VeraSol

COMPONENT-BASED OFF-GRID SOLAR ENERGY SYSTEMS

October 2024

System Design Guidelines

Includes Solar-Only PV Systems and Hybrid Systems Comprising PV and Fuelled Generators

Acknowledgement

This Quality Assurance Framework for Component-Based Solar Home Systems was adapted from guidance documents originally developed by Global Sustainable Energy Solutions Pty Ltd (GSES) for the Government of Uganda. These documents were edited by staff at the Schatz Energy Research Center and Kevin Gauna of Sunbrothers to produce a more widely applicable framework across multiple countries and programs with funds gratefully acknowledged from the Energy Sector Management Assistance Program (ESMAP). The development of the original document was funded through the Energy for Rural Transformation Phase III (ERT III) Project, a World Bank project implemented by the Rural Electrification Agency of Uganda.

About VeraSol

An evolution of Lighting Global Quality Assurance, the VeraSol program supports high-performing, durable off-grid products that expand access to modern energy services. VeraSol builds upon the strong foundation for quality assurance laid by the World Bank Group and expands its services to encompass off-grid appliances, productive use equipment, and component-based solar home systems. Like Lighting Global Quality Assurance, the VeraSol program is managed by CLASP in collaboration with the Schatz Energy Research Center at Humboldt State University. Foundational support is provided by the World Bank Group's Lighting Global program, UKaid, IKEA Foundation, Good Energies Foundation, and others. Please visit VeraSol.org for more information.

About Schatz Energy Research Center

Schatz Energy Research Center's mission is to promote the use of clean and renewable energy. The Center accomplishes this by: designing, demonstrating, and deploying clean and renewable energy technologies; implementing collaborative programs that support the deployment of clean energy systems; performing lab and field research; engaging in scientific and policy analysis; providing graduate fellowships and work opportunities for student engineers and scientists; and educating the public about clean and renewable energy.

About Global Sustainable Energy Solutions

GSES® leads Australia in renewable energy engineering, training and consultancy. We specialize in photovoltaic design, solar training, publications and PV system audits. Established in 1998, GSES has a diverse portfolio, executing projects in Australia, New Zealand, Asia, Africa and the Pacific Islands for both government and private enterprise regarding Renewable Energy engineering, consultancy, design, audit and education.

While all care has been taken to ensure this guideline is free from omission and error, no responsibility can be taken for the use of this information in the design and installation of any off-grid solar energy system.

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List of Abbreviations

A summary of the main acronyms and terms used in this document is listed below:

A	Amps (or amperes)
a.c.	Alternating current
Ah	Amp hour
AS	Australian Standards
ASCE	American Society of Civil Engineers
C_x	Capacity of battery at specified charging rate x in hours
d.c.	Direct current
DOD	Depth of discharge
IEC	International Electrotechnical Commission
IP	International Protection (sometimes known as ingress protection)
kW	Kilowatts
LED	Light-emitting diode
MPP	Maximum power point
MPPT	Maximum power point Tracker
NZS	New Zealand Standards
NOCT	Nominal operating cell temperature
OC	Open circuit
PSH	Peak sun hours
PV	Photovoltaic
PWM	Pulse width modulation
SC	Short circuit
STC	Standard test conditions
UL	Underwriters Laboratories
V	Volts
VA	Volt amperes
VRLA	Valve-regulated lead-acid battery
W	Watts
Wh	Watt-hours
W_p	Watts peak (also known as peak watts)

OVERVIEW

This Guideline supports solar installations that are off-grid and include systems where all the energy is supplied from solar photovoltaic modules (or when a fuelled generator is used either as a back-up or daily). Part 1 is common for all off-grid systems, Part 2 and 3 mainly refers to solar only systems while part 4 refers to hybrid systems with fuelled generators. Part 5 describes the process of preparing diagrams and quotations for potential customers and is applicable to all system designs.

An Off-Grid Solar Energy System includes following system configurations:

- d.c.-coupled systems that consist of solar array(s) connected to the batteries by solar controller(s) and loads are d.c. only
- d.c.-coupled systems that consist of solar array(s) connected to the batteries by solar controller(s) and battery inverter(s)
- a.c.-coupled systems comprising solar array(s) connected to the a.c. side of grid forming battery inverter(s) (a.c.-coupled inverter) requirements.er(s) (grid interactive inverter)
- PV systems comprising both a.c. and d.c.-coupled configuration and
- PV systems with a fuelled generator (hybrid system)

These systems can be connected to a single structure or multiple structures via a mini grid. This guideline does not include design or installation guidelines of the poles, wires and protection requirements of a mini grid.

The guideline can be used to design systems that deliver only d.c. to the load; systems that deliver a.c. to the load and configured as a d.c.-coupled system (charge controller, battery and battery inverter); systems that deliver a.c. to the load and configured as an a.c.-coupled system (PV inverter connected directly to solar modules, a battery and an inverter that operates off the battery while providing battery charging from the PV inverter) and PV systems that include a fuelled generator (hybrid systems).

In general, d.c.-coupled systems are used for loads that are primarily at night (e.g., residences, boarding schools and outdoor lighting systems) while a.c.-coupled systems provide the most value for sites that have their main loads during the day (e.g., government facilities and agricultural processing facilities).

Part 1 has information common to both d.c. and a.c.-coupled installations for systems. This includes:

- Carrying out a site survey
- Estimating the energy and power requirements for the loads to be connected
- Estimating the available solar irradiance at the site
- Estimating the output from PV modules installed at the site
- Design parameters and basic specifications for modules, batteries, inverters, controllers and mounting systems

Part 2 is dedicated to the specific requirements of d.c.-coupled configurations (with no fuelled generator). It focuses on the design parameters of an off-grid PV system delivering a.c. to a load while using a d.c.-coupled configuration. This part includes consideration of sub-system losses, including:

- Battery inverter efficiency
- Battery efficiency
- Controller efficiency
- Oversizing factor and allowing for module efficiency decreasing over the lifespan of the installation
- Electrical losses in off-grid PV systems due to component efficiencies and cable voltage drop and the effect of those losses on the overall system design

Part 3 is dedicated to the specific requirements of a.c.-coupled configurations (with no fuelled generator). It focuses on the design parameters of an off-grid PV system delivering a.c. to a load while using an a.c.-coupled configuration. This part includes consideration of sub-system losses, including:

- Battery inverter efficiency
- Battery efficiency
- PV inverter efficiency
- Oversizing factor and allowing for module efficiency decreasing over the lifespan of the installation
- Electrical losses in off-grid PV systems due to component efficiencies and cable voltage drop

Part 4 is dedicated to the specific requirements of hybrid systems using fuelled generators. A fuelled generator in a hybrid system may be used as:

- a back-up for periods of bad weather or when there are low levels of irradiation for a few days

or

- a key part of the system that is operated daily to meet some of the daily energy requirements

Part 4 has one section for sizing the components of a hybrid system where the fuelled generator is being used as a back-up to provide power when there is insufficient energy available from the PV installation and battery and another section for sizing the components where the generator is being used daily to always power some of the load.

Part 5 describes the documents a designer should prepare when providing a quotation to a potential end-user. Guidance is provided for creating a system schematic, single line drawing and bill of materials as part of a full quotation.

A systems designer shall also be fully aware of the installation requirements of the various components, including battery ventilation requirements, and determine the system wiring, isolation, and protection requirements. These are covered in the separate document *Component-Based Off-*

Grid Solar Energy Systems: System Installation Guidelines. To minimise duplication, none of that information is repeated in this guideline.

Designing a system using these guidelines and installing it correctly is not sufficient to ensure a successful project. Additional essential steps include commissioning (to verify that the system has been installed correctly) and ongoing maintenance (to keep it in working order). One way to facilitate successful system operation is to incorporate remote monitoring into the design of the system Remote monitoring can benefit system owners/operators and users, by promptly bringing attention to faults that could impair system performance, and project funders, by providing the necessary information to hold installers or operators accountable for system performance. Commissioning, maintenance, and remote monitoring are beyond the scope of this document. Information on these topics can be found in the separate document Requirements and Guidelines for Installation of Off-Grid Solar Systems for Public Facilities.

This guideline shall be read in conjunction with existing codes of practice that may already be in place in the host country regarding installations of photovoltaic systems. Where this guideline has a requirement that contradicts a similar requirement within a code of practice or regulation, the provisions of this guideline should be followed to the degree possible because this guideline has been based on current best practices. If it is necessary to deviate from these guidelines to comply with local or national regulations or legislation, the effect of the deviation on system operation should be assessed and additional changes made as needed in order to conform to the principles outlined in this document.

PART 1 – COMMON INFORMATION FOR D.C. AND A.C.-COUPLED SYSTEM CONFIGURATIONS

1 Introduction

This guideline provides an overview of the formulae and processes undertaken when designing (or sizing) an off-grid PV power system, sometimes called a stand-alone power system. It provides information for designing an off-grid d.c.-coupled system (with battery charging directly from the modules) or an off-grid a.c.-coupled (battery charging from an a.c. source, usually an inverter connected directly to solar panels) system configuration or hybrid power systems.

The content includes the minimum information required when designing an off-grid PV system. The design of an off-grid PV power system should meet the end-user's required energy demand and maximum power demands. However, there are times when other constraints need to be considered as they will affect the final system configuration and selected equipment. These include:

- available budget
- system component availability
- access to the site and available on-site space
- the need to easily expand the system in the future; and
- availability of technical support for maintenance, troubleshooting and repair.

Whatever the final design criteria, a designer shall be capable of:

- Determining the expected power demand (loads) in kW (and kVA) and the end-user's energy needs in kWh/day
- Determining the size of the PV array (in kW_p) and the capacity of the battery bank (in Ah and V or Wh) needed to meet the end-user's requirements
- Selecting the most appropriate PV array mounting system
- Determining the appropriate d.c. voltage of the battery bank
- Determining the rated capacity of the battery bank[1]
- Determining the size of the battery inverter in VA (or kVA) to meet the end-user's power requirements
- Ensuring the solar array size, battery, and any inverters connected to the battery are well-matched

[1] For the battery to have a long useful life, the rated Ah capacity of the battery will generally need to be substantially larger than the Ah capacity needed to reliably operate the load because of losses in the system and to have the reserve needed to handle short term increases in the load. Also, as the battery ages, its effective capacity decreases.

- For d.c.-coupled systems:
    - Determining the size of the solar controller[2] (sometimes called a regulator) with respect to the PV array
    - For Pulse Width Modulated (non-MPPT) controllers, matching the array to the controller so that its voltage and current outputs:
        - fit the battery voltage and is less than the maximum allowable input voltage of the controller, and
        - do not exceed the maximum controller input voltage and current.
    - For MPPT controllers, matching the array configuration to fit the controller's:
        - maximum allowable input voltage
        - input voltage operating window
        - maximum allowable d.c. input power rating, and
        - maximum d.c. input current rating.
- For a.c.-coupled systems:
    - Determining the PV inverter capacity based on the size of the array
    - Matching the array configuration to the selected PV inverter's:
        - maximum input voltage;
        - voltage operating window;
        - maximum allowable d.c. input power rating; and
        - maximum d.c. input current rating.
    - Matching the a.c.-coupled interactive inverter to the PV inverter; and
    - Matching the a.c.-coupled interactive inverter to the battery charging requirements
- For hybrid power systems:
    - Determining the capacity rating in kilovolt-amp (kVA) for the fuelled generator.
    - Determining the battery capacity, in amp hour (Ah) or kilowatt-hour (kWh) based on the energy that must be supplied by the battery along with maximum depth of discharge, days of autonomy, demand and surge currents and charging current required.
    - Determining the rating of the battery charger if supplied as a separate component and not included in the battery inverter.
    - Determining the minimum required real power, or volt-amp (VA) rating, of the battery inverter using a load assessment form or the hourly load profile.

[2] The solar controller could be a fixed input voltage controller—such as a Pulse Width Modulated (PWM) controller—or a Maximum Power Point Tracking (MPPT) controller.

- Determining whether the rating of the battery inverter changes when it is an inverter/charger or interactive inverter charger using the generator and/or PV array powering a PV inverter.
- Determining the size of the array based on the load energy that the array needs to provide using the selected irradiation value.
- Determining the operational hours of operation for the fuelled generator if the PV array does not provide all the daily load energy during the months having the lowest irradiation values.

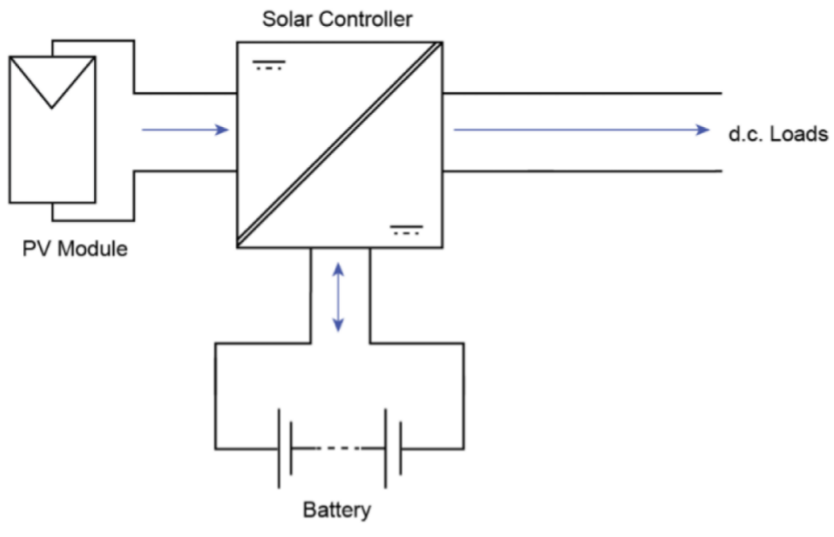
A system designer will also determine the required cable sizes, isolation (switching) and protection requirements. This information is included in the companion guide titled *Component-Based Off-Grid Solar Energy Systems*: *System Installation Guidelines*.

2 Typical Off-Grid PV Power System Configuration (Solar Only)

Off-grid PV power systems can range from a single module, single battery system providing energy to d.c. loads in a small residence to a large system comprising an array with hundreds of kW of PV modules with a large battery bank and an inverter (or inverters) providing a.c. power to the load. Note that those larger systems may integrate a generator using fossil fuel or biofuel generator.

Figure 1 shows the configuration of a system that provides d.c. power only. These systems are typically installed on rural housing and village meeting houses where the d.c. power directly feeds lights and small d.c. appliances or small a.c. appliances that are each powered by their own dedicated inverter operating off the d.c. power. These installations typically range between about 100 Wp to 1000 Wp of solar though smaller or larger installations are possible. The d.c. voltage provided to loads is usually 12 V, 24 V or 48 V. This type of installation is often called a Solar Home System (SHS) and is widely used in remote villages for electrification.

FIGURE 1: SYSTEM POWERING D.C. LOADS ONLY (THIS IS ALSO A SIMPLE D.C.-COUPLED SYSTEM)



Note: Arrows in the drawings show power/energy flow. Wherever applicable, d.c. power flow is shown in blue and a.c. power flow is shown in red.

Systems that include one or more inverters providing a.c. power to all loads can be provided as either:

- d.c.-coupled systems as in Figure 2, or
- a.c.-coupled systems as in Figure 3

FIGURE 2: D.C.-COUPLED SYSTEM

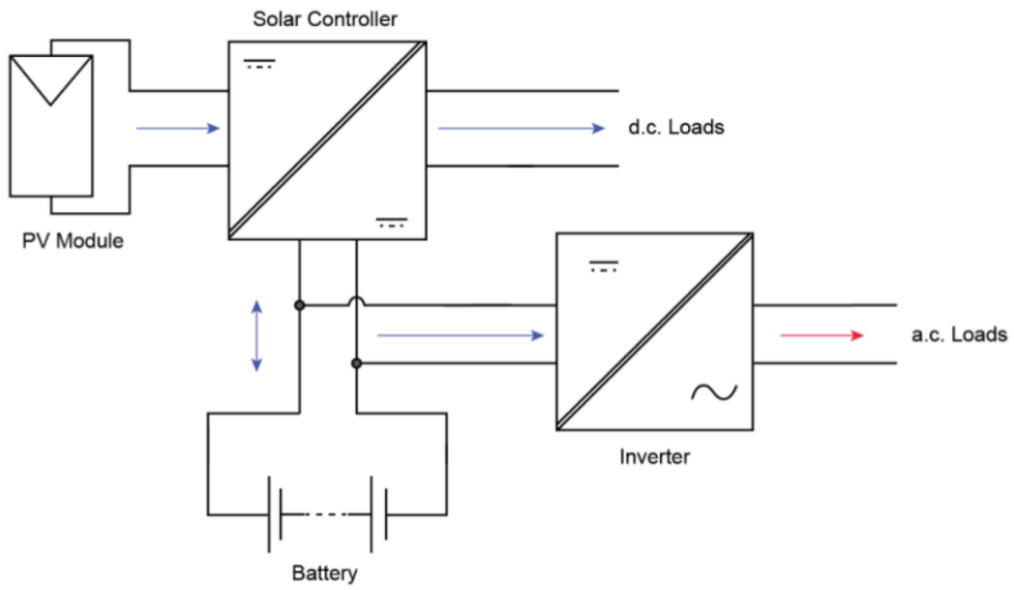
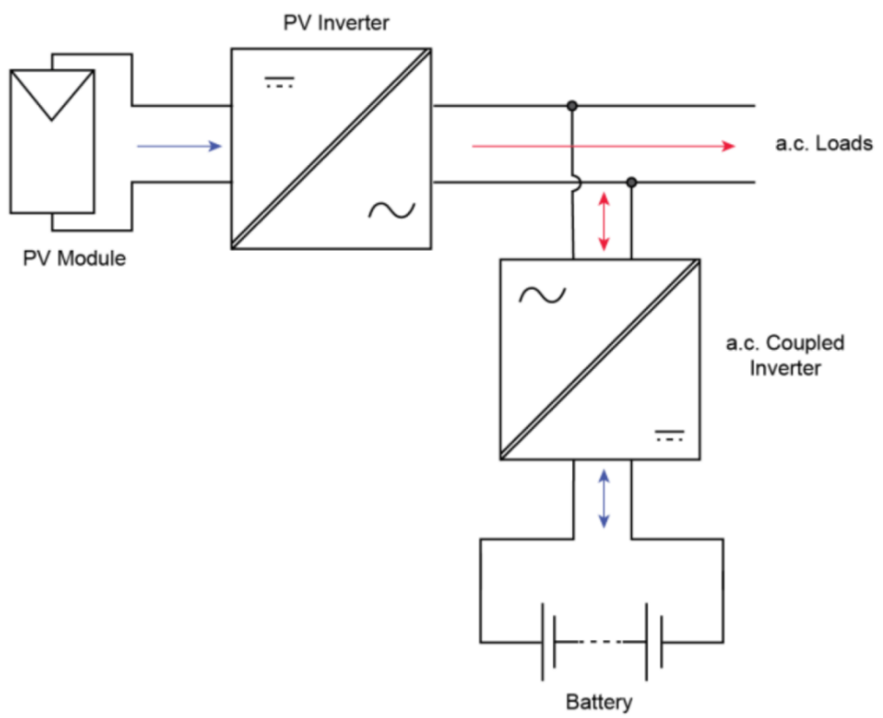


FIGURE 3: A.C.-COUPLED SYSTEM



Many a.c.-coupled inverters are capable of being paralleled with similar inverters up to a specified number. Some manufacturers allow three inverters to be connected in parallel to create three phase and are sometimes collectively called a cluster. These clusters are then allowed to be in parallel up to a specified maximum number. (Refer to Figure 10 in Part 4.) Each cluster is connected to their own battery bank. Hence when this configuration is allowed, extra clusters and hence inverters and batteries can be added in the future, thereby allowing an increase in the inverter and battery capacity. This can be undertaken because the systems are paralleled on the a.c. side not the d.c. side of the system.

Note: Though they are paralleled systems, this can only be undertaken if the manufacturer has allowed this facility. It is only inverters from the same manufacturer where this can be facilitated. The inverters must communicate with each other because one of the inverters (and hence clusters) must take control of forming the a.c. grid and ensuring the inverters are in the appropriate phase and synchronised with each other.

Some systems can be a combination of a.c.-coupled and d.c.-coupled systems where part of the array is connected through a solar controller to the battery and part of the array is connected to the a.c. side via a PV inverter. This configuration is typically used when the battery charger feature inside the a.c.-coupled interactive inverter is not able to provide an effective equalisation charge of the battery. This configuration also allows the battery to recover from a fully depleted state in which a.c.-coupled PV inverters cannot supply power (see Section 24).

This guide contains the basic formulae for d.c.-only, d.c.-coupled and a.c.-coupled systems. It does not include systems that combine the a.c.-coupled and d.c.-coupled systems.

Configurations of systems with fuelled generators are shown in Part 4.

3 Steps When Designing an Off-Grid PV Power System

The steps in designing a system include:

1. Carrying out a site visit and determining the limitations for installing a system and examining the location where the equipment will be installed (see Section 4)
2. Determining the energy needs of the end-user (see Section 7)
3. Determining the voltage and capacity of the battery bank (see Sections 8 & 9)
4. Determining the size of any inverter connected to systems supplying d.c. power (Section 11)
5. Determining the size of the array and solar controller (see relevant sections in Part 2, Part 3 or Part 4, depending on the system configuration)
6. Determine cable size and calculate voltage drop (Refer to Component-Based Off-Grid Solar Energy Systems: System Installation Guidelines)
7. Determine system protection and disconnection requirements (Refer to Component-Based Off-Grid Solar Energy Systems: System Installation Guidelines)
8. Draw a schematic / single line diagram (Section 35)
9. Prepare bill of quantity (Section 36)
10. Providing a quotation to the end-user (Section 37)

4 Site Visit

Prior to designing any off-grid power system a designer should visit the site and undertake, determine, or obtain the following:

1. Discuss the energy needs of the end-user through discussions with the developer or the end user.
2. Prepare an hour-by-hour load analysis or if that is not practical, complete a load assessment form.
3. Assess the occupational safety and health risks that will be present when working on that particular site.
4. Determine the solar access for the site or determine a position where the solar has the most available sunlight.
5. Determine whether any shading will occur over a full year's time and if so, estimate its effect on the output of the system.
6. Determine the orientation (azimuth and tilt angle) of the roof if the solar array is to be roof mounted. (Refer to Section 12.2 and the Component-Based Off-Grid Solar Energy Systems: System Installation Guidelines)
7. Determine the available area for the solar array.
8. Determine whether the roof is suitable for mounting the array (if roof mounted).
9. Determine how the modules will be mounted on the roof (if roof mounted) or arranged on the ground. Note that if roof-mounted, if different sections of the roof that has a different orientation and/or tilt need to be used, a separate MPPT controller must be connected to the solar modules of each different orientation. When Inverters having only one MPPT controller input are used, there will need to be separate inverters for each section of modules that has a different orientation.
10. Determine where the batteries will be located.
11. Determine where the solar controller or PV inverter(s) will be located.
12. Determine where the battery inverter(s) will be located (if applicable).
13. Determine where any battery chargers will be located (if installing a hybrid system)
14. Determine where the generator will be located (if installing a hybrid system and a generator is not already installed).
15. Determine the cabling routes and estimate the lengths of all the cable runs including all the control cables between generators and the battery inverters or other control equipment as applicable.
16. Determine whether monitoring panels or screens are required and through consultations with the end users, determine a suitable location with the end-user.

Following the site visit the designer shall estimate the available solar irradiation for the array based on the available solar irradiation for the site, the tilt, orientation, and effect of any shading. (See Sections 12.1, 12.2, and 12.3).

If the site is remote and the system size is relatively small, then all the above information may be obtained through discussions with the end-user, however the final location of all equipment must be determined by the time of installation. If the system is for a resort or for a village, then a site visit should be undertaken unless all the information can be supplied in detail by the client funding the project.

Some small systems might be provided as plug-and-play systems (sometimes called solar home systems (SHS) or pico-solar systems). In this case the designer/supplier must provide the end-user with relevant manuals (refer to documentation in the *Component-Based Off-Grid Solar Energy Systems*: *System Installation Guidelines)*.

5 Energy Source Matching

Though the price of solar modules has reduced dramatically in recent years it is still best to match some of the energy needs of the end-user with other sources (e.g., LPG) if possible. For example, though microwave ovens are suitable for cooking using electric power from off-grid PV power systems, it may be more appropriate to use biomass (or kerosene or LPG if available) for cooking instead of an electric appliance.

If hot water for showers and washing is required, then a solar hot water system could be used. (Note: The price of PV modules has reduced to such a low price that at times using PV modules with an electric hot water unit is cheaper than installing a separate solar hot water unit; however, it must be set up correctly to ensure that it never uses battery power but only power directly from PV modules).

6 Energy Efficiency

The size of the PV systems is based on the power and energy demand of the lights and appliances, that is, the loads. Reducing the amount of power required and hence the amount of energy required will reduce the size of PV system required. Therefore, it is important to review all the appliances and determine whether any of them can be cost-effectively replaced with more efficient models.

When the system is being designed for a homeowner or small business then the designer should discuss energy efficiency initiatives with the owner for implementation. These could include:

- Replacing inefficient electrical appliances with new energy-efficient electrical appliances
- Replacing incandescent or fluorescent light bulbs with more efficient LED (light-emitting diode) type lights
- Using laptop computers instead of desktop units
- Using energy-efficient flat-screen TVs instead of bulky older units with cathode-ray tubes
- Replacing cooking appliances that have a high electricity demand with LPG, biomass or kerosene appliances

For hotels and resorts, it might include:

- Providing ceiling fans instead of, or as well as, energy-efficient inverter type air-conditioners
- Installing in-room card systems so room power is only available when the guest is in the room
- Using LED exterior lighting that is on a timer so that the level of area lighting is greatly reduced after a pre-set time or motion sensors that illuminate for a pre-set time after detecting motion
- Using office machines (e.g., copiers and printers) that have a standby power mode that greatly reduces their load when not in use after a specified period of time
- Using laptop computers instead of desktop computers
- Use of float switch for water tank to reduce water waste

When the system is for a village (e.g., a mini grid) then energy efficiency should be promoted so that the villagers will use the most efficient appliances within their houses.

7 Load (Energy Assessment)

Three energy considerations arise when designing an off-grid PV power system:

1. The load (power and energy) required to be supplied by the system is not constant over the period of one day
2. The daily usage varies greatly over a week (office buildings typically have much lower loads on holidays and weekends than during the work week)
3. The daily energy usage varies over the year. For example, schools may have months of school holidays when loads are low. Tourism facilities may have very different loads at different times of the year, office building climate control energy requirements may vary substantially according to the time of year.

However, when completing the energy assessment, the typical daily usage should be applied.

Electrical power is supplied from the batteries (d.c.) or via an inverter to produce 230 volts a.c. (or the a.c. voltage typical for the location; 120 V and 220 V are common alternatives, but a.c. voltages can vary anywhere from 100 V to 240 V and may even vary within a country). Electrical energy usage is normally expressed in watt hours (Wh) or kilowatt hours (kWh).

To determine the daily energy usage for an appliance, multiply the power required by the appliance in watts times the number of hours per day it will operate. The result is the energy (Wh) consumed by that appliance per day.

Appliances can either be d.c. or a.c. An energy assessment should be undertaken for each type. Examples of these are shown in Table 1 and Table 2.

System designers need to discuss the electrical energy usage in detail with the end-user. Many systems have failed over the years not because the equipment has failed or the system was installed incorrectly, **but because the end-user believed they could get more energy from their system than the system could deliver**. It failed because the end-user was unaware of the *power/energy limitations* of the system and attempted to use more energy than the system was designed to provide.

The problem is that the end-user may not want to spend the time determining their realistic power and energy needs which are required to successfully complete a load assessment form. They typically just want to know: "*How much for a system to power my lights and radio or TV?*"

A system designer can only design a system to meet the power and energy needs as stated by the end-user. The system designer must therefore use this process to clearly understand the needs of the end-user and at the same time educate the end-user regarding the capacity of the system to be installed. Completing a load assessment form correctly (refer to Table 1 and Table 2 below) does take time; you may need to spend 1 to 2 hours or more with the potential end-user completing the tables. It is during this process that you will need to discuss all the potential sources of energy that can meet their energy needs and you can educate the end-user about energy efficiency and conservation.

Table 1 and Table 2 are used throughout the guideline as a worked example. If the loads are d.c. then Table 1 will be used. If the loads are a.c. then Table 2 will be used.

Table 1 shows d.c. lighting loads and Table 2 shows a.c. appliance loads. In reality, there could be other d.c. loads and lighting could be a.c.

The tables show an energy assessment process that can include two types of seasons. Locations close to the equator typically have limited year-round fluctuation in temperature and no real winter or summer but often have wet/rainy seasons and dry seasons. In countries further from the equator, there can be distinct seasons with large variations in temperature and also differences in the length of the nights between different seasons. This can result in differences in energy consumption between the different seasons. When that occurs, it is advisable to prepare a load assessment that includes estimating the energy usage for possibly two seasons. This guideline assumes two seasons in all the calculations.

WORKED EXAMPLE 1: COMPLETING ENERGY ASSESSMENT FORM

TABLE 1: D.C. LOAD (ENERGY) ASSESSMENT

Appliance	Qty	Power	Dry Season		Wet Season		Contribution to maximum demand
			Daily Usage time	Daily Energy	Daily Usage time	Daily Energy	
		W	h	Wh	h	Wh	W
Light	4	7	4	112	5	140	28
Daily Load energy-d.c. loads (Wh)				112		140	
Maximum d.c. demand (W)							28

TABLE 2: A.C. LOAD (ENERGY) ASSESSMENT

<table>
<tr><th rowspan="3">Appliance</th><th rowspan="3">Qty</th><th rowspan="2">Power</th><th colspan="2">Dry Season</th><th colspan="2">Wet Season</th><th rowspan="3">Power Factor</th><th rowspan="2">Contribution to maximum demand</th><th rowspan="3">Surge Factor</th><th colspan="2">Contribution to surge demand</th><th rowspan="3">Notes</th></tr>
<tr><th>Usage time</th><th>Energy</th><th>Usage time</th><th>Energy</th><th>Potential</th><th>Design</th></tr>
<tr><th>W</th><th>h</th><th>Wh</th><th>h</th><th>Wh</th><th>VA</th><th>VA</th><th>VA</th></tr>
<tr><td>TV</td><td>1</td><td>25</td><td>4</td><td>100</td><td>4</td><td>100</td><td>0.8</td><td>31</td><td>1</td><td>31</td><td>31</td><td></td></tr>
<tr><td>Fan</td><td>1</td><td>60</td><td>0</td><td>0</td><td>6</td><td>360</td><td>0.9</td><td>67</td><td>1</td><td>67</td><td>67</td><td></td></tr>
<tr><td>Refrigerator</td><td>1</td><td>100</td><td>14</td><td>1400</td><td>14</td><td>1400</td><td>0.8</td><td>125</td><td>4</td><td>500</td><td>500</td><td>Duty cycle of 0.58 included

(24 × 0.58 = 14 h)</td></tr>
<tr><td colspan="2">Maximum a.c. power (W)</td><td>185</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="3">Daily Load Energy a.c. (Wh)</td><td></td><td>1500</td><td></td><td>1860</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="8">Maximum a.c. demand (VA)</td><td>223</td><td></td><td>598</td><td></td><td></td></tr>
<tr><td colspan="11">Surge demand (VA)</td><td>598</td><td></td></tr>
</table>

The season with the highest average daily energy usage is used to determine the size of the battery bank. A comparison is undertaken between available solar irradiation for each month and the pattern of seasonal energy use to determine the month that has the greatest disparity between energy needed by the end-user and the energy available from the sun. The kWh/day energy requirement of that month is then used to determine the size of the solar array needed to provide the required kWh of electrical energy during that month in a solar-only system (refer to Section 12.1).

Though the total load energy might be high for some installations it can also be small for other installations, so a careful survey for each installation has to be carried out. The table also shows both d.c. lighting loads and a.c. appliance loads. In real life this could be the case, or all the loads might be d.c. or all a.c. The principle of this guideline is to summarise how to use a load assessment form to design any off-grid system.

Table 1 and Table 2 show the daily energy usage for each appliance. The daily energy usage of each appliance is added together to provide the daily load energy for the d.c. loads and daily load energy for the a.c. loads.

For the a.c. table, a term called power factor is introduced. This is from the formula:

Real power (W) = Apparent power (VA) × Power factor

Real power is sometimes called *true power* or *active power*. Power factor is sometimes expressed as cos φ where φ is the phase angle between voltage and current. However, this definition holds only for sinusoidal current and voltage waveforms. Many electronic devices, including LED lamps, brushless d.c. motors, computers, and mobile-phone power adapters, have nonsinusoidal current waveforms. These are called *nonlinear loads* and can make up a significant proportion of the load on a system using modern, energy-efficient lighting and appliances. When nonlinear loads are present, the power factor is expressed as the product of the displacement factor or displacement power factor, cos φ, and the distortion factor, which takes into account the harmonic currents introduced by nonlinear loads.

The power factor is used in Table 2 to determine the apparent power. Inverters sold on the market have a power factor rating of 1, which indicates that the real power in W is the same as the apparent power in VA. The maximum demand, that is maximum apparent power, is calculated in the table to help select the inverter. The inverter must have a continuous power rating in VA equal to but probably greater than the maximum demand determined in Table 2.

The maximum demand column contains all the appliances that will operate at the exact same time. In Table 2 all appliances are shown to operate, which is expected when there are only three appliances in a house. If a house contains many appliances, the designer in consultation with the end-user must determine which loads might all operate at same time and hence determine the maximum demand or determine diversity factor appropriate for the load.

Some appliances, such as motors, require a higher current to start and hence have a surge power rating as well as a continuous power rating. The inverter must be able to provide sufficient surge power (typically for 1 to 3 seconds) to start motors or other appliances that might have higher currents at the start.

For every appliance that operates at the same time, the surge power should be added into column titled "potential surge". These are added together to determine the maximum surge demand which must be supplied by the inverter. However, when there are many appliances, they will not all be on at the same time, and they definitely will not start at the same time. The designer must determine the actual surge demand that will be used when selecting an inverter—that is the design surge.

When there are many appliances, the designer must try many combinations when determining the maximum and surge demands.

In Table 2 for the load assessment, the TV, fan and refrigerator are using a.c. electricity so we have to take into account the efficiency of the inverters used. Typically, the peak efficiency of an inverter may be over 95% but in many systems, the inverter will sometimes be running even when there is very little load on the inverter and some energy will be used by the inverter even though it is not operating a load, so the average efficiency is typically about 90% to 96%. Then we must divide the total a.c. energy used by the load plus the losses in the inverter to obtain the total energy required to be supplied to the inverter from the battery bank.

Worked Example 2: Calculating Daily Energy as seen (provided) by the battery

(Based on the load in Table 1 and Table 2)

This example shows how to determine the energy at the battery bank for both the humid season and the rest of the year.

Assume the overall efficiency of the chosen inverter is 90%.

Wet Season

Daily battery load (energy) from d.c. loads = 140 Wh

Daily battery load (energy) from a.c. loads = 1860 Wh ÷ 0.9 = 2067 Wh

To get the total load (energy) as seen (provided) by the battery, add the two figures together:

2067 + 140 = 2207 Wh

Dry Season

Daily battery load (energy use) from d.c. loads = 112 Wh

Daily battery load (energy use) from a.c. loads = 1500 Wh ÷ 0.90 = 1667 Wh

To estimate the total load daily (energy) as seen (provided) by the battery, add the two figures together:

1667 + 112 = 1779 Wh

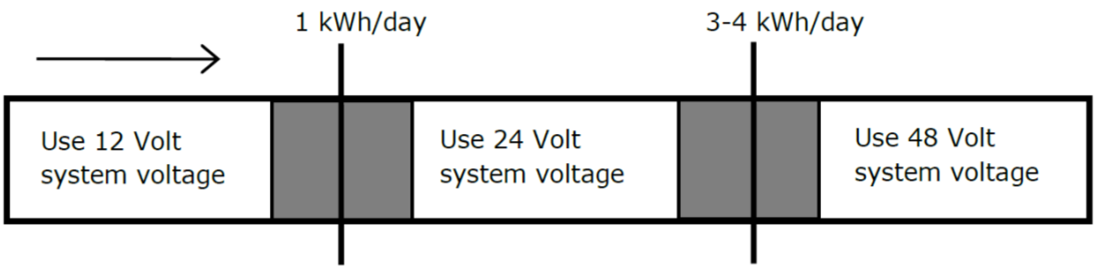
If there are no a.c. loads, then just work out the daily load from the d.c. appliances, and do not include any calculations for an inverter (or inverter efficiency).

8 Selecting Battery Voltage

System battery voltages are generally 12 V, 24 V or 48 V. The actual voltage is determined by the requirements of the system. For example, if the batteries and the inverter are a long way from the PV array and it uses a standard switching type solar controller, then a higher voltage may be required to offset the power lost in the cables. In larger systems, 120 V or 240 V d.c. could be used, but these are not typical and due to the potentially fatal voltages used, the standards for construction at those high voltages are more complex and the resulting system more expensive than would be the case for systems using voltages below 60 V d.c. To avoid the problems of using d.c. battery voltages greater than 60 V, even large systems with more than 200 kWp of array often have a multiple cluster design with each cluster using a 48 V battery bank. However, in a.c.-coupled systems the PV array will often be in the 200 V to 1000 V d.c. range. In off-grid systems the term "system voltage" typically refers the battery voltage.

As a general rule, the recommended battery system voltage increases as the total daily energy usage increases. For small daily loads, a 12 V battery system voltage can be used. For intermediate daily loads, 24 V is used and for larger loads 48 V is used (see Figure 4).

FIGURE 4: GUIDELINE TO SELECTING BATTERY VOLTAGE



The changeover points are roughly at total energy usage of 1 kWh/day and 3-4 kWh/day, but this will also be dependent on the actual power profile. These are only a guide and there will be certain systems where this guide might not be applied. For example, assume a radio transmitter has a 100 W continuous power demand. A 12 V system could still be used even though the total energy usage is 2400 Wh/day. The current being drawn from the battery bank is only 8.33 A (100 W/12 V). On the other hand, a pump drawing 800 W that only operates 3 hours a day will also use 2400 Wh but will draw almost 67 A when it runs, requiring very large cables and high Ah capacity batteries at 12 V. If operated at 48 V, the current draw will be about 17 A and much smaller cables can be used without excessive losses plus the battery Ah requirement will be ¼ that of using a 12 V battery.

One of the general rules of thumb is, if possible, aim to keep the maximum continuous current being drawn from the battery bank less than 150 A. This is to reduce the size of the required cable and minimise any problems with voltage drop.

Note: The term "battery bank" is being used in the guideline, but in some small systems it may be a single 12V monobloc battery.

9 Determining the Required Capacity of the Battery Bank

If the load energy assessment is undertaken based on two different weather seasons, the highest daily energy usage is used to determine the required battery capacity.

Some people in the industry might argue that if some of the loads are working during the day the battery bank capacity does not need to be based on the total daily energy usage and it can be reduced due to the daytime loads being supplied directly by the PV array. However, the available solar irradiation can vary greatly from day to day so the best practice – and the recommendation of this guideline – is to determine the required battery capacity based on the total daily energy usage. This not only helps ensure that the system operates reliably; it also extends the battery life since it is less stressed (depth of discharge) during cloudy periods.

Lithium-ion batteries are sometimes supplied based on their Wh capacity or their ampere-hour (Ah) capacity. The calculations in the following examples can be used to determine either the Wh or Ah capacity. If calculating the Ah capacity, be careful to use the nominal voltage of the chosen battery in calculations, as nominal voltages for lithium batteries are slightly different from those of lead-acid batteries. Common voltages for lithium iron phosphate ($LiFePO_4$) batteries are 12.8 V, 25.6 V and 51.2 V, while common voltages for NMC and other lithium chemistries are slightly lower.

Lead acid batteries are typically supplied based on their Ah capacity.

To convert Watt-hours (Wh) to Amp-hours (Ah), divide Watt-hours (Wh) by the battery system voltage.

Worked Example 3: Calculating the Battery Energy Usage in Ah

The largest energy usage is 2207 Wh/day, so select a battery system voltage of 24 V. This means that the Ah/day usage on the battery bank will be:

Ah/day = Wh/day ÷ system voltage

= 2207 Wh/day ÷ 24

= 92 Ah/day

The minimum size battery to meet the daily energy requirements in the example is 92 Ah.

Note: This minimum size does not account for additional days of autonomy, temperature correction, or limiting the maximum discharge of the battery for the long-term health of the battery. These factors will increase the size of the battery bank and are included in Worked Example 5 and Worked Example 6 below.

However, for long life, lead-acid batteries should not regularly be discharged more than 50% or 60%, with 20% to 30% being a common average discharge level for rural off-grid solar installations. So, the actual Ah of the battery installed will be at least double and often five times the calculated one-day Ah requirement.

Battery capacity is determined by whichever is the greater of the following two requirements:

1. The ability of the battery to meet the energy usage of the system without any charging, typically for one to five days, sometimes specified as "days of autonomy" of the system.

or

2. The ability of the battery to supply peak power demand in delivered Watts (Amperes delivered times Volts at the battery terminals).

Refer to maximum demand values in Table 1 and Table 2 for the calculation of peak power demand in Worked Example 4. How to determine the daily energy usage of the system was shown in Worked Example 2.

Worked Example 4: Calculating Maximum Current that will be Discharged from the battery

The maximum d.c. demand in Table 1 is 28 W.

The maximum a.c. power demand in Table 2 is 185 W. This is the demand out of the inverter, so at the battery terminals the maximum demand considering the inverter efficiency would be:

$$= (185 \text{ W})/0.9$$

$$= 205.6 \text{ W}$$

The maximum current that will be discharged from the batteries is:

$$= (205.6 \text{ W} + 28 \text{ W})/24 \text{ V}$$

$$= 9.73 \text{ A}$$

The critical design parameters include:

- Parameters relating to the energy requirements of the battery
    - Daily energy usage
    - Daily average depth of discharge and maximum depth of discharge
    - Number of days of autonomy
- Parameters relating to the discharge power (current) of the battery
    - Maximum power demand
    - Surge demand
- Parameters relating to the charging of the battery
    - Maximum charging current

Based on these parameters there are a number of factors that will increase the required battery capacity in order to provide satisfactory performance. These factors must be considered when specifying the system battery.

9.1 Days of Autonomy

Extra capacity is necessary where the loads require power during periods of reduced solar input. The battery bank is often sized to provide for a number of days of autonomy (days of operation without solar charging). A common period selected is between 2 to 5 days, but it depends on how critical the loads are and budget. For example, a site could provide critical services and therefore 5 days or more of autonomy might be required to ensure continuous operation. For example, an important telecommunications station may require a solar installation with sufficient battery capacity for 14 days of autonomy. These types of very long autonomy requirements will require careful design treatments to keep battery array costs at an acceptable level. This may include load-shedding capability or separate and dedicated battery arrays for some critical loads.

In general, the minimum that should be used is 1.5 days (with no generator as back-up) for small solar home systems where price is an issue and reliability is not critical. For larger systems and in particular for remote sites, 3 to 5 days is preferred. For the exercises in this guideline 2 days has been used as a compromise.

Long battery life is important for remote sites because battery exchanges are easily the most expensive on-going cost in operating a remote off-grid electricity system. Often transport and labour for the new battery and the transport and cost of recycling the old battery will together be more than the cost of purchasing the new battery itself. There is also the inconvenience of not having power or reduced availability of power.

Worked Example 5: Calculating battery capacity based on days of autonomy

Assume a daily load of 92 Ah (24 V battery voltage) with 2 days autonomy.

Adjusted battery capacity:

= 92 Ah × 2

= 184 Ah

OR

= 2 × 2207 Wh

= 4414 Wh

Note: This calculation does not yet take into account the depth of discharge limits.

9.2 Maximum Depth of Discharge

Battery manufacturers recommend a maximum depth of discharge (DOD). If this is regularly exceeded the life of the battery is severely reduced. This could be 50% for some residential sized lead acid batteries or as high as 80% for some large industrial quality solar batteries.

In lithium-ion batteries the term usable energy is sometimes applied. This may be between 60% and 100% of the rated capacity.

Note: If the usable energy of a lithium-ion battery is specified at 80% (as an example), it is recommended that the battery is not discharged more than 70%. This is because some lithium-ion batteries have low voltage "lock-up" mechanisms to protect the battery from being damaged and causing a fire. It then can become unusable in this state and not recoverable without specialised equipment that is not commonly available.

Worked Example 6: Calculating battery capacity based on maximum depth of discharge.

Assume a maximum DOD of 70% for a lead acid battery and the usable capacity with a lithium-ion battery is 80% but 70% is applied.

Adjusted Battery Capacity:

= 184 / 0.7

= 263 Ah

OR

= 4414 / 0.7

= 6306 Wh

9.3 Battery Discharge Rate

For lead acid batteries, the actual discharge rate selected for the capacity rating is highly dependent on the power consumption of connected loads. For lead acid type batteries, this is indicated by the capital letter *C* (for capacity) and small numbers that follow representing the hours of charge available at that discharge rate. The Ah capacity of some solar batteries, particularly small 12 V solar batteries, are typically given for a discharge rate of C_{100}. This means that the time it takes to fully discharge the rated Ah capacity of the battery at the given amperes of delivery is 100 hours.

For deep-cycle monobloc batteries, often used in small Solar Home Systems, the Ah capacity is often provided at the C_{20} discharge rating. Examples of battery capacity ratings at different discharge rates are provided in Table 3.

Many appliances operate for short periods only, drawing power for minutes rather than hours. This affects the battery selected, as battery capacity varies with discharge rate. Information such as a power usage profile over the course of an average day is required for an estimate of the appropriate discharge rate to use in the design. For many systems, and particularly small systems, this is often impractical to obtain.

TABLE 3: EXAMPLE OF VARYING BATTERY CAPACITIES BASED ON DISCHARGE RATES TO SPECIFIED CUT-OFF VOLTAGES

Capacities C_1 – C_{100} (20°C)					
Type	C_1 1.70 V/C	C_5 1.70 V/C	C_{10} 1.70 V/C	C_{20} 1.75 V/C	C_{100} 1.80 V/C
SB12/60 A	34	45	52	56	60
SB12/75 A	48	60	66	70	75
SB12/100 A	57	84	89	90	100
SB12/130 A	78	101	105	116	130
SB12/185 A	103	150	155	165	185
SB6/200 A	104	153	162	180	200
SB6/330 A	150	235	260	280	330

Source: GNB Sonnenschein Batteries

Where the daily average power is representative of typical operation, such as for most residential loads, the battery capacity for 5 days of autonomy is often selected at the 100 h (C_{100}) rate of discharge for the battery while for 1 ½ or 2 days of autonomy is often selected at the 20 h (C_{20}) rate of discharge for the battery.

In commercial or industrial applications, the daily average power can be significantly less than the typical power consumption while loads are in operation. In this case, it may be necessary to select the battery capacity for 2 to 5 days autonomy at a higher discharge rate than C_{100}, e.g. a 10 h (C_{10}) or 20 h (C_{20}) rate.

For example, if the primary load is an industrial machine that operates for four hours each day and consumes 1200 W, the average power over a full day will be 200 W; however, the battery needs to be sized using the capacity at the 1200 W discharge rate.

For lithium-ion batteries the battery capacity is only slightly reduced at higher discharge currents. The battery can be selected based on the capacity rating provided by the manufacturer without undue consideration of the discharge rate.

Though lead acid batteries typically have a capacity rating stated with the C_x notation, lithium-ion batteries capacities are often quoted using the X C notation. The hours for this notation are determined as 1/X.

Examples include:

- 1C is the 1-hour rating (1/1)
- 2C is the 0.5-hour rating (1/2)
- 0.5C is the 2-hour rating (1/0.5)
- 0.05C is the 20-hour rating (1/20)
- 0.01C is the 100-hour rating (1/0.01)

Worked Example 7: Checking battery capacity against maximum load current.

In a 24 V system the discharge current for the battery with all the loads on is only approximately 9.73 A. The C_{20} capacity to provide this current is 195 Ah.

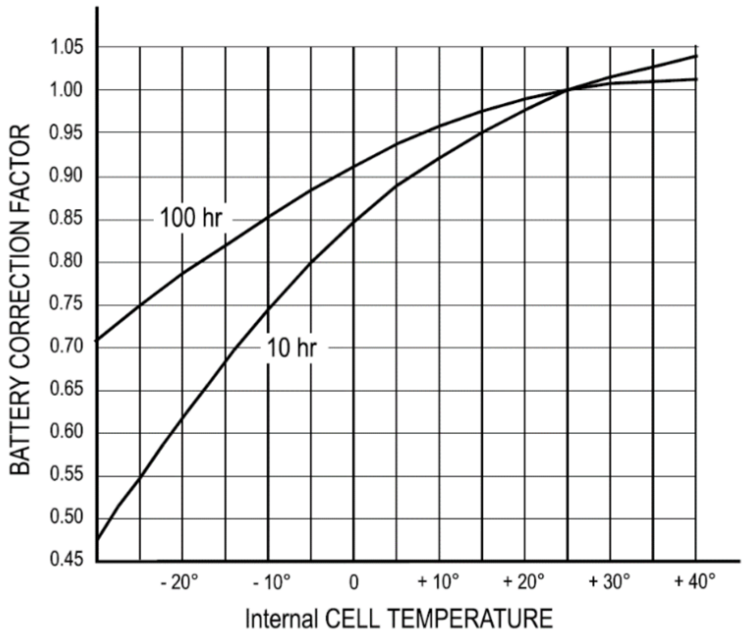
A battery capacity of 263 Ah (@ C_{20}) is suitable.

Other notations are sometimes used; for example, the C-rate is sometimes expressed as a fraction (e.g. $C/20$ instead of C_{20} or $0.05C$). IEC standards use I_t A instead of C.

9.4 Battery Temperature Derating

The capacity of lead-acid batteries is affected by temperature. As the temperature goes down, the battery capacity also goes down. Figure 5 shows a typical battery correction factor for low temperature operation. Note that the temperature correction factor is 1 at 25°C as this is the reference temperature at which battery capacity is specified, while the European standards now uses 20°C as the test temperature. So, if using this graph for those batteries tested at 20°C and no other graph is available, change the bottom scale to reflect 20°C as the temperature with a factor of 1 and adjust other temperatures accordingly.

FIGURE 5: TEMPERATURE CORRECTION FACTOR



Worked Example 8: Adjusting battery capacity due to temperature effect.

Consider a location at which the minimum temperature is 15°C. If you want to be conservative, add 5% to the battery capacity to allow for this factor.

Allow 5% to the capacity to allow for effect of temperature.

Adjusted battery capacity = 263 × 1.05 = 276 Ah or

Adjusted battery capacity = 6306 × 1.05 = 6621 Wh

9.4.1 Battery Selection

For lead-acid batteries, deep discharge type battery/cells must be selected, and they must provide the required system voltage and capacity preferably in a single series string of battery cells.

Parallel strings of batteries are not recommended.

Where paralleling strings cannot be avoided, each string must be separately fused.

Worked Example 9: Selecting the battery using manufacturer's data.

For lead acid batteries, a battery of at least 276 Ah (@ C_{20}) should be used.

Using Table 3 the SB6/330 A battery has a C_{20} rating of 280 Ah and hence this would be the selected battery. It is 6 V so 4 of these in series will be required to have 24 V battery bank.

10 Selecting a Battery

For lead-acid batteries, the deep discharge type batteries/cells selected should be rated for the required system voltage and capacity and if possible, use a single series string of battery cells or monobloc batteries. Batteries designed for solar installations also exist as single 2 V cells and if purchasing 2 V batteries for the battery bank, it is preferable that solar type batteries are selected. In any case, batteries must be designed for deep discharge applications; engine starting (cranking) batteries have a short life when used in solar installations as they are not designed for deep cyclic discharges.

Parallel strings of batteries are not recommended. However, it is accepted that for some systems it is unavoidable. If parallel batteries are unavoidable, then follow the manufacturer's recommendation for the maximum number of parallel strings.

The maximum number of parallel strings is usually only 3 to 5 and some manufacturers void their battery warranty if more than 2 batteries are placed in parallel. For small solar home systems using 6 V and 12 V monobloc batteries, it is recommended that 4 strings of batteries in parallel should be the maximum (if approved by manufacturer) and ensure all the requirements for wiring parallel battery strings are followed as specified in the installation guideline. For larger systems where 2V battery cells are being used the number of strings must be kept to a minimum and preferably no more than 3. This can be achieved by using battery cells with high Ah capacities.

In addition to the requirements and recommendations listed in this section, batteries shall also comply with the requirements outlined in Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview, Section 3.5.

Lithium-ion batteries shall be supplied with a manufacturer's approved battery management system (BMS).

11 Selecting a Battery Inverter

When selecting a battery inverter to power an a.c. appliance that is to be connected to an off-grid PV system that is also delivering d.c. power to the user, the inverter must have an input d.c. voltage rating that is the same as the voltage of the d.c. power provided by the system.

In addition to the requirements and recommendations listed in this section, inverters shall also comply with the requirements outlined in *Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview*, Section 3.7.

The type of inverter selected for the installation depends on factors such as availability, cost, surge requirements and power quality requirements. Inverters are available in three basic output types: square wave, modified square wave (sometimes called modified sine wave) and sine wave. There are few square wave inverters used today since most a.c. equipment works poorly on square wave a.c. power and modified square wave inverters are comparable in price.

Modified square wave inverters generally have good surge capacity, are available in a wide range of power capacities and are usually cheaper than sine wave types. However, many appliances, such as some audio equipment, some televisions and all appliances that have a.c. motors (e.g., fans) can be damaged or provide poor service because of the non-sinusoidal voltage waveform.

Sine wave inverters are increasingly affordable and often provide even better-quality power than some urban grid supply.

The battery inverter is typically responsible for disconnecting AC loads when the battery is discharged. In an a.c.-coupled system or a system with a generator, the battery inverter can also incorporate a battery charger (see Sections 25 and 26). Therefore, the battery inverter shall be appropriate for the battery chemistry, as voltage set points and recommended charging behaviour will differ between battery types. For instance, if lead-acid batteries are used, the charge controller should be designed to fully charge the batteries and provide equalization charges as prescribed by the battery manufacturer. If lithium-ion batteries are used, then the selected inverter should be able to communicate with the battery management system (BMS) provided with the lithium-ion battery. Many inverter manufacturers provide a list of lithium-ion batteries approved for use with their products, including special instructions or restrictions that pertain to certain combinations of inverter and battery.

11.1 Battery Inverter Sizing

For systems where there are only a few a.c. appliances (e.g. as shown in Table 2) the selected battery inverter should be capable of supplying continuous power to all loads that are connected to it and must have sufficient surge capacity to start all loads that may surge when turned on, should they all be switched on at the same time. Electric motors are particularly likely to have a large surge capacity requirement.

For households with many a.c. loads where some loads, e.g. microwave ovens and power tools, are only operating occasionally it is not practical to select an inverter based on the total power rating of all the loads. The inverter should be selected based on determining what loads would typically be operating at the same time. Attention might need to be given to load control and prioritisation strategies. For example, if the inverter has surge capacity sufficient for only one motor but there are several motors that it powers, the motor switching design should make it impossible for two or more of the connected motors to be switched on at the same time.

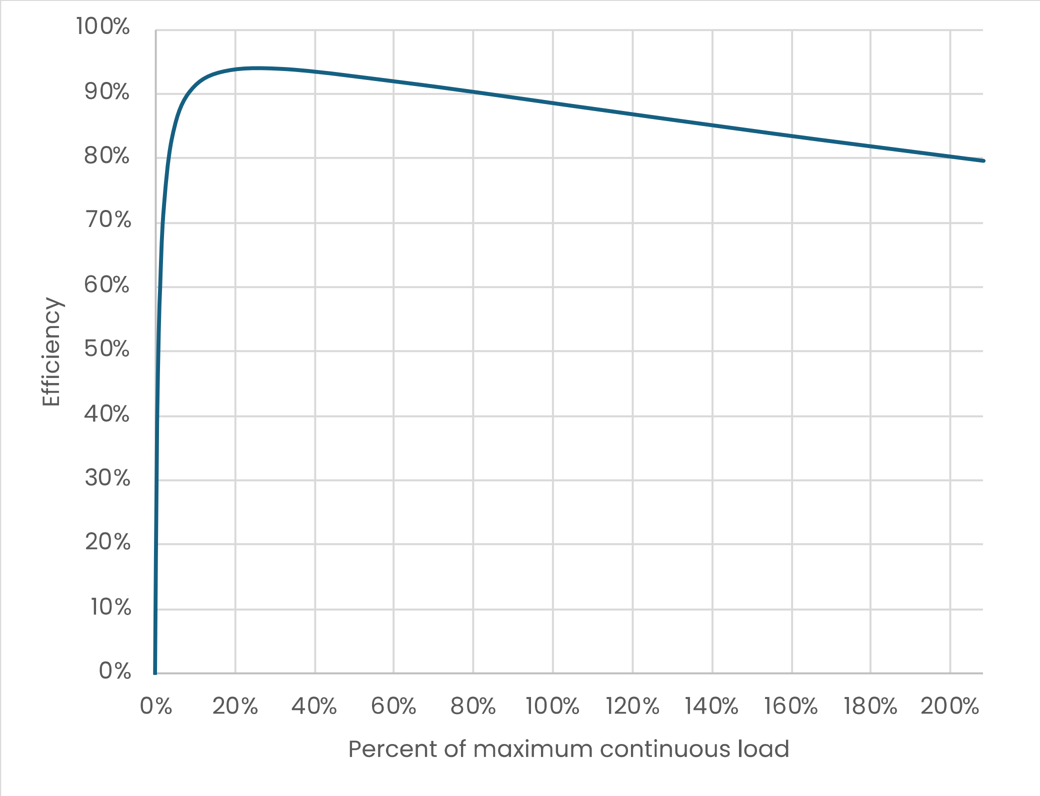
Worked Example 10: Specifying minimum inverter rating

From the load (energy) assessment in Table 2, the selected inverter must be capable of supplying 223 VA continuously with a surge capability of 598 VA for a short period of time, typically only a few seconds.

11.2 Battery Inverter Efficiency

The efficiency of the battery inverter is dependent on the output power. Most inverter datasheets state only a typical or maximum value of efficiency. Many inverter manufacturers also make efficiency vs. load curves available, but these may be in a separate white paper or other document, rather than the datasheet or manual. Since the inverter consumes some power even with no load, its efficiency approaches zero as the load decreases to zero. As load increases, the inverter efficiency will peak and then gradually decrease due to resistive and other losses at high output power. The efficiency vs. load curve for a typical inverter is shown in Figure 6.

FIGURE 6: TYPICAL INVERTER EFFICIENCY VS. LOAD CURVE



Data Source: Victron Energy, https://www.victronenergy.com/upload/documents/output-rating-operating-temperature-and-efficiency.pdf

The efficiency value to be used in design calculations depends on what loads are used throughout a typical day. If power consumption is relatively steady throughout the day, the typical value stated in the datasheet may be appropriate. However, if the system is sized to accommodate a large peak load that rarely occurs, the inverter may operate at a low efficiency value much of the time. For example, this can occur if a system for a health centre is designed to support a steam sterilizer (autoclave) that uses several kW, but only for a very short time, such that it is a relatively small contributor to the average daily energy consumption. If the load at other times is small (e.g. a few LED lights and a laptop computer), the inverter may operate at only a few percent (or less) of its rated continuous load for most of the day.

In this situation, the d.c. power demand should be calculated in a way that takes into account the actual inverter efficiency vs. load curve. This calculation is beyond the scope of this document, but can involve one of these approaches:

- Selecting a battery inverter with low no-load power consumption and therefore higher efficiency at low load.
- Calculating a weighted average inverter efficiency based on the expected load during each hour of the day.

- Incorporating the no-load power consumption of the inverter into sizing calculations as a constant (24-hour) d.c. load.

Other options to address this issue include:

- Installing multiple inverters of different maximum power ratings (at times referred to as a "cascade of inverters") so that each inverter operates more efficiently. The design of such an installation can be more expensive than other options, could still suffer from excess power draw due to no-load power consumption of the larger inverters, and is outside the scope of this document.
- Powering lights and small electronic loads using d.c. power while powering large loads such as the sterilizer with a.c. power. This reduces loss due to the inverter efficiency when only small loads are in use, but is only appropriate to employ if d.c. loads are being considered for the facility. Facility staff should be made aware of which loads are powered via d.c. outlets, d.c. fixtures and outlets should be clearly labelled, and appliances that require replacement, like bulbs, should be readily available in the market.

12 Solar Irradiation

Solar data obtained from ground mounted instruments should be the first choice for estimating the solar energy input at the site. Such data may be available from various local sources, typically the national meteorological or agricultural departments.

One important source for solar irradiation data that is available at no cost is the following site established through funding from the European Commission:

https://re.jrc.ec.europa.eu/pvg_tools/en/#MR

With this site, latitude and longitudes can be entered and irradiation data can be obtained for horizontal, optimum tilt, and also for a specified array tilt angle.

Another source for solar irradiation data is NASA POWER (https://power.larc.nasa.gov/data-access-viewer/). Another site, RETSCREEN (https://www.nrcan.gc.ca/energy/software-tools/7465), is a program available from Canada that incorporates the NASA data. Please note that the NASA data has, in some instances, had higher irradiation figures than that recorded by ground collection data in some countries. If there is no other data available, this source can be used. One advantage of the NASA data is that it is shown as monthly averages and the timing of high and low solar inputs can be easily seen.

Solar irradiation is typically provided as kWh/m^2; however, it can be stated as daily Peak Sun-hours (PSH). PSH is the equivalent number of hours to equal the kWh/m^2 listed if the solar irradiance always equals 1 kW/m^2. For example, 4.5 kWh/m^2 is 4.5 PSH.

Table 4 provides example irradiation data for four locations around Uganda, which will be used in some of the following steps in the worked example. Similar data can be obtained for other sites.

TABLE 4: IRRADIATION DATA FOR UGANDA AT A 10° TILT ANGLE (KWH/M2 OR PSH PER DAY)

Region	Near Kampala	Southwest	Northwest	Northeast
Latitude	0° 4'35" North	1° 9'13" South	2° 50'38" North	3° 30'07" North
Longitude	32° 44'23' East	30° 19'22" East	31° 25'17' East	34° 05'01' East
Month	**Irradiation (kWh/m²)**	**Irradiation (kWh/m²)**	**Irradiation (kWh/m²)**	**Irradiation (kWh/m2)**
Jan	6.050	4.570	6.950	6.830
Feb	6.280	4.810	6.820	6.850
Mar	6.290	4.910	6.650	6.670
Apr	5.270	4.690	5.960	5.690
May	4.970	4.730	5.680	5.380
Jun	4.600	5.220	5.250	4.920
Jul	4.790	4.570	4.950	4.790
Aug	5.160	4.810	5.320	5.270
Sep	5.660	4.910	5.940	6.070
Oct	5.900	4.690	5.860	6.310
Nov	5.610	4.730	6.080	6.420
Dec	5.590	5.220	6.540	6.550
Year	**5.510**	**4.800**	**6.000**	**5.970**

PV arrays in off-grid PV systems ideally should be installed facing the optimum orientation/azimuth. The optimum tilt direction is generally true (not magnetic) north in the Southern Hemisphere and true south in the Northern Hemisphere – that is the PV array should face towards the equator. However, this can change due to local climatic conditions (clouds that consistently form at a particular time of the day) or topographical conditions (mountains or structures causing shading at consistent times in the mornings or afternoons). In latitudes between 0° and 10° north the array can be oriented either north or south with little change in output. Also, orientations that are as much as 90° away from the optimum direction have a relatively small impact on daily irradiation totals when the latitude of sites are less than 10°.

If the PV array is mounted on the roof of a building, the roof may not be facing the optimum direction of true north (Southern Hemisphere) or true south (Northern Hemisphere) or may not be at the optimum tilt angle. The irradiation data for the actual roof orientation (true installed azimuth) and pitch (true tilt angle) shall be used when preparing the design. Please see the discussion on tilt and orientation (Section 12.2) for determining peak sun hours for sites not facing the ideal direction.

12.1 Irradiation for Design Month

Two PV array output energy considerations arise when designing an off-grid PV power system:

1. the energy available from the PV array will vary greatly during the day according to the time of day and cloud passages
2. the energy available from the PV array will vary during the year as weather conditions vary over the year and as the sun changes its position in the sky over the year

Since the system is based on photovoltaic modules, the designer should compare the available energy from the sun and the actual energy demands over a typical year. The worst month will be when the ratio between solar energy available and energy demand is smallest. The solar energy available during that worst month should be chosen as the design basis for the installation for a solar only system.

If the daily energy usage varies throughout the year, then a comparison should be undertaken between the average daily irradiation and the average daily load energy for each month of the year or at least two seasons.

The design month is the month where the ratio of available irradiation (PSH) to daily load energy for that month is the smallest. The irradiation of the design month is then used when determining the size of the required PV array for solar only systems.

If the energy usage stays relatively constant throughout the year, then the design month will be the month with the lowest irradiation.

Worked Example 11: Determining the design month and selecting average daily irradiation for that month

The rest of year energy usage (at the battery bank):

= 1779 Wh

= 1.78 kWh

The Humid Season energy usage (at the battery bank):

= 2207 Wh

= 2.21 kWh

Assume:

- the site is near Kampala, Uganda and the array is tilted at 10 degrees
- for the benefit of the example it is assumed rest of year is from April to September (approx.)
- the humid season is from October to March (approx.)

It is appreciated this might not be correct, but the intention is to show the effect of two seasons and how to calculate design month.

Using the irradiation data in Table 4 and the seasonal energy usage data, the ratio of irradiation (which is proportional to the PV energy output) to load energy is shown in Table 5:

TABLE 5: RATIO OF IRRADIATION (PROPORTIONAL TO PV ENERGY OUTPUT) TO LOAD ENERGY REQUIREMENT

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Irradiation (kWh/m^2)	6.05	6.28	6.29	5.27	4.97	4.6	4.79	5.16	5.66	5.9	5.61	5.59
Daily energy used (kWh)	2.21	2.21	2.21	1.78	1.78	1.78	1.78	1.78	1.78	2.21	2.21	2.21
Ratio of irradiation to daily energy	3.4	3.53	3.53	2.96	2.79	2.58	2.69	2.9	3.18	3.31	3.15	3.14

The lowest ratio is 2.58, so June will be the design month. The available irradiation in June is 4.60 kWh/m^2, or 4.60 peak sun hours.

12.2 Effect of Orientation and Tilt

If the array is mounted and not oriented true north (Southern Hemisphere) or south (Northern Hemisphere) and/or not at the optimum tilt angle (inclination), the daily output from the array will generally be less than the maximum possible.

Roofs often have pitch of 20° to 30°. In locations near the equator, irradiation would only decrease by a small percentage if the array tilt ranged between 10° and 30° and is minimally dependent on the orientation. Because of this minimal dependence on tilt and orientation, mounting at the existing roof pitch is often preferable. However, if the roof is flat or has a shallow tilt angle ($< 5°$), the array should be tilted at an angle of at least 10°. For locations more than 10° from the equator, economic analysis may be required to determine whether mounting the panels at the existing roof angle is preferable to mounting them at a different angle.

12.3 Shading of the Array

In rural areas and villages where off-grid PV systems will be used for electrification, the PV array may be shaded part of the day by local vegetation, e.g. nearby trees or landforms such as mountains. This may greatly affect the output of the array if it occurs between about 9 am and 3 pm.

There are many survey devices and computer programs to help determine the effect on irradiation due to shading. The result of shading will be a lower value of solar irradiation that reaches the array. That lower irradiation level must be used when determining the size of the solar array required to provide the calculated daily energy needs of the end-user.

13 Factors That Affect a Solar Module's Output Power

The output of the solar module is affected by temperature, type of solar module, foreign materials on its surface (dirt, leaves, pollution products, etc.) and possibly manufacturer's tolerances and/or module mismatches (connecting modules of different characteristics together). This means that the outputs of the solar modules will need to be adjusted relative to their standard rated values when estimating the actual energy output of the solar array. The rated output of a solar module is determined with a solar cell temperature of 25°C with an irradiance of 1000 W/m^2. However, actual cell temperatures in real-world use are greater than the standard 25°C. Also, average irradiance is generally much less than 1000 W/m^2. Solar array outputs are therefore always less than the standard rated values, and this requires that module outputs must be "derated" when estimating their actual outputs.

13.1 Derating Due to Temperature

A solar module's output power decreases with a solar cell temperature above 25°C and increases with temperatures below 25°C. When exposed to the sun, the average cell temperature will be higher than the ambient temperature because of the glass on the front of the module insulates it from the cooler air around it and the module absorbs some heat from the sun. The output power and/or current of the module must be based on the actual temperature of the cell. This is estimated by the following formula:

$T_{\text{cell-eff}} \quad = \quad T_{\text{a.day}} + T_{\text{r}}$

Where,

$T_{\text{cell-eff}}$ = the average daytime effective cell temperature in degrees Celsius (°C)

$T_{\text{a.day}}$ = the average daytime ambient temperature for the month that the sizing is being undertaken

T_{r} = the rise in temperature due to the type of installation used for the array

The value of T_{r} is selected from Table 6.

TABLE 6: VALUES OF TEMPERATURE RISE (T_{r})

Installation of Array Frame	Temperature rise (T_{r})
Ground Mounted Array	25°C
Array on roof where array tilt angle is at least 20° different from the tilt of the actual roof	25°C
Array structure is parallel to the roof with an air gap between the array and the roof greater than 150 mm	30°C
Array structure is parallel to the roof with an air gap less than 150 mm	35°C

The three major types of solar modules available on the market each have different temperature coefficients. These are:

1. Monocrystalline modules
2. Polycrystalline modules
3. Thin film modules

Monocrystalline Modules typically have a temperature coefficient between $^{-0.3\%}/_{°\text{C}}$ and $^{-0.45\%}/_{°\text{C}}$. Assuming it is $^{-0.45\%}/_{°\text{C}}$, for every degree above 25°C, the rated output power must be derated by 0.45%.

Polycrystalline Modules typically have a temperature coefficient of $^{-0.4\%}/_{°\text{C}}$ to $^{-0.5\%}/_{°\text{C}}$.

Thin film modules have a quite different temperature characteristic, resulting in a lower coefficient, typically around $^{0\%}/_{°\text{C}}$ to $^{-0.3\%}/_{°\text{C}}$.

Note: On a solar module data sheet, three temperature coefficients will be provided. The different temperature coefficients provided are for maximum (or peak) power (W_{p}), open circuit voltage (V_{OC})

and short circuit current (I_{SC}). Some brochures might also include a temperature coefficient for maximum power voltage.

Always check with the product manufacturer for the exact temperature coefficient for the module being used in the system design. That data should be available in the product brochure and must be available if the product has been tested and approved in accordance with the IEC and UL standards.

The symbol used for temperature coefficient is γ and it is expressed on data sheets as a negative number (e.g. $\gamma = {}^{-0.5\%}/_{°C}$).

The derating of the array due to temperature will be dependent on the type of module installed, the average ambient maximum temperature for the location and the type of module mounting system used.

The typical ambient daytime temperature in many countries is between 20°C and 30°C. So, it would not be uncommon to have module cell temperatures of 50°C and higher.

The percentage power loss due to the effective cell temperature is the cell temperature coefficient multiplied by the difference between the cell effective temperature and the temperature at standard test conditions (STC) of 25°C (T_{STC}).

Written as a formula it is:

$$[\text{Percentage power loss due to effective cell temperature}] = \gamma \times (T_{\text{cell-eff}} - T_{\text{STC}})$$

Note: As the temperature coefficient γ is expressed as a negative number, using the above formula will provide a negative answer when ambient temperatures are above 25°C. This is why it is then defined as a loss for arrays installed in the hot regions.

This loss is generally expressed as a temperature derating factor (f_{temp}) which is calculated as follows:

$$f_{temp} = 1 - [\text{the percentage power loss due to temperature}]$$

Note: In this formula the negative % value of percentage power loss is turned into a positive number that represents the percentage of the original output that is left for use.

Worked Example 12: Calculating the temperature derating factor of a solar module

The solar array is mounted parallel to a pitched roof with an air gap of 100mm. The solar module has a power temperature coefficient of $-0.39\%/_{°C}$.

The average daytime ambient temperature in the design month of June is 26°C. What is the percentage (%) power loss due to temperature for this solar module? What is the temperature derating factor?

From Table 6 the rise in temperature ($\mathrm{T_r}$) is 35°C. The effective cell temperature is therefore:

$$
\begin{aligned}
T_{\text{cell-eff}} &= T_{\text{a.day}} + T_{\text{r}} \\
&= 26°\text{C} + 35°\text{C} \\
&= 61°\text{C}
\end{aligned}
$$

As a fraction, $-0.39\%/_{°C}$ is represented as $-0.0039/_{°C}$.

The temperature derating factor (f_{temp}) is calculated as follows:

$$
\begin{aligned}
f_{\text{temp}} &= 1 - (\gamma \times (T_{\text{STC}} - T_{\text{cell-eff}})) \\
&= 1 - \left(-0.39\%/_{°C} \times (25°\text{C} - 61°\text{C})\right) \\
&= 1 - \left(-0.0039/_{°C} \times (-36°\text{C})\right) \\
&= 1 - (0.140) \\
&= 0.86
\end{aligned}
$$

This means that the array actually provides only 86% of its rated output power due to its operation at 61°C instead of STC (25°C).

13.2 Derating Due to Dirt and Other Foreign Materials on the Module Surface

The output of a PV module can be reduced as a result of a build-up of dirt on the surface of the module. The actual value of this loss will be dependent on the conditions at the actual location of the modules, but in some city locations this could be high due to the amount of car pollution and dust in the air. It can also be high in coastal regions during long periods of no rain when salt may build up on the module surface.

In dusty or salty environments this loss could be as high as 20%.

For most rural areas, the typical loss will be no more than 5% though installations adjacent to factories, quarries or unpaved roads may be much higher if modules are not regularly cleaned by the end-user.

This loss is generally expressed as a dirt derating factor (f_{dirt}).

$f_{\text{dirt}} = 1 -$ [the loss due to dirt]

Worked Example 13: Calculating the dirt derating factor

If the loss due to dirt is 5%, what is the dirt derating factor?

As a decimal fraction, 5% converts to:

$$= {}^{5}/_{100}$$

$$= 0.05$$

Therefore, the dirt derating factor (f_{dirt}) is:

$f_{dirt} = 1 -$ [the loss due to dirt]

$$= 1 - (0.05)$$

$$= 0.95$$

13.3 Manufacturer's Output Tolerance

The output of a PV module is specified in watts and with a manufacturing tolerance based on a cell temperature of 25°C. Historically this has been ±5% though in recent years typical figures have been 0% to +3% however, in small print on the data sheet there is often the statement: Measuring tolerance: ±3%. This effectively means the module could have a manufacturer's tolerance which leads to a loss of up to 3% (though there could also be a gain of 3%).

When designing a system, it is important to incorporate the actual figure for the selected module and take into account any measuring tolerances and to assume the worst-case conditions so the resulting design will not be underpowered.

This manufacturer's tolerance loss is generally expressed as a manufacturer's derating factor (f_{man}).

$f_{man} = 1 -$ [manufacturer's tolerance (or measuring tolerance loss)]

Worked Example 14: Calculating the manufacturers' derating factor

If the loss due to *measuring tolerance* is 3%, what is the manufacturer's derating factor?

As a fraction, 3% converts to:

$$= {}^{3}/_{100}$$

$$= 0.03$$

Therefore, the manufacturer's derating factor (f_{man}) is:

$f_{man} = 1 -$ (measuring tolerance loss)

$$= 1 - (0.03)$$

$$= 0.97$$

13.4 Solar Module Ageing Factor

Another factor that will result in derating the solar array is ageing of the solar modules. When in service, solar modules gradually lose some capacity over time, though quite slowly. Manufacturers generally will provide a warranty that their solar module will not fall more than 15% below the rated value for 25 years. For the designer, it is reasonable to assume the useful life of the off-grid system is 20 years, so the array needs to continue to service the design load for those 20 years and may last longer. This means that the initial rating of the modules used will need to be about 10% higher than the value that will be sufficient to serve the load when new.

Worked Example 15: Calculating the module ageing derating factor

If the loss due to *ageing* is 10%, what is the derating factor for ageing?

As a fraction, 10% converts to:

$$= {}^{10}/_{100}$$

$$= 0.1$$

Therefore, the derating factor for aging (f_{ageing}) is:

$$f_{\text{ageing}} = 1 - (\text{ageing loss})$$

$$= 1 - (0.1)$$

$$= 0.90$$

Note: In Section 17.4 and Section 22.4, an oversizing factor of 30% is recommended. This 30% takes into account the ageing of the module, and therefore in later examples the ageing is not separately taken into account. It has been left here for informational purposes.

To determine the total derating factor for the solar modules, it is necessary to multiply all the derating factors together and then apply the result to the rated output of the modules.

Worked Example 16: Calculating derated module output power (ageing not included)

If the following factors are true:

$$f_{\text{temp}} = 0.86$$

$$f_{\text{dirt}} = 0.95$$

$$f_{\text{man}} = 0.97$$

what is the overall derating factor for the modules?

$$\begin{aligned}\text{[overall derating factor]} &= f_{\text{temp}} \times f_{\text{dirt}} \times f_{\text{man}} \\ &= (0.86) \times (0.95) \times (0.97) \\ &= 0.79\end{aligned}$$

This means that the actual output from the module is expected to be 0.79 times the rated output.

Thus a 100 W_p module can be expected to provide at least:

$$100\ \mathrm{W_p} \times 0.79 = 79\ \mathrm{W_p}$$

Note: The output will also be reduced by some percentage if the module is not properly oriented as to azimuth and tilt.

14 Selecting a Solar Module

In addition to the requirements and recommendations listed in the following sections, PV modules shall also comply with the requirements outlined in *Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview*, Section 3.4.

15 Selecting an Array Structure

The array structure and module attachment system selected for the PV modules shall be designed to resist the ultimate wind actions for the site where the array will be located and be constructed of material suitable for the location.

16 Relationship between Solar Controller and Solar Modules

Historically, switched solar controllers were the most common solar controllers. The initial versions applied "on-off" type switching between the solar array and the battery using relays. These operated such that the solar array was either directly connected to the battery and charging the battery with the relay in the "on" (or closed) state or the solar array was disconnected from the battery with the relay in the "off" (or open) state.

The modern switched type controllers employ Pulse Width Modulation (PWM) technology. PWM controllers use electronic switches to rapidly turn on and off the direct connection between the solar array and battery to provide an average charging current necessary to maintain the required battery voltage.

Traditionally solar modules were designed to charge a 12 V battery. To effectively charge the 12 V battery, the solar module comprised 36 solar cells and manufacturers data sheets specified the module as a nominal 12 V module.

To have an efficient system, the switch type controller should be connected to a solar array which has a "nominal" voltage equivalent to the nominal battery voltage. That is, a solar system using a switch type controller with a 12 V battery should be connected to a 36-cell module with a "nominal" voltage of 12 V. A 24 V battery should be connected to 72 cells while a 48 V battery should be connected to 144 cells.

In the current market, the great majority of solar modules are used for grid-connected systems and the number of cells depends more on the power desired than the voltage required of the module. The solar module designed for the grid connect market typically comprise 60 or 72 cells though there have been some with 48 or even 96 cells. Therefore, many solar modules that are readily available should not be used with switching type solar controllers because they have more than the 36 cells and the module voltage does not match the voltage of the battery bank. If a 60-cell module is connected to a switched controller and a 12 V battery, the solar module will charge the battery however 40% (24 of the solar cells) of the module capacity would never be used resulting in an inefficient system.

The result is that in recent years' solar controllers known as maximum power point trackers (MPPT) have become more common. These can have an input voltage range much greater than the charging voltages of the battery. These are d.c.-to-d.c. power converters where the controller is designed to track the maximum power point of the solar array. This maximum power point voltage will (and should) be greater than the voltage of the battery connected to the output of the MPPT controller. Since the battery must be charged at a voltage applicable to its voltage rating, the extra power available, due to the input voltage being higher than the battery voltage, is converted into a battery charging current greater than that which would be available if the solar array was directly connected to the battery.

PART 2 - DETERMINING THE SOLAR SYSTEM FOR D.C.-COUPLED CONFIGURATIONS

17 Sizing a Solar Array – General

The calculations for determining the size of the PV array are dependent on the type of controller used. As described in Section 16, historically, switched solar controllers were the most common controllers used with "on-off" type switching using relays the oldest type and semiconductor-based Pulse Width Modulation (PWM) types the modern version. Semiconductor based maximum power point trackers (MPPT) are now commonly available.

The switching solar controller, also referred to as a PWM Controller in this guideline, has its output voltage tied to a fixed input voltage making it necessary to have that specific voltage available from the solar array —hopefully at a voltage near the maximum power point of the array — while a MPPT controller can manage a wide range of input voltages while seeking and tracking the voltage of the maximum power point of the solar array and simultaneously managing the output voltage to match the battery requirements. The MPPT controller can deliver more charge to the battery per day than a switching controller but for small installations the switching controller is still used because of its low cost and simplicity. The MPPT controller is required when the solar module being used does not have the suitable voltage (number of cells) for effective battery charging with a switching type controller.

The size of the PV array should be selected to take account of:

a) seasonal variation of solar irradiation
b) seasonal variation of the daily energy usage
c) manufacturing tolerance of modules
d) dirt accumulation
e) temperature of array (the effective cell temperature)
f) allowing for the module efficiency decreasing over time(ageing)
g) inverter efficiency
h) battery efficiency
i) controller efficiency
j) cable losses
k) oversize factor to allow for effective charging.

Points (a) through to (f) have been covered in Sections 12 and Section 13. This section looks at points (g) through to (k). Points (g), (h), (i) and (j), when grouped together, are commonly known as the sub- system efficiency, the sub-system being defined as the solar array and the associated loads.

17.1 Sub-System Losses in an Off-Grid PV System

The sub-system losses are all those in the circuit from the output of the PV array to the load.

If the system is only providing d.c. loads, then the sub-system losses are:

- cable losses (due to voltage drop)
- solar controller losses
- battery losses

If the system is only providing a.c. loads, then the sub-system losses are:

- cable losses (due to voltage drop)
- solar controller (d.c.-coupled system)
- battery losses
- battery inverter losses

The battery losses can be based on either coulombic efficiency (in terms of Ah) or watt-hour efficiency.

The average coulombic efficiency of a new lead-acid battery (in terms of the ratio of Ah of discharging to Ah of charging) is typically 90% (variations in battery voltage are not considered, only Ah in and out) while the average watt-hour (Wh) efficiency (in terms of the Ah times the voltage of the battery during discharging and charging over a specific time) of a new battery is typically 80%. As the battery ages, the coulombic and watt-hour efficiency both decline slowly.

When determining the PV array size for systems using switching solar controllers, the calculations are based in Ah and coulombic efficiency is used.

When determining the PV array size for systems using a MPPT controller, Wh efficiency is used.

All these losses are expressed as percentages which are then converted into a fraction when applied in determining the PV array output.

Worked Example 17: Converting % to a number used on calculations

If battery has an efficiency of 90%, then the fraction used in determining the required PV array power output would be 0.9.

17.2 Determining the Energy Requirement of the PV Array

The design month's daily load energy is used for determining the size of the PV array.

To determine the energy required from the PV array these sub-system losses need to be taken into account. That means that the output of the PV array must be greater than the daily load it is supplying. The total required output is calculated by dividing the required daily load energy by all the sub-system losses in the system expressed as decimal fractions.

17.3 What About the Loads that Operate During the Day?

When sizing the array, convention has been to be conservative and assume that all the loads are supplied by the battery bank so that the battery efficiency was taken into account for all loads when determining the size of the solar array required to meet the daily energy demand.

However, some of the load energy will be supplied directly during the day since typically the available output from the controller will be directly connected to both the battery and the input terminals of the battery inverter. To determine exactly how much, a detailed interval analysis would be required whereby the load power profile is compared to the available solar output power profile. However, the available solar power and the loads will vary during the day and from day to day so the percentage of the load during the day that is directly powered by the array can only be estimated.

With the introduction of a.c.-coupled system configurations where the PV array interconnects with a PV-powered (grid-connected) inverter directly onto the a.c. grid, the a.c.-coupled proponents emphasised how efficient these systems were in supplying the load directly, which is true for loads during the day. Meanwhile, these systems had a greater loss when supplying the loads via the battery bank due to losses in the battery itself plus losses in the a.c. inverter and plus losses in the a.c.-to-d.c. battery charging feature in the battery inverter. So, people designing systems using an a.c.-coupled configuration started to estimate how much of the daily energy was supplied directly by the PV array during the day.

To not do this for d.c.-coupled systems could lead to an apparent cost disadvantage when designing a system and make the d.c.-coupled system appear more expensive in a competitive quote situation. This guideline describes how to determine the array size if the loads are divided between daytime loads being supplied directly by PV array and those loads being supplied by the battery bank due to night-time operation of the loads.

Therefore, the total energy that has to be supplied by the PV array is equal to the amount of energy being supplied to loads directly by the PV array plus the amount of energy being supplied to the loads from the battery that has been charged by the PV array adjusted to take the battery efficiency into consideration.

Therefore, the total number of modules required in the array equals the number of modules to supply the daytime load directly plus the number of modules needed to charge the battery for delivery of energy to the load during the night and when the daytime load exceeds the generation from the solar modules.

However, for small home systems with only a few modules configured in d.c.-coupled arrangement and considering the fact there are days when it is cloudy, it is recommended that the PV array is designed based on the assumption that all the loads are supplied by the battery being charged by the PV array. This is a conservative approach; however, it is only the coulombic efficiency of typically 90% which is the difference in d.c.-coupled systems. Therefore, the number of modules based on this conservative approach would only be a maximum of 10% higher than the number required if all the loads were supplied by the PV during the day.

17.4 Oversize Factors

If the system does not include a fuelled generator which can provide extra charging to the lead acid battery bank, then the solar array should be oversized to enable equalisation charging of the battery bank. Otherwise, the battery life will be shortened due to it having to remain in a partially charged condition for many days during cloudy periods. That leads to sulfation of the battery and the loss of some battery Ah capacity unless an equalizing charge is carried out shortly after the sulfation occurs.

Therefore, when designing a solar system comprising lead acid batteries the array should be oversized by at least 30% to allow for faster full charging of the battery and to provide equalizing charging when needed. An oversize factor of 30% should also effectively cover the ageing of the solar module in the first 10 years.

An oversize factor of 10%, to effectively cover the aging of the solar module should be included with systems that include lithium-ion batteries.

18 Sizing a PV Array— PWM (Switching Type) Solar Controller

When using a PWM solar controller, the calculations are all based on determining the required Ah from the array. The losses in the cable and the solar controller are only reflected as voltage drops which therefore dictate the operation point on the current-voltage characteristic curve (IV curve) of the solar array. That is, if the battery is at 12 V, then the PV array will be operating at 12 V plus the voltage drop in the connecting cable plus any voltage drop across the controller. Since the maximum power point of a nominal 12 V module will be at 17-18 V and the maximum charge voltage of a lead acid battery is between 14.4 V and 15 V, then the typical voltage drop of around 1 V that occurs between the array and the battery is not an issue for most of the time the battery is being charged.

The only losses that need to be taken into account are any battery inverter losses (when a.c. appliances are powered by an inverter connected to the system), so the battery losses are assumed to be its average coulombic efficiency (in terms of Ah in and Ah out) of a new battery. That is typically 90% (variations in battery voltage are not considered).

Worked Example 18: Calculating the required output current of an array based on load energy using PWM controller

Figures used in this example are from Table 1 and Table 2.

Assume all the loads are supplied by the PV array charging the battery bank.

Based on the design month, the solar array is to be sized based on the average energy usage during the humid season.

The efficiency of the chosen inverter is 90%.

The daily battery load (energy) due to a.c. loads is:

$$= {}^{1500\ \mathrm{Wh}}\!/_{(90\%)}$$

$$= {}^{1500\ \mathrm{Wh}}\!/_{0.9}$$

$$= 1667\ \mathrm{Wh}$$

The daily battery load (energy) due to d.c. loads is 112 Wh.

To get the total load (energy) as provided by the battery, add the a.c. and d.c. loads together:

1667 + 112= 1779 Wh

The system voltage is 24 V.

The daily energy requirement expressed in Ah from the battery is 74.13 Ah $({}^{1779\ Wh}\!/_{24\ V})$.

Allowing for the battery efficiency, the solar array then needs to produce:

$$= {}^{74.13\ \mathrm{Ah}}\!/_{0.9}$$

$$= 82.4\ \mathrm{Ah}$$

The PSH in the design month is 4.6.

Therefore, the required PV array derated output current is:

$$= {}^{82.4\ \mathrm{Ah}}\!/_{4.6\ \mathrm{PSH}}$$

$$= 17.9\ \mathrm{A}$$

The oversize factor then needs to be applied. A minimum of 30% is recommended when using lead acid batteries and 10% when using lithium-ion batteries.

Worked Example 19: Adjusting the required array output current based on oversize factor

The adjusted required PV array derated output current is:

$$= 17.9\ \mathrm{A} \times 1.3$$

$$= 23.3\ \mathrm{A}$$

The PV array will be derated due to:

- manufacturer’s tolerance
- dirt
- module temperature greater than 25°C
- potentially for ageing of the module that results in decrease in efficiency and hence power output; however, the 30% oversizing factor takes this into account.

Traditionally, solar modules have had nominal voltages of 12 V by using 36 cells per module. These were designed to charge a 12 V battery. In the current market the great majority of solar modules are used for grid-connected systems and the number of cells depends more on the power desired than the voltage required of the module. Therefore, many solar modules that are readily available are not suitable to be used with simple switching type solar controllers because they have many more than 36 cells and the module voltage does not match the input voltage needed by the switching controller. **The designer, when using a PWM switching type solar controller, must use solar modules that have a nominal voltage rating that is appropriate for the battery voltage**. In the market today these are either 36-cell modules for 12 V batteries or 72-cell modules suitable for 24 V battery banks. Today 36-cell modules are typically costlier than 60-cell or 72-cell modules when compared on a per W_p basis because they have become a specialty item and are no longer mainstream. For rural residences, 36-cell panels matched with a simple switching controller still provides the simplest and most cost-effective solution for lighting and basic entertainment but locating a source of cost effective 36-cell modules is not always easy. A few manufacturers provide 72-cell modules that are internally split into two 36-cell units which can be electrically connected as paralleled 36-cell modules for 12 V battery charging or series connected as a 72-cell module for 24 V battery charging.

The typical charge voltage range for different lead acid battery banks is as follows:

- 12 V battery bank
    - 12 V - 15 V (wet cells/flooded), OR
    - 12 V - 14.4 V (valve regulated battery)
- 24 V battery bank
    - 24 V - 30 V (wet cells/flooded), OR
    - 24 V - 28.8 V (valve regulated battery)
- 48 V battery bank
    - 48 V - 60 V (wet cells/flooded), OR
    - 48 V - 57.6 V (valve regulated battery)

To allow for temperature and the various charge voltages, the *module effective current* used when determining the size of an array using crystalline type modules are as follows:

- 12 V modules - current at 14 V and at the effective cell temperature
- 24 V modules - current at 28 V and at the effective cell temperature
- 48 V modules - current at 56 V and at the effective cell temperature

Unless the current vs voltage curves (IV curves) for different temperatures are available for the module selected, it is difficult to obtain this information. The module manufacturer's data sheets usually only provide short circuit current (I_{SC}) and maximum power point (I_{mp}) current; the operating current will be between these two values. The published values are usually only provided for Standard Test Conditions and for cells at the Nominal Operating Cell Temperature (NOCT) or .

If the IV curves at different temperatures are not available, it is recommended that the current halfway between I_{sc} and I_{mp} be used as the module current. That is:

$$[\text{calculated module current}] = {(I_{SC} + I_{mp})}/{2}$$

Also allowing for dirt and manufacturer's tolerance:

$$[\text{derated module current}] \\ = [\text{module effective current}] \times [\text{manufacturer's tolerance derating factor}] \\ \times [\text{dirt derating factor}]$$

or

$$[\text{derated module current}] \\ = [\text{calculated module current}] \times [\text{manufacturer's tolerance derating factor}] \\ \times [\text{dirt derating factor}]$$

The number of modules in a string is determined by dividing the battery voltage by the nominal voltage of the module. It is reasonable to assume the nominal voltage of a module is number of cells per module divided by three. Thus a 36-cell module has a nominal voltage of 12 V, a 60-cell module has a nominal voltage of 20 V, and a 72-cell module has a nominal voltage of 24 V.

The number of module strings that need to be in parallel is determined by dividing the adjusted required array current by the derated module current.

Worked Example 20: Calculating the number of modules required using PWM controller. (Assuming no daytime loads)

A 72-cell module with the following characteristics is selected:

STC Electrical Data:

$$P_{mp} = 330 \text{ W}$$
$$V_{oc} = 46.2 \text{ V}$$
$$V_{mp} = 37.8 \text{ V}$$
$$I_{sc} = 9.27 \text{ A}$$
$$I_{mp} = 8.73 \text{ A}$$

Power temperature coefficient = ${}^{-0.39\%}/_{\circ C}$

V_{oc} temperature coefficient = ${}^{-0.29\%}/_{\circ C}$

Manufacturer's tolerance = 0 to +5%

Test tolerance ±3%

Note: For this example, the oversize factor has taken the ageing factor into account. The module has 72 cells, and hence provides a nominal 24 V.

The number of modules in a string

= [the battery voltage] / [nominal voltage of the module]

= 24 V/24 V

= 1

Calculated module current:

= (9.27 + 8.73)/2

= 9 A

Manufacturer's Tolerance = test tolerance = 3%

This is a derating factor of 0.97

Assume dirt derating is 5% and hence derating factor of 0.95

Therefore, the derated current per module string is:

= 9 A × 0.97 × 0.95

= 8.3 A

From Worked Example 19, adjusted required array current = 22.3

A number of module strings in parallel:

= 23.3 A / 8.3 A

= 2.8 (round up to 3)

If there are daytime loads: For systems with switching (PWM) type controllers there will be no battery losses for the loads being supplied directly.

If the percentage of daily load energy being supplied directly is known when determining the number of modules required to meet the load directly in the day, the only d.c. sub-system losses are the inverter loss, cable losses and any loss in the controller.

Worked Example 21: Calculating the number of modules required using PWM controller (all loads supplied by PV array during day

Assume all the power is being supplied directly to the loads by the PV array, therefore no battery losses.

From Worked Example 18, the daily energy requirement expressed in Ah from the battery is 74.13 Ah ($^{1779\ \text{Wh}}/_{24\ \text{V}}$). (Battery inverter losses already taken into account.)

The PSH in the design month is 4.6.

Therefore, the required PV array output current is:

$$= {}^{74.13\ \text{Ah}}/_{4.60\ \text{PSH}}$$

$$= 16.12\ \text{A}$$

Allowing for 30% oversizing, the adjusted PV array output current required is:

$$= 1.3 \times 16.12\ \text{A}$$

$$= 20.96\ \text{A}$$

The derated array current for each module is 8.3 A.

Number of module strings in parallel:

$$= {}^{20.96\ \text{A}}/_{8.3\ \text{A}}$$

$$= 2.53$$

Realistically, depending on how much power is supplied directly to loads by the PV array, the number of module strings required in parallel for this example varies between 2.53 and 2.8 with both cases probably ending up with the same three strings in parallel when the selected modules are used, or maybe a smaller module would be selected to obtain the 3 modules.

19 Sizing a PV Array- MPPT Solar Controller

When using a MPPT controller the calculations are in Wh and the d.c. sub-system losses in the system include:

- Battery losses (watt-hour efficiency)
- Cable losses
- MPPT losses (controller efficiency); and
- Inverter losses (inverter efficiency)

In order to determine the energy required from the PV array, it is necessary to increase the energy to and from the battery bank to account for all the sub-system losses.

Worked Example 22: Calculating the size of array based on load energy when using MPPT controller (assuming no daytime loads)

The energy supplied by the battery bank allowing for the inverter efficiency is 1779 Wh.

Assume:

- Cable losses are 3% (transmission efficiency of 97%)
- MPPT efficiency of 95%
- Battery efficiency of 80%
- All the load energy is provided by the battery

d.c. subsystem efficiency:

= 0.97 × 0.95 × 0.8

= 0.737

Energy required from the PV array:

= 1779 Wh / 0.737

= 2414 Wh

The design month PSH is 4.6.

Therefore, the required PV array derated output power is:

= 2414 Wh / 4.6 PSH

= 525 W

Allowing for an oversize factor of 30%, the adjusted required derated array output is:

= 525 W × 1.3

= 682.5 W

The output of the solar module is affected by temperature, dirt, possibly manufacturer's tolerances and/or module mismatches and module ageing. This means that the power output of the solar module should be derated when determining the energy output of the solar array.

Solar modules have a rated output measured at Standard Test conditions (STC). Based on the factors affecting the power output of the module (P_{mod}) as detailed in Section 13, the derated power output (P_{derated}) of the module is determined as follows:

$$P_{derated} = P_{mod} \times f_{temp} \times f_{dirt} \times f_{man} \times f_{ageing}$$

Worked Example 23: Calculating number of modules required based on load energy when using MPPT controller (assuming no daytime loads)

In the worked example:

- Derating due to temperature: $f_{\text{temp}} = 0.86$
- Derating due to dirt: $f_{\text{dirt}} = 0.95$
- Derating due manufacturers tolerance: $f_{\text{man}} = 0.97$
- **Note**: For this example, ageing factor has not been taken into account since it is effectively covered by the 30% oversizing factor that allows for battery equalization and fast recharging in order to extend battery life

Module rating is $330\ \text{W}_\text{p}$

Derated module output:

$$= 330\ \text{W} \times 0.86 \times 0.95 \times 0.97$$

$$= 261.5\ \text{W}$$

The adjusted required derated array output from Worked Example 22 is 682.5 W.

The required number of modules is:

$$= {}^{682.5\ \text{W}}/_{261.5\ \text{W}}$$

$$= 2.61$$

$$= 3\ \textit{(rounded)}$$

In reality, a smaller module could be selected so that exactly 3 modules are required based on this example. Using a 330 W_p module, the actual required array W_p is 2.61 × 330 W_p = 861 W_p (not the 990 W_p that 3 solar modules would provide). Three 290 W_p modules would provide 870 W_p, which slightly exceeds the requirement of an 861 W_p array.

19.1 If there are daytime loads

For systems with MPPT controllers there will be no battery losses for the loads being supplied directly.

If the percentage of daily load energy being supplied directly is known, when determining the number of modules required to meet the load directly in the day the d.c. sub losses would only include:

- Cable losses;
- MPPT losses (controller efficiency); and
- Battery inverter losses (inverter efficiency)

Worked Example 24: Calculating number of modules required based on load energy when using MPPT controller (all loads supplied during by PV array during the day)

The energy supplied by the battery bank allowing for the inverter efficiency = 1779 Wh

Assume:

- All the load energy is provided directly by the PV array during the day
- Cable losses are 3% (transmission efficiency of 97%)
- MPPT efficiency of 95%

d.c. subsystem efficiency factor (which excludes battery bank efficiency):

$$= 0.97 \times 0.95$$

$$= 0.922$$

Energy required from the PV array:

$$= {}^{1779\ \mathrm{Wh}}/_{0.922}$$

$$= 1930\ \mathrm{Wh}$$

The design month PSH is 4.6.

Therefore, the required derated PV array output power is:

$$= {}^{1930\ \mathrm{Wh}}/_{4.6\ \mathrm{PSH}}$$

$$= 420\ \mathrm{W}$$

Allowing for oversize factor of 30%, the adjusted required derated PV array output power is:

$$= 420\ \mathrm{W} \times 1.3$$

$$= 546\ \mathrm{W}$$

Derated module output is 261.5 W.

The required number of modules is:

$$= {}^{546\ \mathrm{W}}/_{261.5\ \mathrm{W}}$$

$= 2.08$ *(so probably round down to 2)*

An array comprising two 330 W_p modules (660 W_p) is required.

However, an array of $2.08 \times 330\ \mathrm{W_p} = 686\ \mathrm{W_p}$.

Based on Worked Example 23 and Worked Example 24 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery bank, the required array is rated between 686 W_p (all loads supplied power directly by solar array) and 861 W_p (all loads supplied power from the battery bank).

20 Selecting a Solar Controller: PWM Controller

In addition to the requirements and recommendations listed in this and the following sections, solar controllers shall also comply with the requirements outlined in *Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview*, Section 3.6.

PV controllers on the market range from simple switched units that only prevent battery overcharge (and usually also excessive discharge) to microprocessor-based units that incorporate many additional features such as:

- PWM and equalisation charge modes
- D.C. Load control
- Voltage and current metering
- Amp-hour logging
- Priority load connections (low priority connections shut down when the normal discharge limit for the battery is reached. Priority loads can continue running until the battery is more deeply discharged)
- Generator start/stop control (for a back-up generator to automatically start if the battery reaches its pre-set discharge limit)

Unless the controller is a model that is internally current limited, these should be sized so that they are capable of carrying at least 125% of the array short circuit current and withstanding the open circuit voltage of the array. If there is a likelihood that the array may need to be increased in the future, then the controller should be further oversized to cater for future growth.

The charge controller shall be appropriate for the battery chemistry, as voltage set points and recommended charge controller behaviour will differ between battery types. For instance, if lead-acid batteries are used, the charge controller should be designed to fully charge the batteries and provide equalization charges as prescribed by the battery manufacturer. If lithium-ion batteries are used, then the selected charge controller should be able to communicate with the battery management system (BMS) provided with the lithium-ion battery. Many charge controller manufacturers provide a list of lithium-ion batteries approved for use with their products, including special instructions or restrictions on certain combinations.

(**Note**: sometimes the controller is called a regulator.)

Worked Example 25: Calculating required current rating of PWM controller

If three modules in parallel are selected (Worked Example 19) with I_{sc} of 9.27 A, the controller chosen must have a current rating > 1.25 × 3 × 9.27 A = 34.7 A at a system voltage of 24 V.

21 Selecting a Solar Controller: MPPT-Type Controller

In addition to the requirements and recommendations listed in this and the following sections, solar controllers shall also comply with the requirements outlined in *Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview*, Section 3.6.

The MPPT controller must be matched with the array in relation to:

- Maximum PV power rating in watts;
- Input voltage; and
- Input current if nominated by the manufacturer.

Worked Example 26: Calculating required power rating of MPPT controller

The number of modules required was 2 (Worked Example 24) or 3 (Worked Example 23) so unless a different size module was chosen, select a MPPT which will be suitable for 3 modules.

The module rating is 330 W_p.

The required power rating of the MPPT is:

$$= 3 \times 330 \ \mathrm{W_p}$$

$$= 990 \ \mathrm{W}$$

The charge controller shall be appropriate for the battery chemistry, as voltage set points and recommended charge controller behaviour will differ between battery types. For instance, if lead-acid batteries are used, the charge controller should be designed to fully charge the batteries and provide equalization charges as prescribed by the battery manufacturer. If lithium-ion batteries are used, then the selected charge controller should be able to communicate with the battery management system (BMS) provided with the lithium-ion battery. Many charge controller manufacturers provide a list of lithium-ion batteries approved for use with their products, including special instructions or restrictions on certain combinations.

21.1 Matching the PV array to the Voltage Specifications of the MPPT

The MPPT typically will have a recommended minimum nominal array voltage and a maximum input voltage. In the case where a maximum input voltage is specified and the array open circuit voltage is above the maximum specified, the MPPT could be damaged.

The maximum power point voltage of a solar module decreases as the cell temperature rises. Individual monocrystalline solar cells typically have an output voltage around 0.5 V, and this results in a 36-cell module requirement for effective charging of a 12 V battery connected to the module via a switched controller. For the MPPT to work effectively the maximum power point voltage of the array must always be greater than the maximum charge voltage of the battery. So, though a 36-cell module could be connected to a battery via an MPPT, but the MPPT will typically work more efficiently if the number of solar cells in the array is greater than 36 for a 12 V battery.

Some MPPT controllers may allow the minimum array nominal voltage to be equal to that of the battery bank. However, the MPPT will charge the battery more efficiently when the minimum nominal array voltage is higher than the nominal voltage of the battery. Some manufacturers state 5 V to 6 V higher than the battery voltage.

Table 7 shows the suggested minimum number of cells in a string for the different nominal battery voltages when using a MPPT controller; however, lower numbers may be satisfactory (where module availability or cost is an issue) and designs should always follow manufacturer's recommendations.

TABLE 7: MINIMUM NUMBER OF CELLS IN A STRING

Nominal Battery voltage (V)	Suggested Number of Cells per string of modules
12	54
24	90
48	162

Worked Example 27: Determining number of modules required based on number of cells in module

Battery voltage is 24 V so the array should have 90 cells in series for optimum efficiency. The module selected for the worked example has 72 cells so a minimum of two of these in series is recommended per string.

The output voltage of a module is affected by cell temperature changes in a similar way to the output power. The manufacturers will provide a voltage temperature coefficient on the module specification sheet. It can be specified in V/°C (or mV/°C) but it generally expressed as a percentage %/°C.

To ensure that the V_{oc} of the array does not reach the maximum allowable voltage of the MPPT the minimum day time temperature for that specific site is required. For most locations, this will be the temperature at dawn on the day of the year that is historically the coldest.

In early morning at first light the cell temperature will be very similar to the ambient temperature because the sun has not had time to heat up the module. Though the energy from the sun at sunrise is very low and therefore the current (amperes) that can be generated from the module will be very low, the solar module reaches almost maximum open circuit voltage as soon as the sun is on the horizon. The maximum open circuit voltage is determined similarly to the temperature derating factor for module power.

Worked Example 28: Calculating the smallest maximum voltage required for the MPPT

The selected module has the following characteristics:

V_{oc} = 46.2 V

V_{oc} temperature coefficient = -0.29%/°C

The temperature coefficient (V/°C) is:

$$= {}^{-0.29}/_{(100/°C)} \times 46.2\text{ V}$$

$$= -0.134\text{ V}/°\text{C}$$

If the minimum temperature is 20°C, this is 5°C below the STC temperature of 25°C. Therefore, the effective variation in voltage is:

$$= -5°\text{C} \times -0.134\text{ V}/°\text{C}$$

$$= 0.67\text{ V}$$

So, the maximum open circuit voltage of the module is:

$$= 46.2\text{ V} + 0.67\text{ V}$$

$$= 46.9\text{ V}$$

As stated, the MPPT should be selected to be suitable for three modules. To achieve the required power, these could either be installed three in series or three in parallel. However, if there are three in parallel then this does not meet the minimum voltage requirement of at least 90 cells in series.

Therefore, with three in series the MPPT must have a maximum voltage rating equal to or greater than:

$$= 3 \times 46.9\text{ V}$$

$$= 140.7\text{ V}$$

When modules are connected in series then the maximum V_{oc} of the string shall always be less than the maximum allowable voltage of the MPPT.

Once the module V_{oc} at the coldest temperature is calculated then the maximum number of modules allowed in series is determined by dividing the maximum MPPT allowable voltage divided by module V_{oc} at the coldest temperature.

PART 3 – DETERMINING THE SOLAR SYSTEM FOR a.c.-COUPLED SYSTEM CONFIGURATIONS

22 Sizing a Solar Array - General

The size of the PV array should be selected to take account of:

a) seasonal variations of solar irradiation

b) seasonal variations of the daily energy usage

c) manufacturing tolerance of modules

d) dirt

e) temperature of array (the effective cell temperature)

f) allowing for the module efficiency decreasing over time (ageing)

g) battery inverter efficiency

h) battery efficiency

i) PV inverter efficiency

j) cable losses

k) oversize factor to allow for effective charging.

The points a through to f have been covered in Sections 12 and 13. This section looks at points g) through j). Points g), h), i), and j) are commonly known as the sub-system efficiency; the sub-system being defined as the components between the solar array and the loads. Note that sizing of the battery inverter is identical to the procedure for d.c.-coupled systems and is covered in Section 11.

22.1 Sub-System Losses in an Off-Grid PV System

The sub system losses are all those from the output of the PV array to the load.

If the system is providing a.c. loads via the battery, then the sub-system losses are:

- PV Inverter losses
- cable loss (due to voltage drop)
- battery inverter/charging losses (a.c. coupled system)
- battery losses
- battery inverter losses

If the system is providing all a.c. loads directly during the day then at that time, the sub-system losses are:

- PV Inverter losses
- cable loss (due to voltage drop)

The battery losses are based on the watt-hour efficiency of the battery and the average watt-hour (Wh) efficiency of a new lead-acid battery is typically 80%. Lithium-ion batteries may have higher efficiencies, potentially up to 90%-95%.

Note: Typically, a.c.-coupled systems do not have d.c. loads; however, if some do exist, then all relevant losses between the solar array and the d.c. loads shall be taken into account.

22.2 Determining the Energy Required from the PV Array

The design month's daily load energy is used for determining the size of the PV array.

In order to determine the energy required from the PV array, it is necessary to divide the required daily load energy by all the sub-system losses in the system.

22.3 What About the Loads that Operate During the Day?

In the past, when sizing the array, convention had been to be conservative and assume that all the loads were supplied by the battery bank so that the battery efficiency was taken into account when determining the size of the solar array required to meet the total daily energy demand.

However, realistically some of the load energy will be supplied directly to the load from the PV inverter during the day. To determine exactly how much, a detailed interval analysis would be required where the load power profile is compared to the available solar power over an extended period of time. The available solar power will vary during the day and the loads typically do also so the result of an interval analysis can only provide a rough estimate of future conditions. Since long cloudy periods of a week or more are possible in most island countries, for maximum battery life (and therefore minimum O&M cost), it is recommended that the design assume all energy must come from the battery even though on mostly clear days' substantial amounts may indeed be delivered directly from the panels and the battery is given a rest.

With the introduction of a.c.-coupled systems where the PV array connects directly to a PV (grid connected) inverter connected to the a.c. bus, then the losses to the a.c. loads that are directly powered by the PV inverter include:

- cable loss (due to voltage drop in the cables between the solar array and loads); and
- PV inverter losses.

The losses when providing a.c. loads from the battery include

- cable loss due to voltage drop (in the cables from the PV array to batteries and to the load);
- PV inverter losses (a.c.-coupled system)
- battery inverter/charging losses (a.c.-coupled system)
- battery watt-hour losses
- battery inverter losses (when feeding a.c. into the grid via the battery inverter)

With the additional losses seen when powering a.c. loads from the battery, designers often either undertook detailed interval analyses or roughly estimated the percentage of the load energy supplied directly by the PV array to the a.c. loads.

Therefore, the total energy that has to be supplied by the PV array = total amount of energy being directly supplied to loads by the PV array + the total amount of energy being supplied to the loads from the battery bank that is being charged by the PV Array.

The total number of modules required = the Number of modules needed to supply the load directly from the PV inverter + the Number of modules needed to charge the battery.

For public facilities (e.g. schools, government facilities, health centres) it is recommended that the design assume that all energy provided to the load must come from the battery since then the design will not greatly stress the battery during cloudy periods and battery life will be maximized.

Since battery replacement costs are generally by far the largest component of O&M costs, extending the life of the battery will reduce those costs significantly.

For commercial applications (e.g. resorts, shops, factories) a design that includes allowing for direct solar power of loads during the day can be used in order to reduce the up-front installation cost if the customer is advised of the increase in O&M cost that may occur due to shortened battery life.

22.4 Oversize Factors

For lead acid systems, if the system does not include a fuelled generator which can provide extra charging to the lead acid battery bank, the solar array should be oversized to enable equalisation charging of the battery bank. Otherwise the battery life will be shortened due to it having to remain in a partially charged condition for many days during cloudy periods. That leads to sulfation of the battery and the loss of some battery Ah capacity unless an equalizing charge is carried out shortly after the sulfation occurs.

Therefore, when designing a solar system comprising lead acid batteries, the array should be oversized by at least 30% to allow for faster full charging of the battery and to provide equalizing charging when needed. An oversize factor of 30% should also effectively cover the ageing of the solar module in the first 10 years.

An oversize factor of 10%, to effectively cover the aging of the solar module, should be included with systems that include lithium-ion batteries.

23 Sizing a PV Array - a.c. Coupled System

As stated in the previous section the loads may be supplied by the PV array as follows:

- PV array powers a.c. loads directly via the PV inverter
- PV array powers a.c. loads from the battery bank through the PV inverter with the battery inverter acting as the a.c. source

Worked Example 29: Calculating size of array and number of modules based on required load energy (All loads supplied by PV array charging batteries)

Assume the loads are only a.c. and that the d.c. loads as specified in Table 1 are a.c. and are supplied by the PV array charging the battery bank.

Assume the following system losses (efficiencies):

- cable loss from PV array to a.c. loads via batteries is 4% (efficiency of 96%)
- PV inverter efficiency is 97%
- battery inverter charging efficiency is 96%; battery Wh efficiency is 80%
- battery inverter efficiency 96%

For design month,

Daily a.c. load (energy) = 1500 Wh + 112 Wh = 1612 Wh

System efficiency factor when providing a.c. loads = PV inverter efficiency × cables losses × battery inverter charging efficiency × battery efficiency × battery inverter efficiency

$0.97 \times 0.96 \times 0.96 \times 0.80 \times 0.96 = 0.687$

The required energy output of PV array to provide the a.c. loads is:

1612 Wh/0.687 = 2346 Wh

The design month PSH is 4.6

Therefore, the required derated PV array output power needed is:

2346 Wh ÷ 4.6 PSH = 510 W

Allowing for an oversizing factor of 30%, the adjusted required derated array output is:

510 W × 1.3 = 663 W

Derated module output = 261.5 W (refer to Worked Example 23)

Note: for this example, ageing factor has not been taken into account since it is effectively covered by the 30% oversizing factor that allows for battery equalization and fast recharging in order to extend battery life.

The required number of modules is:

663 W/261.5 W= 2.54

This should be rounded up to three modules. However, in reality you could select a smaller module (e.g. 280 W_p), because the actual required array is 2.54 × 330 W_p = 838 W_p, and three modules of 280 W_p each will provide a total of 840 W_p capacity, which is adequate.

24 Selecting a PV Inverter – a.c. Coupled System

In addition to the requirements and recommendations listed in this section, inverters shall also comply with the requirements outlined in Component-based Off-Grid Solar Energy Systems – Quality Assurance Framework Overview, Section 3.7.

The final selection of the inverter for the installation will depend on:

- The power output of the array;
- Whether the system will have one inverter or multiple (smaller) inverters; and
- The matching of the allowable inverter string configurations (based on voltage and current) with the size of the array and the specifications of the individual modules within that array.

Note: It is very important the PV inverter and the battery inverter are matched. Correct matching requires the PV inverter and the battery inverter to be able to communicate with each other to ensure that the PV array output power is controlled, to avoid overcharging the battery bank.

Worked Example 30: Calculating size of array and number of modules based on required load energy (All loads having their power supplied directly from the PV Array)

Assume the loads are all a.c.

Assume the following system losses (efficiencies):

- cable loss from PV array to a.c. loads is 1% (efficiency of 99%)
- PV inverter efficiency is 97%. Daily a.c. load (energy) = 1612 Wh

System efficiency factor when providing a.c. loads = 0.99 × 0.97 = 0.96

The required energy output of PV array to provide a.c. loads = 1612/0.96 = 1679 Wh

The design month PSH is 4.6.

Therefore, the required derated PV array output power is:

1679 Wh / 4.6 PSH = 365 W

Allowing for an oversizing factor of 30%, the adjusted required derated array output is:

365 W × 1.3= 474.5 W

Derated module output = 261.5 W

The required number of modules = 474.5 W / 261.5 W = 1.81

This would be rounded up to 2 modules, but it would be an array of 1.81 × 330 W_p = 597 W_p that is required if all loads could be supplied power directly by the PV array.

Based on worked examples 29 and 30 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery bank (see Section 22.3), the required array is rated between 597 W_p (all loads supplied power directly by solar array) and 838 W_p (all loads supplied power from the battery bank).

It is important to consider what happens if the battery is fully depleted, since the PV inverter cannot supply a.c. power if the battery inverter is not operating (see Section 26.6). In normal operation, the battery inverter/charger should manage the battery state of charge to prevent the battery from reaching a state where it can no longer power the system. However, full depletion of the battery can still occur, for example if the PV inverter(s) are out of service for a prolonged period. The system design should include a plan for how to recover from this condition. Some PV inverters have an emergency charging mode in which the batteries can be charged from a generator, if one is present. Alternatively, some systems include a d.c.-coupled solar array and charge controller in addition to the a.c.-coupled solar array(s). The manual for the specific model of inverter should be consulted to determine what emergency charging functions are available.

24.1 How Many Inverters?

A small system will generally include only one inverter though a larger system may have multiple inverters. Reasons why multiple inverters may be used include:

1. The array is spread over a number of roofs that have different orientations and tilt angles. Modules in the same string must have the exact same orientation within ± 5° (azimuth and tilt). If there are paralleled strings connecting to the same maximum power point tracker (MPPT) input in an inverter, then those two strings must also have the same orientation within ± 5° (azimuth and tilt).

   A separate MPPT will be required for each section of the array which has a different orientation and tilt angle. This may be achieved by using an inverter that has multiple MPPTs or by using multiple inverters. Therefore, the section of the array connected to one MPPT could be on a separate roof (and different orientation) than another section of the array mounted on another roof if connected to a separate MPPT within the same inverter or to an MPPT in another inverter.

   If there are so many different sections of the array that have different orientations that it is impossible to connect them all with one inverter that has multiple MPPTs then separate inverters must be available to provide more MPPT controllers so a different controller is available for each section of the array which has a unique orientation and tilt angle.

   There are module inverters (also called micro inverters) and module MPPTs (also called optimisers). These independent inverters and MPPTs are mounted on each individual solar module (sometimes connecting to 2 modules) and available on the market which can also overcome the issue of arrays mounted with different orientations and tilt angles since each module has its own inverter and controller. So there are no strings, all modules have their own MPPT and inverter, and each module can have a different orientation.

2. Multiple inverters allow a portion of the system to continue to operate if one inverter fails.

3. Allows the system to consist of identical clusters connected together, so that increasing the system involves adding a predetermined number of modules with each cluster having one or more inverters and its own battery bank. The main advantage of using multiple clusters is that spare parts needed are the same for all clusters and tend to be relatively inexpensive so a large array can consist of a number of identical, small and simple independent arrays.

Also troubleshooting and training of operating and maintenance personnel are simplified because all clusters are identical and relatively simple. Finally, if one cluster has a failure, the rest can continue to operate though with the loss of the output from the failed cluster. Each cluster can also utilize a portion of the array that has its own unique orientation and can even be physically separate from other clusters.

The potential disadvantage of multiple inverters – either installed in a number of identical clusters or as a small one on each module – is that in general the initial cost of a number of inverters with lower power ratings is generally more expensive than one single inverter with a higher power rating. However, the advantages of higher system reliability, ease of operation and maintenance and less expensive spare parts requirements may be more valuable than a somewhat higher first cost.

24.2 Selecting the Size of PV Inverter

Inverters currently available are typically rated for:

- maximum d.c. input power;
- maximum specified output power;
- maximum d.c. input voltage;
- minimum d.c. MPPT input operating voltage; and
- maximum d.c. input current.

Note: Some inverter data sheets also specify maximum PV array power.

The array and the inverter must be matched so that no ratings are exceeded at any point.

The array power must be matched to the inverters stated maximum PV array power if stated by the manufacturer.

The number of modules in a string, and hence maximum and minimum voltages of the string, must be matched to the:

- maximum d.c. input voltage and
- minimum d.c. MPPT input operating voltage.

The number of parallel strings, and hence maximum d.c. currents, must be matched to not exceed the maximum input current of the MPPT that the strings are connected to.

24.3 Matching Array Power to the Inverter

The maximum power of the array is calculated by the following formula:

Array Peak Power = Number of modules in the array × the rated maximum power (P_{mod}) of the selected module at STC

Note: P_{mod} is also described as the peak power of the module. The unit is watt-peak (W_p).

If the inverter data sheet does specify the maximum array power, then the designer shall not design an array with its rated power greater than the specified maximum array power.

If the inverter data sheet only specifies the maximum d.c. power input to the inverter the designer should attempt to contact the manufacturer and determine if there is a maximum allowed PV array power rating.

The array's output power at the inverter will be less than the rated maximum power of the array due to the effects of temperature, dirt, manufacturer's tolerances, and the voltage drop between the array and the inverter. However, if there is no specified maximum array power for the inverter input, the designer shall not design an array with a rated output greater than the inverters rated d.c. input power unless the designer has obtained permission from the manufacturer and is assured that all warranties will be honoured.

Worked Example 31: Selecting inverter to suit array power

The example being used so far only requires an array consisting of three (3) modules each with a peak rating of 330 W_p.

Array Peak Power = 3 × 330 W_p = 990 W_p

It would be difficult getting an inverter this small that would have a voltage window suitable for only 3 modules in series. Unless individual module inverters are used, the module wattage would probably need to be reduced. That will require more modules in the string to meet both the load requirements and to meet the operating voltage requirement of the inverter.

So, if we match the PV array and inverter, we will assume the array has to have six 330W_p modules in series in order to meet the input voltage window of the inverter. Six 330 W_p modules in series will have a peak power rating of 1980 W_p, double the power required to meet the load. If 165 W_p modules of the same voltage as the proposed 330 W_p modules are available, six of those in series would provide the required input voltage and would also provide the required 990 W_p to service the load at a lower cost.

Worked Example 32: Matching array power to inverter power specifications

The inverter data sheet provides the following information:

Max d.c. Power	2000 W
Max. input voltage	600 V
MPP voltage range	160 V to 500 V
Max. input current	10 A

The array in the example is (6 × 330 W_p) 1980 W_p so it meets the requirements for power. So does the (6 × 165 W_p) 990 W_p and this option meets the output requirement for the load.

24.4 Matching Array Voltage to Inverter

The number of modules in a string, and hence the maximum and minimum voltages of the string, must be matched to the:

- maximum d.c. input voltage; and
- minimum d.c. MPPT input operating voltage.

The output power of a solar module is affected by the temperature of the solar cells. As shown in previous sections for polycrystalline and monocrystalline PV modules this effect can be as much as 0.5% for every 1-degree variation in temperature.

This variation in power due to temperature is also reflected as a variation in the open circuit voltage and maximum power point voltage. Array I_{sc} is little affected by array temperature.

With few exceptions, high quality grid interactive inverters include MPPT.

The inverter manufacturer should specify the following voltages on the data sheet:

- Minimum input voltage for the inverter;
- Minimum MPPT input operating voltage;
- Maximum MPPT input operating voltage; and
- Maximum input voltage for the inverter.

The MPPT units in the inverter will only track the maximum power point voltage of the array when the arrays MPP voltage is between the inverter's specified MPP minimum operating voltage and maximum MPP operating voltage, that is, the voltage input is within the operating window of the MPPT. If the solar array voltage is outside this window the MPPT does not track the MPP voltage of the array and the output power of the system may be greatly reduced.

The minimum voltage is the voltage where the inverter will turn off at the end of the day or cloudy weather. Between the minimum operating voltage of the MPPT and this voltage the MPPT does not necessarily track the maximum power point voltage. So it is important that the MPP voltage of the array is always greater than the minimum operating voltage of the MPPT of the inverter when there is enough sunlight to provide useful power.

The maximum voltage of the inverter is the point where any voltage above that specified may damage the inverter.

For the best performance of the system, the output voltage of the solar array should be matched to the operating voltages of the inverter. To minimise the risk of damage to the inverter the maximum voltage of the inverter shall never be reached.

As stated earlier the output voltage of a module is affected by cell temperature with changes in a similar manner as the output power. The PV module manufacturers will provide a voltage temperature coefficient. It can be specified in V/°C (or mV/°C), but it is now generally specified in %/°C. It is often given as a negative value; the voltage decreases as the temperature increases.

Therefore, relative to the nameplate ratings, the PV module voltage will decrease when the temperature is above the STC temperature of 25°C and increase when the temperature is below 25°C.

In practice the array should be designed such that:

- At the maximum temperature expected during the day the array's MPP voltage is always greater than the inverter minimum MPPT operating voltage.
- At the coldest temperature of the day (in most countries near the equator, this will be at sunrise) the open circuit voltage of the array must be less than the maximum input voltage specified for the inverter.

The design should also ensure that the array's MPP voltage at the coldest temperature is less than the inverters MPPT maximum operating voltage, but this is not critical since this means that the MPPT will not track properly above that voltage and no damage to the inverter should occur. The critical issue is that the open circuit voltage at the coldest temperature is never above the maximum input voltage. If this requirement is met and the arrays MPP voltage at the coldest temperature is above the inverters MPPT maximum operating voltage, then the MPPT will connect to the array at the inverters MPPT maximum operating voltage. This sequence will only happen first thing in the early morning when the power output is small. As the temperature increases due to increasing solar input, the array's MPP voltage will decrease and will reduce sufficiently to enter the MPPT voltage window, and the maximum power point will be properly tracked for maximum output from the unit.

In order to design systems where the output voltages of the array do not fall outside the range of the inverter's d.c. operating voltages and its maximum input voltage, the minimum and maximum day time temperatures for that specific site are required. These should be the record high and record low temperatures for the site as recorded by the meteorology office to minimize the chance that the inverters will be damaged due to the input voltage exceeding the maximum voltage allowed for that inverter.

The following sections detail how to determine the minimum and maximum number of solar modules allowed to be connected in series to match the operating voltage window of an inverter. Many of the inverter manufacturers have software programs that can be downloaded for doing this matching.

24.4.1 Minimum Number of Modules in a String

When the temperature is at a maximum then the maximum power point (MPP) voltage (V_{mp}) of the array should never fall below the minimum operating voltage of the MPPT of the inverter. The actual voltage at the input of the inverter is not just the V_{mp} of the array, the voltage drop in the d.c. cabling must also be included when determining the actual inverter input voltage.

Since the daytime ambient temperature in some areas of the ECOWAS countries can reach or exceed 35°C, it is recommended that maximum effective cell temperature of 75°C is used.

(Note: if this seems high, Germany specifies 70°C to use for the cell temperature and on average their summer temperatures are less than 35°C.

24.4.1.1 Determine Minimum MPP Voltage (V_{mp}) of a Module at the Inverter

The minimum V_{mp} of a module is determined by calculating the reduction in V_{mp} due to the effective maximum cell temperature.

The reduction in V_{mp} is calculated by multiplying the voltage temperature coefficient (V/°C) by the difference between the effective cell temperature and the STC temperature (25°C).

Since the maximum temperature to use has been specified as 75°C then the difference between the maximum cell temperature and the STC temperature will be 75°C - 25°C = 50°C. So, a reduction in V_{mp} is 50°C times the voltage temperature coefficient (V/°C). (**Note**: It is a reduction because the temperature coefficient has a negative value)

The effective V_{mp} out of the module due to the maximum temperature = V_{mp} less the calculated reduction in V_{mp}.

This value is then reduced by the voltage drop in the cabling. Since voltage drop is typically expressed as percentage (%) value then the reduction factor due to voltage drop is equal to (1 - %voltage drop).

Therefore, the effective minimum MPP voltage input at the inverter for each module in the array is:

The effective V_{mp} out of the module at the maximum temperature × (1 - %voltage drop)

Many module manufacturers do not supply the voltage coefficient for V_{mp}. It is supplied only for V_{OC} (the open circuit voltage). If the V_{mp} temperature coefficient is not available, then either

- V_{oc} temperature coefficient can be used;

or

- P_{mp} temperature coefficient applied to the V_{mp} voltage can be used for determining the V_{mp} temperature coefficient.

The P_{mp} temperature coefficient can be used because the current (amperes) temperature coefficient is negligible, so the V_{mp} temperature coefficient is very similar to the P_{mp} temperature coefficient.

Worked Example 33: Calculating V_{mp} of module at the inverter for specified highest expected cell temperature

A module data sheet provides the following information:

P_{mp} = 330 W

V_{oc} = 46.2 V

V_{mp} = 37.8 V

I_{sc}= 9.27 A

I_{mp} = 8.73 A

Power Temperature coefficient	= - 0.39%/°C
V_{oc} temperature coefficient	= -0.29% /°C
Manufacturer's Tolerance	=0 to +5%
Test Tolerance	= ±3%

Therefore, in V/°C the V_{oc} temperature coefficient = -0.29/(100 per °C) × 46.2 V = -0.134 V/°C

Applying the power temperature coefficient then the V_{mp} temperature coefficient is -0.39/100°C × 37.8 V = -0.147 V/°C. This will be used in the rest of the example.

Based on the maximum temperature of 75°C then the reduction in V_{mp} due to temperature (takes the negative value into account)

= 50ºC times the voltage temperature coefficient (V/°C).

= 50ºC × 0.147 V/°C

= 7.35 V

So the effective V_{mp} of the module due to temperature = 37.8 V - 7.35 V = 30.45 V

If we assume a maximum voltage drop in the cables of 1% then the voltage at the inverter for each module would be

0.99 × 30.45 V = 30.14 V

This is the effective minimum MPP voltage input at the inverter for each module in the array.

24.4.1.2 Determine the Effective Minimum MPPT Operating Voltage of the Inverter

The inverter data sheet specifies the actual minimum MPPT operating voltage.

However, The MPP voltage of a solar module rises with an increase in irradiance. Since the array is typically operating with irradiance levels less than 1 kW/m² (the STC value), when the effective cell temperature is high then the actual MPP voltage will be reduced relative to the STC value. The exact variation is dependent on the quality of the solar cell, so it is recommended that a safety margin of 10% is added to the minimum MPPT operating voltage.

Note: This is just a recommendation and there will be times when it might not be practical. However, be aware that if it is not applied then the system might underperform if the effective cell temperature does approach 75°C.

Worked Example 34: Calculating minimum input Voltage of Inverters MPPT

The inverter data sheet provides the following information:

Max d.c. Power	2000 W
Max. input voltage	600 V
MPP voltage range	160 V to 500 V
Max. input current	10 A

The minimum operating voltage of the MPPT is 160 V

Allowing for the recommended safety margin of 10%, the effective minimum operating voltage of the MPPT = 1.1 × 160 V = 176 V

24.4.1.3 Determine Minimum Number of Modules in the string

The minimum number of modules in a string is determined by dividing the effective minimum operating voltage of the MPPT by the effective minimum MPP voltage input at the inverter for each module.

Since it is the minimum number, it should always be rounded up.

Worked Example 35: Calculating minimum number of modules in a string

The effective minimum operating voltage of the MPPT = 176 V

The effective minimum MPP voltage input at the inverter for each module = 30.14 V

Therefore, the minimum number of modules in a string = 176 V/30.14 V = 5.8

This would be rounded up to 6.

24.4.2 Maximum Number of Modules in a String

At the coldest daytime temperature, the open circuit voltage of the array shall never be greater than the maximum allowed input voltage for the inverter. The open circuit voltage (Voc) is used because this is greater than the MPP voltage and it is the voltage applied at sunrise when the system detects the sun and begins its start-up sequence – that will be prior to the inverter starting to operate and connecting to the a.c. bus that connects to the a.c. loads.

In early morning, at first light, the cell temperature will be very close to the ambient temperature because the sun has not had time to heat up the module. Therefore, the lowest dawn temperature for the area where the system is installed shall be used to determine the maximum Voc.

In some areas, the minimum dawn ambient temperature can reach 0°C or lower. You should use the figure for your site, for the examples in this guideline 15°C is used.

24.4.2.1 Determine Maximum Open Circuit Voltage (V_{OC}) of a Module at the Inverter

The maximum V_{OC} of a module is determined by calculating the increase in V_{OC} due to the minimum daytime cell temperature.

The increase in V_{OC} is calculated by multiplying the voltage temperature coefficient (V/°C) by the difference between the effective cell temperature and the STC temperature (25°C).

Using 15°C as the minimum temperature, then the increase in V_{mp} is (15°C - 25°C) = -10°C times the voltage temperature coefficient (V/°C). (Note it is an increase because the coefficient is a negative number and the difference in temperatures is also a negative number, so the two multiplied becomes a positive number. Keep in mind that lower temperatures result in higher voltages.)

The effective V_{OC} of the module due to the minimum temperature = V_{OC} plus the increase in V_{OC}.

There is no voltage drop because the V_{OC} is being applied at first light before the inverter has turned on and hence no current is flowing.

This is the effective maximum open circuit voltage input at the inverter for one module.

Worked Example 36: Calculating Maximum V_{oc} of module based on minimum effective cell temperature

Assuming the minimum effective cell temperature is 15°C, the module data sheet provides the following information:

V_{oc} = 46.2 V

V_{oc} temperature coefficient = 0.29%/°C

Therefore, in V/°C the V_{oc} temperature coefficient = 0.29/100 per °C × 46.2 V = 0.134 V/°C

Based on the minimum temperature of 15°C, the increase in V_{oc} due to temperature = 10°C times the voltage temperature coefficient (V/°C)

= 10°C × 0.134 V/°C

= 1.34 V

So the effective V_{oc} of the module due to temperature = 46.2 V + 1.34 V= 47.54 V

This is the effective maximum open circuit voltage input at the inverter for each module in the array.

24.4.2.2 Determine Maximum Operating Voltage of the Inverter

The inverter data sheet specifies the actual maximum operating voltage.

Worked Example 37: Determining maximum operating voltage of inverter

The inverter data sheet provides the following information:

Max. input voltage	600 V

24.4.2.3 Determine Maximum Number of Modules in the string

The maximum number of modules in a string is determined by dividing the maximum operating voltage of the inverter by the effective maximum open circuit voltage input at the inverter for one module. Since it is the maximum number, it should always be rounded down.

Worked Example 38: Calculating maximum number of modules in the string

The maximum voltage of the inverter = 600 V

The effective maximum V_{oc} input at the inverter for each module = 47.54 V

Therefore, the maximum number of modules in a string = 600 V/47.54 V = 12.62

This would be rounded down to 12.

In the worked example the inverter will allow between 6 and 12 modules in a string and still stay within the maximum and minimum voltage ratings of the inverter.

24.4.2.4 How Many Strings?

Depending on how many modules have been selected to meet the end-user's requirements, the array could include one string or could include multiple strings. The final configuration is determined by matching the output currents of the array to the maximum input current of the inverter.

Worked Example 39: Calculating how many strings connected to the inverter

When determining the array power and matching it to the inverter an array of 6 modules has been selected. So, these could either be installed as one string of 6 modules or two strings of 3 modules, 3 strings of 2 modules or 6 strings of 1 module.

In worked example 35 the minimum number of modules in a string is 6. So, this determines the configuration, that one string of 6 modules.

24.5 Matching Array Current to the Inverter

Inverters have a maximum input current. However, since many inverters now have multiple MPPTs and can have multiple connections (often module connector sockets) for the PV array d.c. wiring to the inverter, these also have a maximum current specified. The final configuration of the array shall ensure that no string or array connection has an output current greater than that specified for the inverter.

Worked Example 40: Matching maximum array current to the maximum input current of inverter

The inverter data sheet provides the following information: Max. input current = 10 A

The module data sheet provides the following information:

I_{sc}= 9.27 A

I_{mp} = 8.73 A

So, one string is suitable.

It should be noted that most standards, including IEC 60364-7-712 and the National Electrical Code used in the United States, require a safety factor of 1.25 to be applied to the STC short-circuit current when calculating overcurrent protection for PV conductors, but this safety factor has not been consistently applied to the inverter itself. The 2021 update to the Australia/New Zealand standard for photovoltaic installations, AS/NZS 5033, applied this requirement to the inverter input terminals. Inverter manufacturers have responded to this change in different ways:

- Most manufacturers have either revised their datasheets with increased maximum I_{sc} ratings that include the factor of 1.25 or have stated that this factor is already included.
- Others have retained the existing datasheet ratings but stated that higher values may be used when a 1.25 safety factor is required.

If a safety factor of 1.25 is to be included, the inverter specified in Example 40 above would not be acceptable, because the maximum short-circuit current including the safety factor is 1.25 × 9.27 A or 11.6 A, which exceeds the inverter rating of 10 A.

The following recommendations should be followed related to this safety factor:

- A safety factor of 1.25 should be included in the maximum PV I_{sc} calculation when required by applicable codes or regulations.
- Designers should use the most recent version of the datasheet or manual for the specific inverter model under consideration; datasheets obtained from distributors or other third parties can be outdated.
- Since manufacturers sometimes release updated models with similar names, or produce different versions of products for different countries or regions, make sure that the documentation used for system design pertains to the correct product.
- If it is unclear whether a factor of 1.25 is included in the manufacturer's current ratings, contact the manufacturer for clarification, or check the manufacturer's website for country-specific application notes or example calculations.

PART 4 – HYBRID POWER SYSTEMS

25 Hybrid System Configurations

How the fuelled generator interconnects within the hybrid system depends on the type of inverter, the load characteristics and the size of the system. Figure 7 to Figure 10 show some configurations for PV/fuelled generator hybrid systems.

FIGURE 7: FUELLED GENERATOR CONNECTED TO BOTH THE BATTERY (VIA A BATTERY CHARGER) AND THE A.C. LOAD (VIA A CHANGEOVER SWITCH)

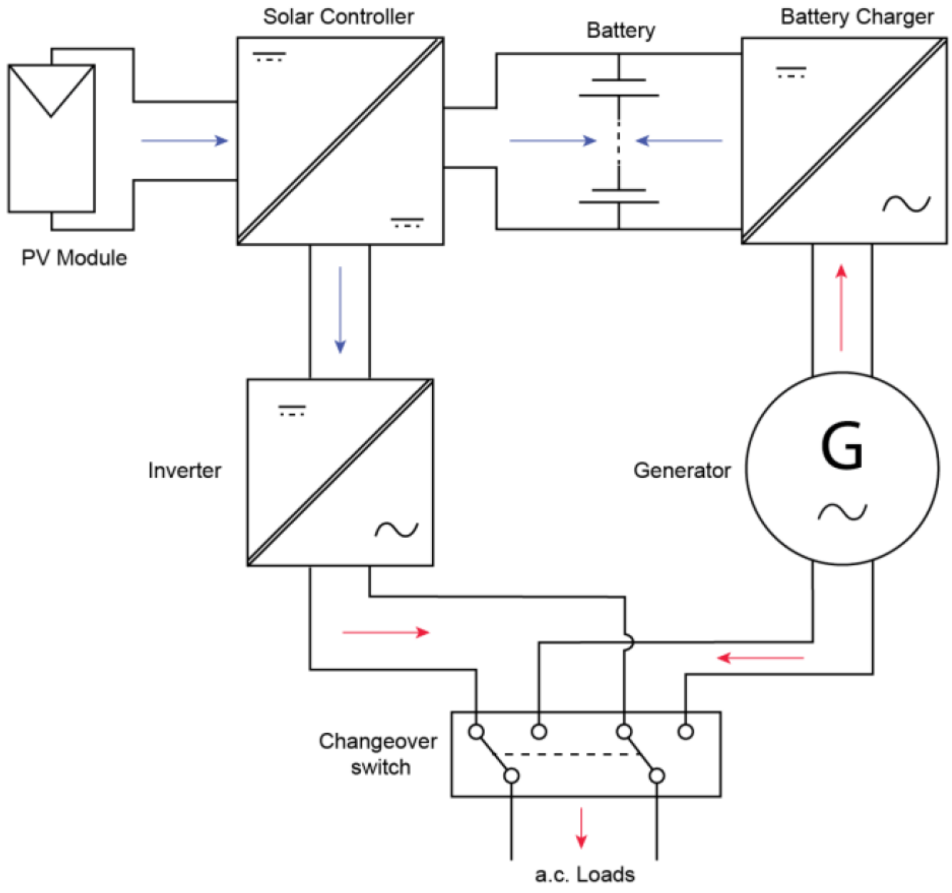


FIGURE 8: FUELLED GENERATOR CONNECTED TO AN INVERTER/CHARGER OR AN INTERACTIVE D.C. INVERTER CONNECTING TO A D.C.-COUPLED SYSTEM

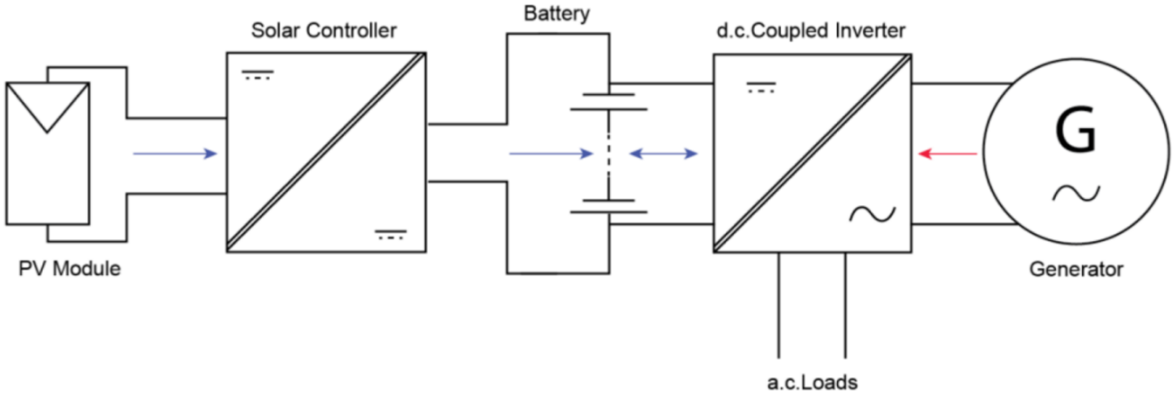


FIGURE 9: GENERATOR CONNECTED TO AN A.C.-COUPLED INVERTER CONNECTING TO AN A.C.-COUPLED SYSTEM

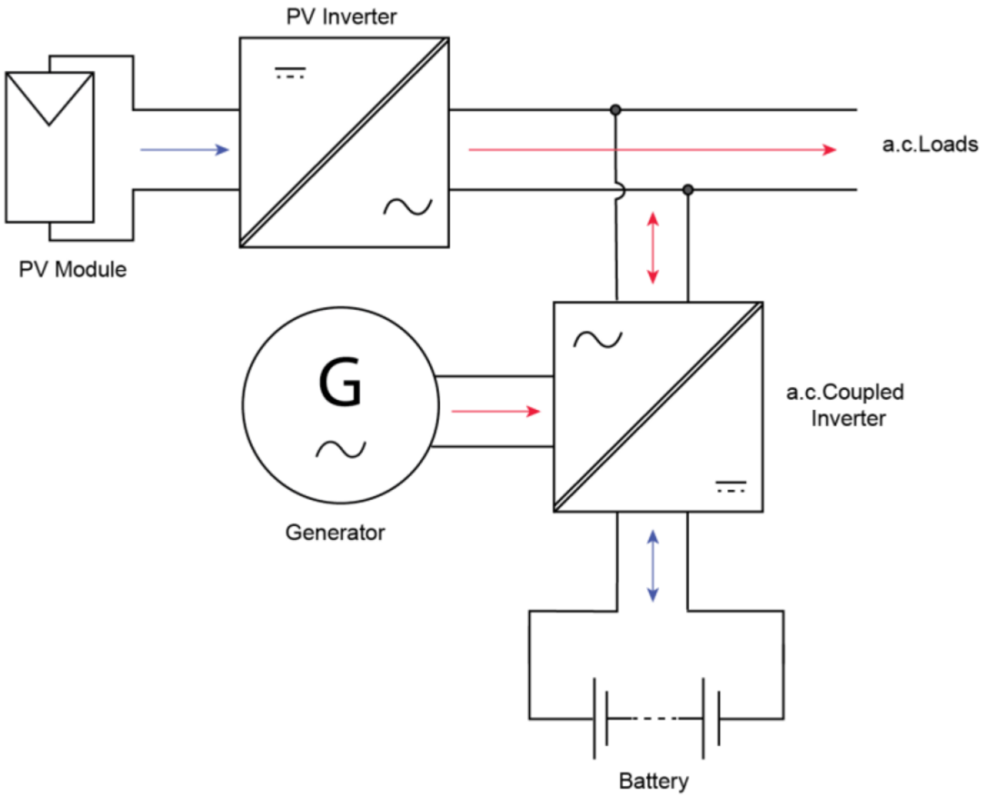
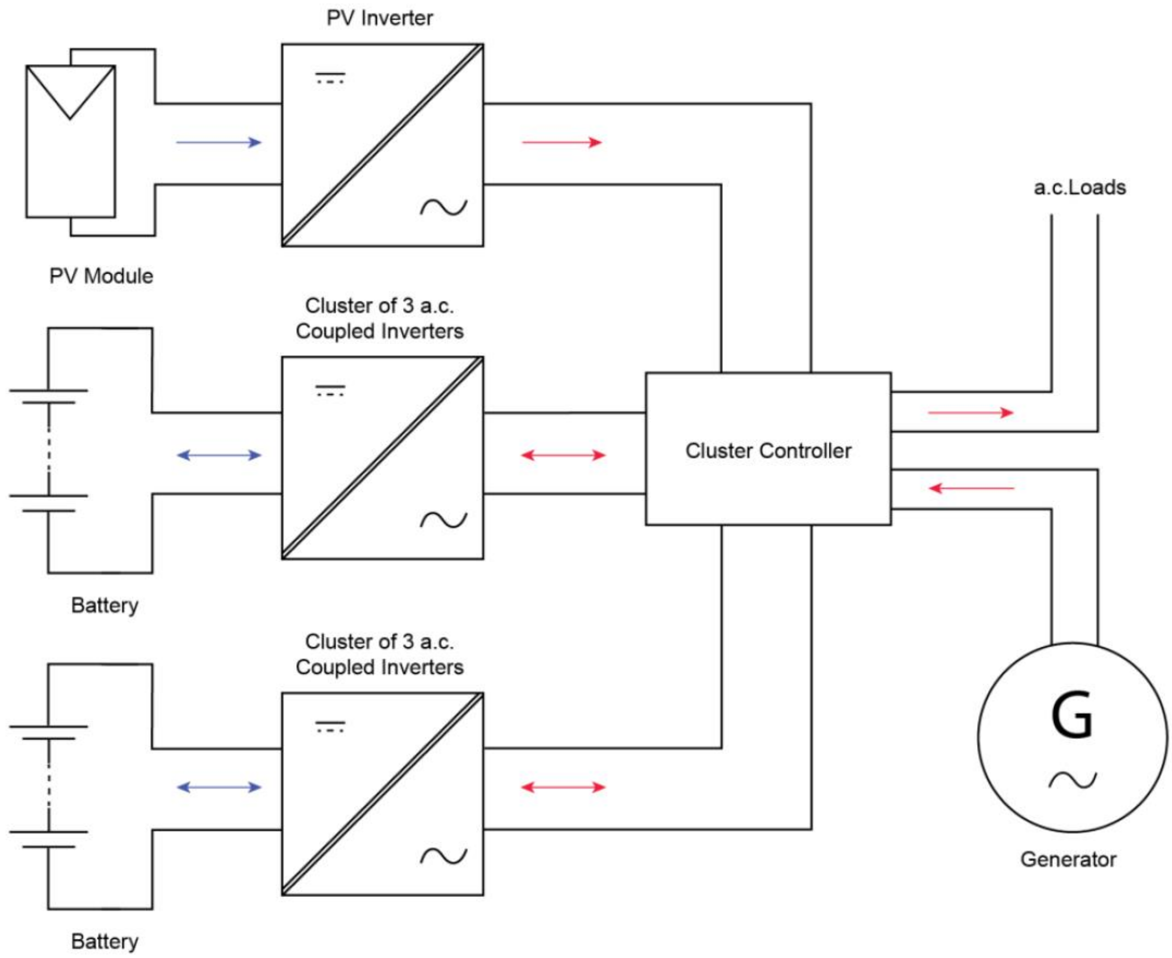


FIGURE 10: A.C.-COUPLED SYSTEM WITH MULTIPLE INVERTERS CONNECTED TO A CLUSTER CONTROLLER WITH THE GENERATOR CONNECTED TO IT



Certain models of a.c.-coupled interactive inverters require a cluster controller or cluster box for interconnecting the multiple a.c. generating devices. These are generally required when there are numerous clusters of a.c.-coupled inverters in parallel. Each cluster comprises three single phase inverters providing 3-phase power.

The cluster controller (or box) is provided by the manufacturer of the a.c.-coupled inverter and the installer shall follow the installation requirements of the manufacturer. Note that Figure 10 shows the PV inverter connected to the cluster controller. The PV inverter can also be connected directly onto the a.c. load line and the PV system does not need to be located in the same location as the rest of the system (battery, a.c.-coupled inverters, cluster control and generator).

All the configurations shown above can potentially be used for hybrid systems where the generator is either used as a back-up or is being used daily. However, where the generator is being used daily, it is very unlikely to use the hybrid system shown in Figure 7 that has a separate battery charger.

26 Types of Inverters

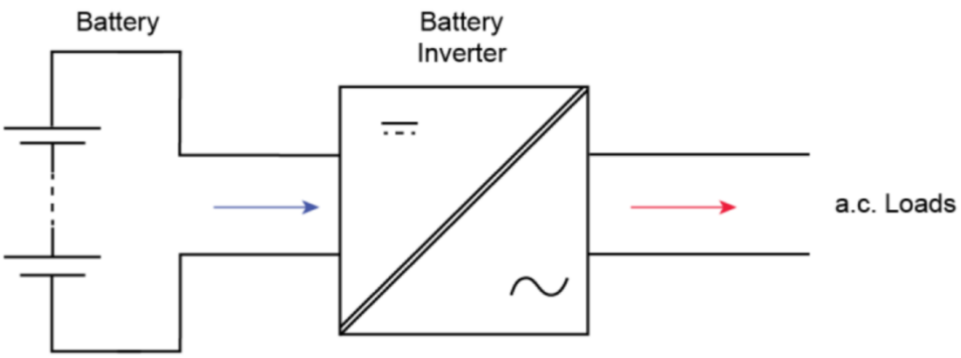
Within a hybrid system, there are 5 different types of inverters that could be used. These include:

1. Basic Battery Inverter
2. Inverter/Charger
3. PV Inverter
4. d.c.-Coupled Inverter
5. a.c.-Coupled Inverter

26.1 Basic Battery Inverter

The battery inverter as shown in Figure 11 converts the d.c. power from the battery to provide a.c. power to the loads. Some manufacturers allow these inverters to parallel with a similar model inverter, but one will have to be the leader to ensure they are synchronised. Theses inverters cannot parallel to any other a.c. source like a generator. If used in a hybrid system, they would require a separate battery charger as shown in Figure 7. The PV array that is part of the hybrid system will be connected to the battery bank via a solar controller.

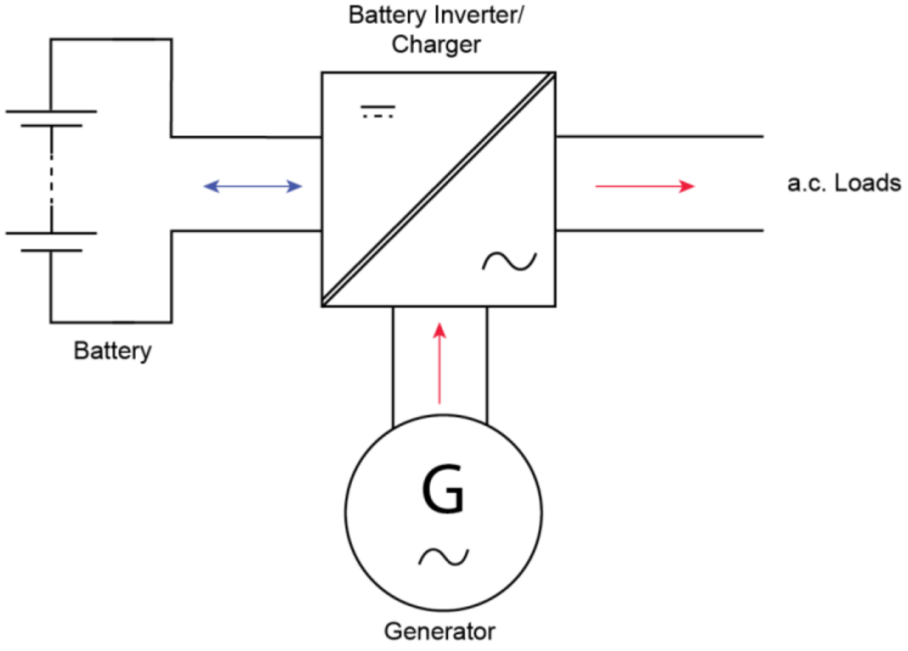
FIGURE 11: BASIC BATTERY INVERTER APPLICATION



26.2 Inverter/Charger

The inverter/chargers as shown in Figure 12 do not parallel with the generator. They are either in inverter mode or charger mode. When the generator is not operating, the inverter will convert the d.c. power from the battery to provide a.c. power to the loads. When the generator starts, the inverter will switch the generator a.c. power to the loads, and the inverter will operate in charging mode converting the generator's a.c. power to d.c. power and charge the battery. The PV array that is part of the hybrid system will be connected to the battery bank via a solar controller.

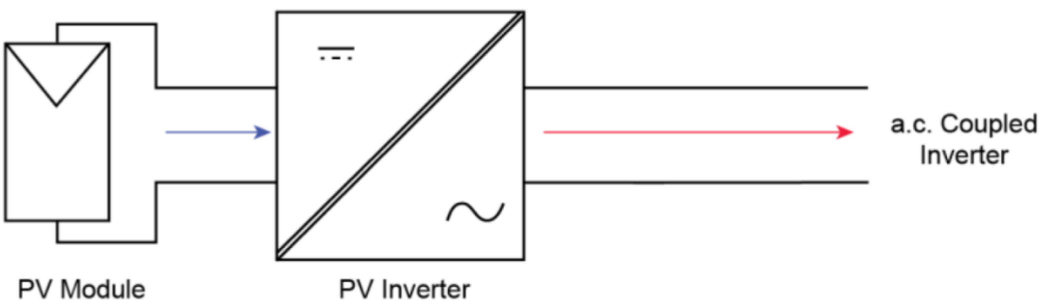
FIGURE 12: INVERTER/CHARGER APPLICATION



26.3 PV Inverter

The PV inverter shown in Figure 13 converts the d.c. power from the PV array to provide a.c. power to the a.c. bus. However, there must already be a.c. power on the a.c. bus from another source (generator or a.c.-coupled inverter) for the PV inverter to operate.

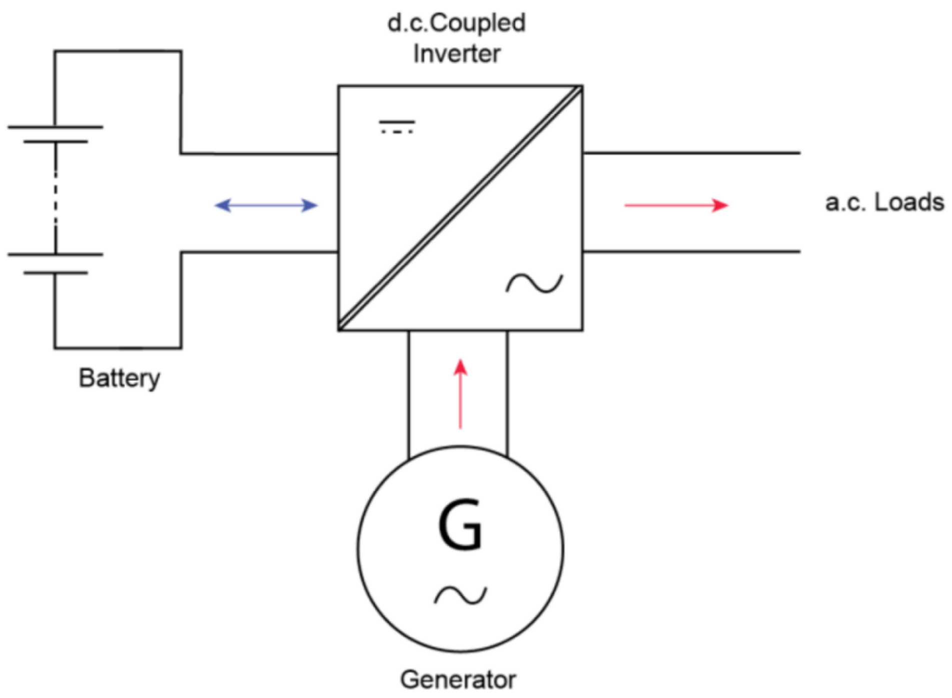
FIGURE 13: PV INVERTER APPLICATION



26.4 d.c.-Coupled Inverter

When the generator is not operating, the d.c.-coupled inverter as shown in Figure 14 will convert the d.c. power from the battery to provide a.c. power to the loads. When the generator starts, the inverter will synchronise with the generator so that the a.c. loads can be supplied by the generator and inverter in parallel. If there is excess generator power compared to the load, the d.c.-coupled inverter will convert to a battery charger and charge the battery bank from the generator while the generator continues to provide a.c. power to the loads. The d.c.-coupled inverter will only parallel with the generator connecting to the inverter. There can be no other sources of a.c. power on the a.c. load line from the inverter. The PV array that is part of the hybrid system will be connected to the battery bank via a solar controller.

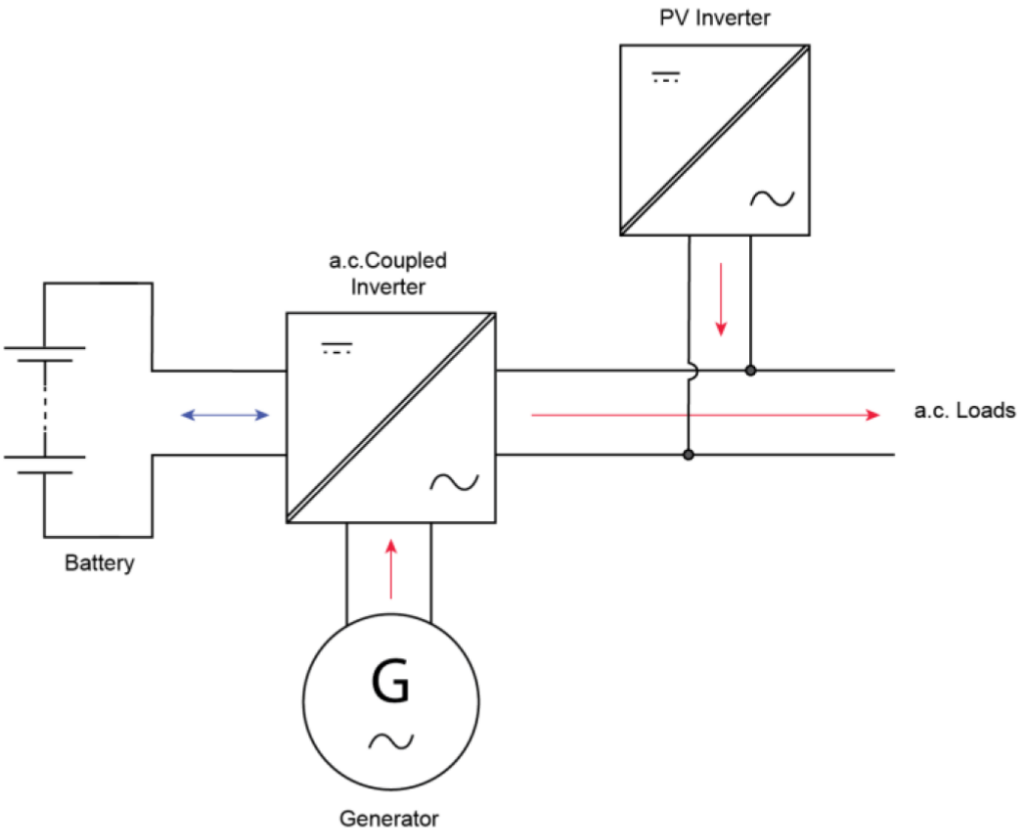
FIGURE 14: D.C.-COUPLED INVERTER APPLICATION



26.5 a.c.-Coupled Inverter

When the generator is not operating, the a.c.-coupled inverter as shown in Figure 15 will convert the d.c. power from the battery to provide a.c. power to the loads. When the generator starts the inverter will synchronise with the generator so that the a.c. loads can be supplied by the generator and inverter in parallel. If there is excess generator power compared to the load, the a.c.-coupled inverter will convert to a battery charger and charge the battery bank from the generator while the generator continues to provide a.c. power to the loads. The a.c.-coupled inverter will allow PV inverters to be connected to the a.c. bus. The a.c.-coupled inverter and PV inverters must be compatible and be able to communicate with each other. If there is excess a.c. power from the PV array (and PV inverter) compared to the load, the a.c.-coupled inverter will convert to a battery charger and charge the battery bank from the PV array via the PV inverter.

FIGURE 15: A.C.-COUPLED INVERTER APPLICATION

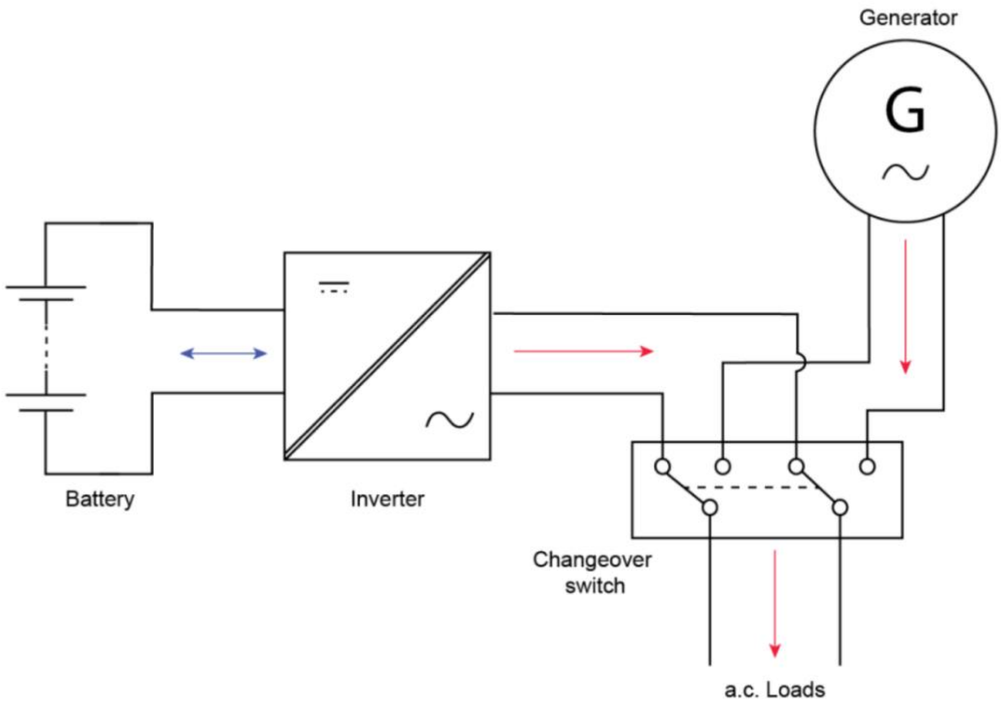


26.6 Hybrid Systems

In a hybrid system the a.c. power is supplied and controlled by the battery inverter. Sometimes it can be called a "grid-forming" inverter. That is, the inverter takes the d.c. power from the battery and creates the a.c. power at the required single or three-phase voltage and frequency. For example, this could be 230 V single phase at 50 Hz and 400 V three-phase at 50 Hz (though the voltages and frequencies will differ based on equipment and location and should ideally match the voltage and frequency used locally).

Not all inverters are designed to connect in parallel with other generating sources. The typical inverter (refer to Figure 11) and inverter/charger (refer to Figure 12) fall into this category in that they cannot parallel with the fuelled generator and for this reason the load shall be connected by a changeover contactor as shown in Figure 16. For the inverter/charger shown in Figure 12, the changeover switch is internal to the inverter/charger. However, some of this type of inverter and inverter/charger are able to parallel with each other up to a specified number, typically 3 or 4. In these systems one inverter will take the lead (leader) while the others will follow (followers). That is, the leader creates the 50 Hz waveform and then followers will then synchronise with the leader.

FIGURE 16: SIMPLE CHANGEOVER CONTACTOR



The inverter/charger in Figure 12 will have an a.c. input terminal for a generator (or possibly the grid) to connect. When there is a.c. power at these terminals the inverter will revert to acting as a battery charger and an internal changeover switch will connect the loads to the generator. Different brands of inverters and inverter/chargers will not parallel with each other and even with the same brand, some models will not operate properly in parallel and must be connected through a separate device that properly combines their individual outputs.

The d.c.-coupled (Figure 14) and a.c.-coupled (Figure 15) inverters are able to parallel with other generating sources, but again typically only one or two sources, except possibly in large systems in the hundreds of kW. When operating alone, the inverter does take the lead, forming the grid at the appropriate voltage and frequency; however when the generator starts, the inverter will then synchronise with the generator and the generator becomes the lead with respect to the voltage and the input to the grid. According to its design, the interactive inverter may then continue supplying the loads in parallel with the generator or it may revert to acting only as a battery charger.

For the d.c.-coupled and a.c.-coupled inverters, different brands will not work in parallel because each one wants to be the lead and there will be communication issues. There is also a maximum number that can be connected in parallel. The manufacturer will specify that. When they are in parallel, one inverter will be the "leader" and the others ("followers") will synchronise with the leader inverter.

The PV inverter, often called the grid-connect or grid-tie inverter, will only generate a.c. power when there is already a.c. power on their output terminal supplied by another source. In grid-connect systems this is the grid power. In hybrid systems it is an a.c.-coupled inverter. Having the PV inverter require an a.c. source is due to a safety issue: when the grid is not available the PV inverter must turn off to avoid powering the grid when it has been shut down for maintenance or due to a fault.

The a.c.-coupled inverter is different from the d.c.-coupled inverter because it will provide a source of a.c. power, even when it is operating in battery charging mode, when there is no grid power present from another source.

The PV inverter (current source inverter) converts the d.c. power from the PV array to a.c. power but it does this by synchronizing with an external a.c. source. It is not able to form the a.c. power (voltage and frequency) like the inverters (voltage source inverters) that are connected to batteries.

The grid PV inverters are able to parallel with other PV inverters because they are following an a.c. grid. Technically this is the same for hybrid systems. However, because the a.c. inverter and PV inverter need to communicate with each other when charging the battery, the designer shall ensure that the two items are matched and compatible when designing a system.

The hybrid systems designer must:

- Ensure they select the correct type of inverter(s) for the application;
- Not parallel more inverters than approved by the manufacturer;
- Not connect different brands of inverter in parallel in the same installation; and
- Ensure that the PV inverter and the a.c.-coupled inverter are compatible.

27 Site Visit- Hybrid Systems

Prior to designing any hybrid system, the designer should visit the site and conduct the steps as outlined in Section 4. The primary steps to conduct during a site visit were covered in detail in Part 1 (Sections 4, 5, 6, 7, 12, and 13) and are not repeated for this part of the guideline. However, some additional information regarding conducting a load assessment at a site that already has a generator or grid energy is provided in Section 28.

28 Load Assessment

In a hybrid system electrical power is either supplied from a d.c. source such as batteries or PV modules via an inverter, or the fuelled generator is used to produce 230 volts (single-phase) or 400 volts (three phase) at 50 Hz a.c. (or the nominal a.c. voltage and frequency appropriate for the location). During the day the electrical power may be entirely from the PV modules through a PV inverter (grid connect type inverter); however, the “grid waveform” required for the PV inverter to operate will be formed by the a.c.-coupled inverter (battery inverter) connected to the batteries. The battery inverter will deliver energy to the load using the battery as a source when there is insufficient solar output to meet the load requirements. When there is insufficient sun and insufficient battery charge to meet the load requirements, the fuelled generator will provide sufficient power to meet the full load requirement. Electrical energy usage is normally expressed in watt-hours (Wh) or kilowatt hours (kWh).

Part 1, Section 7 details how to complete a load assessment form through discussions with the client. This method is still appropriate for smaller systems where the fuelled generator is being used as a back-up or when power comes primarily from the fuelled generator during the months with the lowest solar irradiation.

Where the daily energy usage is in the 10s or 100s of kWh range, e.g., village mini-grid, hotel/resort, or commercial business, developing a load assessment form to detail all the loads may be impractical. As a minimum, the designer does need to obtain the average daily energy usage for workdays and for weekends and for all months of the year. For some cases, the client might already have detailed information on the energy usage, but in any case, when designing a system for sites with large daily energy usage it is recommended that the designer obtain the typical hourly energy usage as well as the variations in average daily energy usage for the various months of the year.

For facilities already electrified by a fuelled generator or the utility grid, the daily energy profile can be obtained by using a data logger that logs kWh, energy used each hour, or kW power demand observed at hourly intervals. This should be installed for as long as possible but should be a minimum of one week unless the cost of data logging is overly prohibitive, and the daily loads are expected to be very consistent. Ideally it should be installed for different times of the year if it is known that the energy usage varies seasonally. If this is not possible then the designer will need to discuss with the client how the energy profile differs during other times of the year relative to the information obtained from the data logger.

The data logger should be installed at the main switchboard of the existing generator/grid connection covering the loads that will be powered to record the following information:

- Voltage per phase (V)
- Load current per phase (A)
- Power factor per phase
- Real power (kW)
- Apparent power (kVA)
- Energy over a stated period of time (kWh)
- Maximum demand (kVA)
- Time
- Date

A load profile generated from monitored data for a real site is shown in Figure 17. This diagram shows the average instantaneous power being consumed by the loads for a typical week. The figure shows that for this site there is no fixed daily pattern. The only regular feature is that the peak demand is about 6 pm each day, although other peaks do show up on most days. This profile helps to select the size of the inverter and the hours when the fuelled generator should operate.

To design the capacity of the battery bank, the daily total load in kWh is required. This may be monitored directly or calculated from the instantaneous power.

Figure 18 shows the cumulative energy in kWh for each day for the site. The data is reset to zero every night at midnight. This is the same week as shown in Figure 17 and it can be seen that the average daily energy usage is between 200 kWh and approximately 240 kWh.

FIGURE 17: INSTANTANEOUS POWER FOR A DATA LOGGED SITE

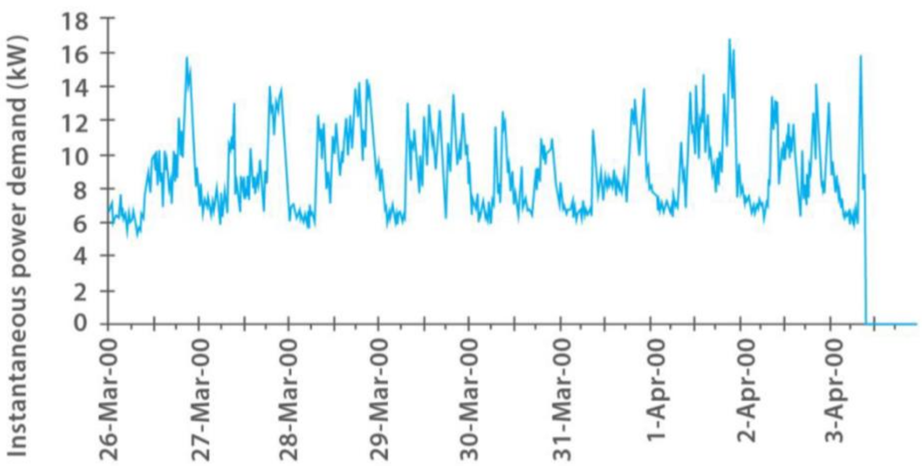
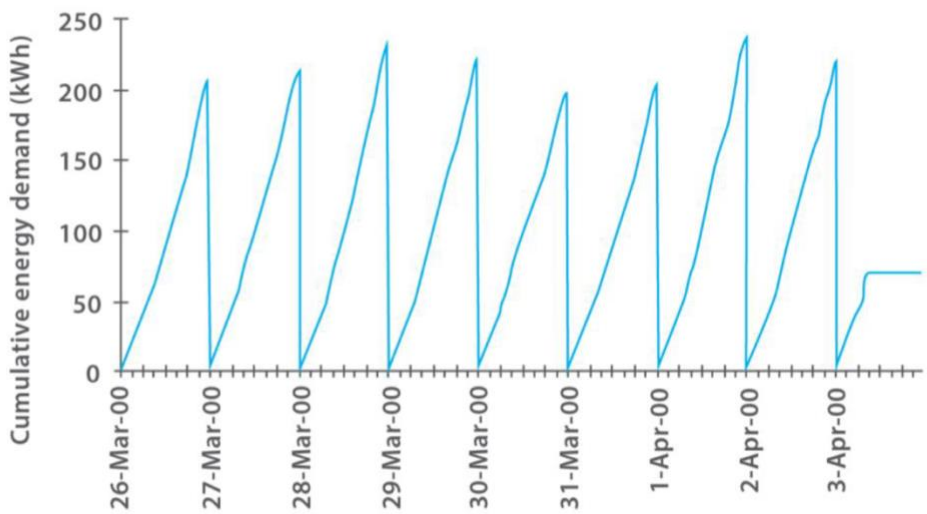


FIGURE 18: CUMULATIVE ENERGY FOR THE DATA LOGGED SITE



29 Determining the Capacity and Selecting the Battery Inverters

The type of battery inverter selected will be dependent on the system configuration. The different configurations were detailed in Section 25 while the types of inverters were detailed in Section 26.

The battery inverter must be sized to meet the peak power demand and also the surge demand. In Section 11, it was shown that the power rating of the inverter is determined from the load assessment form.

For systems where there are only a few a.c. appliances, the battery inverter should be capable of supplying continuous power to all loads that are connected to it and must have sufficient surge capacity to start all loads that may surge when turned on, should they all be switched on at the same time. Loads with electric motors are particularly likely to have a large surge capacity requirement.

For households with many a.c. loads where some loads, e.g., microwave ovens and power tools, are only operating occasionally, it is not practical to select an inverter based on the total power rating of all the loads. The inverter capacity should be selected by determining what loads may typically be operating at the same time. Attention may need to be given to load control and prioritisation strategies. For example, if the inverter has surge capacity sufficient for only one motor but there are several motors that it powers, the motor switching design should make it impossible for two or more of the connected motors to be switched on at the same time.

If a load assessment form has been completed, then the inverter shall be sized based on the peak demand shown by the data in the form. To do that, the power rating of the appliances needs to be converted to apparent power (VA) based on the power factor of the appliance. This is because inverters are rated at unity power factor, i.e., a 5 kW inverter is also a 5 kVA inverter, but if a load is 5 kW and 6 kVA then the 5 kW/5 kVA inverter will not be sufficient to provide power to the load. An inverter with a minimum rating of 6 kVA (6 kW) will be required. In general, for new installations, it is always good practice to oversize because load growth is likely. So, the inverter selected will typically be larger than needed for the existing demand.

As a minimum, the battery inverter must be rated to suit the maximum and surge power demands. Inverter chargers and interactive inverters can have higher ratings based on their capacity needed when acting as battery chargers. The following sections summarise how to determine the ratings for the four battery inverters described in Section 26: inverter, inverter charger, d.c.-coupled interactive inverter, and a.c.-coupled interactive inverter. The fifth inverter described in Section 26 was the PV inverter that has its size based on the size of the array, a process that is detailed in Section 24 and is not repeated here.

With hybrid systems the inverters can be supplied as single-phase or three-phase, though sometimes three-phase inverters are not available at the power rating desired and three single phase inverters are used with one inverter acting as the "leader" and the others the followers. The "leader" ensures that the three inverters are each 120 degrees out of phase with the others.

If the required capacity of the required inverter is greater than 20 kVA, then these may be supplied as either one inverter or as a "cluster" of inverters. Some brands will provide their inverters with a maximum of 5 kVA per inverter; hence a 3-phase 15 kVA inverter will consist of three of these inverters. The inverter manufacturers may then allow these three inverter clusters to be connected in parallel up to a specified number, each cluster will then have their own battery bank and in effect will be independent of the others. One cluster will be assigned the role of "leader" and the others will be set to be "followers".

As an example, if one 90 kVA 3-phase inverter is required then it could either be supplied as one single large 3-phase inverter or as six clusters of three 5 kVA inverters. The cluster approach allows inverter (and battery) capacity to be added to a system up to the limit of parallel clusters allowed by that manufacturer. This approach has the added advantages of being able to operate with somewhat reduced power if one cluster malfunctions, while greatly simplifying maintenance personnel training requirements and significantly reducing the cost of the spare parts stock needed.

29.1 Inverter

In systems that use standard battery inverters, the inverter must be sized to meet the maximum and surge demands as described above.

29.2 Inverter charger

Battery inverter-chargers will be sized to meet the maximum and surge demands as described above. However, in some systems, the battery inverter-charger required may have a higher rating than the size determined via maximum and surge demand calculations. This could occur if the system design calls for the required charging current to exceed the charging capacity of the inverter that is sized to meet the maximum load and surge demand calculations. In particular, when the battery is low and a fuelled generator is operating, the system design may be such that a very high charge current is required for the inverter to charge the batteries in a shorter time period than is normally the case when charging from the solar modules.

29.3 d.c.-Coupled Interactive Inverter

Theoretically, the d.c.-coupled interactive inverter can operate in parallel with the fuelled generator and hence the sizing of the fuelled generator and d.c.-coupled interactive inverter combined can be sized to meet the maximum and surge demands, hence resulting in the selection of an inverter rated smaller than that required to meet the maximum and surge demands by itself. In practice, though, the d.c.-coupled inverter should be sized the same as the inverter charger described in Section 29.2. That is, it is sized to meet the maximum and surge demand and, if needed, should be oversized if that is needed to meet its charging requirement. This allows the system to meet the maximum and surge demands without always needing to operate the generator.

29.4 a.c.-Coupled Interactive Inverter

The a.c.-coupled interactive battery inverter is initially sized the same as the d.c.-coupled interactive battery inverter. It is sized to meet the maximum and surge demand and may be oversized to provide for additional charging capability if required by the overall system. However, since the charging source is the PV array and the fuelled generator, the a.c.-coupled inverter generally must be sized to at least match the size of the PV array and its corresponding PV inverter(s).

Because of the low cost of PV modules and the ease that a.c.-coupled systems allow for larger PV arrays, it is not uncommon to have a PV array and PV inverter much larger than the a.c.-coupled interactive inverter. For example, a PV array of 30 kW may be connected to a 25 kW (25 kVA) or 30 kW (kVA) PV inverter while the a.c.-coupled interactive inverter only needs to be 10 kVA to meet the maximum and surge demands.

It is recommended that the battery inverter rating is between 50% and 100% of the PV inverter. If there are many daytime loads such that a high proportion of the PV array will be supplying loads directly during the day, then the a.c.-coupled interactive inverter rating could be as low as 50% of the PV inverter rating. However, if there are not many daytime loads then the a.c.-coupled interactive inverter rating should be closer to the full PV inverter rating in order to allow all the available PV power to be used in charging the battery bank via the a.c.-coupled interactive inverter and to assure sufficient generation for powering the loads when the PV is not generating sufficiently due to a rainy day or clouds. In general, for hybrid installations in remote areas, it is important to design the system to minimize the requirement to operate the fuelled generator since fuel costs and therefore electricity costs are very high. Carefully monitored fuelled generators supplying remote island telecom installations show a per kWh cost of well over $1.00 and in some cases over $2.50 per kWh. For standalone solar at sites where the fuel cost is not much more than the solar generation cost, keeping the operation of the generator to a minimum is not so important.

30 Determining Capacity and Selecting Battery Chargers

A separate battery charger may be required for systems that are not using battery inverters that include an internal battery charger for charging from the grid.

Critical factors when selecting a battery charger that charges from the grid include:

- Appropriateness for the type of battery selected
- System voltage
- Voltage regulation
- Output current limiting
- Battery manufacturer's recommended charge voltage
- Availability of controls and metering as needed for proper operation of the system.

The maximum rate of charge of the batteries must be specified by the battery manufacturer and the battery charger must not provide a charge current greater than that specified by the battery manufacturer. The battery charger must have a d.c.-voltage rating sufficient to provide the charging voltage required by the battery.

For systems with lead-acid batteries, the battery charger ideally should be capable of providing all available charging current during the initial charging stage and then gradually reduce the current to maintain a manufacturer's specified voltage after being fully charged. This allows the charger to carry out float charging and, as required, extra current for equalisation charging.

If lithium-ion batteries are used, then the selected inverter should be able to communicate with the battery management system (BMS) provided with the lithium-ion battery.

31 Selecting the Fuelled Generator and Determining its Capacity

31.1 Selecting the Fuelled Generator

When selecting a fuelled generator, the following critical factors should be considered:

- Can the generator meet the maximum and surge demand of all the appliances that may operate when the generator is running? In general, this will be the same calculation as that undertaken in determining the rating of the battery inverter, but the battery charger must be included as an additional component of the load for the fuelled generator.
- How consistent is the load power profile? Will the profile result in the generator being under-loaded for a long period of time? Under-loaded generators may have increased maintenance costs and typically also consume more fuel per kWh delivered.
- Will the generator be used only when the battery/PV cannot supply the load, or will it be used daily for a specified number of hours?
- What should be the engine speed: 1500 rpm (revolutions per minute) or 3000 rpm? Higher speed engines will require more maintenance but typically have a lower initial cost; so higher speed engines usually are selected for installations that have generators that are only started when the solar cannot provide sufficient energy to meet the load while higher efficiency, lower speed engines are generally installed where the engine is regularly used every day.
- What is the preferred fuel type: diesel, petrol (gasoline), LPG or biofuels? This will be determined by a combination of the size of the generator, fuel availability, fuel cost, noise, access to maintenance and its cost, generator lifetime, load type and environmental considerations.
- Physical specifications, including weight, dimensions, transportability, temperature ratings, ingress protection (IP) ratings (against the entry of moisture, dust, etc.), noise ratings and fuel efficiency.
- Electrical specifications, including apparent power, voltage and frequency regulation, rated voltage, rated amperage, harmonic distortion, number of phases, monitoring and control system typology.

If the generator is operating on a daily program, then a medium speed (1500 rpm) diesel generator is recommended.

For systems using a d.c.-coupled or have a.c.-coupled interactive inverters where the generator must be capable of operating in parallel with the inverter(s), a generator must be selected that is designed to properly work in parallel with other sources of power generation. Since the inverter and generator must synchronise, the output of the generator should have minimum harmonic distortion, or the inverter may have difficulty synchronising with the generator.

High speed (3000 rpm) petrol generators should only be used with systems where the generator does not operate in parallel with the inverter(s) and is only required as a back-up that operates to carry all the load when the battery charge is too low to handle the load.

31.2 Determining the Capacity of the Fuelled Generator

Theoretically, if the fuelled generator can operate in parallel with interactive inverters (a.c.- and d.c.-coupled systems) and the sizing of the fuelled generator and the interactive inverter combined can meet the maximum and surge demands, it may seem that a smaller generator can be installed than that required to meet the maximum and surge demands. In practice, though, the generator must be sized to meet the maximum and surge demands of all the loads when it is operating. This allows the generator to meet the maximum and surge demands should the solar installation fail to deliver power to the load.

31.2.1 Generator as a Back-up

The battery charger, whether a part of the interactive inverter(s) or as a standalone device, should always be included as a load on the generator. This could be the kVA rating of a separate battery charger, though for most designs, it will be the rating of the inverter-charger in the d.c.- or a.c.-coupled interactive battery inverter. Though the battery charger rating of the inverter may be less than that of the full rating of the inverter that is used, for the purpose of sizing the generator, it is assumed that the battery charger rating is the same as the continuous rating of the inverter.

The generator should therefore be sized to meet the larger of the results of the S_{GEN} calculated using the following two formulas:

$$S_{\mathrm{GEN}} = \left(S_{\mathrm{BC}} + S_{MAX\_\mathrm{CHG}}\right) \times F_{\mathrm{GO}}$$

and

$$S_{\mathrm{GEN}} = \frac{\left(S_{\mathrm{BC}} + S_{\mathrm{SUR\_CHG}}\right) \times F_{\mathrm{GO}}}{\mathrm{ALT\ SURGE\ RATIO}}$$

Where,

S_{GEN} = Minimum apparent power rating of the generator (kVA)

S_{BC} = Maximum apparent power consumed by the battery charger under conditions of maximum output current and typically maximum charge voltage (kVA)

S_{MAX_CHG} = Maximum a.c. demand from the loads when generator is operating (kVA)

F_{GO} = Generator oversize factor (dimensionless)

$S_{\mathrm{SUR\_CHG}}$ = Maximum AC surge demand during battery charging (kVA)

ALT SURGE RATIO = Ratio of instantaneous current to continuous current output of the alternator

The oversize factor is a safety margin and often an oversize of 10% is allowed. That represents an oversize factor of 1.1.

Worked Example 41: Calculating minimum kVA rating of generator required

S_{BC} = 5 kVA

S_{MAX_CHG} = 10 kVA

F_{GO} = 1.1

$S_{\mathrm{SUR\_CHG}}$ = 15 kVA

ALT SURGE RATIO = 2

What is the minimum sized generator you should select? The generator must be sized to meet the following formula:

$$S_{GEN} = (S_{BC} + S_{MAX\_CHG}) \times F_{GO}$$

= (5 +10) × 1.1

= 16.5 kVA

and

$$S_{\mathrm{GEN}} = \frac{(S_{\mathrm{BC}} + S_{\mathrm{SUR\_CHG}}) \times F_{\mathrm{GO}}}{\mathrm{ALT\ SURGE\ RATIO}}$$

= ((5 + 15) × 1.1)/2

= 22/2

= 11 kVA

Therefore, the generator capacity shall be at least 16.5 kVA

31.2.2 Generator Used Daily

In some sites a generator may already be installed and therefore may not have any excess capacity available for properly charging the battery bank at the same time as it serves the load. In that case the generator will need to be operated such that it only charges the battery when the load is low, and the generator has excess capacity relative to the load. Every site will be different.

If the system to be installed is a new system, then the designer has the choice:

- select a generator just to meet the load maximum demand requirements when the generator is operating and arrange the generator operation so that the battery charging will only occur during low load periods;

or

- include the battery charger as one of the loads that operates at full capacity when the generator is operating, in which case the generator can charge the battery at any time.

Currently, the cost of PV when meeting loads directly is cheaper than operating a diesel generator; however, when combined with the cost of batteries it is not. To determine which option is the best – whether to install a larger generator to allow for effective battery charging by the generator when operating or to add more modules to the PV array to do most of the charging through increased solar capacity – then the extra fuel cost of operating the larger generator plus the added cost of installing and using a larger generator needs to be compared with the costs of adding more solar modules and their cost of operation. This analysis needs to be undertaken for each site and it will depend on the size of the equipment required and the load characteristics.

If the generator is sized to include the capacity of the battery charger, then the generator size is determined using the formula specified in 31.2.1.

If the generator is sized to only meet the power of the loads operating while the generator is operating, this is the same as sizing the battery inverter, except the ability of the generator to supply surge current should be investigated with the generator manufacturer.

The generator should therefore be sized to meet the following two formulas:

$$S_{\text{GEN}} = (S_{\text{MAX\_DEM}}) \times F_{\text{GO}}$$

and

$$S_{\text{GEN}} = \frac{(S_{\text{SUR\_DEM}}) \times F_{\text{GO}}}{\text{ALT SURGE RATIO}}$$

Where,

S_{GEN} = Minimum apparent power rating of the generator (kVA)

S_{MAX_DEM} = Maximum a.c. demand during when generator operating (kVA)

F_{GO} = Generator oversize factor (dimensionless)

S_{SUR_DEM} = Maximum AC surge demand when generator operating (kVA)

ALT SURGE RATIO = Ratio or instantaneous current to continuous current output of the alternator

The oversize factor is a safety margin and typically an oversize of 10% is allowed which is an oversize factor of 1.1.

Worked Example 42: Calculating minimum kVA rating of the generator

S_{MAX_DEM} = 10 kVA

F_{GO} = 1.1

S_{SUR_DEM} = 15 kVA

ALT SURGE RATIO = 2

What is the minimum sized generator you should select?

The generator must be sized to meet the following two formulas:

$$S_{GEN} = (S_{MAX\_DEM}) \times F_{GO}$$

= 10 × 1.1

= 11 kVA

and

$$S_{\mathrm{GEN}} = \frac{(S_{\mathrm{SUR\_DEM}}) \times F_{\mathrm{GO}}}{\mathrm{ALT\ SURGE\ RATIO}}$$

= (15 × 1.1)/2

= 16.5/2

= 8.25 kVA

The generator shall be at least 8.25 kVA.

31.3 Derating of Generators

Generators need to be derated for the site-specific temperature, humidity and altitude. The derating factors should be supplied by the generator manufacturer; however, typical values are shown in Table 8. The deratings are *added* together, *not multiplied* as often is the case with losses in a system.

TABLE 8: GENERATOR DERATING FACTORS

Site factor		Derating
Air Temperature		Derate 2.5% for every 5°C above 25°C
Altitude		Derate 3% for every additional 300 m above 300 m altitude
Humidity	Air temperature between 30°C and 40°C	Derate 0.5% for every 10% above 60% humidity
	Air temperature between 40°C and 50°C	Derate 1.0% for every 10% above 60% humidity
	Air temperature between 50°C and 60°C	Derate 1.5% for every 10% above 60% humidity

Source: ***AS/NZS 4509.2:2010*** Clause 3.4.11.5.

Worked Example 43: Calculating derated output of the generator

The 30 kVA generator is located at an altitude of 900 m. Air temperature is 32°C and humidity is 90%. What is the total general derating factor? What is the derated output of the generator at this site?

Temperature is 32°C which is 7°C (32°C - 25°C) above the rated test temperature of the generator (25°C).

Therefore, the derating factor due to temperature = 7 × 0.5% = 3.5%

Altitude is 900 m, which is 600 m (900 m - 300 m) above the maximum altitude (300 m) the generator can operate before being derated.

Therefore, the derating factor due to altitude = 600/300 × 3% =6%

Temperature is 32°C so the derating factor from table is 0.5% for every 10% humidity above 60% humidity.

Humidity is 90% which is 30% (90-60) above the maximum humidity (60%) the generator can operate before being derated.

Therefore, the derating factor due to humidity = 30/10 × 0.5% = 1.5%

Total derating factor = 3.5%+ 6% + 1.5% = 11% which can be expressed as 0.11

So, the derated output of the generator is:

(1-0.11) × 30 kVA = 0.89 × 30 kVA = 26.7 kVA

32 Generator as Back-up Only

Systems using generators as back-up only typically use the generator when either:

- The daily energy usage has increased due to a specific event, e.g., a family function
- There is a failure in the solar installation that reduces or shuts down its generation

or

- During periods of extended cloudy weather

It was recommended in Part 1 that the PV array be sized based on the average irradiation given in Peak Sun Hours (PSH) figure for the design month. The design month is the month where the ratio of available irradiation (PSH) to daily load energy for that month is the smallest. The irradiation of the design month is then used when determining the size of the required PV array. Determining the design month and hence the relevant irradiation value used for designing the PV array is detailed in Section 12.1.

When a fuelled generator is available as a back-up, then the PV array may be sized based on the yearly average irradiation figure instead of the irradiation of the design month. The generator will then need to operate to make up for inadequate energy generation by the PV array in the months when the irradiation figure is less than the yearly average. However, with today's relatively low cost of PV modules and the high cost of fuel, it is recommended that even with a back-up generator, that the PV array be designed for the design month as detailed in Section 12.1.

32.1 Determining the Battery Capacity and Selecting the Battery Bank

For hybrid systems where the generator is only being used as a back-up, determining the required battery capacity and selecting the battery bank is undertaken in much the same way as is detailed in Part 1 (Sections 9 and 10) and hence is not repeated in this guideline. System designers have the option to lower the days of autonomy for these systems if fuel for the generator is reliably available and the system is properly designed for more frequent generator starts.

Section 8 details how to select the d.c. system battery voltage; however, with many of the larger hybrid systems the battery voltage is determined by the interactive battery inverter model selected.

32.2 Sizing the Solar Array and Associated Solar Controllers and PV Inverters

For hybrid systems where the generator is only being used as a back-up, determining the required PV array size is undertaken exactly the same way as detailed in the Part 2 for d.c.-coupled systems and Part 3 for a.c.-coupled systems and is not repeated in this guideline. As stated above, it is recommended that the PV array be sized based on the irradiation for the design month.

The oversizing factor of 30% specified in the Parts 2 and 3 can be ignored because the back-up generator will be able to provide the extra charging required when equalising the lead acid batteries.

However, it is recommended that this oversize factor of 30% be included to overcome the issue of the efficiency of the solar modules decreasing with time as well as minimising the volume of high-cost fuel needed for the generator.

As can be seen in Part 1, the PV system can either be a d.c.-coupled or a.c.-coupled system configuration. With the d.c.-coupled configuration, the solar controller can either be a switching controller, a pulse width modulated (PWM) controller or an MPPT controller. This results in numerous formulae for determining the available energy that can come from a PV array. In the Part 1, 2 and 3, words were sometimes used in the formulas instead of symbols. However due to the many configurations possible with a hybrid system, it is easier to introduce symbols for developing the different formulae. The formulae do have similarities and it is mainly the different sub-system losses that vary depending on the configuration.

The various formulae also vary slightly depending on whether the load energy is being supplied directly by the PV array or by the battery bank being charged by the PV array. The difference in the two formulae is determined by whether or not the battery charge/discharge efficiency needs to be included in the formula.

Based on the various formulas in Parts 2 and 3, the following three sections summarise the energy output formulas for the different system configurations. Note: When calculating the size of the array in the Parts 2 and 3, an oversize factor is applied. This is not included in the formula when just determining the energy delivered by the PV array.

32.2.1 d.c.-Coupled System: PWM Type Solar Controller

Load Energy (d.c.) directly supplied by PV array:

$$E_{d.c.1} = I_{MOD} \times N_p \times H_{TILT} \times V_{d.c.}$$

Load Energy (a.c.) directly supplied by PV array:

$$E_{a.c.1} = I_{MOD} \times N_p \times H_{TILT} \times V_{d.c.} \times \eta_{INV}$$

Load Energy (d.c.) directly supplied by battery bank charged by PV array:

$$E_{d.c.2} = I_{MOD} \times N_p \times H_{TILT} \times V_{d.c.} \times \eta_{COUL}$$

Load Energy (a.c.) directly supplied by PV array:

$$E_{a.c.2} = I_{MOD} \times N_p \times H_{TILT} \times V_{d.c} \times \eta_{COUL} \times \eta_{INV}$$

Where,

$E_{d.c.1}$ = d.c. energy directly supplied by PV Array (Wh)

$E_{d.c.2}$ = d.c. energy directly supplied by battery bank charged by PV Array (Wh)

$E_{a.c.1}$ = a.c. energy directly supplied by PV Array (Wh)

$E_{a.c.2}$ = a.c. energy directly supplied by battery bank charged by PV Array (Wh)

I_{MOD} = Derated current from a module (A)

N_p = Number of parallel strings of modules (Dimensionless)

H_{TILT} = Daily irradiation (in PSH) for the specified tilt angle and orientation (H)

$V_{d.c.}$ = Battery bank (system) voltage (in V)

η_{COUL} = Coulombic efficiency of the battery (dimensionless)

η_{INV} = Inverter efficiency (dimensionless)

Now,

$$I_{MOD} = I_{T,V} \times F_{MAN} \times F_{DIRT}$$

Where,

$I_{T,V}$ = The output current (in A) of the module at the average effective cell temperature and system operating voltage

F_{MAN} = De-rating factor for manufacturer's tolerance (dimensionless)

F_{DIRT} = De-rating factor for dirt (dimensionless)

Note: The battery and inverter efficiency can be combined and called sub-system efficiency.

32.2.2 d.c. Bus: MPPT Controller

Load Energy (d.c.) directly supplied by PV array:

$$E_{d.c3} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{PV\text{-}Load}$$

Load Energy (a.c.) directly supplied by PV array:

$$E_{a.c3} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{INV} \times \eta_{PV\text{-}Load}$$

Load Energy (d.c.) directly supplied by battery bank charged by PV array:

$$E_{d.c4} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{WH} \times \eta_{PV\text{-}Load}$$

Load Energy (a.c.) directly supplied by PV array:

$$E_{a.c4} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{WH} \times \eta_{INV} \times \eta_{PV\text{-}Load}$$

Where,

$E_{d.c.3}$ = d.c. energy directly supplied by PV Array (Wh)

$E_{d.c.4}$ = d.c. energy directly supplied by battery bank charged by PV Array (Wh)

$E_{a.c.3}$ = a.c. energy directly supplied by PV Array (Wh)

$E_{a.c.4}$ = a.c. energy directly supplied by battery bank charged by PV Array (Wh)

P_{MOD} = Derated power from a module (W)

N = Number of modules in the array (Dimensionless)

H_{TILT} = Daily irradiation (in PSH) for the specified tilt angle and orientation (H)

η_{WH} = Watt-Hour efficiency of the battery (dimensionless)

η_{MPPT} = MPPT efficiency (dimensionless)

η_{INV} = Inverter efficiency (dimensionless)

$\eta_{PV\text{-}Load}$ = Cable (transmission) efficiency (dimensionless)

Now,

$$P_{MOD} = P_{STC} \times F_{TEMP} \times F_{MAN} \times F_{DIRT}$$

Where,

P_{STC} = The rated output power (P) of the module at Standard test conditions

F_{TEM} = Derating factor for module temperature (dimensionless)

F_{MAN} = Derating factor for manufacturer's tolerance (dimensionless)

F_{DIRT} = Derating factor for dirt (dimensionless)

Notes:

1. The actual value of $\eta_{PV\text{-}Load}$ will vary for each formula depending on the number of cables and length of cables between the PV array and the load
2. The battery, inverter, MPPT and cable efficiency can be combined and called sub-system efficiency

32.2.3 a.c.-Coupled system

There is typically no d.c. load in a.c.-coupled systems so no formulas have been provided for d.c. loads.

Load Energy (a.c.) directly supplied by PV array

$$E_{a.c.5} = P_{MOD} \times N \times H_{TILT} \times \eta_{PVinv} \times \eta_{PV\text{-}Load}$$

Load Energy (a.c.) directly supplied by the inverter via the battery bank charged by the PV array will include the efficiency losses associated with battery charging.

$E_{a.c.6} = P_{MOD} \times N \times H_{TILT} \times \eta_{PVINV} \times \eta_{INV\text{-}CHG} \times \eta_{Wh} \times \eta_{INV} \times \eta_{PV\text{-}Load}$

Where:

$E_{a.c.5}$ = a.c. energy directly supplied by PV Array (Wh)

$E_{a.c.6}$ = a.c. energy directly supplied by battery bank charged by PV Array (Wh)

P_{MOD} = Derated power from a module (W)

N = Number of modules in the array (Dimensionless)

H_{TILT} = Daily irradiation (in PSH) for the specified tilt angle and orientation (H)

η_{Wh} = Watt-Hour efficiency of the battery (dimensionless)

η_{PV} = PV Inverter efficiency (dimensionless)

η_{INV_CHG} = Inverter efficiency acting as battery charger (dimensionless)

η_{INV} = Inverter efficiency (dimensionless)

$\eta_{PV\text{-}Load}$ = Cable (transmission) efficiency (dimensionless)

Now,

$P_{MOD} = P_{STC} \times F_{TEMP} \times F_{MAN} \times F_{DIRT}$

Where,

P_{STC} = The rated output power (P) of the module at Standard test conditions

F_{TEM} = De-rating factor for the module temperature (dimensionless)

F_{MAN} = De-rating factor for manufacturer's tolerance (dimensionless)

F_{DIRT} = De-rating factor for dirt (dimensionless)

Notes:

1. The actual value of $\eta_{PV\text{-}Load}$ will vary for each formula depending on the size of cables and length of cables between the PV array and the load
2. The battery, PV inverter, inverter (as charger), inverter, and cable efficiency can be combined and called sub-system efficiency

32.3 Calculating the Generator's Operating Hours

32.3.1 Generator Required due to Excess Loads or Extended Cloudy Weather

If the energy requirements are higher than what the system was designed for, e.g. a social function being held, then either the generator may operate during the time the function is being held or the generator will be required to start when the battery reaches a specified discharge level, typically 70% depth of discharge for a lead acid battery or the minimum usable energy level in a lithium-ion battery.

The time taken to recharge the battery bank by a generator is dependent on:

- The amount of energy (in Wh or ampere hours) that is reflected in the 70% depth of discharge or effective battery capacity that is required to be replaced by the generator providing charging.
- The efficiency of the battery bank: either Ah (coulombic) efficiency or energy (Wh) efficiency.
- The charging current (or power) from the battery charger (either stand-alone battery charger or inverter operating as a charger).

The generator run-time to recharge the battery is calculated by either of the following two formulas:

$$T_{GEN} = Batt_{Ah} / (I_{bc} \times \eta_{coul})$$

Where,

T_{GEN} = Required generator run time (hours)

$Batt_{Ah}$ = Battery ampere hours that needs to be replaced by the generator charging (Ah) I_{bc} = Charging current from battery charger (A)

η_{coul} = Battery coulombic efficiency or

$$T_{GEN} = Batt_{Wh} / (P_{bc} \times \eta_{Wh})$$

Where,

T_{GEN} = Required generator run time (hours)

$Batt_{Wh}$ = Battery energy that needs to be replaced by the generator charging (Wh)

P_{bc} = Charging power from battery charger (power)

η_{Wh} = Battery energy (Wh) efficiency

Worked Example 44: Calculating generator run time for charging batteries (system with lead-acid batteries)

A lead-acid battery has a capacity of 1200 Ah. It has been discharged by 80%.

Battery Charger has a charging current of 80 A. Coulombic efficiency is 90% (0.9).

How long will the generator need to operate to fully recharge the battery?

Battery Ah that needs to be replaced = 0.8 (80%) × 1200 Ah = 960 Ah.

The generator run time is:

$$T_{GEN} = Batt_{Ah} / (I_{bc} \times \eta_{coul}) = 960 \text{ Ah} / (80 \text{ A} \times 0.9) = 13.33 \text{ hours}$$

Worked Example 45: Calculating generator run time for charging batteries (system with lithium-ion batteries)

A lithium-ion battery has a capacity of 60 kWh but a useable capacity of 54 kWh, which has been fully depleted.

Battery Charger has a charging power of 5 kW

The energy efficiency of the lithium-ion battery is 95% (0.95).

How long will the generator need to operate to fully recharge the battery?

The generator run time is:

$$T_{GEN} = Batt_{Wh} / (P_{bc} \times \eta_{Wh}) = 54000 \text{ Wh} / (5000 \text{ W} \times 0.95) = 11.37 \text{ hours}$$

32.3.2 Generator Required due to PV Array Sized for Yearly Average Irradiation

When the PV Array is sized for the yearly average irradiation figure instead of that for the design month, then there will be months when the irradiation will be less than the yearly average and the generator will be required to operate to overcome the energy deficit in the system on those days.

While the generator is operating it will meet some loads directly, however, to keep the explanation simple it is assumed that when the generator is operating it will meet the energy deficit by charging the batteries. This conservative approach does result in the generator not actually operating for as long as predicted.

To determine the generator run time then the solar fraction needs to be determined. The solar fraction (F_{pv}) is defined as: The total load energy that is supplied by the PV array (E_{PV}) divided by the total daily load energy required by the site (E_{load}). The formula is:

$$F_{pv} = E_{PV} / E_{load}$$

Where,

F_{pv} = Solar Fraction

E_{PV} = Load Energy supplied by PV

E_{load} = Daily Load Energy Required

The exact formula will depend on:

- Whether the loads are all d.c., all a.c. or a combination of both.
- The configuration of the PV system, that is: is it a d.c.-coupled system using a PWM controller, a d.c.-coupled system using a MPPT controller, or an a.c.-coupled system?

The formula can be very complicated if consideration is given to whether all the load energy is being supplied directly from the batteries (being charged by the PV array) or some of the load energy is being supplied directly by the PV array and the rest is then being supplied by the batteries (that are charged by the PV array). As can be seen in Section 32.2 there are many formulae used for determining the load energy being supplied by the PV array, but they are similar, and the variation is just in the sub-systems losses that are taken into account in the formulae.

The solar fraction for a site will vary for each month that the monthly average irradiation is less than the yearly irradiation figure used in determining the capacity of the PV Array.

Once the solar fraction is calculated then the balance of daily energy that must be supplied by the generator charging the battery can be calculated by the following formula:

$$E_{Load\text{ - }BC} = (1 - F_{pv}) \times E_{load}$$

The generator run time can then be determined as follows:

$$T_{GEN} = E_{Load\text{ - }BC} \,/\, (P_{bc} \times \eta_{Wh} \times \eta_{inv})$$

Where,

T_{GEN} = Required generator run time (hours)

$E_{Load\text{-}BC}$ = Load energy that needs to be supplied by the generator charging (Wh)

P_{bc} = Charging power from battery charger (power)

η_{Wh} = Battery energy (Wh) efficiency

η_{inv} = Inverter energy (Wh) efficiency

Worked Example 46: Calculating generator run time based on solar fraction

A hybrid system has been designed where the PV array has been sized based on the average yearly irradiation. The daily load energy (E_{load}) = 20 kWh

In the month with lowest irradiation, the PV array will meet a load of 16 kWh

The inverter/Charger has a charging power of 5 kW

The inverter has an efficiency of 93%

The battery has a Wh efficiency of 80%

What is the solar fraction?

How long will the generator be required to operate to overcome the energy deficit? The solar fraction is:

$$F_{pv} = E_{PV}/E_{load} = 16 \text{ kWh}/20 \text{ kWh} = 0.8$$

The load energy that must be supplied by generator charging the batteries is:

$$E_{Load\text{-}BC} = (1- F_{pv}) \times E_{load} = (1-0.8) \times 20 \text{ kWh} = 4 \text{ kWh}$$

The generator run time is:

$$T_{GEN} = E_{Load\text{-}BC} / (P_{bc} \times \eta_{Wh} \times \eta_{inv}) = 4 \text{ kWh}/(5 \text{ kW} \times 0.80 \times 0.93) = 1.08 \text{ hours}$$

33 Generator Used Daily

33.1 Determining the Proportion of Daily Energy Being Provided by the Different Sources

For large villages and resorts where the daily energy usage is in the many hundreds of kWh, a generator may need to operate daily. In particular it may be needed during the evening peak (for example 6 p.m. to 10 p.m.) and possibly the morning peak around breakfast time. The generator is used because the power requirements at that time can be very large and trying to meet the power demand (and energy usage) by battery power may be more expensive than that from the generator since the available solar will either be small (morning) or non-existent (evening). However, if prices of lithium batteries decrease as predicted this cost could come down rapidly in the next few years.

For this section it is assumed that all the loads are a.c. only.

For a hybrid system where the generator is operating daily, the total daily energy requirement is determined as follows:

$$E_{Load} = E_{gen} + E_{gen\text{-}batt} + E_{PV} + E_{PV\text{-}batt}$$

Where,

E_{Load} = Total Daily Energy Requirement

E_{gen} = Energy supplied by generator directly

$E_{gen\text{-}batt}$ = Energy supplied by generator charging battery bank

E_{PV} = Energy supplied directly by PV array

$E_{PV\text{-}batt}$ = Energy supplied directly by PV array charging battery

How much power is available from the generator for charging the batteries will be dependent on the capacity rating of the generator and the loads that are being powered directly by the generator at that point of time. Any excess generator capacity can be used to charge the battery.

In some sites the generator might already be installed and there may not be any excess capacity available for properly charging the battery bank at the same time. Every site will be different.

If the system to be installed is a new system, then the designer has the choice:

- select a generator just to meet the load maximum demand requirements when the generator is operating;

or

- include the battery charger as one of the loads that operates at full capacity when the generator is operating

Currently the cost of PV when meeting loads directly is cheaper than operating a diesel generator, however when combined with the cost of batteries it is often not. To determine which option is the best, a larger generator to allow for effective battery charging by the generator when operating or adding more modules to the PV array, the extra fuel costs in operating the larger generator plus the cost of a larger generator needs to be compared with the costs of adding more solar modules. This analysis needs to be undertaken for each site and it will depend on the size of the various equipment required.

33.2 Determining the Energy to be Supplied by the Battery

When preparing the load profile, the system designer must determine what loads (and therefore energy) will be met directly by the fuelled generator.

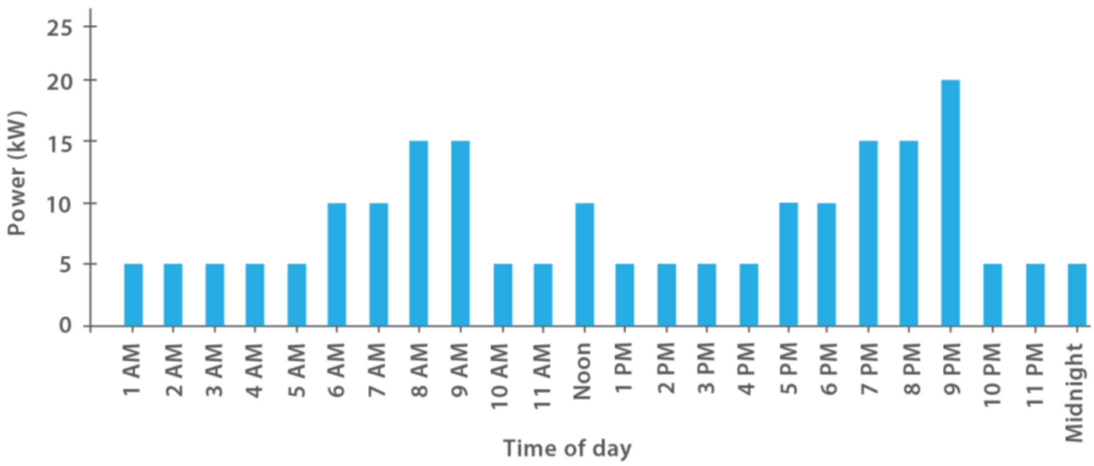
If the load profile has the form of a "double hump" (higher than average morning and evening loads) then ideally the generator should operate mainly during the largest of, or both of these two humps. If the system is being designed with the generator operating only once per day, then it should operate during the hump (the period of high-power usage) when the greatest *energy* use occurs. This is generally in the evening.

Once the system designer has determined how much energy is supplied directly from the generator, the designer must then determine the energy that is required to be met directly by the batteries. The simplest and most conservative approach is to assume that no solar power/energy is supplied directly to the loads, thus the daily load energy not supplied from the generator is supplied from the batteries.

It is recommended that, even with two generator starts every day that the designer use the conservative approach that assumes that the batteries must meet the total daily energy demand outside of the generator run times. While in theory the battery only needs to store the largest amount of energy between the two peaks and hence the two generator operating times, it becomes very complicated to determine this value with a reasonable level of confidence. Such a small battery would also leave little time for responding to generator failures.

Worked Example 47: Calculating average daily energy supplied by batteries

The site has a daily load of 200 kWh and has the following load profile with two humps:



The generator operates only between 6 p.m. and 9 p.m. each night. (**Note**: The energy shown for each time is for the proceeding hour e.g. 1 a.m. is for midnight to 1 a.m.)

What daily energy must be supplied directly by the batteries?

From the above load profile, 50 kWh (15 +15+20) of load operates between 6 p.m. and 9 p.m. This is therefore supplied directly from the generator.

Therefore, the energy that must be supplied directly by the battery bank is the total daily load minus 50 kWh:

$$E_{batt,day} = 200\ \text{kWh} - 50\ \text{kWh} = 150\ \text{kWh}$$

Note: In practice, the actual energy provided by the battery will depend on the amount of solar energy input when the generator is not running.

In worked example 47, the solution assumes that there is no input from solar, which is a "worst case" situation of a very overcast day. If this is the basis for sizing of the battery, the generator will never need to start more than once per day. However, the daily depth of discharge should be less than estimated because the solar will provide loads directly and possibly charge the battery during the day. This may result in longer battery life, but it may also mean that the investment in batteries is not being utilised as much as it could. The alternative is to size the battery assuming that there is a certain amount of solar input.

If the renewable energy input is taken into account in sizing the battery, the size specified will of course be smaller (and lower cost). The maximum demand will then be at higher discharge rate for that smaller battery, than for a larger battery. The ability of the battery to meet the maximum and surge demands is therefore more critical.

Whatever assumptions are used in the design process, the system must be able to cope with variations in both load and also solar input. These variations in both load and solar input make it very difficult to accurately determine how much load each day is expected to be supplied from the batteries.

In addition, the effect of these variations on the actual operation of the generator will depend on how the generator is controlled.

1. If the generator starts at a pre-determined time each day, then the battery depth of discharge will vary, and the generator run-time will vary;
2. If the generator is started on 'low battery' state of charge signal, then the generator start time will vary each day, and the frequency of starts may vary;
3. If the generator is started on both time of day or state of charge, the result will be a mixture of the above, depending on which condition is reached first.

Note: in the previous discussion, generator starting due to excessive inverter load has been omitted for clarity and it is assumed that the inverter will have sufficient capacity to meet the required load.

The variations in operating conditions mentioned above may have serious consequences. Firstly, the client may only want the generator to start during certain times of the day. Secondly, and more importantly in a PV-generator-hybrid system, if the generator fully charges the battery in the morning just before the PV array starts to generate, valuable PV power may be wasted, and fuel consumption and generator operating time may increase. Also, the generator should not start in the middle of sunny days and therefore potentially wasting solar power. Avoiding these potential problems requires careful thinking-through of the implications of battery sizing and generator control strategies in relation to the points mentioned above.

Alternately, some system designs run the generator concurrently with solar energy generation (i.e. during the day) with the aim of saving fuel that would have been consumed if all loads are only on generator power. This system design, if properly implemented, may reduce fuel costs, increase load capacity, and/or lower generator maintenance costs.

33.3 Determining the Battery Capacity and Selecting the Battery Bank

When the generator is operating every day, the battery capacity depends on the energy that the battery will supply each day and the design depth of discharge. The concept of "days of autonomy" does not apply in this case, because the generator would recharge the battery if there has been no input from the solar.

In terms of energy, the battery capacity is:

$$E_{batt} = (E_{batt,day}) / (DOD_{day} \times \eta_{inv})$$

Where,

E_{batt} = The battery energy storage capacity (to 100% DOD), (Wh)

DOD_{day} = Daily depth of discharge of the battery, expressed as a percentage

$E_{batt,day}$ = The load energy drawn from the batteries each day, (Wh)

η_{inv} = inverter energy watt-hour efficiency (%)

This requires the daily depth of discharge to be specified. The above formula can be applied to lead acid batteries which though they often have a maximum depth of discharge of 70-80% they should not have a daily depth of discharge greater than 50% while only 30% is preferred.

For lithium-ion batteries, the battery is defined as having a specified capacity and then a maximum usable energy value—often 80-100% of the actual capacity. The formula for determining the usable battery capacity is:

$$E_{batt\text{-}usable} = E_{batt,day} / \eta_{inv}$$

Where,

$E_{batt\text{-}usable}$ = usable battery energy storage capacity (between 80%-100% of rated capacity)(Wh)

$E_{batt,day}$ = load energy drawn from the batteries each day (Wh)

η_{inv} = Inverter energy (Wh) efficiency

For lead acid batteries the batteries are specified in Ampere Hours (Ah). The capacity in Ah is then given by:

$$C_x = \frac{E_{batt}}{V_{dc}}$$

Where,

E_{batt} = The battery energy storage capacity (to 100% DOD), (Wh)

$V_{d.c.}$ = Nominal voltage of the battery voltage, (V)

C_x = Battery capacity, specified for an appropriate discharge rate x, (Ah)

For hybrid systems the battery voltage is determined by the battery inverter d.c. input voltage and these typically are 12 V, 24 V, or 48 V. However, some brands of inverters may have battery voltages of 36 V d.c., 120 V d.c. or higher. Most medium-sized hybrid systems tend to have inverters with a 48 V d.c. rating. For rural area electricity supply, a battery voltage higher than 48 V is not recommended due to higher voltages having safety issues requiring much more highly trained maintenance personnel.

It is recommended that the C_{10} rating of battery is applied.

Worked Example 48: Calculating average daily energy supplied by batteries

From worked example 47, the battery bank must provide 150 kWh per day and the design daily depth of discharge is specified as 70%.

The inverter has an efficiency of 93%

What is the required battery capacity in kWh? If the nominal system voltage is 48 V, what is the capacity in Ah?

Given:

DOD_{day} = 0.7 and $E_{batt,day}$ = 150 kWh

The required battery capacity is:

E_{batt} = (150/ 0.7 × 0.93)

= 230.4 kWh

Rounded to:

230 kWh

Assume the battery bank is 48 V d.c.

The capacity in Ah is then:

$$C_x = \frac{E_{batt}}{V_{dc}}$$

= 230,000 Wh / 48 V

= 4800 Ah

33.4 Determining the Energy Supplied by Generator Charging Battery Bank

If the generator is sized to allow the inverter charger (or battery charger) to operate at full capacity, then the amount of daily load energy that will be supplied via the generator charging the battery bank will depend on the effective charging capability of the inverter charger. Some inverter/chargers charging capacity will be specified in kW (or Watts) while others may be specified in Amperes. The charging current (or power) allowed by the inverter/charger shall not be greater than the maximum charge current (or power) of the selected battery unless the inverter charge software can be set to limit the charge current to the maximum acceptable current for the installed battery.

If the maximum charging capacity of an inverter/charger is specified as a current, then the daily load that will be met by the generator charging the battery bank is:

$$E_{gen} = T_{GEN} \times I_{bc} \times V_{d.c.} \times \eta_{inv-chg} \times \eta_{coul}$$

Where,

T_{GEN} = Generator run time (hours)

I_{bc} = Charging current from battery charger (A)

$V_{d.c.}$ = Nominal voltage of the battery voltage, (V)

η_{coul} = Battery coulombic efficiency

$\eta_{inv-chg}$ = Inverter's charging energy (Wh) efficiency

If the maximum charging capacity of an inverter/charger is specified in power, then the daily load that will be met by the generator charging the battery bank is:

$$E_{gen} = T_{GEN} \times P_{bc} \times \eta_{inv-chg} \times \eta_{Wh}$$

Where,

T_{GEN} = Generator run time (hours)

η_{Wh} = Battery energy (Wh) efficiency

$\eta_{inv-chg}$ =Inverter's charging energy (Wh) efficiency

P_{bc} = Charging power from battery charger (W)

Worked Example 49: Calculating load energy supplied by generator charging batteries

Assume the inverter for the system in the worked example is 25 kW and it can provide the full 25 kW when charging the battery and the generator has the capacity to provide the 25 kW allowing for charger efficiency.

The inverter's charger has an efficiency of 93%.

The battery bank has an energy efficiency of 80%.

What load energy can be supplied by the generator charging the battery bank? From worked example 44 the generator operates for 3 hours.

From the equation:

$$E_{gen} = T_{GEN} \times P_{bc} \times \eta_{inv\text{-}chg} \times \eta_{Wh}$$

We get:

3 h × 25 kW × 0.93 × 0.8 = 55.8 kWh

33.5 Determining the Daily Load Energy to Be Provided by the PV Array

If the generator has the capacity to meet the loads and provide charging of the battery bank, the amount of daily load energy to be supplied by the PV array is:

$$E_{pv} = E_{PV\text{-}dir} + E_{PV\text{-}batt} = E_{Load} - E_{gen} - E_{gen\text{-}batt}$$

Where,

E_{Load} = Total Daily Energy Requirement

E_{gen} = Energy supplied by generator directly

$E_{gen\text{-}batt}$ = Energy supplied by generator charging battery bank

$E_{PV\text{-}dir}$ = Energy supplied directly by PV array

$E_{PV\text{-}batt}$ = Energy supplied directly by PV array charging battery

However, if the generator does not have the capacity to provide charging of the battery bank a different equation must be used. If the generator only has the capacity to meet the loads, the amount of daily load energy to be supplied by the PV array is:

$$E_{pv} = E_{PV\text{-}dir} + E_{PV\text{-}batt} = E_{Load} - E_{gen}$$

In practice since the loads will vary over time the generator may still be able to charge the battery bank at times, but trying to estimate exactly how much is difficult and usually not very accurate. Assuming that no charging occurs from the generator is the conservative approach.

Once the amount of daily load energy to be supplied by the PV array is determined then the designer will need to determine the size of the array. How this is undertaken will depend on the configuration of the system. The different formulas are contained in Part 2 and Part 3 and the designer should refer to relevant sections guideline when determining the size of the array. The respective formulae have also been summarised in Section 32.2 of this guideline and a summary of the different system losses is provided in Section 34 of this guideline.

Worked Example 50: Calculating load energy to be provided by PV array

Based on worked example 47 and 49, what is the load energy that shall be provided by the PV array assuming that the generator has the capacity to meet the loads and provide charging of the battery bank?

$$E_{pv} = E_{Load} - E_{gen} - E_{gen\text{-}batt}$$

From worked example 46:

E_{Load} = 200 kWh

E_{gen} = 50 kWh

From worked example 48:

$E_{gen\text{-}bat}$ = 55.8 kWh

Therefore,

$$E_{pv} = 200\ \text{kWh} - 50\ \text{kWh} - 55.8\ \text{kWh}$$

$$= 94.2\ \text{kWh}$$

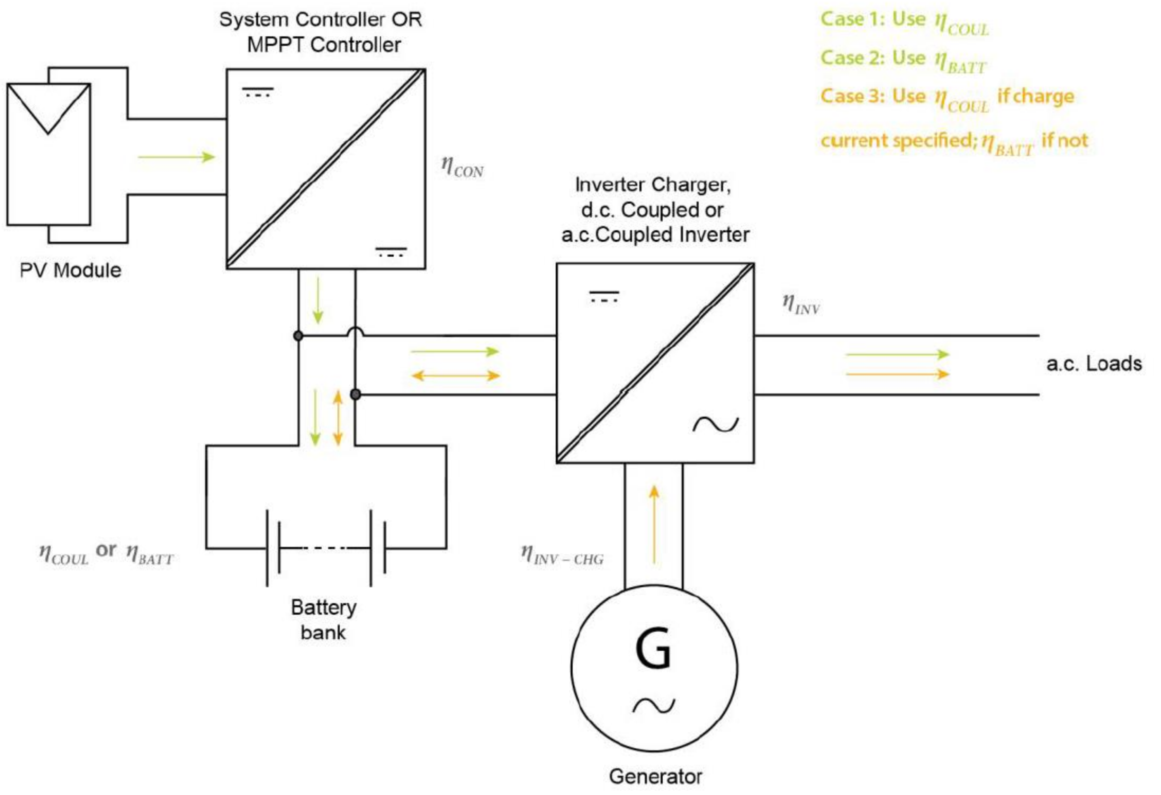
34 Summary of Hybrid Losses

Hybrid systems can consist of a.c.-coupled systems, d.c.-coupled systems or a combination of both. Trying to remember and apply all the formulas related to losses between the energy sources and the loads for the various configurations can be very difficult. It is best that the designer always first draws the configuration of the system that is proposed for the design and then determines the sub-system losses for that configuration among the various energy sources, (e.g., PV array, battery, generator) and the loads. These will be required when trying to determine the size of the PV array required. This section summarises the various losses in the different configurations.

34.1 System Efficiencies in a d.c.-Coupled System Supplying a.c. Loads

Figure 19 shows the various system losses in a d.c.-coupled system providing a.c. energy to loads. Table 9 summarises the typical losses for the many pathways between the energy sources and the loads.

FIGURE 19: SYSTEM LOSSES IN A D.C.-COUPLED CONFIGURED HYBRID SYSTEM-EXCLUDING CABLE LOSSES



Note: The arrows in Figure 19 and Figure 20 show how power/energy flows from one component to another. They are not colour coded as d.c. and a.c. as shown in earlier figures.

TABLE 9: SYSTEM EFFICIENCY LOSSES FOR D.C.-COUPLED SYSTEM SUPPLYING A.C. LOADS

Case 1: Switched/PWM Solar controller. The PV Array charges battery via a switching or PWM controller & the battery inverter supplies a.c. loads. **The system is based upon Ah.**	**Case 2: MPPT Solar controller.** The PV array charges battery via a MPPT controller & the battery inverter supplies a.c. loads. **The system is based upon Wh.** Note: Individual cable losses can be combined and stated as cable losses (transmission losses) between PV array and inverter or loads.	**Case 3: Generator and inverter-charger.** When the generator is running, it can charge the battery via the inverter-charger and the maximum charge current is based upon the battery requirement and the maximum current rating for the charging circuit in the inverter. When the generator is off the battery inverter-charger supplies all the a.c. loads. **The system is based upon Ah.** Note: The inverter-charger could be bidirectional or d.c.-coupled interactive.
1) Battery coulombic efficiency losses when charging *(typical ~10%)*	1) Cable losses between the PV array to MPPT *(typ <1%)*	1) Battery coulombic efficiency losses when charging *(typ ~10%)*
2) Battery inverter efficiency losses *(typ ~4-12%)*	2) MPPT efficiency losses may also apply *(typ ~4-5%)*	2) Battery inverter efficiency losses *(typ ~4-12%)*
	3) Cable losses between MPPT and battery *(typ <1%)*	
	4) Battery watt-hour efficiency losses when charging *(typ ~10-30% depending on technology)*	
	5) Cable losses between battery and battery inverter *(typ <1%)*	
	6) Battery inverter efficiency losses *(typ ~4-12%)*	

34.2 System Efficiencies in an a.c.-Coupled System Supplying a.c. Loads

Figure 20 shows the various system losses in an a.c.-coupled system providing a.c. energy to the loads. Table 10 summarises the typical losses for the many pathways between the loads and the energy sources.

FIGURE 20: SYSTEM LOSSES IN AN A.C.-COUPLED CONFIGURED HYBRID SYSTEM-EXCLUDING CABLE LOSSES

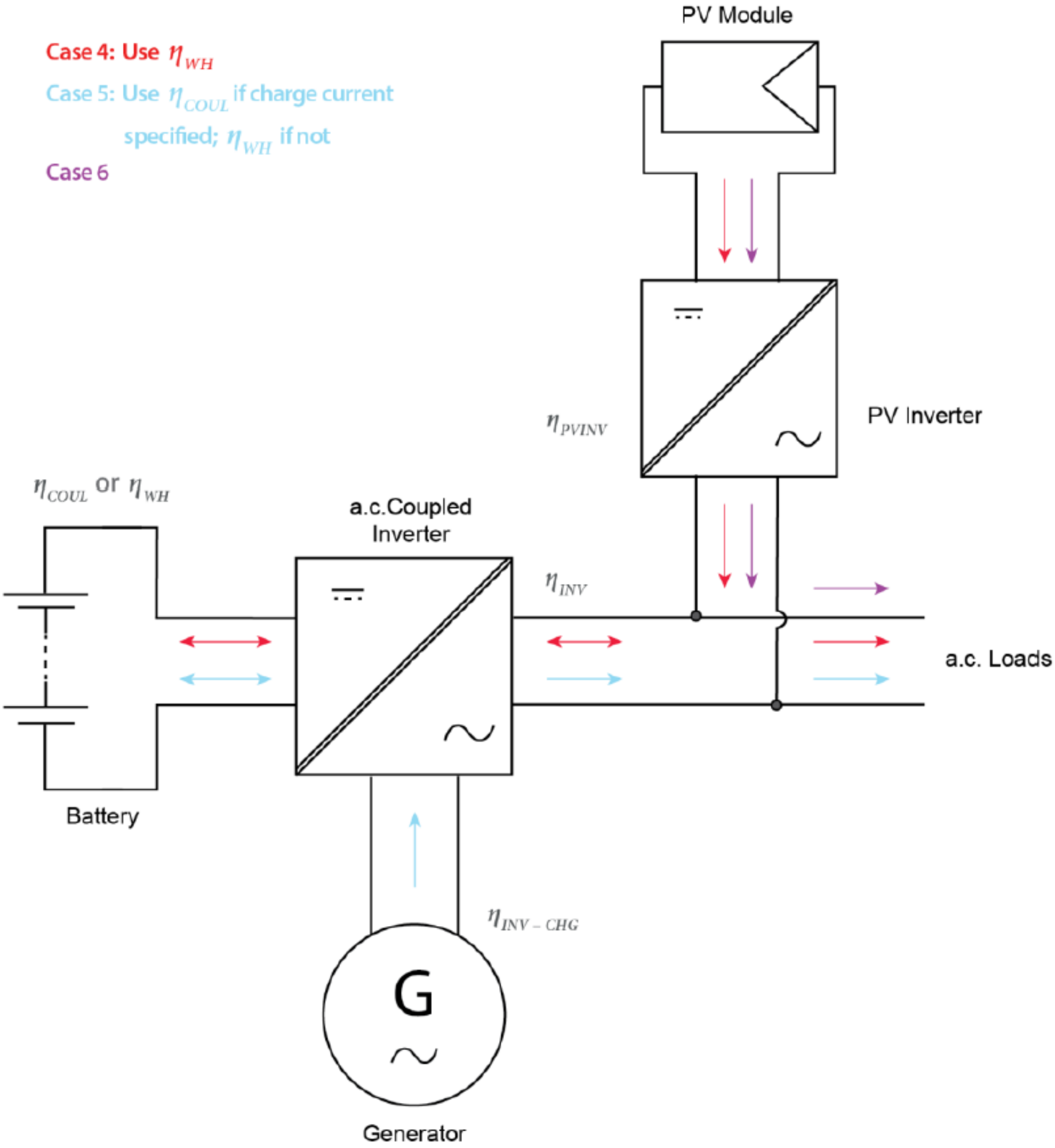


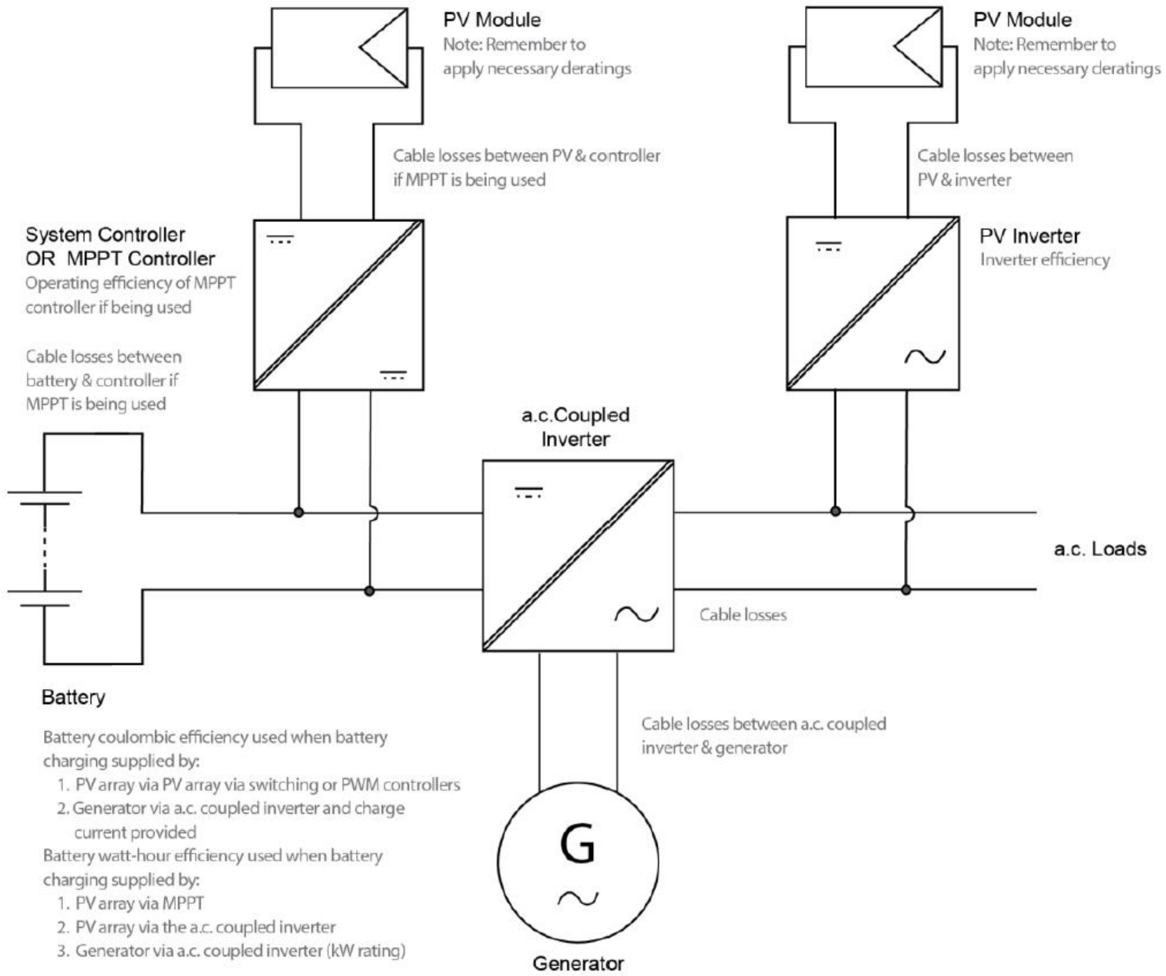
TABLE 10: SYSTEM EFFICIENCY LOSSES FOR A.C.-COUPLED SYSTEM SUPPLYING A.C. LOADS

Case 4: PV array is connected to PV inverter, charges batteries via battery inverter and batteries supply load. The battery inverter would be a.c.-coupled interactive.	Case 5: generator powers the a.c. load and charges battery via the battery inverter. At times the battery supplies none, some or all of the a.c. load. The battery inverter would be a.c.-coupled interactive.	Case 6: PV array is connected to PV inverter and supplies a.c. loads directly.
1) Cables losses between the PV array to PV inverter *(typ <1%)*	1) Cable losses between the generator and battery inverter *(typ <1%)*	1) Cables losses between the PV array to PV inverter *(typ <1%)*
2) PV inverter efficiency losses *(typ ~3-6%)*	2) Battery inverter efficiency losses *(typ ~4-12%) acting as charger*	2) PV inverter efficiency losses *(typ ~3-6%)*
3) Cable losses between PV inverter and battery inverter *(typ <1%)*	3) Cable losses between battery inverter and battery *(typ <1%)*	
4) Battery inverter efficiency losses *(typ ~4-12%) acting as charger*	4) Battery watt-hour efficiency losses *(typ ~20%)*	
5) Cable losses between a.c. battery inverter and battery *(typ <1%)*	5) Cable losses between battery and battery inverter *(typ <1%)*	
6) Battery watt-hour efficiency losses *(typ ~20%)*	6) Battery inverter efficiency losses *(typ ~4-12%)*	
7) Cable losses between battery and battery inverter when inverting *(typ <1%)*	**Note**: If battery charging current from a.c. coupled interactive battery inverter is specified then losses similar to that of Case 3 in Table 9 would be applied.	
8) Battery inverter efficiency losses *(typ ~4-12%)*		

34.3 Combined a.c.- and d.c.-Coupled System Configurations

Figure 21 shows the various system losses in a combined a.c.- and d.c.-coupled system providing a.c. energy to loads.

FIGURE 21: SYSTEM LOSSES IN A COMBINED A.C.- AND D.C.-COUPLED CONFIGURED HYBRID SYSTEM



PART 5 – PREPARING DIAGRAMS, BILL OF MATERIALS AND QUOTATION

35 Draw-Schematic/Single Line diagram

A schematic circuit diagram is the representation of a power system using the simple symbol for each component. This diagram should show the main connections and arrangement of the system components along with their data such as current rating, voltage, power rating, cable size, etc. Table 11 shows universally accepted electrical symbols to represent the different electrical components are generally applicable for a solar home system circuit diagram. A designer must prepare this diagram and include it as part of design document. This will help in procuring and installing the right components and wiring the system correctly. An example is provided in Figure 22.

TABLE 11: ELECTRICAL SCHEMATIC SYMBOLS

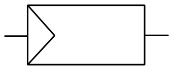
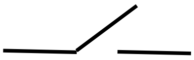
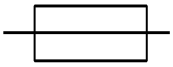
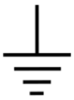
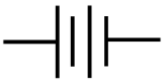
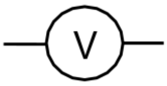
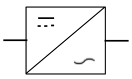
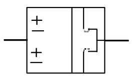
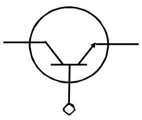
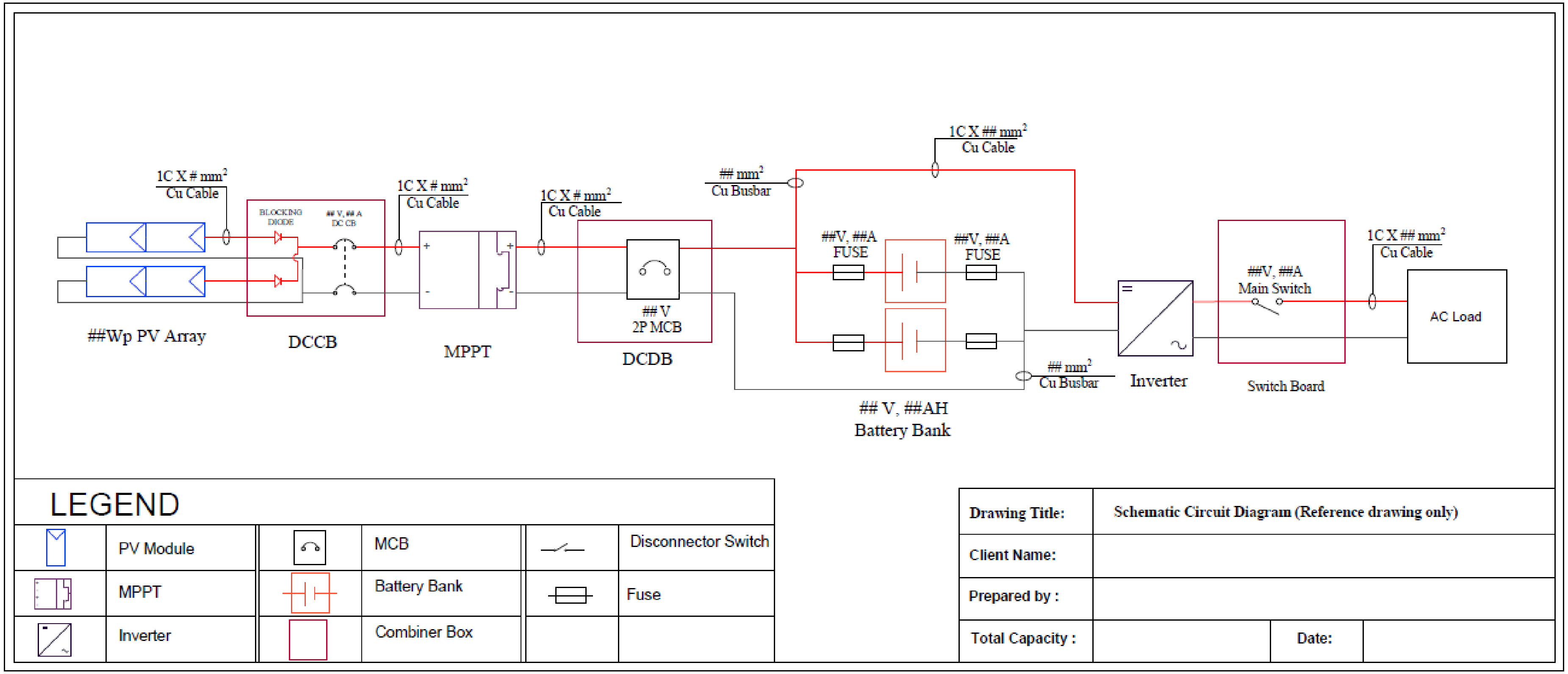
Symbol	Identification	Explanation
	PV module	Represents solar PV modules
	Circuit breaker	Represents a fixed mounted low voltage circuit breaker
	Disconnect switch	Represents a switch (open position shown)
	Fuse	Represents fuses in d.c. circuit
	Ground (earth)	Represents a grounding (earthing) point
	Battery	Represents a battery in an equipment package
	Ammeter	Represents ammeter
	Voltmeter	Represent voltmeter
	Inverter	Represents inverter
	MPPT	Represents Maximum Power Point Tracker
	PWM Controller	Represents PWM Controller

FIGURE 22: A SCHEMATIC CIRCUIT DIAGRAM FOR AN EXAMPLE LARGE SOLAR HOME SYSTEM



A hybrid system would also include a fuelled generator and more protection/isolation equipment.

36 Prepare Bill of Materials

After design is complete, a bill of materials or bill of quantity should be prepared to estimate the system cost. An example of a bill of materials for a typical small Solar Home System is presented inTable 12.

TABLE 12: EXAMPLE BILL OF MATERIALS AND COSTINGS FOR A TYPICAL SOLAR HOME SYSTEM

Sl. No.	Description	Specification	Qty.
1	Poly-crystalline solar PV module		
2	Storage battery		
3	Battery inverter		
4	MPPT		
5	Mounting structure for roof		
6	Battery rack		
7	Single core d.c. cable		
8	Two or three core a.c. cable		
9	Battery fuses		
10	d.c. switch to disconnect PV modules		
11	d.c. switch to disconnect battery		
12	a.c. switch to disconnect a.c. loads		
13	d.c. combiner box		

A hybrid system would also include generators and more isolation/protection equipment and cables.

37 Providing a Quotation

When providing a quotation to a potential end-user, the designer should provide (as a minimum) the following information:

- Full specifications of the system proposed including quantity, make (manufacturer) and model number of the solar modules, full specifications of any inverter(s) and drawings and specifications of the array mounting structure where applicable.
- A copy of the load assessment sheet showing the details of how the load was calculated.
- The expected performance of the system and how it will meet the power and energy requirements specified in the load assessment sheet.
- A firm quotation which shows the installed cost of the complete system.
- Warranty information relating to each of the items of equipment and the overall system performance.
- A complete listing of the regular maintenance requirements for the installation.