must be of the same type of metal.
5. Look carefully for places where bare wire might touch metal at a different potential.
6. Check for nicks or cuts in the wire insulation.
7. At completion, inspect all connections again.
8. Battery cable terminations should be crimped, and bolted battery connections should use stainless steel bolts, nuts, washers and spring washers (Standards Australia, 1999–2000*b*).

Standards Australia (2005) also recommends that plugs, sockets and couplers should be multipolar and rated for DC voltage at least 1.2 times the array open circuit voltage. Their current rating should equal or exceed that of the associated cables. Plugs and socket outlets normally used for AC mains power should not be used. Refer to Standards Australia (2005) for details and further recommendations.

6.8.5 Earthing (grounding)

Earthing involves the provision of low resistance paths from selected points within the PV system to earth (ground). Standards Australia (2005) provides a decision flowchart to help determine the necessary equipment earthing. Earthing is not required in some cases, including if double insulation is used. Equipment grounding involves ensuring all metal enclosures and parts of the array frame that might be touched by hands are well earthed.

System earthing (*Ibid.*) normally involves connecting one of the current-carrying conductors (commonly the negative but possibly the positive or a centre tap) to earth. The manufacturer's requirements for power conditioning equipment, such as inverters, should be taken into account in choosing the most suitable arrangement of system earthing. This aspect is considered in detail by Standards Australia (2005).

Good contact with the earth is required via a ground rod. Contact with subterranean water helps. Rocky soil may be a problem.

6.8.6 Lightning protection

Lightning protection is required when a system is deemed to be prone to lighting (Standards Australia, 1999–2000*a*) but is usually not necessary (Standards Australia, 2002). Such protection may include clamping circuits, metal oxide varistors, transient absorption zener diodes and/or circuit breakers. These act as open circuit devices until the voltage across them rises above the rated threshold breakdown voltage, at which point they provide a short-circuit to ground (see Florida Solar Energy Centre, 1987). They will not protect against a direct lightning strike. The system design guidelines (Standards Australia, 2002) include an informative appendix on lightning risk assessment and protection, and common practices are described by the IEA-PVPS (2003).

6.8.7 Metering and alarms

Battery terminal voltage, input current and, in the case of a system including a backup generator, generator run hours, should be metered. Alarm indicators of high and low battery voltage are desirable (Standards Australia, 2002).

6.8.8 Battery housing and signage

Batteries must be protected from the elements, whereas people, the natural environment and equipment must be protected from acid and the risk of explosion of evolved gas. Batteries can be buried below the frost line in water-tight enclosures, with drain holes, if sub-zero temperatures are anticipated, or housed in a building where temperatures remain above zero. The batteries themselves should never be placed directly onto concrete, as this will increase the self-discharge rate, particularly when the concrete is moist. High temperatures and localised heat sources should also be protected against.

The Australian requirements are detailed by Standards Australia (1997). Adequate venting must be provided, to minimise any potential for explosions, whenever liquid electrolyte batteries are used. In large, open sheds, a wall extending 500 mm above the batteries may be used to separate them from potential spark sources and particular methods are recommended for other situations (Standards Australia, 2002).

Enclosures must also be safeguarded against access by unauthorised people, particularly children. Safety signage is required, including one with the words "WARNING: SPARK HAZARD" (Standards Australia, 1999–2000*a*). For small systems, truck or marine battery boxes are an inexpensive option and will even withstand direct sunlight.

6.8.9 Housing of electronics

It is essential that all electronic equipment, including regulators, controllers and inverters, be well protected from the environment to ensure good reliability and long life. All printed circuit boards must be covered by a conformal coating, to protect against dust.

Provision also needs to be made for adequate ventilation, to keep circuitry temperatures to acceptable levels. This in turn can lead to problems with dust, and dust filters should therefore be considered on the ventilation air inlets. Electronic equipment should not be mounted directly above batteries for three reasons: acidic fumes may damage the equipment, the equipment may cause sparks, and tools may drop onto the batteries during maintenance, causing short circuits and sparking.

6.8.10 Module mounting

The type of module mounting used for a PV array will impact on the power output, the capital cost and the maintenance requirements. Support structures can vary widely but should be configured to comply with local standards for structures, with wind loading being the most critical design criterion (Standards Australia, 2002). This and other mechanical engineering and materials science issues for PV systems are discussed in detail by Messenger and Ventre (2000). Elementary mechanical engineering books give methods for calculating wind loadings on such structures. Significant advancements in recent years in the aerodynamics of solar and electric cars and other transportation vehicles suggest there is considerable scope for innovation in the design of mounting structures for solar arrays to minimise wind loadings. In particular, for large arrays, attention to the aerodynamic design of structures at the perimeter of the array may facilitate the use of appropriately designed low cost and low weight structures in central regions of the array.

Ground mounting, such as in Fig. 6.7, is the most common at present, either fixed at an angle appropriate to the site, or on a tracker. Most PV panel manufacturers offer suitable ground mounting hardware for their panels, particularly of the fixed tilt type. Some residential systems use roof mounting, in which case a gap of at least 7 cm should be provided beneath the modules for air flow, while some small lighting systems and telephone transmitters have their solar panels mounted on poles.

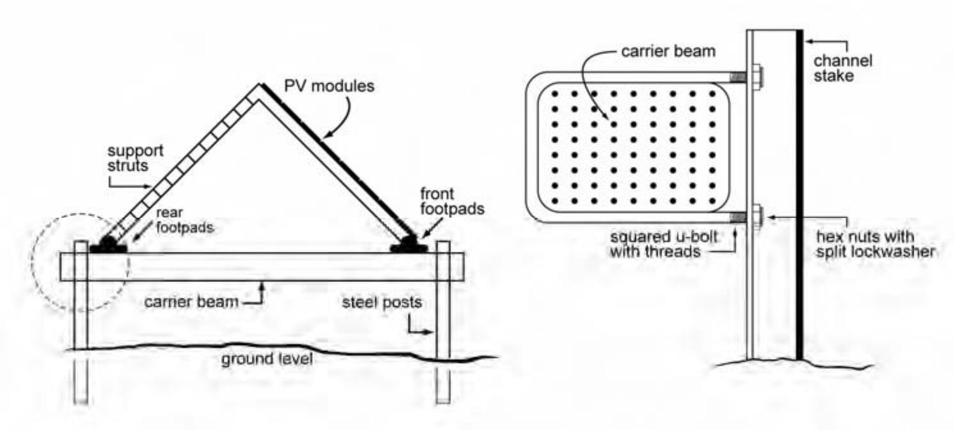

Figure 6.7. Simple ground mounting for PV arrays using materials readily available from a hardware store (reprinted with permission of Sandia National Laboratories, 1991).

It is important to avoid contact between dissimilar materials that could cause damaging electrolysis (Standards Australia, 1999–2000*b*; Messenger & Ventre, 2000). Materials used in mounting structures include:

1. Aluminium
    - light, strong and resistive to corrosion
    - easy to work with
    - compatible with most PV module frames
    - difficult to weld.
2. Angle iron
    - easy to work with
    - corrodes rapidly if not galvanised and slowly if galvanised
    - easily welded.
3. Stainless steel
    - will last for decades
    - expensive and difficult to work with
    - difficult to weld
    - good for salt spray environments.
4. Wood
    - cheap, readily available and easy to work with
    - needs treatment with preservatives
    - not suitable in damp environments.

Stainless steel nuts and bolts should be used with all mounting materials.

Fixed arrays

Fixed arrays are the most commonly used. The modules are placed on a support structure, facing within 5° of north in the southern hemisphere (Standards Australia, 1999–2000*b*) and of south in the northern hemisphere, at an angle determined by the requirement. For example, for the most constant output over the year, an angle of latitude plus ~23° is used, which places the array at right angles to the sun's rays in mid-winter. A minimum tilt angle of 10° is recommended, to allow natural cleaning of the array surface by rain (Standards Australia, 2002). Standards Australia (2002) recommends the tilt angles given in Table 6.1.

Table 6.1. Approximate optimum array tilt angles for fixed arrays.

	tilt angle relative to latitude (°)		
latitude (°)	constant seasonal load	winter-peaking load	summer-peaking load
5–25	+5	+5 – +15	–5 – +5
25–45	+5 – +10	+10 – +20	+10

Seasonally-adjusted tilting

The array angle can be changed manually against the horizontal axis (e.g. monthly or seasonally), to allow for the changing solar elevation at noon. This is a relatively simple way of increasing output and does not add significantly to the cost. Flexibility in tilt angles for seasonal changes is marginally economical for small systems. For mid-latitude locations, adjustment to the tilt angles every three months increases the annual energy production by less than 5%. Such arrays need to be marked to indicate either the tilt angle or the time of year suited by each position (Standards Australia, 1999–2000*b*).

Single-axis tracking

The array can be tilted automatically every hour or more frequently, along the vertical axis, to follow the sun from east to west. Output can be increased significantly. Theoretical estimates of insolation increases relative to optimally-tilted fixed arrays for a range of sites, using meteorological data, found values of 29–37% (Nann, 1990). However, it is not always possible to convert all the theoretical insolation gain into output power due, for example, to mutual shading (Townsend & Whitaker, 1997). An experimental study found that insolation on an array could be increased by 18% compared to a fixed array by azimuth tracking around a vertical axis or by 11% using a tilted-axis tracker (Helwa, 2000). A single axis tracking array is illustrated in Fig. 6.8. Reinforced concrete foundations with anchor bolts are recommended and the movement path should be carefully checked to ensure it is free from obstructions. The system cost is higher, as is the maintenance requirement (Lepley & Hammond 1997), so that their cost effectiveness for each particular application requires careful consideration.

Two-axis tracking

Power output can be further increased by tracking the sun along both the north-south and east-west axes. Helwa (2000) measured a 30% insolation improvement relative to a fixed-tilt array. However, both the capital and maintenance costs can be high and few large systems are currently installed. However, smaller, light sensitive trackers, with one or two modules on a pole, as in Fig. 6.8, are now being used for water pumping systems around Australia (Solar Energy Systems, 2004).

As more tracking systems are developed and tested, their relative cost and reliability are expected to improve. Their use for larger PV systems may then increase, especially for ground-mounted grid-connected systems where maintenance is less of an issue than it is for remote installations.

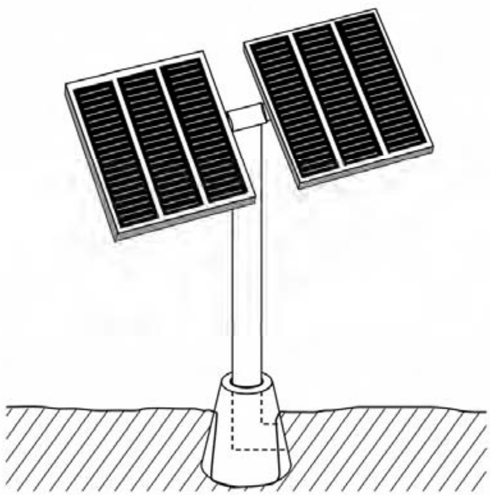

Figure 6.8. Passive tracker for a small PV array (reprinted with permission of Sandia National Laboratories, 1991). These are no longer manufactured owing to their use of ozone-depleting chemicals.

Concentrator arrays

Concentrator arrays use optical lenses and mirrors to focus sunlight onto small areas of high efficiency cells (Swanson, 2003). The high cell costs are allayed by relatively low cost apertures. Since direct solar radiation is the most effectively-concentrated, concentrator systems are suitable only for sites with characteristically high levels of direct versus indirect radiation. Accurate tracking of the sun is necessary for these systems, particularly when the concentration ratio is high. Tracking tends to increase the intercepted insolation but, with concentration, the trade-off is the ability to access only the direct fraction (see Chapter 1). The overall result depends on the clarity of the sky at the site. Luque *et al*. (1995) compared the radiation available to fixed flat plates tilted at latitude angle, with direct normal radiation at several locations in Europe and the USA. In some locations with clear skies, such as Albuquerque, the direct normal insolation exceeds that on the fixed tilted planes but for others, such as Pittsburgh, it is less.

A large (220 kW_p) remote solar power station has recently been commissioned in the north-west corner of South Australia (Australian Greenhouse Office, 2003*b*). It consists of ten mirrored parabolic reflectors concentrating by 500 times onto silicon cells. Each dish uses about 130 m^2 of curved mirror sections. The solar system is connected to a diesel grid, which supplies power to a remote community. Another three systems, with total capacity of 720 kW_p are under construction for installation in the Northern Territory (Watt, 2004).

EXERCISES

6.1 Discuss the use of batteries in photovoltaic systems, taking particular consideration of:

- conditions faced by batteries when charged by solar cells
- the suitability of the various battery types to different applications
- the availability, costs, ratings and manufacturers of batteries in your country.

6.2 Discuss the suitability of different wire and connector types commercially available for a range of photovoltaic applications, including:

- the range of wires and connectors available that are potentially of use in any photovoltaic application
- reasons for or against the suitability of certain types of wire and connectors for specific applications
- lists of suppliers, prices, ratings and descriptions
- any applications or conditions for which suitable wires or connectors cannot be found locally
- life expectancy of wiring
- any occasions when there is an economic-versus-suitability trade-off.

6.3 Draw a schematic of a stand-alone photovoltaic system, labelling each component, then:

(a) Briefly discuss the function and reliability of each component and its importance to the system.

(b) What are some of the more common problems that occur with each system component?

(c) What factors affect the choice of battery type?

(d) How do you expect stand-alone system design to evolve in the future?

(e) In what ways may the climatic conditions have adverse effects on system operation?

6.4 (a) In a stand-alone system, explain what problems may result from the use of a regulator that short circuits solar panels. What relevance do the system voltage and current have?

(b) Explain the concept of *self-regulation* as applied to battery charging with solar cells.

(c) What problems may result from a system using self-regulation?

(d) Why do solar panels have open circuit voltages under standard test conditions so far in excess of the nominal battery operating voltage?

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Chapter 7

DESIGNING STAND-ALONE PHOTOVOLTAIC SYSTEMS

7.1 INTRODUCTION

Design of a stand-alone PV system centres on the selection and sizing of appropriate components to meet the requirements of a particular load. Component costs and efficiencies are required, in addition to load characteristics. Trade-offs can usually be made between components to meet budget constraints, although system reliability and life expectancy are likely to be compromised (Durand, 1994). Some information or estimate of the solar insolation characteristics at the site is required, as is an indication of the criticality of the power supply. Different design approaches are outlined in this chapter.

Depending on the situation, major design criteria may include (Meyer, 2004):

- lowest life cycle cost—this can be three times the initial investment cost, with extensions of battery life having a strong impact on its reduction
- tolerance of load and insolation variations
- modularity and flexibility
- ease of maintenance and repair
- quality of power supply
- reliability
- social factors.

7.2 SYSTEM AVAILABILITY

System *availability* (*A*) is defined as the percentage of time that a power system is capable of meeting the load requirements (Ball & Risser, 1988). For instance, a system designed for 95% availability is expected to meet the requirements of the load 95% of the time. In stand-alone PV-based systems, availability depends primarily on battery size. Typically, non-critical stand-alone systems are designed with an availability of about 95%, whereas critical systems are likely to require 99% availability.

Telecommunication repeater stations, for example, would be considered critical, a PV cathodic protection unit may be non-critical, while low availability is acceptable for a grid-connected system.

In a PV system, weather, failures, system maintenance and excessive demands are the primary contributors to lowering system availability. However, system costs increase rapidly in trying to obtain the last few percent of availability. This is illustrated in Fig. 7.1.

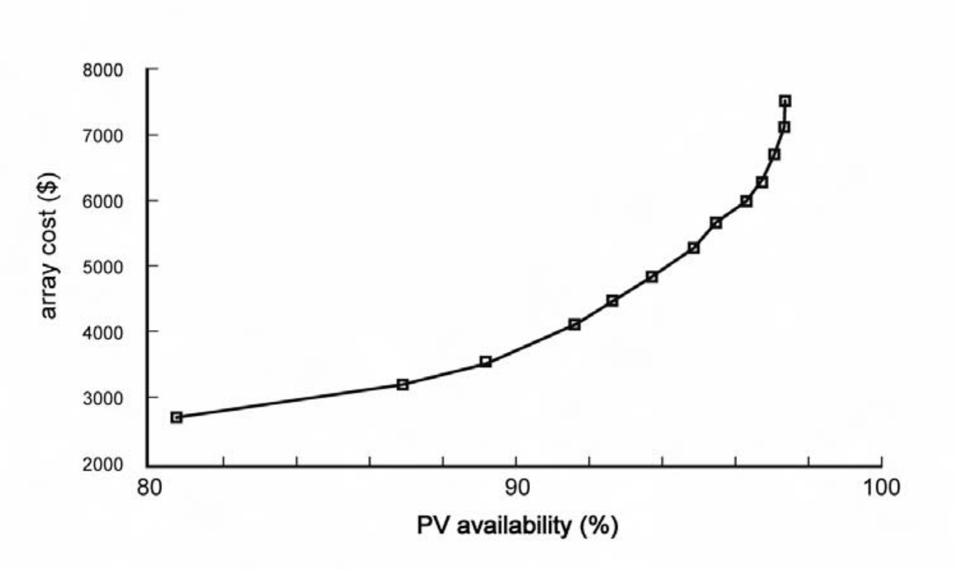

Figure 7.1. Availability as a function of cost for a PV-based power system in the north-eastern United States (reprinted with permission of Sandia National Laboratories, 1991).

In designing a system, the requirements of each specific application, solar variability at the site and financial limitations will determine the appropriate *availability* figure to apply. For normal power systems, such as for households, the general approach is to design a system with non-critical availability, increasing the system components later if necessary and as more finance becomes available.

As a comparison, very few large-scale power source generators, be they coal fired, nuclear or hydroelectric, achieve availabilities greater than 80–90%. Importantly, for photovoltaic systems with availabilities below 80%, there is in general no surplus capacity, as less electricity is generated even on a cloudless summer day than is consumed by the load. Consequently, the curve of Fig. 7.1 becomes approximately linear for photovoltaic availability in the range 0–80%.

7.3 HYBRID SYSTEMS

In some applications, it is both economical and desirable to use a hybrid system, whereby the PV supplies some or most of the load, but with a diesel or petrol generator as a backup. This allows the PV system to be designed to quite a low availability, usually resulting in considerable savings on battery capacity and to a lesser extent on PV panels. Obviously, for many applications, particularly in remote areas, generators and PV are quite incompatible. However, for applications such as homesteads, where on-site labour is available for maintenance, they should be seriously considered, especially when a system design falls within the region in Fig. 7.2 labelled *consider hybrid.*

Using the hybrid indicator

The *hybrid indicator* of Fig. 7.2 has the load (in watt-hours per day) graphed on the vertical axis and the array-to-load ratio graphed on the horizontal axis. The 'array-to-load ratio' is the array power rating in peak watts (i.e. for 1 kW/m^2 insolation levels) divided by the load in watt-hours per day (i.e. W_p/Wh.)

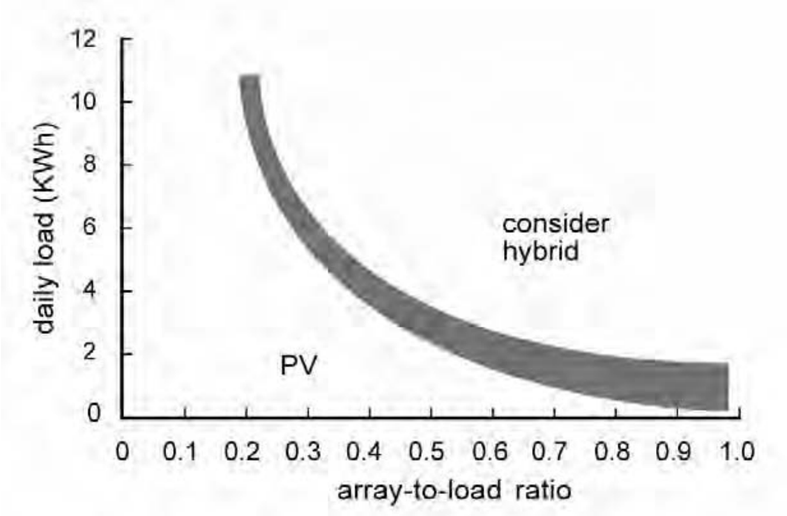

Figure 7.2. The *hybrid indicator* (Sandia National Laboratories, 1991).

To use this graph, first design the system as if it were to be powered purely by PV and then look at its location on the graph. As can be seen from Fig. 7.2, hybrid systems are preferable for larger loads and higher array-to-load ratios. The latter occur in climates where there is a lot of cloudy weather, necessitating a large area of PV panels, hence giving a large ratio. This makes it more economical to reduce the PV area in favour of other generators. The hybrid indicator is a guide only, as there may be other reasons to prefer PV or a hybrid system. In addition, the above curve is shifting with time as the cost of photovoltaics continues to fall relative to diesel and other generators.

7.4 A SIMPLIFIED PV SYSTEM DESIGN APPROACH

Telecom Australia, now Telstra, was instrumental in developing PV powered telecommunications systems for use in remote regions of Australia and hence in developing Australia's PV market. Telstra now has over 3 MW_p of PV installed across the country, mostly in PV battery systems, with a few PV diesel hybrids (McKelliff, 2004). Although Telstra now uses sophisticated spreadsheet models for system design and has developed its own solar resource maps, its original simplified system design approach (Mack, 1979) forms the basis of the more iterative models now used and represents a conservative approach, where high availability is needed and in which array size is optimised as a function of the battery capacity.

1. **Load determination**—To specify the load as accurately as possible, and hence achieve a system design that optimises components and costs, the following information is needed:
    - nominal system voltage
    - range of voltages able to be tolerated by load
    - average load per day
    - load profile throughout the year.

    For a microwave repeater station, for example, the voltage may be 24 ± 5 V, the average load 100 W (current = 4.17 A), and the required storage 15 days.

2. **Select battery capacity**—For telecommunications loads, the design approach is quite conservative, allowing for 15 days of battery storage to give very high availabilities. For the example given above, this would be

    $4.17 \text{ A} \times 24 \text{ h} \times 15 \text{ days} = 1500 \text{ Ah}.$

3. **First approximation of tilt angle**—This is based on site information and usually involves selecting a tilt angle 20° greater than the latitude. For example, for Melbourne, which is at latitude 37.8°S, the first approximation for tilt angle is 37.8° + 20° = 57.8°.

4. **Insolation**—From the available site insolation data, the actual insolation falling on the array at the selected tilt angle can be estimated. An example of typical insolation data throughout the year falling on a horizontal plane in Melbourne is provided in Appendix G. Using this insolation data, sample calculations are provided for determining the actual corresponding amount of insolation that will fall on the photovoltaic array when tilted at an angle of 57.8°. An assumption made in these calculations is that the diffuse component of the insolation data is independent of tilt angle. This is a reasonable approximation, provided the tilt angle is not too great.

5. **First approximation of array size**—As a rule of thumb, the initial array size in peak amps (1 kW/m^2) is selected to be five times the average load current. This figure is large because:
    - the sun does not shine at night
    - there is reduced light intensity during mornings, afternoons and periods of cloudy weather
    - the batteries have a limited charging efficiency

- there is some self-discharge of the batteries
- dust often partly obscures light penetration.

Using the initial array size and the modified insolation data from (4), the ampere-hours generated throughout the year can be calculated. In these calculations, allowance needs to be made for loss owing to dust coverage, assumed to be in the vicinity of 10%, although this may be an overestimation for the impact of dust. An Arizona study (Hammond, 1997) found that for modules at normal incidence to the sun, soiling causes a maximum of 3% loss between periods of rain but that the loss increased with incidence angle, to 4.7% at 24° and 8% at 58°. Bird droppings, however, can have a more serious impact.

The electricity generated can then be compared to the amount consumed by the load throughout the year. When calculating the load consumption, allowance needs to be made for self-discharge of the battery, usually set at about 3% of the battery charge per month.

Assuming the batteries are at a full state of charge in summer, the state of charge of the batteries throughout the year can be determined.

6. **Optimising array tilt angle**—Retaining the same array size, the above procedures can be repeated with small variations in the array tilt angle until the depth-of-discharge of the batteries is minimised. This represents the optimal tilt angle.
7. **Optimising array size**—Using the optimal tilt angle, the array size can be optimised, in conjunction with the depth-of-discharge of the batteries, by using successive approximations of array size in conjunction with the above procedures.
8. **Summarise the design.**

An example of the above procedure is provided in Appendix G. Its limitations are threefold:

1. A mechanism for determining battery capacity needs to be devised and used in conjunction with this approach, and even then the array-storage combinations need to be able to reflect changes in array costings relative to those for the storage.
2. The techniques are only useful once the direct and diffuse components are known.
3. The iterative nature of the calculations requires use of a computer.

7.5 SANDIA NATIONAL LABORATORY APPROACH

This approach (Chapman, 1987) was developed by Sandia National Laboratories in the United States and is considerably more sophisticated than that presented in Section 7.4, automatically incorporating many years of accumulated insolation data. It overcomes the limitations listed for the approach considered above and is applicable to any system with a fixed tilt array, allowing the designer to choose tilt angles in the range from latitude – 20° to latitude + 20°.

The system design is based on a specific *loss-of-load probability* (*LOLP*) specified by the designer. By definition, *LOLP* is the probability at any point in time that the load will not be satisfied by the PV-storage system and, as such, is directly related to *availability* (*A*), as previously dealt with, where

$$LOLP = 1 - A \tag{7.1}$$

In reality, for a specified *LOLP*, there is a continuum of array size/storage capacity combinations, where the relative costs and efficiencies of the constituent components determine the least-cost approach. In general, the system cost increases approximately exponentially as the *LOLP* approaches zero.

In the development of this model for system design, extensive work has been carried out in correlating variability in insolation with average data commonly available. The correlations have resulted from the study of about 24 years of hourly data and as such should, on a statistical basis, provide accurate correlations. The latitude is a required variable for the system design, indicating that the model makes use of theoretically-calculated light intensities as a function of air mass throughout each day, in an approach similar to that outlined earlier (whereby average global data can be reasonably accurately converted into approximate direct and diffuse components).

An interesting outcome of the study that led to the formation of this model and approach is that accuracy of system design is not lost by basing the design only on data for the month with the lowest insolation levels over the year. This of course greatly simplifies the design approach. In addition, through the use of calculations similar to those in Section 7.4, but over a wide range of possible design values and in conjunction with appropriately-treated average global insolation data, curves have been generated that facilitate:

1. Determination of battery capacity for a specified *LOLP*.
2. Optimisation of array tilt angle.
3. Obtaining insolation data at the appropriate tilt angle.
4. Determination of the array size that, in conjunction with (1), provides the required *LOLP*.

In fact, four sets of the curves exist, each giving a different battery capacity in (1) for the specified *LOLP*. Completion of (2)–(4) above results in each set of curves providing a different system design (different array size/battery storage combination) with the same *LOLP*. These four sets can then be analysed on the basis of cost to determine the least-cost approach that satisfies system specifications.

Costing may be done purely on an initial cost basis, or else a lifetime cost basis, depending on consumer preference. For the latter, battery life, which varies significantly with temperature and depth-of-discharge (DOD), must be considered. The battery life for flooded lead-acid batteries can be estimated from

$$CL = (89.59 - 194.29T)e^{-1.75DOD} \qquad (7.2)$$

where CL is the battery life (in cycles), T is the battery temperature and DOD is the depth-of-discharge.

In a PV-storage system, the *DOD* varies from cycle to cycle. We define each cycle as one day, and *DOD* as the maximum *DOD* for that day. It has been shown statistically that the distribution of *DOD*s for all battery cycles can be generalised as a function of the *LOLP* and the days of storage, thus enabling Eqn. (7.2) to be used to give a close estimate of actual battery life.

A complete design example using this approach is provided in Appendix E. In principal, it has a great deal of merit, overcoming many of the limitations associated with the procedures used in the simplified method given in Section 7.4. However, it also has two significant limitations:

1. It is difficult to check the system design unless the designer is given more details regarding the derivation of the various graphs (nomograms) on which the design procedures are based.
2. By optimising the design for the worst winter month, there is no checking procedure to ensure that summer months are not excessively disadvantaged.

7.6 AUSTRALIAN STANDARD AS4509.2

This Australian Standard (Standards Australia, 2002) provides some guidelines, a worked example and blank worksheets for system design. It includes sections on electrical load assessment and the design procedure explicitly considers incorporation of other renewable energy generators and backup (fossil fuel) generation, considering in detail their interconnection. The worked example in its appendices is not prescriptive, explicitly stating that “other methods may be equally applicable”.

The main PV-related design steps are:

1. Estimation of DC and AC electrical loads and their seasonal variation.
2. Scale up of the load by an *oversupply coefficient* in the range 1.3–2.0, depending on reliability of insolation data and load criticality, if the available insolation data is only annual average, monthly or ‘worst month’.
3. Energy resource assessment, from on-site measurements or available data.
4. Determination of the worst and best months, based on the smallest and largest ratio of solar energy to load energy.
5. System configuration, including range of accessible energy sources and genset, if required. Inclusion of a genset allows the specification of a smaller array and smaller battery for equivalent system availability.

6. Component sizing, allowing for full battery recharging within, say, 14 days and for ability to provide gassing charge:
   - Select first estimate for array tilt angle (see Table 6.1) and estimate insolation for that plane (see Chapter 1).
   - Size battery according to required days of autonomy, desired daily and maximum depth-of-discharge, daily energy demand, surge demand and maximum charging current.
   - Check whether battery size is determined by the required storage capacity or the power demand, which depends on the system parameters, especially the required days of autonomy.
   - Size the array and configure into strings to supply the chosen fraction of the load energy, the remainder to be supplied by a genset or otherwise.
   - Specify, with the aid of worksheets, inverter(s), regulator(s), battery charger, genset, battery ventilation.
   - Choose cable sizes, with aid of Appendix C of the Standard.

Other standards and guidelines are also available and some are listed in Appendix E of this book.

7.7 SYSTEM DESIGN SOFTWARE

A large number of both commercial and freely available computer programs for sizing and simulation of performance of stand-alone and grid-connected photovoltaic systems have become available in recent years (Knaupp, 2003; Silvestre, 2003; National Renewable Energy Laboratory, 2004). Some directly interface with databases of insolation and other meteorological information. Different programs use different algorithms for carrying out the calculations and vary in the transparency of the methods and in the provision of intermediate results for verification. Of course, these programs cannot be reliably used without checking the results by other means and local standards and guidelines still need to take precedence.

Sizing programs, sometimes in spreadsheet form, help calculate the system components for a given loads, insolation, orientation and, in the case of stand-alone systems, days of autonomy. They aid selection of modules, cables, batteries and power conditioning electronics. Simulation programs, additionally, simulate the system behaviour. The reader is referred to Knaupp (2003) and Silvestre (2003) for brief descriptions of a selection of available programs.

EXERCISES

7.1 (a) What is a ‘hybrid’ system when considering photovoltaics?

(b) Discuss the advantages and disadvantages of hybrid systems over purely photovoltaic-powered systems.

(c) Which applications are best suited to hybrid systems?

7.2 (a) Give examples of your telephone utility’s uses for solar cells, referring to specific installations in your country.

(b) Outline the utility's experiences with solar cells and its attitude towards them.

(c) Is PV likely to play an increasingly or decreasingly important role in your utility's systems of the future?

(d) What problems does your utility face in using solar cells in your country?

7.3 For a location at latitude 34°N, find the angle of solar array tilt that will maximise a system's output for November, using the approximate methods outlined in the text. The average global radiation at this location, on a horizontal surface in November, is 12 MJ/m^2/day, and the corresponding figure for diffuse radiation is 4.1 MJ/m^2/day.

7.4 Design a stand-alone PV system for a location at latitude 23°N. The system is to supply a constant load of 250 W at 48 V_{dc}. Starting in January, the global figures for radiation on a horizontal surface for the 12 months of the year are (the numbers in parentheses are the corresponding figures for diffuse radiation): 15.5 (3.2), 17.2 (4.2), 21.6 (4.0), 23.3 (6.0), 24.9 (7.0), 24.1 (8.8), 23.8 (8.9), 22.9 (8.1), 20.7 (7.3), 18.9 (4.8), 15.6 (4.7) and 14.5 (3.8) MJ/m^2/day, respectively.

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Chapter

8

SPECIFIC PURPOSE PHOTOVOLTAIC APPLICATIONS

8.1 INTRODUCTION

Photovoltaic systems are very versatile; they can be smaller than a coin or larger than a football field, they can power anything from a watch to an entire town and the only fuel source required is light (Sandia National Laboratories, 1991). These factors, combined with their simplicity of operation, have made them especially attractive as power supplies for a range of independent specific-purpose applications. The most common of these are discussed in this chapter. In Australia at the end of 2003, there was 13.59 MW_p of cumulative installed PV capacity for off-grid non-domestic use, 26.06 MW_p for off-grid domestic use, 4.63 MW_p for grid-connected distributed supply and 1.35 MW_p for centralised grid-connected supply (Watt, 2004). This does not include the many small-scale applications, such as garden lights, watches or calculators, which are commonly used around the country.

8.2 SPACE

When first developed, photovoltaic cells were suitable only for space applications, owing to their high cost. Solar cells continue to be used to power spacecraft, satellites and remotely-controlled vehicles on Mars. As can be expected, because of the importance of high reliability, space applications require extremely high quality control and standards of production (Hardingham, 2001). Efficiency of the solar cells is also of importance because of the weight and area limitations on spacecraft.

Cells used in space are not protected by the earth's magnetic field and atmosphere and are subject to high energy particles and radiation, which reduce life expectancy to about seven years. The ability of a solar cell to withstand such bombardment in space without serious degradation is known as *radiation hardness*.

Research priorities for the next generation of space cells include weight and cost reduction, since the PV panels can account for 10–20% of a satellite's weight and 10–30% of its cost (Allen, 1991). Also important is the ability to pack the array into a small area for launching. Many space cells are made from gallium arsenide and related compounds, rather than silicon, yielding higher efficiency but at much higher cost.

8.3 MARINE NAVIGATIONAL AIDS

The use of photovoltaic cells to power marine navigational aids became economical many years ago, owing to the high cost of replacing primary batteries. Since the loads are small, photovoltaic cells are well suited to this application, provided the lamps and lenses have high efficiency. A system typically comprises:

- 10–100 W_p of solar cells
- low-maintenance battery in weatherproof storage box
- voltage regulator or self-regulation
- military specification timing and motor control circuitry
- automatic lamp changer with military specification DC motor.

Environmental protection of system components is of prime importance and is achieved by:

- weatherproof and salt-resistant battery housing and photovoltaic module encapsulation
- salt and water resistant wiring
- lens and circuitry housing seals
- use of spikes to prevent birds perching on and fouling light lenses and PV module surfaces.

A high system availability is required, since navigational aids are a critical application. However, obsolete circuitry is still used, with hundreds of components that could be replaced by a single microprocessor or microcomputer chip. Since navigational aids require military certification, it will take many years for the system designs to be modernised. Photovoltaics are the standard choice for powering remote lighthouses around the coast of Australia, as well as signal buoys in harbours and rivers.

8.4 TELECOMMUNICATIONS

Repeater stations for telecommunications are powered by photovoltaic cells in numerous countries. These systems are well suited to harsh terrains, such as Papua New Guinea or countries where there are vast unpopulated areas without grid support, such as Australia. The latter was one of the first countries to substantially use photovoltaics for these purposes, with the involvement documented in the following sections.

Telecommunications has been the backbone of the Australian PV market for many years. Telecom (now Telstra) first experimented with PV installations in 1972 and is still a major PV customer. Costs fell from A$30 to A$2 per voice channel in the ten years to 1989 (Mack & Lee, 1989). There is now over 3 MW_p of installed PV capacity in the Telstra network (McKelliff, 2004). Telstra uses PV to power repeater stations within communications systems that link major centres and for individual customer services in remote and rural areas. Three different telecommunications applications for PV are discussed below (Mack & Lee, 1989).

8.4.1 Transportable PV power supplies

Typical trunk microwave radio repeater loads have reduced from around 1000 W to under 100 W over the past few decades, opening the market to photovoltaics. By 1976, Telecom had developed a transportable solar power supply which used a standard shipping container to:

- house photovoltaic arrays during shipment
- house batteries in the working system
- provide facilities for maintenance crews
- provide a mount for solar panels.

These systems formed the basis of the first major telecommunications trunk link in the world. The 500 km link from Alice Springs to Tennant Creek opened in 1979, with 13 repeater stations powered entirely by photovoltaics. The systems are designed for extremely high availabilities, typically including 15 days of battery storage. The batteries used have:

- pure lead positive plates
- low self-discharge (typically 3% per month)
- long life (about 8 years).

The systems proved so successful that more than 70 similar microwave repeater stations have subsequently been installed across the country, as shown in Fig. 8.1. Reliability has been improved by the use of passively-cooled storage shelters for batteries and electronic equipment. Although PV battery systems are preferred, hybrid systems are sometimes used. These use a diesel generator to provide less than 10% of the annual power requirement, but significantly reduce the necessary solar array and battery size and ensure system availability approaches 100%. The resultant cost reduction further increases the cost-effectiveness of photovoltaics, although increased maintenance for such systems is inevitable, such that these hybrid systems are not suited for use in very remote areas.

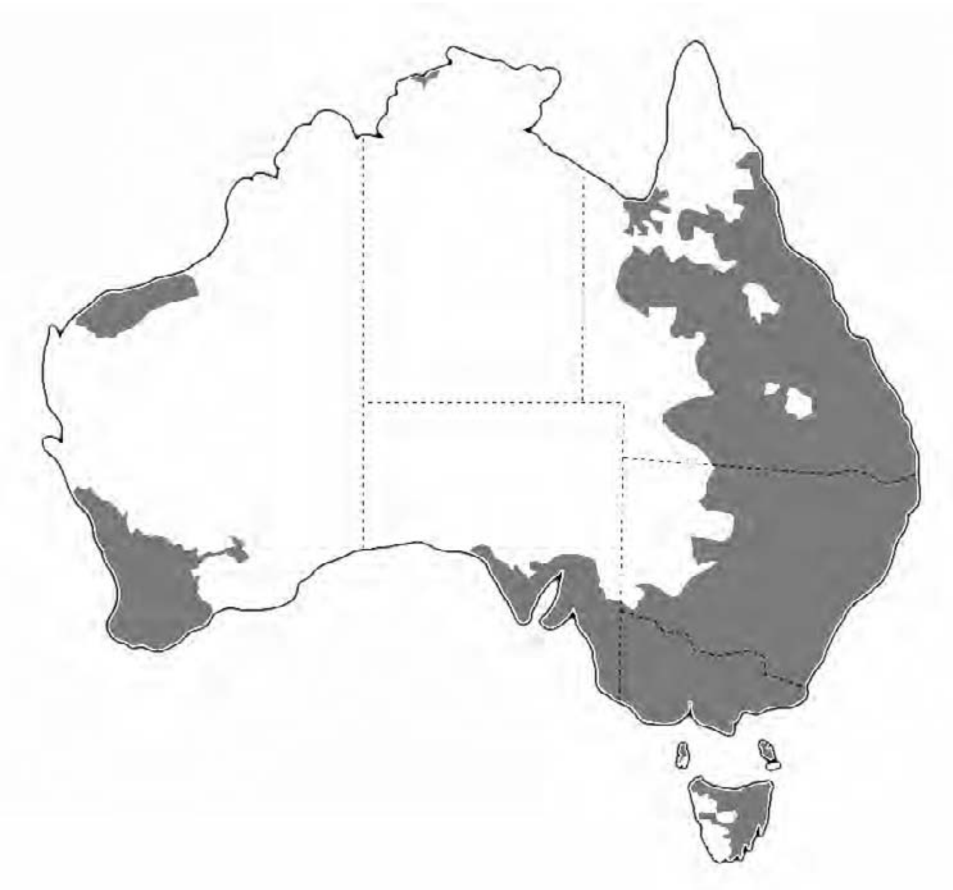

Figure 8.1. Map of Australia with the grey area indicating grid-connected regions (after ESAA, 2002).

8.4.2 Radio telephone services

Remote area subscribers in Australia are provided with photovoltaic-powered radio telephones to link them to the nearest repeater. These small stand-alone systems comprise:

- photovoltaic panels (one or two standard size), normally pole mounted
- single 12 V battery
- transmitter circuitry and aerial.

The load is variable, but can be controlled by the consumers, if they are adequately informed. Consumer education also reduces the level of availability required, and hence the system cost.

In addition to the Telecom network systems described above, many independent UHF, VHF and microwave radio operators, such as the military, the police and businesses use photovoltaic power.

8.4.3 Mobile phone networks

In April 2004 Telstra opened its first solar-powered mobile phone base station at Roebuck Plains, near Broome. It provides additional mobile telephone coverage in and around Broome and off the north-west coast of Australia. The new system is more heat tolerant than usual, allowing the use of air conditioning to be avoided (Fig. 8.2).

Figure 8.2. The first solar-powered mobile telephony base station in the Telstra network, located at Roebuck plains, Western Australia, (Used with permission of Silcar Pty Ltd. Design & Construction)

8.4.4 Optical fibre networks

Many long distance trunk networks using optical fibres are currently being installed in Australia and around the world. Photovoltaics are used to power network repeater stations situated away from the electricity grid. Some consideration has been given to the use of specially designed photovoltaic devices with high conversion efficiency to laser light, which in turn can be transmitted along optical fibres (Wenham & Cranston, 1993).

8.5 CATHODIC PROTECTION

The corrosion of oil and gas pipes, wells, chemical storage tanks, bridges etc. is a major problem, particularly in remote areas away from grid-connected power.

Cathodic protection (CP) involves the use of an electrical current to counteract natural, corrosive electrochemical currents. Water and acids in soil act as electrolytes to allow the transfer of electrons to the metal structures, which act as anodes and are consequently oxidised, or corroded. An externally-applied counteracting current allows the metal structure to become cathodic, thereby eliminating corrosion.

A similar effect can be achieved using a sacrificial anode near the metal structure, provided the sacrificial anode is more anodic; that is, it establishes a greater electrochemical potential than the structure to be protected.

8.5.1 System sizing

In designing a photovoltaic-powered CP system, the following aspects must be considered (Tanasescqu *et al*, 1988):

1. The load is the amount of current required to overcome the open circuit potential between the metal (anode) and the surrounding electrolyte.
2. The current requirement is determined by the area of bare metal. In general, metal structure coatings will have a specified integrity factor. Typical of a good plastic coating is an integrity factor of 99.999%, which means a structure with a surface area of 10^5 m^2 has 1 m^2 exposed.
3. The resistance of the CP circuit determines the voltage necessary to provide the current from (2). This can be measured, but will vary with moisture content, temperature, compactness and even salt content of the soil.

   Resistance measurements are complicated by such factors as:
   - pipe capacitance
   - electrochemical polarisation, owing to ionic conductivity of the soil (depolarisation time can be 16–18 hours for a well insulated pipe)
   - ground bed resistance (R) where

   $$R = \frac{\rho\left[\ln(2L/r) + \ln(L/S) - 2\right]}{2\pi L} \tag{8.1}$$

   for a horizontal bed, such as with a high water table, or

   $$R = \frac{\rho\left[\ln(4L/r) - 1\right]}{2\pi L} \tag{8.2}$$

   for vertical beds, such as with a deep well or bore hole, where L is the anode column length, ρ is the soil resistivity, S is the depth and r is the radius of the anode.

Owing to such uncertainties and variability over time (see Fig. 8.3) and distance, a safety factor for both the voltage and current needs to be included in the load determination.

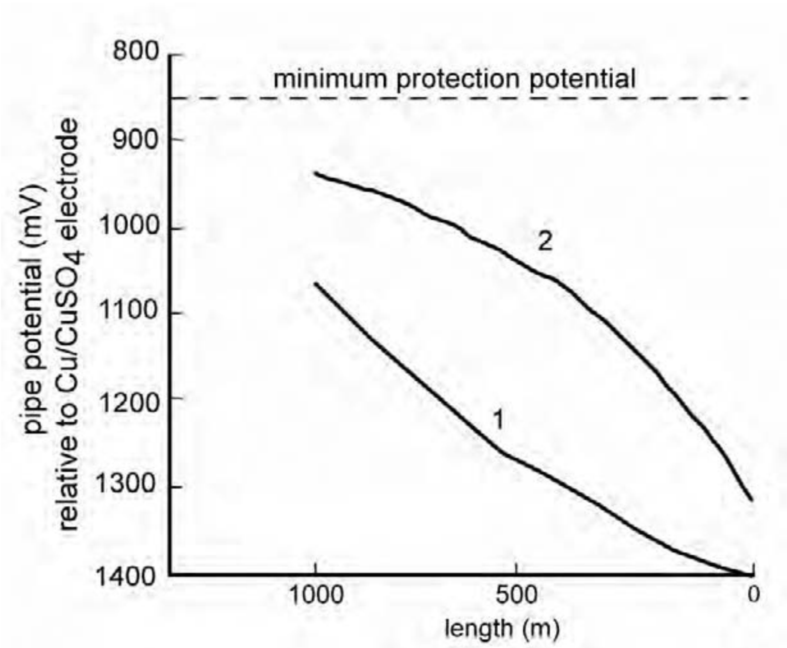

Figure 8.3. Typical pipe potential distribution for a sunny day (curve 1), and at night following a cloudy day (curve 2) (Tanasescqu *et al*, 1988, Used with kind permission from Springer Science and Business Media).

8.5.2 Controllers

During operation, a controller is virtually essential in a CP system, to adjust the current so as to keep the reference voltage on the metal structure constant (i.e. control the current to overcome the varying electrochemical potential). Different types of controllers are available.

1. To control the current, DC-to-DC conversion can be used to provide superior protection at high efficiency.
2. Rather than using DC-to-DC conversion, the controller may simply, though less efficiently, incorporate a rheostat to effectively control the voltage and hence current applied to the structure.

8.5.3 Power sources

Past CP systems

In grid-connected areas, power rectifiers were used on cathodic protection devices. In remote areas, diesel or natural gas driven motor generators (or even thermoelectric generators) have been used. However, fuel and maintenance costs were a severe problem, particularly for small loads, while line extensions to connect to the main grid were generally too expensive.

Present CP systems

Photovoltaic powered systems are now considered to be a reliable and economic solution for CP. This was initially the case for small structures such as small pipelines or storage tanks, etc. but as photovoltaic prices have fallen, they have been used increasingly for larger pipelines, well head protection etc.

Low availability system designs are adequate for most structures. A 90% availability would be expected to extend the life expectancy of the structure being protected by a factor of 10.

Batteries are used in most systems, although the importance of continuous protection has not been clearly demonstrated (Ball & Risser, 1988). Float types, such as lead calcium, are not suitable, and deep cycle types, such as nickel cadmium or deep cycle lead-acid batteries are therefore used.

The first large photovoltaic-powered CP installation was in Libya in 1979. It was used for protecting the equipment and structures on oil drilling rigs and pipe lines (Tanasescqu *et al.*, 1988). This use of photovoltaics for cathodic protection was soon followed by major oil companies throughout Africa, the Middle East and Asia. In the USA, Federal Department of Energy regulations require that all underground storage tanks and pipelines carrying combustible liquids or gases have cathodic protection (Ball & Risser, 1988), a requirement that provides a large potential market for photovoltaics.

Unfortunately, poor understanding of photovoltaics on the part of many corrosion engineers, has and still is preventing its use in many installations. As the advantages of photovoltaics become better understood, its use will increase. Vandalism and theft are also problems. For these reasons, pole mounting is preferable, but can lead to increased wiring losses and higher installation costs, unless specially-designed integrated systems are used. The German Energy Pillar System, for instance, combines an aluminium pillar with photovoltaic panels, a step up charge converter and batteries in a ready-to-install system that, once installed, transfers site data to a central processing point for monitoring purposes (Korupp & Marthen, 1992).

An example of the design of a CP system follows (based on Tanasescqu *et al.,* 1988).

Fig. 8.4 illustrates the use of cathodic protection along a pipeline. The protection current must be adjusted so as to keep ΔV_{min} high enough to counteract the electrochemical potential, which is given by

$$V(x) \propto \exp(-rx) \tag{8.3}$$

where r is the decay constant, which is a function of the resistance per unit length of the pipe, and is typically $5 \times 10^{-4}\ \mathrm{m}^{-1}$.

If L is the length of pipe protected, then

$$K = \frac{2}{r} \ln\left(\frac{\Delta V_{max}}{\Delta V_{min}}\right) \tag{8.4}$$

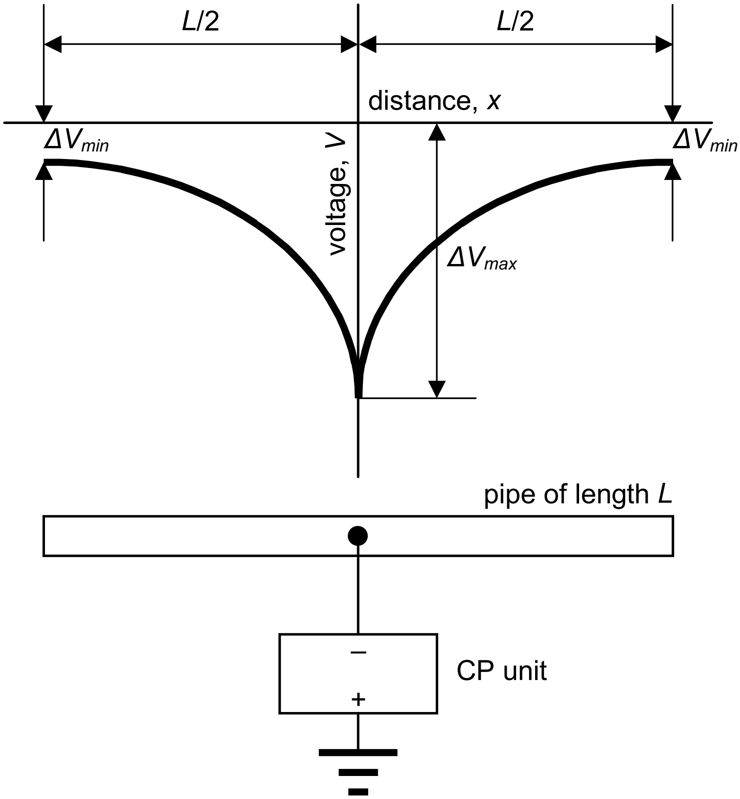

Figure 8.4. Potential (voltage) distribution along a pipe with cathodic protection (Tanasescqu *et al.*, 1988, Used with kind permission from Springer Science and Business Media)

An important trade-off exists. If L is too long, ΔV_{max}, which increases faster than proportionately with L, becomes too large. A large ΔV_{max} gives much larger currents than required in regions close to the power source. The net result is an excessive value for the ratio of *injected power* to *required power*. Conversely, if L is too short, excessive numbers of CP systems are required to protect the total length. However, in general, because of the modular nature of photovoltaics, it is quite convenient to have many small systems spaced relatively close together.

A typical system may comprise:

- a 60 W_p photovoltaic panel
- 90 Ah of battery storage, at 12 V
- a serial charge regulator
- a closed-loop current controller, using a $Cu/CuSO_4$ reference electrode in the ground.

Future CP systems

Markets for photovoltaic-powered cathodic protection systems will continue to grow as a better understanding of photovoltaic systems is gained, as photovoltaic prices fall and as metal coatings improve in quality. The latter result in higher integrity factors, which would therefore reduce loads, making photovoltaic systems more economical.

8.6 WATER PUMPING

Photovoltaics are increasingly meeting the needs for water pumping systems in the range between the very small systems, where hand pumps dominate, and the large generator-powered systems (Ball & Risser, 1988). They are also becoming increasingly popular in very remote areas where reliability, long life and freedom from refuelling provide significant advantages over windmills or diesel-powered systems. They offer low maintenance, cleanliness, ease of use and installation, reliability, long life, unattended operation, and can be easily matched to any need. Table 8.1 gives the breakdown in sizes of photovoltaic-powered water pumping systems in use in the late 1980s. These systems are primarily used for rural water supply, and to a lesser extent for irrigation, stock watering, and commercial and industrial use (McNelis *et al.,* 1988). By 2000, more than 20,000 PV-powered water pumps were installed in developing countries, notably India, Ethiopia, Thailand, Mali, the Philippines and Morocco (Martinot, 2003). A market overview and comparison of commercially-available photovoltaic pumps has been published (von Aichberger, 2003), and Short and Thompson (2003) discuss the positive and potentially negative effects on communities in developing countries.

Table 8.1. Estimated number of photovoltaic-powered water pumping systems in use by 1988 (Ball & Risser, 1988).

size (W_p)	**no. systems**
0–500	11,000
500–1,000	100
1,000–2,000	8,000
>2,000	2,000

The most significant disadvantages of photovoltaic-powered systems are the high initial cost, the variation of solar insolation, the diffuse nature of solar energy (low energy density, which necessitates relatively large systems), and the relative immaturity of the industry with regard to system design experience and system component development, although the latter is rapidly being overcome.

On a life-cycle-cost basis, photovoltaic water pumping systems of less than 2 kW_p are becoming quite economical, relative to diesel-powered systems (Halcrow & Partners, 1981), while PV systems less than 1 kW_p are always cheaper than diesel (Bucher, 1991). Fig. 8.5 shows typical unit water costs as a function of volume pumped per day for both photovoltaic-powered water pumping and diesel-driven pumps. In addition, Fig. 8.6 shows the unit water costs as a function of pumping head. The costs of course vary from installation to installation, depending on the specific characteristics, requirements, configurations and type of components used.

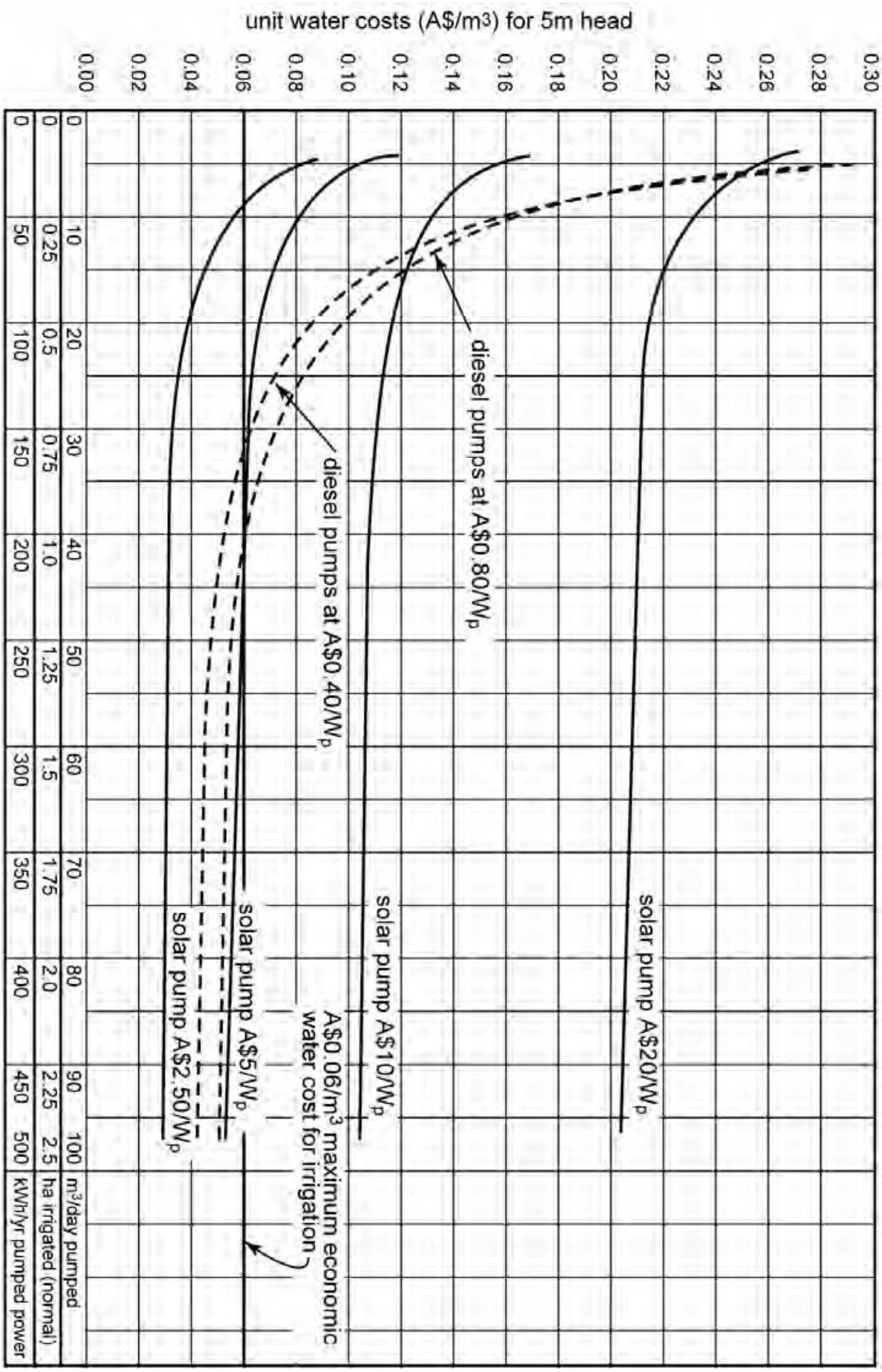

Figure 8.5. Unit water costs for 5 m head as a function of volume pumped per day ($A/m^3) for both photovoltaic-powered water pumping and diesel pumps (Used with permission of Halcrow & Partners, 1981).

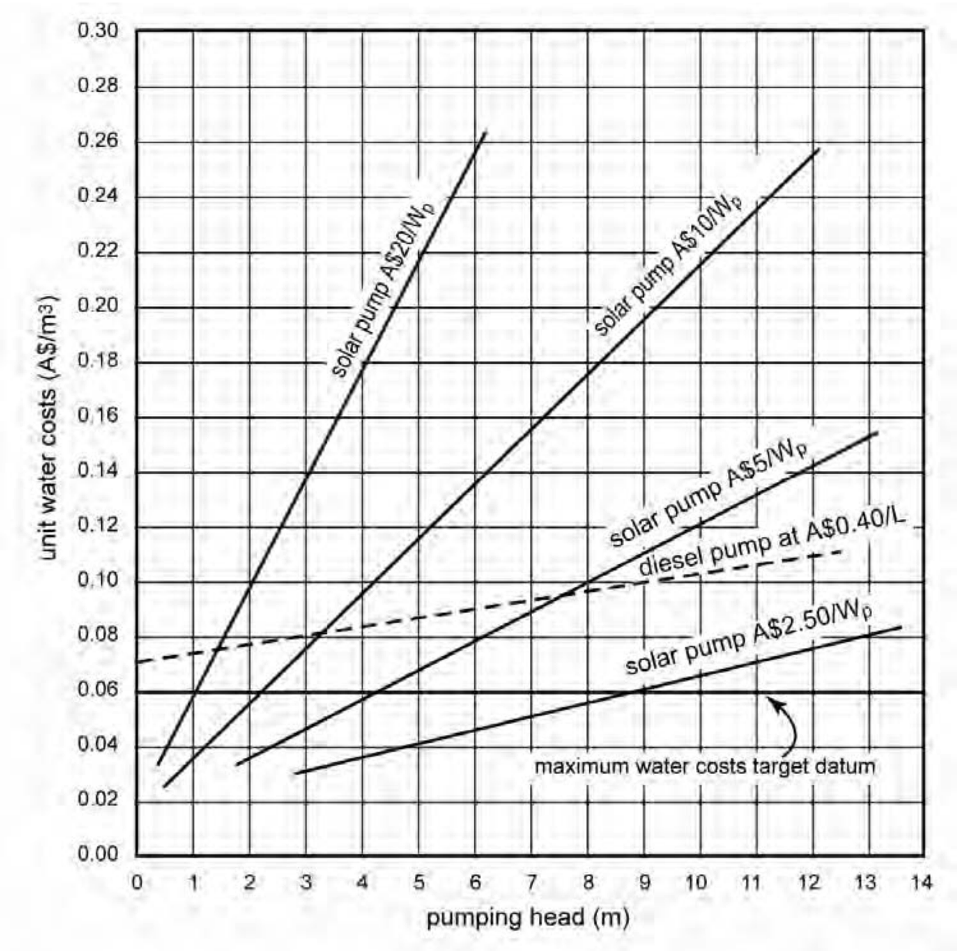

Figure 8.6. Typical unit water costs as a function of pumping head for 40 m^3/day average pumping output (Used with permission of Halcrow & Partners, 1981).

It is imperative that systems be designed specifically for the application. The system configuration, component types and their respective sizes are influenced greatly by such aspects as water source capacity, water source replenishment rate, water volume required per day, solar insolation availability, pumping time/flow rate, static water level, draw-down level, discharge head, seasonal head variations, pipe size and friction, and pumping subsystem component characteristics and efficiencies. Information on each of the above needs to be known to facilitate proper system design. In addition, as shall be seen in Chapters 11 and 12, careful matching of the pump, motor and photovoltaic arrays is essential. Fig. 8.7 indicates the losses in a typical photovoltaic-powered pumping system.

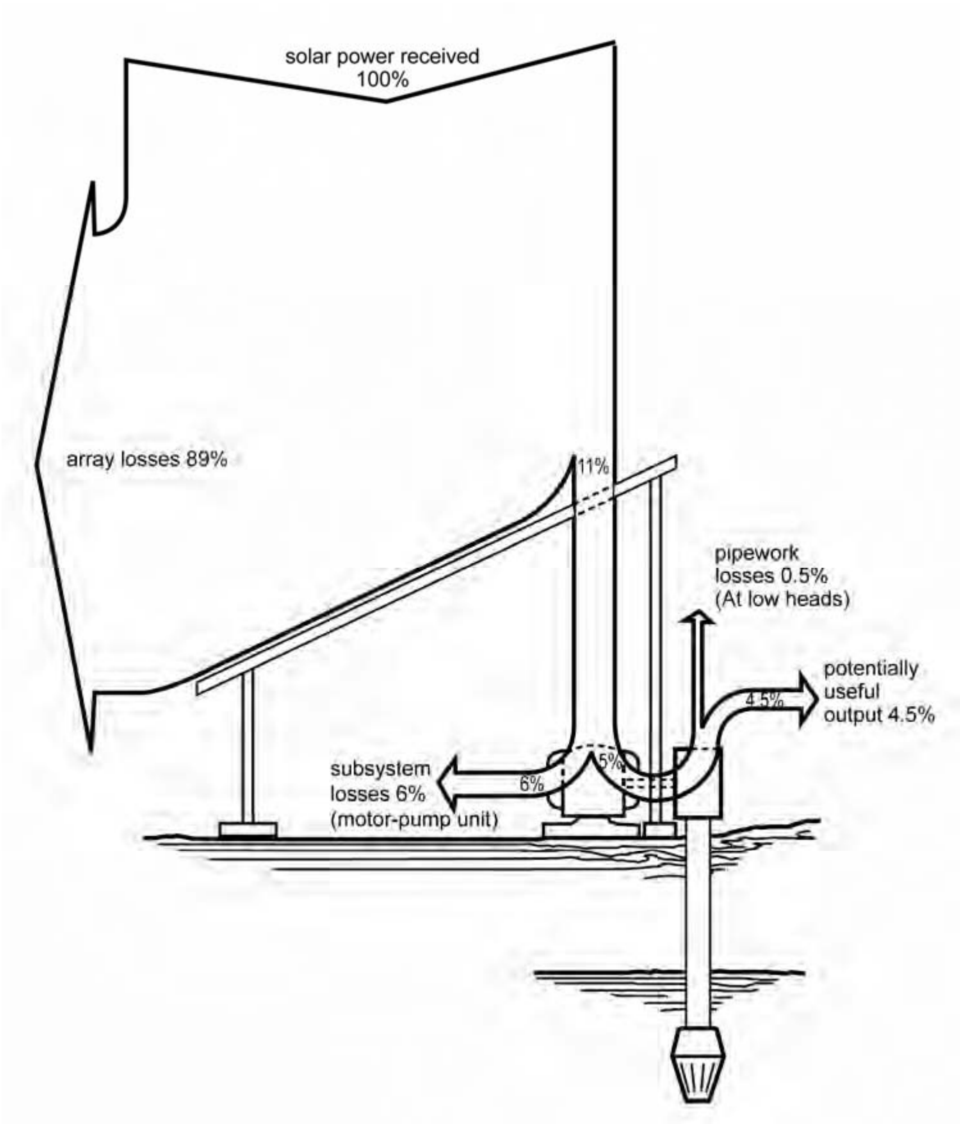

Figure 8.7. Losses in a typical photovoltaic-powered water pumping system (Used with permission of Halcrow & Partners, 1981).

8.7 CONSUMER PRODUCTS FOR INDOOR USE

The consumer product market is already very large, and growing rapidly. It is currently dominated by Japanese manufacturers, producing a wide range of watches, calculators and small toys powered by low cost amorphous silicon solar cells. There is also an increasing market in larger products, such as garden lights, and torches.

Figures quoted for the generating capacity of photovoltaics for consumer products may be grossly overrated, since they assume light intensities of 1 kW/m^2. However, the cells are designed for use indoors and do not give a fraction of this output, even if outdoors, because of resistive losses. For instance, in 2002, figures indicate that

60 MW_p of photovoltaic cells were produced for consumer products (Maycock, 2003) but, in reality, the electricity actually generated would be less than 1% of this figure (and not much more, even if used outdoors). Hence most PV statistics do not include these products. The International Energy Agency (IEA) PV statistics, for instance (www.iea-pvps.org), record only modules larger than 40 W_p.

8.8 BATTERY CHARGERS

Where rechargeable batteries are already used as a power source, solar modules can be used to keep the batteries fully charged during periods of reduced use, compensating for self-discharge. This is already a common application on yachts and recreational vehicles, but may be used increasingly for laptop computer, tractor and car batteries.

Charging regimes are often important and careful notice should be taken of Section 6.7.2 on regulators, particularly with reference to *self-regulation* scenarios.

8.9 PHOTOVOLTAICS FOR DEVELOPING COUNTRIES

About 40% of people in developing countries do not have access to electrical power (Martinot, 2003; Goldemberg *et al.*, 2000) although small battery-operated appliances are used in some locations, with consumers travelling to central battery recharging facilities as necessary. In remote and inaccessible regions, supply of fuel and maintenance services for diesel generators is also difficult. There is therefore a potentially enormous market for photovoltaic-based systems, particularly for such items as (Shepperd & Richards, 1993):

- household lighting, including PV lanterns
- household power
- TV and radio for education and entertainment
- communication systems
- water purification for drinking
- water pumping for irrigation and domestic water
- lighting and household power
- refrigeration of medicines and vaccines
- village battery charging stations
- wireless telephony
- community facilities
- productive activities.

Each of these can be designed as a stand-alone photovoltaic system, with village systems supplying multiple uses. The IEA PV Power Systems Programme has operated a specific developing country task (IEA PVPS, 2003).

Photovoltaics is particularly attractive because of its high reliability, non-dependence on fuel supplies, long life and low maintenance (Eskenazi *et al.*, 1987). However, some level of continuing support, education and training of users is necessary to avoid a high incidence of system failures (Lloyd, 2000), although these aspects are now better managed than in the past (Bushlight, 2004; Wade, 2003*a*, 2003*b*). In addition, the modular nature of photovoltaics allows small or large systems to be installed virtually anywhere and subsequently increased in capacity as necessary. Since the capital cost of photovoltaic systems is high, however, most villages in developing countries need financial assistance for the supply of such a power system.

Many countries, including Brazil, China, Thailand, Laos, Spain, Sri Lanka, India, South Vietnam and Indonesia, have active photovoltaic programs, largely aimed at providing power to rural communities. The largest markets for small solar home systems are India (450,000 systems planned), China (150,000), Thailand (150,000), Kenya (120,000), Morocco (80,000), Mexico (80,000) and South Africa (50,000).

As an example of the typical systems used, about 10,000 systems with an average output of 150 Wh/day, using the following configuration, have been installed in Indonesia (Schlangen & Bergmeijer, 1992):

- one 45 W_p photovoltaic module, mounted on a small pole fed through the roof of the house
- one 12 V, 70 Ah vented lead-acid battery, mounted in a frame attached to an inside wall
- one small regulator, to protect the battery against over-charge or excessively deep discharge
- two 6 W lights
- one plug and socket for connection of TV, radio or other appliances.

Similarly, in Spain, 1500 Andalucian homes are supplied with power via two 52 W_p modules, a battery and regulator (BP Solar, 1993) and in Malaysia, 11,600 PV systems are used to power homes, long-houses, health clinics, community halls, schools and churches. Applications range from basic lighting to vaccine refrigerator-freezers (BP Solar, 2002).

8.10 REFRIGERATION

Photovoltaic panels are widely used to power refrigerators for (Ball & Risser, 1988):

- medical purposes, which account for about 20% of all photovoltaic powered refrigerators
- recreational vehicles, such as campervans
- commercial use
- residential use.

Critical medical supplies, costing many thousands of dollars can be lost if there is a power failure to a vaccine or medical supply refrigerator. Therefore, its availability must approach 100%. The World Health Organisation sets specifications for refrigerators used in international aid projects (WHO, 2000). Because of their rapid deployment, modularity and low maintenance needs, photovoltaics are often used, even when cheaper energy sources are available. New applications are continually being developed. In Greece, for example, use of photovoltaic-powered ice storage units for pre-cooling goats milk on remote farms is being examined (Kallivrousis *et al*., 1992).

DC refrigerators of high efficiency are becoming cheaper and should be used in all applications to avoid conversion losses and the extra cost of a larger inverter, as well as to improve reliability. Most units are 12 or 24 V_{dc}. They are typically five times more efficient than conventional AC units, therefore requiring much smaller photovoltaic systems. Aspects that contribute to their efficiency include:

- shape
- increased insulation
- tight door seals
- compartmentalisation, with independent thermostat control of each
- efficient compressors/motors with efficient heat removal (without fans)
- manual defrosting
- top loading.

Consumer education on the best use of a refrigerator is important if the advantages outlined above are to be realised, and the power supply is to be minimised. This should include (Ball & Risser, 1988) knowledge of the thermal effects of:

- refrigerator location, including the need for ventilation for heat dissipating coils
- door opening habits
- seasonal variations in use (in general, this is well matched to photovoltaic output)
- time and temperature of loading.

8.11 PHOTOVOLTAIC POWERED TRANSPORT

Transport of people and goods is an energy challenge that is difficult to meet directly with solar cells owing to the relatively small collecting areas on vehicles and the large power and energy demands. Solar power may be used to help power conventional systems, using an existing grid as effective storage, such as the tramway in Karlsruhe, Germany. Photovoltaic modules (100 kW_p) on the roof of the Centre for Art and Media (ZKM) supply power for the Karlsruhe urban tram system. The energy is fed directly to the DC system to power the trams with additional requirements supplied by the usual grid-based system. The large DC loads make storage and inverters unnecessary. A similar, 250 kW_p system operates in Hanover. A fixed, ground-mounted 24 kW_p photovoltaic array supplies sufficient energy to the grid to offset the energy demands of the funicular railway near the Parliament Building, Bern, Switzerland. The system was installed in 1992 and produced 105% and 95% of the railway's energy requirements in 1993 and 1994, respectively. A 36 kW_p installation meets the entire energy needs of a funicular near Livorno, Italy (EC, 2002).

On-board solar assistance for transport is also quite practical. Several small road cars with photovoltaic roofs have come to market, but to date have experienced small sales volumes. A solar-assisted bus, using 15 photovoltaic laminates integrated into the roof, carries disabled visitors around Kew Gardens in the UK, and a supermarket chain in the UK uses top-mounted photovoltaics to power refrigeration in truck trailers. Similarly, PV arrays on trucks are being trialled in the US as a means of keeping batteries topped up while drivers stop at truck stops, without the need for idling the motor.

Highway noise barriers represent a huge investment in expensive structures that have been found a second use as mounts for large numbers of grid-connected photovoltaic modules in Europe. Apart from being convenient support structures, they provide an excellent ‘showcase’ opportunity for exposure of PV to large numbers of people. An excellent example is the A9 motorway near Amsterdam Airport with a 220 kW_p system spread along 1.65 km (EC, 2002).

Solar powered boats are attractive for use in waters where fuel spillages are particularly discouraged, such as on lakes, or where engine noise would detract from the surroundings, such as in nature reserves. Two photovoltaic-powered shuttle boats, each seating 24 passengers, began service between Lausanne and Saint Sulpice on Lake Geneva in Switzerland in 1997. The vessels’ electric motors are operated by power generated by a photovoltaic array covering 14 m^2, located on the roof of each vessel, providing environmentally-friendly public transport. On overcast days they can be charged from the grid at the pier. The 27.5 m Bécassine carries 60 passengers on a Swiss lake, powered by a 1.8 kW_p photovoltaic array. Energy storage is in a 180 V, 72 Ah battery. *Solar Sailor* is a tour boat, operating on Sydney Harbour, powered by photovoltaics, wind and an efficient, quiet compressed gas motor. The ‘sails’ are fibreglass aerofoils, with solar cells on the upper surface, that can be oriented to optimise wind and/or solar power.

Photovoltaic-powered airships are an active research and development area, making use of the large surface area for the mounting of low weight modules. Proposed applications for solar-powered aircraft include cargo transport, telecommunications, remote sensing and atmospheric measurement. NASA’s pilotless solar aeroplane unfortunately crashed in 2003 but there are plans for a 20-day, around-the-world flight of a PV-powered aeroplane with a solo pilot (Krampitz, 2004). That flight will require up to seven stops unless the storage capacity of batteries is dramatically improved.

8.12 SOLAR CARS

Solar car races provide a small but growing market, particularly for high efficiency photovoltaic cells. Recent races include those held since 1987 in Australia and since the early 1990s in the USA, Japan and Europe (Roche *et al.*, 1997; Cotter *et al.*, 2000; WSC, 2004).

The efficiency of the photovoltaic cells is of prime importance for car races, owing to the practical limitations on the physical area of photovoltaics useable. Price is often no obstacle, with US\$600/W_p currently being charged for the best cells. The leading cars in recent World Solar Challenge races have used extremely expensive cells made from gallium arsenide and related material, usually only affordable for space applications. Nevertheless, many top place getters are student cars built using standard cells. The emphasis is on efficient vehicle design, including:

- aerodynamics (which is more important than weight)
- motor efficiency (often two motors are used)
- power conditioning and control circuitry
- battery storage densities and efficiencies.

It is likely to be many years before large numbers of regular commuter vehicles are powered by photovoltaics, owing to the need for:

- cost reductions
- on-road compatibility with other vehicles, such as trucks

- acceptance by transport authorities, particularly on the grounds of safety
- standardised, reliable designs (although this is rapidly evolving)
- consumer acceptance
- mass-produced low-weight solar panels
- regenerative braking, which is necessary to maintain efficiency where frequent stopping occurs (this is now well developed and being used commercially in hybrid petrol-electric cars)
- establishment of recharging stations (which could themselves be powered by photovoltaics).

Targets for zero or low emission vehicles, such as in California, accelerate the development and use of electric cars in urban environments. This could stimulate the use of photovoltaics in everyday commuter vehicles, to either directly power vehicles through integration into the car panels or else be mounted at local photovoltaic powered charging stations or at individual households (Ingersoll, 1992).

A critical component of solar powered cars is the battery. It must allow deep cycling, yet have a longer life than present car batteries. Self-discharge rates are not critically important but the charge capacity-to-weight ratio is. The availability of solar recharging facilitates the inclusion of additional small loads on the battery, such as ventilation fans in cars, which previously could not be accommodated during periods of non-use, owing to battery discharge. Both amorphous and crystalline silicon-based solar battery recharging kits are available as small modules that plug into car cigarette lighter sockets.

At present, the design procedure for the photovoltaic array and electrical components is less well defined than for the battery. Consequently, battery and photovoltaic selections are typically made independently of each other. As with all photovoltaic systems, user education is important. For solar cars, efficient driving is important to ensure optimal use of the batteries and the solar input.

8.13 LIGHTING

In the USA alone, there are thousands of photovoltaic-powered lighting systems installed (Ball & Risser, 1988; Florida Solar Energy Center, 1998). The majority of these (80%) are in the 200–400 W_p range. In most remote areas of the world, photovoltaic-powered DC lighting is now quite cost-effective compared with kerosene lamps, batteries, candles, or diesel or petrol generators, and far more economical than grid extensions. Even in urban areas, photovoltaic lights are often used to avoid the high cost of running either underground or overhead power lines. Such items as off-the-shelf garden lights, which can be installed without an electrician, are gaining popularity.

Some of the current applications for photovoltaic lighting include:

- billboards
- security lighting
- public transport shelters
- emergency warning lights
- area lighting (e.g. race tracks, streets)

- domestic use.

Lamp efficiencies have increased enormously in recent years, but still tend to be higher for higher powered lamps. Common lamp control techniques, which contribute to higher efficiency include:

- photo cells (to turn the light on only when sufficiently dark, and turn it off automatically when light levels are adequate)
- timers (for specific periods of operation or coding for identification)
- switches (to allow manual control, especially for domestic use)
- sensors, such as motion and infrared detectors (especially useful for security systems).

Although gradually improving in quality, many of the photovoltaic-powered garden lighting kits marketed over the last decade tend to be gimmicky and unsuitable for their intended use for any reasonable period of time. Common problems include:

- use of low-efficiency amorphous silicon solar panels which degrade with time and produce insufficient electricity
- use of low-efficiency lamps, which provide inadequate lighting
- poor encapsulation, which allows moisture to penetrate and corrode solar cell contacts
- flimsy plastic moulding, which is easily broken and degrades with outdoor exposure
- inadequate charge controllers, which permit overcharging and over-discharging of batteries.

Most stand-alone photovoltaic lighting systems operate at 12 or 24 V_{dc}. Since fluorescent lamps are over four times more efficient than incandescent lamps, they are preferred in photovoltaic systems. 'White' LED lighting is a recent innovation that is gaining popularity for applications that require only low light outputs. They can operate with very low energy requirements, and hence only need small PV systems.

Most lighting systems are considered non-critical, except for warning devices and security systems, so that availability, and hence cost, can be relatively low. Since lighting is typically needed after sundown, all photovoltaic lighting systems need batteries. Deep cycling, and preferably sealed, batteries are recommended.

From the customer's perspective, price, ease of installation, clarity of instructions and safety, as well as performance and reliability, are of key importance when purchasing lighting kits (Servant & Aguillon, 1992).

8.14 REMOTE MONITORING

Of the 20,000 photovoltaic-powered monitoring (telemetry) systems installed in the USA alone by the late 1980s, 84% were in the 0–50 W range, and almost all are 12 V_{dc} (Ball & Risser, 1988). Their applications include monitoring of (Maycock, 2003):

- climatic conditions, including storm warnings
- highway conditions

- structural conditions
- insect trapping
- seismic recording
- scientific research
- auto-dial alarms
- water supply reservoir levels
- radiation and pollution monitoring.

With any monitoring system, power is required for the instrumentation and the data communications equipment. Since these power requirements are typically quite low (loads can often be measured in mAh per day), monitoring applications are ideal for photovoltaic systems. Because of the simplicity and reliability of photovoltaic power supplies, they are even sometimes replacing AC-powered battery chargers in grid-connected areas. Even where high voltage grid power is immediately available, it can be more economical to supply small loads from PV than to install step-down transformers (Brooks, 2000).

It is important to include varistors in the photovoltaic system, to protect the data acquisition equipment from surges, particularly due to lightning.

Rechargeable batteries (NiCd, or gelled electrolyte lead-acid batteries) are often included in data acquisition equipment packages. If using NiCd batteries, self-regulation is probably suitable and preferable.

8.15 DIRECT-DRIVE APPLICATIONS

PV systems can be connected directly to the load, typically using only one module (Ball & Risser, 1988). Such direct-drive systems have considerable appeal, as they avoid the use of batteries, blocking diodes, and all power conditioning circuitry. The module must be able to produce the necessary current for the load, while the load must be able to tolerate voltages as high as the module's open circuit voltage. Many complete packages that include photovoltaics are now available. Most of these are portable systems. Typical applications include:

- ventilation fans
- portable radios
- toys
- solar tracking devices
- solar collector pumps
- water pumping systems.

The last of these is covered in detail in Chapters 11 and 12 and represents a major application for photovoltaics in the future.

For direct drive applications in general, good correlation is obviously required between power demand and solar intensity, since the systems can only operate during daylight hours. As long as the load impedance is matched to the photovoltaic module's output, any small series-connected or permanent magnet (but not shunt type) DC motor can, theoretically, be powered by a direct drive photovoltaic system (Roger, 1979). Manual disconnect switches are recommended for fixed installations, while portable systems can be turned away from the sun, or covered, to cease operation.

8.16 ELECTRIC FENCES

There are enormous fenced areas in Australia, many of which are away from power grids. Electric fences have been found to be extremely effective in preventing intrusion from wild animals, such as dingos and kangaroos, while simultaneously preventing farm stock, such as cattle, from escaping. A detailed guide to electric fence design is given by Hurley (2004).

Stand-alone photovoltaic systems are well suited to powering the very small loads associated with electric fences. A typical system would comprise:

- photovoltaic panels
- battery
- blocking diode
- high voltage, current limiting circuitry, which constitutes the load (converting low DC voltage of panels to high voltages)
- power conditioning circuitry as necessary.

A high voltage with a very low current is applied to the metal wires in the fence. This type of system is good for protecting long lengths of fence since it has virtually a zero current draw under normal conditions. Photovoltaics is considered a suitable power source since it is:

- cheap, relative to alternatives
- effective
- reliable
- relatively free from maintenance requirements
- portable, for temporary fencing.

EXERCISES

8.1 (a) Give an overview of solar cell applications, past, present and future.

(b) Give specific details as to why solar cells are well suited to each application.

(c) Why is there sometimes resistance to using solar cells in applications already considered economical for photovoltaics?

(d) How substantial a contribution are photovoltaics likely to make to the world's electrical requirements in the future?

8.2 Discuss the suitability of photovoltaic powered systems for third world countries. Consider:

- a range of applications
- feasibility and practicality

- advantages and disadvantages
- barriers and obstacles preventing their use.

8.3 Trace out the history of solar cars, particularly with reference to vehicle electrical components (solar panels, batteries, inverters, control circuitry, motor etc.). Include:

- reliability of each component
- evolution in solar panels to suit such an application
- suitable battery types
- different types of motors used and their respective suitability
- the advantages and disadvantages of different types of control circuitry
- present status with regard to economic feasibility, reliability, best designs etc.

8.4 What is the potential for solar cars to become a common vehicle for city commuters? Consider:

- cost
- safety
- current status
- potential problems and obstacles.

8.5 Discuss the economics of using refrigerators in photovoltaic-powered RAPS systems. Include:

- information on the availability of DC refrigerators and their relative efficiencies
- DC versus AC refrigerators
- typical applications, common problems etc.
- references.

8.6 Discuss the use of solar cells in space applications. How and why are space solar cell designs and materials different from those used in terrestrial applications?

8.7 (a) What is 'cathodic protection'?

(b) Discuss the use of photovoltaics for cathodic protection, making reference to systems already installed.

(c) What complications exist when designing photovoltaic-powered cathodic protection units?

8.8 Photovoltaics have proven to be economical for powering marine navigation aids for many years. Discuss their use in such applications and environments. What are common problems for such systems?

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Chapter

9

REMOTE AREA POWER SUPPLY SYSTEMS

9.1 HOUSEHOLD POWER SYSTEMS

Remote area power supply systems in non-grid areas may take on a range of configurations with a mix of possible electrical energy generating sources, plus inverters and batteries. Present generating options include:

- photovoltaic modules
- wind turbines
- small hydroelectric generators
- diesel or petrol generators
- hybrid systems comprising two or more of the above.

In Australia, these remote area power supply systems are generically called RAPS systems and are typically used for loads larger than simple PV-battery systems. They were developed originally for rural homesteads, stations and holiday homes, but are now being used for small community power supplies, in Aboriginal settlements and on islands.

RAPS systems are installed for a range of reasons, including:

- expensive grid connection (Krauter, 2004)
- grid overload, resulting in unreliable supply
- desire to use renewable energy

- desire for independence and low running costs
- avoidance of overhead wires in environmentally sensitive areas.

Stand-alone photovoltaic power systems that require availabilities in excess of 90% often need considerable oversizing of the array for summer months and sunny days to ensure adequate electricity generation in the winter months and for periods of prolonged cloudy weather. This oversizing is very costly, but is necessary for many applications in remote areas, where maintenance and refuelling are difficult and expensive.

In comparison, where humans are in close proximity and are able to do at least rudimentary maintenance and refuelling, more flexibility can be exercised in photovoltaic system design. PV-only availability can therefore be reduced, usually resulting in vastly more efficient use of photovoltaics throughout the year. For example, to maximise the efficiency of photovoltaic use in the system, it is necessary that all generated electricity be used either directly by the load, or be stored in the batteries. For a stand-alone photovoltaic system design, this involves considerable downsizing of the photovoltaic component to the linear region of the *photovoltaic availability* versus *photovoltaic cost* curve of Fig. 7.1. The corresponding reduction in availability necessitates incorporating an additional energy source to supplement the photovoltaic generation, so that in combination, high system availability is achieved.

House design and orientation, as well as selection of appropriate energy sources and appliances for different end uses, such as cooking, heating and lighting, are of critical importance when using a RAPS system (see Fig. 9.1 and Standards Australia, 2002). The topic of passive solar house design will not be covered in detail in this book, but excellent information is available from the Australian Greenhouse Office (2004*b*) web site.

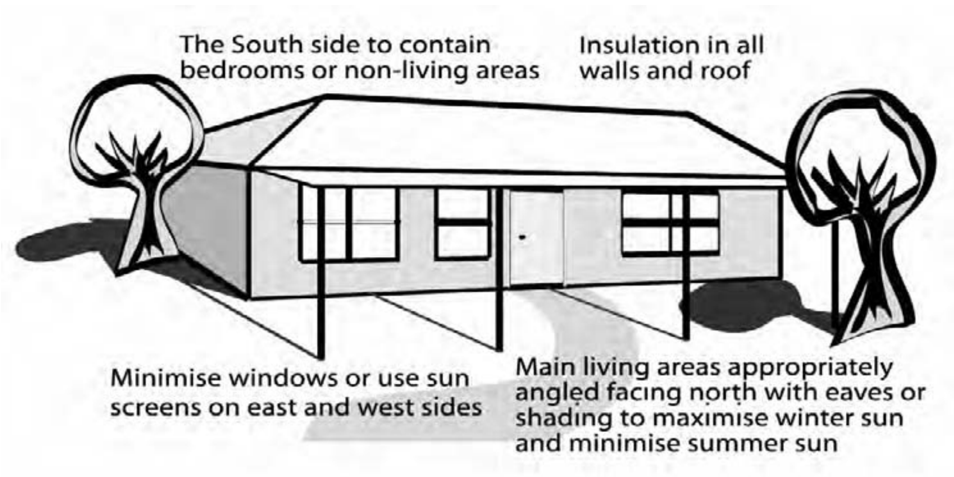

Figure 9.1. A home based on energy efficient passive solar design principles for the southern hemisphere. The directions north and south are reversed for the northern hemisphere.

With regard to appliances used in RAPS households (Australian Greenhouse Office, 2004*c*), some general rules apply:

- Do not use electricity for cooking (other than small appliances and microwave ovens), hot water, space heating, clothes drying or air-conditioning. Many less expensive alternatives exist.
- Electric refrigerator-freezers are borderline cases, but can be used, provided highly efficient models are selected.

In many countries, new appliances, particularly refrigerators, freezers, dishwashers, air conditioners, washing machines and clothes dryers receive 'energy ratings', making it easier for consumers to select efficient appliances. Sometimes, regulators require labelling to allow consumers to make informed choices between competing products and/or products are required to meet regulated standards for energy efficiency. In Australia at present, clothes washers, clothes dryers and dishwashers have mandatory energy labelling; air conditioners, refrigerators and freezers require labelling and need to meet minimum standards and water heaters, electric motors, lamps, ballasts, transformers and commercial refrigeration have minimum standards without a labelling requirement (Australian Greenhouse Office, 2004*a*). A list of Australian Standards for energy efficiency is also provided at the above web site.

Power used by equipment left for long periods on 'standby' is an underappreciated load (Australian Greenhouse Office, 2004*a*) that should be minimised in RAPS situations.

9.1.1 The choice between AC and DC

Grid-connected households use AC power for virtually all appliances. For RAPS systems, however, this may not be the most cost-effective choice. DC appliances are commonly more efficient and avoid the need for an inverter, with its associated loss. However, DC wiring is heavier duty, requires special switches and may need specialised personnel for installation. In addition, a much smaller range of DC appliances is available and their smaller market usually makes them more expensive.

A combination of AC and DC wiring has advantages when considering the range of available appliances and their relative efficiencies, but may introduce safety problems and complications during maintenance. Care should be taken to meet the relevant local standards (Standards Australia, 1999–2000*a*, 1999–2000*b*, 2002). Several countries have accreditation processes for system designers and installers that produce a body of qualified people who are aware of industry best practice standards and all relevant national standards. In Australia, this is administered by the Australian Business Council for Sustainable Energy (BCSE, 2004).

9.1.2 Appliances

(See Pedals, 2003; Australian Greenhouse Office, 2004*a*, 2004*b*, Castañer *et al.*, 2003; Lawrence Berkeley Laboratories, 2004.)

Lights

Fluorescent lights are about four times more efficient than incandescent lights and should be used with RAPS systems (Ball & Risser, 1988). Modern electronic ballast AC fluorescent lights and also DC fluorescent lights are superior to the older style fluorescent lights. Most incandescent lights that are operated for a few hours per day can be cost-effectively replaced with compact fluorescents (Castañer *et al.*, 2003).

Light emitting diodes (LED) are now also an option following the development of blue and white LED products (Steigerwald *et al.*, 2002; Holcomb *et al.*, 2003). LED lighting is approximately the same lighting efficiency as fluorescents (Bohler, 2002) and is well suited to small, low power lighting tasks.

Refrigerators and freezers

Refrigerators and freezers can be major energy users and should be chosen carefully. If appliances in your country have an energy rating, make sure you purchase the most efficient model. Otherwise choose the smallest possible for your needs. To reduce the load on your RAPS system, gas appliances can be used, although they are often more expensive. Never connect the electric element on a gas refrigerator to a RAPS system, as it consumes large amounts of power. A DC chest-style refrigerator is said to use only one third the power of an AC unit when inverter losses are taken into account (Pedals, 2003).

Dishwashers

Preferably use the type that allows connections to both hot water and cold water, as this uses only 30% of the electricity of one connected solely to cold water with an internal heater. The best approach is determined by the type of hot water system installed. For instance, if the hot water is heated by electricity generated by the RAPS system, connect to cold water. On the other hand, if your water is heated by solar collectors or a slow combustion stove, connect to hot water. This will use considerable hot water but is still more economical than using the RAPS system to generate electricity to heat the dishwashing water.

Microwave ovens

Microwave ovens are the only oven type suited to a RAPS system. They offer highly efficient cooking, with relatively small heat losses. Other specific purpose cooking appliances can use large amounts of electricity, so should be used sparingly, if at all.

Stoves using induction heating are often less efficient that claimed, depending on how they are used. However, if used appropriately, they may be suitable for connection to a RAPS system. Wood or gas stoves should be considered.

Home entertainment and computing equipment

Hi-fi systems, videos, televisions and computers generally use low levels of power but, since they may be used for long periods, it is wise to check manufacturers' energy ratings and buy the lowest rated units. Headphones and liquid crystal displays use considerably less power than sound speakers and conventional cathode ray picture tubes respectively. An international standard for energy-efficient electronic equipment, *Energy Star*, was produced by the US Environmental Protection Agency and has been adopted by several countries, including Australia (Australian Greenhouse Office, 2003*a*).

General appliances

Grid-connected households use a wide range of electric appliances in the kitchen, laundry and generally. These include toasters, electric jugs, vacuum cleaners and washing machines, all of which typically draw large amounts of power, albeit for only short periods. If a diesel or petrol generator is incorporated into the RAPS system, it is advisable to synchronise use of such appliances with the generator run times.

Front loading washing machines are considerably more energy and water efficient than the top loading agitator type. Never use the electrical heating elements, and if hot water is necessary, use water heated by other means, such as via a solar water heater, rather than via electricity.

Electric motors often require very large starting currents (up to five times the rated power use for normal operation) and hence, where possible should not be driven through the inverter but rather directly from the generator. This will allow considerable cost saving through a smaller inverter. However, inverters commonly have a rating for a high transient load that may accommodate motor starting. Appliances with motors that start automatically, such as refrigerators, should be tolerated by the inverter. Battery charging should also occur while the generator is running.

In general, the most important design criterion for a RAPS system is to avoid the use of electrical appliances wherever possible, in favour of non-electrical substitutes. Table 9.1 gives a typical load analysis of appliances in a home using a RAPS system. Further information on typical lighting and appliance energy use is tabulated by Castañer *et al.* (2003) and Lawrence Berkeley Laboratories (2004), while Fig. 9.2 gives a schematic of such a home.

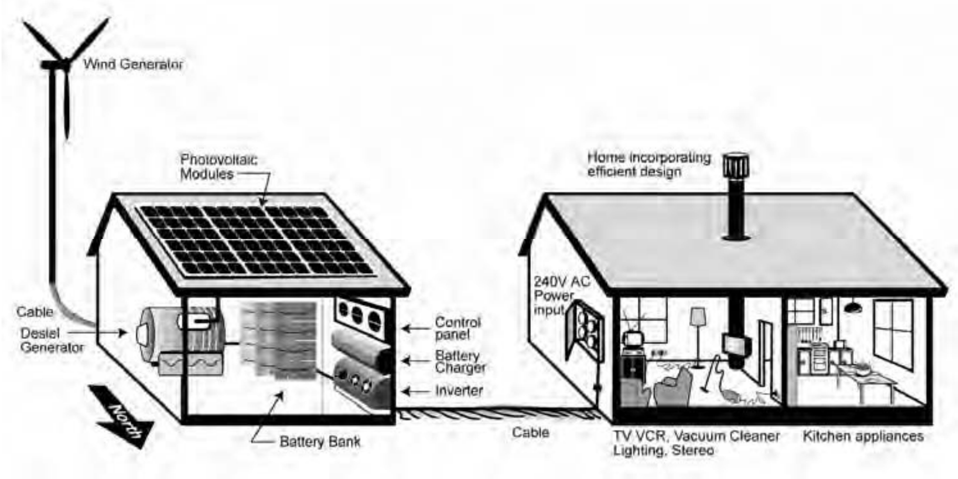

Figure 9.2. A typical hybrid RAPS system (Department of Primary Industries and Energy, 1993).

Table 9.1. Typical load analysis of appliances in a RAPS home (Department of Primary Industries and Energy, 1993).

	typical power (W)			average hours/day			energy use—average		
	example			example			example		
Appliance	**min**	**max**	**est.**	**min**	**max**	**est.**	**min**	**max**	**est.**
	(W)	(W)	(W)	(h)	(h)	(h)	(Wh/day)	(Wh/day)	(Wh/day)
Kitchen									
Lights	11	100		1.00	3.00		11	300	
Refrigerator	100	260		6.00	12.00		600	3,120	
Microwave oven	650	1,200		0.17	0.25		111	300	
Toaster	600	600		0.03	0.08		18	48	
Other									
Laundry									
Lights	11	100		0.25	1.00		3	100	
Iron	500	1,000		0.17	0.42		85	420	
Washing machine	500	900		0.22	0.33		110	300	
Dryer	1,800	2,400		0.20	0.54		360	1,300	
Sewing machine	15	75		0.07	0.07		1	5	
Water pumps	300	500		0.25	1.00		75	500	
Other									
Lounge room									
Lights	15	100		1.00	4.00		15	400	
Television	25	200		0.50	5.00		13	1,000	
Video recorder	100	100		0.50	5.00		50	500	
Stereo	60	80		0.50	3.00		30	240	
Radio	10	40		0.33	3.00		3	120	
Vacuum cleaner	100	1,000		0.13	0.25		13	250	
Other									
Bedroom 1									
Lights	11	100		0.50	2.00		6	200	
Other									
Bedroom 2									
Lights	11	100		0.50	2.00		6	200	
Other									
Bedroom 3									
Lights	11	100		0.50	2.00		6	200	
Other									
Bathroom									
Lights	11	100		0.17	1.00		2	100	
Other									
Garage/external									
Lights	11	100		0.17	2.00		2	200	
Power tools	200	800		0.17	0.17		34	136	
Other									
Total power	**5,052**	**9,955**				**Total energy**	**1,554**	**9,939**	
Est. peak P (½ total)	**2,526**	**4,978**				**Allowance for system losses (50%)**[2]	**777**	**4,970**	
Assume	**2,500**	**5,000**				**Total generated energy required**	**2,331**	**14,909**	[3]

Notes

1 Average Wh/day = typical power (W) × average hours use per day (h/day).

2 Allowance of 50% should be added for estimated energy losses between point of generation and end use in appliances.

3 kWh/day = Wh/day/1000

9.1.3 Consumer education

To use a RAPS system effectively will involve:

- modified and disciplined living habits to minimise energy use and to synchronise usage with solar and wind conditions and with diesel operating times
- a basic appreciation of levels of energy usage of different appliances
- a superficial understanding of the RAPS system and its electrical generating components
- evening out maximum loads supplied by the generator and also general loads to be supplied via the inverter.

Probably the most common failure mechanism or cause for dissatisfaction with RAPS systems results from inappropriate use of the system, rather than poor system design (Lloyd, 2000; Krauter, 2004).

Difficulties in adjustment can often be experienced by families and individuals moving from grid-connected areas to locations where RAPS systems are necessary.

9.1.4 Photovoltaic-diesel/petrol generator hybrid systems

The most common configuration for RAPS systems currently being installed is a photovoltaic-battery-inverter system, with a diesel or petrol generator for emergency use or for peak loads. Such systems are commonly used where availabilities near 100% are required, which would be prohibitively expensive using photovoltaics alone, and in residential or commercial applications where diesel generators previously dominated and were therefore already available. In the latter cases, once the basis of the RAPS system is added to the generator, photovoltaics can be added incrementally, as funds permit, gradually reducing the diesel requirement. Fig. 9.3 gives the electrical block diagram for a typical photovoltaic-diesel RAPS hybrid system. The vast majority of such systems use fixed-tilt arrays but some use single- or two-axis tracking or even concentration, as in the dish-concentrator systems in the north-west of South Australia (Australian Greenhouse Office, 2003*b*).

Despite the high initial costs, where diesels are currently used, the addition of solar panels, batteries and controller can greatly improve the efficiency of generator usage as well as substantially reducing system operating costs. Conversely, a diesel generator removes the need for oversized photovoltaic arrays, which would be both costly and poorly utilised.

Conventional diesel generator system design simply involves selecting a locally available unit that is closest to the peak load requirements of the application. By comparison, hybrid system design is complex, requiring expert assistance in component selection and interaction with the user to determine priorities. Guidance on the interconnection of generators and renewable energy sources is provided by the Australian Standard (Standards Australia, 2002).

Some of the costs that need to be considered include system components—photovoltaic array, batteries, inverter, tracker, generator, wiring, control boards and regulators. In addition, the fuel costs for diesel and petrol generators must be estimated, as must the installation costs, maintenance costs and lifetimes for all components, which will vary.

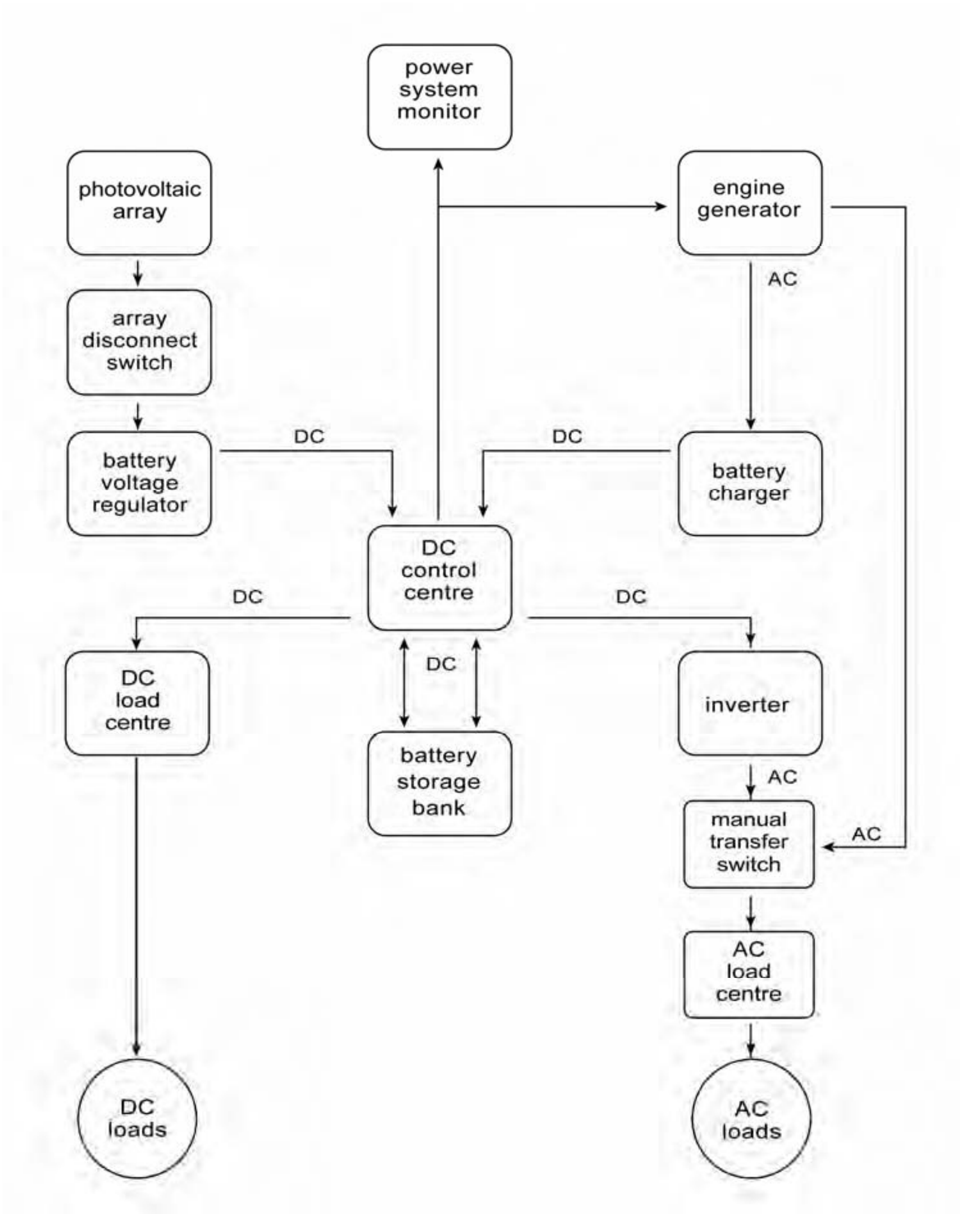

Figure 9.3. Schematic diagram of a typical photovoltaic-diesel RAPS hybrid system (after Sandia National Laboratories, 1991, used with permission).

9.1.5 Diesel generators

Advantages

Diesel generators have been a boon for people living in remote areas, offering close to grid-equivalent power supplies where electricity was previously available for lighting only, via small DC systems.

Their advantages include:

- availability of power on demand
- mature technology with service support usually readily available
- good output AC waveform with little or no distortion
- good voltage regulation
- can be used to charge batteries via a battery charger
- wide range of models available up to quite large currents
- good temporary overload characteristics
- low capital cost for the power produced.

Disadvantages

There are some major disadvantages to diesel-only power systems, which explains the keen interest in RAPS systems. These disadvantages include:

- high operating and maintenance costs
- need for fuel delivery and storage
- noise (especially troublesome for night-time operation) and smell
- emissions of potentially dangerous exhaust fumes, which necessitates care in siting, and of greenhouse gases
- need to be run near full load (80–90% of rated power) for maximum efficiency (see Fig. 9.4) and reduced maintenance costs
- reduced efficiency for up to half an hour, until properly warmed up
- need for periodic operation, typically a minimum of four hours every two weeks.

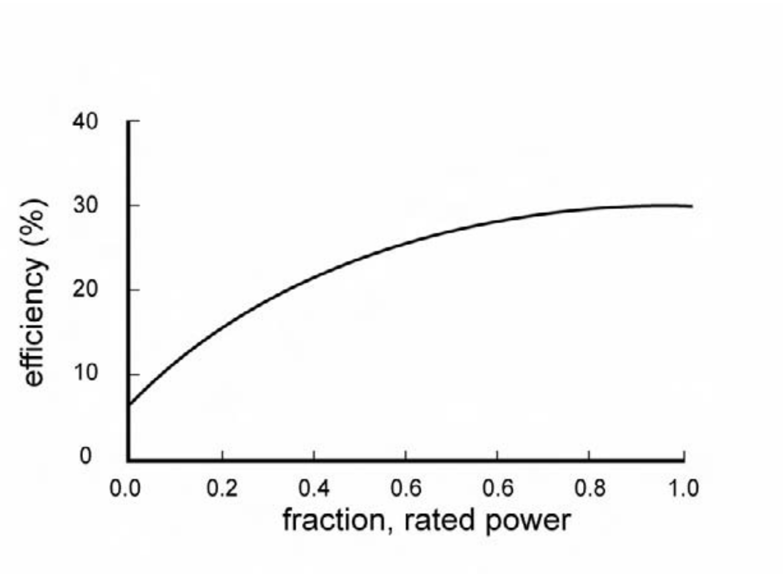

Figure 9.4. Diesel generator efficiency as a function of load.

9.1.6 Petrol generators

When compared with diesel generators, petrol generators:

- produce lower emissions of greenhouse gases
- are lighter and more transportable
- are cheaper for a given output rating
- can be converted to LPG
- require more maintenance as they operate at higher speeds (3000 rpm versus 1500 rpm for diesel)
- are less efficient
- are noisier
- have smaller fuel tanks, necessitating more frequent refuelling
- have much shorter lives (typically 1000 hours versus 10,000 hours for diesel).

9.1.7 Hybrid system design

General considerations

In view of the disadvantages cited above, a diesel-only system has severe limitations in operating efficiency. The addition of batteries alone greatly enhances system efficiency, although it necessitates the inclusion of an inverter and control circuitry.

For a diesel-battery or photovoltaic-diesel-battery system, batteries with appropriate characteristics must be selected. For instance, many batteries commonly used in photovoltaic systems have strictly limited charging/discharging rates, which could lead to their destruction if used in a diesel system with less than three days of storage. Other types of battery are only for 'float' applications where they remain almost fully charged most of the time.

Batteries used in RAPS systems with diesel generators must be of the deep-cycle type, but do not necessarily need low self-discharge rates. Fork lift batteries are probably a cheap, well suited type of battery for such systems. However, most photovoltaic system suppliers now offer specially designed 'solar' batteries and these should be used wherever possible.

Inverters are expensive and where possible should be downsized from the peak loads by having periods of peak demand coinciding with periods of diesel or petrol generator usage.

For a fixed array size exactly matching the load, the loss-of-load-probability (LOLP) is given in Fig. 9.5 as a function of days of storage. By definition, an array size that exactly matches the load is one where the total annual photovoltaic generation exactly matches the total load consumption.

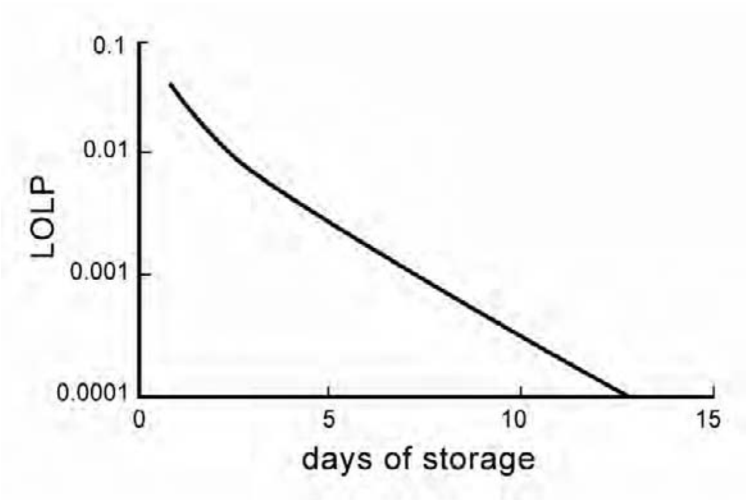

Figure 9.5. Loss-of-load-probability (LOLP) as a function of days of storage (©1987 IEEE Jones & Chapman).

From Fig. 9.5, it can be seen that an array sized to meet the load, in conjunction with one day's battery storage, gives an average availability (1 – *LOLP*) of approximately 94%. This value should be taken as the upper bound on the fraction of the energy in a hybrid system that can be economically displaced by the photovoltaic array. In reality, to make use of all the photovoltaic-generated power in summer, the array size needs to be a little less than that needed to supply the energy requirements of the load. The implications of this on photovoltaic array sizing and tilt angle are that:

- An increased tilt (i.e. greater than the latitude) gives more uniform all-year-round generation, but at the expense of total annual output.
- It is good policy to select the array size and tilt angle together, aiming for the photovoltaic generation on a clear summer day to be equal to the load.
- The array generation should not be too much below the load or else the diesel will be required semi-continuously to supply the difference. (Not everyone agrees with this aim.)
- As a guide, do not consider a hybrid system unless the inclusion of photovoltaics offsets at least 30% of the estimated diesel's operation and maintenance costs (Jones & Chapman, 1987). (Refer to the hybrid indicator of Chapter 7.)
- The system design should provide for infrequent use of the diesel, but for relatively long periods of time on each occasion used, at close to full load.
- It is preferable for the array not to meet the load fully so as to optimise the system cost and ensure the generator will be operated for a reasonable length of time every two weeks.
- The system voltage should be selected in accordance with the inverter characteristics and requirements. In general, this involves limiting the DC current to 100 A maximum.

System design in practice

The steps typically taken in designing a system can be summarised as follows:

1. Determine the load in consultation with the user (consumer education included).
2. Design initially for a photovoltaic-only system with non-critical availability (95%) as per stand-alone system design procedures.
3. Locate the design on the hybrid indicator to ascertain the viability of a photovoltaic-only system as opposed to a photovoltaic-diesel hybrid system.
4. For a photovoltaic-diesel hybrid system, downgrade the availability/array size so that on a clear sunny day in summer, at the design tilt angle, the electrical energy generated (allowing for subsystem inefficiencies) just matches or is slightly less than that consumed by the load over a 24 hour period. The most suitable design will probably correspond to a photovoltaic availability of about 80%.
5. Select the diesel so that its rating matches the peak load. This will facilitate battery charging whenever the peak load is not being drawn, while enabling the generator to be always almost fully loaded when operating.
6. Select the inverter to supply the peak general loads. This will also determine the system DC voltage.
7. Select appropriate deep cycle batteries that satisfy your design and also the charging/discharging rates of the system.
8. Select an appropriate controller.
9. Discuss the system design with the user and the cost and system operation implication of increasing or decreasing the photovoltaic component (by a string at a time). If less photovoltaics is desired (to cut system costs), the array tilt angle should be decreased to provide greater annual electrical energy generation. This will boost summer generation at the expense of winter generation but will reduce overall diesel operating time and hence O&M costs.

Alternative approach for low capital intensive system

This is a typical method used by RAPS suppliers to provide a minimum cost system design:

1. Initially design for a diesel-battery system and calculate the reduction in diesel operating time per day corresponding to the inclusion of each string of photovoltaic panels.
2. The user then determines the component mix.
3. The ultimate system design must be settled on before the appropriate balance of system components (inverter, battery etc.) can be selected.

9.2 RAPS SYSTEM COSTS

RAPS systems vary widely in size, configuration and cost. At the time of writing, turnkey off-grid system prices were found to be in the range A$18–24/$W_p$ for systems up to 1 kW_p and A$12–18/$W_p$ for larger systems. The average off-grid system price was estimated to have fallen to around A$20/$W_p$ from a peak of AU$30/$W_p$ for 1997–1999 (Watt, 2004*b*). Installation costs can also vary substantially depending on site characteristics and accessibility.

9.3 PORTABLE RAPS SYSTEMS

There are numerous situations where portable RAPS systems can be of value owing to their independence of existing infrastructure, speed of installation and their modularity. Systems on standby can be of great benefit for temporary relief during maintenance or for aid purposes for workers and victims devastated by disaster (Kubots *et al.*, 1993). Similar systems can be used by groups or communities preferring nomadic lifestyles to increase their independence and general quality of life.

9.3.1 Portable systems for remote aboriginal communities

Transportable photovoltaic DC power supply systems were developed in Western Australia for installation in remote Aboriginal communities with no access to grid power (Department of Primary Industries and Energy, 1989). The systems supply DC power for refrigeration, communications and lighting, and limited AC power for hand tools, televisions and video equipment. Other potential loads include water pumping, cool ro`oms, evaporative coolers and tyre inflating equipment.

The photovoltaic power supply and all the loads are supplied in a self-contained ‘Solar Pack’. The systems are durable, have low operational costs and require minimal maintenance. They are supplied with the aims of improving Aboriginal health, independence and general quality of life. The conventional approach for supplying power to these remote communities has been via a diesel generator. This has largely been unsatisfactory because of the:

- expensive and often logistically difficult transport of fuel by road
- frequent maintenance requirements
- inflexible system output, which cannot be adapted to changes in the size of the community
- difficulty in transportation
- noise.

The transportable Solar Pack overcame many of these problems. Typical system components include:

- photovoltaic array in range 500–1350 W_p
- battery of deep-cycle lead-acid traction cells configured for 24 V_{dc}
- electronic controller and switchgear to protect and isolate batteries as necessary, to prevent overcharging and to disconnect non-essential loads during poor weather
- 100 W VHF transmitter-receiver for communicating with the flying doctor and other vital services

- two 24 V chest type freezers (designed for maximum efficiency and using brushless DC motors), each with two compressors and a combined capacity of 460 litres, for food, medicines and vaccines
- fluorescent 20 W lamps incorporating inverters to allow operation at 24 V_{dc}
- a small inverter (24 V_{dc} to 240 V_{ac} at 50 Hz) for television, power tools, video recorders
- mains-powered battery charger for 12 V automotive batteries
- portable, insulated shipping container.

The total system weighs approximately 6 tonnes and is transported on the back of a truck. The first unit was installed in 1985 in the Pilbara region of Western Australia, for the Ngurawaana community. A number of such systems are now operating in Western Australia, the Northern Territory and South Australia. The acceptance and performance of the units have been good, even with repeated transportation over poor roads. The only maintenance required is monthly battery top-ups.

A smaller, 1 tonne, unit for transport on a four-wheel drive utility is also available, for use in areas not accessible via a 10 tonne truck.

Prefabricated containerised PV-diesel systems were installed in 2004 in five remote Western Australian indigenous communities in the Fitzroy Crossing area, each with about 15 people (Sage & Saunders, 2004). Each system was identical, comprising:

- 6 m × 2.4 m × 2.4 m container with air conditioner
- 10 kW diesel genset
- 10 kVA single-phase inverter
- 4 kW_p photovoltaic modules mounted above container
- 56 kWh battery.

9.3.2 Integrated solar home systems

Krauter (2004) describes a prototype integrated solar home system for use in rural locations. A photovoltaic module, charge controller, battery, inverter, wiring and support structure are all integrated and assembled by the manufacturer. This makes installation simpler and improves reliability. The inclusion of a water tank provides cooling for the module and, optionally, a source of hot water.

9.3.3 Stationpower®

Queensland-based utility, Ergon Energy, has developed a PV hybrid system, Stationpower®, able to cater for loads from 20 to 150 kWh/day (Watt, 2004*a*). The systems are modular, transportable, and can be supplied self-contained or as additions to existing diesel generating sets. Most systems use photovoltaics, which are supplied in one or more 2.1 kW_p adjustable, steel frame bays. Wind and hydro can also be used and the systems switch automatically between generator types. Australian made SunGel valve-regulated lead acid gel batteries are used. One or more Power Solutions Australia 5 kW, 120 V_{dc} interactive inverters, with built-in battery chargers, are used to allow synchronous operation with the diesel generator, or with other inverters, as well as to provide remote system monitoring. Simple weatherproof plug interconnects allow for easy replacement of components and system upgrade. Stationpower® systems are designed for harsh environments, with rugged construction, and dust-, water- and vermin-proof enclosures. Diesel enclosures provide sound attenuation and battery enclosures are thermally insulated. Installations undertaken to date include a four-bay Stationpower® system with a wind turbine and 25 kW inverter capacity at Inkerman Station, Cape York, a 267,000 ha cattle station with eight full-time staff. Annual diesel fuel and generator cost savings are estimated to have been $25,000 since the system was installed. Stationpower® is used by the Queensland Parks & Wildlife Service to provide reliable, minimum maintenance power for remote and inhospitable areas. Typical systems use three bays with 15 kW inverter capacity and an acoustic canopy for the generator.

9.4 RELIABILITY AND MAINTENANCE

Reliability and maintenance are crucial issues in remote areas owing to the difficulty, delay and expense of technical support. Some of the issues were highlighted in a report on a survey of installed renewable energy RAPS systems in Australia (Lloyd *et al.*, 2000). Concerns expressed by customers included poor reliability, lack of maintenance support and insufficient education and training of users. Approximately one third of the renewable energy systems visited in remote indigenous communities were not operational at the time of the visit. System faults were attributed to batteries (28%), inverters (16%), control systems (15%) and other reasons (22%). Even more serious failure rates have been reported from Brazil (Krauter, 2004).

This highlights the need for development of local training and infrastructure and ongoing information dissemination (Gregory & McNelis, 1994). Excellent guidelines for good maintenance practices are available (Architectural Energy Corporation, 1991; Roberts, 1991).

9.5 GOVERNMENT ASSISTANCE SCHEMES

There are growing commitments by many governments around the world to assist people with the acquisition of RAPS systems.

In Australia, the NSW Government established a Remote Area Power Assistance Scheme in 1988 to help permanent residents of remote areas gain an adequate domestic power supply. By 2004, Federal government schemes available were the Photovoltaic Rebate Program (PVRP) and the Remote Renewable Power Generation Program (RRPGP) (Watt, 2004*b*; Australian Greenhouse Office, 2004*c*). The PVRP is to encourage photovoltaics on buildings and has applied to both grid-connected and stand-alone systems. Approvals for grid systems overtook stand-alone systems in 2002. The RRPGP encourages the displacement of diesel by renewable energy for power generation in off-grid areas. Almost all small systems installed include photovoltaics. RRPGP includes a four-year ‘Bushlight’ sub-program that aims to provide affordable, consistent and reliable renewable energy services for up to 10,000 people in 200 remote indigenous communities in Western Australia, Northern Territory, Queensland and South Australia. There are around 1217 remote indigenous communities in Australia, many not connected to electricity grids and relying on diesel or petrol engines for electricity.

The various State government schemes may also be accessed through the Australian Greenhouse Office (2004*c*) web site and were reviewed in 2003 (Grenfell, 2003). The Northern Territory Power and Water Corporation Diesel Grid PV Program is jointly funded from the RRPGP and the Northern Territory Power and Water Corporation. It aims to reduce diesel use and peak loads on diesel-fuelled electricity grids (Watt, 2004*b*). Installed systems include a 56 kW_p amorphous silicon array at the remote aboriginal community of Bulman, which is expected to save 25,000 litres of diesel fuel annually, and a 225 kW_p crystalline silicon array at the Kings Canyon tourist facility, expected to reduce diesel use by 105,000 litres per year. Funds for Queensland's Working Properties Rebate Scheme are provided by the RRPGP and the Queensland Government. Rebates are paid for renewable energy components of remote area power systems. The Western Australian Sustainable Energy Development Office provides grants for energy use efficiency or the use of renewable energy.

Similar schemes to the above either have or are being introduced in many countries, particularly in the developing world. Extensive rural electrification programs involving PV systems have been established in countries such as Sri Lanka, India, Indonesia, China, Greece, Spain and many African countries (Hayes, 2004; Hirshman, 2004; Eckhart, 2004). In addition, many international aid programs, whether for lighting, communications or medical facilities, have involved some use of stand-alone PV-based power systems (Huacuz & Gunaratne, 2003).

EXERCISES

9.1 (a) Compile a list of suppliers and manufacturers of solar panels in your country. Include details on the range of panels sold, prices, warranties, after sales service, volume of panels sold per year (and anything else of interest).

(b) Which of the suppliers would claim to have the expertise and experience necessary to design and install for you a photovoltaic-based RAPS system for a given power output each day? What guarantee would they give you that the system would meet specifications?

9.2 (a) When would a photovoltaic system be used in preference to a diesel generator?

(b) Explain the concept of a hybrid system and its potential advantages compared to systems based on one source of power only.

9.3 (a) List characteristics of diesel generators relevant to their use in photovoltaic-diesel-battery hybrid systems.

(b) How do these characteristics affect the design and use of such a hybrid system?

(c) When might such a hybrid system be used in preference to a photovoltaic-battery system?

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Chapter 10

GRID-CONNECTED PHOTOVOLTAIC SYSTEMS

10.1 INTRODUCTION

Photovoltaics can be used in grid-connected mode in two ways: as arrays installed at the end use site, such as on rooftops, or as utility-scale generating stations. This chapter deals with the related technical, economic and other issues to be considered, and examines various government and utility programs worldwide. A technical guide for the connection of photovoltaic and other renewable energy generators to local electricity networks in Australia has been produced by the Australian Business Council for Sustainable Energy (2004).

Grid-connected PV overtook stand-alone systems as the largest global market sector in 2000 (Solarbuzz, 2004*a*; IEA-PVPS, 2004*a*), as indicated in Fig. 10.1 for International Energy Agency member countries, although off-grid applications continue to dominate in Australia (Watt, 2004). Globally, there are some extremely large grid-connected systems, including 4 MW_p and 5 MW_p installations near Hemau, Bavaria and near Espenhain, Saxony, respectively. A huge 64 MW_p system is under discussion for Moura, Portugal. Currently, the largest in Australia is at Singleton in NSW. It is a ground-mounted 400 kW_p PV ‘farm’ that produces 550 MWh per year, and was commissioned in 1998 (SEDA, 2004). The largest Australian rooftop array is on the roof of the Queen Victoria Markets in Melbourne. This was commissioned in 2003, uses 1328 PV laminates, each 1.59×0.79 m^2, and incorporates a public viewing board that displays the output (City of Melbourne, 2004). The system is rated at 200 kW_p and is expected to generate 252 MWh/year.

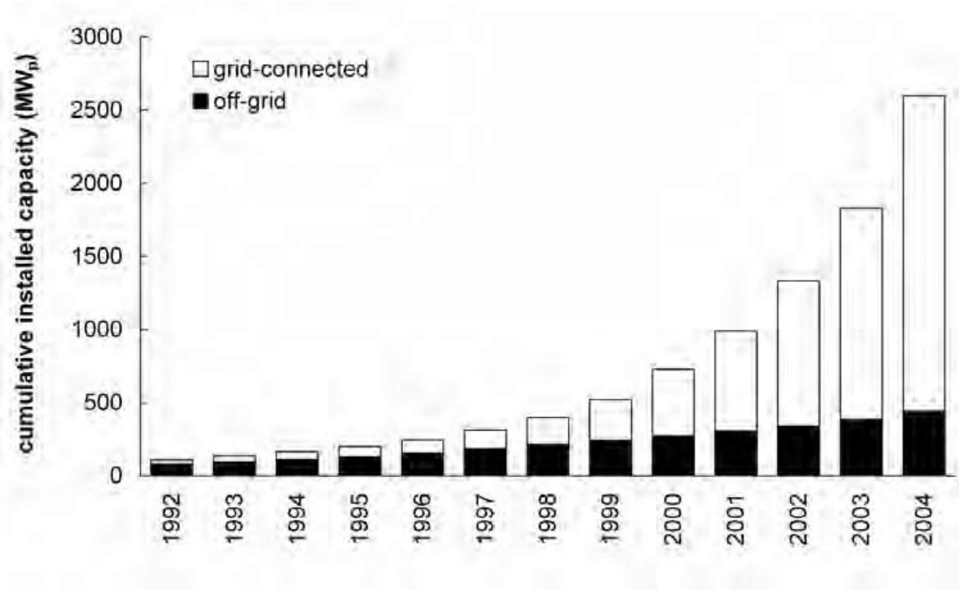


Figure 10.1. Cumulative installed capacity of PV modules in the IEA PVPS reporting countries. (Data from the IEA-PVPS website www.iea-pvps.org, IEA-PVPS, 2004*a*.)

10.2 PV SYSTEMS IN BUILDINGS

PV systems can provide power for a number of functions in a building (Stone & Taylor, 1992):

1. **Architectural**—for both electricity generation and roofing, walls, windows, skylights or shading devices.
2. **Demand-side management**—for offsetting daytime peak loads.
3. **Controls**—for direct driving of fans, pumps, 'smart' windows etc.
4. **Hybrid energy systems**—supplementing other sources for lighting, heat pumps, air conditioners, emergency power supplies etc.

Fig. 10.2 shows an integral photovoltaic system in a grid-connected home.

Development of appropriate products to meet such functions is opening up a large market, since buildings consume a major portion of generated electricity—two thirds in the USA (*Ibid.*).

A wide range of specific building-integrated PV (BIPV) products are now on the market (Hänel, 2000; Posnansky *et al.*, 1998; Reijenga, 2003; von Aichberger, 2003), especially for roofs, façades and as architectural elements in atria etc. The safety arrangements for these systems are discussed in Section 10.5. To date, however, normal modules are most commonly placed on roofs to supplement grid power. For a household system, the essential components are: PV modules, a grid-interactive inverter, so that the electricity is utility-compatible, and metering equipment to feed and measure the power exchange between the house and the grid.

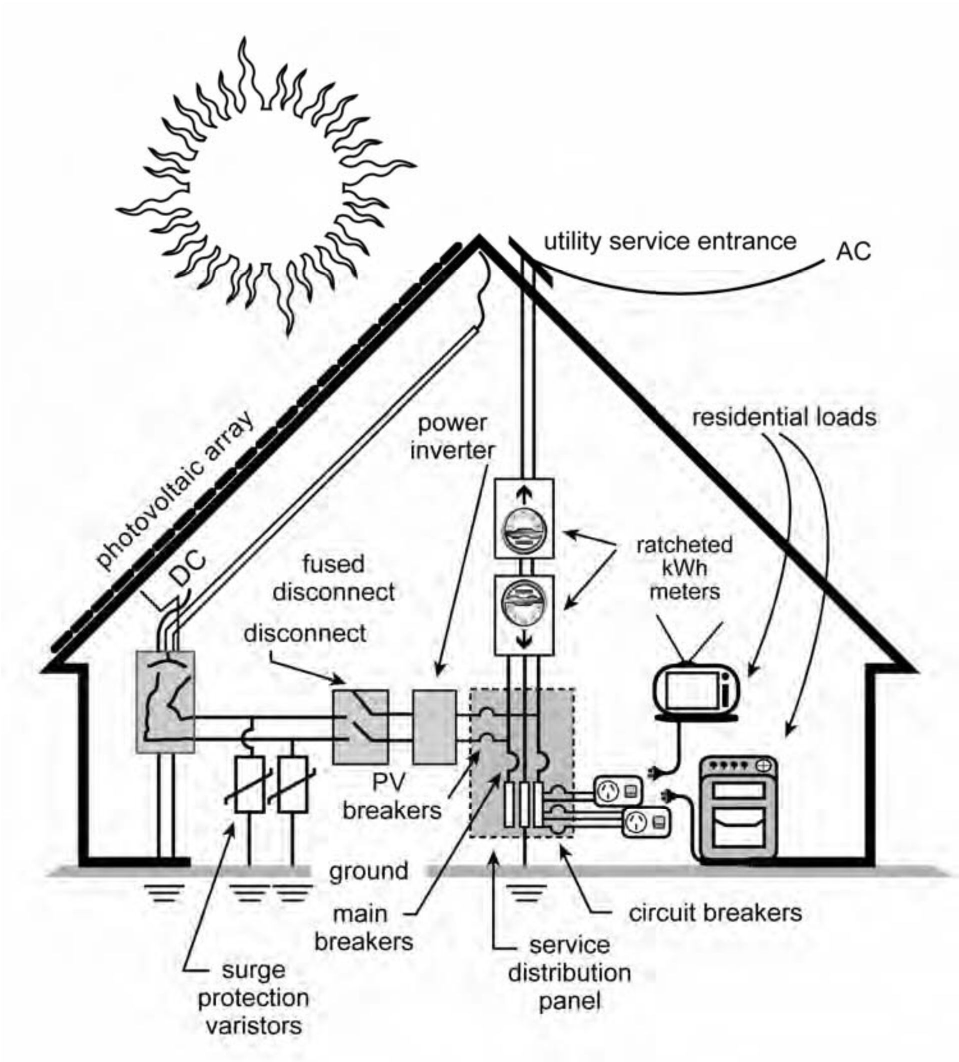


Figure 10.2. A grid-connected home with an integral photovoltaic system (SERI, 1984).

10.2.1 Module mounting approaches

For household systems, modules can be mounted on array frames next to the house, in a position where no shading from buildings or trees would occur. However, in many cases, rooftop mounting offers the best aspect and the safest and most economical option. Various approaches to rooftop mounted PV arrays are illustrated in Fig. 10.3.

Typically, the integral mount shown would be used with new construction, replacing the conventional roofing material. The use of frameless laminates can reduce costs

(Hubbuch, 1992), while solar tiles (von Aichberger, 2003) provide easy installation and a standard roof profile.

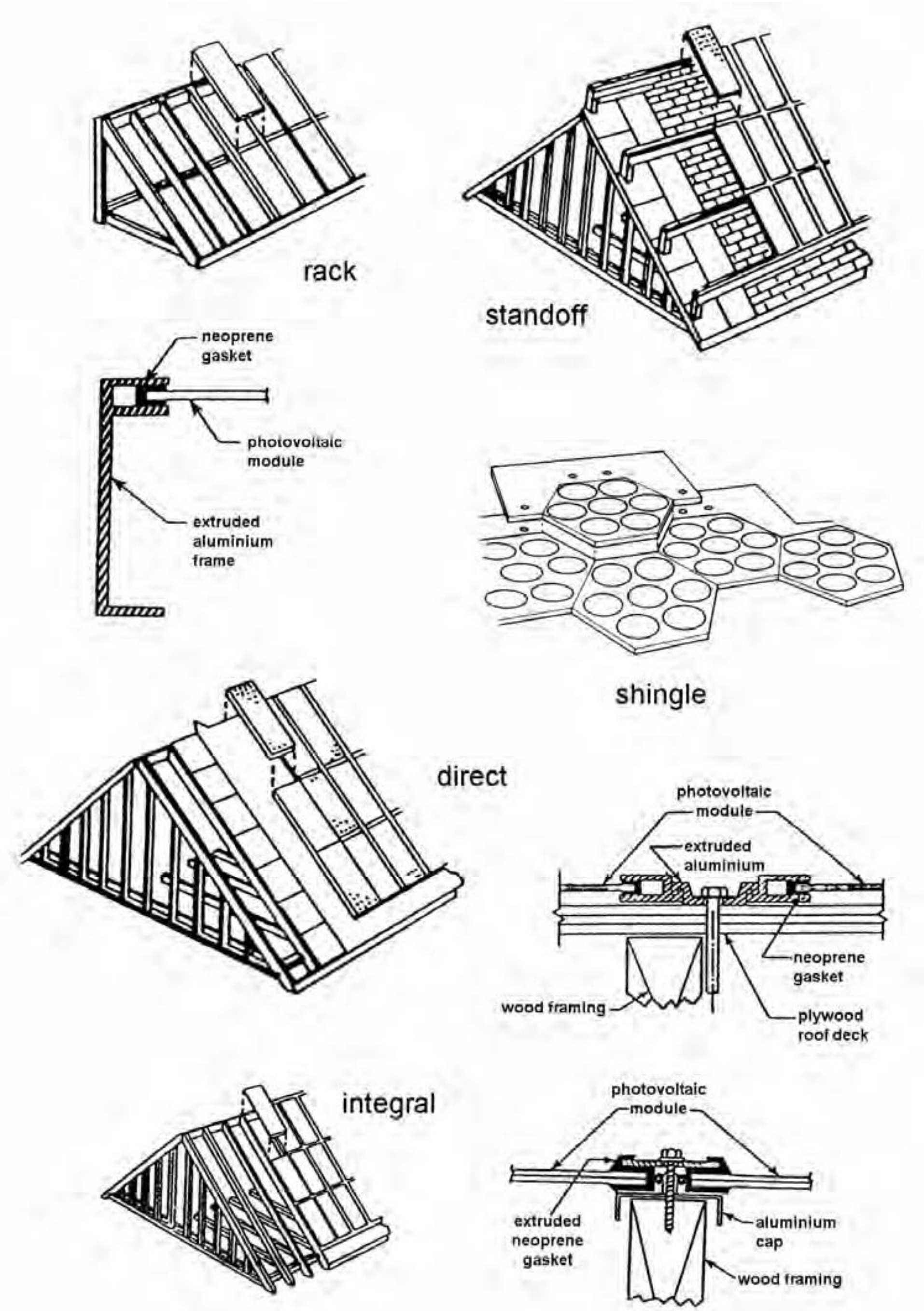


Figure 10.3. Alternative means of mounting photovoltaic arrays on rooftops (SERI, 1984).

The standoff or rack mounts would be used for retrofitting and, although their costs are likely to be higher than for integral systems, allow more air flow around the modules and offer the opportunity for optimal tilting. Direct mounts are secured onto the roofing material but are likely to suffer from overheating owing to limited air flow behind the modules.

10.2.2 The inverter

As for stand-alone PV systems, an inverter, or power conditioning unit, is needed, since photovoltaic arrays generate DC power at low voltage. Two main types of inverters can be used to achieve AC power at the voltage used in the main grid. These are:

1. **Line-commutated**—where the grid signal is used to synchronise the inverter with the grid.
2. **Self-commutated—**where the inverter's intrinsic electronics lock the inverter signal with that of the grid.

An alternative division of the available products is by application:

1. **Central** inverters are designed to convert the output of all the parallel strings of modules in large arrays, with total power in the range 20–400 kW. Self-commutated designs based on insulated gate bipolar transistors (IGBTs) or field effect transistors (FETs) are now dominant.
2. **String** inverters accept power only from a single string, with total power in the range 1–3 kW.
3. **Multi-string** inverters include various independent DC-to-DC converters, which feed their outputs to a common inverter. These allow the acceptance of power from module strings with different configurations or orientations, each able to operate at its own maximum power point.
4. **AC module** inverters sit behind individual modules, resulting in an integrated AC module.

An Australian (Standards Australia, 2002*b*) and various international standards (Appendix E) apply to grid-connected inverters. Issues to be considered when selecting an inverter include (Florida Solar Energy Centre, 1987; Bower, 2000; Abella & Chenlo, 2004; Standards Australia, 2002*b*; Schmid & Schmidt, 2003; Krampitz, 2004):

- **Efficiency**—An improvement of 1% can result in 10% more power output over a year. Some designs pay particular attention to partial-load efficiency. Inverters with line-frequency transformers can achieve a power conversion efficiency of 92%, whereas those with a high-frequency transformer can yield 94%, although in general higher efficiency is possible if the transformer can be avoided. In addition to operating efficiency, standby power losses during periods of negligible load need to be assessed.
- **Safety** (particularly via disconnect modes)—Run-on or 'islanding', for instance, can result in the grid being energised, even when disconnected (see Section 10.5). Isolation transformers are therefore commonly used. Similarly, protection is required against over-currents, surges, under- or over-frequency,

under- or over-voltages for DC input and AC output (Standards Australia, 2002*c*).

- **Power Quality**. The harmonic content must be low, with the Australian standard (Standards Australia, 2002*b*) specifying total harmonic distortion (THD) limits of 5% for current 2% for voltage, to protect both loads and utility equipment. The harmonic spectra are usually monitored up to about 50 harmonics, but inverters using high frequency commutation can produce distortion outside that range. The waveform and power factor must be acceptable to the utility. DC injection, which is inherently prevented by inverters with line-frequency transformers but not by transformerless or high-frequency transformer designs, would saturate the utility transformers and cause outages. Hence, Standards Australia (2005) specifies that for a single-phase inverter, the DC output current of the inverter must not exceed the greater of 0.5% of its rated output current or 5 mA. The waveform must be close to sinusoidal at 50 Hz (or 60 Hz in the USA), the frequency must be within about 0.5 Hz of 50 Hz, while the acceptable power factor range is typically 0.95 leading to 0.95 lagging. In Australia, the power factor must be within the range 0.8 leading to 0.95 lagging.
- **Compatibility with the array**—The array's maximum power voltage at standard operating conditions must be compatible with the inverter nominal DC input voltage. The maximum array open circuit voltage should also be well within the inverter's tolerable voltage range. Maximum power point trackers are commonly included with grid-connected inverters to control the operating voltage of the array (Schmid & Schmidt, 2003). Several different tracking algorithms are in use, including 'constant voltage', 'perturbation and observation', and 'incremental conductance', each with its particular advantages and disadvantages (Kang *et al.*, 2004).
- **Electromagnetic Interference**—This must be low enough to comply with relevant local requirements.
- **Lightning and voltage impulse protection.** These must comply with local rules.
- **Presentation**—Items to check include compliance with relevant electrical codes, size, weight, construction and materials, protection against local weather conditions, terminals, and instrumentation.

Inverter costs vary considerably and have been falling in recent years, but tend towards 20% of the overall cost of systems smaller than 5 kW_p or 10% for larger systems.

10.2.3 On-site storage

On-site storage is not essential for grid-connected systems, since it is possible to sell excess power to the grid during daylight and buy power at night. However, the addition of storage to PV systems can greatly increase their value (Byrne *et al.*, 1993). Storage can be provided on site, typically via batteries or, for larger systems, via pumped hydro, providing storage for peak period use.

In the longer term, such technologies as flywheels, fuel cells, underground caverns, superconducting magnets, compressed air, ice or hydrogen may offer economical storage options. A household size D battery and flywheel storage system are illustrated in Fig. 10.4.

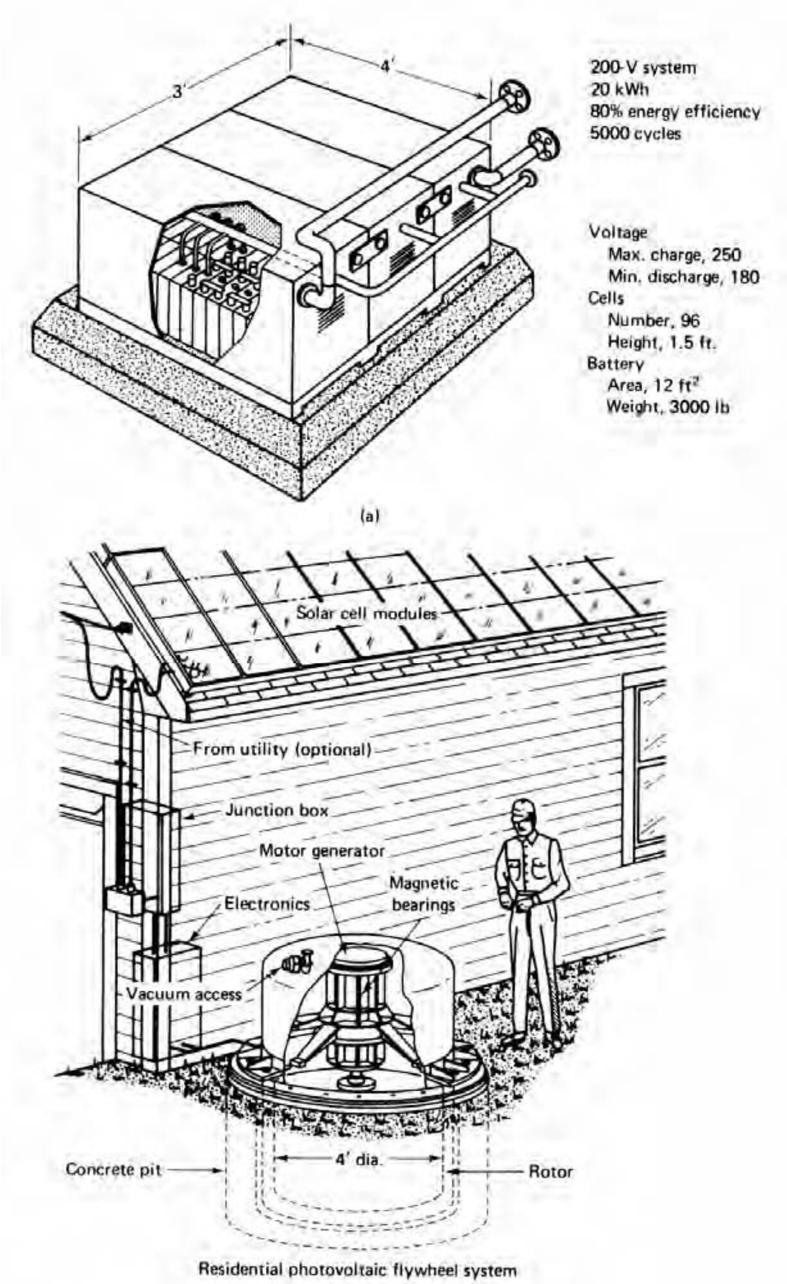


Figure 10.4. Energy storage concepts for residential systems. (*a*) Possible battery configuration (Feduska *et al.*, 1977). (*b*) Flywheel storage (©1980 IEEE Millner & Dinwoodie).

On-site storage can also be used as a demand-side management tool, to reduce peak load power requirements, and hence costs, for the building as well as providing high value peak load power to the grid. An emerging market is the provision of PV-powered uninterruptible power supplies (UPSs) for buildings or equipment, particularly where grid supply is unreliable, but also as an option to diesel systems currently used, particularly in commercial buildings. For these applications, some form of on-site storage is included, but otherwise storage is currently not a typical option for grid systems.

10.2.4 Size and economics

To make much impact on typical household electricity use, a photovoltaic system of about 2 kW_p, or 20 m^2, would be needed (SERI, 1984). A system rated at 3–4 kW_p would supply most household needs. Depending on the house design, a limit of about 7 kW_p, or 70 m^2, is often imposed by the available roof area.

The cost of photovoltaic modules suitable for household use in the USA in 2004 was about US$3.20–5.00/$W_p$ (Solarbuzz, 2004*b*). Total grid-connected PV system costs can be up to double this. For economic viability at current electricity prices, system costs need to be further improved. The cost-effective price for an end user is still higher than for central power supply. In 2004, delivered PV power cost around US$0.30/kWh, which was 2–5 times average residential electricity tariffs (Solarbuzz, 2004*c*). Note that prices vary from country to country. Average Australian module prices in 2004 were about A$7/$W_p$ and typical turnkey grid-connected system prices ranged from A$12/$W_p$ for small systems down to A$6/$W_p$ for large systems (Watt, 2004).

Technology experience curves are used to monitors falling prices as industry experience and cumulative production grows (Poponi, 2003). These curves may be used to predict 'break even' years, although the results are sensitive to the assumptions adopted.

Based on PV learning curves over the past three decades, and expected growth, PV-based electricity prices are expected to be close to grid electricity prices in Australia from about 2015 (Australian Business Council for Sustainable Energy, 2004*a*). In countries like Japan, where electricity prices are higher, breakeven prices may be reached sooner, although lower annual output compared with Australia will impact on the timing.

To keep costs down, more emphasis needs to be placed on simplification of design, provision for maintenance, standardisation, and in-built protection and control systems. 'Net' metering, with a single, bidirectional meter, also minimises system and billing costs (Poponi, 2003). Net metering is mandated in many US States and is common in Europe. It is available from many Australian electricity retailers, but the use of separate meters is likely to remain common until electronic metering becomes more widely available. Net metering is not suitable for feed-in tariff or other differential tariff regimes.

10.2.5 Other issues

Other issues that need to be addressed for household photovoltaic systems include (SERI, 1984):

- **aesthetics**—colour, size, shape, tilt, pattern, transparency
- **solar access**—current and future shading, partial, complete or time of day, from trees or buildings
- **building codes**—roof structure, strength of mounting, zoning for generation, light reflection
- **insurance issues**—fire resistance, roof loading, safety, damage to grid or other utility users
- **maintenance**—routine and emergency, component replacement
- **impact on utility**—overloading distribution transformers, power factor, harmonics, isolation of PV (DC) current, disconnection mechanisms, grounding, metering
- **contract with utility**—buyback rates, equipment approvals, billing arrangements.

10.3 UTILITY APPLICATIONS FOR PHOTOVOLTAICS

The potential for utility use of PV is wider than merely central generation. Utility familiarity with PV usage could be gained via some of the following, smaller scale applications (Sandia National Laboratories, 1990; Bigger *et al.*, 1991):

- **Distribution feeder voltage and energy support**—for relieving thermal overload on transformers and conductors by reducing localised peak daytime current flows. The use of PV could delay or eliminate more expensive line reconditioning, substation transformer replacement or new circuit construction to serve overloaded areas. At critical transmission and distribution points it could also reduce electrical losses, provide kVAR support, increase reliability of supply and increase the effective capacity value of the PV system. The use of PV in such situations can double the value of the PV system, compared to the value attributed to energy and capacity savings alone.
- **Transmission tower beacons**—for powering these beacons, which are required on all towers more than 60 m high and close to airports.
- **Transmission sectionalising switches**—for isolating portions of distribution or transmission lines for maintenance or power flow optimisation. In the USA, for example, such remotely-operated switches are used about every 30 km and many could be converted to PV.
- **Street and security lighting**—for meeting municipality and government agency requirements.
- **Rest area fans and lights**—for parks, roadside convenience facilities and boat launching sites in remote or environmentally-sensitive areas.
- **Remote water pumping**—for new systems as well as to replace wind-powered systems or power line replacements.
- **Power supply to remote residences**—for customers who would not otherwise receive utility supply, particularly small users, such as individual houses or vacation homes.
- **Grid security**—to provide reliable PV-battery power supply or backup for critical supervisory control and data (SCADA) in electricity, gas and oil supply systems (Varadi & Braun, 2003). It can sometimes be more cost-

effective to install PV systems even very close to high voltage power lines than to install transformers to step down the voltage (Sandia National Laboratory, 1990). Strategically located grid-connected PV in the north-east USA and south-east Canada could have prevented the cascading blackouts in that area on 14 August 2003 (Perez & Collins, 2004). This report shows how dispersed PV could have reduced the huge regional power transfers that were needed to service air conditioning in load centres such as Detroit, Cleveland, Toronto and New York City.

- **Grid backup**—PV-battery grid backup for important equipment in case of poor grid reliability, particularly in developing countries, but also for computer systems and emergency power generally in commercial buildings (Varadi & Braun, 2003).
- **Telemetry and metrology**—for powering sensors where grid power is too expensive or too insecure (Varadi & Braun, 2003).

PV systems for distributor feeder support are discussed later in this Chapter, while many of the stand-alone systems were discussed in previous Chapters.

As environmental factors are increasingly included in the economic analyses undertaken by utility planners, an increasing adoption of PV technologies is likely. For instance, a recent study of air emissions from various generating technologies (Rannels, 1992) concludes that photovoltaics can cost-effectively displace existing fossil fuel generating plant, if offsets for emission reductions are given.

Despite the apparent opportunities and benefits of PV use, most electricity utilities are faced with a number of perceived risks, which they have no historical basis for quantifying, when assessing the feasibility of photovoltaic systems. These include (*Ibid.*):

- **technical risks**—the possibility the system will not perform as specified
- **construction risks**—the possibility of cost overruns, or inability to meet the construction schedule
- **operating risks**—the possibility of breakdown or unavailability of power when needed
- **regulatory and tax risks**—the possibility of changes that may disallow tax credits, accelerated depreciation rates etc.
- **financial limitations**—high costs of finance, based on the above perceived risks.

Until a number of demonstration systems have been operated under utility conditions in each jurisdiction, overcoming these perceived risks to the satisfaction of most utility planners will be difficult. Nevertheless, the continuous increase in PV system databases is assisting utility acceptance.

10.4 DESIGN ISSUES FOR CENTRAL POWER STATIONS

Despite the relative ease of installation and cost effectiveness of the small, distributed PV systems discussed above, much utility interest in PV to date has centred around the development and testing of central, grid-connected PV stations, since most utilities are more familiar with larger scale, centralised power supplies. These larger systems would typically have their own transformer or substation. The technical and economic issues involved in large, central-generating PV plant are discussed below:

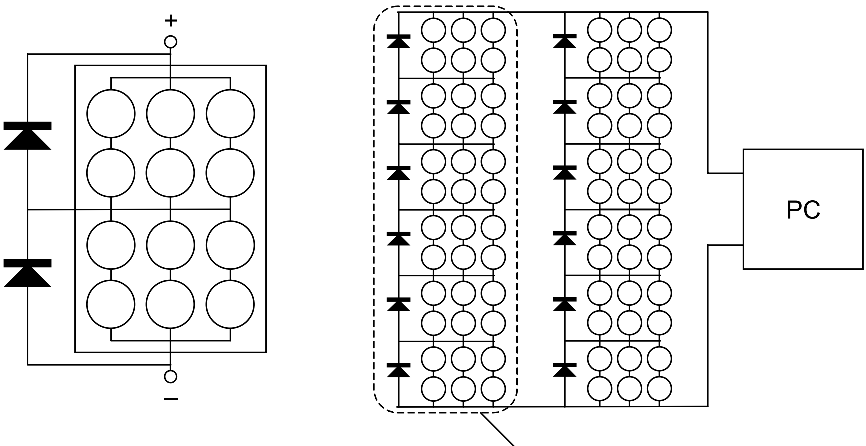
10.4.1 Cell interconnection

In determining the best way of connecting cells in large systems, the potential losses must be examined. For instance, many parallel cells improve tolerance to open circuits but not to short circuits. Table 10.1 shows losses in total power with 0.05% each of open-circuited and short-circuited cells, while Figs. 10.5 and 10.6 illustrate, respectively, the connection of cells and modules with bypass diodes into power conditioning equipment; and connection approaches and advantages of paralleling, branch circuits and blocking diodes.

Table 10.1. Losses in total power with open-circuited and-short circuited cells (Ross, 1984).

cells per substring	series blocks	cells in parallel 1	4	8	16	notes
		0.001	0.001	0.001	0.001	1
20	50	0.011	0.050	0.025	0.015	2
		0.012	0.051	0.026	0.016	3
		0.001	0.001	0.002	0.002	4
10	100	0.005	0.022	0.013	0.008	4
		0.006	0.023	0.015	0.010	4
		0.001	0.002	0.002	0.002	
5	200	0.003	0.010	0.007	0.004	
		0.004	0.012	0.009	0.006	
		0.001	0.002	0.004	0.006	5
2	500	0.001	0.004	0.003	0.002	5
		0.002	0.006	0.007	0.008	5

Notes: (1) short circuit losses; (2) open circuit losses; (3) total losses; (4) optimum design region; (5) sensitive to shorted cells.



module
3 parallel strings
2 series blocks
2 cells per substring
2 diodes per module

source circuit
3 parallel strings
6 series blocks
2 cells per substring
1 diode per series block

Figure 10.5. Module circuit design (©1980 IEEE Gonzalez & Weaver).

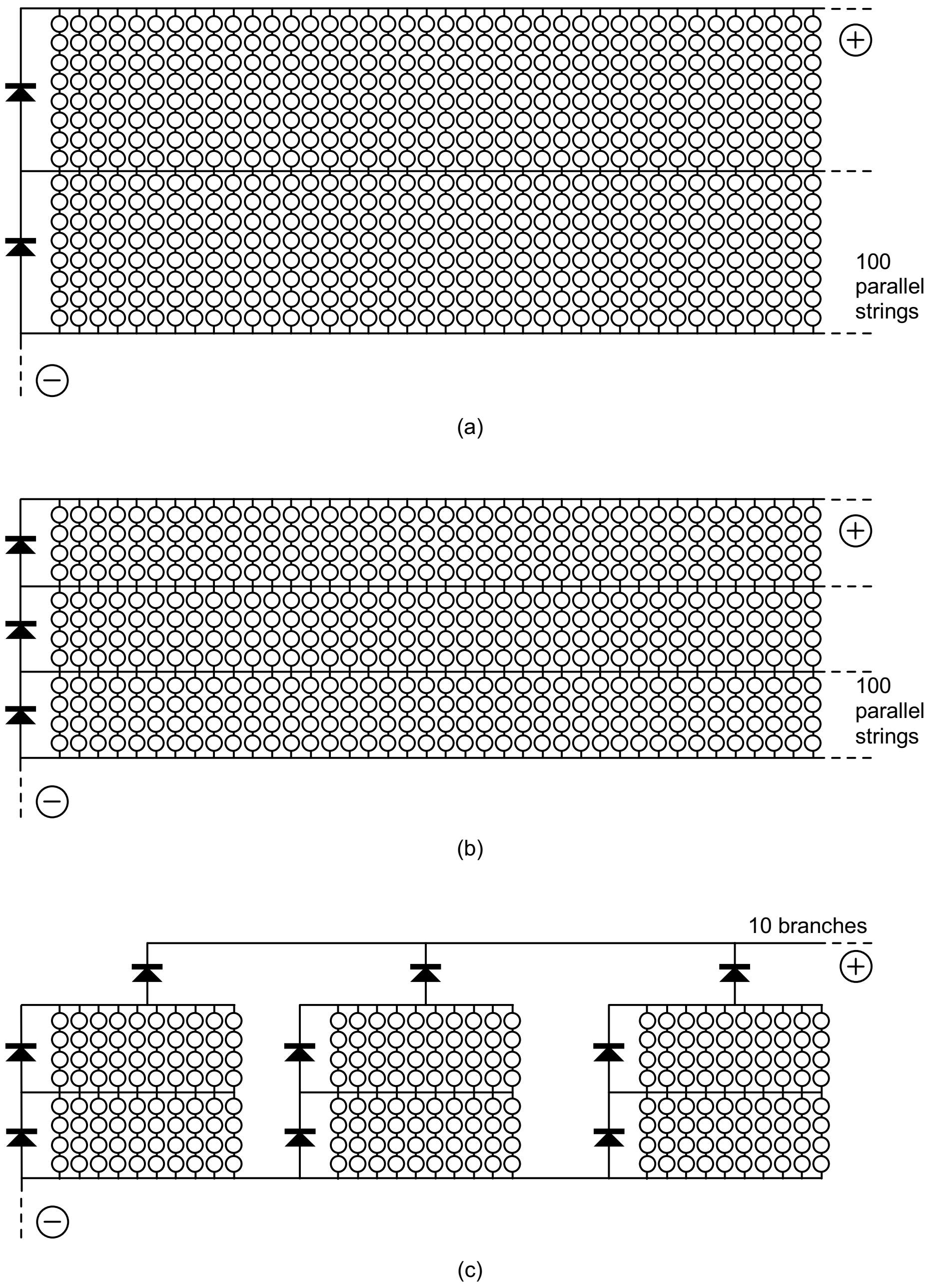


Figure 10.6. Possible arrangements of modules in a large solar array, with placement of diodes to avoid large-scale failure or failure of a single cell (SERI, 1984). (*a*) Open-circuited cells can reduce output current of an array. (*b*) Increasing the degree of paralleling and the number of bypass modes helps reduce the effects of open circuit defects. (c) An array with blocking diodes for every branch circuit prevents a defective branch from loading the other branches.

Optimum system tolerance is achieved with single-string source circuits and large numbers of bypass diodes. Field studies indicate that the best approach in large systems is not to replace modules containing failed cells, but to design the system to be tolerant to such failures.

10.5 SAFETY

Many safety issues are common for building-integrated, building-mounted or central station grid-connected PV systems.

Safety aspects that need to be considered (Florida Solar Energy Centre, 1987; Abella & Chenlo, 2004) include fire resistance, correct wiring, placement, grounding, and security against local weather conditions, particularly wind. Modules can be graded according to their effective resistance against severe, moderate or light fires (Florida Solar Energy Centre, 1987).

Simple disconnection of large (high voltage) arrays from loads or inverters does not make them safe since they are live whenever illuminated. Protection of the DC side is controversial and regulations vary between countries. Floating (unearthed) arrays and inverters are commonly used in Europe but earthing is mandatory in the USA. Commercial systems are only now available to meet the various specifications that differ from place to place. Some of these are listed in Appendix E.

The Australian Standard (Standards Australia, 2005, 2002*a*, 2002*b*) defines the safety requirements in Australia. The inverter system must be able to be isolated from live conductors by a labelled and lockable switch, which is lockable in the off position to interrupt all live conductors. The inverter must be connected on the utility side of any residual current devices (RCDs) rather than the provision of an RCD on the output of the inverter. An isolation device is necessary on each inverter input from the array and various labelling requirements are specified (Standards Australia, 2005).

Protective features are described in an Australian Standard (Standards Australia, 2005):

1. **Blocking diodes and over-current devices**—As with any generating system, protection against large current flows must be in-built. Blocking diodes and over-current devices (e.g. circuit breakers or fuses) are used for protection in photovoltaic arrays. Blocking diodes protect against large current flows into shorts to ground, while over-current devices provide fuse protection in the event of failure of the blocking diode. Blocking diodes are not substitutes for over-current devices and are optional (*Ibid.*). Refer to Standards Australia (2005) or local standards for detailed recommendations and/or requirements for various array arrangements. The discussion in Chapter 6 and by Standards Australia (2005) also applies for grid-connected systems.

2. **Array arcing**—An open circuit in a high voltage branch of a solar array can produce voltages higher than the 70 V required to maintain an arc, as illustrated in Fig. 10.7. These can burn for hours, but can be prevented by introducing redundant connections, to prevent open circuiting and parallel cell connections.

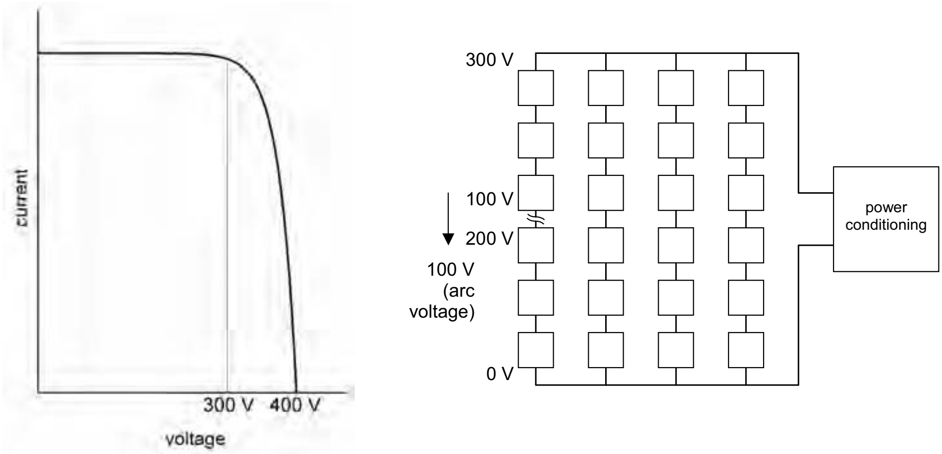


Figure 10.7. Open circuits in high voltage PV arrays can lead to arcing (©1981 IEEE Ross).

3. **Earthing (grounding)**—A number of sites in a photovoltaic system require grounding to prevent possible electrocution:
   - **Frame grounding**—prevents frames reaching unsafe voltages in case of a ground fault.
   - **Circuit grounding**—prevents the cell circuit from floating above ground and overstressing primary insulation. One terminal or centre voltage point is tied to ground.

   Reference should be made to Standards Australia (2005) or local standards for detailed advice.

10.5.1 Islanding

Grid-connected photovoltaic systems can continue to operate when the grid shuts down, a phenomenon called ‘islanding’, if the injected real and reactive powers are equal between production and consumption in the separated section of the grid (Schmid & Schmidt, 2003). While this may appear to be an advantage in areas where grid reliability is poor, it poses a serious problem for grid maintenance crews, who may not be aware that lines are still energised. If the grid is reconnected during islanding, transient over-currents can flow through the circuit breaker and the photovoltaic system inverters (Kitamura *et al.*, 1993).

There are two basic approaches to the control of islanding (Matsuda *et al.*, 1993)—via the inverter or via the distribution network. Inverter techniques involve detection of either grid voltage and frequency variations or increases in harmonics, or monitoring of grid impedance. The German safety code for single-phase grid-connected systems smaller than 5 kW recommends two independent switching systems, one including a mechanical switch, such as a relay, reliant on monitoring grid impedance and frequency. In Australia, permitted methods for grid connection are specified by a Standard (Standards Australia, 2002*b*).

Recent studies (Abella & Chenlo, 2004) have concluded that islanding is virtually impossible where there is low PV penetration in the grid. Although high penetration levels are rare now, they may become more common in future, and active protection methods may be necessary, since passive methods are not effective under perfectly balanced load conditions. Problems could also potentially arise if large numbers of inverters on a section of grid interfere with each other's sensing of grid conditions.

Standards Australia (2002*b*) specifies anti-islanding requirements in Australia and it should be consulted for all installations. A grid disconnection device incorporating an electromechanical switch is to be provided unless there is galvanic insulation (e.g. a transformer) and the inverter is unable to continue supplying power in the absence of an otherwise energised grid. Semiconductor switches are acceptable in cases of galvanic isolation. Both passive and active anti-islanding protection are required to prevent the situation where islanding may occur by multiple inverters providing a frequency and voltage reference for one another. Permitted methods of active protection include frequency shift, frequency instability, power variation and current injection. Passive protection devices sense both frequency and voltage. Disconnection must occur within two seconds of the specified islanding conditions beginning.

10.6 THE VALUE OF PV-GENERATED ELECTRICITY

The 'value' of PV generated power can be viewed from several perspectives including:

- **global**—taking into account such issues as the use of capital, environmental impact, including climate change, access to power
- **societal**—local impacts, manufacturing, employment, cost of power, security of energy supplies, balance of trade, infrastructure
- **individual**—initial cost, increased house value, reduction in utility bills, energy independence
- **utility**—PV output in relation to demand profiles, impact on capital works, 'green power' or mandatory renewable energy requirements, maintenance etc.

The following discussion is taken from a utility perspective.

10.6.1 Energy credit

The value to the grid of PV-generated electricity depends largely on the time of day when the grid experiences peak demand. Electricity supplied during this peak can be worth 3–4 times that generated 'off-peak'. Hence, PV is well suited to 'summer peaking' grids. The trend in Australia is towards summer rather than winter peaks, which is also happening in some US states and elsewhere. The value of PV during summer peaks was recognised in the 2004 Australian Energy White Paper and underlies the 'Solar Cities' funding program (Commonwealth of Australia, 2004). Partly due to increased popularity of air conditioning, summer peak loads have grown rapidly and the efficiency of use of the grid infrastructure has consequently fallen. In one area in Adelaide, the upper 50% of the distribution feeder capacity was used for only 5% of the time (Watt *et al.*, 2003). PV systems being assessed for use as peaking stations would be competing with such options as load management, combustion turbines, cycled coal plants, pumped hydro and perhaps, in future, compressed air or ice storage, all with target costs equivalent to retail electricity tariffs (Iannucci & Shugar, 1991).

Analysis of an American project that was designed and built to measure the benefits of grid-support PV (see Section 10.6, below) attributed a value of US$28/kW/year for offsetting the marginal cost of keeping peak-following generation capacity online (Wenger *et al.*, 1994). On the peak load day in financial year 1993–94, the nominally 500 kW_p, single-axis-tracking PV plant reduced the 4pm peak load by 430 kW and, additionally, reduced the heat load on the distribution transformer in the period before the peak, reducing its temperature and enhancing its peak capacity.

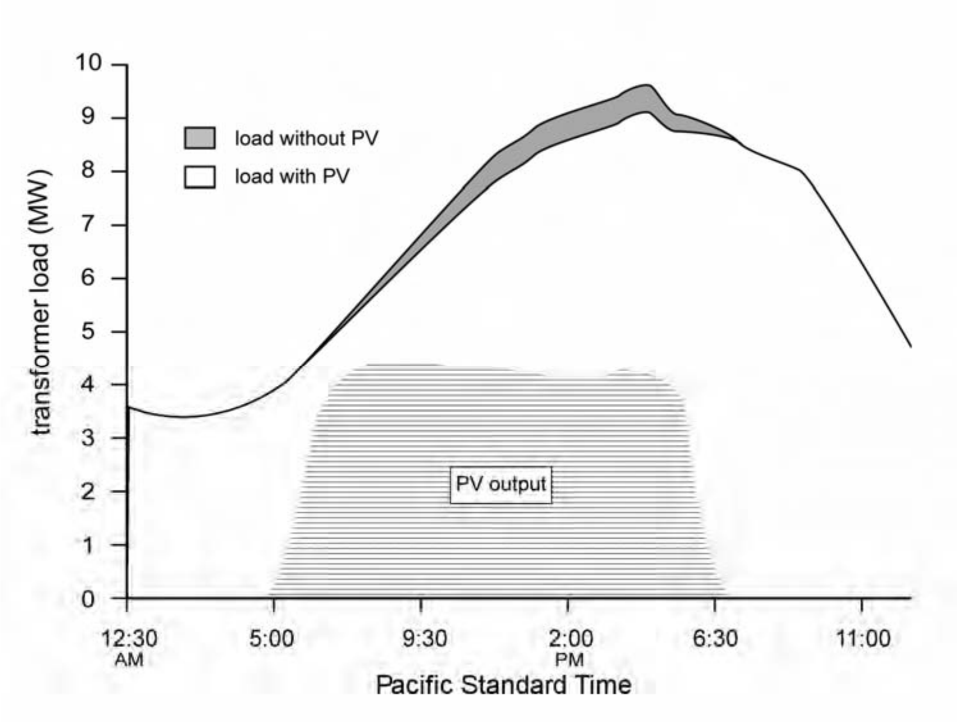


Figure 10.8. Distribution transformer load and PV output of a grid-support system on the peak load day during the monitored year. (©1994 IEEE, Adapted from Wenger e*t al.*)

Although there is a good match between days of peak load and of peak PV output for fixed arrays where air conditioning controls the peaks, the time of day is not always well matched for feeders supplying mainly residential loads, since residential peak loads tend to lag behind peak insolation. Watt *et al.* (2003) have proposed the use of west-facing PV to shift their peak output time to better match the peak summer load. Of course, this reduces the annual energy output of the array but optimises the value of its contribution to the grid. Financial arrangements would need to reflect that increased value in order to make such solutions attractive for householders.

Interestingly, users with PV systems may change their usage habits, perhaps adding greater value to the PV system via energy management strategies (Haas, 1993).

10.6.2 Capacity credit

The assigned capacity credit is based on the statistical probability with which the grid can meet demand.

There is a certain probability that the PV plant will not be available during periods of peak demand (due mainly to lack of sunshine), just as there is for conventional electricity generating plant (because of forced outages or outages for maintenance). In the Carissa Plains example cited later, the capacity factor during peaks is very similar to that of conventional equipment, so similar capacity credit could be given.

In NSW at present, a PV plant would generate little electricity during winter evening peaks, so little capacity credit could be given over winter, unless dedicated storage were included. However, even though a grid overall may be 'winter peaking', subsections may be 'summer peaking', increasing the value of a PV plant, if suitably located. In addition, the electricity loads in most Australian States are graduating towards being 'summer peaking', while commercial demand, which is increasing rapidly, tends to peak over the middle of the day and is well matched to PV output.

10.6.3 Distributed benefits

Owing to the modularity of PV systems, they need not be centralised within the grid but can be distributed throughout it, as is the case for most of the small systems discussed earlier, which are installed on buildings. Apart from energy and capacity benefits, this can also give substantial 'distributed benefits', such as delaying the need for transformer, conductor or circuit upgrading, reducing transmission, distribution and transformer losses, increasing reliability and providing kVAR support in some specialised cases (Rannels, 1991; Wenger *et al.*, 1994). Such distributed benefits can double the value of the PV generated energy, compared to assessments based only on energy and capacity credits (Bigger *et al.*, 1991; Wenger *et al.*, 1994). A study in Arizona (Solar Flare, 1993) calculated total benefits of US$700/kW/year for a PV system at a suitable site. Depending on the value attributed to externalities, the break-even cost for the installed PV systems discussed in the above reference varied from US$2.36/$W_p$, with no distributed benefits, to US$3.96/$W_p$ using the externality values set for the state of Nevada. Analysis of a Californian case (Wenger *et al.*, 1994) estimated a total value of US$293–424/kW/year.

A situation where PV could contribute distributed benefits is that of imminent thermal overload. A distribution transformer or line to a particular region of the grid may be approaching thermal overload as the demand at the end of the line grows, say on summer days. Normally, an extra line would be added or the infrastructure upgraded, at considerable capital expense. Alternatively, photovoltaics could be added to the distribution line, as illustrated in Fig. 10.9.

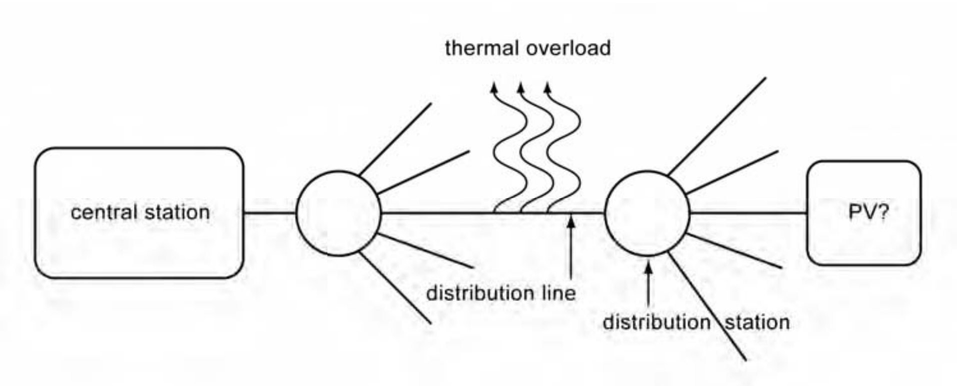


Figure 10.9. Possible placement of a PV station in a grid prone to thermal overload.

By generating electricity locally, the amount of power to be transmitted along the distribution line is reduced, delaying the need for upgrading. In addition, just by reducing the current through a transformer prior to its peak load, its lower temperature allows it to carry a higher peak without overheating (Wenger *et al.*, 1994).

PV can also be used for demand side management, to the benefit of both the utility and customer. For instance, PV systems on the rooftops of large electricity users can reduce peak load energy and demand. With lighting accounting for up to 40% of the electricity requirement of commercial and light industrial buildings, PV assisted lighting systems could be a simple and feasible means of reducing summer peak loads (Berg & Wieghagen, 1991).

The distributed utility concept is becoming more attractive as planning becomes less dominated by the concept of economies of scale (Iannucci & Shugar, 1991). In modern utilities, cost minimisation relies also on such aspects as generator placement, line losses, transmission upgrade costs and reliability. Central power stations can therefore be integrated with modular, strategically placed, distributed generation to increase the system's sustainability, efficiency, strategic power delivery and customer service. The central stations would then be used to supply the base load, for which they are best suited, while customers would be provided with a more reliable and higher quality power supply, tailored to meet local demand. More flexibility in customer supply could also be incorporated, with such options as DC supply, load management and storage (*Ibid.*). Suitable metering systems and tariff structures are needed to facilitate such options.

New utility planning tools are required to assess these concepts, as well as to incorporate consideration of such issues as:

- environmental, social or other externality values of renewable energy sources
- benefits of fuel diversity
- security value attributed to the risk of investment in plant requiring indigenous vs non-indigenous fuels
- reduced risk inherent in incremental, rather than large step changes in supply infrastructure

- increasing costs of transmission and distribution (owing, for instance, to equipment and labour price escalations, new requirements for underground construction etc.)
- increasing difficulty in acquiring rights-of-way for transmission lines and sites for substations, owing to environmental, electromagnetic field or other concerns
- possibility of changes to regulations, subsidies, taxation regimes etc., which currently favour fossil fuel intensive energy systems.

10.6.4 Example 1—Distribution Feeder 1103, Kerman, California

Pacific Gas & Electric (PG&E), a major Californian utility, has investigated the relevance of distributed photovoltaic systems in their network. A small sub-section, the 'Kerman Feeder 1103' has been analysed in some detail (Shugar, 1990) to evaluate the electrical impact and economics of connecting in a 500 kW_p photovoltaic array. The 500 kW_p Kerman substation began commercial operation in June 1993 (Wenger *et al.*, 1994), after construction at a cost of \$US12.34/W_p (modules US\$9/W_p and BOS US\$3.34/W_p) (Solar Flare, 1993). Of this cost, US\$1.14/W_p was attributed to the experimental nature of the system.

Fig. 10.8 showed the feeder load and the Kerman single-axis tracking PV array output throughout the day of peak load in 1993–94 (Wenger, 1994). The peak is significantly reduced and transformer temperature reduced by 4°C at the peak time by reduced heating earlier in the day.

Fig. 10.10 shows the monthly PV energy output and its *performance index* (actual energy production divided by expected energy production) for the Kerman PV grid support system. The poor performance index in some months is attributed to inverter failures (Wenger, 1994).

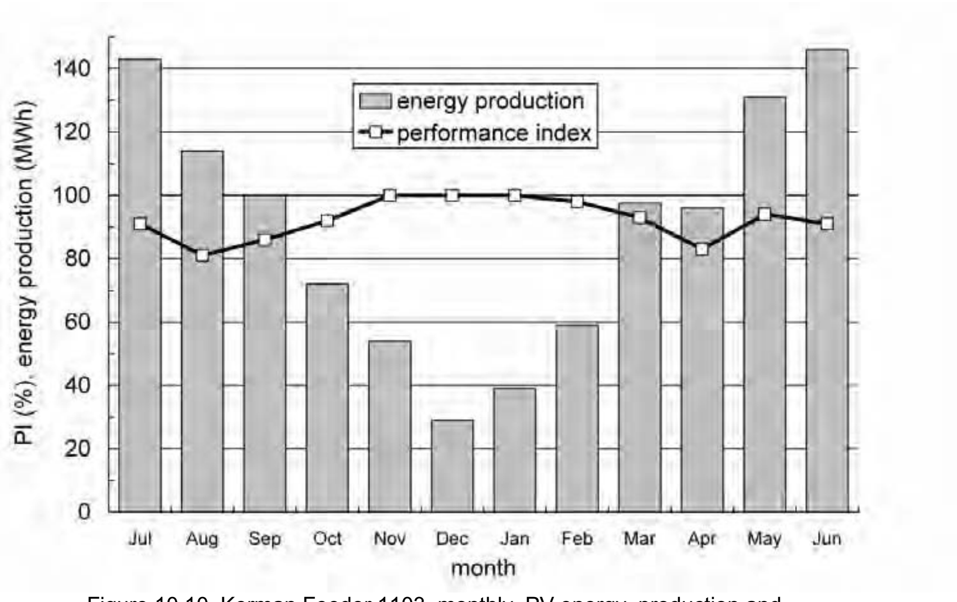


Figure 10.10. Kerman Feeder 1103, monthly PV energy production and performance index (©1994 IEEE, adapted from Wenger *et al.*).

The economic benefits of the photovoltaic array, in 1995 US$/kW/year, were then estimated and the results are graphed in Fig. 10.11.

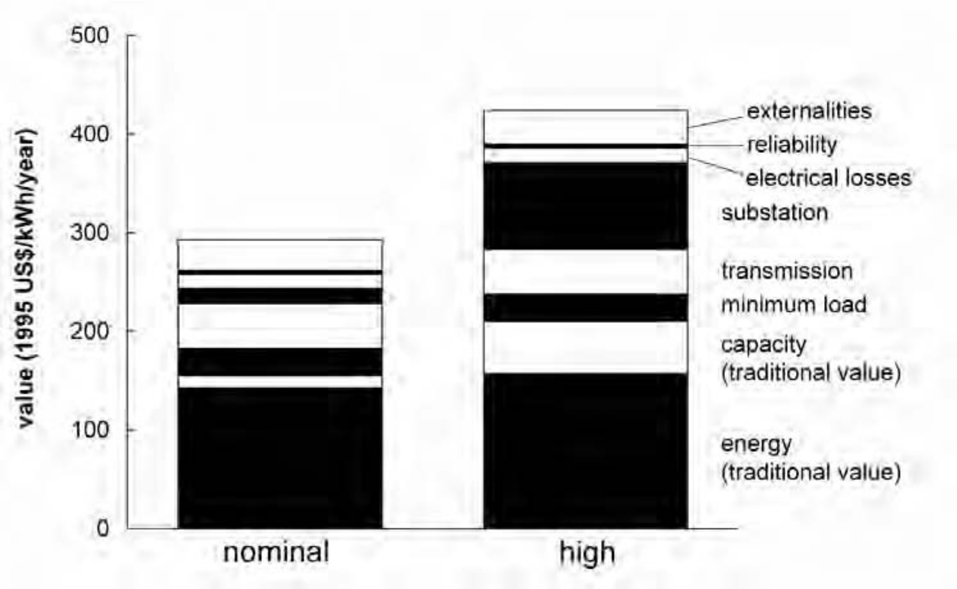


Figure 10.11. Value of Kerman PV plant to utility company in 1995 US$/kW/year (©1994 IEEE, adapted from Wenger *et al.*).

In summary, the benefits identified were (Wenger, 1994):

1. **Energy benefits** based on avoided fuel costs, valued at US$143–157/kW/year.
2. **Capacity credit** based on the avoided cost of provision of extra capacity to improve reliability and valued at US$12–53/kW/year.
3. **Reduced ohmic and reactive power losses** reduced by 58,500 kWh/year and 350 kVAR, since less power had to be transmitted, resulting in savings of US$14–15/kW/year.
4. **Substation savings** reflect the savings from the extension of the life of the 10.5 MVA distribution transformer by reducing its peak temperatures ($89/kW/year) and reduced maintenance on the load-tap-changer (fewer tap changes). Together, these contributed US$16–88/kW/year.
5. **Transmission benefits** are similar in concept to the capacity credit value but reflect the cost of avoided investment in the distribution system and its maintenance. They were valued at US$45/kW/year.
6. **Reliability benefits** reflect the economic savings to customers that would result from more rapid load recovery after a circuit outage with the PV plant present. A value of about US$4/kW/year was estimated as a saving to the utility but further benefits accrue to customers. Improved reliability is of economic benefit to utilities since it reduces pressures to upgrade. Voltage support of about 3 V was found to be predictable.

7. **Environmental benefits** of 155 tons of CO_2 and 0.5 tons of NO_x avoided per year were evaluated at US$31–34/kW/year.

8. **Minimum load savings** from avoiding the marginal costs of keeping peak load-following plant online.

10.6.5 Example 2—Kalbarri, Western Australia

Kalbarri is a town 500 km north of Perth at the end of a 136 km distribution line at the northern extreme of the main power grid in Western Australia. This project aimed to demonstrate and investigate PV grid support, test inverter technology, and provide experience with PV trackers and inverters (Jennings & Milne, 1997; CADDET Australian National Team, 1998). 20 kW_p of PV modules are mounted on 16 single-axis trackers, each with 16 modules. A 35 kVA three-phase current-controlled power inverter and a 100 kVA transformer connect them to the grid, which was subject to voltage fluctuations.

The Kalbarri peak load was dominated by air conditioning and occurred in summer, typically in afternoons or early evenings, while the PV tended to peak around 2.30 pm. The PV system was not expected to have a significant effect on the 3 MW peak load and was too small to have an impact on the town's voltage stability, but it does provide real-world data on PV potential.

10.7 INTERNATIONAL PV PROGRAMS

Electricity costs are almost universally subsidised to various extents, including by direct financial subsidies for social or other reasons and by externalisation of the costs of environmental damage (Kjaer, 2004; Riedy & Diesendorf, 2000; European Environment Agency, 2004; Schmela, 2003; Pershing & MacKenzie, 2004). One estimate of global annual energy subsidies over the period 1995–1998 was US$244 billion, of which just 3.7% was attributed to renewables and end-use efficiency (Pershing & MacKenzie, 2004). This 'market failure' makes difficult the entry of new, small players. It is not socially or politically feasible to suddenly remove such subsidies to conventional energy sources, so a commonly applied 'second-best' alternative is to offer support to new market entrants with perceived advantages to the community. Kjaer (2004) describes how either prices or quantities of renewable energy may be controlled, and compares the methods in the European context. An overview and detailed discussion of national policy instruments is provided by Sawin (2004), while strategies used to support PV are discussed in Haas (2002).

10.7.1 USA

During the 1970s and 1980s, the US Department of Energy implemented a pioneering residential PV research, development and demonstration program to monitor household loads, evaluate and provide technical information on residential PV systems in different regions, build and monitor isolated PV powered homes, clusters of homes (e.g. 30 homes) and commercial buildings, and to assess impacts on the power distribution network (see Fig. 10.12).

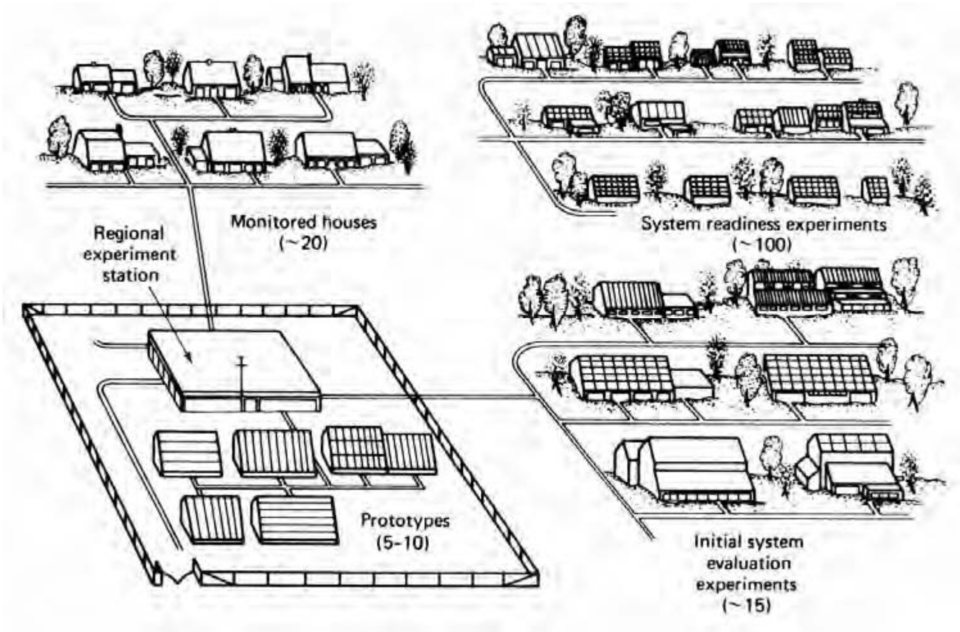


Figure 10.12. Schematic of the DOE residential program—prototype through commercial systems (Pope, 1979).

This program was superseded by the 'Solar 2000' program, which sought to develop economically-competitive PV systems and hence increase installed capacity in the USA from less than 50 MW in 1991 to 200–1000 MW by 1995–2000 and 10,000–50,000 MW by 2010–2030 (Rannels, 1992). It actually fell far short of its target since by end of 2001 only 167.8 MW had been installed in the country (IEA-PVPS, 2004*b*).

Nevertheless, other US PV programs were successful. These included the Utility PV Group (UPVG), which aimed to educate utility end users as to the value of PV in their systems and to lower costs by aggregating utility purchases (Stone, 1993). It had plans for 50 MW_p of cost-effective and emerging PV technology in US utility grids in the five years from 1993.

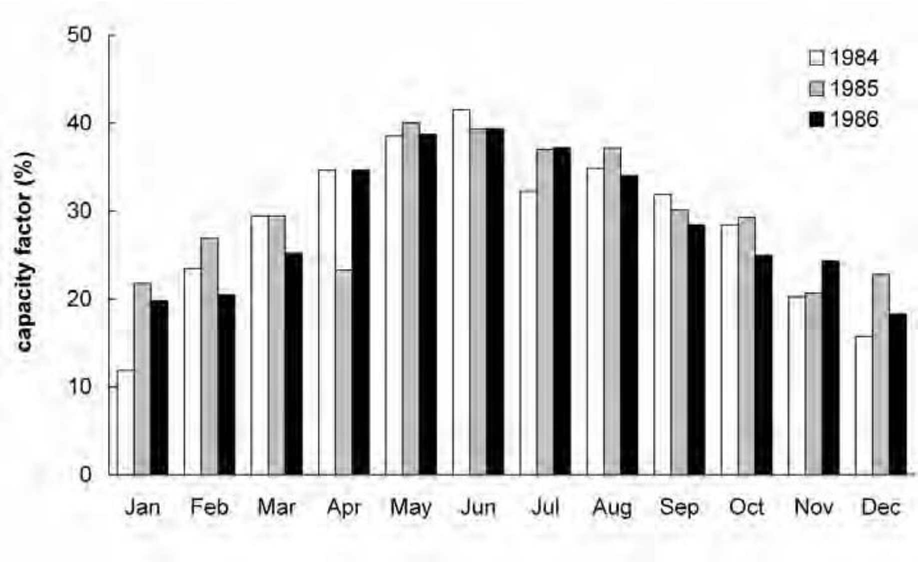
The National Renewable Energy Laboratory's PV:BONUS program included support for PV used in roofing, windows, domestic and commercial buildings, and in kit homes for off-grid sites (Solar Flare, 1993).

The PVUSA project aimed to demonstrate PV in utility settings. By 1991, nine 20 kW_p emerging module technology systems were being tested, plus two 200 kW_p and one 400 kW_p systems using more mature technologies (Candelario *et al.,* 1991). The average capacity factors recorded for fixed arrays were 21% (with a range of 10–30%), and for two-axis tracking arrays 30% (*Ibid.*).

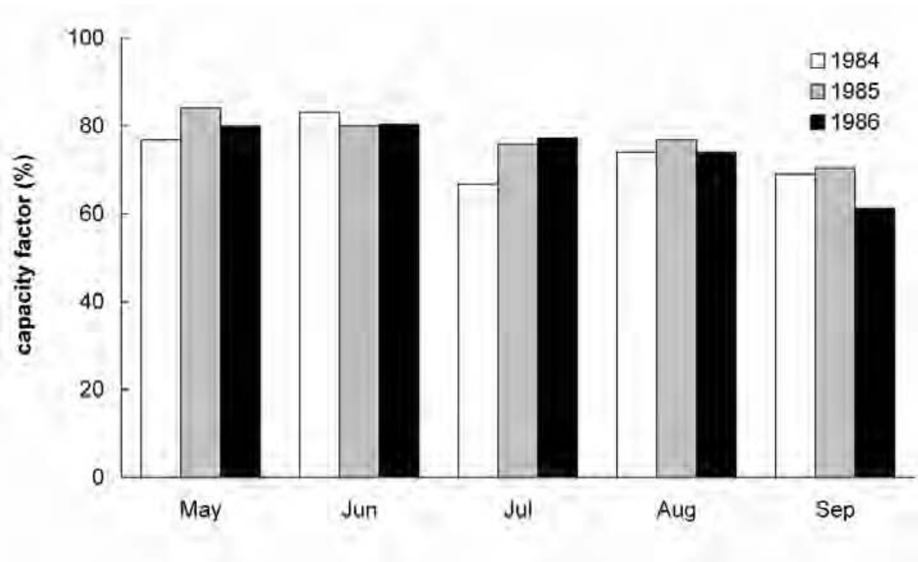
The Kerman substation described above was a PVUSA project. Others are described below.

1. **Carissa Plains**—A 5.2 MW_{ac} PV system was installed at Carissa Plains, north of Los Angeles, USA, and connected to the Pacific Gas and Electric (PG&E) grid. The system's performance, in terms of capacity factor over

three years, is shown in Figs. 10.13*a* (24 hour) and 10.13*b* (peak hours only). The plant's availability over the years 1985–1988 was 97% (Rannels, 1991). The PG&E peak electricity demand occurs in summer afternoons. The very high capacity factor of the Carissa Plains plant during periods of peak demand (12.30–18.30, May–September) made it an almost ideal peaking plant. The Carissa Plains installation has since been dismantled and sold off.



(*a*)



(*b*)

Figure 10.13. Capacity factors achieved over three years at the Carissa Plains PV power station (©1987 IEEE, Hoff). (*a*) 24 hour capacity factor. (*b*) Peak hour capacity factor.

2. **Sacramento**—A 200 kW_p PV array was installed at the Sacramento Municipal Utility District's Hedge Substation during 1993, at an estimated price (in 1993) of US\$7.70/W_p (Solar Flare, 1993).

More recently, incentive programs were instrumental in the installation of 80 MW of grid-connected PV in the USA in 2005 (Solarbuzz, 2006). Twenty-three percent of the total market was new installed PV generating capacity on flat, commercial roofs and large commercial projects overall accounted for 33% of the country's total. A database of US state and federal incentives for renewable energy is maintained by the Interstate Renewable Energy Council (IREC, 2004).

Green pricing schemes, in which consumers and businesses elect to pay a premium for electricity generated from renewable energy, have been an effective market driver in the USA. Sales through such schemes increased 30% during 2003 (Schmitz *et al.*, 2004). The Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory have studied the effectiveness of different marketing aspects of the US schemes (Wiser, 2004). Green pricing programs prompted the development of 290 MW of renewable energy generation capacity up to the end of 2002 and another 140 MW was expected by the end of 2003.

10.7.2 Japan

Government-supported programs in Japan have brought that country to its current position of dominance as both manufacturer of and market for photovoltaics. Since the 'Sunshine Project' commenced in 1974, the Japanese have moved rapidly from R&D to widespread PV application. The emphasis has been on utility-connected systems, particularly residential rooftop systems, which take advantage of the high level of grid connection and minimise land use (Kurokawa, 1993). Net metering, under which utilities buy excess power at retail rates, was introduced in 1992 (Sawin, 2004).

The 1994 residential 'Solar Roofs' program has been a major driving force, with 150,000 approvals by March 2004 for subsidised residential rooftop systems, with average size 3.7 kW_p (Hirshman, 2004*a*). Over the lifetime of the program, the rebate has been progressively decreased from 50% in 1994 to 12% in 2002, but buyers have been compensated by falling prices. A total of 420 MW_p of PV was installed between 1994 and 2002 and total installed capacity has increased by an average of more than 42% per year since 1992 (Sawin, 2004). Subsidies are gradually being replaced by mandatory renewable energy targets and by 'green power' schemes, although many local governments now offer PV incentives. Japan has now embarked on another 30 year program, with a target of 4.8 GW_p installed by 2010 and 100 GW_p installed by 2030 (Ikki & Ohigashi, 2004). The latter is expected to be equivalent to 10% of Japanese electricity use, and is accompanied by cost targets of 7 ¥/kWh, compared with 50 ¥/kWh in 2003 (Goto *et al.*, 2004).

10.7.3 Europe

Europe is the second-ranking PV market powerhouse after Japan, experiencing explosive growth in production and usage rates over the decade 1993–2003. The INTUSER Consortium (2003) listed incentive and support schemes for investment and production in Austria, Belgium, Denmark, Finland, France, Germany, Italy, Luxembourg, the Netherlands, Portugal, Spain and the UK.

Switzerland had a PV program stemming from a 10 year moratorium on nuclear power (Real & Ludi, 1991). An R&D program commenced in 1987, followed by testing of a 3 kW prototype system. In 1988, 10 × 3 kW_p PV systems, using a specially-designed 3 kW high-efficiency inverter, were installed. A one-to-one buying and selling cost for the electricity used or produced by the households has been arranged with the utility. By 1990, 100 systems had been installed (*Ibid.*). Their 'Energy 2000' project aimed to have 50 MW_p of grid-connected PV installed by 2000, although only 21 MW_p had been installed by 2003 (IEA-PVPS, 2004).

One aim of the Swiss program is to reduce PV land use requirements. Therefore, in addition to the rooftop systems, several large arrays have been installed along motorway sound barriers, providing a very visible demonstration of the technology (Nordmann & Clavadetscher. 2004). This idea has since been applied elsewhere in Europe. Recent Swiss support measures that strongly facilitate consumer investment, are outlined by Bonvin (2004).

Austria began a '200 kW Photovoltaic Rooftop Program' in 1992. Financial support is provided to householders for building-integrated, utility-connected PV systems up to 3.6 kW_p and more recently via a feed-in tariff.

Germany has had the most spectacularly effective incentive schemes in Europe (Sawin, 2004). The '1000 Roofs Demonstration Program' began in 1991 and the more ambitious '100,000 Roofs Program' in 2000. These provided low-interest loans but have subsequently been replaced by the 2004 'Renewable Energy Law'. This mandates a feed-in tariff, which is intended to allow the capital cost of the PV system to be paid back through power sales to the grid over the system life. The tariff available decreases by 6.5% each year from 2006 (Schmela, 2004; Siemer, 2004). These approaches have encouraged very rapid growth in rooftop systems, some very large. By 2004, investors were favouring the establishment of huge 'solar parks' of ground-mounted PV to profit from the advantages of scale and because of a perceived insufficiency of available large roofs (Paul, 2004). Sales are expected to grow by 50% in 2004 (Paul, 2004) and reach €1 billion according to the German Solar Industry Association (Renewable Energy World, 2004*a*).

Spain in 1998 set feed-in tariffs comparable to Germany's, but the market failed to grow as well owing to remaining barriers, such as the freedom for utilities to set high charges for connection and the need for producers selling power to the grid to register as businesses (Sawin, 2004). A revised Spanish feed-in tariff scheme was approved early in 2004 and is expected to be a great boost to the industry there (Renewable Energy World, 2004*b*), although it has been strongly criticised for its limited funding (Hirshman, 2004*b*).

Italy's rooftop PV support program, begun in 2001, became a victim of regional politics and bureaucracy and disappointingly resulted in only 2 MW_p of installed capacity three years later (Hirshman, 2004*c*). A new feed-in tariff, based on experience in Germany and elsewhere, is expected to come into force in late 2004.

A single support scheme for the whole European Union has been proposed for introduction in 2005 (Kjaer, 2004). Until that might occur, there is a range of programs through different European countries.

10.7.4 India

While most PV being installed in developing countries is in small stand-alone systems, India, although also supporting a large market in small-scale systems, has established a Rural Electrification Supply Technology Mission, aimed at electrifying the 20,000 or so remote villages across India by 2012 using renewable and hybrid energy systems (Chaurey, 2004). This program is backed up by the Electricity Act 2003, which includes provision for independent power producers to establish renewable energy based power systems in remote areas and for state based power providers to specify renewable energy content (*Ibid.*). One of the earliest village systems was a 100 kW_p mini-grid PV system in Kalyanpur, at a cost of US$1.5 million (Solar Flare, 1993). It provides electricity for 500 houses, 40 street lights and 15 water pumps (*Ibid.*). Villagers pay a monthly charge, mainly for lighting.

Government support has also been provided for grid-connected PV plants, as a means of increasing PV production volume and hence reducing costs. India ranks fifth in the world for grid-connected PV capacity. A BIPV demonstration program is underway and several major BIPV projects have been undertaken on large office and government buildings.

By 2003, India was the fifth largest PV module manufacturer in the world, with 60 major component manufacturers, and significant research, demonstration and market development programs. In addition to catering for its own growing market, it is moving rapidly into export markets (Chaurey, 2004).

10.7.5 China

China has a vast unmet demand for electricity (Hirshman, 2003), particularly for village mini-grid systems in the western provinces (Cabraal, 2004; Li, 2004). Some 800 village systems were installed in China in 2002–03, using 19 MW_p of PV (Honghua *et al.*, 2004). Systems ranged in size up to 150 kW_p. In addition, plans are under way for the installation of 10 MW_p of PV in smaller solar home systems by 2005, while PV is also widely used for mobile phone networks, microwave repeater stations, optical fibre links and train signalling (*Ibid.*). The China Brightness Project aims to install over 100 MW_p of PV in off-grid applications by 2010 (Yi, 2004).

For grid-connected PV in China, the 'Renewable Energy Development & Utilisation Promotion Law', expected to be implemented in 2005, is likely to mandate renewable energy contributions to the grid. A number of grid systems are also expected to be installed for the 2008 Beijing Olympic Games.

To meet the installation targets set, China's 'Five Year Plan for New and Recycled Energy' has set a module production target of 15 MW_p, up from 2 MW_p in 2003. The longer term 'Development Program for New and Recycled Energy' has a 320 MW_p target for 2015 (Yi, 2004).

10.7.6 Australia

Australia has had a number of renewable energy support programs since the mid 1980s, often state-based and usually specific to off-grid applications. A federal government scheme, the 'Remote Renewable Power Generation Program', is expected to continue until 2009. It is administered by the states under various subprograms and aims to replace diesel fuel used in off-grid applications via grants covering up to 50% of renewable energy component costs. Although not PV specific, almost all of the smaller installations incorporate PV and over 2 MW_p of PV had been installed by 2003 (Watt, 2004).

A PV-specific program, the ‘PV Rooftop Program’, has operated since 2000 and is available for both grid and off-grid rooftop systems. It aims to develop BIPV technologies and installation techniques. Grants are available for residential systems as well as for community buildings. More than 5000 systems using over 6 MW_p of PV were installed by 2004. This was the first support program for grid-connected PV. Grants are also available via State Governments and electricity utilities for PV installations on schools. Educational material is also supplied.

The Sydney 2000 Olympic Games aimed to be the ‘Green Games’, and support was provided for sustainable technologies. Over 600 sustainable energy houses were built near the Olympic Village. Some of these were initially used for the athletes and then sold for private housing. Each home incorporated 1 kW_p of PV. Several other PV systems were installed in the Olympic complex, including a 70 kW_p array on the Superdome roof, several PV water pumping systems and a PV lighting system outside the main stadium that, with its distinctive blue PV lighting towers, has become the symbol of the games facilities. Many of these installations were built by electricity retailers for their GreenPower customers (see below).

An Australia-wide Mandatory Renewable Energy Target (MRET) for grid electricity supplies began in 2001. A total of 9500 GWh of renewable electricity, additional to supplies previously available, mainly from large hydro schemes, must be supplied each year by 2010. This level of renewable energy generation must then be maintained to 2020. The scheme operates via the creation of one Renewable Energy Certificate (REC) for each MWh of renewable electricity. RECs can be deemed for small-scale applications, such as residential PV systems. To date, MRET has had little impact on PV sales, since the deeming period was initially set at five years. However, this is to be extended to 15 years, which may boost PV installations. For details of MRET, the background legislation and operational aspects, see ORER (2004).

Green pricing schemes were pioneered in 1997 in Australia by the New South Wales Government Sustainable Energy Development Authority (which ceased in 2004) and have since spread to other states (Greenpower, 2004). Electricity retailers offer various schemes with, for example, mixes of PV and other renewable energy generation guaranteed to be added to the ‘pool’ from which GreenPower customers draw their electricity (*Ibid.*). Several large PV systems have been installed by utilities to service their GreenPower customers, including the Olympic Park systems discussed above. Other GreenPower installations include a 400 kW_p PV system in Singleton NSW by EnergyAustralia and two 50 kW_p arrays at the Western Plains Zoo in Dubbo and at Queanbeyan by Country Energy.

A new ‘Solar Cities’ scheme was announced in 2004, and is aimed at evaluating high penetration rates of PV, solar water heaters and energy efficiency measures in nominated areas, particularly those experiencing summer peak loads (Commonwealth of Australia, 2004).

EXERCISES

10.1 (a) Give an overview of photovoltaic applications relevant to present markets, explaining why photovoltaics are both suitable and economical for each.

(b) What changes are likely to take place in future PV markets and applications? What changes are needed in PV products to best access these new markets?

10.2 (a) By use of a diagram, explain what is meant in interconnected photovoltaic systems by the terms ‘source circuit’, ‘parallel string’, ‘series block’ and ‘substring’.

(b) For large systems with one bypass diode per series block, explain how decreasing the number of series cells per substring can increase system tolerance to cells failing by open circuiting.

(c) Explain how large currents can be prevented from flowing through shorts to ground in large photovoltaic systems with multiple source circuits.

(d) Explain how arcing can occur in large, high voltage photovoltaic systems with multiple source circuits when an open circuit arises between series blocks.

10.3 For a selected country, investigate the attitudes of those in charge of essential services such as electricity generation and distribution, telecommunications, railways and water supply to the use of photovoltaics? What changes are required to enhance PV use and how might this occur?

10.4 Describe the components in a grid-connected residential photovoltaic system and discuss issues relevant to the use of photovoltaics in this application.

10.5 Discuss the use of power conditioning circuitry available in Australia (inverters, maximum power point trackers, DC-to-DC converters etc.) Include:

- types and characteristics of power conditioning circuitry available in Australia
- selection criteria
- supplies, costs
- economics of use
- benefits
- reliability.

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Chapter

11

PHOTOVOLTAIC WATER PUMPING SYSTEM COMPONENTS

11.1 INTRODUCTION

Water pumping is essential world-wide for numerous purposes, including irrigation, stock watering, village water supplies and domestic use. An estimated 1.2 billion people do not have access to clean water (von Aichberger, 2003). However, the pumping of groundwater can be done sustainably only to the extent that the extraction rate equals the aquifer's replenishment rate. Otherwise, a lowered water table leads to dry wells, and ecological and social damage (Pearce, 2004). Harvesting rainwater can be a better option in many cases. A wide variety of power sources are used for pumping, depending on local conditions. The advantages and disadvantages of many of these alternatives are listed in Appendix F.

Water pumping applications can vary widely, both in their requirements and in the conditions under which the pumping must take place. Considerable variability exists in volumes of water required, timing of water requirements, water source capacity, depth from which it is to be pumped, replenishment rates of the source, seasonal variability of static head, bore or well diameters, and solar insolation characteristics. For instance, water pumping from a river for irrigation normally has no immediate problems with the water source capacity or replenishment rate, although over-exploitation can occur, and usually involves relatively low static heads. In comparison, in some terrains deep bores are necessary and may be characterised by low water capacities, slow replenishment rates, large seasonal variations in water level and small bores, which place constraints on motor and pump sizes and types. The particular case of water pumping for livestock is treated in detail by Stokes *et al.*, (1993). Fig. 11.1 gives some of the common water pumping terms.

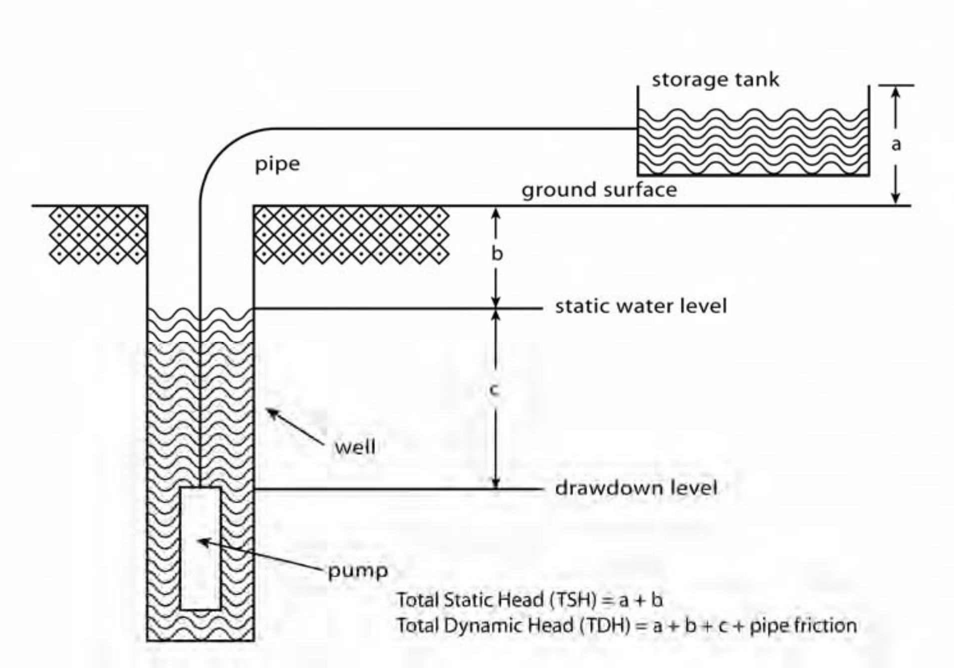

Figure 11.1. Common water pumping terms (after Sandia National Laboratories, 1991, used with permission).

11.2 SYSTEM CONFIGURATIONS

There is a range of possible components and configurations for photovoltaic water pumping systems, as shown in Fig. 11.2. Selection of the most suitable components and configurations for each specific application and site is critical to the economic viability and the long-term performance of the system (Sharma *et al.*, 1995).

In the simplest photovoltaic water pumping systems, the solar panels are directly connected to a DC motor that drives the water pump. For such simplified systems, DC motors and centrifugal pumps are virtually mandatory, because of their ability to be matched to the output of the solar panels.

Volumetric pumps, often referred to as (*positive*) *displacement* pumps, have completely different torque-speed characteristics and are not well suited to being directly coupled to solar panels. Therefore when volumetric pumps are used, power conditioning or maximum power point tracking circuitry is commonly included between the solar panels and the motor/pump, to convert the electrical energy into a suitable useable form.

Similarly, a range of motor types is used for water pumping systems, including DC series motors, DC permanent magnet motors, DC permanent magnet brushless motors, AC asynchronous induction motors and AC synchronous motors. As with the different pump types, each motor has its advantages and disadvantages, which determine suitability to particular applications. However, for AC motors, an inverter must be included between the solar panels and the motor.

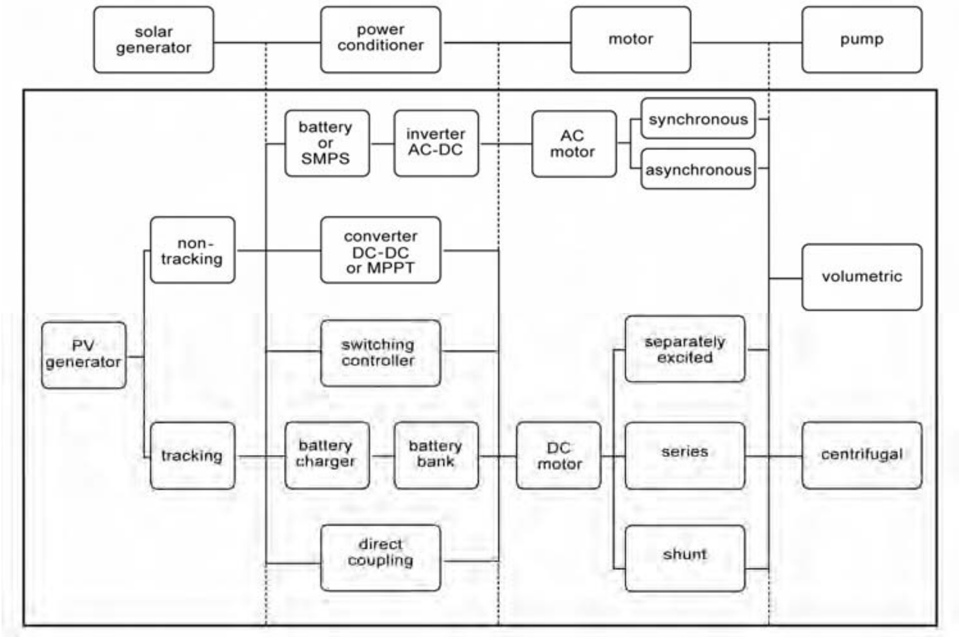

Figure 11.2. Photovoltaic water pumping system components and configurations (Used with permission of Regional Energy Resources Information Centre, Koner, 1993).

Batteries for energy storage are sometimes a necessity in such systems, particularly if it is critical that pumping take place at specific times, if pump rates exceed replenishment rates for the water source, or even to provide power conditioning for the pump/motor. Batteries have the benefit of holding the operating point of the solar panels near their maximum power points. They can thus be considered to be a ‘power conditioning’ element in the circuit between solar panels and motor, although they may also be used to provide energy storage for a period of days during poor weather.

Where possible, however, the use of batteries or other forms of storage should be avoided because of their relatively short life expectancies, requirements for maintenance, poor reliability, high cost, their need for protection by a voltage regulator and for environmental reasons. In fact, the system becomes quite complex if an AC motor is used with a volumetric pump. Batteries or power conditioning circuitry may be used to provide the high starting currents, although if batteries are used, a voltage regulator at their input and an inverter at their output to drive the AC motor, are necessary. In addition, the speed of a volumetric pump is not well matched to that of an AC motor, thus necessitating some form of transmission with appropriate gearing.

Four different physical configurations are identified by Barlow *et al.* (1993):

1. **Submerged pump and motor**. This arrangement is often used for medium depth bores with centrifugal pumps, which are then automatically primed and safer from damage and theft.
2. **Submerged pump with surface motor**. This allows easier motor maintenance but introduces reliability and efficiency problems through the mechanical drive down the bore. The reciprocating displacement (Jack) pump uses a vertically-reciprocating shaft to transfer energy from the surface motor.
3. **Floating pump/motor set**. This design is unsuited to boreholes but attractive for pumping from dams, canals and open wells.
4. **Surface suction pump set**. This setup is convenient for maintenance but can be problematic for pump priming.

11.3 WATER PUMPS

There is an abundance of names and classifications for pumps but they may all be separated into two categories (Thomas, 1987; Krutzch & Cooper, 2001):

1. **Dynamic**—in which the water velocity is continuously incremented, then reduced at the output, leading to a pressure increase.
2. **Displacement**—including reciprocal and rotary types, in which energy is added periodically by forcing volume changes of an enclosure.

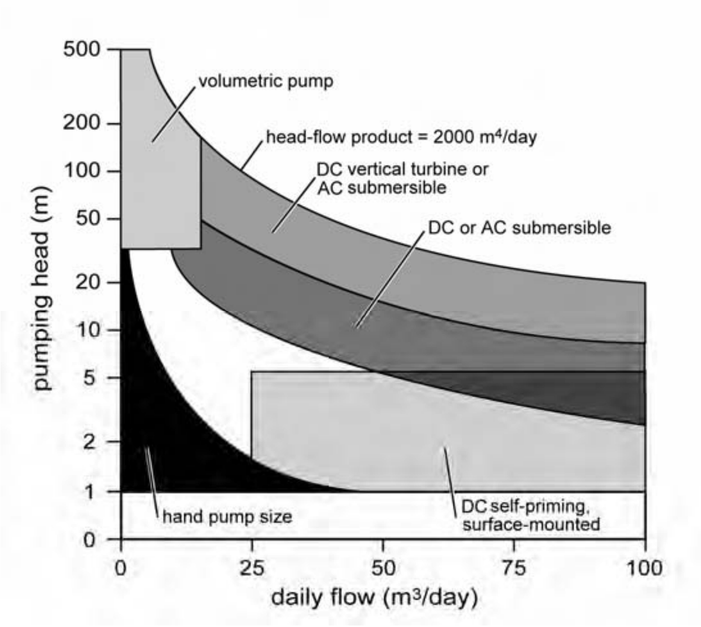

Figure 11.3. Approximate ranges of application of photovoltaic water pumping configurations (after Thomas, 1987, used with permission of Sandia National Laboratories).

The two broad categories of pumps used for photovoltaic-powered systems, centrifugal and volumetric (displacement), are described below. A rough guide to ranges of applications is given in Fig. 11.3.

Fig. 11.4 shows a 'tree' of pump categories. A brief discussion of pumping technologies and a market survey of available products has been produced by von Aichberger (2003).

- dynamic
  - centrifugal
    - axial-flow
      - single-stage
        - closed or open impeller
          - fixed or variable pitch
      - multi-stage
        - closed or open impeller
          - fixed or variable pitch
    - mixed flow, radial flow
      - single suction
        - self- or non-priming
          - open, semi-open or closed impeller
        - single- or multi-stage
          - open, semi-open or closed impeller
    - peripheral
      - single- or multi-stage
        - self- or non-priming
  - special effect
    - jet (eductor)
    - gas lift
    - hydraulic ram
    - electromagnetic
- displacement (volumetric)
  - reciprocating (jack)
    - piston, plunger
      - steam—double-acting
        - simplex or duplex
      - power
        - single- or double-acting
          - simplex or duplex
    - diaphragm
      - simplex or duplex
        - fluid or mechanically operated
  - rotary
    - single rotor
      - vane or piston or flexible member or screw or peristaltic
    - multiple rotor
      - gear or lobe or circumferential piston or screw

Figure 11.4. Pump category tree (after Krutzch & Cooper, 2001).

11.3.1 Centrifugal pumps

Centrifugal pumps have a rotating impeller that throws the water radially against a casing, as indicated in Fig. 11.5. The kinetic energy added to the water by the impeller is then converted to potential energy in the form of pressure or 'head' in the diffuser or volute section. As the water exits the pump through the diffuser, the cross-section increases, causing the velocity (kinetic energy) to reduce and, by conservation of energy, the potential energy to increase (United Nations Economic & Social Commission for Asia & the Pacific, 1991; Dufour & Nelson, 1993; Sahdev, 2004). They are normally used in low head/low pressure, high volume applications, particularly if direct connection to the solar panels is required. They are well suited to high pumping rates and, because of their compactness, wherever small diameter bores or wells exist. They are characterised by the torque being proportional to the square of the speed (angular velocity of the impeller). Fig. 11.6 shows a performance curve for a typical centrifugal pump. As can be seen, these pumps have relatively high efficiencies, although typically lower than for helical rotors, but rapidly lose pumping performance as their speed reduces and in fact do not pump at all unless quite substantial spin speeds are achieved. This is, of course, a concern for a photovoltaic-powered system when light intensity is low. However, maximum performance is achieved at high spin speeds, making them easy to match to motors, which tend to develop maximum torque (maximum efficiency) at similar speeds.

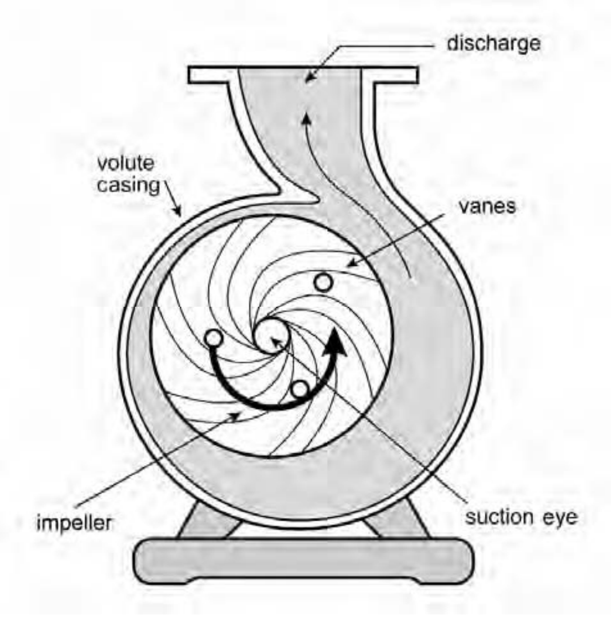

Figure 11.5 Centifugal pump operation (Used with permission of The Chemical Engineers' Resource Page, Sahdev, 2004).

For conventional centrifugal pump designs, high efficiencies are only obtained for low pumping pressures and hence relatively small pumping heads of less than about 25 m. To overcome this limitation, either multistage or regenerative centrifugal pumps can be used. With the latter, water that leaves the pump under pressure is channelled back through cavities in the casing into an adjacent chamber, where it is pumped to a greater pressure, hence suiting increased pumping heads.

Efficiencies of these pumps, however, tend to be a little lower, owing to leakage of water from the high pressure chamber to the low pressure chamber. In addition, the clearances between impellers and casing need to be substantially less to give good performance, which creates reliability problems. Another modification to suit centrifugal pumps to larger heads is to include a water injector (jet pump). However it is more common to use multistage centrifugal pumps for larger heads. These have been used successfully to pump water up to heights of 600 m but not with solar power (von Aichberger, 2003). Unfortunately, centrifugal pumps can only operate at maximum efficiency at a single operating point, even when a maximum power point tracker is used, so efficiency is reduced at all but an optimal insolation level (Sharma *et al.*, 1995).

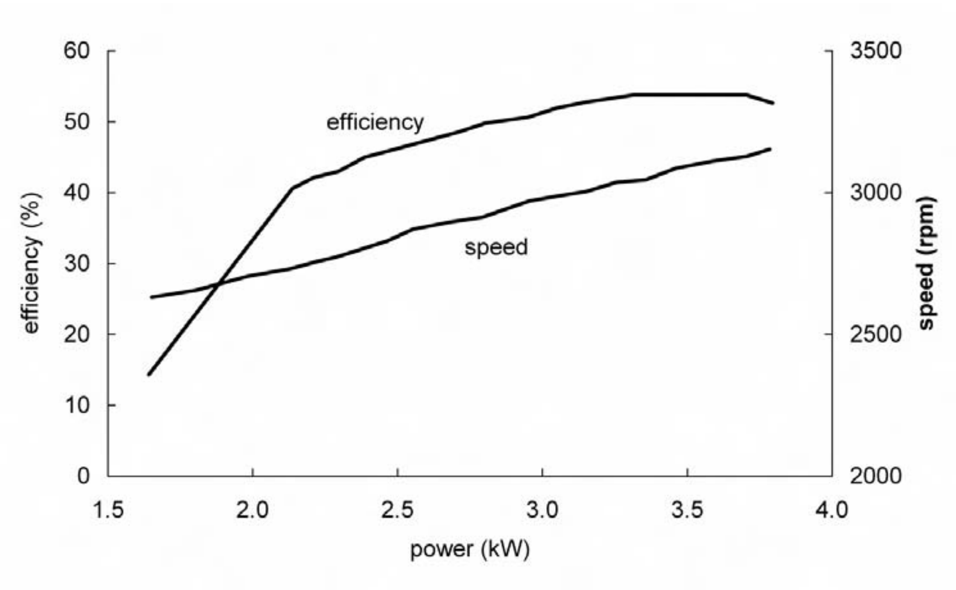

Figure 11.6. Typical efficiency characteristics of a centrifugal pump at variable speed (60 m head, 10 m^3/h flow rate, 3 kW power). (Used with permission of Thomson, Landau, M., Sachau, J. & Raatz, A. (1992), 'Photovoltaic pumping system for intermittent operation', Proc. 11th EC Photovoltaic Solar Energy Conference, Montreux, Switzerland, pp. 1391–1394, Fig.1, Published by Taylor & Francis 1993)

Other advantages of centrifugal pumps include their simplicity (with a minimum of moving parts) and corresponding reliability, low cost, robustness, tolerance to pumping particulates and low starting torque. On the other hand, another potential limitation of centrifugal pumps is their inability to be self-priming, although technology exists for overcoming this impediment (von Aichberger, 2003). Consequently, they are frequently used as submersible pumps, preferably in conjunction with a submersible motor. For many years this has been a problem, since the preferred DC motors were not submersible owing to the presence of the brushes.

Long driving shafts were therefore required between motor and pump, which in turn led to other complications. For this reason, submersible AC motors were often used, despite their lower efficiencies and requirements for inverters. Now, however, submersible DC motors have become more readily available. In these, electronic commutation is used to remove the need for brushes.

Another alternative has been the use of self-priming centrifugal pumps (side pumps), where a chamber containing water at the side of the pump keeps the pump effectively submerged and hence primed.

The major trade-off involved with the design and use of centrifugal pumps is the requirement for high efficiency versus the need for an impeller with long life and good tolerance of aggressive impurities in the water (Halcrow & Partners, 1981). High efficiency can be obtained with small clearances and narrow passages, but this is undesirable for pump reliability and the ability to pump liquids contaminated with particles. In addition, high efficiency can be obtained with a high speed impeller, which again acts to shorten the life of the pump. In summary, pumps need to be designed and selected for specific applications and environments.

Apart from the usual use of photovoltaic water pumps for the supply of potable water, there is also a significant Australian market for centrifugal pumps for desalination of land affected by elevated water tables.

11.3.2 Displacement or volumetric pumps

Displacement or *volumetric* pumps are the other class of pumps often used for water pumping applications, particularly for lower pump rates from deep wells or bores. Included within this class are piston pumps, diaphragm pumps, rotary-screw type pumps and progressive cavity pumps, such as the popular helical rotor (Fig. 11.7) (Revard, 1995).

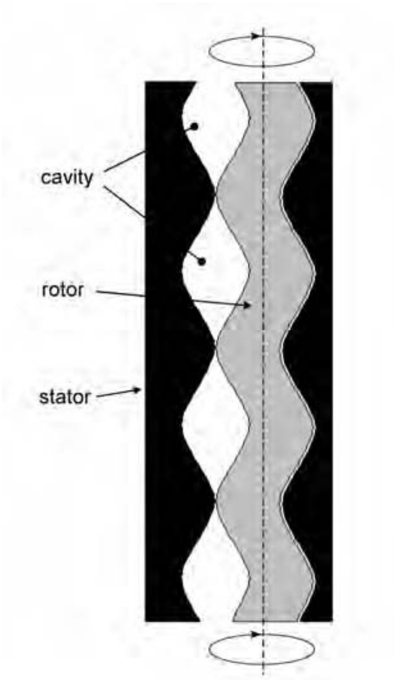

Figure 11.7. Helical rotor type of displacement pump (after Revard, 1995).

Fig. 11.8 gives the performance curves of a typical positive displacement pump. The pumping rate with these pumps is directly related to the speed of operation, with a fairly constant torque required. The resulting flat torque-speed characteristic makes it almost impossible to drive these pumps directly from a photovoltaic source (Halcrow & Partners, 1981). This is because the torque developed by a motor depends directly on the current in the armature. The requirement for this to remain approximately constant (to suit a constant torque pump) therefore requires an approximately constant current. This type of load is not well matched to the output of solar cells, where the current generated is directly proportional to the light intensity. For instance, if the operating torque corresponds to a current from the solar modules that closely matches their maximum power under bright sunshine, then a small reduction in light intensity will result in insufficient current being generated to maintain the pumping speed. The pump/motor will accordingly slow down in pumping rate so as to require less current. However, because of the flat torque-speed characteristic, the pump will actually cease entirely whenever the current generated drops below the critical level. To prevent this happening for large parts of the day, a critical current would have to be selected that was well below the maximum current generated by the solar panels throughout the day. This of course means sacrificing much of the power-generating capabilities of the solar panels, hence producing a system with low overall efficiency.

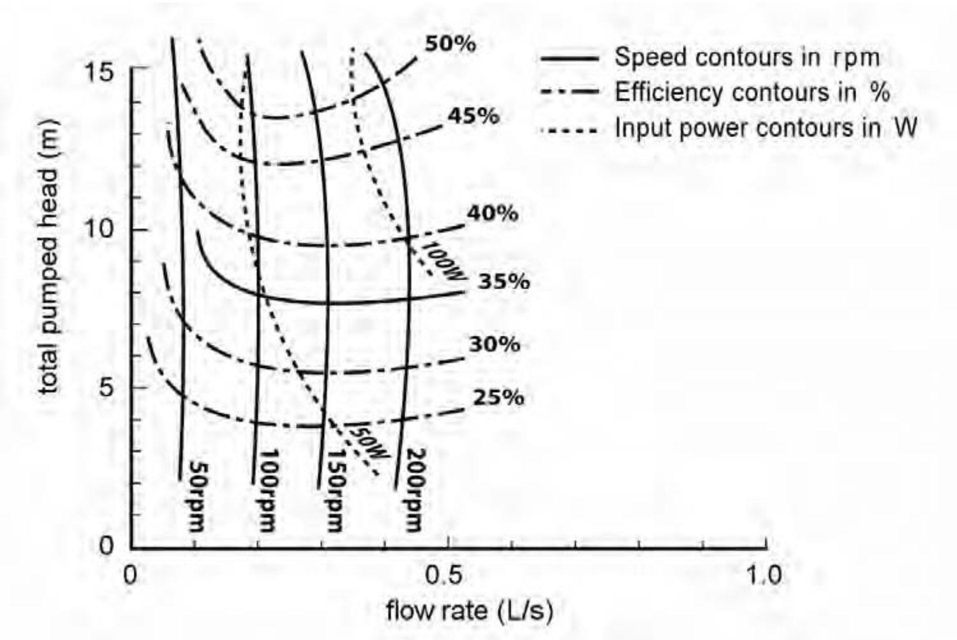

Figure 11.8. Performance curves of a typical positive displacement pump. (Speeds shown are pump speeds. For motor, multiply by 8.5. Efficiencies include belt transmission between motor and pump.) (Used with permission of Halcrow & Partners, 1981).

The other problem limiting the use of these pumps in direct connection to solar panels is the high starting (breakaway) torque associated with binding of the seals. Furthermore, the low number of strokes per unit time of volumetric pumps necessitates the use of an appropriately-geared transmission to match to the speed of the motor (Halcrow & Partners, 1981), which adds further complexity to the system.

Despite these limitations, for large heads (>20 m) the efficiencies obtainable exceed those of single-stage centrifugal pumps, particularly under part load conditions. Having mentioned this benefit, it is important to understand the implications of using these pumps under part load. Under part load, these pumps require the same current but reduced voltage, because of the flat torque-speed characteristic. This is not compatible with photovoltaic output and hence power conditioning circuitry would be required before this benefit could be utilised.

Another benefit is that they are less sensitive to head variations (seasonal and during pumping) and are self-priming, which alleviates the need for submersible motors and long driving shafts between motors and pumps. Also, their efficiencies tend to suffer less from partial load conditions than do centrifugal types (Sharma *et al.*, 1995).

The performance of volumetric pumps is quite poor for small heads, owing to the large component of friction. The exception to this is perhaps the free-diaphragm pump, which has low internal friction and hence may be well suited to small heads. Fig. 11.9 gives the typical performance curves of such a pump, and it has been hoped that these may be able to be operated directly by an actuator, although to date, no great success in this area has been achieved. Diaphragm pumps are available for photovoltaic applications, mainly for low flows from deep wells or for domestic water supply pressurisation. The diaphragm requires frequent replacement but this type has the advantage that it can run dry without damage.

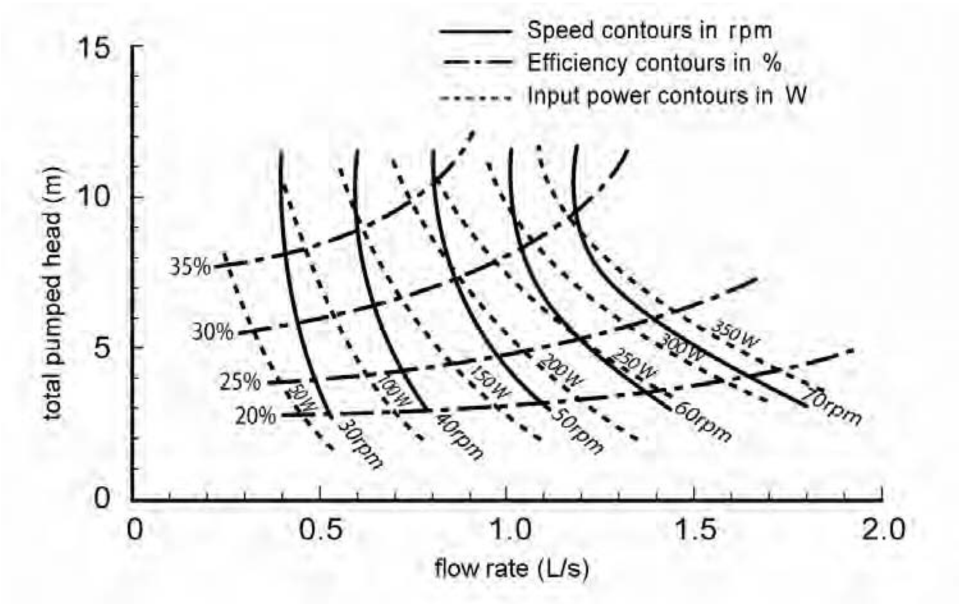

Figure 11.9. Performance curves of a free-diaphragm pump (Used with permission of Halcrow & Partners, 1981).

The best known volumetric pump is the reciprocating piston type ('Bucket' pump), which is the sort used in hand pumping. These can be powered by hand, diesel, wind or electricity, but as with other volumetric pumps, they suffer from poor efficiencies below heads of 10–20 m (Halcrow & Partners, 1981). They are available for use with photovoltaics, commonly with the motor at the surface and the energy transmitted down the bore by a shaft. However, the coaxial balanced piston pump uses a submersed motor (von Aichberger, 2003).

Vane pumps (Platt & Little, 2001) are another alternative, principally for low flow rate applications such as domestic supply pressurisation or circulation of water in solar thermal heaters (Fig. 11.10). Fig. 11.11 gives the performance curves of a typical rotary positive displacement pump.

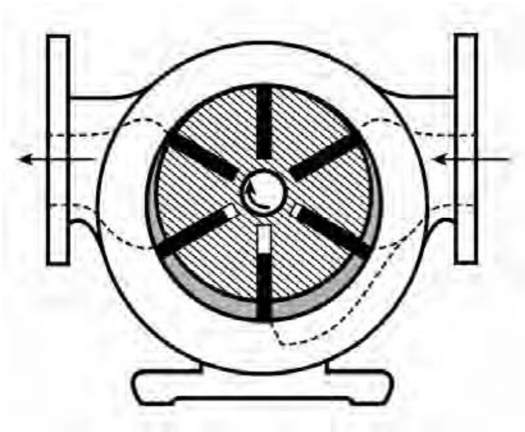

Figure 11.10. The vane pump works by using vanes that slide outward by centrifugal force to form sealed ‘capsules’ of fluid between adjacent vanes and the casing (Used with permission of the McGraw-Hill Companies, Platt, R.A. & Little, C.W.J. (2001), ‘Vane, gear and lobe pumps’, , in Karassik, I.J., Messina, J.P., Cooper, P. & Heald, C.C., *Pump Handbook*, McGraw-Hill, pp. 3.123–3.154).

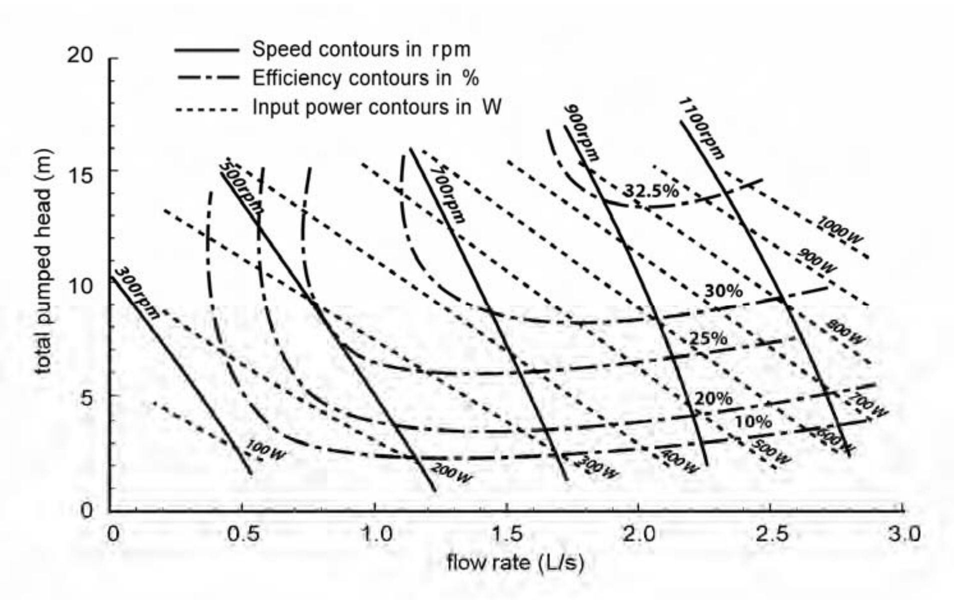

Figure 11.11. Performance curves of a typical rotary positive displacement pump (Used with permission of Halcrow & Partners, 1981).

11.4 MOTORS

11.4.1 Introduction

Small motors (< 2 kW) of high efficiency that are well suited to photovoltaic water pumping are still relatively rare. Fig. 11.12 shows the typical fall off in performance as motor size decreases, which compounds the problem of reduced pump efficiency at smaller sizes (Bucher, 1988). Fig. 11.12 also clearly shows the superior efficiency of DC versus AC motors. Owing to the high cost of solar panels, it becomes justifiable in many applications to use more expensive DC motors to gain an efficiency advantage. However, the trend in photovoltaics is for steadily falling prices, with the potential for a further cost reduction over the next decades (Poponi, 2003). This will tend to shift priorities away from efficiency as being the dominating feature in motor design, in favour of lower cost, lower maintenance machines. However, AC motors in general tend to be cheaper, which often complicates the choice.

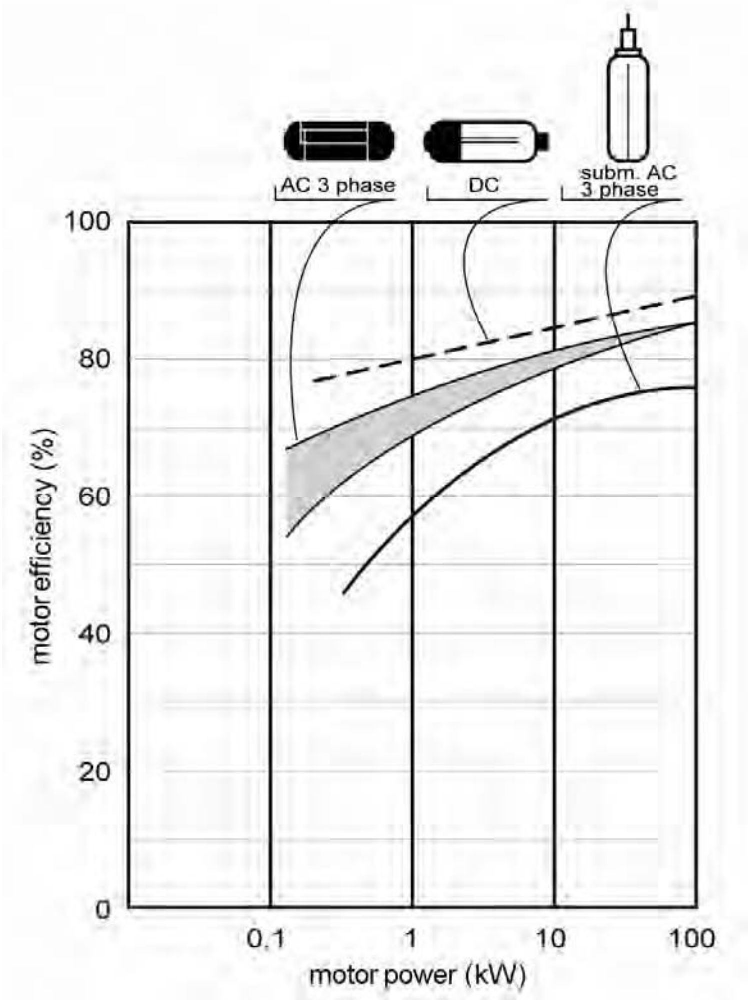

Figure 11.12. Performance of DC and AC motors as a function of size (Bucher, 1988, Used with kind permission from Springer Science and Business Media).

There have been significant developments with small (typically 1–3 kW continuous rating) DC brushless permanent rare earth magnet motors. These developments have been stimulated by the demands of highly competitive, high budget, international solar car races. In the World Solar Challenge, motor efficiencies as high as 92–96% were reported, although corresponding costs are high (Cotter *et al.*, 2000). Heat losses and dissipation primarily determine the corresponding power handling capabilities, with the consequence that these small, high efficiency motors can handle relatively large amounts of power.

The Australian Greenhouse Office (2004) provides extensive public information about motors, including a database of the characteristics of available motors and aids for motor selection. Since 2001, there have been mandatory minimum energy performance standards in Australia for three-phase electric motors from 0.73 to 185 kW, and all motors licensed for sale in Australia in that range are required to be registered in a public database.

11.4.2 DC motors

Fig. 11.13 shows the cross-section of a two-pole DC machine. Crosses represent current flowing into the page and dots represent current flowing out of the page.

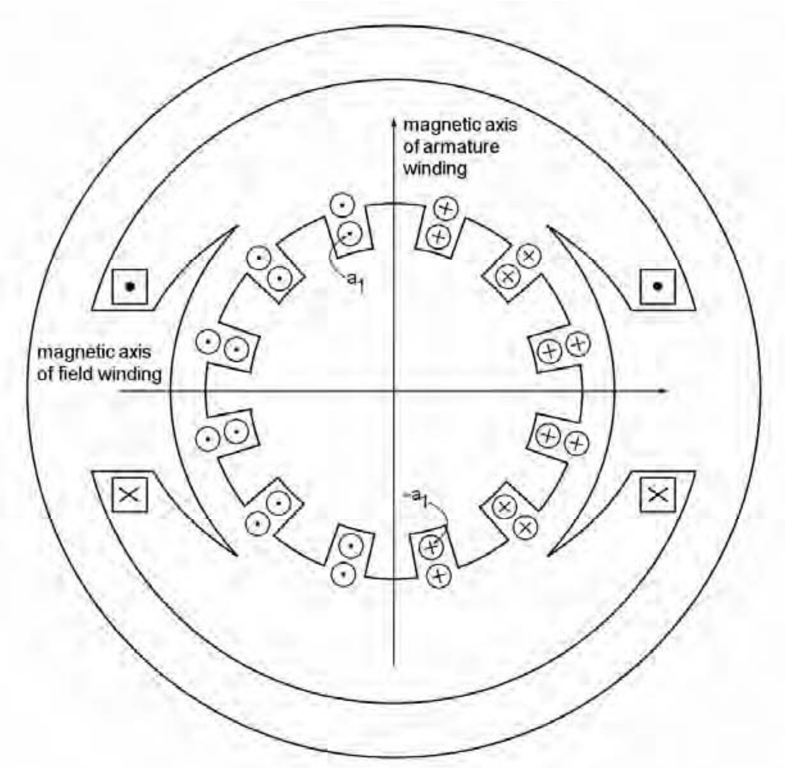

Figure 11.13. Cross-section of a two-pole DC machine (Used with permission of McGraw-Hill Companies, adapted from Fitzgerald, A.E., Kingsley C. Jnr. & Kusko, A. (1971), *Electric Machinery*, McGraw Hill, Tokyo, Japan).

There are four basic types of DC motors:

1. The **series DC motor**, as represented by Fig. 11.14*a*, has the field windings connected in series with the armature windings. This configuration has a severe limitation when being driven directly by photovoltaic panels because a

drop in motor current accompanying a fall in light intensity on the solar panels affects both the field and armature windings. On the other hand, they tend to be able to pump more water than shunt DC motors on sunny days (Cultura, 2004).

2. The **permanent magnet DC motor**, as illustrated in Fig. 11.14*b*, overcomes the above limitations of the series connected DC motor. Here the field windings are replaced by permanent magnets, therefore producing a constant flux, independent of the armature current and light intensity. This also greatly improves the starting torque of the motors, particularly at low light levels, and gives them excellent performance under reduced load. At half load, such motors typically lose less than 10% of their efficiency.

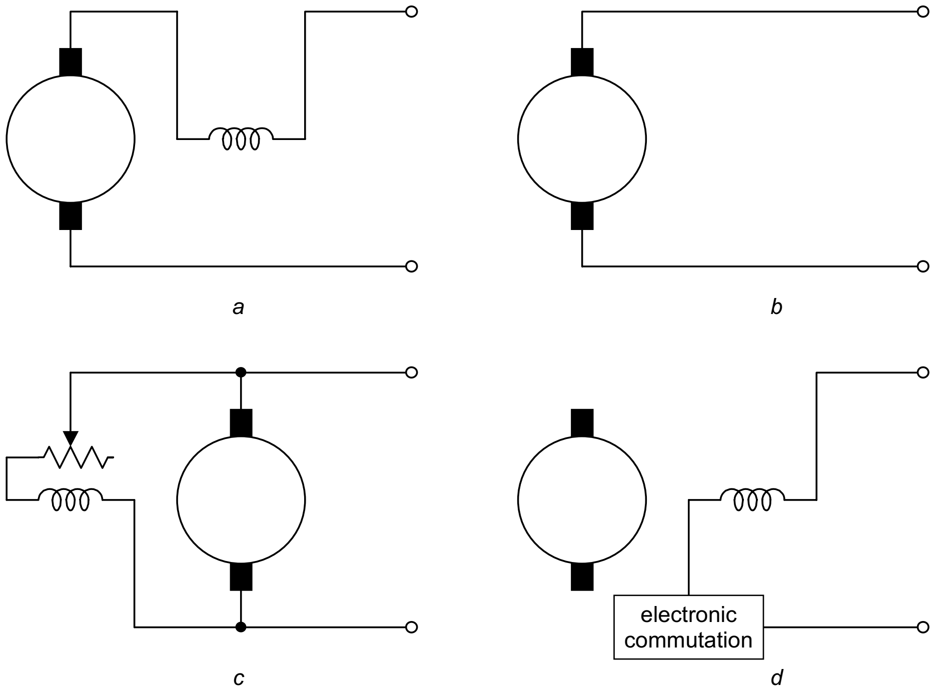

Figure 11.14. DC motor types. (*a*) Series DC motor. (*b*) Permanent magnet DC motor. (*c*) Shunt DC motor. (*d*) Brushless permanent magnet DC motor. (Used with permission of McGraw-Hill Companies, adapted from Fitzgerald, A.E., Kingsley C. Jnr. & Kusko, A. (1971), *Electric Machinery*, McGraw Hill, Tokyo, Japan)

3. The **DC shunt motor** is represented by Fig. 11.14*c*. With these, the field current is determined directly by the motor voltage according to

$$I_f = \frac{V_m}{R_f} \tag{11.1}$$

where I_f is the field current, V_m is the motor voltage and R_f is the field resistance. Similarly, for the armature:

$$V_m = I_a R_a + K\Phi N \tag{11.2}$$

where I_a is the armature current, R_a is the armature resistance and $K\Phi N$ is the back *emf* generated (where K is the motor constant, Φ is the magnetic flux, and N is the motor speed). However, on start up, N is zero, which means, if the motor is directly coupled to the solar panels, the output voltage will be pulled down by the small armature resistance, owing to the limited solar array current output. Hence I_f will be reduced to extremely small values. The consequence of this is an extremely low starting torque, thereby limiting start-up to extremely high light fluxes, if at all. This feature alone makes this type of motor unsuitable for direct coupling to photovoltaic panels, with the result that these can only be used in conjunction with appropriate power conditioning circuitry.

4. The **brushless DC motor**, as illustrated in Fig. 11.14*d*, has the permanent magnets in the rotor and electronically commutates the stator to remove the need for brushes. The electronic commutating circuitry constitutes a parasitic power drain, but no more than the series resistance losses of conventional brushes, and this motor type offers superior performance and long life (Divona *et al.*, 2001). Applications include electric vehicles, solar racing cars, electric mopeds, variable speed fans, computer hard disk drives, consumer electronics, machine tools, sheep shears and aerospace (Gieras & Wing, 2002). They tend to be more expensive but have the significant advantages of highest efficiency and enhanced reliability, owing to the avoided need for brush replacement. Magnet materials in use are alnico (Al, Ni, Co, Fe), ceramics (ferrites) including barium ferrite and strontium ferrite, and rare earths, including samarium cobalt and neodymium iron boron (Gieras & Wing, 2002). The commutating circuits derive their timing from Hall-effect or optical sensors around the shaft.

The first three DC motor types have the severe limitation of requiring brushes. In many situations, the presence of brushes is not a problem. However, for photovoltaic applications where system reliability must be extremely high and maintenance low, their use may be considered unacceptable. Brushes require periodic replacement (every 1–5 years) and the carbon dust from wearing brushes may cause arcing, overheating and considerable power loss (Halcrow & Partners, 1981). If replacement does not take place when required, serious damage may result. It is therefore essential that a failsafe brush design be employed to stop motor operation, before such damage eventuates. The other limitation of brushes is that they prevent the motors from being submersed. This restricts their use with submersible pumps except via undesirable long transmission shafts. This in itself is quite unfortunate since conventional centrifugal pumps are normally submersible and, because of their torque-speed characteristics, are the most suitable of all pumps for direct coupling to photovoltaic panels.

Fig. 11.15 gives the performance curves for a typical low cost, low efficiency DC motor. Higher efficiency motors have similar shaped curves. General advantages and disadvantages of DC motors include:

1. Advantages:

- high efficiencies
- no need for an inverter
- well suited to direct coupling to photovoltaic panels
- high reliability if brushless
- submersible if brushless.

2. Disadvantages:
   - brushed type not submersible
   - brushed type requires higher maintenance
   - expensive
   - not readily available in larger sizes.

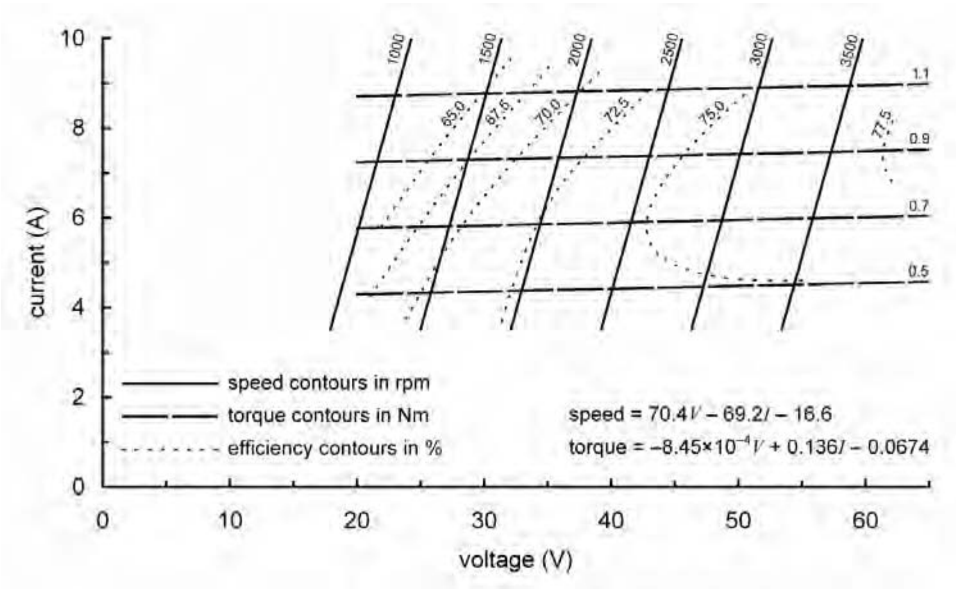

Figure 11.15. Performance curves for typical low cost, low efficiency permanent magnet DC motor (Used with permission of Halcrow & Partners, 1981).

11.4.3 AC motors

A wide range of AC motors are commercially available, owing to the wide range of applications for which they have been used for many years. However, with most of these, the emphasis has been on low cost rather than operating efficiency. In particular, small motors of about 1 kW or less suffer from very low efficiencies, making them not well suited to photovoltaic-powered systems. In addition, they require costly inverters at their inputs, which can exacerbate reliability problems. Furthermore, to provide high starting currents, additional power conditioning circuitry is generally required. In general, however, AC motors are very reliable and relatively inexpensive, being typically half the cost of an equivalent size DC motor.

The two basic types of AC motor available are asynchronous induction motors and synchronous motors. However, standard induction motors produce extremely low starting torques, making them suitable only for low starting torque pumps such as centrifugal pumps, unless appropriately modified to increase the torque generated at high slip frequencies.

11.4.4 Motor losses

Support bearings

Friction in the support bearings has a load-dependent term and a load-independent term, which jointly contribute significantly to the losses in high efficiency motors.

To achieve high reliabilities and low maintenance, lubrication with grease is essential. Although expensive, a high quality lubrication grease that has a temperature-independent kinematic viscosity is recommended, and has been demonstrated to reduce frictional losses by up to 60%.

Magnetic circuit

Imperfections in the magnetic circuit will always contribute losses although, if properly designed, these should be quite small. Low efficiency motors generally have losses in the magnetic circuit as the dominant cause of poor performance. Permanent magnet motors generally need to be carefully designed to ensure operation at the maximum of their BH product.

Motor heating

Motor heating can be a serious loss mechanism and can lead to lower reliabilities and shortened lifetimes. As the temperature increases, the resistance of windings increases, thereby increasing the resistive losses, which in turn act to further increase the motor temperature. It is therefore necessary to keep motors cool, both to achieve high performance and to increase reliability and lifetimes.

Submersible motors are easily kept cool, but surface-mounted motors may need special attention paid to cooling, such as by a heat pipe or ventilation.

11.4.5 Integrated pump/motor machines

Integrated pump/motor machines, where the pump and motor are matched and interconnected within the same housing by the manufacturer, have become popular. Such configurations act to simplify systems and provide high efficiencies when operating at or near their design point. However, careful attention should be paid to performance losses and mismatch that results from using these machines away from their design point, such as with a different head or flow rate.

It is feasible to integrate permanent magnet brushless motors with pumps to such an extent that the motor also serves as the impeller, within an hermetically-sealed, submersible unit (Divona *et al.*, 2001).

11.5 POWER CONDITIONING CIRCUITRY

The role of power conditioning circuitry (Ross, 2003; Schmid & Schmidt, 2003) is to provide the motor/pump with the most suitable voltage-current combination, while ensuring the solar panels operate at their maximum power points. In effect, it alters the load impedance to match the optimum impedance of the array. The circuitry of course must consume very little power to justify its inclusion and, in most systems, will typically consume 4–7% of total power (Matlin, 1979). It is also expensive, usually costing more than the electric motor (Halcrow & Partners, 1981), while historically often providing reliability problems.

As the light intensity falls, the current generated by solar panels falls proportionately while the voltage at the maximum power point remains approximately constant. However, for a motor/pump, as the current falls, the voltage also falls. Consequently, without power conditioning circuitry, as the light intensity falls, the solar array operates at a current and voltage progressively further and further from its maximum power point.

For instance, with centrifugal pumps, the torque is approximately proportional to the speed squared, while the torque produced by the motor will be directly related to the current flowing in the motor windings. Consequently, as the current from the solar array falls, the torque produced by the motor falls, the speed of the pump therefore decreases, the back *emf* produced by the motor correspondingly falls, and hence the voltage required by the motor falls. In this situation for a DC motor, the required form of power conditioning is for a DC-to-DC converter, to effectively convert the excess voltage able to be produced by the solar panels into additional current.

For displacement pumps, the torque required for pumping is, in general, primarily dependent on the pumping head, pipe and pump friction, and pump pipe diameters, but depends little on the speed of pump operation (neglecting high break-away torques). In this instance, a certain threshold current is required by the motor to provide the torque necessary to maintain operation of the pump. The speed of pumping is then determined primarily by the driving voltage available, as the pumping rate will increase until the back *emf* produced in the motor matches the applied voltage from the solar panels. Consequently, the motor/pump load line appears as a horizontal line when superimposed on the current-voltage characteristic of the solar panel. This is an unacceptable mechanism of operation since the falling of the array current below the required level will result in no pumping at all while current generating potential above the critical level will be wasted. Again, a DC-to-DC voltage converter is required and, in fact, is essential when a DC motor is driving a typical displacement pump.

In addition, the high starting (breakaway) torques require high starting currents, which in general cannot be supplied by the solar panels. When starting, the speed is zero and there is no back *emf* produced. Consequently, a DC-to-DC converter can again be beneficially used to produce the high starting currents by effectively converting the excess array voltage into current. Fig. 11.16 shows a circuit that, in principle, facilitates such a conversion, although the control circuitry, which can be the most demanding and unreliable component, is not shown. An alternative approach commonly used for providing high starting currents is through the use of a ‘starting capacitor’, which stores sufficient charge to provide a large current burst to start the motor/pump.

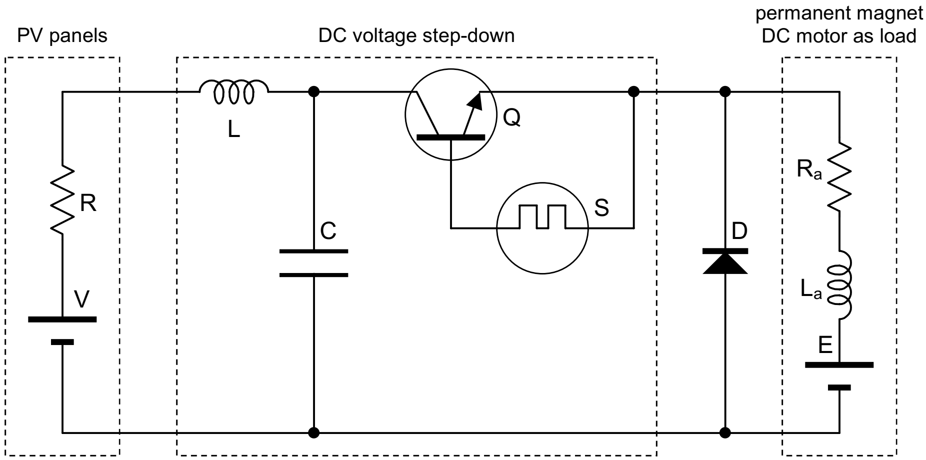

Figure 11.16. Simple DC-to-DC converter (Kheder & Russell, 1988, Used with kind permission from Springer Science and Business Media), R = resistor, V = voltage source, L = inductor, C = capacitor, Q = transistor, S = control signal, D = diode, R_a = armature resistance, L_a = armature inductance, E = motor back emf.

Maximum power point tracking (MPPT) circuitry may be included in any system to boost efficiency. Ironically, however, the most benefit is gained when the system is badly designed and the array and subsystem are poorly matched (Halcrow & Partners, 1981). A well designed system using a centrifugal pump will automatically have an acceptable match between the solar array and subsystem over a wide range of insolation levels. In this instance, no control circuitry is warranted, other than perhaps water level switches or pressure switches. If, however, a MPPT is to be used, ensure internal transient protection is included, to minimise the risk of damage in the event of lightning strikes. MPPT circuitry can reduce the potential for the PV output energy to be converted into heat, with consequent motor damage, rather than mechanical energy (Messenger & Ventre, 2000).

Batteries in such systems can be used effectively for power conditioning by holding the solar array at a constant voltage, which is selected to closely match the maximum power point of the solar array over the complete range of insolation levels. In addition, the storage of energy allows the motor/pump to be always operated under optimum conditions. Fig. 11.17 shows the power demand as a function of time to optimally operate the pumping system. In comparison, Fig. 11.18 shows the power received by the sun throughout a clear sunny day. The benefits of the battery in this instance are clear.

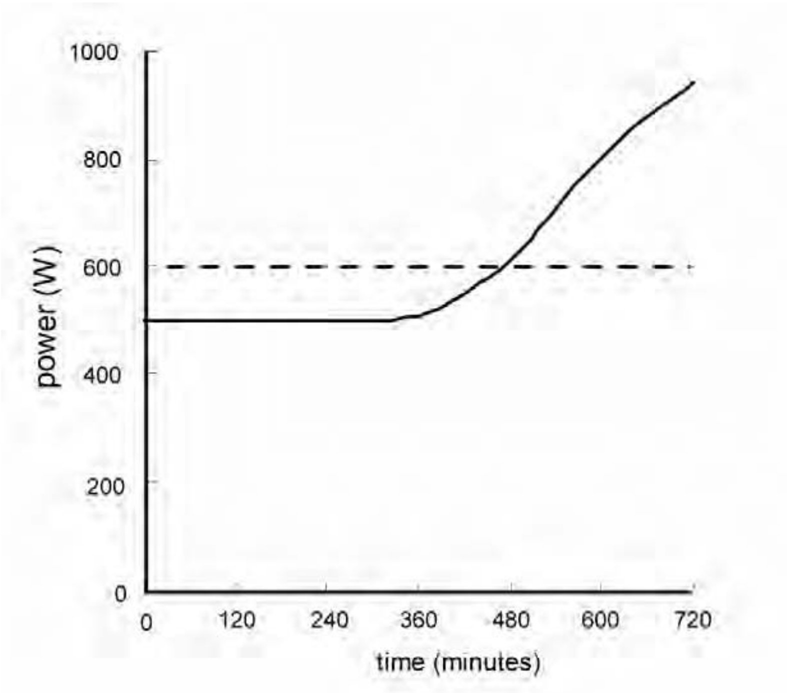

Figure 11.17. Power demand, as a function of time, for optimal operation of a typical water pumping system with limited water source replenishment rate. The requirements for increased power result from falling water level (Baltas *et al.,* 1988, Used with kind permission from Springer Science and Business Media.)

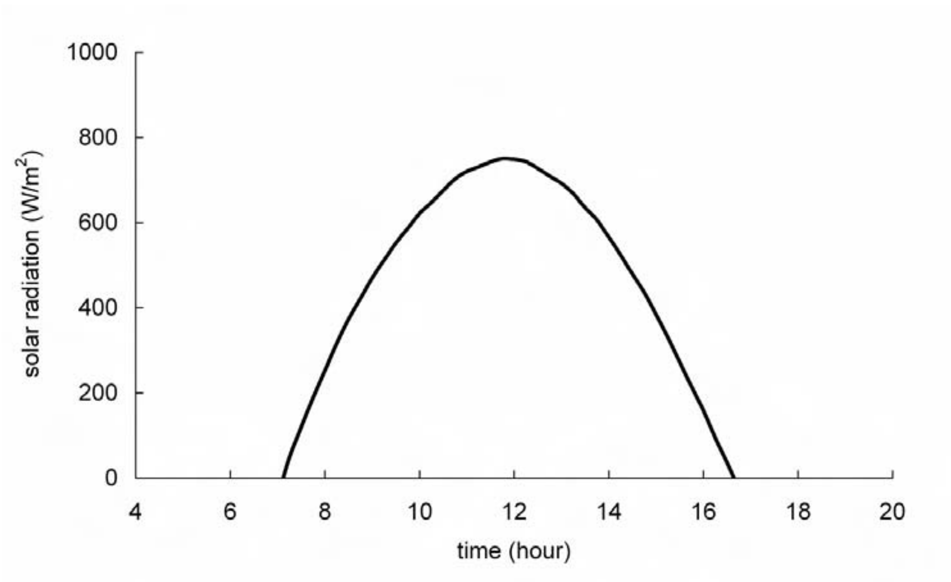

Figure 11.18. Solar radiation received on an inclined plane throughout a clear sunny day.

However, all systems using batteries should include voltage regulation circuitry to prevent the battery from over-charging (see Chapter 6). In addition, it may be necessary to include control circuitry to switch the load on and off. If, for instance, the pumping rate exceeds the replenishment rate for the water source, then the load must be switched on and off accordingly.

In this mode of operation, the response of motor/pump combinations to transient operation should be considered when choosing and designing the system. Short-term electromechanical storage (e.g. flywheel and synchronous machine) has been proposed as a means of allowing centrifugal pumps to operate intermittently, at full load and hence high efficiency (Landau *et al.,* 1992).

When AC motors are used, a DC-to-AC inverter is essential. Such an inverter may be variable frequency, to add greater flexibility to the control, and may include an MPPT and various other forms of power conditioning circuitry. Unfortunately, many inverters can only operate from a stable voltage source and hence require batteries or DC-to-DC converters at their inputs, thereby adding to the system cost. Also, many inverters produce square waves (or at least poor sine waves) and can hence cause problems with motor heating. Centrifugal pumps are commonly driven by three-phase AC motors from pulse-width modulating inverters, an arrangement that allows relatively easy maximum power point tracking of the photovoltaics (Schmid & Schmidt, 2003).

11.6 BATTERIES

Batteries may be used in water pumping systems for two independent purposes—storage of energy and as a power conditioning mechanism.

As a storage medium, batteries are greatly inferior, in most instances, to pumped stored water. However, with some critical applications, or where continuous pumping is necessary, batteries may be required, in which case three days' storage is commonly used.

The role of batteries for power conditioning was briefly considered in the last section. They allow power to be transferred to the load under optimal conditions, whereby both pump and motor can potentially be at their respective peak efficiencies whenever operating. This has four significant advantages relative to a directly-coupled system:

1. It ensures the solar array continues to operate at the maximum power point when the light intensity is reduced, hence ensuring the maximum possible electrical energy is generated.
2. It avoids the situation whereby motors/pumps operate at reduced load for considerable portions of each day. Centrifugal pumps in particular suffer from greatly reduced pumping efficiencies when operated at reduced load.
3. Batteries can provide the high currents required by some loads when starting.
4. Some inverters for AC motors will only operate from batteries.

The disadvantages of using batteries, however, are quite substantial:

1. Most batteries require regular maintenance.

2. Voltage regulation is necessary to protect the batteries from over-charging or excessive discharging.
3. They have fairly limited lives.
4. They are costly.
5. They reduce the reliability of a system that should potentially be extremely high.
6. Their columbic efficiency (charge out divided by charge in) is normally only about 85%.
7. They necessitate a blocking diode being placed at the array output to prevent the batteries from discharging through the array at night.
8. They require considerable over-sizing of the solar arrays, with respect to voltage, to allow them to reach a state of full charge at roughly 14 V (while at the worst extremes of temperature), to compensate for the voltage drop across the blocking diode, to allow for a power loss (voltage drop) in the regulator and to make some allowance for small losses in voltage that accompany variations in light intensity.
9. They can cause heavy metal pollution if not properly recycled, and recycling is not a viable option in many parts of the world.

To illustrate the effect of (8), for a 12 V system, a typical solar panel for battery charging will have 36 cells connected in series, each with an open circuit voltage (V_{oc}) of about 600 mV under standard test conditions (1 kW/m^2, 25°C), giving a solar panel V_{oc} of 21.6 V, and a voltage at the maximum power point (V_{mp}) of 18.0 V. With a 30° temperature rise, V_{mp} falls to 15.8 V. Allowing for variations in light intensity and a 1 V drop across the regulator reduces V_{mp} to about 13.8 V, which is considered necessary to bring the battery to a full state of charge (14–14.5 V). To illustrate the enormous loss incorporated into such a setup, 26 cells series-connected rather than 36 (with the inclusion of batteries) should be sufficient to provide 12 V output in a directly-coupled system. Such a solar panel would then have a V_{oc} of 15.6 V under standard test conditions and a V_{mp} of 13.3 V. Allowing for a more typical 20°C rise in temperature to 45°C reduces V_{mp} to 12.2 V. No allowance has to be made for blocking diode losses, voltage regulator losses, and variations in light intensity. The reason the latter can be neglected is because under reduced solar insolation conditions, excess voltage will always exist for a directly-coupled system because of the relatively greater reductions in current.

If batteries are required, they need to be capable of regular deep discharges and should be housed in a weather-resistant box, which is preferably non-metallic, if non-sealed batteries are selected. When interconnected, each parallel string of batteries should be provided with a fuse as close as possible to the battery terminals.

The advantages and disadvantages of lead-acid batteries as opposed to nickel-cadmium batteries are discussed in Chapter 6. These are valid when considering batteries for storage. However, when batteries are to be used simply for power conditioning, nickel-cadmium batteries should be seriously considered. The additional cost becomes less significant owing to the small quantity required, while the ability to be deep cycled, overcharged and left for long periods fully discharged, in conjunction with their longer life expectancy, robustness, greater reliability and freedom from requiring ongoing maintenance, make them well suited for such use. To use float type lead-acid batteries under such conditions will cause problems with excessive charging and discharging rates, and deep cycling. More conventional fork lift lead-acid batteries are better suited to such use since the high self-discharge rates become relatively unimportant, while their ability to charge and discharge quickly is necessary.

11.7 ARRAY WIRING AND MOUNTING

11.7.1 Array wiring

Reference should be made to the stand-alone system design guidelines mentioned in Chapter 6 (Standards Australia, 2002). Array cables should be heavy duty, with all connections in water-tight junction boxes with strain relief connectors (Ball & Risser, 1988). The gauge of wire should be selected so as to keep resistive losses to less than 2.5%. For reliability, splicing of the leads from the motor to the array output cable should utilise crimp-on connectors with resin-filled heat shrink tubing or equivalent, to ensure long lasting, dry connections. All wiring should be attached to support structures with, for example, nylon cable ties. PVC conduit should be used for the array output wiring to the motor/pump, regulator or batteries. For a submersed motor/pump, heavy duty double-insulated cable is essential. Also, the array and mounting frames need to be grounded using substantial copper wire (*Ibid.*). Grounding through the motor/pump and water source should not be relied on as the system may be dismantled for various reasons. Lightning protection should be considered, and bypass and blocking diodes should be included where appropriate.

11.7.2 Array mounting

All support structures should be anodised aluminium, galvanised steel or stainless steel and need to be designed to withstand the maximum possible wind loading for the particular location (*Ibid.*). Lock washers or equivalent should be used on all bolts to remove risk of them coming loose during the subsequent 20 years. The structures should be located as close as possible to the water source to minimise wire lengths, and where necessary fencing may be used to protect from animals, theft, vandals etc. (I*bid.*).

Tracking support structures can be useful to enable the solar panels to point more directly at the sun throughout most of the day. Motorised or passive tracking mechanisms in Madrid, for example, have been calculated to boost annual water flow by 40% or more. However, trackers operating outside for extended periods can introduce considerable expense, maintenance and reliability problems (Illanes *et al.*, 2003). Vilela *et al.* (2003) calculate that tracking could increase the pumped water volume by up to 53%, partly by allowing the pump to start earlier each morning. A more affordable alternative is to use a manual tracking system, whereby a simple adjustment by an operator can take advantage of the changing sun position. One such regime is where a seasonal adjustment of the tilt angle is made a few times each year, to compensate for the variations in the sun's angle of declination. Another form of adjustment allows for redirection of the solar panels twice a day to take greater advantage of both the morning and afternoon sun. Yet another mechanism for adjustment is a continuously-variable one, where it becomes the responsibility of the operators to redirect the panels whenever they wish. The mechanical structures for the latter tend to be more complicated, less robust and more prone to failure. Of course, the option of manually redirecting the solar panels depends on the availability of an operator, which for some remote or inaccessible locations may not be feasible nor practical. However, to give an appreciation of the potential benefits, in 1981 the World Bank, using one of the most efficient photovoltaic water pumping systems then available (Arco Solar System), added a simple manual tracking system requiring two adjustments per day. The result was that a 30% relative improvement in the daily efficiency of the system was achieved (Halcrow & Partners, 1981*b*).

EXERCISES

11.1 (a) Discuss the use of solar cells in water pumping systems.

(b) What are the alternative techniques for water pumping and how does the use of solar cells compare to each of these?

11.2 (a) What are the advantages and disadvantages of a directly-coupled photovoltaic-powered water pumping system (where the solar panels are directly connected to the motor/pump, with no interface circuitry or batteries)?

(b) What limitations does such a configuration impose on choice of pumps?

(c) In what situations or applications would such a configurations be:

(i) preferred

(ii) unacceptable?

11.3 Can you tell the difference between a permanent magnet, brushless DC motor, and a synchronous AC motor?

11.4 (a) Outline the potential range in water pumping system configurations, using AC and DC motors, the wide variety of water pump types and power conditioning circuitry.

(b) Obtain information on the availability, price, operating performance and characteristics of the different components that make up a photovoltaic-powered water pumping system.

(c) Are there problems in matching these components, from efficiency and compatibility perspectives, within such a system?

(d) Discuss the suitability of the different configurations for specific pumping applications, indicating the relevant strengths and weaknesses of each.

11.5 (a) What are the advantages and disadvantages of photovoltaics for water pumping?

(b) Discuss the variability in types of water sources and their characteristics.

(c) Explain the relevance of the different water source types to component selection in corresponding photovoltaic water pumping systems.

11.6 (a) For photovoltaic water pumping, when would you use a positive displacement pump in preference to a centrifugal pump?

(b) How are the general characteristics of displacement pumps different from those of centrifugal pumps?

(c) How do these differences affect photovoltaic system design and operating performance?

11.7 (a) What are the advantages and disadvantages of using batteries in photovoltaic water pumping systems?

(b) When is it necessary to use batteries in such systems and, in each case, what are the necessary battery characteristics and why?

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Chapter

12

PV WATER PUMPING SYSTEM DESIGN

12.1 INTRODUCTION

Considerable emphasis in this book is placed on the design of photovoltaic water pumping systems, firstly because water pumping is a major application for photovoltaics and secondly because the design of each system is considerably more complicated than most applications, owing to the large range of water source types, consumer requirements and system configurations. Where batteries are required for storage, design procedures are relatively straightforward and follow the design principles outlined in earlier chapters for stand-alone systems. However, direct interfacing between photovoltaic panels and the water pump motor introduces significant mismatch problems as the light intensity varies. This leads to large variations in overall system efficiency throughout each day and between ‘sunny’ and ‘cloudy’ weather, making it inappropriate to assume that the power delivered to the load is directly related to the light energy incident on the solar panels. It is therefore necessary to process insolation data differently for directly-coupled systems. The basic design principles are covered in this chapter, with worked examples given in Appendix H.

12.2 BASIC STEPS IN SYSTEM DESIGN

Designing a photovoltaic water pumping system has two very important aspects:

1. Selection of the most suitable system component types—crucial in providing a low maintenance, long life system of high reliability.
2. Matching of system components—a difficult area requiring considerable know-how and expertise, and ultimately responsible for efficient operation of the system.

To demonstrate the importance of the latter, the World Bank analysed one of the most efficient water pumping systems from their testing program at the time (referred to in the last chapter) and found the components to be poorly matched. Improved matching was demonstrated to give an 18% improvement in operating efficiency, on top of a 30% increase obtained through the introduction of manual tracking (Halcrow & Partners, 1981). It appears that this level of mismatch or worse is quite common with many system designs.

One of the most important questions to be asked before designing a particular system is: "What level of reliability is necessary and to what extent can maintenance be carried out?"

The answer to this will indicate a bias towards either a direct-coupled system with simplicity, reliability, low maintenance and long life, or a system that sacrifices these attributes, to an extent, to gain greater efficiency. The features included in the latter, which contribute to the increased complexity, higher maintenance, poorer reliability and shorter life expectancy, include power conditioning circuitry, inverters, and perhaps batteries.

Of course, other constraints influence the type of system selected, and each system needs to be designed on its own merits. No one system will be ideal for all applications and, of all photovoltaic applications, water pumping probably introduces the greatest variability of system design with regard to configuration and component selection. Several computer simulation and design tools and methodologies are available to assist designers (e.g. Mayer *et al.*, 1992; Sharma *et al.*, 1995; Protogeropoulos & Pearce, 2000; Arab, 2004). However, use of some of these requires a high level of water pumping knowledge and good data on site conditions and component performances. Thomas (1987) describes a sizing system based on nomographs to assist potential buyers. There are also practical guides to solar water pumping, such as that by Dankoff (1997).

The general approach to designing a system can be summarised as follows:

1. Determine the volume of water to be pumped each day, and at what head.
2. Calculate the pump rate from the number of sunlight hours.
3. Select the pump type.
4. From the torque-speed characteristic of the pump, select a motor with a compatible torque-speed characteristic.
5. Select appropriate solar modules.

6. Select module mounting method—fixed or manual tracking.

For a system using batteries, step 5 simply involves the use of 'stand-alone system' design principles, outlined in earlier chapters.

However, prior to following these guidelines, it is useful to ascertain whether a directly-coupled system (no batteries, no inverter and no power conditioning circuitry) is feasible for the particular application. If so, such a system may be advisable, even though its use provides reduced flexibility in component choice and system configuration, while maximum power point tracking circuitry is becoming more freely available. However, there are occasions when directly-coupled systems are unsuitable. These include:

1. When pumping heads are too large to be able to use a centrifugal pump with reasonable efficiency.
2. When suitable DC motors are not available, such as with some large systems.
3. When the pumping rate in bright sunshine exceeds the water source replenishment rates.
4. When it is essential batteries be used for energy storage (i.e. where 'availability' of pumped water must be very high and tank storage is unsuitable, e.g. portable units).
5. Locations characterised by excessive cloudy weather, making the poor part-load efficiencies of a directly-coupled system unacceptable.

Many water pumping applications are not characterised by any of the above and are accordingly suited to a directly-coupled system. However, the use of maximum power point tracking circuitry is increasingly common for pump applications, including in many commercially supplied pump systems (von Aichberger, 2003).

12.3 DESIGN OF A DIRECTLY-COUPLED SYSTEM

A directly-coupled system is one where a low starting torque pump (such as a centrifugal pump) can be driven by a DC motor that receives its power directly from the solar panels. No batteries, inverters, or power conditioning circuitry are used, other than perhaps safety cut-out relays activated by level, flow or pressure sensing transducers. When the sun shines sufficiently brightly, the system operates and water is pumped either for storage or direct use.

An approach for designing directly-coupled PV-powered water pumping systems is provided in Appendix H. Important considerations are as follows:

1. The volume of water to be pumped and over what period. The volume to be pumped may vary significantly throughout the year and in fact may be entirely non-critical for some months of the year, as for some irrigation applications. This will have important implications regarding array tilt angles. For instance:
    - If the demand profile throughout the year is reasonably constant (such as for a domestic water supply), a tilt angle in the vicinity of latitude + 20° will be necessary to give the most uniform insolation levels throughout the year falling on the solar panels.

- If the amount of water to be pumped is to be reasonably constant throughout the year, but with a definite bias towards summer months (such as for drinking water), a tilt angle in the vicinity of latitude + 10° will probably be desirable.
- If the annual amount of water pumped is to be maximised (such as with a large storage reservoir), a tilt angle in the range latitude to latitude – 10° should be used.
- If the water pumped during summer months is to be maximised (such as for some irrigation applications), a tilt angle in the vicinity of latitude – 20° will be preferable, to ensure the solar panels point more directly at the midday summer sun.

In general, more uniform pumping throughout the year will be provided by increasing the tilt angle.

2. The pumping head and its seasonal variations must be known and, where possible, information regarding water source replenishment rates should be obtained.
3. The inclusion and economics of water storage should be considered in conjunction with consumer needs.
4. Any available insolation data should be obtained and used in conjunction with the guidelines given in Appendix B and Chapter 1. Fig. H.1 indicates the procedure for determining the light intensity incident on the solar panels at angle β at noon.
5. Select a pump to suit starting torque requirements, the range of operating heads, any physical dimension constraints imposed by the application, and one that will pump the required volume of water when operating at its maximum efficiency point. It is essential the torque-speed characteristics of the selected pump be known, to facilitate system matching.
6. Select a motor with a torque-speed characteristic compatible with that of the pump. It is important that the motor operate near maximum efficiency when producing the necessary torque, to drive the pump at its design speed. Recall that

$$V_m = I_a R_a + K\Phi N \qquad (12.1)$$

where V_m is the motor voltage, I_a is the armature current, R_a is the resistance of the armature, K is the motor constant, Φ is the flux density and N is the speed of rotation.

In Eqn. 12.1, the voltage applied to the motor terminals (V_m) has two components—$I_a R_a$ is the resistive voltage drop across the armature windings and $K\Phi N$ is the back *emf* generated, which is hence proportional to the speed of rotation N and the flux density Φ.

If we now consider a permanent magnet DC motor, then Φ remains approximately constant, independent of the voltage applied or current consumed, and I_a becomes the total motor current I_m, since no current is required for field windings. Thus, we can rewrite Eqn. (12.1) as

$$V_m = I_m R_a + K\Phi N \qquad (12.2)$$

The electromagnetic torque (τ_e) developed by such a motor is proportional to the armature current (and hence I_m) and also the flux density Φ (which is a constant). This gives us

$$\tau_e = K'\Phi I_m \qquad (12.3)$$

where K' is a constant related to the physical dimensions of the motor and the number of windings in the armature (Hambley, 2002).

When the motor drives a load (such as a water pump), the speed of the motor will continue to alter until steady state is reached; that is, when

$$\tau_e = \tau_l \qquad (12.4)$$

where τ_l is the torque required to drive the load at that particular speed.

For any commercial pump, the torque versus speed (τ_l versus N) characteristics should be available from the supplier. For each value of N, τ_l is thus obtainable and, using Eqns. (12.3) and (12.4), I_m can be calculated. Subsequent use of I_m and N in Eqn. (12.2) gives the corresponding value of V_m. Therefore, for each N of the pump, the motor voltage and current required from the solar panels are determined. However, the actual voltage generated by the solar panels needs to be about 2% higher than that calculated, to allow for resistive losses in the wiring.

7. Appropriate sizing of the photovoltaic system will enable overall system specifications to be met, while simultaneously maximising overall system efficiency. For this, both the voltage and current at maximum power point need to be optimised. Unfortunately, little choice exists with regard to the voltages available with standard commercial modules. They are normally designed for 12 V systems (including considerable excess voltage capacity to allow for battery charging, regulation, blocking diode etc.), and can be connected in series to increase system voltage to multiples of 12 V. This restriction can be overcome by the use of a DC-to-DC converter. In comparison, a reasonable choice in short circuit currents exists, owing to the range of solar cell sizes and technologies used by different manufacturers. An approach for optimising the photovoltaic configuration by matching the requirements of the water pumping subsystem to the output of the photovoltaics is provided in Appendix H.

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Appendix

A

STANDARD AM0 AND AM1.5 SPECTRA

Table A.1 is an abbreviated version of that provided online by the National Renewable Energy Laboratory (NREL, 2004), which is from Standard ASTM G173-02 (ASTM, 2003). This abbreviated version of the standard spectral distribution is for information only. Since this version is only a sample of the more extensive complete table, using the abbreviated version in the applications for which the standard was developed will not produce the same technical results as would use of the complete table published in the standard.

Permission to reproduce this abbreviated version of the standard has been granted by ASTM.

The ASTM standard spectral distributions are computed using the SMARTS spectral model of Gueymard (1995, 2001).

Table A.1. Standard AM0, global AM1.5, and direct and circumsolar AM1.5 spectra. (Extracted, with permission, from G173-03 Standard Tables for Reference Solar Spectral Irradiances: Direct Normal and Hemispherical on 37° Tilted Surface, copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428.)

wave-length (nm)	**AM0** ($W/m^2/nm$)	**global AM1.5** ($W/m^2/nm$)	**direct and circumsolar AM1.5** ($W/m^2/nm$)
280	8.2000E–02	4.7309E–23	2.5361E–26
290	5.6300E–01	6.0168E–09	5.1454E–10
300	4.5794E–01	1.0205E–03	4.5631E–04
310	5.3300E–01	5.0939E–02	2.7826E–02
320	7.7500E–01	2.0527E–01	1.1277E–01
330	1.1098E+00	4.7139E–01	2.6192E–01
340	1.0544E+00	5.0180E–01	2.9659E–01
350	1.0122E+00	5.2798E–01	3.2913E–01
360	1.0890E+00	5.9817E–01	3.9240E–01
370	1.2934E+00	7.5507E–01	5.1666E–01
380	1.1520E+00	7.0077E–01	4.9751E–01
390	1.2519E+00	7.9699E–01	5.8457E–01
400	1.6885E+00	1.1141E+00	8.3989E–01
410	1.5370E+00	1.0485E+00	8.0910E–01
420	1.5990E+00	1.1232E+00	8.8467E–01
430	1.2120E+00	8.7462E–01	7.0134E–01
440	1.8300E+00	1.3499E+00	1.0993E+00
450	2.0690E+00	1.5595E+00	1.2881E+00
460	1.9973E+00	1.5291E+00	1.2791E+00
470	1.9390E+00	1.5077E+00	1.2749E+00
480	2.0680E+00	1.6181E+00	1.3825E+00
490	2.0320E+00	1.6224E+00	1.3968E+00
500	1.9160E+00	1.5451E+00	1.3391E+00
510	1.9100E+00	1.5481E+00	1.3497E+00
520	1.8600E+00	1.5236E+00	1.3349E+00
530	1.8920E+00	1.5446E+00	1.3598E+00
540	1.8000E+00	1.4825E+00	1.3096E+00
550	1.8630E+00	1.5399E+00	1.3648E+00
560	1.7860E+00	1.4740E+00	1.3118E+00
570	1.8280E+00	1.4816E+00	1.3240E+00
580	1.8340E+00	1.5020E+00	1.3455E+00
590	1.7218E+00	1.3709E+00	1.2316E+00
600	1.7700E+00	1.4753E+00	1.3278E+00
610	1.7240E+00	1.4686E+00	1.3237E+00
620	1.7110E+00	1.4739E+00	1.3299E+00
630	1.6650E+00	1.3924E+00	1.2589E+00
640	1.6130E+00	1.4340E+00	1.2962E+00
650	1.5260E+00	1.3594E+00	1.2299E+00
660	1.5580E+00	1.3992E+00	1.2668E+00
670	1.5340E+00	1.4196E+00	1.2853E+00
680	1.4940E+00	1.3969E+00	1.2650E+00
690	1.4790E+00	1.1821E+00	1.0746E+00
700	1.4220E+00	1.2823E+00	1.1636E+00
710	1.4040E+00	1.3175E+00	1.1954E+00
720	1.3487E+00	9.8550E–01	8.9940E–01
730	1.3357E+00	1.1285E+00	1.0294E+00
740	1.2830E+00	1.2195E+00	1.1119E+00
750	1.2740E+00	1.2341E+00	1.1273E+00
760	1.2590E+00	2.6604E–01	2.4716E–01
770	1.2146E+00	1.1608E+00	1.0646E+00
780	1.1930E+00	1.1636E+00	1.0687E+00
790	1.1704E+00	1.0910E+00	1.0045E+00
800	1.1248E+00	1.0725E+00	9.8859E–01
810	1.1100E+00	1.0559E+00	9.7488E–01
820	1.0740E+00	8.6188E–01	7.9899E–01
830	1.0563E+00	9.1601E–01	8.4930E–01
840	1.0500E+00	1.0157E+00	9.4124E–01
850	9.1000E–01	8.9372E–01	8.2900E–01
860	1.0000E+00	9.8816E–01	9.1764E–01
870	9.7700E–01	9.6755E–01	8.9933E–01
875	9.3562E–01	9.2687E–01	8.6204E–01
880	9.4856E–01	9.3957E–01	8.7434E–01
885	9.5469E–01	9.4423E–01	8.7913E–01
890	9.4236E–01	9.2393E–01	8.6078E–01
895	9.2600E–01	8.1357E–01	7.5956E–01
900	9.1378E–01	7.4260E–01	6.9429E–01
905	9.1800E–01	8.1709E–01	7.6337E–01
910	8.9496E–01	6.2467E–01	5.8553E–01
920	8.8540E–01	7.4414E–01	6.9657E–01
930	8.6866E–01	4.3210E–01	4.0679E–01
940	8.4000E–01	4.7181E–01	4.4411E–01
950	8.2867E–01	1.4726E–01	1.3944E–01
960	8.0627E–01	4.2066E–01	3.9685E–01
970	7.9140E–01	6.3461E–01	5.9689E–01
980	7.7512E–01	6.0468E–01	5.6941E–01
990	7.5694E–01	7.3227E–01	6.8843E–01

Table A.1 (continued).

wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)	wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)
1000	7.4255E–01	7.3532E–01	6.9159E–01	1500	3.0077E–01	2.5061E–01	2.4339E–01
1010	7.3055E–01	7.1914E–01	6.7695E–01	1510	2.9394E–01	2.7052E–01	2.6269E–01
1020	7.0127E–01	6.9896E–01	6.5839E–01	1520	2.8786E–01	2.6450E–01	2.5688E–01
1030	6.9208E–01	6.9055E–01	6.5092E–01	1530	2.6731E–01	2.5522E–01	2.4789E–01
1040	6.7440E–01	6.7170E–01	6.3366E–01	1540	2.6857E–01	2.6491E–01	2.5737E–01
1050	6.6117E–01	6.5463E–01	6.1802E–01	1550	2.6961E–01	2.6990E–01	2.6226E–01
1060	6.4831E–01	6.3585E–01	6.0073E–01	1560	2.6546E–01	2.6568E–01	2.5821E–01
1070	6.2165E–01	6.0469E–01	5.7178E–01	1570	2.6068E–01	2.4175E–01	2.3497E–01
1080	6.2250E–01	5.9722E–01	5.6519E–01	1580	2.6381E–01	2.4464E–01	2.3772E–01
1090	6.0442E–01	5.5573E–01	5.2656E–01	1590	2.4154E–01	2.4179E–01	2.3486E–01
1100	6.0000E–01	4.8577E–01	4.6113E–01	1600	2.5259E–01	2.3810E–01	2.3133E–01
1110	5.8700E–01	4.7899E–01	4.5496E–01	1610	2.3312E–01	2.1760E–01	2.1146E–01
1120	5.6850E–01	1.4189E–01	1.3562E–01	1620	2.3407E–01	2.3449E–01	2.2783E–01
1130	5.6401E–01	7.0574E–02	6.7568E–02	1630	2.3655E–01	2.3651E–01	2.2984E–01
1140	5.5573E–01	2.5599E–01	2.4447E–01	1640	2.2571E–01	2.1511E–01	2.0913E–01
1150	5.4623E–01	1.2164E–01	1.1648E–01	1650	2.2840E–01	2.2526E–01	2.1902E–01
1160	5.2928E–01	2.8648E–01	2.7371E–01	1660	2.2412E–01	2.2332E–01	2.1721E–01
1170	5.2875E–01	4.5873E–01	4.3731E–01	1670	2.2208E–01	2.2168E–01	2.1573E–01
1180	5.2199E–01	4.4069E–01	4.2052E–01	1680	2.0641E–01	2.0558E–01	2.0017E–01
1190	5.0583E–01	4.6239E–01	4.4124E–01	1690	2.0845E–01	2.0523E–01	1.9991E–01
1200	5.0005E–01	4.4825E–01	4.2789E–01	1700	2.0539E–01	1.9975E–01	1.9464E–01
1210	4.9225E–01	4.5336E–01	4.3267E–01	1710	1.9894E–01	1.8790E–01	1.8316E–01
1220	4.8433E–01	4.5805E–01	4.3724E–01	1720	1.9799E–01	1.8698E–01	1.8231E–01
1230	4.7502E–01	4.6003E–01	4.3928E–01	1730	1.9309E–01	1.7407E–01	1.6979E–01
1240	4.5968E–01	4.6077E–01	4.4011E–01	1740	1.9001E–01	1.6818E–01	1.6405E–01
1250	4.5860E–01	4.5705E–01	4.3684E–01	1750	1.8518E–01	1.6566E–01	1.6162E–01
1260	4.5018E–01	4.3110E–01	4.1235E–01	1760	1.8243E–01	1.5998E–01	1.5608E–01
1270	4.4212E–01	3.8744E–01	3.7087E–01	1770	1.7969E–01	1.4172E–01	1.3831E–01
1280	4.3543E–01	4.2204E–01	4.0387E–01	1780	1.7553E–01	1.0050E–01	9.8143E–02
1290	4.1851E–01	4.1285E–01	3.9522E–01	1790	1.7371E–01	8.8904E–02	8.6831E–02
1300	4.1537E–01	3.5312E–01	3.3855E–01	1800	1.6800E–01	3.1828E–02	3.1112E–02
1310	4.0714E–01	3.0114E–01	2.8908E–01	1810	1.6859E–01	9.6911E–03	9.4762E–03
1320	3.9875E–01	2.5872E–01	2.4864E–01	1820	1.6000E–01	9.8755E–04	9.6578E–04
1330	3.8548E–01	2.2923E–01	2.2052E–01	1830	1.5921E–01	5.2041E–06	5.0896E–06
1340	3.7439E–01	1.6831E–01	1.6216E–01	1840	1.5552E–01	6.2703E–08	6.1337E–08
1350	3.7081E–01	1.6025E–02	1.5488E–02	1850	1.5337E–01	2.9993E–06	2.9348E–06
1360	3.6464E–01	2.1404E–06	2.0706E–06	1860	1.4933E–01	1.1151E–05	1.0920E–05
1370	3.5912E–01	2.9200E–07	2.8266E–07	1870	1.4565E–01	2.6662E–10	2.6148E–10
1380	3.5682E–01	8.1587E–05	7.9042E–05	1880	1.4667E–01	7.7505E–05	7.6123E–05
1390	3.4736E–01	4.9328E–04	4.7836E–04	1890	1.4041E–01	2.2333E–04	2.1956E–04
1400	3.3896E–01	3.2466E–09	3.1513E–09	1900	1.4041E–01	8.6221E–07	8.4916E–07
1410	3.4046E–01	4.6653E–04	4.5332E–04	1910	1.3654E–01	2.3045E–05	2.2726E–05
1420	3.3270E–01	8.2718E–03	8.0437E–03	1920	1.3463E–01	4.5069E–04	4.4451E–04
1430	3.2277E–01	6.1601E–02	5.9912E–02	1930	1.3145E–01	5.5242E–04	5.4474E–04
1440	3.1269E–01	3.9601E–02	3.8547E–02	1940	1.2950E–01	3.2821E–03	3.2357E–03
1450	3.1774E–01	2.7412E–02	2.6699E–02	1950	1.2627E–01	1.6727E–02	1.6482E–02
1460	3.1367E–01	8.5421E–02	8.3161E–02	1960	1.2610E–01	2.1906E–02	2.1569E–02
1470	3.1010E–01	4.9678E–02	4.8397E–02	1970	1.2375E–01	4.8847E–02	4.8055E–02
1480	3.0626E–01	6.0637E–02	5.9063E–02	1980	1.1968E–01	7.5512E–02	7.4234E–02
1490	3.0093E–01	1.7478E–01	1.6993E–01	1990	1.1977E–01	8.5613E–02	8.4124E–02

Table A.1 (continued).

wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)	wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)
2000	1.1673E–01	3.8156E–02	3.7491E–02	2500	5.1380E–02	7.0642E–03	7.0328E–03
2010	1.1512E–01	3.9748E–02	3.9071E–02	2510	4.9600E–02	2.2163E–03	2.2063E–03
2020	1.1192E–01	4.4981E–02	4.4239E–02	2520	4.8140E–02	3.7054E–04	3.6879E–04
2030	1.0969E–01	8.4856E–02	8.3460E–02	2530	4.7700E–02	6.3593E–07	6.3279E–07
2040	1.0720E–01	8.9781E–02	8.8344E–02	2540	4.6770E–02	3.7716E–07	3.7521E–07
2050	1.0592E–01	6.7927E–02	6.6892E–02	2550	4.6260E–02	2.8222E–13	2.8066E–13
2060	1.0320E–01	6.9193E–02	6.8157E–02	2560	4.5400E–02	3.1020E–11	3.0842E–11
2070	1.0095E–01	6.5676E–02	6.4715E–02	2570	4.4850E–02	1.5258E–18	1.5151E–18
2080	9.9330E–02	8.6812E–02	8.5528E–02	2580	4.4100E–02	3.8214E–22	3.7933E–22
2090	9.7540E–02	8.9100E–02	8.7779E–02	2590	4.3410E–02	5.4793E–31	5.4369E–31
2100	9.6240E–02	8.6133E–02	8.4869E–02	2600	4.2910E–02	4.4912E–28	4.4556E–28
2110	9.4630E–02	8.9654E–02	8.8320E–02	2610	4.2500E–02	5.9447E–34	5.8970E–34
2120	9.3140E–02	8.7588E–02	8.6281E–02	2620	4.1900E–02	5.6505E–29	5.6056E–29
2130	9.2380E–02	8.9774E–02	8.8422E–02	2630	4.1160E–02	2.8026E–45	2.8026E–45
2140	9.1050E–02	9.0767E–02	8.9390E–02	2640	4.0220E–02	1.1750E–16	1.1657E–16
2150	8.9710E–02	8.4639E–02	8.3369E–02	2650	3.9960E–02	1.4295E–19	1.4186E–19
2160	8.7890E–02	8.4170E–02	8.2912E–02	2660	3.9480E–02	2.6068E–25	2.5880E–25
2170	8.5370E–02	8.1996E–02	8.0776E–02	2670	3.9100E–02	0.0000E+00	0.0000E+00
2180	8.4640E–02	8.1808E–02	8.0597E–02	2680	3.8430E–02	0.0000E+00	0.0000E+00
2190	8.3140E–02	7.9068E–02	7.7905E–02	2690	3.7790E–02	1.0226E–29	1.0178E–29
2200	8.2790E–02	7.1202E–02	7.0175E–02	2700	3.7120E–02	0.0000E+00	0.0000E+00
2210	8.0810E–02	7.9315E–02	7.8174E–02	2710	3.6680E–02	1.1250E–35	1.1239E–35
2220	7.9990E–02	7.7730E–02	7.6631E–02	2720	3.6380E–02	5.6052E–45	5.6052E–45
2230	7.8400E–02	7.5773E–02	7.4727E–02	2730	3.6010E–02	6.0734E–19	6.0929E–19
2240	7.6510E–02	7.3118E–02	7.2140E–02	2740	3.5530E–02	2.3314E–27	2.3435E–27
2250	7.5370E–02	7.1937E–02	7.1034E–02	2750	3.5180E–02	1.6648E–28	1.6758E–28
2260	7.4090E–02	6.6929E–02	6.6143E–02	2760	3.4550E–02	0.0000E+00	0.0000E+00
2270	7.3100E–02	6.4867E–02	6.4138E–02	2770	3.4260E–02	8.3791E–24	8.4528E–24
2280	7.1390E–02	6.6288E–02	6.5551E–02	2780	3.3640E–02	4.8067E–34	4.8532E–34
2290	7.1190E–02	6.3220E–02	6.2534E–02	2790	3.3200E–02	1.2170E–16	1.2295E–16
2300	6.9640E–02	5.8824E–02	5.8193E–02	2800	3.2760E–02	1.6484E–12	1.6665E–12
2310	6.8900E–02	6.3870E–02	6.3189E–02	2810	3.2420E–02	4.0233E–10	4.0695E–10
2320	6.7630E–02	5.2031E–02	5.1489E–02	2820	3.2060E–02	2.0548E–11	2.0789E–11
2330	6.6220E–02	5.6824E–02	5.6231E–02	2830	3.1700E–02	3.9008E–06	3.9475E–06
2340	6.5220E–02	4.5836E–02	4.5366E–02	2840	3.1180E–02	1.9609E–07	1.9849E–07
2350	6.4340E–02	4.1536E–02	4.1115E–02	2850	3.0680E–02	1.1566E–06	1.1708E–06
2360	6.3070E–02	5.0237E–02	4.9724E–02	2860	3.0160E–02	2.5356E–05	2.5672E–05
2370	6.2390E–02	3.0817E–02	3.0514E–02	2870	2.9600E–02	6.3129E–06	6.3922E–06
2380	6.1810E–02	4.2552E–02	4.2128E–02	2880	2.9400E–02	2.4724E–04	2.5037E–04
2390	6.0360E–02	3.7109E–02	3.6748E–02	2890	2.9070E–02	1.8623E–04	1.8860E–04
2400	5.9740E–02	4.4150E–02	4.3726E–02	2900	2.8810E–02	8.1152E–04	8.2183E–04
2410	5.9150E–02	3.3813E–02	3.3504E–02	2910	2.8500E–02	2.7220E–03	2.7566E–03
2420	5.7820E–02	2.6590E–02	2.6358E–02	2920	2.8040E–02	2.8948E–03	2.9316E–03
2430	5.7190E–02	4.5099E–02	4.4725E–02	2930	2.7570E–02	5.8858E–03	5.9606E–03
2440	5.6270E–02	4.3249E–02	4.2926E–02	2940	2.7140E–02	1.6273E–03	1.6479E–03
2450	5.4590E–02	1.3611E–02	1.3523E–02	2950	2.6680E–02	5.2276E–03	5.2935E–03
2460	5.4510E–02	3.3363E–02	3.3157E–02	2960	2.6380E–02	4.5971E–03	4.6549E–03
2470	5.3400E–02	1.6727E–02	1.6635E–02	2970	2.6120E–02	3.5233E–04	3.5676E–04
2480	5.2100E–02	8.0395E–03	7.9996E–03	2980	2.5800E–02	1.3381E–03	1.3548E–03
2490	5.2220E–02	3.5113E–03	3.4957E–03	2990	2.5540E–02	1.0280E–02	1.0407E–02

Table A.1 (continued).

wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)	wave-length (nm)	AM0 (W/m²/nm)	global AM1.5 (W/m²/nm)	direct and circumsolar AM1.5 (W/m²/nm)
3000	2.5250E–02	7.8472E–03	7.9442E–03	3500	1.4230E–02	1.1917E–02	1.2032E–02
3010	2.4980E–02	6.8479E–03	6.9320E–03	3510	1.4050E–02	1.1963E–02	1.2077E–02
3020	2.4660E–02	6.3369E–04	6.4143E–04	3520	1.3930E–02	1.2122E–02	1.2226E–02
3030	2.4420E–02	6.0753E–03	6.1491E–03	3530	1.3800E–02	1.1127E–02	1.1217E–02
3040	2.3930E–02	2.0242E–03	2.0487E–03	3540	1.3670E–02	9.0310E–03	9.1011E–03
3050	2.3950E–02	1.0321E–03	1.0446E–03	3550	1.3570E–02	1.0538E–02	1.0616E–02
3060	2.3760E–02	6.3012E–03	6.3761E–03	3560	1.3360E–02	1.0795E–02	1.0872E–02
3070	2.3440E–02	1.7492E–03	1.7699E–03	3570	1.3250E–02	8.3376E–03	8.3951E–03
3080	2.3150E–02	3.6224E–03	3.6646E–03	3580	1.3080E–02	1.0187E–02	1.0255E–02
3090	2.2800E–02	2.3805E–03	2.4080E–03	3590	1.2980E–02	9.4523E–03	9.5145E–03
3100	2.2430E–02	4.4010E–03	4.4513E–03	3600	1.2850E–02	1.0262E–02	1.0328E–02
3110	2.2110E–02	8.4569E–04	8.5524E–04	3610	1.2740E–02	9.4787E–03	9.5385E–03
3120	2.1740E–02	9.8197E–03	9.9294E–03	3620	1.2640E–02	1.1614E–02	1.1686E–02
3130	2.1450E–02	5.7614E–03	5.8246E–03	3630	1.2510E–02	9.9550E–03	1.0016E–02
3140	2.1180E–02	3.3241E–03	3.3603E–03	3640	1.2400E–02	1.1480E–02	1.1549E–02
3150	2.0880E–02	6.6744E–03	6.7457E–03	3650	1.2280E–02	1.0123E–02	1.0183E–02
3160	2.0730E–02	9.2320E–03	9.3294E–03	3660	1.2150E–02	1.0914E–02	1.0978E–02
3170	2.0520E–02	1.2516E–02	1.2645E–02	3670	1.2040E–02	7.9003E–03	7.9464E–03
3180	2.0320E–02	1.0621E–02	1.0730E–02	3680	1.1890E–02	8.3312E–03	8.3789E–03
3190	2.0190E–02	4.2388E–03	4.2817E–03	3690	1.1770E–02	9.6922E–03	9.7458E–03
3200	1.9940E–02	4.3843E–04	4.4280E–04	3700	1.1550E–02	1.0878E–02	1.0937E–02
3210	1.9760E–02	1.3634E–04	1.3768E–04	3710	1.1510E–02	9.3640E–03	9.4130E–03
3220	1.9540E–02	1.6089E–03	1.6245E–03	3720	1.1440E–02	1.0376E–02	1.0429E–02
3230	1.9380E–02	3.4080E–04	3.4404E–04	3730	1.1340E–02	9.2707E–03	9.3169E–03
3240	1.9210E–02	3.7464E–03	3.7816E–03	3740	1.1080E–02	8.8494E–03	8.8923E–03
3250	1.9090E–02	2.6067E–03	2.6308E–03	3750	1.1040E–02	9.2903E–03	9.3341E–03
3260	1.8800E–02	1.2248E–03	1.2360E–03	3760	1.0940E–02	8.8633E–03	8.9041E–03
3270	1.8600E–02	1.2186E–03	1.2292E–03	3770	1.0860E–02	9.1243E–03	9.1649E–03
3280	1.8370E–02	2.8644E–03	2.8890E–03	3780	1.0740E–02	9.5746E–03	9.6158E–03
3290	1.8260E–02	8.7571E–03	8.8310E–03	3790	1.0630E–02	7.7564E–03	7.7891E–03
3300	1.7920E–02	1.7794E–03	1.7944E–03	3800	1.0530E–02	9.8592E–03	9.8988E–03
3310	1.7700E–02	3.9235E–03	3.9565E–03	3810	1.0430E–02	8.2451E–03	8.2771E–03
3320	1.7300E–02	5.9987E–05	6.0496E–05	3820	1.0340E–02	9.6550E–03	9.6908E–03
3330	1.7130E–02	4.6616E–03	4.7014E–03	3830	1.0250E–02	9.5925E–03	9.6268E–03
3340	1.6850E–02	3.4602E–03	3.4903E–03	3840	1.0150E–02	8.9756E–03	9.0066E–03
3350	1.6600E–02	8.0277E–03	8.0998E–03	3850	1.0050E–02	8.8274E–03	8.8569E–03
3360	1.6360E–02	5.2402E–03	5.2892E–03	3860	9.9400E–03	7.9940E–03	8.0197E–03
3370	1.6180E–02	3.9389E–03	3.9770E–03	3870	9.8300E–03	7.3604E–03	7.3839E–03
3380	1.6010E–02	5.1115E–03	5.1624E–03	3880	9.7500E–03	6.5340E–03	6.5543E–03
3390	1.5900E–02	9.8552E–03	9.9552E–03	3890	9.7100E–03	6.8818E–03	6.9028E–03
3400	1.5640E–02	1.2509E–02	1.2638E–02	3900	9.6000E–03	7.9254E–03	7.9487E–03
3410	1.5540E–02	7.0802E–03	7.1547E–03	3910	9.5200E–03	7.1353E–03	7.1560E–03
3420	1.5430E–02	1.3165E–02	1.3305E–02	3920	9.4100E–03	6.9466E–03	6.9665E–03
3430	1.5220E–02	8.6892E–03	8.7810E–03	3930	9.3200E–03	7.0502E–03	7.0699E–03
3440	1.5050E–02	8.0348E–03	8.1181E–03	3940	9.2300E–03	7.4027E–03	7.4228E–03
3450	1.4920E–02	1.1153E–02	1.1267E–02	3950	9.1100E–03	7.6277E–03	7.6475E–03
3460	1.4800E–02	1.2530E–02	1.2657E–02	3960	9.0200E–03	7.7482E–03	7.7679E–03
3470	1.4660E–02	1.2264E–02	1.2386E–02	3970	8.9300E–03	7.6806E–03	7.6997E–03
3480	1.4480E–02	1.1224E–02	1.1335E–02	3980	8.8400E–03	7.3872E–03	7.4049E–03
3490	1.4360E–02	1.0419E–02	1.0520E–02	3990	8.7800E–03	7.3723E–03	7.3894E–03
				4000	8.6800E–03	7.1043E–03	7.1199E–03

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ASTM (2003), *G173–03 Standard Tables for Reference Solar Spectral Irradiances: Direct Normal and Hemispherical on 37° Tilted Surface* (www.astm.org/cgi–bin/SoftCart.exe/STORE/filtrexx40.cgi?U+mystore +eteh4957+–L+G173NOT:(STATUS:<NEAR/1>:REPLACED)+/usr6/ htdocs/astm.org/DATABASE.CART/REDLINE_PAGES/G173.htm).

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Appendix B

EQUATIONS FOR CALCULATING SUN POSITION

Definitions

AZI = solar azimuth (0–360°)
ALT = solar altitude (elevation), relative to horizontal (zenith = 90°)
ZEN = zenith angle, relative to vertical = $90° - ALT$
ORI = orientation of surface normal relative to azimuth
HSA = horizontal shadow angle
VSA = vertical shadow angle on perpendicular normal plane
INC = angle of incidence relative to surface normal
LAT = geographical latitude of site (negative for South)
DEC = declination (between sun-earth line and equatorial plane)
HRA = hour angle from solar noon (15° per hour)
SRA = sunrise azimuth (i.e. azimuth at sunrise)
SRT = sunrise time
NDY = number of day of year
N = day angle
TIL = tilt angle of surface relative to horizontal

Expressions

$$DEC = 23.45° \sin\left[\frac{2\pi}{365}(284 + NDY)\right]$$

or more accurately

$$DEC = 0.33281 - 22.984 \cos N + 3.7372 \sin N - 0.3499 \cos(2N) + 0.03205 \sin(2N) - 0.1398 \cos(3N) + 0.07187 \sin(3N)$$

$$N = \frac{360°}{365} NDY$$

$$HRA = 15°(hour - 12)$$

$$ALT = \operatorname{asin}[\sin DEC \sin LAT + \cos DEC \cos LAT \cos HRA]$$

$$AZI' = \operatorname{acos}\left[\frac{\cos LAT \sin DEC - \cos DEC \sin LAT \cos HRA}{\cos ALT}\right]$$

$$AZI = \begin{cases} AZI', \text{for } HRA < 0 \text{ (i.e. AM)} \\ 360° - AZI', \text{for } HRA > 0 \text{ (i.e. PM)} \end{cases}$$

$$HSA = AZI - ORI$$

$$VSA = \operatorname{atan}\left[\frac{\tan ALT}{\cos HRA}\right]$$

$$INC = \operatorname{acos}[\sin ALT \cos TIL + \cos ALT \sin TIL \cos HSA]$$

$$= \begin{cases} \operatorname{acos}[\cos ALT \cos HSA], \text{for vertical surfaces} \\ ZEN = 90° - ALT, \text{for horizontal surfaces} \end{cases}$$

$$SRA = \operatorname{acos}[\cos LAT \sin DEC + \tan LAT \tan DEC \sin LAT \cos DEC]$$

$$SRT = 12 - \frac{\operatorname{acos}(-\tan LAT \tan DEC)}{15°}$$

For an alternative method, the US Naval Observatory (2003) gives "an algorithm for computing the sun's angular coordinates to an accuracy of about 1 arcminute within two centuries of 2000".

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Updated World Wide Web links can be found at www.pv.unsw.edu.au/apv_book_refs.

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Appendix

C

CHARACTERISTIC DAYS AND DECLINATIONS

In solar energy availability estimations, it is common to use characteristic days and declination values to represent each month. For the monthly characteristic declinations, the extraterrestrial insolation is equal to its monthly average value. The values given in Table C.1 are reproduced from Table 4.2.1 of Iqbal (1983).

Table C.1. Character days and declinations.

month	date	declination (°)	characteristic day number
January	17	–20.84	17
February	14	–13.32	45
March	15	–2.40	74
April	15	+9.46	105
May	15	+18.78	135
June	10	+23.04	161
July	18	+21.11	199
August	18	+13.28	230
September	18	+1.97	261
October	19	–9.84	292
November	18	–19.02	322
December	13	–23.12	347

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Iqbal, M. (1983), *An Introduction to Solar Radiation*, Academic, Toronto.

Appendix D

SOME INSOLATION DATA SOURCES

Updated World Wide Web links can be found at www.pv.unsw.edu.au/apv_book_refs.

D.1 GROUND-BASED MEASUREMENTS

World Radiation Data Centre

- wrdc.mgo.rssi.ru
- wrdc-mgo.nrel.gov

Baseline Surface Radiation Network (BSRN), World Radiation Monitoring Center (WRMC)

- bsrn.ethz.ch

National Climatic Data Center (USA)

- www.ncdc.noaa.gov/oa/ncdc.html

Meteonorm (commercial)

- www.meteotest.ch/en/mn_home?w=ber

International Solar Irradiation Database, University of Massachusetts–Lowell

- energy.caeds.eng.uml.edu/solbase.html

Other

- Censolar (1993), *Valores Medios de Irradiacion Solar sobre Suelo Horizontal* (*Mean Values of Solar Radiation on Horizontal Surface*), International H-World Database, Sevilla, Spain, Progensa, ISBN 84-86505-44-5.
- Sandia National Laboratories (1991), *Stand-Alone Photovoltaic Systems. A Handbook of Recommended Design Practices* (SAND87-7023) (www.sandia.gov/pv/docs/Programmatic.htm).
- SOLMET, 'Solar radiation—Surface meteorological observations', National Climatic Data Center, Asheville, NC, USA, Report TD-9724, 1979.

D.2 SATELLITE–DERIVED DATA

NASA Surface Meteorology and Solar Energy

- eosweb.larc.nasa.gov/sse

Interfaces to RETScreen free modelling program

- www.retscreen.net

SeaWiFS Surface Solar Irradiance

- www.giss.nasa.gov/data/seawifs

International Satellite Cloud Climatology Project:

- isccp.giss.nasa.gov

D.3 AUSTRALIA AND NEW ZEALAND

Australian Solar Radiation Data Handbook

- anzses.sslaccess.com/Bookshop.html

Bureau of Meteorology

- www.bom.gov.au/sat/solrad.shtml
- www.bom.gov.au/climate/averages
- www.bom.gov.au/climate/averages/climatology/sunshine_hours/ sunhrs.shtml
- *Catalogue of Solar Radiation Data Australia*, Australian Government Publishing Service, Canberra, 1979. (Lists type of information available through the Bureau of Meteorology, measurement sites and types of measurements.)

Solar resource in Victoria

- www.sustainable-energy.vic.gov.au/renewable_energy/resources/ solar/index.asp

ANUCLIM

- cres.anu.edu.au/outputs/climatesurfaces/creswww.pdf

UNSW Centre for Photovoltaic Engineering:

- www.pv.unsw.edu.au/Research/idl.asp (Data for Canberra)

Other

- Paltridge, G.W. & Proctor, D. (1976), 'Monthly mean solar radiation statistics for Australia', *Solar Energy*, **18**, 235–243.
- Maunder, W.J. (1971), 'Elements of New Zealand's climate, in Gentilli, J. (Ed.), 'Climates of Australia and New Zealand', *World Survey of Climatology*, **13**, Elsevier, Amsterdam, pp. 229–264.
- Benseman, R.F. & Cook, F.W. (1969), 'Solar radiation in New Zealand—The standard year and radiation on inclined slopes', *New Zealand Journal of Science*, **12**, pp. 696–708.

D.4 EUROPE

General

- sunbird.jrc.it/pvgis/pvestframe.php

Satel–Light

- www.satel–light.com/core.htm

Helioclim

- www.helioclim.net/index.html

SoDa

- www.soda-is.com

European Solar Radiation Atlas

- www.ensmp.fr/Fr/Services/PressesENSMP/Collections/ScTerEnv/Livres/atlas_tome1.htm
- www.ensmp.fr/Fr/Services/PressesENSMP/Collections/ScTerEnv/Livres/atlas_tome2.htm

Other

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D.6 USA

University of Wisconsin Solar Energy Lab

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- rredc.nrel.gov/solar

Integrated Surface Irradiance Study

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D.10 THEORETICAL MODELS AND CALCULATORS

'Bird' clear sky and spectral insolation models

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- www.nrel.gov/analysis/analysis_tools_tech_sol.html

Building energy software tools directory

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Sun_Chart solar position calculator

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Sustainable Design software tools

- www.susdesign.com/design-tools.html

Maui Solar Energy Design Software Corporation

- www.mauisolarsoftware.com

D.11 GLOBAL GAZETTEER

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Appendix E

STANDARDS

E.1 ASTM INTERNATIONAL

(See www.astm.org)

- BSR/ASTM Z8507Z-200x Measurement of electrical performance and spectral response of nonconcentrator multijunction photovoltaic cells and modules.
- C1549-02 Standard test method for determination of solar reflectance near ambient temperature using a portable solar reflectometer.
- E1021-95(2001) Standard test methods for measuring spectral response of photovoltaic cells.
- E1036-02 and E1036M-96e2 Standard test methods for electrical performance of nonconcentrator terrestrial photovoltaic modules and arrays using reference cells.
- E1038-98(2004) Standard test method for determining resistance of photovoltaic modules to hail by impact with propelled ice balls.
- E1040-98 Standard specification for physical characteristics of nonconcentrator terrestrial photovoltaic reference cells.
- E1125-99 Standard test method for calibration of primary non-concentrator terrestrial photovoltaic reference cells using a tabular spectrum.

- E1143-99 Standard test method for determining the linearity of a photovoltaic device parameter with respect to a test parameter.
- E1171-01 Standard test method for photovoltaic modules in cyclic temperature and humidity environments.
- E1175-87 (1996) Standard test method for determining solar or photopic reflectance, transmittance, and absorptance of materials using a large diameter integrating sphere.
- E1328-03 Standard terminology relating to photovoltaic solar energy conversion.
- E1362-99 Standard test method for calibration of non-concentrator photovoltaic secondary reference cells.
- E1462-00 Standard test methods for insulation integrity and ground path continuity of photovoltaic modules.
- E1596-99 Standard test methods for solar radiation weathering of photovoltaic modules.
- E1597-99 Standard test method for saltwater pressure immersion and temperature testing of photovoltaic modules for marine environments.
- E1799-02 Standard practice for visual inspections of photovoltaic modules.
- E1802-01 Standard test methods for wet insulation integrity testing of photovoltaic modules.
- E1830-04 Standard test methods for determining mechanical integrity of photovoltaic modules.
- E1918-97 Standard test method for measuring solar reflectance of horizontal and low-sloped surfaces in the field.
- E1980-01 Standard practice for calculating solar reflectance index of horizontal and low-sloped opaque surfaces.
- E2047-99 Standard test method for wet insulation integrity testing of photovoltaic arrays.
- E2236-02 Standard test methods for measurement of electrical performance and spectral response of nonconcentrator multijunction photovoltaic cells and modules.
- E424-71(2001) Standard test methods for solar energy transmittance and reflectance (terrestrial) of sheet materials.
- E434-71(2002) Standard test method for calorimetric determination of hemispherical emittance and the ratio of solar absorptance to hemispherical emittance using solar simulation.
- E490 Standard solar constant and air mass zero solar spectral irradiance tables.
- E772-87(2001) Standard terminology relating to solar energy conversion.
- E816-95(2002) Standard test method for calibration of pyrheliometers by comparison to reference pyrheliometers.
- E824-94(2002) Standard test method for transfer of calibration from reference to field radiometers.
- E913-82(1999) Standard method for calibration of reference pyranometers with axis vertical by the shading method.

- E927-04a Standard specification for solar simulation for terrestrial photovoltaic testing.
- E941-83(1999) Standard test method for calibration of reference pyranometers with axis tilted by the shading method.
- E948-95 (2001) Standard test method for electrical performance of photovoltaic cells using reference cells under simulated sunlight.
- E971-88 (1996)e1 Standard practice for calculation of photometric transmittance and reflectance of materials to solar radiation.
- E972-96 (2002) Standard test method for solar photometric transmittance of sheet materials using sunlight.
- E973-02 Standard test method for determination of the spectral mismatch parameter between a photovoltaic device and a photovoltaic reference cell.
- E973M-96 Standard test method for determination of the spectral mismatch parameter between a photovoltaic device and a photovoltaic reference cell [Metric].
- G130-95(2002) Standard test method for calibration of narrow- and broad-band ultraviolet radiometers using a spectroradiometer.
- G138-03 Standard test method for calibration of a spectroradiometer using a standard source of irradiance.
- G159-98 Standard tables for references solar spectral irradiance at air mass 1.5: Direct normal and hemispherical for a 37° tilted surface.
- G167-00 Standard test method for calibration of a pyranometer using a pyrheliometer.
- G173-03 Standard tables for reference solar spectral irradiances: Direct normal and hemispherical on 37° tilted surface.
- G177-03 Standard tables for reference solar ultraviolet spectral distributions: hemispherical on 37° tilted surface.
- WK3436 Standard test method for hot spot testing of photovoltaic modules.
- WK558 Reference solar spectral irradiances: Direct normal and hemispherical on 37° tilted surface.

E.2 AUSTRALIA—STANDARDS AUSTRALIA

- AS/NZS 1170.2:2002 Structural design actions—Wind actions.
- AS/NZS 1170.2 Supp 1:2002 Structural design actions—Wind actions—Commentary (Supplement to AS/NZS 1170.2:2002).
- AS 4086.2-1997 Secondary batteries for use with stand-alone power systems—Installation and maintenance.
- AS 4509.1-1999 Stand-alone power systems—Safety requirements. (1999, first amendment 2000).
- AS 4509.2-2002 Stand-alone power systems—System design guidelines (2002).
- AS 4509.3-1999 Stand-alone power systems—Installation and maintenance (1999, first amendment 2000).
- AS 4777.1-2005 Grid connection of energy systems via inverters—Installation requirements.

- AS 4777.2-2002 Grid connection of energy systems via inverters—Inverter requirements.
- AS 4777.3-2002 Grid connection of energy systems via inverters—Protection requirements.
- AS/NZS 3000 series, General electrical installation standards.
- AS/NZS 5033-2005 Installation of photovoltaic (PV) arrays.

E.3 CANADA—STANDARDS COUNCIL OF CANADA

- CAN/CSA-F382-M89 Characterization of storage batteries for photovoltaic systems.

E.4 CHINA—STANDARDIZATION ADMINISTRATION OF CHINA (SAC)

- GB/T 11010-1989 Spectrum standard solar cell.
- GB/T 11011-1989 General rules for measurements of electrical characteristics of amorphous silicon solar cells.
- GB/T 12085.9-1989 Optics and optical instruments—Environmental test methods—Solar radiation.
- GB/T 12785-2002 Test methods for submersible motor-pumps.
- GB/T 13337.1-1991 Stationary acid spray-proof lead-acid batteries—Technical conditions.
- GB/T 13337.2-1991 Stationary acid spray-proof lead-acid batteries—Capacity specifications and size.
- GB/T 13468-1992 Measurement and calculation methods of electric energy balance for pumps systems.
- GB/T 16750.1-1997 The types, general parameters and conjunction sizes of electrical submersible pumping equipment.
- GB/T 16750.2-1997 Electrical submersible pump—Technical specifications.
- GB/T 16750.3-1997 The test method for electrical submersible pump units.
- GB/T 17386-1998 Recommended practice for sizing and selection of electric submersible pump installations.
- GB/T 17387-1998 Recommended practice for the operation, maintenance and troubleshooting of electric submersible pump installations.
- GB/T 17388-1998 Recommended practice for electric submersible pump installations.
- GB/T 17683.1-1999 Solar energy—Reference solar spectral irradiance at the ground at different receiving conditions—Part 1: Direct normal and hemispherical solar irradiance for air mass 1.5.
- GB/T 18050-2000 Recommended practice for testing of electric submersible pump cable systems.
- GB/T 18051-2000 Recommended practice on electric submersible pump system vibration tests.
- GB/T 18210-2000 Crystalline silicon photovoltaic (PV) array-on-site measurement of I-V characteristics.
- GB/T 18332.1-2001 Lead-acid batteries for electric vehicles.

- GB/T 18332.2-2001 Nickel-metal hydride batteries of electric road vehicles.
- GB/T 18479-2001 Terrestrial photovoltaic (PV) power generating systems—General and guide.
- GB/T 18911-2002 Thin-film terrestrial photovoltaic (PV) modules—Design qualification and type approval.
- GB/T 18912-2002 Salt mist corrosion testing of photovoltaic (PV) modules.
- GB/T 19115.1-2003 Off-grid type wind-solar photovoltaic hybrid generate electricity system of household-use—Part 1: Technology condition
- GB/T 19115.2-2003 Off-grid type wind-solar photovoltaic hybrid generate electricity system of household-use—Part 2: Test methods.
- GB/T 19393-2003 Rating of direct coupled photovoltaic (PV) pumping systems.
- GB/T 2296-2001 Designation method of solar cells (photovoltaic device).
- GB/T 2297-1989 Terminology for solar photovoltaic energy system.
- GB/T 2816-2002 Submersible pumps for deep well.
- GB/T 2900.11-1988 Terminology of (secondary) cell or battery.
- GB/T 2900.62-2003 Electrotechnical terminology. Primary cells and batteries.
- GB/T 4797.4-1989 Environmental conditions appearing in nature for electric and electronic products-Solar radiation and temperature.
- GB/T 5170.9-1996 Inspection methods for basic parameters of environmental testing equipments for electric and electronic products—Solar radiation testing equipments.
- GB/T 6492-1986 Astronautic standard solar cell.
- GB/T 6494-1986 Measurement procedures for electrical characteristics of astronautic solar cells.
- GB/T 6495.1-1996 Photovoltaic devices—Part 1: Measurement of photovoltaic current-voltage characteristics.
- GB/T 6495.2-1996 Photovoltaic devices—Part 2: Requirements for reference solar cells.
- GB/T 6495.3-1996 Photovoltaic devices—Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data.
- GB/T 6495.4-1996 Photovoltaic devices—Part 4: Procedures for temperature and irradiance corrections to measured I-V characteristics of crystalline silicon photovoltaic devices.
- GB/T 6495.5-1997 Photovoltaic devices—Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method.
- GB/T 6495.8-2002 Photovoltaic devices—Part 8: Measurement of spectral response of a photovoltaic (PV) device.
- GB/T 6496-1986 The general rules of astronautic solar cell calibration.
- GB/T 6497-1986 The general rules of terrestrial solar cell calibration.
- GB/T 7021-1986 Glossary of terms for centrifugal pump.

- GB/T 9535-1998 Crystalline silicon terrestrial photovoltaic (PV) modules—Design qualification and type approval.
- GB/Z 18333.1-2001 Lithium-ion batteries for electric road vehicles.
- GB/Z 18333.2-2001 Zinc-air batteries for electric road vehicles.

E.5 EUROPEAN COMMITTEE FOR ELECTROTECHNICAL STANDARDIZATION (CENELEC)

(See www.cenelec.org/Cenelec/CENELEC+in+action/Web+Store/Standards/default.htm)

- EN 50380 Datasheet and nameplate information for photovoltaic modules.
- EN 60891 Procedures for temperature and irradiance corrections to measured I-V characteristics of crystalline silicon photovoltaic devices (IEC 891:1987 + A1:1992).
- EN 60904-1 Photovoltaic devices—Part 1: Measurement of photovoltaic current-voltage characteristics (IEC 904-1:1987).
- EN 60904-2 Photovoltaic devices—Part 2: Requirements for reference solar cells. Includes amendment A1: 1998 (IEC 904-2:1989 + A1:1998).
- EN 60904-3 Photovoltaic devices—Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data (IEC 904-3:1989).
- EN 60904-5 Photovoltaic devices—Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method (IEC 904-5:1993).
- EN 60904-6 Photovoltaic devices—Part 6: Requirements for reference solar modules. Includes amendment A1:1998 (IEC 60904-6:1994 + A1:1998).
- EN 60904-7 Photovoltaic devices—Part 7: Computation of spectral mismatch error introduced in the testing of a photovoltaic device (IEC 60904-7:1998).
- EN 60904-8 Photovoltaic devices—Part 8: Measurement of spectral response of a photovoltaic (PV) device (IEC 60904-8:1998).
- EN 60904-10 Photovoltaic devices—Part 10: Methods of linearity measurement (IEC 60904-10:1998).
- EN 61173 Overvoltage protection for photovoltaic (PV) power generating systems—Guide (IEC 1173:1992).
- EN 61194 Characteristic parameters of stand-alone photovoltaic (PV) systems (IEC 1194:1992, modified).
- EN 61215 Crystalline silicon terrestrial photovoltaic (PV) modules design qualification and type approval (IEC 1215:1993).
- EN 61277 Terrestrial Photovoltaic (PV) Power Generating Systems General and Guide (IEC 61277:1995).
- EN 61345 UV Test for Photovoltaic (PV) Modules (IEC 61345:1998).
- EN 61427 Secondary Cells and Batteries for Solar Photovoltaic Energy Systems—General Requirements and Methods of Test (IEC 61427:1999).
- EN 61646 Thin-film terrestrial photovoltaic (PV) modules design qualification and type approval (IEC 1646:1996).

- EN 61683 Photovoltaic systems—Power conditioners—Procedure for measuring efficiency (IEC 61683:1999).
- EN 61701 Salt mist corrosion testing of photovoltaic (PV) modules (IEC 61701:1995).
- EN 61702 Rating of direct coupled photovoltaic (PV) pumping systems (IEC 61702:1995).
- EN 61721 Susceptibility of a photovoltaic (PV) module to accidental impact damage (Resistance to impact test) (IEC 61721:1995).
- EN 61724 Photovoltaic system performance monitoring guidelines for measurement, data exchange and analysis (IEC 61724:1998).
- EN 61727 Photovoltaic (PV) systems characteristics of the utility interface (IEC 1727:1995).
- EN 61829 Crystalline silicon photovoltaic (PV) array on-site measurement of I-V characteristics (IEC 61829:1995).
- PREN 50312-1 Photovoltaic systems—Solar home systems—Part 1: Safety—Test requirements and procedures.
- PREN 50312-2 Photovoltaic systems—Solar home systems—Part 2: Performance—Test requirements and procedures.
- PREN 50313-1 Photovoltaic Systems—Solar modules—Part 1: Safety—Test requirements and procedures.
- PREN 50313-2 Photovoltaic systems—Solar modules—2: Performance—Test requirements and procedures.
- PREN 50314-1 Photovoltaic systems—Charge regulators—Part 1: Safety—Test requirements and procedures.
- PREN 50314-2 Photovoltaic systems—Charge regulators—Part 2: EMC—Test requirements and procedures.
- PREN 50314-3 Photovoltaic systems—Charge regulators—Part 3: Performance—Test requirements and procedures.
- PREN 50315-1 Accumulators for use in photovoltaic systems—Part 1: Safety—Test requirements and procedures.
- PREN 50315-2 Accumulators for use in photovoltaic systems—Part 2: Performance—Test requirements and procedures.
- PREN 50316-1 Photovoltaic lighting systems—Part 1: Safety—Test requirements and procedures.
- PREN 50316-2 Photovoltaic lighting systems—Part 2: EMC—Test requirements and procedures.
- PREN 50316-3 Photovoltaic lighting systems—Part 3: Performance—Test requirements and procedures.
- PREN 50322-1 Photovoltaic systems—Part 1: Electromagnetic compatibility (EMC)—Requirements for photovoltaic pumping systems.
- PREN 50330-1 Photovoltaic semiconductor converters—Part 1: Utility interactive fail safe protective interface for PV-line commutated converters—Design qualification and type approval.
- PREN 50331-1 Photovoltaic systems in buildings—Part 1: Safety requirements.

E.6 GERMANY—DEUTSCHES INSTITUT FÜR NORMUNG (DIN)

(See www.dke.de/dke_en/)

- DIN 43539-1:1985 Storage cells and batteries; testing; general information and general test methods.
- DIN EN 50380:2003 Datasheet and nameplate information for photovoltaic modules; In German: EN 50380:2003.
- DIN EN 60891:1996 Procedures for temperature and irradiance corrections to measured I-V characteristics of crystalline silicon photovoltaic devices (IEC 60891:1987 + A1:1992); In German: EN 60891:1994.
- DIN EN 60904-1:1995 Photovoltaic devices—Part 1: Measurement of photovoltaic current-voltage characteristics (IEC 60904-1:1987); In German: EN 60904-1:1993.
- DIN EN 60904-2:1995 and Amendment A1: 1998-11 Photovoltaic devices—Part 2: Requirements for reference solar cells (IEC 60904-2:1989); In German: EN 60904-2:1993.
- DIN EN 60904-3:1995 Photovoltaic devices—Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data (IEC 60904-3:1989); In German: EN 60904:1993.
- DIN EN 60904-5:1996 Photovoltaic devices—Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open circuit voltage method (IEC 60904-5:1993); In German: EN 60604-5:1995.
- DIN EN 60904-6:1996 and Amendment A1: 1998-11 Photovoltaic devices—Part 6: Requirements for reference solar modules (IEC 60904-6:1994); In German: EN 60904-6:1994.
- DIN EN 60904-7:1998-11 Photovoltaic devices—Part 7: Computation of spectral mismatch error introduced in the testing of a photovoltaic device (IEC 60904-7:1998); In German: EN 60904-7:1998.
- DIN EN 60904-8:1998 Photovoltaic devices—Part 8: Measurement of spectral response of a photovoltaic (PV) device (IEC 60904-8:1998); In German: EN 60904-8:1998.
- DIN EN 60904-10:1998 Photovoltaic devices—Part 10: Methods of linearity measurement (IEC 60904-10:1998); In German: EN 60904-10:1998.
- DIN EN 61173:1996 Overvoltage protection for photovoltaic (PV) power generating systems—Guide (IEC 61173:1992); In German: EN 61173:1994.
- DIN EN 61194:1996 Characteristic parameters of stand-alone photovoltaic (PV) systems (IEC 61194:1992, modified); In German: EN 61194:1995.
- DIN EN 61215:1996 Crystalline silicon terrestrial photovoltaic (PV) modules—Design qualification and type approval (IEC 61215:1993); In German: EN 61215:1995.
- DIN EN 61277:1999 Terrestrial photovoltaic (PV) power generating systems—General and guide (IEC 61277:1995); In German: EN 61277:1998.
- DIN EN 61345:1998 UV test of photovoltaic (PV) modules (IEC 61345:1998); In German: EN 61345:1998.
- DIN EN 61427 Secondary cells and batteries for solar photovoltaic energy systems—General requirements and methods of test (IEC 61427:1999); German version EN 61427:2001.

- DIN EN 61646:1998-03 Thin-film terrestrial photovoltaic (PV) modules—Design qualification and type approval (IEC 61646:1996); In German: EN 61646:1997.
- DIN EN 61683:2000 Photovoltaic systems—Power conditioners—Procedure for measuring efficiency (IEC 61683:1999); In German: EN 61683:2000.
- DIN EN 61701:2000 Salt mist corrosion testing of photovoltaic (PV) modules (IEC 61701:1995); In German: EN 61701:1999.
- DIN EN 61702:2000 Rating of direct coupled photovoltaic (PV) pumping systems (IEC 61702:1995); In German: EN 61702:1999.
- DIN EN 61721:2000 Susceptibility of a photovoltaic (PV) module to accidental impact damage (resistance to impact test) (IEC 61721:1995); In German: EN 61721:1999.
- DIN EN 61724:1999 Photovoltaic system performance monitoring—Guidelines for measurement, data exchange and analysis (IEC 61724:1998); In German: EN 61724:1998.
- DIN EN 61725:1998 Analytical expression for daily solar profiles (IEC 61725:1997); In German: EN 61725:1997.
- DIN EN 61727:1996 Photovoltaic (PV) systems—Characteristics of the utility interface (IEC 61727:1995); In German: EN 61727:1995.
- DIN EN 61829:1999 Crystalline silicon photovoltaic (PV) array—On-site measurement of I-V characteristics (IEC 61829:1995); In German: EN 61829:1998.
- DIN IEC 21(Sec)366:1996 Guidelines for the reduction of explosion hazards associated with secondary cells and batteries—Part 1: Lead-acid starter batteries (IEC 21(Sec)366:1994).
- DIN IEC 21A/163/CD:1995 Guide to the equipment manufacturers and users of alkaline secondary cells and batteries on possible safety and health hazards—Part 1: Nickel-cadmium (IEC 21A/163/CD:1994).
- DIN IEC 60050-482:2001 International electrotechnical vocabulary—Part 482: Primary and secondary cells and batteries (IEC 1/1848/CDV:2001).
- DIN IEC 60896-21:2001 Stationary lead-acid batteries—Part 21: Valve regulated types; Functional characteristics and methods of test (IEC 21/534/CD:2001).
- DIN EN 60896-22:2003 Stationary lead-acid batteries—Part 22: Valve regulated types; Requirements and selection guidelines (IEC 21/580/CDV:2002); In German: prEN 60896-22:2002.
- DIN IEC 61427:2002 Secondary cells and batteries for solar photovoltaic energy systems—General requirements and methods of test (IEC 21/548/CD:2001).
- DIN IEC 61727 Characteristics of the utility interface for photovoltaic (PV) systems (IEC 82/266/CD:2001).
- DIN IEC 62093 Balance-of-system components for photovoltaic systems—Design qualification and type approval (IEC 82/257/CD:2001).
- DIN IEC 62124:2001 Photovoltaic (PV) stand-alone systems—Design qualification and type approval (IEC 82/259/CD:2001).

- DIN IEC 61959-2:2001 Draft IEC 61959-2, Ed. 1: Mechanical tests for sealed portable secondary cells and batteries—Part 2: Secondary batteries (IEC 21A/321/CD:2001).
- DIN IEC 82/238/CD:2000 Certification and accreditation for photovoltaic (PV) components and systems (IEC 82/238/CD:2000).
- Draft DIN VDE 0126 (VDE 0126):1999 with Authorization, Automatic disconnecting facility for photovoltaic installations with a rated output = 4,6 kVA and a single-phase parallel feed by means of an inverter into the public low-voltage mains.
- VDE V 0126 Part 17-1:2004 Solar cells—Part 17-1: Datasheet information and product data for crystalline silicon solar cells.

E.7 GLOBAL APPROVAL PROGRAM FOR PHOTOVOLTAICS (PVGAP)

(See www.pvgap.org)

- PVRS1 Photovoltaic stand-alone systems—Design qualification and type approval (First edition 1997).
- PVRS2 Crystalline silicon terrestrial photovoltaic (PV) modules (Second edition 2003.)
- PVRS3 Thin-film terrestrial photovoltaic (PV) modules, (First edition 1999).
- PVRS4 Photovoltaic (PV) stand-alone systems, with a system voltage below 50V (Third draft 2002)
- PVRS5 Lead-acid batteries for solar photovoltaic energy systems (modified automotive batteries).
- PVRS5A Lead acid batteries for solar photovoltaic energy systems—General requirements and methods of test for modified automotive batteries.
- PVRS6 Charge controllers for photovoltaic (PV) stand-alone systems with a nominal system voltage below 50 V (First edition 2000).
- PVRS6A Annex—Specification and testing procedure (First edition 2000).
- PVRS7 Lighting systems with fluorescent lamps for photovoltaic (PV) stand-alone systems with a nominal system voltage below 24V (First edition 2003).
- PVRS7A Annex—Specification and testing procedure, to PVRS 7 (First edition 2003).
- PVRS8 Inverters for photovoltaic (PV) stand-alone systems (First edition 2000).
- PVRS9 Procedures for determining the performance of stand-alone photovoltaic systems (First edition 2000).
- PVRS10 Code of practice for installation of photovoltaic systems.

E.8 INDONESIA—BADAN STANDARDISASI NASIONAL (BSN)

- SNI 04-1934-1990 Photovoltaic solar energy system.
- SNI 04-3850.1-1995 Photovoltaic devices—Part 1: General.
- SNI 04-3850.2-1995 Photovoltaic devices—Part 2: Characteristics measurement.

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E.9 INSTITUTION OF ELECTRICAL AND ELECTRONICS ENGINEERS (IEEE)

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- ISO 9488:1999 Solar energy—Vocabulary.
- ISO 9845-1:1992 Solar energy—reference solar spectral irradiance at the ground at different receiving conditions—Part 1: Direct normal and hemispherical solar irradiance for air mass 1.5.
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E.12 JAPAN—JAPANESE STANDARDS ASSOCIATION (JSA)

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- JIS C 8912:1998 Solar simulators for crystalline solar cells and modules.
- JIS C 8913:1998 Measuring method of output power for crystalline solar cells.
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- JIS C 8915:1998 Measuring methods of spectral response for crystalline solar cells and modules.
- JIS C 8916:1998 Temperature coefficient measuring methods of output voltage and output current for crystalline solar cells and modules.
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- KSBISO9060 Solar energy; specification and classification of instruments for measuring hemispherical solar and direct solar radiation.
- KSC8524 Glossary of terms for photovoltaic power generation.
- KSC8525 Measuring methods of spectral response for crystalline solar cells.
- KSC8526 Measuring method of output power crystalline solar cell modules.
- KSC8527 Solar simulators used in measuring crystalline solar cells and modules.
- KSC8528 Measuring method of output power for crystalline solar cells.
- KSC8529 Temperature coefficient measuring methods for crystalline solar cells and modules.
- KSC8530 Environmental and endurance test methods for crystalline solar cell modules.
- KSC8531 Crystalline solar cell module.
- KSC8532 Measuring procedure of residual capacity for lead acid battery in photovoltaic system.
- KSC8533 Measuring procedure of power conditioner efficiency for photovoltaic systems.

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- KSCIEC61194 Characteristic parameters of stand-alone photovoltaic (PV) systems.
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- SS-EN 61 215 Crystalline silicone terrestrial photovoltaic (PV) modules—Design qualification and type approval.
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E.19 TÜV RHEINLAND

(See www.tuv.com)

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E.20 UNDERWRITERS LABORATORIES (UL)

(See www.ul.com/dge/photovoltaics)

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E.23 BEST PRACTICE GUIDELINES AND ACCREDITATION

Training and accreditation standards are referenced by the Institute for Sustainable Power (Institute for Sustainable Power).

The Business Council for Sustainable Energy Australia (BCSE) lists relevant photovoltaics standards and carries out accreditation for designers and installers (Business Council for Sustainable Energy).

‘BIPV Best Practice Guidelines’ for Australia are available at:
http://www.bcse.org.au/default.asp?id=75&articleid=454

In September 2004 the U.S. Electrical Contracting Foundation commissioned a study to define best practices for installing photovoltaic systems in USA. The National Electrical Contractors Association is to develop a National Electrical Installation Standard (Solaraccess, 2004).

E.24 INTERNATIONAL SOLAR ENERGY SOCIETY (ISES) AND DEUTSCHE GESELLSCHAFT FÜR SONNENENERGIE EV (DGS)

These organisations and others announced in 2004 their intention to ‘establish reliable quality assurance standards and best-practice guidelines for the integration of solar thermal and photovoltaics applications in engineering, energy and architecture applications’ and create ‘a reference system of technical standards for the financial community’ (DGS/ISES, 2004; Solaraccess, 2004; Siemer, 2004).

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Appendix

F

ALTERNATIVE SOURCES OF POWER FOR WATER PUMPING

F.1 INTRODUCTION

A wide variety of power sources are used for water pumping, depending on local conditions. Each power source has various advantages and disadvantages, as discussed below, and each has specific applications where it is the favoured energy source and determines the corresponding pumping technique (Halcrow & Partners, 1981).

F.2 HUMAN LABOUR USING HAND PUMPS

Advantages:

- readily available in most developing countries
- low investment cost
- can be flexibly deployed
- simple technology, easy to maintain.

Disadvantages:

- high feeding costs and associated wages
- low output, limited by the strength of the human body to about 10^3 m/day from a depth of 10 m, or 5 m^3/day from 20 m
- diverts a valuable resource from more productive activities.

F.3 DRAUGHT ANIMALS

Advantages:

- readily available
- medium investment costs
- convenient power output for small-scale irrigation
- can be flexibly deployed.

Disadvantages:

- high feeding costs involving extra food production
- feed required even when no power can usefully be employed.

F.4 PETROL- OR DIESEL-FUELLED SMALL ENGINES

Advantages:

- widely available technology
- high outputs possible on demand
- portable
- low initial capital investment per unit of output
- easy to use.

Disadvantages:

- fuel costs dominate and are increasing in real terms
- fuel shortages are common in many developing countries
- spare parts are often hard to obtain in remote areas
- good maintenance difficult to obtain in remote areas of developing countries
- relatively short useful life
- breakdown common
- high imported element involving scarce foreign currency in most developing countries.

F.5 CENTRALISED RURAL ELECTRIFICATION

Advantages:

- low marginal investment cost for prime mover (electric pump) if transmission lines installed
- pump sets are reliable provided supply is guaranteed
- can be low cost depending on power source and system.

Disadvantages:

- electricity supply often unreliable in developing countries owing to peaky demand, low load factors and sparse consumer population
- very high system investment cost and high generating and distribution costs
- extended power failures could cause widespread crop loss
- limited to uses less than about 1 km from the nearest grid.

F.6 WIND PUMPS

Advantages:

- relatively mature renewable energy technology when used for stock watering
- low cost in areas with adequate wind regimes
- zero fuel costs
- suitable for local manufacture
- relatively simple maintenance needs.

Disadvantages:

- not yet well developed for irrigation purposes
- moderate output, fluctuating with wind conditions
- critically site-dependent.

F.7 WATER WHEELS, TURBINES, RAM PUMPS AND CURRENT TURBINES

Advantages:

- low cost, long life, low maintenance, fuel-free power source if suitable site conditions are available to exploit water power.

Disadvantages:

- depends on relatively rare site conditions, which limit the areas that could benefit from this type of prime mover.

F.8 STEAM ENGINES

Advantages:

- potentially low cost renewable energy technology, especially if agricultural waste can be used as fuel.

Disadvantages:

- fuel requires land use or transport of coal
- steam engine technology is generally obsolete, while modern equipment is not readily available
- safety problems with boilers
- constant or frequent attendance needed.

F.9 BIOGAS-FUELLED SMALL ENGINES

Advantages:

- allows the advantages of small engines, described above, but is independent of supply of petroleum fuel
- immature technology for biogas production, but has low-cost potential
- fertiliser produced as a by-product from the digester.

Disadvantages:

- includes most disadvantages of small engines (spares, maintenance etc.)

- high water requirements for digester
- feedstock for digester may be scarce particularly in arid regions
- relatively high labour needs for digester operation
- relatively high investment costs in digester and gas storage equipment, making it most suitable for larger systems.

F.10 SOLAR RADIATION, USED VIA PHOTOVOLTAICS

Advantages:

- energy resource is almost universally available
- high correlation between energy availability and needs
- low environmental impact
- reliable
- zero fuel costs
- long life
- low maintenance and running costs
- can be operated by unskilled labour
- suitable for systems of any size.

Disadvantages:

- sophisticated technology, not suited to local manufacture
- applications and balance of system components still under development
- high investment cost
- diffuse energy resource
- skilled engineers needed for maintenance
- output subject to solar insolation variations.

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Appendix

G

STAND-ALONE PHOTOVOLTAIC SYSTEM DESIGN

G.1 INTRODUCTION

The following material outlines two approaches used when designing photovoltaic stand-alone systems. Australian Standard AS4509.2, discussed in Chapter 7, is more recent than either and is normally the method to be used by accredited installers in Australia. The first method detailed here was used extensively by Telecom in Australia during its early days of photovoltaics application and represents a very conservative approach in which array size is optimised as a function of battery capacity. The second was developed by Sandia National Laboratories in the USA and is considerably more sophisticated, automatically incorporating many years of accumulated insolation data. Examples of both approaches are provided.

G.2 STAND-ALONE SYSTEM DESIGN PROCEDURE

The following example deals with the design of a stand-alone PV system for powering a microwave repeater station (based on Mack, 1979).

Step 1—Load determination. A microwave repeater station typically draws 100 W on average and requires voltages in the range 24 ± 5 V. The corresponding average current is therefore 4.17 A.

Step 2—Select battery capacity. For the above load and allowing for 15 days of battery storage, we require a battery capacity of

$$4.17 \text{ A} \times 24 \text{ h} \times 15 \text{ days} = 1500 \text{ Ah}.$$

Step 3—First approximation of tilt angle. This is based on site information and usually involves selecting a tilt angle 20° greater than the latitude. For example, for Melbourne, which is at latitude 37.8°S, the first approximation for tilt angle is latitude + 20° = 57.8°.

Step 4—Insolation. From available site insolation data, calculate insolation falling on the array at the calculated tilt angle.

Table G.1. Average monthly readings of direct and diffuse radiation falling on a horizontal plane in Melbourne.

month	direct (*S*)	diffuse (*D*)
	mWh/cm^2	mWh/cm^2
January	629	210
February	559	144
March	396	166
April	309	127
May	199	98
June	167	79
July	195	82
August	254	120
September	368	148
October	500	197
November	491	241
December	676	214

Example 1—From Table G.1, in January:

$$S = 629 \text{ mWh/cm}^2$$
$$D = 210 \text{ mWh/cm}^2.$$

Therefore, on a plane tilted at 57.8°, the direct component, from Eqn. 1.21, is

$$S_{57.8} = 629\frac{\sin(\alpha + 57.8°)}{\sin\alpha} \qquad (G.1)$$

where

$$\alpha = 90° - 37.8° - \delta \text{ (from Eqn. 1.6)}$$
$$\delta = 23.45° \times \sin[(15 - 81) \times 360 / 365]$$
$$= -21.3°$$

given that the day of the year $d = 15$. Therefore

$$\alpha = 73.5°$$
$$S_{57.8} = 493 \text{ mWh/cm}^2.$$

The total insolation (direct + diffuse) falling on the array is therefore

$$R_\beta = S_{57.8} + D$$
$$= 703 \text{ mWh/cm}^2.$$

The assumption is made that D is independent of tilt angle. This is a reasonable approximation provided the tilt angle is not too great.

Example 2—In June

$$\begin{aligned} d &= 166 \\ \delta &= 23.45° \times \sin[(166\text{–}81) \times 360°/365] \\ &= 23.3° \\ \alpha &= 28.9° \\ S_{57.8} &= 167 \times \sin(28.9° + 57.8°)/\sin(28.9°) \\ &= 345 \text{ mWh/cm}^2 \\ R_\beta &= 424. \end{aligned}$$

Step 5—First approximation of array size

(a) The first approximation for the array size is 5 × 4.17 = 20.9 A_p.

(b) Calculate Ah generated per month, allowing for 10% loss owing to dust coverage. For example, in January: 703 mWh/cm^2 × 0.9 × 31 days × 20.9 A / 100 mWcm^2 = 4100 Ah.

(c) Calculate the monthly load in Ah, allowing for an additional component of 3% of the battery charge for self-discharge. For example, in January: (4.17 A × 24 h × 31 days) + (0.03 × 1500 Ah) = 3147 Ah, assuming the batteries were initially fully charged.

(d) From the difference between the Ah generated per month (b) and that consumed by the load (c), calculate the state of charge of the batteries at the end of the month.

(e) Repeat (b)–(d) for the other months.

Step 6—Optimising array tilt angle. Retaining the same array size, repeat (4) and (5)(b)–(e) above with small variations in the array tilt angle until the depth-of-discharge of the batteries is minimised. This represents the optimal tilt angle.

Step 7—Optimising array size. Using the optimal tilt angle, by successive approximations, keep repeating (5)(b)–(e) for different array sizes until the maximum depth-of-discharge of the batteries is within the range 50±2%. For example, for 1500 Ah capacity, the maximum depth-of-discharge should be in the range 720–780 Ah.

Step 8—Summarise the design.

G.3 SANDIA NATIONAL LABORATORY APPROACH

The following example is based on the approach developed by Sandia National Laboratory, Albuquerque, USA (Chapman, 1987) and automatically incorporates over 23 years of insolation data.

An interesting outcome of the study involved in the formation of this model and approach is that accuracy of system design is not lost by basing the design only on data for the month with the lowest insolation levels over the year. This of course greatly simplifies the design approach. In addition, through the use of calculations similar to those in the approach described above, but over a wide range of possible design values and in conjunction with appropriately-treated average global insolation data, curves have been generated that facilitate:

1. determination of battery capacity for a specified *loss-of-load probability* (*LOLP*)
2. optimisation of array tilt angle
3. obtaining insolation data at the appropriate tilt angle
4. determination of the array size that, in conjunction with (1), provides the required *LOLP*.

Four sets of the curves exist, each giving a different battery capacity in (1) for the specified *LOLP*. When followed through (2)–(4), each set of curves provides for a different system design (different array size/battery storage combination) with the same *LOLP*. These four sets can then be analysed on the basis of cost to determine the least-cost approach to satisfying system specifications.

Step 1—Define site-specific and application-specific parameters

- latitude
- horizontal insolation for worst month (usually June in Australia, December in the northern hemisphere)
- daily energy demand
- *LOLP* required.

For example:

- latitude—30°N
- average daily horizontal insolation in December—3 kWh/m^2
- daily demand—5 kWh$_{ac}$
- *LOLP*—0.001 (critical load such as a vaccine refrigerator).

If the average daily summer demand exceeds the average daily winter demand by more than 10%, attention needs to be paid to the possibility of battery discharge during summer (which may necessitate re-optimisation of tilt angle).

Step 2—Determine battery storage for each of the four designs

This is read directly from the appropriate nomogram, as a function of *LOLP*. Fig. G.1 shows this nomogram for design 2, showing that for an *LOLP* of 0.001, storage (*S*) is 5.80 days.

Similarly, looking at the appropriate nomograms, designs 1, 3 and 4 give storage values of 3.49, 8.13 and 10.19 days, respectively. From the *S* values, the actual battery capacity can be calculated from

$$CAP = \frac{S \times L}{DOD \times \eta_{out}} \qquad \text{(G.2)}$$

where S is the number of days of storage, L is the average load per day, DOD is the allowable depth-of-discharge for the batteries and η_{out} is the storage-to-demand path efficiency.

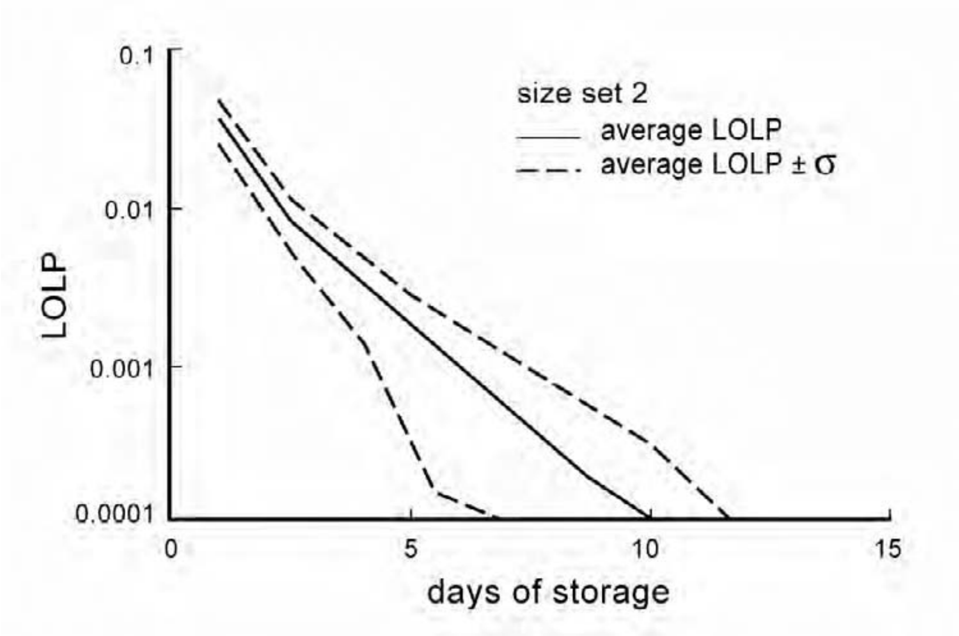

Figure G.1. Number of days of battery storage as a function of *loss-of-load probability* for design 2 (©1987 IEEE, Chapman).

For η_{out}, since we are using an AC load, we need an inverter. If we allow for a peak load of 1000 W_{ac}, our inverter should be rated about 20% higher, i.e. 1200 W_{ac}. The inverter efficiency will vary as a function of load and needs to be determined in conjunction with the anticipated load profile throughout each day. A typical average daily inverter efficiency of 0.76 is assumed.

The other contributor to η_{out} is the battery controller which, because of parasitic power drains, will be in the vicinity of 95% efficient. Losses associated with charge leaving the battery need not be considered here, since the rating of battery capacity is in terms of charge obtainable from the battery. Therefore, we consider battery inefficiencies only in terms of charge being stored in the batteries.

$$\eta_{out} = 0.95 \times 0.76 = 0.72$$

$$L = 5 \text{ kWh/day}$$

$$S = 5.80 \text{ (for design 2)}$$

$$DOD = 0.8 \text{ (using a deep-cycle type battery)}$$

Therefore

$$CAP = 5.80 \times 5 / (0.8 \times 0.72)$$

$$= 50 \text{ kWh.}$$

Step 3—Determine array size for each of the four designs

The ‘design insolation in the plane of the array’ (*POA*) can be determined from the appropriate nomogram. By reading off the *POA* for different tilt angles (i.e. one nomogram exists for each tilt angle), the tilt angle is easily optimised by selecting the one that gives the maximum *POA* value. These values are, of course, a function of the latitude. Fig. G.2 shows the nomogram for design 2, for the case where the tilt angle equals the latitude.

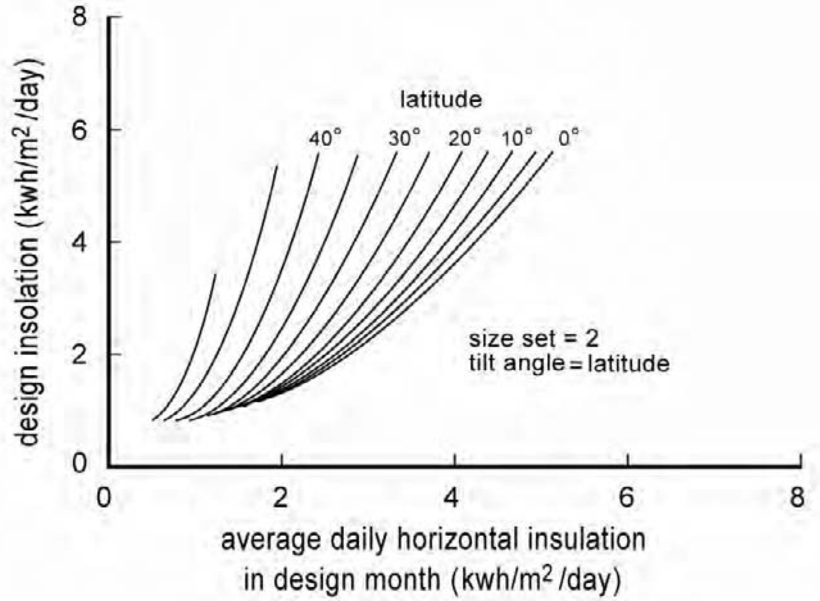

Figure G.2. Design insolation in the plane of the array (POA) as a function of the daily global insolation (©1987 IEEE, Chapman).

For our example, where the horizontal insolation is 3 kWh/m^2/day and the latitude is 30°, we get a *POA* value of 4.3 kWh/m^2/day.

The corresponding array area (A) is calculated from

$$A = \frac{L}{POA \times \eta_{in} \times \eta_{out}} \qquad \text{(G.3)}$$

where L is the average daily load (kWh/day), *POA* is the design insolation value (kWh/m^2/day), η_{in} is path efficiency from insolation to storage and η_{out} is storage-to-load efficiency.

The advantage of determining array size in terms of area is that it remains independent of the voltage-current configuration. The disadvantage is that the purchase of solar panels involves the specification of currents (and voltages) and/or power rating for standard test conditions.

If a maximum power point tracker (MPPT) is not used, the array voltage is determined by the batteries and each solar module can be assumed to operate at its rated maximum power point current (since excess voltage is built into each module to allow for temperature effects). In this instance, the array size is most conveniently specified in terms of peak current (I_p) according to

$$I_p = \frac{L \times I_0}{POA \times \eta_{bat} \times DF \times V_{bat} \times SD \times \eta_{out}} \tag{G.4}$$

where I_0 is the peak light intensity (1 kW/m^2) under which the array will produce current I_p at the nominal battery voltage V_{bat}, POA is the design insolation, η_{bat} is the battery coulombic efficiency (typically 85% during lowest insolation months), DF is the dust factor, (typically 0.90; i.e. 10% loss owing to dust), L is the average daily load, SD is a factor for self-discharge of the batteries and η_{bat} is the battery-to-load efficiency as dealt with previously.

For deep cycle batteries, in the worst month, self-discharge can be neglected, as little charge generally remains, unless the *LOLP* figure is extremely small. For a 24 V_{dc} configuration

$$\begin{aligned} I_p &= 5000 \times 1 / (4.3 \times 0.85 \times 0.90 \times 24 \times 0.72) \\ &= 88.0 \text{ A rated current (at nominally 24 V).} \end{aligned}$$

As a power rating by the manufacturer using standard test conditions (25°C), this will typically correspond to

$$\begin{aligned} & 88 \text{ A} \times 34 \text{ V } (25°\text{C}) \\ = \; & 3.0 \text{ kW as a manufacturer's rating.} \end{aligned}$$

However, if an MPPT is used, we cannot make assumptions about the operating voltage of the array, since the MPPT will adjust it to the maximum power point. Accordingly, we need to look at the efficiency of the array at the maximum power point (η_{mp}), which is a function of the array's cell temperature (T_c) and the array efficiency (η_r), which should be given by the manufacturer. That is

$$\eta_{mp} = \eta_r \left[1 - C_r \left(T_c - T_r\right)\right] \tag{G.5}$$

where C_r is the maximum power coefficient of variation with temperature (typically 0.005 °C^{-1}) and T_r is the reference temperature.

Depending on the site, at latitude 30°N, a typical ambient temperature during a winter's day will be 10°C and the array will operate at approximately 20°C above ambient. Assuming the manufacturer quotes and array efficiency of 10% at a reference temperature of 25°C, then

$$\begin{aligned} \eta_{mp} &= 10.0 \times (1 - 0.005 \times (30.0 - 25.0)) \\ &= 9.75\% \text{ efficiency.} \end{aligned}$$

The resulting array area required will be given by Eqn. (G.3), where η_{in} (the insolation-to-storage efficiency) is given by

$$\eta_{in} = \eta_{mp} \times \eta_{bat} \times \eta_{mppt} \times D \times SD \tag{G.6}$$

where η_{mppt} is the MPPT efficiency (typically 95%).

Therefore

$$\eta_{in} = 0.0975 \times 0.85 \times 0.95 \times 0.90$$
$$= 0.071$$

and, from Eqn. (G.3)

$$A = 5000/(4300 \times 0.071 \times 0.72)$$
$$= 22.8 \text{ m}^2$$

or, in terms of the manufacturer's ratings (at 25°C)

$$\text{array rating} = 1000 \text{ W/m}^2 \times 0.10 \times 22.8 \text{ m}^2$$
$$= 2.28 \text{ kW}_p.$$

This compares to the 3.0 kW_p rating required without the MPPT. A trade off obviously exists between cost, system complexity, system efficiency and reliability.

These calculations have been done on the basis of design 2 and can be simply repeated for designs 1, 3 and 4 by using the appropriate nomograms, which will give different values for *POA* and *S*. This is shown in Table G.2.

Table G.2. Plane-of-array design insolations as a function of storage (*S*).

	plane-of array insolation (kWh/m^2/day) tilt angle = latitude +					
Design	–20°	–10°	0°	10°	20°	*S* (days)
1	3.00	3.23	3.37	3.44	3.45	3.59
2	3.53	3.93	4.28	4.50	4.46	5.80
3	3.73	4.21	4.61	4.84	4.71	8.13
4	3.85	4.38	4.79	4.99	4.79	10.19

From Table G.2, the optimum tilt angle can be seen to be latitude + 10°. This then leaves four potential combinations of array size and storage capacity, each of which provides the required *LOLP*. Selection is then made on the basis of least cost. Costing may be done purely on an initial cost basis, or else a lifetime cost basis, depending on consumer preference. For the latter, battery life, which varies significantly with temperature and depth-of-discharge (*DOD*), must be considered.

The battery life for flooded lead acid batteries can be estimated from

$$CL = (89.59 - 194.29T)\exp(-1.75 \times DOD) \qquad \text{(G.7)}$$

where C*L* is the battery life (in cycles), *T* is the battery temperature and *DOD* is the depth-of-discharge.

In a PV-storage system, the depth-of-discharge varies from cycle to cycle. We define each cycle as one day, and *DOD* as the maximum depth-of-discharge for that day.

It has been shown statistically that the distribution of *DOD*s for all battery cycles can be generalised as a function of the *LOLP* and the days of storage, thus enabling Eqn. (G.7) to be used to give a close estimate of actual battery life.

Using a temperature of 25°C (constant) and an *LOLP* of 0.001, the anticipated battery life for designs 1–4 are 10.7, 10.9, 10.9 and 10.9 years, respectively. The lives are quite long because, for an *LOLP* of 0.001, the batteries remain well charged most of the time.

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Appendix

H

SYSTEM DESIGN FOR PV-POWERED WATER PUMPING

H.1 INTRODUCTION

Aspects of insolation data manipulation are discussed in preparation for designing a stand-alone, directly-coupled PV powered water pumping system. This is followed by an analysis and discussion of typical PV module characteristics and output and the relevance for water pumping system design. An example system design is provided, including discussion of each part of the procedure.

H.2 INSOLATION DATA MANIPULATION

Determine the maximum (solar noon) daily light intensity (I) incident on the array (at inclination angle β for each of the design months, for both sunny days (I_s) and typical cloudy days (I_c). Refer to Chapter 1 for further details about insolation data and note that various computer programs are available to help with such calculations (Silvestre, 2003). For our purpose here we use an approximation that discriminates between 'sunny' and 'cloudy' days (see Chapter 1, Section 1.8.3.2). Using Eqn. (1.19) from Chapter 1 (Hu & White, 1983), in conjunction with Fig. H.1, we get, for sunny days

$$I_{si} = 1.353 \times 0.7^{AM^{0.678}} \times 1.10 \times \sin(\alpha + \beta) \qquad \text{(H.1)}$$

where the units are kW/m^2, α is the noon-time altitude of the sun for month i, given by Eqn. (1.22), β is the angle of inclination of the array on which I_{si} is incident, AM is the air mass ($1/\sin\alpha$) and the factor 1.10 allows for the inclusion of the diffuse component for a cloudless day.

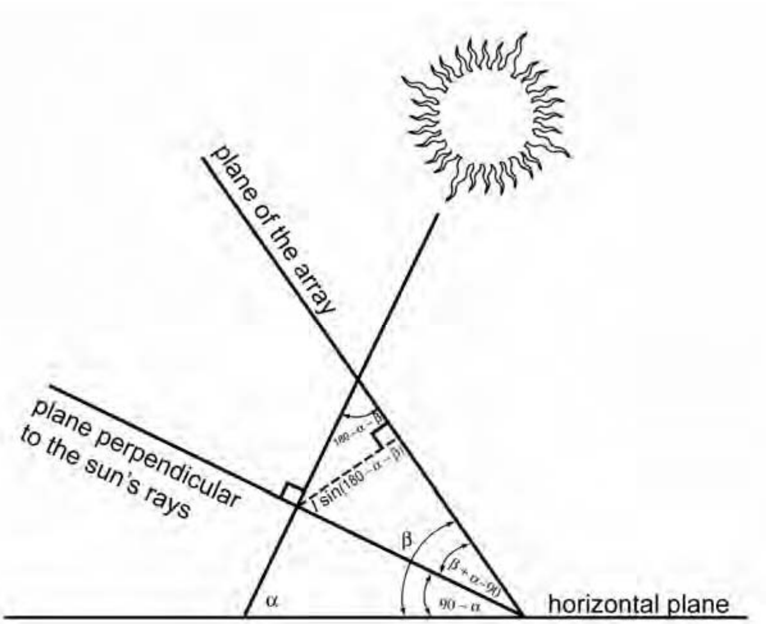

Figure H.1: Procedure for determining light intensity incident on solar panels at angle β at noon.

Similarly, for typical cloudy days, the maximum light intensity I_{ci} for month i is estimated from

$$I_{ci} = 1.353 \times 0.7^{AM^{0.678}} \times 0.20 \qquad \text{(H.2)}$$

where the factor 0.20 represents the assumed diffuse light intensity, which is assumed to be independent of b.

1. From the values for I_{si} and I_{ci} for each month i, use Fig. H.2 to estimate the light intensity incident on the array at inclination angle β throughout each day for sunny and cloudy days, respectively. This facilitates the calculation of the kWh/m^2/day for both sunny and cloudy days by using appropriate values for the 'time' axis, as given by N in Fig. H.2.

2. Determine the percentage of sunny days given by Fig. H.2 with I equated to I_{si} for each month. This can be found from Eqn. (H.3), which gives the average daily global radiation (G_i) falling on the array at inclination β for each month (i) in the design period as the sum of the sunny-day and cloudy-day components of insolation

$$G_i = X_i \times 6.76 \times N_i \times I_{si} + Y_i \times 6.76 \times N_i \times I_{ci} \qquad \text{(H.3)}$$

where X_i and Y_i represent the fraction of sunny and cloudy days, respectively.

For a directly-coupled system, we make the assumption that no pumping takes place during cloudy weather because of poor sub-system performance in the presence of greatly reduced operating currents. We therefore use the sunny weather component of the global radiation in Eqn. (H.3) ($X \times N \times 6.76 \times I_s$) as being the useful global insolation (R_u) incident on the solar panels.

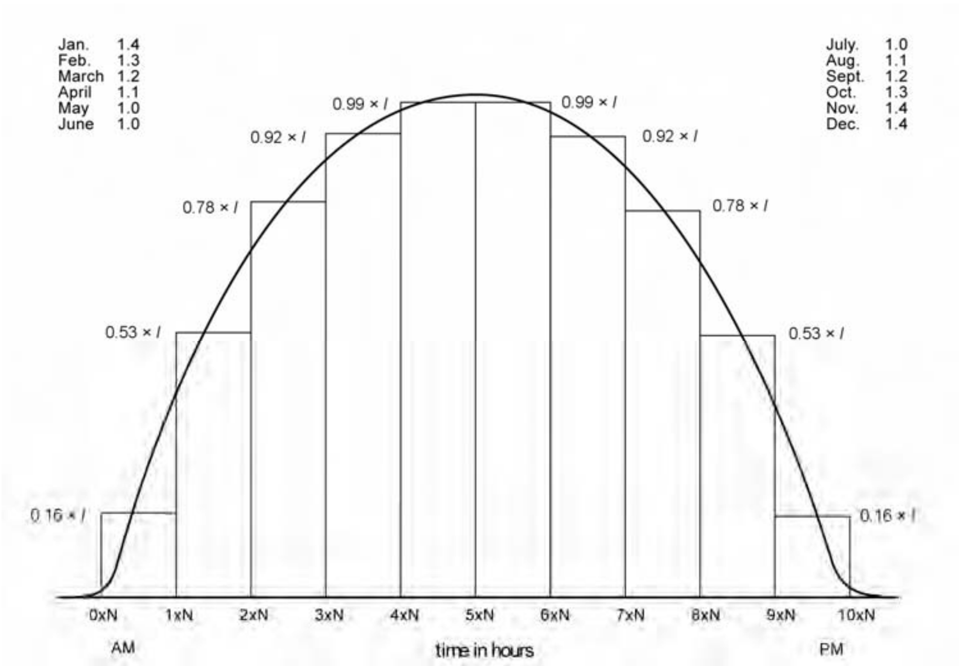

Figure H.2. Profile of light intensity throughout a typical sunny day, as a function of the peak daily intensity *I*. The histograms of width *N* represent an approximation to the daily light intensity profile, with *N* being determined by the time of the year.

3. Average the calculated values of I_{si} throughout the year (or period for which the design is being undertaken), to give I_{sa}. For this, each I_s value should be weighted according to the number of days in the particular *i*th month (M_i) and the percentage of those that are expected to be sunny. For instance, for *i* representing the month or particular period of time

$$I_{sa} = \frac{\sum_i (X_i M_i I_{si})}{\sum_i (X_i M_i)} \tag{H.4}$$

We then convert each sunny day (for each month), as given by Fig. H.2, into an appropriate equivalent number of hours of sunshine (E) as given by

$$E_i = \frac{6.76 N_i I_{si}}{I_{sa}} \tag{H.5}$$

This is equivalent to saying that on a sunny day, with peak intensity I_s, we have E hours of sunshine at the light intensity of I_{sa}. To determine the corresponding monthly number of such hours for month i (E_{mi}) we use

$$E_{mi} = X_i M_i E_i \tag{H.6}$$

and if needed, the overall annual total of such hours (E_y) is given by

$$E_y = \sum_i E_{mi} \tag{H.7}$$

Note, however, that two hours of operation at $I_{sa}/2$ intensity is not equivalent to one hour of operation at I_{sa} intensity, owing to poorer part-load performance of centrifugal pumps and non-optimal matching of the load to the solar panel current-voltage characteristics. Therefore, for the first iteration, assume the above number of equivalent daylight hours is for only $0.80 \times I_{sa}$ kW/m^2 and accordingly design for maximum system efficiency at this light intensity. This will build a necessary degree of conservatism into the design, and will also greatly increase the daily system efficiency, when allowing for the reduced light intensities for large parts of each day (Fig. H.2).

4. For a system with adequate water storage, the design can be done so as to provide the correct annual amount of pumped water. For systems with limited or no water storage, the water demand and water pumped throughout the whole design period need to be matched. In either case, we determine a volume V that must be pumped each sunny day (which will be an absolute or an average value depending on storage capabilities). This volume V is to be pumped in E hours using solar panels that will provide the necessary power at a light intensity of $0.80 \times I_{sa}$.

   For a design without storage, any imbalance between E_i and V_i values throughout the year should be minimised by optimising the tilt angle. Varying the tilt angle will change E_i values for different months relative to each other. Ideally, we want E_i values proportional to V_i values for the design months.

H.3 PV MODULE CHARACTERISTICS

A typical module will have 36 cells connected in series, each cell typically having the parameters:

$$\begin{aligned} V_{oc} &= 600 \text{ mV } (25°\text{C}) \\ FF &= 75\% \\ V_{mp} &= 475 \text{ mV } (25°\text{C}) \\ V_{mp} &= 430 \text{ mV } (45°\text{C}) \\ I_{mp}/I_{sc} &= 0.95 \end{aligned}$$

Each cell can be reasonably accurately represented by the equation

$$V = \left(\frac{nkT}{q}\right)\ln\left(\frac{I_L - I}{I_0}\right) - IR_s \tag{H.8}$$

where V is the terminal voltage, I is the current, I_L is the light-generated current, n is the ideality factor (taken to be 1.3), R_s is the series resistance, q is the charge on an electron (1.6×10^{-19} C), k is Boltzmann's constant (1.38×10^{-23} J/K), T is absolute temperature (typically 318 K for field operation), and I_0 is the dark saturation current, given by

$$\begin{aligned} I_0 &= \frac{I_L}{\exp\left(\dfrac{qV_{oc}}{nkT}\right)} \\ &= 2.17 \times 10^{-7} \times I_L \quad \text{(at 45°C)} \end{aligned} \tag{H.9}$$

where V_{oc} is the open circuit voltage, which is typically 600 mV at 25°C for commercial solar cells, but falls to about 555 mV at 45°C.

For commercial cells, R_s is designed to be approximately inversely proportional to the rated short circuit current, so that percentage power loss in R_s is approximately constant with cell size (about 2.5%); that is

$$R_s \approx \frac{1}{40 I_{sc}} \tag{H.10}$$

where I_{sc} is the short circuit current under 1 kW/m^2.

To allow for variations in light intensity, let

$$I_L = L \times I_{sc} \tag{H.11}$$

where L is the factor representing the light intensity such that $L = 1$ corresponds to 1 kW/m^2 and $L = 0.5$ corresponds to 500 W/m^2. We can now rewrite Eqn. (H.8) as

$$V = 0.0361 \times \ln\left(\frac{L \times I_{sc} - I}{2.17 \times 10^{-7} \times I_{sc}}\right) - \frac{I}{40 \times I_{sc}} \tag{H.12}$$

for $T = 318$ K.

For a number of cells interconnected in series, the voltage at any current I from Eqn. (H.12) should simply be multiplied by the number of series-connected cells.

The next step is to generate the five current-voltage curves from Eqn. (H.12) that correspond to the five light intensities (i.e. five values for L) from Fig. H.2. These are shown in normalised form in Fig. H.3, with corresponding tables of normalised values being given in Table H.1. The currents on the vertical axis and in the normalised tables will be explained later. Each voltage on the horizontal axis is multiplied by the factor m, which is the number of nominally 12 V modules connected in series in each string.

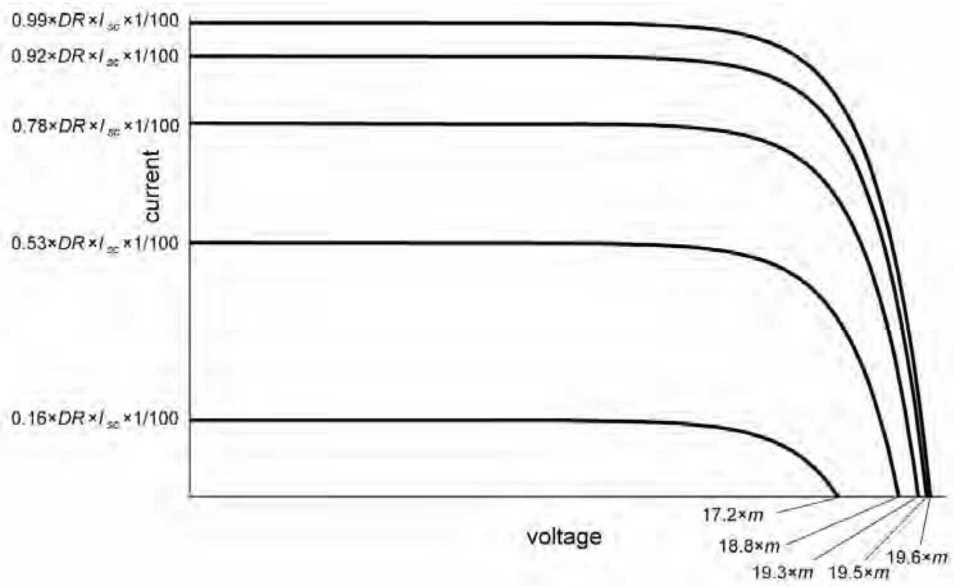

Figure H.3. Current-voltage characteristic curves for a typical commercial PV system at the light intensities given by Fig. H.2. The curves were generated using Eqn. (H.12).

Table H.1. Normalised values for the currents and voltages corresponding to the five curves in Fig. H.3.

curve 1		curve 2		curve 3		curve 4		curve 5	
current	voltage	current	voltage	current	voltage	current	voltage	current	voltage
0.000	19.6	0.000	19.5	0.000	19.3	0.000	18.8	0.000	17.2
0.113	19.4	0.113	19.3	0.113	19.1	0.113	18.5	0.034	16.8
0.226	19.3	0.226	19.1	0.226	18.8	0.226	18.0	0.066	16.5
0.339	19.0	0.339	18.9	0.339	18.5	0.283	17.7	0.090	16.1
0.451	18.8	0.451	18.6	0.451	18.1	0.339	17.4	0.113	15.5
0.564	18.5	0.564	18.2	0.508	17.9	0.395	16.9	0.124	15.2
0.678	18.1	0.678	17.7	0.564	17.6	0.429	16.6	0.135	14.7
0.734	17.8	0.734	17.4	0.598	17.3	0.451	16.2	0.141	14.3
0.790	17.5	0.791	16.9	0.632	17.1	0.474	15.8	0.147	13.8
0.847	17.0	0.824	16.5	0.654	16.8	0.485	15.5	0.152	13.2
0.881	16.7	0.847	16.1	0.678	16.6	0.497	15.1	0.154	12.8
0.903	16.4	0.858	15.9	0.702	16.2	0.508	14.5	0.157	11.8
0.925	16.0	0.869	15.6	0.722	15.8	0.512	14.2	0.158	11.3
0.937	15.7	0.880	15.3	0.734	15.5	0.514	14.1	0.159	10.4
0.949	15.3	0.892	14.8	0.745	15.1	0.517	13.8	0.160	9.5
0.960	14.9	0.903	14.2	0.750	14.9	0.519	13.6	0.160	0.0
0.965	14.7	0.909	13.6	0.756	14.6	0.521	13.3		
0.971	14.3	0.914	12.8	0.762	14.2	0.523	13.0		
0.976	13.9	0.916	12.2	0.765	14.0	0.525	12.5		
0.981	13.3	0.917	11.8	0.768	13.7	0.526	12.2		
0.987	11.8	0.919	10.4	0.770	13.5	0.527	11.8		
0.989	10.4	0.920	8.4	0.772	13.2	0.528	11.3		
0.990	8.0	0.920	0.0	0.773	13.0	0.529	10.4		
0.990	0.0			0.776	12.2	0.530	0.0		
				0.777	11.8				
				0.778	11.3				
				0.780	0.0				

Modules specifically tailored to give the exact desired voltage at maximum power point can of course be designed and constructed by using a different number of series-connected cells. This, however, will cost a premium price, making it uneconomical to use specially-designed modules unless the quantities required are enormous.

Considering the standard modules at 45°C:

- one single module (36 cells) should give V_{mp} = 15.5 V
- two in series (72 cells) should give V_{mp} = 31.0 V
- three in series (108 cells) should give V_{mp} = 46.5 V
- four in series (144 cells) should give V_{mp} = 62.0 V.

As can be seen from Fig. H.3, the maximum power point voltage changes very little with variations in light intensity.

We therefore choose an appropriate number of series-connected modules to give us a maximum power point voltage (at 45°C) as close as possible to the voltage at which the subsystem attains maximum operating efficiency (allowing for a 2% voltage drop along the length of the wiring).

The final part of the design procedure is the determination of the current-generating capacity required for the solar panels. An iterative approach is simplest and well suited to solving through the use of computers. An initial choice of array size (current rating) is made by following the guidelines of steps (4) and (5) in Section H.2, above, where it is suggested that we want the subsystem to operate at its maximum efficiency when the light intensity (L_{mp}) is given by

$$L_{mp} = 0.80 I_{sa} \tag{H.13}$$

Therefore, we want a rated maximum power point current (I_{mp}) at 1 kW/m^2 insolation of

$$I_{mp} = \frac{100 I_m}{0.80 I_{sa}} \tag{H.14}$$

where I_m is the motor current at maximum subsystem efficiency.

Once the required I_{mp} value is determined, we must appropriately upgrade the rating to ensure the solar panels will in fact produce the current I_{mp}. The contributing reasons for necessitating this upgrade in rating include:

- dust on the surface (Halcrow & Partners, 1981; Hammond *et al.*, 1997)
- insolation levels possibly lower than anticipated
- tolerances in solar panel outputs
- degradation of solar panels.

These factors can be compensated for by appropriately over-sizing the solar array design. Typically, we should allow for 6% loss owing to dust, depending on location, 10% for degradation of the solar panels (unless manufacturers give guarantees to the contrary) and 10% for combined tolerances in solar panel outputs and insolation levels. A combined reduction of 26% from rated value translates to an over-sizing requirement of 35% (1/0.74). We call this a derating factor DR, which in this case is 0.74. In other words, we select solar panels with a rated maximum power point current 1.35 times greater than that calculated as being necessary. To convert this to a short circuit current rating, simply divide by 0.95.

We are now in a position to refer back to Fig. H.3 and consider the vertical axis. If I_{sc} is the rated short circuit current, as specified by the manufacturer, then we must:

1. Use Fig. H.2 to make adjustment for the light intensity being different from 1 kW/m^2 (= 100 mW/cm^2), which means multiply by ($0.99 \times I / 100$), for the top curve, where I is given by Eqn. (H.1).
2. Multiply by the derating factor DR (which is suggested to be 0.74).

Consequently, for the top curve, we get a short circuit current of:

$$0.99 \times 0.74 \times I / 100 \times I_{sc}$$

or

$$(0.0073 \times I) \times I_{sc}$$

where I is in mW/cm^2.

Having now selected the array size, the vertical and horizontal axes of Fig. H.3 can be specified, and the load line (with efficiency weightings) superimposed. This facilitates, in conjunction with Fig. H.2, the calculation of pumped volumes of water and system average efficiencies throughout both sunny and cloudy days and for the whole design period. If this procedure is being carried out by a computer, it becomes a relatively simple task to try different values for the current to iteratively tune into the system design for maximum overall efficiency and preferred pumping regime.

It should be noted that a degree of conservatism has automatically been built into the design back in steps (4) and (5) when we defined the number of pumping hours (E) in terms of the number of equivalent hours of sunshine with light intensity (I_{sa}), but then subsequently used the light intensity of $0.80I_{sa}$ as the one for which the maximum subsystem efficiency would correspond. This conservatism was necessary for two reasons. Firstly, it allows for reduced subsystem performance (efficiency) when operating under light intensities greater or less than the design value of $0.80I_{sa}$. Secondly, it compensates for subsystem performance below that expected, which could result from:

- discrepancies between manufacturers' curves and those measured in practice
- degradation of subsystem components
- unexpected changes in static head etc.

The net result of the conservatism is that the design, on paper, should result in 10–20% more water being pumped than is required in the specification. This figure may be increased or decreased as required, although any modifications should probably be done in consultation with the consumer.

H.4 EXAMPLE OF A DIRECTLY-COUPLED SYSTEM DESIGN

Specification

Design a directly-coupled pumping system (no batteries or power conditioning circuitry) for irrigation purposes near Melbourne (latitude 37.8°S). The only months of interest are December and January, during which period 2.5 million litres are required to be pumped. The relevant insolation data is given in Table H.2. The total pumping head is 8.8 m and this remains approximately constant during pumping and from season to season. There are no problems with the water source replenishment rate. Other months of the year are considered to be non-critical.

Table H.2. Average daily insolation data for a horizontal surface for the design months.

month	*S*	*D*	*R*
December	676	214	890
January	629	210	839

Design procedure

Step 1—Load specification

Everything necessary is specified above.

Step 2—Select tilt angle and adapt the solar insolation data

Since the design period is only for December and January, the tilt angle is simple to optimise, since we point the panels directly at the noon-time sun for these months. From Eqn. (1.7) in Chapter 1, we calculate that the declination of the sun for December is the maximum of 23.4°, while for mid-January it is not much different, at about 21.8°. Using the value of 22.8°, we get a noon-time solar altitude, as given by Eqn. (1.6) from Chapter 1, of 75°. Consequently, our tilt angle should be 15°. Similarly, from Eqn. (1.5) of Chapter 1, we correct the tilt angle to give the solar insolation incident on the solar panels, as shown in Table H.3.

Table H.3. Solar insolation incident on the solar panels, corrected for tilt angle.

month	α	*S*	*D*	S_{15}	R_{15}
December	75.6	676	214	698	912
January	73.5	629	210	656	866

Step 3—Dislocation data manipulation

(a) **Determine I_s and I_c values**

For December, using Eqns. (H.1) and (H.2),

$$I_{s1} = 1.353 \times 0.7^{AM^{0.678}} \times 1.1 \times \sin(180° - 75.6° - 15°)$$

where $AM = 1/\sin(75.6°)$, giving

$$I_{s1} = 103 \text{ mW/cm}^2$$
$$I_{c1} = 9.4 \text{ mW/cm}^2.$$

For January (with a = 73.6)

$$I_{s2} = 102 \text{ mW/cm}^2$$
$$I_{c2} = 9.3 \text{ mW/cm}^2.$$

(b) **Calculate the mWh/cm²/day for sunny and cloudy days**

Using Fig. H.2, we get the 'sunny day' mWh/cm²/day as

$$6.76 \times N_i \times I_{si}$$

with N_i = 1.4 for December and January and the I_{si} values as given in (c). Similarly, the 'cloudy day' mWh/cm²/day is given by

$$6.76 \times N_i \times I_{ci}$$

for each month respectively.

(c) **Determine the percentage of sunny and cloudy days**

For December, using Fig. H.2 and Eqn. (H.3),

$$R_{15} = X \times 6.76 \times 1.4 \times 103 + Y \times 6.76 \times 1.4 \times 9.4$$

where R_{15} = 912, X and Y are the percentages of sunny and cloudy weather, respectively, and $X + Y = 1$ (or $Y = 1 - X$). This gives

$$912 = 975 \times X + 89 \times (1 - X)$$

and

$$X = 0.93,\ Y = 0.07.$$

In other words, during the days, it is sunny 93% of the time and cloudy only 7% of the time.

For January

$$866 = 695 \times X_2 + 89 \times (1 - X_2)$$
$$X_2 = 0.89$$
$$Y_2 = 0.11.$$

That is, it is sunny 89% of the time.

Neglecting the cloudy weather as being useless for pumping, the useful radiation incident on the solar panels is

$$R_{u1} = 0.93 \times 912$$
$$= 848 \text{ mWh/cm}^2\text{/day (December)}$$
$$R_{u2} = 0.89 \times 866$$
$$= 771 \text{ mWh/cm}^2\text{/day (January).}$$

(d) **Determine equivalent number of pumping hours (E) at light intensity I_{sa}**

Using Eqn. (H.4),

$$I_{sa} = (103 \times 31 \times 0.98 + 102 \times 31 \times 0.89) / (31 \times 0.93 + 31 \times 0.89) = 103 \text{ mW/cm}^2.$$

Using Eqn. (H.5),

$$E_1 = 6.76 \times 1.4 \times 103 / 103 = 9.5 \text{ hours}$$

$$E_2 = 9.4 \text{ hours}$$

and using Eqn. (H.6), the monthly number of such hours is

$$E_{m1} = 9.5 \times 31 \times 0.93 = 274 \text{ hours}$$

$$E_{m2} = 9.4 \times 31 \times 0.89 = 259 \text{ hours.}$$

Also, for the design period

$$Ey = E_{m1} + E_{m2} = 533 \text{ hours (of equivalent sunshine at } I_{sa}\text{).}$$

Step 4—Pump selection

We require 2.5 million litres in total in an average year to be pumped throughout December and January combined. This gives a pumping rate (P) of

$$P = 2.5 \times 10^6 / (533 \times 60 \times 60) = 1.30 \text{ L/s.}$$

In this instance, we do not need to be concerned about the fact that more water will be pumped in December than January, because this is simply the result of there being more sunny days on average in December, hence necessitating the increased water being pumped during that month.

Frictional losses in the pipes, since not otherwise stated, are assumed to effectively add 2% to the total head, which in this case gives a total of 9 m. Fig. H.4 gives the performance curves of a centrifugal pump well suited to a head of 9 m and operation at a pumping rate of 1.30 L/s.

Step 5—Select motor with compatible torque-speed characteristics

From Fig. H.4, the centrifugal pump operating at a head of 9 m and a pumping rate of 1.3 L/s will have a speed of about 2700 rpm. This corresponds to an input power (P_{in}) of about 230 W. Consequently, since the torque (τ) is not given directly, it can be calculated from the power (P_{in}) and angular velocity (ω) as follows:

$$\tau = P_{in} / \omega \qquad \text{(H.15)}$$

$$= 230 / (2\pi \times 2700 / 60) = 0.814 \text{ Nm.}$$

The performance curves of the DC motor in Fig. H.5 indicate that it will be a suitable match for the selected pump, giving about 76% efficiency at the design point for operation.

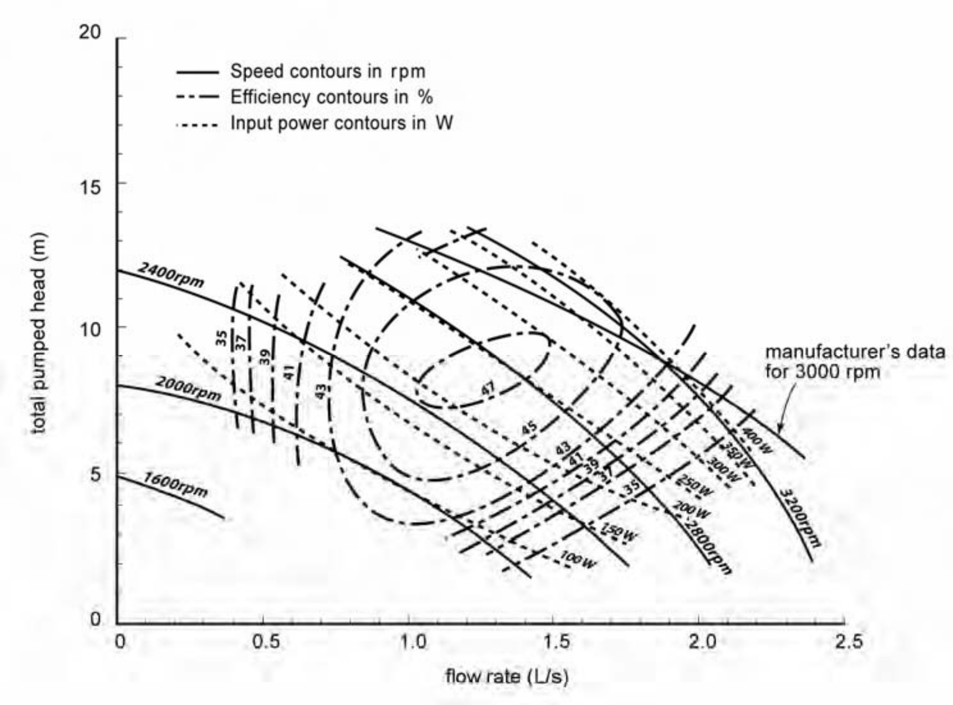

Figure H.4: Centrifugal pump with performance characteristics and pumping rates suited to the specification (Used with permission of Halcrow & Partners, 1981).

Step 6—Determine the load line for the subsystem, weighted by efficiencies

Fig. H.4 gives the necessary pump characteristics, although not in the most desirable form. However, from the supplied curves, the torque (τ_l) can be determined for each speed (N), via the input power to the pump as given by Eqn. (H.15) above. For each τ_l value we then refer to Fig. 11.11 in Chapter 11 for our chosen motor.

The curves are provided, although it is far simpler and more accurate to use the provided equations, which can be rearranged to give

$$I_m = \frac{\tau + 0.0674}{0.136} \tag{H.16}$$

$$\tau_l = \frac{P_{in}}{\omega}$$

$$V_m = \frac{N + 69.2 I_m + 16.6}{70.4} \tag{H.17}$$

Finally, by including the pump and motor efficiencies (η_p and η_m, respectively) by reading the values off the curves, a table can be formed (Table H.4) that includes all the necessary information for the motor/pump load line, weighted by the subsystem efficiencies. V_a in the final column is the voltage necessary from the array. Its values are 2% higher than the motor voltages (V_m), owing to the losses in the wiring.

Table H.4. Calculated values for determining the load line.

N	$\omega=\pi N/30$	P_{in}	$\tau_l = P_{in}/\omega$	η_m	η_p	η_{sub}	$I_m = I_a$	V_m	V_a
(rpm)	(rad/s)	(W)	(Nm)	(%)	(%)	(%)	(A)	(V)	(V)
3200	335	400	1.19	75.5	41.0	31.0	9.20	55	56
3000	314	300	0.96	76.0	45.0	34.2	7.60	50	51
2800	293	250	0.85	75.5	47.5	36.0	6.75	46	47
2600	272	220	0.81	75.0	47.5	35.6	6.45	43	44
2400	251	170	0.68	74.0	45.0	33.3	5.50	40	41
2200	230	110	0.48	73.0	35.0	25.5	4.03	35	36
2120 [1]	222	89	0.40	73.0	21.4	15.6	3.44	34	35
2100	220	50	0.23	0	0	0	2.19	32	33

Note
1. At $N = 2120$, $\eta_p = (0.22 \text{ kg/s} \times (10.1 - 0.2) \text{ m} \times 9.8 \text{ m/s}) / 100 \text{ J/s} = 21.4\%$. Therefore, at a 9 m head on the same efficiency line, $P_{in} = (0.22 \text{ kg/s} \times (9 - 0.2) \times 9.8) / 0.214 = 89$ W.

Step 7—Photovoltaic system sizing

The I-V curves for our PV panels are given in Fig. H.3. Our task is to configure the modules so as to match the PV output to the requirements of the motor/pump.

Voltage sizing

Since the maximum power point voltage remains roughly constant as light intensity changes, we need it to correspond to the voltage at which the subsystem achieves maximum efficiency. From Table H.4, this occurs for an array voltage of 47 V. From our standard normalised curves for commercial modules in Fig. H.3 and Table H.1, we find that, for three nominal 12 V modules connected in series, the maximum power point voltage at 45°C will be about 46 V, which is a little lower than ideal although quite acceptable. This selection therefore specifies the horizontal axis in Fig. H.3 with $m = 3$.

Current sizing

For peak subsystem performance, Table H.4 indicates that we require a motor current of 6.75 A. Since, however, we want this current when the light intensity is only $0.80 \times I_{sa}$, then our rated maximum power point current (I_{mp}) at 100 mW/cm^2 needs to be as given by Eqn. (H.14)

$$\begin{aligned} I_{mp} &= 6.75 \times 100 / (0.80 \times 103) \\ &= 8.2 \text{ A.} \end{aligned}$$

We then allow for a derating factor (DR) of 0.74 and divide by 0.95 to convert to a short circuit current rating (I_{sc}) of

$$\begin{aligned} I_{sc} &= 8.2 / (0.74 \times 0.95) \\ &= 11.6 \text{ A.} \end{aligned}$$

That is, this is the manufacturer's rated current we need to ensure that, in the long term, we will still get a maximum power point current of 6.75 A when the light intensity is $0.80 \times I_{sa}$.

We can now specify the vertical axis of Fig. H.3 for each month, with the short circuit current for the top curve in December being given by

$$\begin{aligned} I_{sc} &= (0.99 \times 0.74 \times 103 / 100) \times 11.6 \\ &= 8.75 \text{ A.} \end{aligned}$$

This gives us the curves of Fig. H.5 for the month of December. Also from Table H.4 we can superimpose the subsystem load line onto the I-V curves to determine the operating points for each light intensity. This is also shown in Fig. H.5.

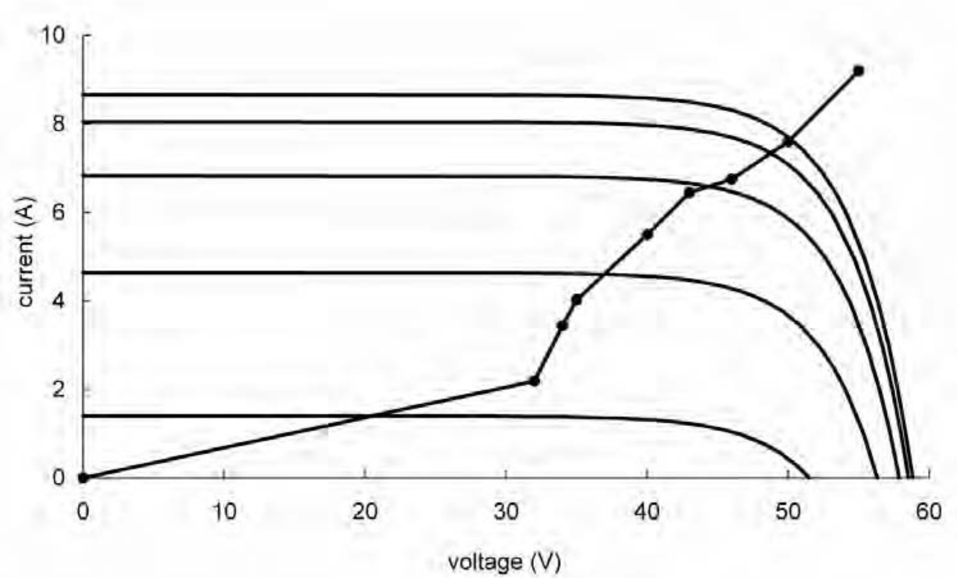

Figure H.5. I-V curves corresponding to the daily insolation profile, as given by Fig. H.2 for the month of December, with the motor-pump load line from Table H.4 superimposed.

We are now in a position to determine the daily and monthly water pumped for each month and hence throughout the design period.

Notes

1. For a cloudy day, the peak light intensity of 9.4 mW/cm^2, as given by Eqn. (H.2), is insufficient to initiate or maintain any pumping.
2. The total water pumped throughout the design period should come to about 10–20% more than that specified, owing to the deliberate conservatism built into the design to allow for such things as the subsystem not meeting the manufacturer's specifications, degradation etc. If the calculated volume is outside this range, then optimisation of the array size (current rating) needs to take place.

3. If the calculated pumped water profile throughout the year does not match the demand profile, then the tilt angle needs to be optimised.

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