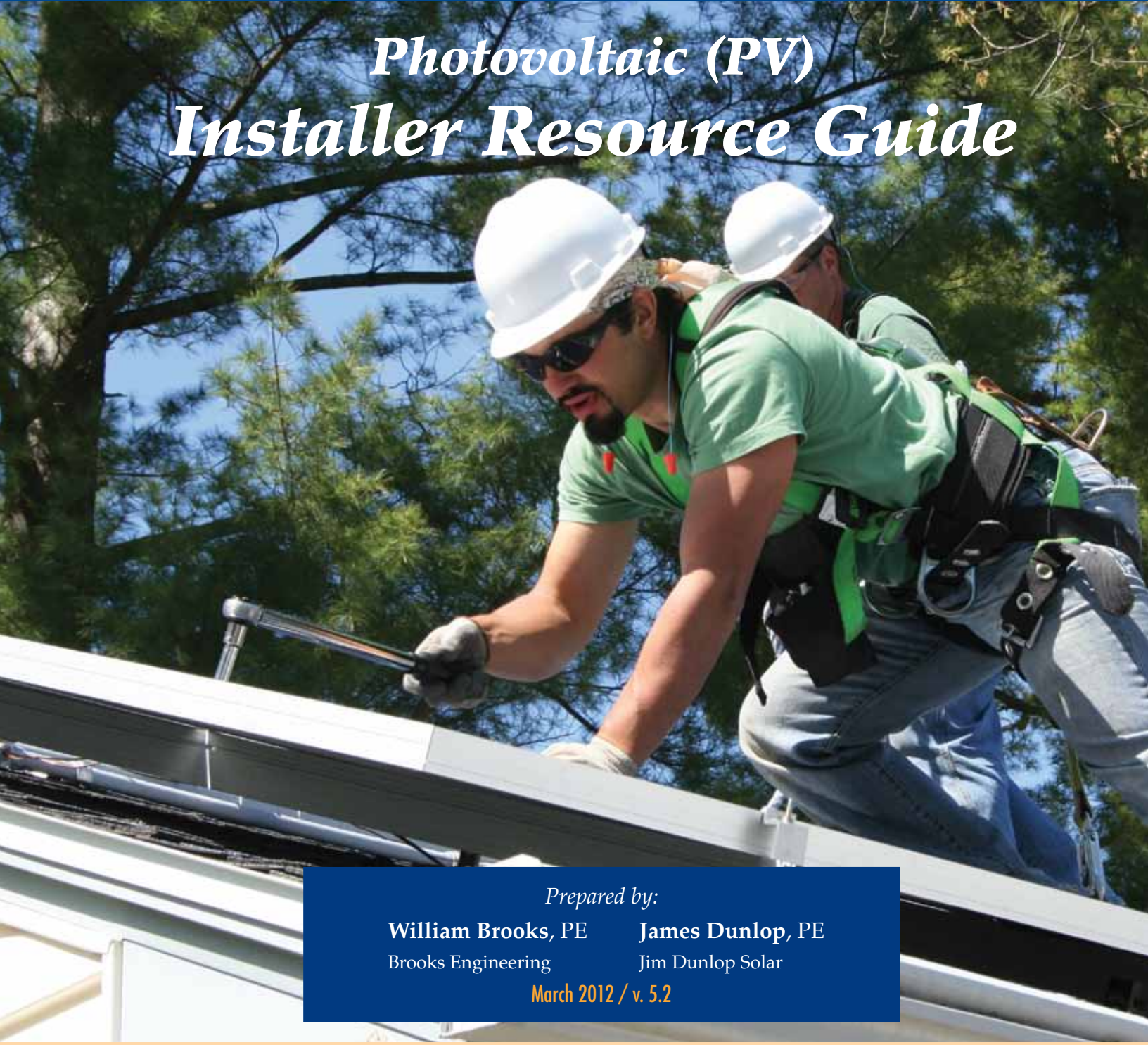


NABCEP

Photovoltaic (PV) Installer Resource Guide



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Acknowledgements:

NABCEP wishes to thank the companies and individuals who have made this Resource Guide possible. This document is the result of the efforts of its principal authors: **Bill Brooks** (Brooks Engineering) and **Jim Dunlop** (Jim Dunlop Solar). It is also the result of the tireless and myriad contributions of the Study Guide Committee. We are grateful to the following individuals for their contributions:

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Forward/Scope

This document was developed to provide an overview of some of the basic requirements for solar photovoltaic (PV) system installations and those who install them. Readers should use this document along with the *2011 National Electrical Code® (NEC®)*, the governing building codes and other applicable standards. These codes and standards are referenced often throughout this document, and are the principal rules that govern the installation of PV systems and any other electrical equipment. A thorough understanding of these requirements is essential for PV system designers and installers.

This document is a collaborative effort, and is considered a work in progress. Future editions of this guide will incorporate comments, corrections and new content as appropriate to reflect new types of products, installation methods or code requirements. Public comments are welcomed and can be directed to the following:

www.pvstudyguide.org.

Units of Measure

Both the International System of Units (SI) and the U.S./Imperial customary units of measure are used throughout this document. While SI units are generally used for solar radiation and electrical parameters, U.S./Imperial customary units are used most commonly in the U.S. construction industry for weights or measure. PV professionals are expected to be comfortable with using both systems of measurement and converting between the two given the appropriate unit conversion factors.

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Welcome to the 2012 edition of the NABCEP Certified PV Installer Study and Resource Guide. This edition follows the most recent version of the NABCEP PV Installer Job Task Analysis which can be found at www.nabcep.org.

Over the years we have received many suggestions for improving our Study and Resource Guide. We often receive suggested corrections to perceived inaccuracies in the copy. With the publication of this guide we are also launching an on-line forum (www.pvstudyguide.org/) where comments and suggestions may be posted. NABCEP Study Guide Committee members will monitor the forum; the second edition of the PV Study Guide will include the most relevant and appropriate suggestions that are received. We think that this open comment period approach will ultimately improve the Study Guide and are looking forward to hearing from you. Please keep your postings positive and as brief and succinct as possible. The forum will stay open until April 30, 2012.

As ever, we wish to remind all readers of this Study and Resource Guide that it is in no way intended to be the definitive word on PV installation nor is it intended to be viewed as the sole study resource for candidates for the NABCEP Certification Examination. The text and the resources in the appendix of this document are an excellent starting point for candidates preparing for the Installer Exam however all candidates should be cognizant that there are many other sources of good information on the topics covered by the JTA and they should use them. The ultimate way to prepare for the NABCEP exam is by reviewing the Job Task Analysis and Exam Blueprint that are appended to this guide. An honest and thorough self-evaluation of these will best help the candidate to see what areas in the body of knowledge required to pass the exam they need to study the most.

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Introduction

This *Photovoltaic (PV) Installer Resource Guide* is an informational resource intended for individuals pursuing the Photovoltaic Installer Certification credential offered by North American Board of Certified Energy Practitioners (NABCEP). This guide covers some of the basic requirements for PV installations and for those who install them, and includes numerous references to books, articles, websites, and other resources for additional information. Individuals should use this guide in conjunction with the many other resources in their preparations for the NABCEP certification and exam.

Candidates for the NABCEP PV Installer Certification should first carefully read the NABCEP Candidate Handbook, which outlines certain prerequisites for education, training and system installation experience in a responsible role to qualify for the certification and exam. For further information on the certification program, how to apply, and to download the latest NABCEP Candidate Information Handbook, see: <http://www.nabcep.org/certification/how-to-apply-2>.

This guide is organized and closely associated with the NABCEP Photovoltaic Installer Job Task Analysis (JTA). The JTA outlines the expected duties of a qualified PV installer, and defines the general knowledge, skills, and abilities required of those who specify, install and maintain PV systems. The JTA is the basis for the NABCEP PV installer certification program and examination content, and should be referenced often when reviewing this document. The JTA is available for download from the NABCEP website, see: <http://www.nabcep.org/certification/pv-installer-certification>.

The objectives of this guide are to provide general information and additional resources concerning the key areas of the JTA. Following are the major content areas addressed in the JTA and in this guide, which serve as the specification for developing the NABCEP PV installer examinations. The percentages indicate the relative numbers of exam items based on each content area.



JTA Job Description *for NABCEP Certified PV Installer*

Given a potential site for a solar photovoltaic system installation and given basic instructions, major components, schematics, and drawings, the PV installer will: specify, adapt, implement, configure, install, inspect, and maintain any type of photovoltaic system, including grid-connected and stand-alone systems with or without battery storage, that meet the performance and reliability needs of customers in the United States and Canada, by incorporating quality craftsmanship and complying with all applicable codes, standards, and safety requirements.

- | | |
|---|-------|
| • Verify System Design | (30%) |
| • Managing the Project | (17%) |
| • Installing Electrical Components | (22%) |
| • Installing Mechanical Components | (8%) |
| • Completing System Installation | (12%) |
| • Conducting Maintenance and Troubleshooting Activities | (11%) |

This guide is not an all-inclusive or definitive study guide for the exam, and exam questions are not necessarily based on the contents in this resource guide. Sample problems and scenarios are presented solely for example purposes, and are not to be considered representative of exam questions. A limited number of actual exam items that have been retired from the item bank are contained at the end of this document.

An Introduction to Photovoltaic Systems

PV systems are electrical power generation systems. They vary greatly in size and their applications, and can be designed to meet very small loads from a few watts or less up to large utility-scale power plants producing tens of megawatts or more. PV systems can be designed to supply power to any type of electrical load at any service voltage.

The major component in all PV systems is an array of PV modules that produces dc electricity when exposed to sunlight. Other major components may include power conditioning equipment, energy storage devices, other power sources and the electrical loads. Power conditioning equipment includes inverters, chargers, charge and load controllers, and maximum power point trackers. Energy storage devices used in PV systems are mainly batteries, but may also include advanced technologies like flywheels or other forms of storing electrical energy or the product, such as storing water delivered by a PV water pumping system. Other energy sources coupled with PV systems

may include electrical generators, wind turbines, fuel cells and the electric utility grid. See Fig. 1.

Balance-of-system (BOS) components include all mechanical or electrical equipment and hardware used to assemble and integrate the major components in a PV system together. Electrical BOS components are used to conduct, distribute and control the flow of power in the system.

Examples of BOS components include:

- Conductors and wiring methods
- Raceways and conduits
- Junction and combiner boxes
- Disconnect switches
- Fuses and circuit breakers
- Terminals and connectors
- Grounding equipment
- Array mounting and other structural hardware

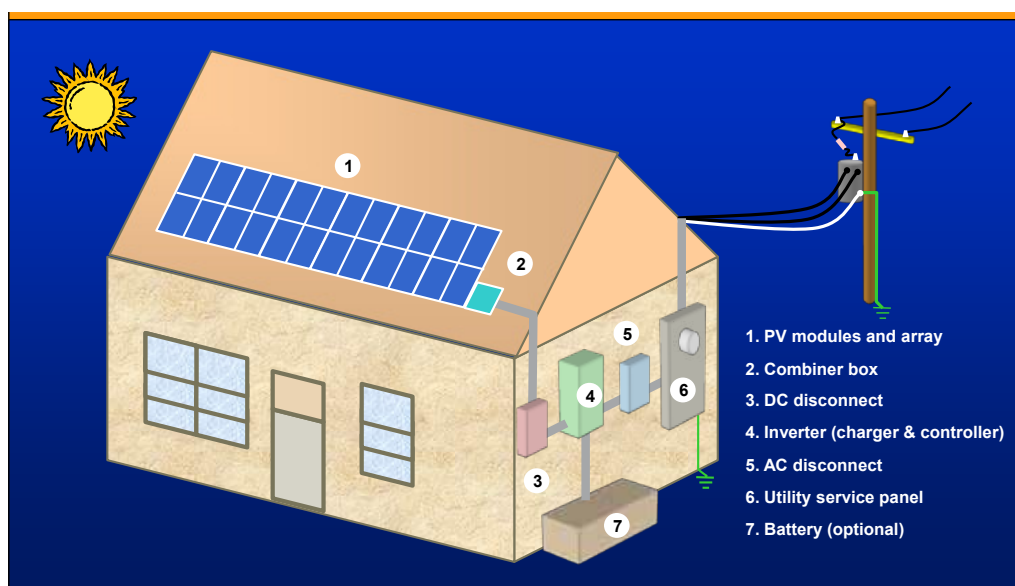


Figure 1. - PV system components

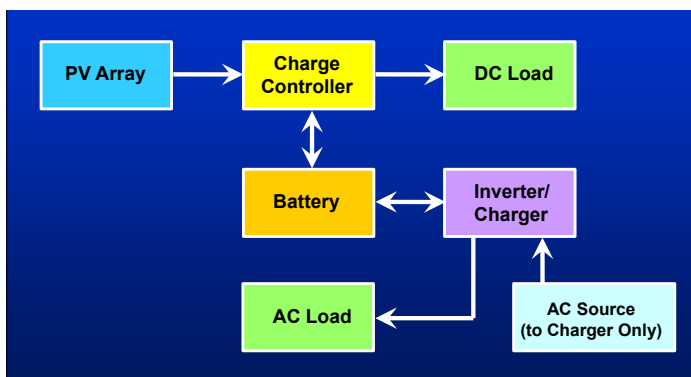


Figure 2. Stand-alone PV systems operate autonomously and are designed to meet specific electrical loads.

Types of PV systems are classified based on the loads they are designed to operate, and their connections with other electrical systems and sources. The specific components needed depend on the type of system and its functional and operational requirements.

Stand-alone PV systems operate independently of other electrical systems, and are commonly used for remote power or backup applications, including lighting, water pumping, transportation safety devices, communications, off-grid homes and many others. Stand-alone systems may be designed to power dc and/or ac electrical loads, and with a few exceptions, use batteries for energy storage. A stand-alone system may use a PV array as the only power source, or may additionally use wind turbines, an engine-generator, or another auxiliary source. Stand-alone PV systems are not intended to produce output that operates in parallel with the electric utility system or other sources. See Fig. 2.

Interactive PV systems operate in parallel and are interconnected and synchronized with the electric utility grid. When connected to local distribution systems, interactive systems supplement utility-supplied energy to a building or facility. The ac power produced by interactive systems

either supplies on-site electrical loads or is back-fed to the grid when the PV system output is greater than the site load demand. At night, during cloudy weather or any other periods when the electrical loads are greater than the PV system output, the balance of power required is received from the electric utility. Interactive PV systems are required to disconnect from the grid during utility outages or disturbances for safety reasons. Only special battery-based interactive inverters can provide stand-alone power for critical loads independent from the grid during outages. See Fig. 3.

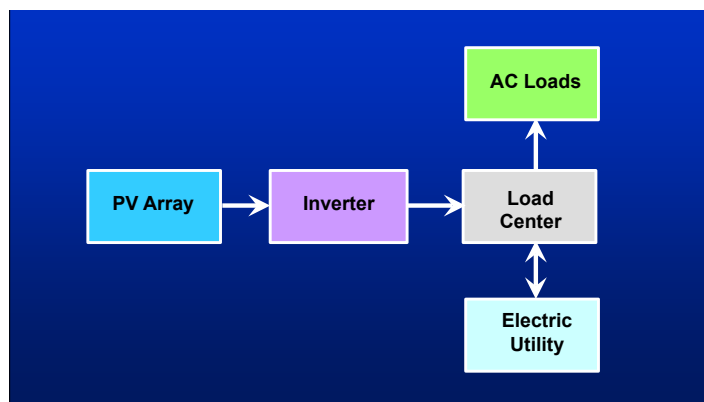


Figure 3. Utility-interactive PV systems operate in parallel with the electric utility grid and supplement site electrical loads.

PV systems can be designed to supply power to any type of electrical load at any service voltage.

2. Verify System Design

While the PV installer may not actually design PV systems, they must know how to interpret and review system designs and effectively execute the installation based on the plans. They must also be able to evaluate site issues affecting the design, identify discrepancies in the design or with code compliance, and recommend and implement appropriate corrective actions or alternatives. Although a PV installer is not expected to be an electrical systems design engineer, experienced installers have a thorough understanding of system designs, including their major components, functions and installation requirements.

2.1 Determine Client Needs

An accurate assessment of the customer's needs is the starting point for specifying, designing and installing PV systems. Developing and planning PV projects requires an understanding of the customer's expectations from both financial and energy perspectives. Companies and individuals offering PV installation services must interpret the customer's desires, and based on the site conditions, clearly explain the options, their trade-offs and costs. They must also explain the functions and operating principles for different types of PV systems, and estimate their performance relative to the customer's electrical loads. In many cases, installation contractors will be submitting proposals and bidding on projects, but the same considerations apply.

Customer development also includes addressing all other issues affecting the proposed installation, such as applicable incentives, legal matters, location of equipment and appearance. Fundamentally, knowledge of the client's needs and desires become the basis for preparing proposals, quotations, and construction contracts.

There are several public domain and commercial software resources available in the PV industry that address different aspects of project development and systems design. The capabilities of these tools range from simple solar resource and energy production estimates, to site survey and system design tools, to complex financial analysis software. Some tools also provide assistance with rebate programs applications and tax incentives, while other programs and worksheets focus on the technical aspects of system sizing and design.

The following lists some of the popular software tools used in the PV industry:

Public Domain (NREL/DOE)

- PVWATTS: www.nrel.gov/rredc/pvwatts/
- In My Back Yard (IMBY): www.nrel.gov/eis/imby/
- HOMER: www.analysis.nrel.gov/homer/
- Solar Advisor Model (SAM): www.nrel.gov/analysis/sam/



NABCEP PV Technical Sales Certification

The NABCEP PV Technical Sales Certification is a credential offered for those specifically engaged in marketing and the customer development process for PV installations. Further information on this certification program is available on the NABCEP website: <http://www.nabcep.org/certification/pv-technical-sales-certification>

Commercial

- Clean Power Estimator: www.cleanpower.com
- PVSYST: www.pvsyst.com
- OnGrid: www.ongrid.net
- PVSol: www.solar design.co.uk/
- PV F-Chart: www.fchart.com
- Maui Solar Software: www.maui solar software.com/

Manufacturers

- Inverter string sizing and various system sizing and design tools

- Clean Power Estimator: www.cleanpower.com
- PVSYST: www.pvsyst.com
- OnGrid: www.ongrid.net
- PVSol: www.solardesign.co.uk/
- PV F-Chart: www.fchart.com
- Maui Solar Software: www.maui-solar-software.com/

Manufacturers

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Assessing Energy Use

Knowledge of the customer's electrical loads and energy use are important considerations for any type of PV installation. The energy produced by PV systems will offset energy derived from another source, and represents a return on the customer's financial investment.

Be prepared to evaluate and discuss the customer's energy use relative to the PV system options and their expected performance. This can be as simple as reviewing electrical bills for the past year or longer if available. See Fig 5. For new construction or off-grid applications, the loads can be estimated from equipment ratings and expected load use profiles, but estimates can be highly inaccurate. Actual measurements are always preferred, and there are a number of low-cost electronic watt-hour meters available that can be readily installed to measure specific loads, branch circuits or entire electrical services. Load information is used to size and design PV systems, estimate their performance and to conduct financial evaluations.

For stand-alone PV applications, load energy consumption dictates the size and cost of the PV system required, and is a critical design parameter. For these designs, accurate load assessments are a must. In many cases, a customer could have a greater benefit in changing

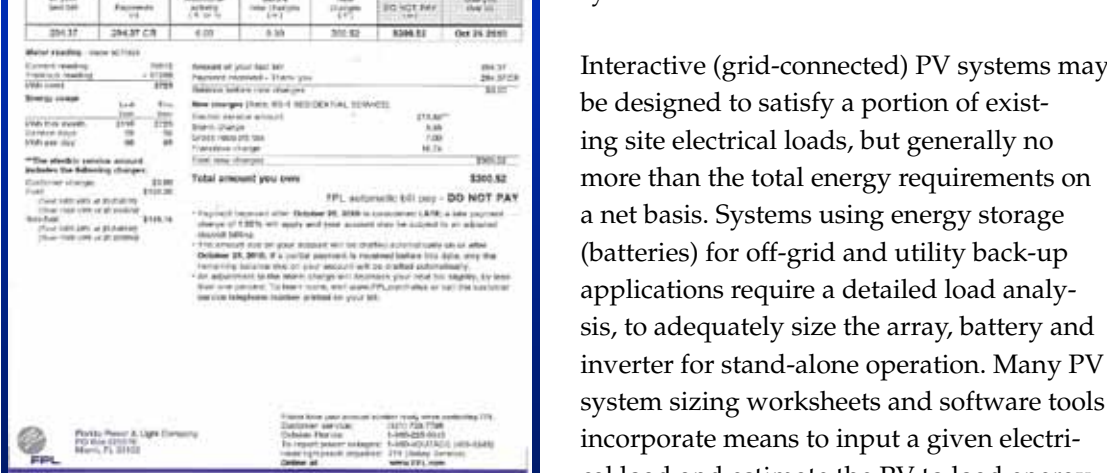
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Figure 5. Electric bills are reviewed as part of a site survey to evaluate customer energy use.



Figure 4. The Database of State Incentives for Renewable Energy (DSIRE) contains information on rules, regulations and policies for renewable energy and energy efficiency programs in all states.

DSIRE

Many websites provide information concerning local and state regulations for PV installations, including incentive programs, utility interconnection rules, and requirements for contractor licensing, permitting and inspection. The Database of State Incentives for Renewable Energy (DSIRE) is an excellent source for this information, and includes up-to-date summary information and numerous links to federal, state and local websites. For additional details, see: www.dsireusa.org

Power and Energy Basics

An understanding of power and energy fundamentals is essential for the PV professional.

Electrical power is expressed in units of watts (W):

1 megawatt (MW) = 1,000 kilowatts (kW) = 1,000,000 watts (W)

Electrical energy is expressed in units of watt-hours (Wh):

1 kilowatt-hour (kWh) = 1000 Wh

Power and energy are related by time. Power is the rate of transferring work or energy, and analogous to an hourly wage (\$/hr) or the speed of a vehicle (mi/hr). Energy is the total amount of work performed over time, and analogous to total income earned (\$) or distance traveled (mi). Simply stated, energy is equal to the average power multiplied by time:

Energy (Wh) = Avg. Power (W) × time (hr)

Electrical loads are any type of device, equipment or appliance that consumes electrical power. Electrical loads are characterized by their voltage, power consumption and use profile. Many types of electrical loads and appliances are available in high-efficiency models. Alternating-current (ac) loads are powered by inverters, generators or the utility grid. Direct-current (dc) loads operate from a dc source, such as a battery. Many small off-grid PV system applications use only dc loads, and avoid having to use an inverter to power ac loads.

2.2 Review Site Survey

Site surveys are used to collect information about the local conditions and issues affecting a proposed PV installation. This information is documented through records, notes, photographs, measurements and other observations and is the starting point for a PV project. Ultimately, information from site surveys is used in combination with the customer desires as the basis for preparing final quotations, system designs, and planning the overall installation.

There are many aspects to conducting a thorough site survey. The level of detail depends on the size and scope of the project, the type of PV system to be installed, and where and how it will be installed. Greater considerations are usually associated with commercial projects, due to the larger equipment and increased safety hazards involved. Obtaining the necessary information during a site survey helps plan and execute PV installations in a timely and cost-effective manner. It also begins the process of assembling the system manuals and project documentation.



Figure 6. A variety of tools and equipment may be required for a site survey.

A number of tools, measuring devices, special equipment and safety gear may be required for conducting site surveys. See Fig. 6. Some of the basic equipment includes:

- Appropriate PPE including hardhats, safety glasses, safety shoes, gloves and fall protection equipment
- Basic hand tools, ladders, flashlights, mirrors and magnifying glasses
- Tape measures, compasses, levels, protractors and solar shading calculators
- Voltmeters, ammeters, watt and watt-hour meters, and power quality analyzers
- Graph paper, calculator, audio recorders, cameras and electronic notebooks

A PV installer must evaluate whether a proposed site will be suitable for the installation and proper operation of the system. In general, a site assessment involves determining:

- A suitable location for the array
- Whether the array can operate without being shaded during critical times
- The mounting method for the array
- Where the balance-of-system (BOS) components will be located
- How the PV system will be interfaced with existing electrical systems

2.2.1 Array Location

PV arrays can be mounted on the ground, rooftops or any other suitable support structure. The primary considerations for optimal PV array locations include the following:

- Is there enough surface area available to install the given size PV array?
- Can the array be oriented to maximize the solar energy received?
- Is the area minimally shaded, especially during the middle of the day?
- Is the structure strong enough to support the array and installers?
- How will the array be mounted and secured?
- How far will the array be from other system equipment?
- How will the array be installed and maintained?

- Will the array be subjected to damage or accessible to unqualified persons?
- Are there local fire codes or wind load concerns that limit rooftop areas for PV installations?
- Are there additional safety, installation or maintenance concerns?

The answers to these and other questions will help determine the best possible locations for installing PV arrays. There are many trade-offs, and designers and installers need to evaluate potential locations based on the site conditions and other available information, and determine if a PV installation is even feasible.

Array Area

Individual PV module characteristics and their layout dictate the overall surface area required for a PV array with a specified peak power output rating. The surface area required for a given array depends on many factors, including the individual module dimensions, their spacing in the array, and the power conversion efficiency of the modules used. Fire safety codes, wind loads and accessibility to the array for installation and maintenance must also be considered when evaluating suitable array locations and layouts, and may limit possible locations to install PV arrays. PV arrays installed in multiple rows of tilted racks or on trackers require additional spacing between each array mounting structure to prevent row to row shading.

Power densities for PV arrays can vary between 6 and 15 watts per square foot (W/sf) and higher, depending on module efficiency and array layout. For example, the power density of a 175 watt crystalline silicon PV module with a surface area of 14.4 sf is calculated by:

$$175 \text{ W} \div 14.4 \text{ sf} = 12.2 \text{ W/sf}$$

For a 4 kW PV array, the total module surface area required would be:

$$4000 \text{ W} \div 12.2 \text{ W/sf} = 328 \text{ sf}$$



This is approximately the area of 10 sheets of plywood. Additional area is usually required for the overall PV array installation and other equipment. All things considered, it usually takes about 80 to 100 sf of surface area for a 1 kWdc rated PV array using standard crystalline silicon PV modules. For example, assuming an array power density of 10 W/sf, a 1 MW PV array would require 100,000 sf of array area, slightly larger than two acres and the approximate size of the rooftops on big box retail establishments. See Fig. 7.

Figure 7. For a power density of 10 watts per square foot, a 500 kW PV array can be installed in a 50,000 square foot area.

Sun Position and the Solar Window

The location of the sun relative to any point on earth is defined by two ever-changing angles. The *solar azimuth* angle defines the direction of the sun's horizontal projection relative to a point on earth, usually symbolized by the Greek letter Psi (ψ). For example, with compass headings, north is 0° or 360° , east is 90° , south is 180° and west is 270° . However, some solar equipment and computer programs use due south as the zero degree reference because it simplifies the complex equations used to calculate sun position. In these cases, solar azimuth angles west of south are typically represented by negative angles (due west is -90°), and east of south is represented as a positive angle (due east is $+90^\circ$).

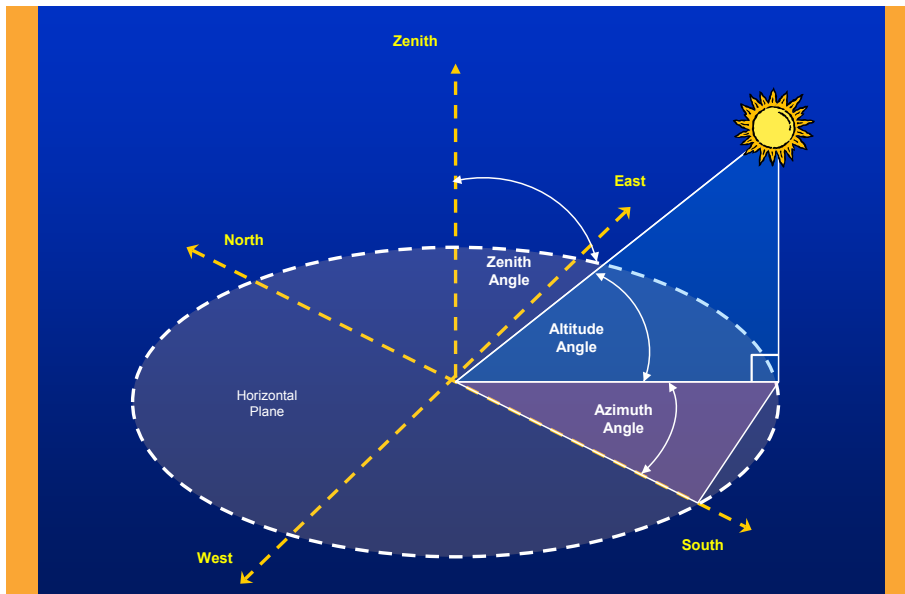


Figure 8. Sun position is defined by the azimuth and altitude angles.

The *solar altitude* angle defines the sun's elevation above the horizon, and commonly symbolized by the Greek letter alpha (α). At sunrise and sunset, when the sun is on the horizon, the sun's altitude is 0° . If the sun is directly overhead, then its altitude is 90° (at the zenith). The sun will be directly overhead at noontime some point during the year only between the Tropic of Cancer and Tropic of Capricorn. This range of tropical latitudes (23.45° north and south of the equator, respectively) is defined by the limits of solar declination and sun position, which also define the beginnings of the seasons. See Fig. 8.

A *sun path* or *sun position* diagram is a graphical representation of the sun's altitude and azimuth angles over a given day of the year, for the specified latitude. These charts can be used to determine the sun's position in the sky, for any latitude, at any time of the day or year. Sun path diagrams are the basis for evaluating the effects of shading obstructions on PV arrays and other types of solar collectors.

Typically, these charts include the sun paths for the solstices and at the equinoxes, and sometimes the average monthly sun paths or for different seasons. At the equinoxes,

Solar Noon

Solar noon is the local time when the sun is directly due south at its highest point in the sky and crossing the local meridian (line of longitude). However, solar noon is not usually the same as 12 p.m. local time due to offsets from Daylight Savings Time, and the site longitude relative to the time zone standard meridian, and eccentricities in the earth-sun orbit. A simple method to determine solar noon is to find the local sunrise and sunset times and calculate the midpoint between the two.

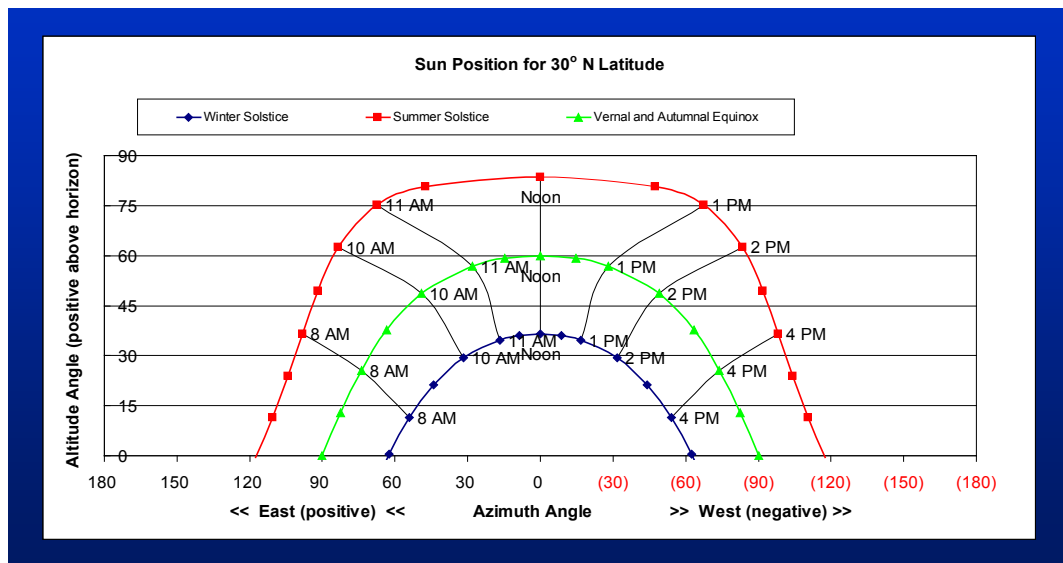


Figure 9. A sun path chart shows the annual range of sun position for a given latitude.

the sun paths are identical, and define the average sun path for the year. Consequently, PV arrays are ideally tilted at angles to face as close to this average sun path as possible. The equinoxes define the first days of spring and fall, and everywhere on earth, the sun rises due east and sets due west, and the sun is above the horizon for exactly 12 hours. On the equinoxes, the sun is directly overhead (solar altitude is 90°), at solar noon everywhere along the equator.

A sun path chart shows all possible sun positions over a day and the year. See Fig. 9. This chart indicates that on the first day of winter (December 21), the sun rises at about 7 a.m. solar time and sets at about 5 p.m. On December 21, the sun's highest altitude is about 37° at noontime. On March 21 and September 21, the first days of spring and fall, the sun rises at 6 a.m. at an azimuth of 90° and the highest sun altitude is 60° at solar noon. On June 21, the first day of summer, the sun rises at about 5 a.m., reaches a maximum altitude of about 83° and sets at about 7 p.m. At 9 a.m. on June 21, the azimuth is approximately 95° (slightly north of east) and the altitude is approximately 49° (about half way between the horizon and zenith).

The winter and summer solstices define the minimum and maximum solar altitude angles and the range of sun paths over a year. For any location on earth, the maximum solar altitude at solar noon is a function of the solar declination and the local latitude. Since we know solar altitude at solar noon on the equator is 90° at the equinoxes, the solar altitude angle will be lower at higher latitudes by an amount equal to that latitude plus the solar declination. For example, at 40° N latitude on the winter solstice, the solar altitude angle at solar noon would be $90^\circ - 40^\circ + (-23.45^\circ) = 26.55^\circ$. Conversely, on the summer solstice at the same latitude, the maximum solar altitude would be approximately 47° higher or about 73.5°, since the solar declination varies between $\pm 23.45^\circ$. At the winter solstice, the sun is directly overhead along the Tropic of Capricorn (23.45° S) at solar noon, and at the summer solstice, the sun is directly overhead along the Tropic of Cancer (23.45° N). See Figs. 10 a-c.

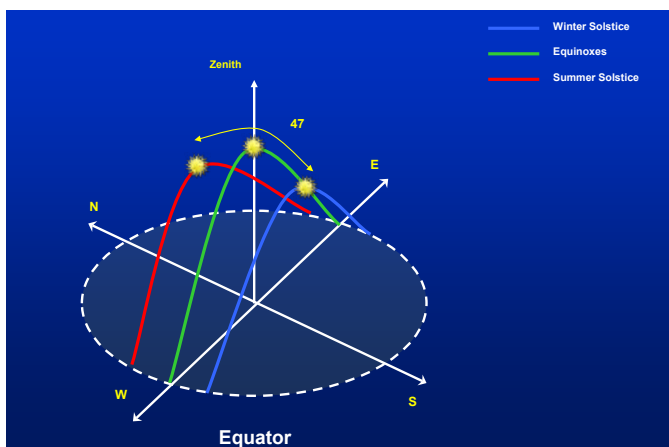


Figure 10a.

Figures 10a -10c. The solar window is defined by the limits of sun paths between the winter and summer solstices.

The *solar window* represents the range of sun paths for a specific latitude between the winter and summer solstices. Wherever possible, PV arrays should be oriented toward the solar window for maximum solar energy collection. As latitudes increase to the north from the equator, the solar window is inclined at a closer angle to the southern horizon. The sun paths and days are longer during summer and shorter during winter. For any location, the maximum altitude of the sun paths at solar noon varies 47° between the winter and summer solstices.

2.2.2 Array Orientation

PV arrays should be oriented toward the solar window to receive the maximum amount of solar radiation available at a site, at any time. The closer an array surface faces the sun throughout every day and over a year without being shaded, the more energy that system will produce, and the more cost-effective the PV system becomes with respect to alternative power options.

Similar to sun position, the orientation of PV arrays is defined by two angles. The *array azimuth angle* is the direction an array surface faces based on a compass heading or relative to due south. North is 0° or 360° , east is 90° , south is 180° and west is 270° . Unless site shading or local weather patterns dictate otherwise, the optimal azimuth angle for facing tilted PV arrays is due south (180° compass heading) in the Northern Hemisphere, and due north in the Southern Hemisphere.

The *array tilt angle* is the angle between the array surface and the horizontal plane. Generally, the higher the site latitude, the higher the optimal tilt angle will be to maximize solar energy gain. A horizontal

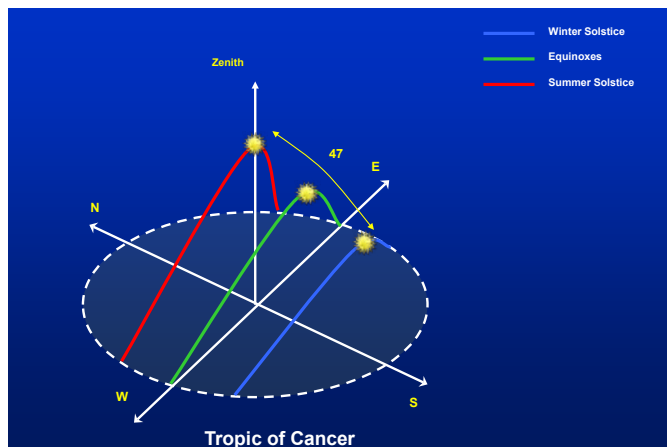


Figure 10b.

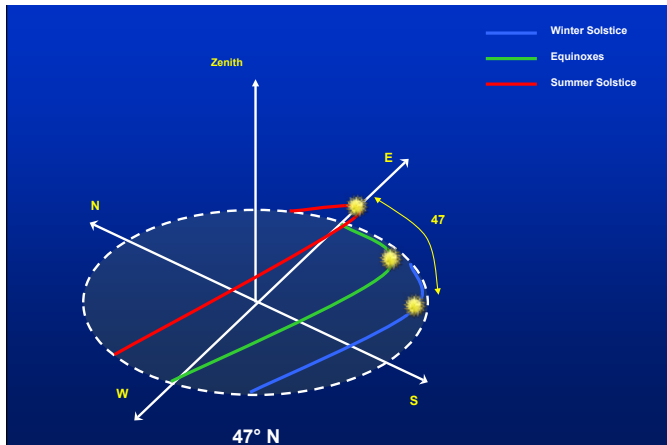


Figure 10c.

Solar Declination

Solar declination (δ) is the ever changing angle between the earth's equatorial plane and the sun's rays. This is the primary geometric factor affecting the sun position and the solar energy received at any point on earth. Solar declination varies continuously from -23.45° to $+23.45^\circ$ over the year in a sinusoidal fashion, due the earth's constant tilt and elliptical orbit around the sun. The limits of solar declination define the tropical and arctic latitudes, and the range of sun position in the sky relative to any point on earth. The winter and summer solstices are defined by the minimum and maximum limits of solar declination, respectively. Solar declination is 0° at the equinoxes, when the earth's equatorial plane is aligned directly toward the sun's rays.

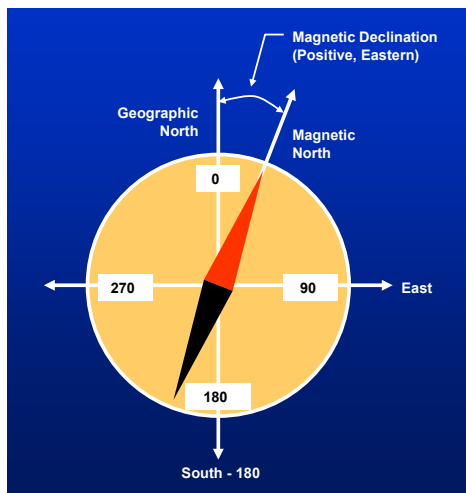


Figure 11. Magnetic compass readings must be corrected for magnetic declination.



Figure 12. The western U.S. has positive (easterly) declination, and will cause a compass needle to point east of geographic north.

Magnetic Declination

Magnetic declination is the angle between magnetic north and the true geographic North Pole, and varies with location and over time. Magnetic declination adjustments are made when using a magnetic compass or with some solar shading devices to accurately determine due south. Magnetic compasses and devices incorporating them usually have a revolving bezel to adjust for magnetic declination. See Fig. 11.

Magnetic declination is considered positive when magnetic north is east of true north and negative when magnetic north is west of true north. The western U.S. has positive (easterly) declination, and the eastern U.S. has negative (westerly) declination. Magnetic declination is near zero on a line running through Pensacola, FL, Springfield, IL and Duluth, MN, called an agonic line. The greatest magnetic declination occurs in the northeastern and northwestern most parts of the U.S. and North America. For example, a compass needle points 15° east of geographic north in Central California. Conversely, a compass needle points about 13° west of geographic north in New Jersey. In most of the central and southern U.S., magnetic declination is small and can usually be neglected, especially considering the small effects of changing array azimuth angle by a few degrees. See Fig. 12.

array has a zero degree tilt angle, and a vertical array has a 90° tilt angle. The array azimuth angle has no significance for horizontal arrays, because they are always oriented horizontally no matter how they are rotated. See Fig. 13.

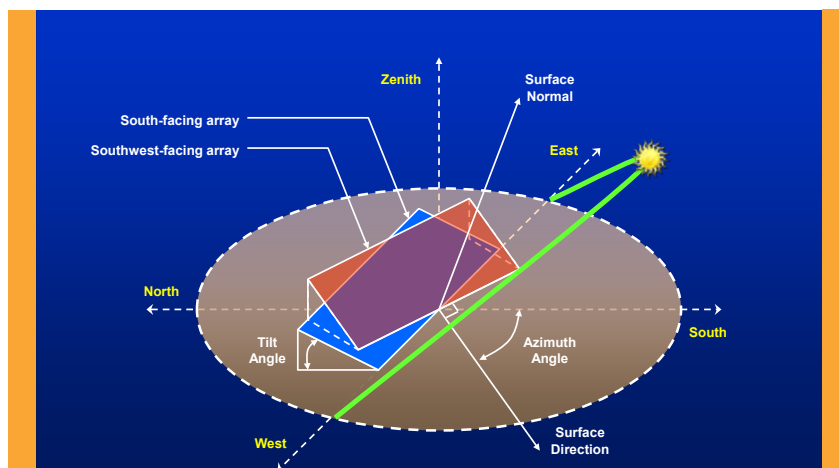


Figure 13. The orientation of PV arrays is defined by the surface azimuth and tilt angles.

For unshaded locations, the maximum annual solar energy is received on a surface that faces due south, with a tilt angle slightly less than the local latitude. This is due to longer days and sun paths and generally sunnier skies during summer months, especially at temperate latitudes. Fall and winter performance can be enhanced by tilting arrays at angles greater than the local latitude, while spring and summer performance is enhanced by tilting arrays at angles lower than the local latitude. Adjustable-tilt or sun-tracking arrays can be used to increase the amount of solar energy received on a daily, seasonal or annual basis, but have higher costs and complexity than fixed-tilt arrays.

Varying the array tilt angle results in significant seasonal differences in the amount of solar energy received, but has a smaller impact on the total annual solar energy received. See Fig 14. For stand-alone PV systems installed at higher than tropical latitudes, the optimal tilt angle can significantly reduce the size and cost of the system required to meet a given load. For systems that have winter-dominant loads, arrays should be tilted at an angle of latitude +15°. If the array is being designed to meet a summer-dominant load, the array should be tilted at an angle of latitude -15° to maximize solar energy collection during summer months.

The effects of non-optimal array orientation are of particular interest to PV installers and potential customers, because many potential array locations, such as rooftops do not have optimal solar orientations. When trade-offs are being made between orientation and aesthetics, having this information available can help the prospective owner and installer make decisions about the best possible array locations and their orientation.

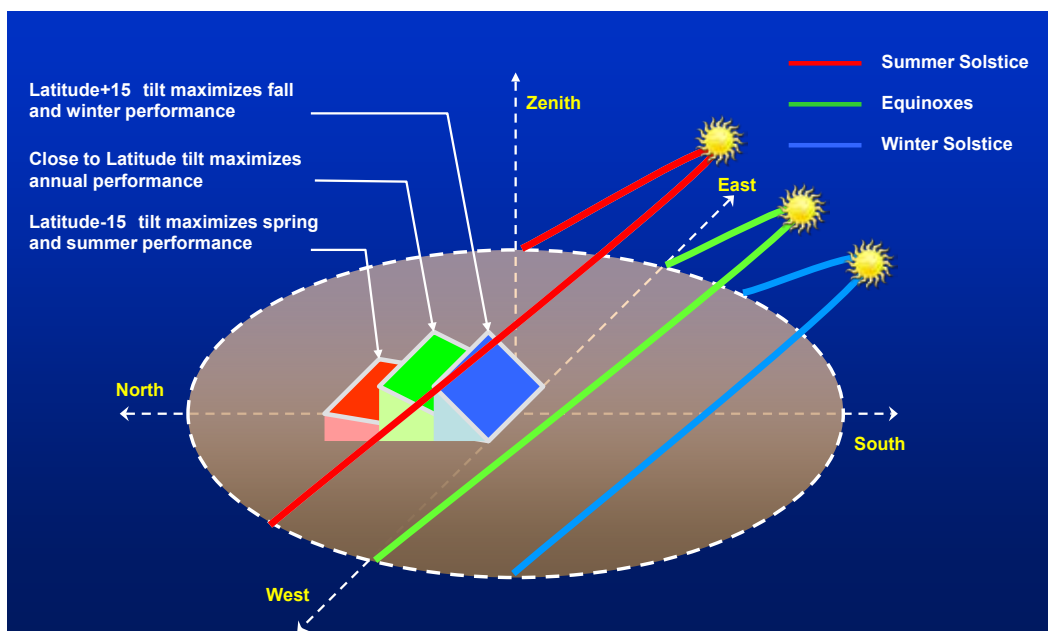


Figure 14. Array tilt angle affects seasonal performance.

Multiplication factors can be used to adjust PV system annual energy production for various tilt angles relative to the orientation that achieves the maximum annual energy production, and are region specific. See Table 1. These tables help provide a better understanding of the impacts of array orientation on the amount of solar energy received, and the total energy produced by a PV system. In fact, the amount of annual solar energy received varies little with small changes in the array azimuth and tilt angles.

For south-facing arrays, array tilt angles close to 30° (a 7:12 pitch roof) produce nearly the maximum amount of energy on an annual basis for much of the continental U.S. However, arrays oriented within 45° of due south (SE and SW) produce very close to the same energy (within 7%) as a south-facing array. Since shading losses are often much higher, these orientation losses tend to be smaller than one might expect. Even horizontally mounted (flat) arrays will produce more energy than systems using tilted arrays facing to the east or west.

For some utility-interactive PV system installations, it may be desirable to face an array toward the southwest or even due west, provided that the array tilt is below 45°. West-

erly orientations tend to shift the peak array power output to the afternoon during utility peak hours, but do not necessarily maximize the energy production or financial benefit to the system owner if they are not the utility. Some net metering programs offer time-differentiated rate structures to encourage the production of energy during utility peak hours. A careful analysis using an hourly computer simulation program is necessary to determine the cost benefit of these orientations. A minimum of six hours of unshaded operation is still important for best system performance.

New York						
Tilt	Flat	15°	30°	45°	60°	Vertical
Direction						
South	0.87	0.86	1.00	0.88	0.82	0.66
SE,SW	0.87	0.93	0.94	0.91	0.85	0.82
E,W	0.87	0.85	0.81	0.74	0.67	0.49

Florida						
Tilt	Flat	15°	30°	45°	60°	Vertical
Direction						
South	0.93	0.99	1.00	0.96	0.86	0.57
SE,SW	0.93	0.86	0.86	0.80	0.82	0.57
E,W	0.93	0.91	0.85	0.77	0.68	0.49

California						
Tilt	Flat	15°	30°	45°	60°	Vertical
Direction						
South	0.89	0.97	1.00	0.97	0.89	0.58
SE,SW	0.89	0.95	0.96	0.93	0.85	0.60
E,W	0.89	0.88	0.84	0.78	0.70	0.52

Arizona						
Tilt	Flat	15°	30°	45°	60°	Vertical
Direction						
South	0.89	0.97	1.00	0.97	0.89	0.60
SE,SW	0.89	0.94	0.95	0.90	0.83	0.59
E,W	0.89	0.87	0.82	0.75	0.66	0.48

Table 1. Array orientation factors can be used to adjust the maximum available solar radiation for non-optimal orientations.

Note: The tables and charts showing the effects array orientation on the solar energy received and the energy produced by PV arrays were derived with data generated from PVWatts running simulations for various locations with different array tilt and azimuth angles.

PVWatts™

PVWatts™ is an online software model produced by the National Renewable Energy Laboratory to estimate the performance of grid-connected PV systems. See Fig 16. The user defines the site location, the maximum power for the PV array, the array mounting and orientation, and selects the appropriate derating factors. The software models the PV system output at each hour over a typical year, using archived solar resource and weather data. This tool can be used to evaluate the solar energy collected and energy produced by grid-tied PV systems for any location and for any array azimuth and tilt angles. To run PVWatts™ online, see: <http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/>.

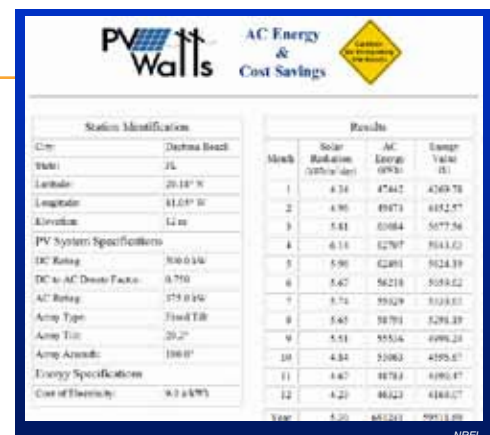


Figure 16. PVWatts is an online tool used to estimate the performance of interactive PV systems.

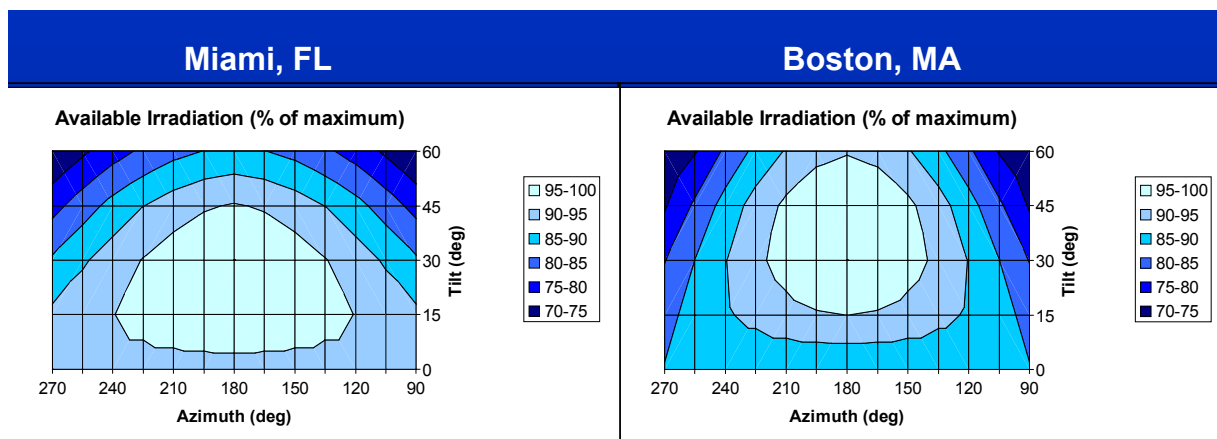


Figure 15. The effects of varying array tilt and azimuth angles are location dependent.

Contour charts may also be used to plot similar data comparing the effects of array orientation on the amount of solar energy received. These charts clearly show that for lower latitudes and array tilt angles closer to horizontal, array azimuth angles as much as 90° from due south have a minimal effect on the solar energy received. The reduction in solar energy received for off-azimuth orientations increases with increasing tilt angles and at higher latitudes. Generally, for most of the central and southern U.S., fixed-tilt arrays with azimuth angles ± 45 degrees from due south and tilt angles ± 15 of the local latitude will receive at least 90% of the annual solar energy as for optimally tilted south-facing surfaces. See Fig. 15.

2.2.3 Perform a Shading Analysis

A shading analysis evaluates and quantifies the impacts of shading on PV arrays. Shading may be caused by any obstructions in the vicinity of PV arrays that interfere with the solar window, especially obstructions to the east, south and west of an array. This includes trees, towers, power lines, buildings and other structures, as well as obstructions close to and immediately around the array, such as antennas, chimneys, plumbing vents, dormer windows and even from other parts of the array itself. Shading of PV arrays can also be caused by accumulated soiling on the array surface, which can be particularly severe in more arid regions like the western U.S., requiring regular cleaning to ensure maximum system output. See Fig 17.

PV arrays should be unshaded at least 6 hours during the middle of the day to produce the maximum energy possible. Ideally, there should be no shading on arrays between the hours of 9 a.m. and 3 p.m. solar time over the year, since the majority of solar radiation and peak system output occur during this period. However, this is not always achievable and tradeoffs are made concerning the specific array location, or mitigating the shading obstructions if possible (e.g., trimming or removing



Figure 17. Shading of PV arrays can be caused by any obstructions interfering with the solar window.

trees, etc.). Even a small amount of shading on PV arrays during peak generation times can dramatically reduce the output of the system.

Sun path charts are the basis for conducting shading evaluations. By measuring the worst-case altitude and azimuth angles of a shading object from an array location, a scale image of the obstruction can be plotted on a sun position chart for the given latitude. This shows the portion of the solar window that is obstructed by shading. Knowing the amount of receivable solar energy during different periods of a day, the shading analysis can be used to estimate the reduction in solar radiation received during the shaded times of the day and year, and ultimately estimate the reduced energy production for a PV system. These are the fundamental principles used for a shading analysis. Most system design and performance estimating tools also incorporate shading factors to derate the system output accordingly.



Figure 18. Various devices are used to determine the extent of shading for potential PV array locations.

To simplify shading evaluations, several devices and software tools have been commercially developed. See Fig. 18. These devices are all based on sun path charts and viewing the solar window at proposed array locations. The devices project or record obstructions in the solar window, and estimate the net solar energy received after shading. PV installers should be familiar with these tools, their principles of operation and how to obtain accurate results. More elaborate architectural software tools, such as Google Sketch-up and CAD programs can allow designers to simulate complex shading problems and provide detailed designs and renderings of proposed PV installations.

Source for shading evaluation tools and software include:

- Solar Pathfinder™: www.solarpathfinder.com
- Solmetric SunEye™: www.solmetric.com
- Wiley ASSET™: www.we-llc.com
- Google SketchUp™: sketchup.google.com

For larger PV systems with multiple parallel rows one in front of another in the array, one row of modules can shade the one in back during winter months if the rows are too closely spaced. A six-inch shadow from an adjacent row of modules is capable of shutting down an entire string or row of modules depending on the direction of the shadows and the electrical configuration of the array. A simple rule for minimum spacing between rows is to allow a space equal to three times the height of the top of the row or obstruction in front of an array. This rule applies to the spacing for any obstructions in front of an array.

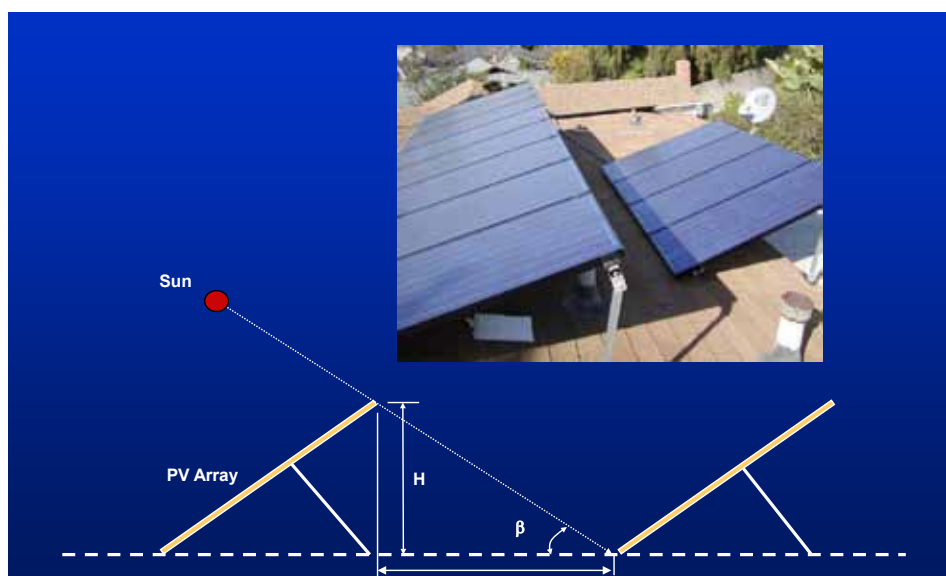


Figure 19. Multiple rows of rack-mounted PV arrays must be separated far enough apart to prevent shading.

For example, if the height of an array is three (3) feet, the minimum separation distance should be nine (9) feet since the height of the adjacent row if it is three feet above the front of the next row. See Fig. 19. In the southern half of the United States, a closer spacing may be possible, depending on the prescribed limits to avoid shading. However, even at the lowest latitudes the spacing should not be less than two times the height of the top of the adjacent module. Multiple rows of PV arrays can also be more closely spaced using lower tilt angles, and even with the orientation penalty of a lesser tilt angle, it is usually a better option than to suffer shading losses.

The minimum required separation distances between PV array rows and other obstructions depends on latitude, the height of the obstruction, and the time of day and year that shading is desired to be avoided. To avoid shading at the winter solstice between 9 a.m. and 3 p.m. solar time, the separation distance between PV arrays and obstructions should be at least 2 times the height of the obstruction at latitudes around 30°, 2-1/2 times the height at latitudes around 35°, 3 times the height at 40° latitude and 4 times the height at 45° latitude. See Fig. 20.

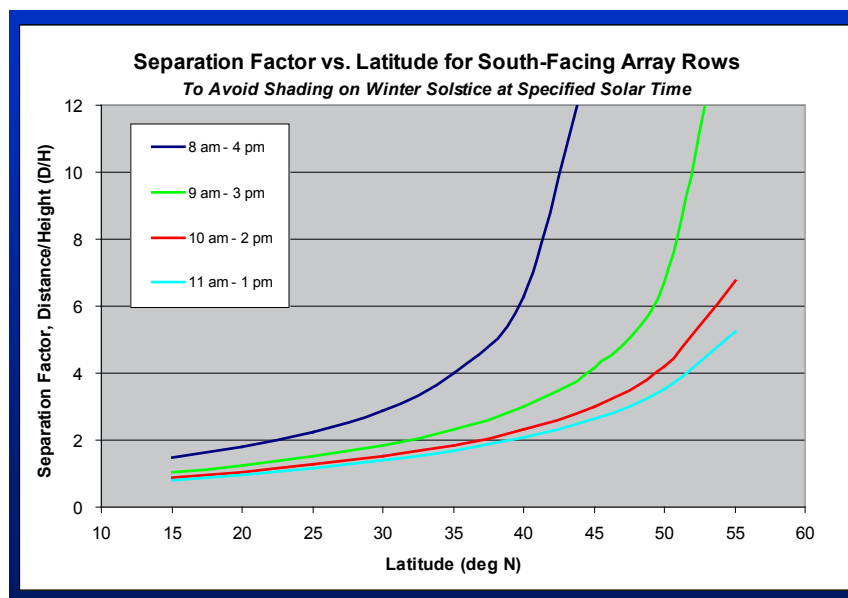


Figure 20. The minimum required separation distances between PV array rows or other obstructions depends on latitude, the height of the obstruction, and the time of day and year to avoid shading.

2.2.4 Array Mounting Methods

PV arrays can be mounted on the ground, rooftops and other structures that provide adequate protection, support and solar access. The site conditions and results of the site survey usually dictate the best mounting system location and approach to use.

Rooftops are very popular locations for installing PV arrays. Because they are elevated, roof mounts offer some physical protection and limited access to the array for safety, and usually provide better sun exposure. Rooftop PV installations also do not occupy space on the ground that might be needed for other purposes. Rooftop and other building-mounted PV arrays must be structurally secured and any attachments and penetrations must be properly weathersealed. Available rooftop areas for mounting PV arrays may be limited by any number of factors, including required spaces about the array for installation and service, pathways and ventilation access for fire codes, wind load setbacks, and spaces for other equipment. Sloped roofs also present a significant fall hazard, and require appropriate fall protection systems and/or personal fall arrest systems (PFAS) for installers and maintenance workers.

The layout of a PV array can have a significant effect on its natural cooling and operating temperatures. A landscape (horizontal) layout may have a slight benefit over a portrait (vertical) layout when considering the passive cooling of the modules. Landscape is when the dimension parallel to the eaves is longer than the dimension perpendicular to the eaves. In a landscape layout, air spends less time under the module before escaping and provides more uniform cooling. Standoff mounts operate coolest when they are mounted at least 3 inches above a roof.

Key items to evaluate during a site survey for roof-mounted PV arrays include:

- Building type and roof design
- Roof dimensions, slope and orientation
- Roof surface type, condition and structural support
- Fall protection methods required
- Access for installation and maintenance

Ground-mounted PV arrays are commonly used for larger systems, or where rooftop installations are not possible or practical. Ground-mounts can use a variety of racks, poles and other foundations to support the arrays. Ground-mounted arrays are generally more susceptible to damage than roof-mounted arrays, although their location and orientation is less constrained than for rooftop installations. If an array is mounted at ground level, NEC 690.31(A) requires that the wiring be protected from ready access. Several options may be possible to meet this requirements, including protecting the wiring with non-conductive screening like PVC, limiting access with security fencing, or by elevating the array. Elevating arrays also provides physical protection, and usually helps avoid shading concerns that may exist at lower heights.

Site surveys for ground-mounted PV arrays should consider:

- Zoning and land use restrictions

- Terrain, elevations and grading requirements
- Soil type and array ground-cover
- Water table, flood zones and drainage
- Array foundation requirements
- Security requirements and fencing
- Access for vehicles, equipment and maintenance

The following are common types of PV array mounting systems:

Integral mounting systems are where modules are integrated into the roofing or building exterior. These systems are sometimes referred to as building-integrated PV or BIPV.

Standoff mounting, referred to by some as flush mounting, uses standoffs attached to the roof to support rails on which PV modules are attached. This is the most common method for residential installations. See Fig. 21.



Figure 21. Standoff mounts are the most common way PV arrays are attached to sloped rooftops.

Ballasted mounting systems are often used in large-scale flat roof commercial projects. These mounting systems require engineering for roof structural loading and ballast requirements. Often roof tethers augment the ballast for seismic concerns or excessive wind requirements. See Fig. 22.



Figure 22. Self-ballasted PV arrays are a type of rack mount that relies on the weight of the PV modules, support structure and additional ballast material to secure the array.

Rack mounting is typically used for non-tracking systems at ground level. This method is typical on large commercial or utility-scale arrays.

Pole mounting, is typically used with manufactured racks mounted on top or attached to the side of a steel pole. Pole-top arrays are common for off-grid residential PV systems,



Figure 23. Pole-mounted arrays use either fixed, adjustable, or sun-tracking arrays installed on a rigid metal pipe.

since the weight of the array is balanced over the pole, allowing easy seasonal adjustment. Side-of-pole mounts are most common in small one- or two-module applications where the entire system, such as remote telemetry, is mounted on a single pole. See Fig. 23.



Figure 24. Sun-tracking arrays are typically mounted on poles and increase the amount of solar energy received.

Tracking mounting systems are systems that follow the sun on a daily or seasonal basis. Tracking may increase summer gain by 30% or more, but winter gain may be 15% or less. Tracking may be two-axis for maximum performance or single-axis for simplicity and reliability. See Fig. 24.

Roof Structure and Condition

An important consideration for roof-mounted PV arrays is to assess the condition of the roofing system and determine whether the roof and its underlying structure can support the additional load.

Structural loads on buildings are due to the weight of building materials, equipment and workers, as well as contributions from outside forces like hydrostatic loads on foundations, wind loads and seismic loads. The requirements for determining structural loads on buildings and other structures are given in the standard *ASCE 7 – Minimum Design Loads for Buildings and other Structures*, which has been adopted into the building codes. A structural engineer should be consulted if the roof structure is in question, or if specific load calculations are required for local code compliance.

Common stand-off roof-mounted PV arrays, including the support structures generally weigh between 3 and 5 pounds per square foot (psf), which should be fine for most roofs designed to recent standards. Generally, houses built since the early 1970's have been through more rigorous inspection and tend to have more standard roof structures than those built prior to that period. If the attic is accessible, a quick inspection of the type of roof construction is worthwhile, and will help determine the appropriate attachment sys-

tem to use for the array. Span tables are available in various references, which can help quantify the load-bearing capabilities of roof trusses or beams. For further information see: www.solarabcs.org/permitting

Wind loads are a primary concern for PV arrays, especially in hurricane-prone regions. The design wind loads for PV arrays can be as high as 150 mph in some Atlantic and Gulf coastal regions, resulting in wind loads exceeding 50 PSF and greater on certain portions of a roof or structure. While common stand-off PV arrays do not generally contribute to any additional wind loads on a structure, the array attachment points to the structure or foundation must be of sufficient strength to withstand the design loads.

For example, a 15 square-foot PV module could impose an uplift load of 750 pounds under a design load of 50 psf. A panel of four of these modules can impose a load of 3,000 pounds on the entire mounting structure. If the panel is secured by six roof attachments, and if the forces are distributed equally, there would be a 500-pound force on each attachment, and it must be designed and installed to resist this maximum uplift force. Several manufacturers of roof mounting systems provide engineering analysis for their mounting systems and attachment hardware. Without this documentation, local inspectors may require that a custom mounting system have a structural analysis from a professional engineer for approval. This engineering documentation easily justifies the additional costs of purchasing mounting hardware from a qualified mounting system manufacturer.

The age and condition of the roof covering must also be evaluated. If the roof covering is due for replacement within the next 5 to 10 years, it typically makes sense to roof the building before installing the PV system, as the array would need to be removed and replaced before and after the roofing work. Different types of roof coverings have different lifetime expectations and degradation mechanisms, and wherever roofing issues are a concern for PV installation, it is highly advisable to engage a licensed roofing contractor in the project.

Before recommending or deciding on any PV array mounting system, verify with the mounting system supplier that the hardware is appropriate for the given application. Also, it is generally not advisable to try to fabricate or copy a mounting system design for smaller projects. This usually costs much more than purchasing a pre-engineered system, and may not meet the structural or environmental requirements of the application. PV array mounting structures also must be electrically connected to the equipment grounding system, and special bonding jumpers and connectors are available to maintain electrical continuity across separate structural components. Oftentimes, local jurisdictions require engineering documentation to certify the structural integrity of the mounting system and attachments.

Commercial Roof Mounting Options

PV arrays are mounted on large commercial buildings with flat composition roofs using a variety of racking systems. These mounting structures may be secured by fasteners and physical attachments to the building structure, or by using ballasted racking, or a combination of both to hold the array in place.

Ballasted mounting systems are significantly heavier than mounting systems designed for direct structural attachments, depending on the amount of ballast used, and usually require special load calculations. The main advantages of ballasted mounts include easier installation, and by eliminating direct structural attachments and penetrations into the structure, the possibility of roof leaks is greatly diminished. Ballasted mounting systems are engineered for specific wind loads and roof structures, and have very specific requirements on how to install the array. Even when wind loading is not a concern, additional restraints may be required on the array for seismic loads.

2.2.5 BOS Locations

Any site survey also includes an evaluation of the proposed locations for all other PV system equipment in addition to the PV array. Appropriate locations must be identified for all BOS components, including support structures, inverters, disconnects, over-current devices, charge controllers, batteries, junction boxes, raceways, conductors and any other electrical apparatus or mechanical equipment associated with the system. The PV installer must ensure that all equipment locations are suitable for the intended equipment.

Considerations for BOS locations include providing for accessibility to the equipment for installation and maintenance. Some BOS components may need to be installed in weather-resistant or rain-tight enclosures if they are not installed indoors. Other components, including many utility-interactive inverters, may already be rated for wet and outdoor exposure. Minimum clearances and working spaces are required for electrical equipment that may be serviced in an energized state. Dedicated clear spaces are also required above and in front of all electrical equipment. These and many other installation requirements are outlined in Article 110 of the NEC: Requirements for Electrical Installations.

Avoid installing electrical equipment in locations exposed to high temperatures and direct sunlight wherever possible, and provide adequate ventilation and cooling for heat-generating equipment such as inverters, generators and chargers. Considerations should also be taken to protect equipment from insects, rodents, and other debris. All electrical equipment must be properly protected from the environment unless the equipment has applicable ratings. This includes protection from dust, rain and moisture, chemicals and other environmental factors. All electrical equipment contains instructions on the proper installation of the equipment, and for the environmental conditions for which it is rated.

Some equipment has special considerations, covered under different sections of the electrical and building codes, and in manufacturer's instructions. For example, battery locations should be protected from extreme cold, which reduces their available capacity. Battery containers and installation must follow the requirements in NEC 480. Major components are generally located as close together as possible, and to the electrical loads or services that they supply, in order to minimize the length of conductors, voltage drop and the costs for the installation.

2.3 Confirm System Sizing

2.3.1 Size the Module Mounting Area

If a roof is selected for the array location, then it is necessary to determine whether the roof is large enough for the proposed number of PV modules. For roof areas with non-rectangular shapes, determining the amount of useable roof area can be a challenge.

When laying out a plan for mounting modules on a roof, access to the modules must be provided in case system maintenance is needed. For easiest access, a walkway should be provided between each row of modules. However, this consumes valuable roof area, so a balance needs to be made between the area for the array and access. New requirements in the 2012 International Fire Code [IFC 605.11] require clear space at the edges and peaks of roofs for firefighter access. This poses a challenge to roof-mounted PV systems. Often, only 50% to 80% of the roof area that has a suitable orientation can be used for mounting modules when room for maintenance, wiring paths, firefighter access and aesthetic considerations are taken into account.

To determine the size of the PV array (ultimately the power rating of the system) that can be installed, the usable roof area must be first established. The dimensions and orientation of individual modules may dictate various layouts for the array that ultimately need to fit within the usable areas of the roof. The location of structural attachments, the desired electrical configuration, and wire routing are also important considerations when determining the best layout for PV modules in an array. Computer-aided drawing tools can be helpful in determining possible acceptable array layouts given module and roof dimensions.

Smaller array surface areas are required to generate the same amount of power with higher efficiency modules. By definition, a 10% efficient PV module has a power density of 100 W/m² (approximately 10 W/sf) peak power output when exposed to 1000 W/m² solar irradiance. Crystalline silicon PV modules may have efficiencies 12% to 15% and higher for special higher-price models. Higher efficiency modules means less support structure, wiring methods and other installation hardware are required for an array. Most thin-film PV module technologies have efficiencies below 10%, and require correspondingly larger array areas to produce an equal amount of power.

For example, consider a roof with overall dimensions of 14' by 25' (350 sf) with a usable area of 250 sf (71% of total). This roof area would be sufficient for a 2.5 kW crystalline silicon array (250 sf x 10 W/sf = 2500 W) or an 8% efficient thin film array of 2 kW.

2.3.2 Arrange Modules in Mounting Area

Siting the PV array in the available mounting area can have a large impact on the performance of a PV array. In addition to shading and orientation, the array layout must be consistent with the electrical string layout. A string is a series-connection of PV modules in an array. Each set of modules in a series string must be oriented in the same direction if the string is to produce its full output potential. For example, if a string has 12 modules in series, all 12 modules must be in the same or parallel planes of a roof and ideally be

shade-free at the same time. It is possible to split a string between two roof faces, provided the modules keep the exact same orientation. The outputs of multiple strings having similar voltage but using different current output modules, or facing different directions may be connected in parallel.

This characteristic of string inverters poses a design challenge on many residential projects. For instance, a roof may be large enough to hold 24 modules on the south and west faces together. However, the south face may be large enough to mount 16 modules and the west face only large enough to mount 8 modules. If the inverter requires 12 modules in series, the west face is not usable and the south face will only permit 12 modules to be installed. This means that only half the potential array area can be utilized by that string inverter system. This example suggests that it might be reasonable to find an inverter with lower input voltage that only requires 8 modules in series, or consider using module level micro-inverters to avoid string sizing requirements altogether.

2.4 Review Design Energy Storage Systems

A battery converts chemical energy to electrical energy when it is discharged, and converts electrical energy to chemical energy when it is charged. Because the power produced by PV arrays does not always coincide with electrical loads, batteries are commonly used in most stand-alone PV systems to store energy produced by the PV array, for use by systems loads as required. Batteries also establish the dc operating voltage for the PV array, charge controllers and dc utilization equipment, including inverters and dc loads, as applicable.

Batteries are sometimes used in interactive systems, but only with special types of battery-based inverters intended for interactive operation. These inverters operate as diversionary charge controllers and dump excess PV array energy to the grid when it is energized [NEC 690.72]. When there is a loss of grid voltage, these inverters transfer

loads from the grid to operate in stand-alone mode. Interactive systems with battery backup cost significantly more to install than simple interactive systems without batteries, due to the additional equipment required (special inverters, batteries and charge controllers). The design and installation of these systems is also more complex, and usually involves conducting a load analysis and reconfiguring branch circuits in dedicated subpanels. See Fig. 25.

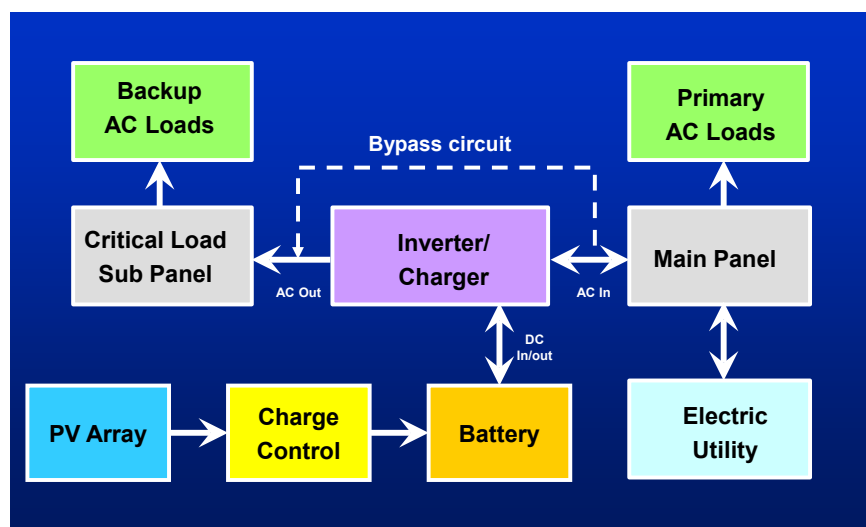


Figure 25. Utility-interactive systems with battery storage are similar to uninterruptible power supplies, and have many similar components.

BATTERY TYPE	ADVANTAGES	DISADVANTAGES
FLOODED LEAD-ACID		
Lead-Antimony	low cost, wide availability, good deep cycle and high temperature performance, can replenish electrolyte	high water loss and maintenance
Lead-Calcium Open-Vent	low cost, wide availability, low water loss, can replenish electrolyte	poor deep cycle performance, intolerant to high temperatures and overcharge
Lead-Calcium Sealed-Vent	low cost, wide availability, low water loss	poor deep cycle performance, intolerant to high temperatures and overcharge, can not replenish electrolyte
Lead-Antimony/Calcium Hybrid	medium cost, low water loss	limited availability, potential for stratification
VALVE-REGULATED LEAD-ACID		
Gelled	medium cost, little or no maintenance, less susceptible to freezing, install in any orientation	fair deep cycle performance, intolerant to overcharge and high temperatures, limited availability
Absorbed Glass Mat	medium cost, little or no maintenance, less susceptible to freezing, install in any orientation	fair deep cycle performance, intolerant to overcharge and high temperatures, limited availability
NICKEL-CADMNIUM		
Sealed Sintered-Plate	wide availability, excellent low and high temperature performance, maintenance free	only available in low capacities, high cost, suffer from 'memory' effect
Flooded Pocket-Plate	excellent deep cycle and low and high temperature performance, tolerance to overcharge	limited availability, high cost, water additions required

Figure 26. Both flooded and sealed lead-acid batteries are commonly used in PV systems.

The lead-acid cell is the most common type of storage battery used in PV systems. Occasionally nickel-cadmium, nickel-iron, or nickel-metal-hydride batteries are used. Newer battery types like lithium-ion are also becoming possible as the costs of these battery systems continue to decrease and performance improves.

A *motive power* or *traction battery* is a type of lead-acid battery designed for use in deep discharge applications, such as electric vehicles. Motive power batteries are robust and are commonly used in stand-alone PV systems. A *starting, lighting and ignition (SLI)* battery has a larger number of thinner plates to provide a greater surface and can deliver higher discharge currents, but are damaged by frequent and deep discharges, and are seldom used in PV systems. Deep discharge-type batteries differ from automobile starting batteries in several respects, mainly their designs use heavier, thicker plates and stronger inter-cell connections to better withstand the mechanical stresses on the battery under frequent deep discharges.

Flooded batteries have a liquid electrolyte solution. Open-vent flooded types have removable vent caps and permit electrolyte maintenance and water additions. *Valve-regulated lead-acid (VRLA)* batteries have an immobilized electrolyte in gel form or absorbed in fiberglass separator mats between the plates. VRLA batteries are spill proof and do not require electrolyte maintenance, however they are more expensive and less tolerant of overcharging and higher operating temperatures than flooded types. Charge controllers must use appropriate charge regulation settings for the type of battery used. See Fig 26.

Vented lead-acid batteries release hydrogen and oxygen gases, even under normal operating conditions. This is due to electrolysis of the electrolyte solution during final charging stages, and results in water loss. Consequently, adequate ventilation must be provided for both vented and sealed battery systems [NEC 480.9 and 480.10]. While it is complicated to calculate the ventilation requirements, it is generally advisable to provide greater ventilation than necessary. A good rule is to provide similar ventilation to a bat-

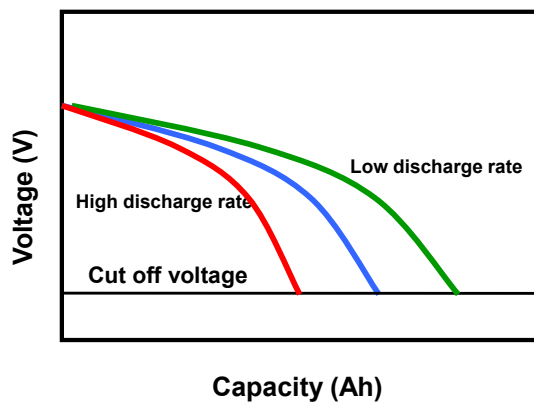


Figure 27. Battery capacity is a measure of the stored energy that a battery can deliver under specified conditions.

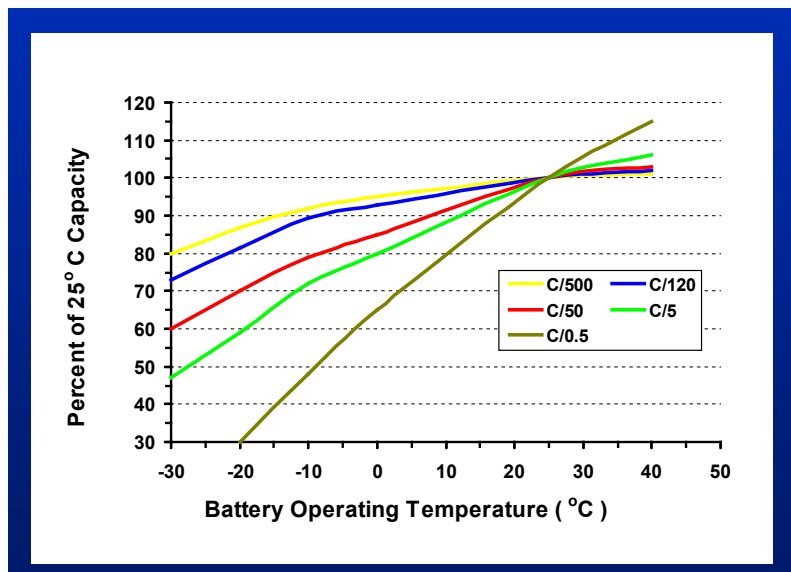


Figure 28. The higher the discharge rate and the lower the temperature, the less capacity that can be withdrawn from a battery to a specified cutoff voltage.

tery room as is required for a combustion water heater. This is something that the AHJ can readily understand since they inspect water heater installations on a daily basis.

Capacity is a measure of battery energy storage, commonly rated in ampere-hours (Ah) or kilowatt-hours (kWh). For example, a 6-volt battery rated at 220 Ah stores 1.32 kWh of energy. Battery design features that affect battery capacity include the quantity of active material, the number, design and physical size of the plates, and electrolyte specific gravity. Usable capacity is always less than the rated battery capacity. Operational factors that affect available battery capacity include discharge rate, cut-off voltage, temperature and age of the battery. See Fig. 27.

The *rate of charge or discharge* is expressed as a ratio of the nominal battery capacity (C) to the charge or discharge time period in hours. For example, a nominal 100 ampere-hour battery discharged at 5 amps for 20 hours is considered a C/20, or 20-hour discharge rate. The higher the discharge rate and lower the temperature, the less capacity that can be withdrawn from a battery to a specified cutoff voltage. See Fig. 28.

State-of-charge is the percentage of available battery capacity compared to a fully charged state. *Depth-of-discharge* is the percentage of capacity that has been removed from a battery compared to a fully charged state. The state-of-charge and depth-of-discharge for a battery add to 100 percent. The *allowable depth-of-discharge* is the maximum limit of battery discharge in operation. Depending on the discharge rate, a cut-off voltage of 11.4 V can result in a maximum allowable depth-of-discharge anywhere from 80 to 98 percent. Depth-of-discharge is usually limited to no more than 75 to 80% for deep cycle batteries, and must also be limited to protect lead-acid batteries from freezing in extremely cold conditions.

Specific gravity is the ratio of the density of a solution to the density of water. Sulfuric-acid electrolyte concentration is measured by its specific gravity, and related to battery state of charge. A fully charged lead-acid cell has a typical specific gravity between 1.26

and 1.28 at room temperature. The *specific gravity* may be increased for lead-acid batteries used in cold weather applications. Conversely, the specific gravity may be decreased for applications in warm climates.

In very cold climates, batteries must be protected from freezing by limiting minimum temperatures in a suitable enclosure, or by limiting the depth of discharge. Because the density of electrolyte decreases with increasing temperature, specific gravity readings must be adjusted for temperature. Inconsistent specific gravity readings between cells in a battery indicate the need for an equalizing charge.

Many factors and trade-offs are considered in battery selection and systems design, and are often dictated by the application or site requirements. Among the factors to consider in the specification and design of battery systems include:

- Electrical properties: voltage, capacity, charge/discharge rates
- Performance: cycle life vs. DOD, system autonomy
- Physical properties: Size and weight
- Maintenance requirements: Flooded or VRLA
- Installation: Location, structural requirements, environmental conditions
- Safety and auxiliary systems: Racks, trays, fire protection, electrical BOS
- Costs, warranty and availability

Most PV systems using batteries require a charge controller to protect the batteries from overcharge by the array. Only certain exceptions apply for special self-regulated systems, which are designed using very low charge rates, special lower voltage PV modules, larger batteries and well-defined, automated loads. If the maximum charge rates from the PV array multiplied by one hour is equal to 3% of the battery nominal amp-hour capacity or greater, a charge controller is required [NEC 690.72]. If a battery is overcharged, it can create a hazardous condition and its life is generally reduced especially for sealed, valve-regulated lead-acid (VRLA) batteries. Most PV systems using battery storage also include overdischarge protection for batteries, by disconnecting loads at a predetermined low-voltage, low state-of-charge condition.

Battery installations in dwellings must operate less than 50 volts nominal, unless live parts are not accessible during battery maintenance. This limits the voltage of lead-acid batteries to no more than 48 volts, nominal. This equates to either 24 series-connected nominal 2-volt lead-acid cells, or 40 series-connected nominal 1.2-volt alkali type nickel cadmium cells. All battery installations in dwellings must have live parts guarded. Live parts must also be guarded for any battery installations 50 volts or greater by elevation, barriers or location in rooms accessible to only qualified persons. Sufficient working spaces and clearances must be provided for any battery installations [NEC110.26].

If the nominal voltage of a battery bank exceeds 48 V, then the batteries shall not be installed in conductive cases, unless they are VRLA batteries designed for installation with metal cases [NEC690.71(D)]. Note that 48 V nominal battery banks exceed the 50 V limit for ungrounded PV systems [NEC 690.41]. Battery systems either must have a system grounded conductor or meet the requirements for ungrounded systems [NEC690.35].

Racks and trays are used to support battery systems and provide electrolyte containment. Racks can be made from metal, fiberglass or other structural nonconductive materials. Metal racks must be painted or otherwise treated to resist degradation from electrolyte and provide insulation between conducting members and the battery cells [NEC 480.9]. Due to the potential for ground faults, metal or other conductive battery racks, trays and cases are not allowed for open-vent flooded lead-acid batteries more than 48 volts nominal. In addition, conductive racks are not permitted to be located within 150 mm (6 in.) of the tops of the nonconductive battery cases [NEC 690.71(D)]. These requirements do not apply to sealed batteries that are manufactured with conductive cases. Any conductive battery racks, cases or trays must also have proper equipment grounding [NEC 250.110].

If batteries are connected in series to produce more than 48 V (nominal), then the batteries must be connected in a manner that allows the series strings of batteries to be separated into strings of 48 V or less for maintenance purposes [NEC 690.71(D-G)]. The means of disconnect may be non-load-break, bolted, or plug-in disconnects. For strings greater than 48 V, there must also be a means of disconnecting the grounded circuit conductors of all battery strings under maintenance without disconnecting the grounded conductors of operating strings.

Whenever the available fault current of a battery exceeds the interrupt ratings of normal overcurrent devices, disconnect means or other equipment in a circuit, special current-limiting overcurrent devices must be installed [NEC 690.9, 690.71]. While many dc-rated circuit breakers do not have sufficient interrupt ratings, current limiting fuses are available with interrupt rating 20,000 A and higher. Because these fuses may be energized from both sides, a disconnect means is required to isolate the fuse from all sources for servicing [NEC 690.16]. A disconnecting means must also be provided for all ungrounded battery circuit conductors, and must be readily accessible and located within sight of the battery system [NEC 690.17].

To prevent battery installations from being classified as hazardous locations, ventilation of explosive battery gasses is required. However, the NEC does not provide specific ventilation requirements. Vented battery cells must incorporate a flame arrester to help prevent cell explosions from external ignition sources, and cells for sealed batteries must have pressure relief vents [NEC 480.9, 480.10].

Special safety precautions, equipment and personal protective equipment (PPE) are required when installing and maintaining battery systems. Hazards associated with batteries include caustic electrolyte, high short-circuit currents, and explosive potential due to hydrogen and oxygen gasses produced during battery charging. Insulated tools should be used when working on batteries to prevent short-circuiting. High-voltage battery systems may present arc flash hazards, and special PPE, disconnecting means and equipment labeling may apply [See NFPA 70E]. Batteries are also very heavy and should only be lifted or supported by methods approved by the manufacturer. Battery installations over 400 lbs may also have to meet certain engineering requirements in seismic regions for the design of non-structural electrical components [See ASCE 7-10].

Electrical Load	Power (W)	Avg. Daily Time of Use (hr)	Avg. Daily Energy (watt-hours)
Lighting	200	6	1200
Refrigerator	300	9.6 (40% duty cycle)	2880
Microwave	1200	0.5	600
Pumps	1000	1	1000
TV and entertainment equipment	400	4	1600
Fans	300	6	1800
Washer	400	0.86 (3 hours 2 times per week)	344
Miscellaneous plug loads	200	12	2400
Total all loads	4000 W (4 kW)		11,824 Wh (11.8 kWh)

Figure 29. A load assessment evaluates the magnitude and duration of electrical loads.

2.4.1 Determine Loads

The sizing of batteries or any other energy storage system is based on the magnitude and duration of the applied electrical loads. The power consumption of the electrical loads defines the maximum discharge rates as well as the total energy withdrawn from the battery on an average daily basis. The size of the battery (total capacity) is selected based on these system parameters and the desired maximum and average daily depth-of-discharge. The maximum battery depth-of-discharge in actual system operation is determined by the low-voltage load disconnect, the discharge rate and the health of the battery.

Identify all existing and planned electrical loads that will be connected to the system, including their ac or dc operating voltage, their power or current consumption, and their expected average daily use. List all loads and multiply the power use by the average daily time of operation to determine daily energy consumption and peak power demand. See Fig. 29. In practice, the inverter should be large enough to power the total connected load, but is only required to be as large as the single largest load [NEC 690.10(A)].

2.4.2 Identify Circuits for Required Loads

Load circuits supplied by stand-alone PV systems must be clearly identified and limited to the design loads. Additional loads beyond what the system has been designed to supply will ultimately result in decreasing battery state-of-charge and reduced battery lifetime. Ensure that only critical loads are connected and that the most efficient loads and practices are used wherever possible. In all cases, do not exceed the load estimates for which the system was designed unless additional generation resources are used.

Multiwire Branch Circuits

Many stand-alone PV systems use inverters with 120 Vac output, with the hot leg connected to both sides (phases) of a common 120/240 V split-phase load center. Normally with 240 V service, the current on one phase is 180 degrees opposed to the current on the other phase, and results in neutral conductor currents equal to the difference between the two phase currents.

OSHA requirements for battery installations include the following:

- Unsealed batteries must be installed in ventilated enclosures to prevent fumes, gases, or electrolyte spray entering other areas, and to prevent the accumulation of an explosive mixture.
- Battery racks, trays and floors must be of sufficient strength and resistant to electrolyte.
- Face shields, aprons, and rubber gloves must be provided for workers handling acids or batteries, and facilities for quick drenching of the eyes and body must be provided within 25 feet of battery handling areas.
- Facilities must be provided for flushing and neutralizing spilled electrolyte and for fire protection.
- Battery charging installations are to be located in designated areas and protected from damage by trucks.
- Vent caps must be in place during battery charging and maintained in a functioning condition.

When the two phases (buses) in the panel are connected together to distribute the 120 V source, the currents on both sides of the panel are now in phase with each other and are additive. If multiwire branch circuits that share a neutral conductor for two branch circuits are connected to this modified distribution panel, the neutral conductor can potentially become overloaded and create a fire hazard. For these installations, a special warning sign is required on the panel to prohibit the connection of multiwire branch circuits [NEC 690.10(C)].

2.4.3 Batteries and Battery Conductors

The goal of battery wiring is to create a circuit that charges and discharges all batteries equally. If batteries are connected in series, this is automatic, but if batteries are connected in parallel, the currents may be unequal due to subtle differences in cable resistance and connections. All batteries used in a battery bank must be the same type, same manufacturer, the same age, and must be maintained at equal temperatures. Batteries should have the same charge and discharge properties under these circumstances.

Series batteries connections build voltage while capacity stays the same as for one battery. See Fig. 30. Parallel battery connections build capacity while voltage stays the same. See Fig. 31. Parallel connections are made from opposite corners of the battery bank to help equalize the voltage drop and current flow through each string. In general, no more than four batteries or series strings of batteries should be connected in parallel. It is better to use larger batteries with higher ampere-hour ratings than to connect batteries in parallel. Large conductors, such as 2/0 AWG, 4/0 AWG or larger, are typically used to minimize voltage drop in battery connections.

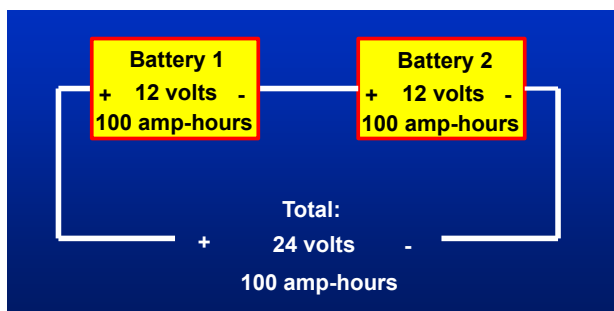


Figure 30. Series battery connections increase voltage.

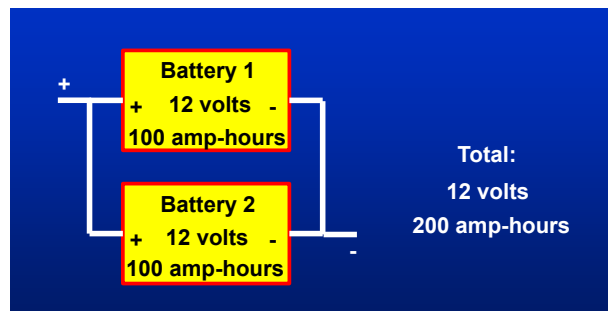


Figure 31. Parallel battery connections increase capacity.

Listed flexible cables rated for hard service usage are permitted to be used for battery conductors, and can help reduce excessive terminal stress that can occur with standard stranded conductors [NEC 690.74, Art. 400]. Welding cable (listed or not listed), automotive battery cables, diesel locomotive cables (marked DLO only) and the like may not meet NEC requirements for battery connections. Properly rated cable will have a conduit rating such as THW or RHW to meet building wiring requirements.

Size Batteries for Loads

Battery sizing in most PV systems is based on the average daily electrical load and a desired number of days of battery storage. The number of days of storage is selected based

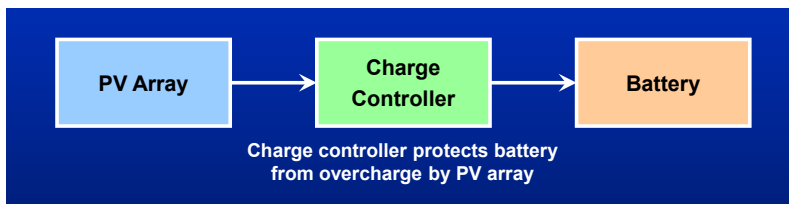


Figure 32. A charge controller is required in most PV systems that use battery storage to regulate battery state-of-charge.

on the importance of the application, and the desired average daily depth-of-discharge for the battery.

Autonomy is defined as the number of days that a fully charged battery can meet system loads without any recharging. Autonomy is calculated by the nominal battery capacity, the average daily load and the maximum allowable depth-of-discharge. Larger autonomy means a larger battery with higher costs, and shallower average daily depth-of-discharge, lower charge and discharge rates, and usually longer battery life.

For example, consider a system load that is 100 Ah per day. A 400 Ah battery is selected, with a desired allowable depth-of-discharge of 75% (300 Ah usable). This battery design would deliver 3 days of autonomy in this system (3 days \times 100 Ah/day = 300 Ah). Critical applications, such as vaccine refrigeration systems, telecommunications or defense and public safety applications may be designed for greater than 3 days of autonomy to help improve system reliability. PV hybrid systems using generators or other backup sources require less autonomy to achieve the same level of system availability.

Charge Controller Operation

A *battery charge controller* limits the voltage and or current delivered to a battery from a charging source to regulate state-of-charge [NEC 690.2]. See Fig 32. A charge controller is required in most PV systems that use battery storage, to prevent damage to the batteries or hazardous conditions resulting from overcharging [NEC 690.72(A)]. Many charge controllers also provide overdischarge protection for the battery by disconnecting dc loads at low state-of-charge. Additional functions performed by charge controllers include controlling loads or backup energy source and providing monitoring and indicators of battery voltage and other system parameters. Special controllers are also available that regulate battery charge by diverting excess power to auxiliary loads. See Fig 33.

Many charge controllers protect the battery from overdischarge by disconnecting dc loads at low battery voltage and state-of-charge, at the allowable maximum depth of discharge limit. See Fig. 34. Some smaller charge controllers incorporate overcharge and overdis-

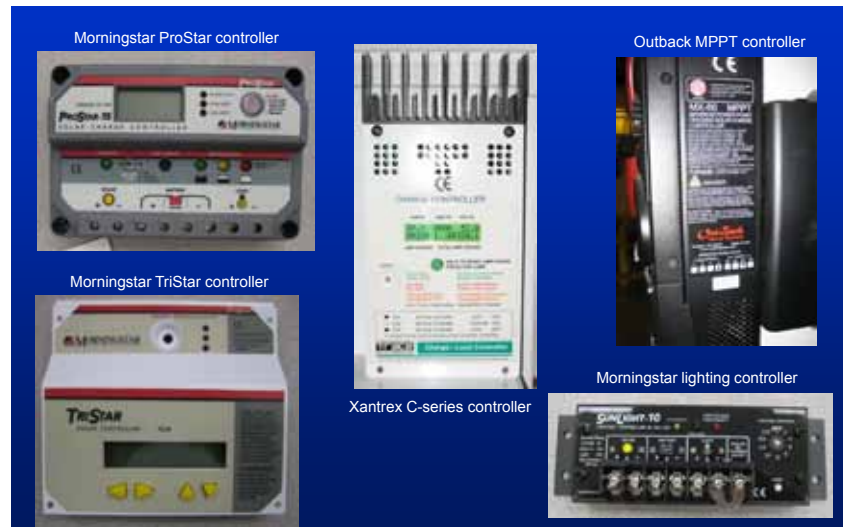


Figure 33. Charge controllers used in PV systems vary widely in their size, functions and features.

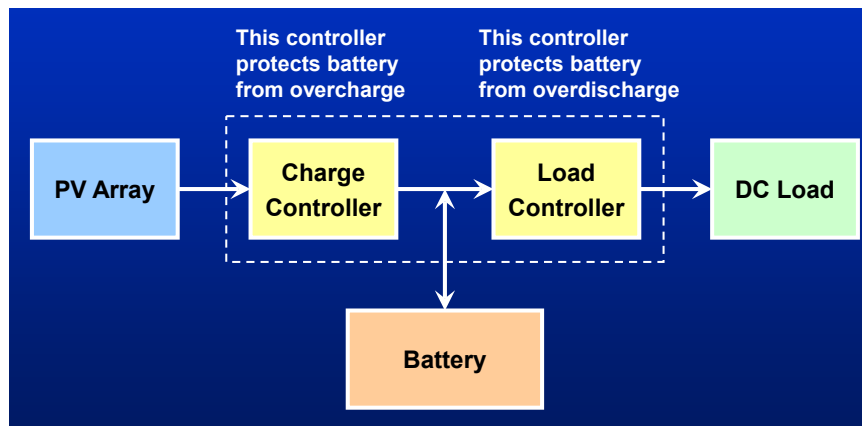


Figure 34. Charge controllers are also used to protect a battery from excessively deep discharges.

charge functions within a single controller. Generally, for larger dc load currents, separate charge controllers or relays are used. If two charge controllers are used, it is possible that they may be the same model but simply installed with different settings for different purposes; one on the array side for charge regulation and one on the load side of the battery for load control.

Battery-based inverters usually have programmable set-points for the low voltage load disconnect and load reconnect voltages. An alarm or indicator usually notifies the operator when the batteries are getting close to or have reached the LVD. It is also possible to employ multiple LVD controllers on the load side of the batteries, to have different LVD settings based on load priorities. Factory defaults for LVDs are often set at a low level so it may be desirable to raise the settings to provide greater protection of the batteries.

Charge controllers have maximum input voltage and current ratings specified by the manufacturer and the listing agency. The PV array must not be capable of generating voltage or current that will exceed the charge controller input voltage and current limits. The charge controller rated continuous current (sometimes specified as input current, sometimes as output current) must be at least 125% of the PV array short-circuit output current, and the charge controller maximum input voltage must be higher than the maximum system voltage [NEC 690.7].

Set points are the battery voltage levels at which a charge controller performs regulation or control functions. The proper regulation set points are critical for optimal battery charging.

The *regulation voltage (VR)* is the maximum voltage set point the controller allows the battery to reach before the array current is disconnected or limited. For interrupting type controllers, the array reconnect voltage (ARV) is the voltage set point at which the array is again reconnected to charge the battery. PWM and constant-voltage type controllers do not have a definable ARV.

The *low-voltage disconnect (LVD)* is the battery voltage set point at which the charge controller disconnects the system loads to prevent overdischarge. The LVD defines the maximum battery depth-of-discharge at the given discharge rate. The *load reconnect volt-*

age (LRV) set point is the voltage that load are reconnected to the battery. A higher LRV allows a battery to receive more charge before loads are reconnected to the battery.

Low-voltage disconnect set points are selected based on the desired battery depth-of-discharge and discharge rates. High discharge rates will lower battery voltage by a greater amount than lower discharge rates at the same battery state-of-charge. For a typical lead-acid cell, a LVD set point of 1.85 VPC to 1.91 VPC corresponds to a depth-of-discharge of 70% to 80% at discharge rates C/20 and lower.

Some PV charge controllers and battery chargers use three-stage charging algorithms to more effectively deliver power to the battery. *Bulk charging* occurs when the battery is below around 90% state-of-charge, and all available PV current is delivered to the batteries. During the bulk charge stage, battery voltage increases as the battery charges. Once the regulation voltage is reached, the charging current is limited to maintain the regulation voltage. *Absorption charging* is a finishing charge that occurs for a specified period after the regulation voltage is reached, usually for a few hours. This charging time at higher regulation voltages helps fully charge the battery, but if sustained for too long can overcharge the battery. Charging current continues to decrease throughout the absorption charge. *Float charging* is a maintenance charge that maintains the battery at a lower float voltage level and minimal current, essentially offsetting battery self-discharge losses. See Fig. 35.

The optimal charge regulation set points depend on the type of battery and control method used. Higher charge regulation voltages are required for all types of batteries using interrupting type controllers, compared to more effective constant-voltage, PWM or linear designs. See Fig. 36.

Equalization charging is a periodic over-charge to help restore consistency among battery cells. Equalization charging is performed on flooded, open-vent batteries to help minimize differences and restore consistency in capacity between

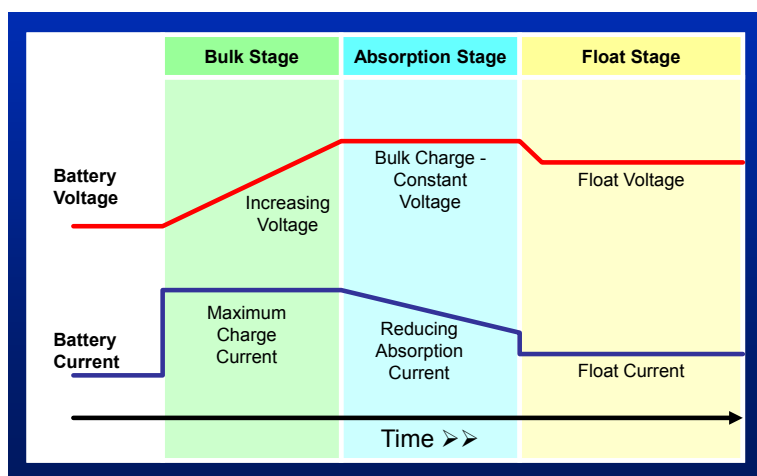


Figure 35. Advanced battery chargers and controllers use multi-stage charging algorithms.

		Battery Type			
Regulator Design Type	Charge Regulation Voltage at 25 °C	Flooded Lead-Antimony	Flooded Lead-Calcium	Sealed, Valve Regulated Lead-Acid	Flooded Pocket Plate Nickel-Cadmium
On-Off, Interrupting	Per nominal 12 volt battery	14.6 - 14.8	14.2 - 14.4	14.2 - 14.4	14.5 - 15.0
	Per Cell	2.44 - 2.47	2.37 - 2.40	2.37 - 2.40	1.45 - 1.50
Constant-Voltage, PWM, Linear	Per nominal 12 volt battery	14.4 - 14.6	14.0 - 14.2	14.0 - 14.2	14.5 - 15.0
	Per Cell	2.40 - 2.44	2.33 - 2.37	2.33 - 2.37	1.45 - 1.50

Figure 36. Optimal charge regulation set points depend on the type of battery and control method used.

individual cells, and can help reduce sulfation and stratification. Some charge controllers provide the capability for manual or automatic or equalization charging. Flooded lead-acid batteries are normally equalized at approximately 2.6 volts per cell (VPC) at 25°C for 1-3 hour periods once or twice a month. Equalization is generally not recommended for VRLA batteries; see manufacturer's instructions.

Temperature compensation is a feature of charge controllers that automatically adjusts the charge regulation voltage for battery temperature changes. Charge controllers may have internal temperature compensation, or use external sensors attached to the batteries. Where battery temperatures vary seasonally more than 10°C, compensation of the charge regulation set point is normally used. Temperature compensation is recommended for all types of sealed batteries, which are much more sensitive to overcharging than flooded types. Temperature compensation helps to fully charge a battery during colder conditions, and helps protect it from overcharge and excessive electrolyte loss during warmer conditions.

The standard temperature compensation coefficient for lead-acid cells is -5 mV/°C. When the battery is cold, the charge regulation voltage is increased, and conversely when the battery is warm, the charge regulation voltage is reduced. For example, consider a nominal 24 V charge controller with a regulation voltage of 28.2 V at 25°C. The temperature compensated regulation voltage is 29.7 V. Conversely, if the battery temperature is 40°C, the charge regulation voltage will be reduced to 27.3 volts.

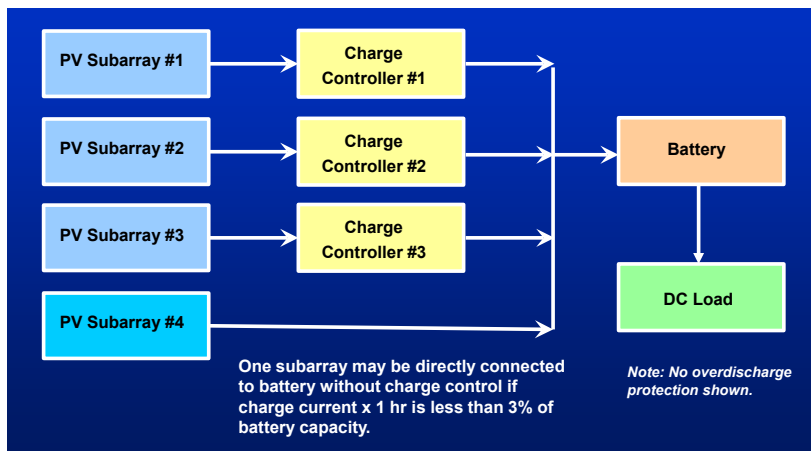


Figure 37. Multiple charge controllers may be used on individual subarrays for larger systems.

For larger systems, the output of multiple charge controllers may be connected in parallel and used to charge a single battery bank. See Fig. 37. Depending on the specific controller, the multiple controllers may regulate independently or through a master-slave arrangement. One subarray may be left unregulated if the maximum charge current multiplied by one hour is less than 3% of the battery capacity. This can help improve the finishing charge.

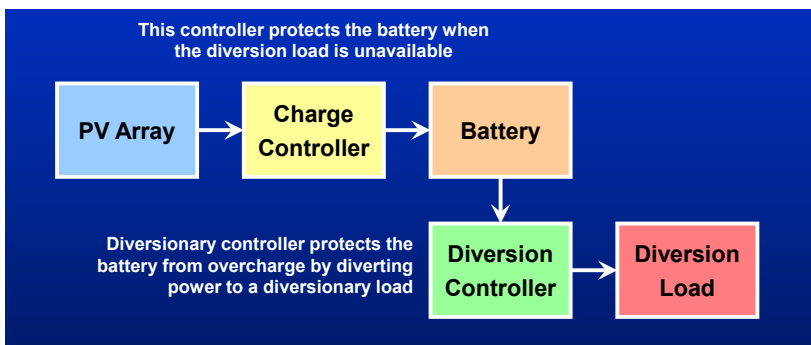


Figure 38. A diversionary charge controller diverts excess PV array power to auxiliary loads.

A *diversionary charge controller* diverts excess PV array power to auxiliary loads when the primary battery system is fully charged, allowing a greater utilization of PV array energy. Whenever a diversionary charge controller is used, a second independent charge controller is required to prevent battery overcharge in the event the diversion loads are unavailable or the diversion charge controller fails [NEC 690.72]. The additional charge

controller uses a higher regulation voltage, and permits the diversionary charge controller to operate as the primary control. See Fig 38.

Several requirements apply to PV systems using dc diversionary loads and dc diversion charge controllers. Typical dc diversionary loads include resistive water heating elements, dc water pumps or other loads that can utilize or store the energy in some other form. These requirements are intended to help prevent hazardous conditions and protect the battery if the diversion controller fails or the dc loads are unavailable.

- The dc diversion load current must be no greater than the controller maximum current rating.
- The dc diversion load must have a voltage rating greater than the maximum battery voltage.
- The dc diversion load power rating must be rated at least 150 percent of the maximum PV array power output.
- The conductors and overcurrent protection for dc diversion load circuits must be sized for at least 150 percent of controller maximum current rating.

Some interactive PV systems use battery-based inverters as a backup power source when the utility is de-energized. Normally, these systems regulate the battery charge by diverting excess PV array dc power through the inverter to produce ac power to feed site loads or the grid. When the grid de-energizes, an automatic transfer switch disconnects loads from the utility network and the system operates in stand-alone mode. If all loads have been met and the grid is not available, the battery can be overcharged. These systems must also have a second independent charge controller to prevent battery overcharge when the grid or loads are not available to divert excess power [NEC 690.72(C)(3)]. See Fig. 39.

Maximum Power Point Tracking MPPT Charge Controllers

Maximum power point tracking (MPPT) charge controllers operate PV arrays at maximum power under all operating conditions independent of battery voltage. Typically, the PV array is configured at higher voltages than the battery, and dc to dc power conversion circuits in the controller automatically provides a lower voltage and higher current output to the battery. MPPT controllers can improve array energy utilization and allow non-standard and higher array operating voltages, requiring smaller conductors and fewer source circuits to charge lower voltage battery banks. MPPT charge controllers are advantageous on cold sunny days in the winter when stand-alone systems have lower battery voltage and the array voltage is high due to the cold operating temperature.

Normally, the output current of a charge controller will be less than or equal to the input current. The exception to this rule is a maximum power point tracking (MPPT) charge

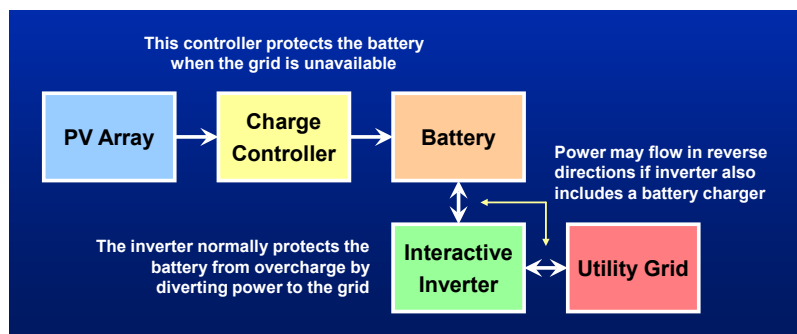


Figure 39. Battery-based interactive inverters operate as diversionary charge controllers to regulate battery state-of-charge.

controller, in which the output current may exceed the input current but at lower voltage. If a MPT charge controller is used, it is important to consult the manufacturer's specifications to determine the maximum output current. The maximum rated output current of the charge controller must be posted on a sign at the dc disconnect [NEC 690.53].

2.4.4 Generators

Electrical generators are often interfaced with PV systems to supplement the PV array when it cannot produce enough energy alone to meet the system loads or charge the batteries. These are often referred to as hybrid systems, because they use more than one energy source. Generators may be directly interfaced with stand-alone systems or with battery-based utility-interactive systems. In regions where the summer solar resource is significantly more than the winter resource, an auxiliary electric generator may be useful to reduce the size of the PV array and battery required to meet the wintertime loads alone.

Many battery-based PV inverters have built-in battery chargers that permit the connection of an auxiliary ac source, such as a generator, to provide supplemental battery charging, or to directly power ac loads. Some of these inverters are programmable and have relay circuits that can automatically start the generator whenever the batteries reach a prescribed low voltage. When the batteries have reached an adequate state of charge, defined by the inverter programming, the inverter will automatically shut down the generator. Most of these advanced inverters can also exercise the generator on a regular basis to ensure that it will start when needed.

Utility-interactive PV systems without batteries require a separate generator transfer switch to isolate the electrical loads from the grid and the PV system. In this design, the generators are either started automatically or manually in the event of a utility outage.

Charging Batteries with a Generator

Typically, PV-generator hybrid systems may be designed to fully charge the batteries in 5 to 10 hours, or at a C/5 to C/10 rate. This means that if the batteries are 80% discharged and the generator is programmed to charge the batteries until they are only 30% discharged, that it would take 5 hours to do so at the C/10 rate. Generally, it is not advantageous to fully charge batteries with the generator, which can be inefficient, and can result in wasting valuable PV energy that may have been available to contribute to the charge. The basic idea to optimize generator run time is to load the generator as high a power level and minimum operation time as possible, to minimize fuel consumption and maintenance.

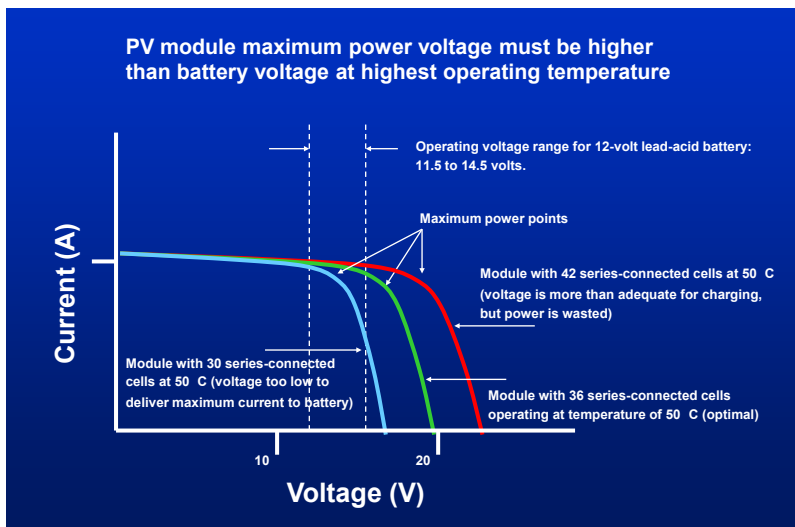


Figure 40. Generally, 36 series-connected silicon solar cells are needed to provide adequate maximum power voltage to fully charge a lead acid-battery.

2.5 Confirm String Size Calculations

PV array source circuits are usually designed to meet the voltage requirement of connected dc utilization equipment, such as batteries, charge controllers, or interactive inverters. All dc equipment must also have appropriate current ratings for the given PV array and source circuit currents. The PV array must operate within acceptable voltage limits for the dc equipment, under all temperatures.

Battery charging applications require the PV array maximum power voltage to be greater than the battery regulation voltage at the highest array operating temperatures. This helps ensure that the maximum PV array current is delivered to the battery. Maximum power point tracking charge controllers permit the use of much higher array voltages than the battery voltage. See Fig. 40.

The experienced PV installer should be able to identify the advantages and disadvantages of systems that operate at different dc voltages, ranging from 12 V systems to systems operating up to 600 V and greater where permitted. The major disadvantage of lower voltage systems are much higher currents for the same power levels, requiring much large and more expensive conductors, overcurrent devices and switchgear. For example, the currents in a 12 V system are twice as high as currents in a 24 V system, and four times as high as for 48 V systems. These higher currents require significantly larger wire sizes. In fact, to maintain a voltage drop within certain limits, say 3%, for the same load at 24 V as opposed to at 12 V, the allowable wire resistance is 4 times as high as for the 12 V loads because the 24 V system cuts the current in half and the percentage voltage drop is based on twice the voltage as 12 V.

Interactive inverters can usually handle PV array dc power input levels 110% to 130% or more of the continuous ac output power rating, especially in warmer climates. Inverters thermally limit array dc input and array power tracking at high temperatures and power levels. PV array must also not exceed the maximum dc input current limits for the inverter.

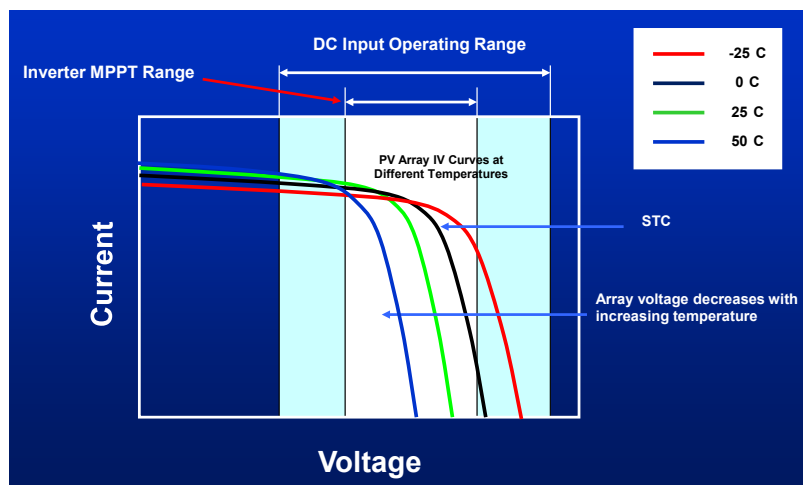


Figure 41. Properly configuring PV arrays for interactive inverters involves an understanding the array I-V characteristics and temperature effects.

Array voltage requirements the most critical part of sizing arrays for interactive inverters. Array voltage is affected by the site ambient temperature range and the array mounting system design. The array voltage must be above the minimum inverter operating and MPPT voltage during hottest operating conditions, factoring in annual voltage degradation of 0.5% to 1% per year. Array voltage must also not exceed 600 dc or the maximum inverter operating voltage during the coldest operating conditions. Exceeding maximum voltage limits violates electrical codes and voids manufacturer warranties. Use record lows or preferably ASHRAE 2% minimum design temperatures to determine maximum array voltage. See Fig. 41.

2.6 Review System Components Selection

The PV installer is often required to make judgments and recommendations concerning the system design based on a variety of factors including site considerations and customer needs. The installer is often required to review or modify designs based on the application requirements, and they must ensure that the overall installation meets code requirements. It is not unusual for something to be left out of a design, and the installer may be responsible for identifying these discrepancies in the design review process. The installer should also know when and where to consult an experienced system designer when design issues extend beyond the installer's capabilities.

2.6.1 Differentiating Among Available Modules and Inverters

Both PV modules and inverters used in PV systems are subject to UL standards and must be listed and approved for the application to meet code compliance. Inverters intended for use in interactive PV systems, or with ungrounded PV arrays must be specially labeled. Likewise ac modules, special modules manufactured with built-in inverters must be clearly labeled as ac modules with the appropriate specifications.

Product approval usually only provides a measure of safety and is not indicative of field performance or reliability. There are relatively few resources to find comprehensive and unbiased analyses on the field performance of these products, but certain periodicals

provide annual reviews, results from independent testing, and comments from installers. Online forums are another good place to find out more about products. Manufacturer's specifications are based on laboratory tests, and it is important to recognize that field performance is far more dynamic. A given product may perform quite well in one set of conditions but under-perform in other conditions (e.g. at given temperatures, voltages, etc.). *Reference:* CEC approved modules and inverters website: www.consumerenergycenter.org

The selection of PV modules for a given project may be based on any number of factors, including:

- Physical characteristics (dimensions and weight)
- Electrical specifications (power tolerance and guaranteed power output)
- Warranties, reliability and reputation of the manufacturer
- Manufacturer certification to quality standards (ISO 9000)
- Module warranty and design qualification (IEC 61215/61216)
- Customer satisfaction and field results
- Costs and availability

Specifying inverters for PV installations includes the following considerations:

- Interactive or stand-alone
- Power rating and maximum current
- Power conversion efficiency
- Location environment rating
- Size and weight
- Nominal dc input and ac output voltages and limits of operation
- Protective and safety features (array ground and arc faults, reverse polarity, etc.)
- Warranties and reliability
- Costs and availability
- Additional features (monitoring, chargers, controls, MPPT etc.)

PV Modules

Photovoltaic or solar cells convert sunlight to dc electricity. They are often referred to as direct energy conversion devices because they convert one basic form of energy to another in a single step. PV modules have no moving parts, and produce no noise or emissions during normal operation. Generally speaking, commercial PV modules are very reliable products with expected lifetimes exceeding 20-25 years in normal service. See Fig 42.

PV cells are made from a variety of semiconductor technologies. Most PV cells are made from multi (poly) or single crystalline silicon (mono) that is doped with certain elements to produce desirable properties. Thin-film technol-



Figure 42. PV modules produce a specified electrical output.

ogies, including amorphous silicon, cadmium-telluride (CdTe), copper-indium-diselenide (CIS), and others continue to be developed, and presently make up about 10% to 15% of the current market. Thin film PV modules are generally less expensive than conventional crystalline silicon modules, but also less efficient and less proven than crystalline silicon.

PV modules are commonly flat-plate types that respond to both direct and diffuse solar radiation. Concentrating PV (CPV) modules are special designs that use optics (lenses or reflectors) to concentrate the solar power received through a larger aperture onto a small-area PV device.

Individual silicon solar cells are manufactured in sizes up to and over 200 in² in area. The electrical current output of a solar cell is directly related to cell area, the cell efficiency, and the amount of solar radiation incident on the cell surface. Modern silicon solar cells may be up to 8 inches in diameter and greater, and produce currents in excess of 8 A.

A common crystalline silicon solar cell produces about 0.5 V to 0.6 V independent of cell area, but decreases with increasing temperature. The temperature effects on voltage have important ramifications for designing PV arrays to meet the voltage requirements of inverters in different climates. See Fig 43.

Usually, 36, 60, 72 or greater number of individual cells are usually connected in series to produce higher voltage PV modules. PV modules using 36 series-connected cells are

optimally suited for charging a 12 V battery. Higher voltage modules are used for higher-voltage grid connected systems, to minimize the numbers of module connections required for an installation. However, PV modules are now becoming so large that they are reaching the limits of safe handling by one person. A 230-watt PV module made of crystalline silicon PV cells typically has an area of about 17 sf, and weighs about 35 pounds. See Fig 44.

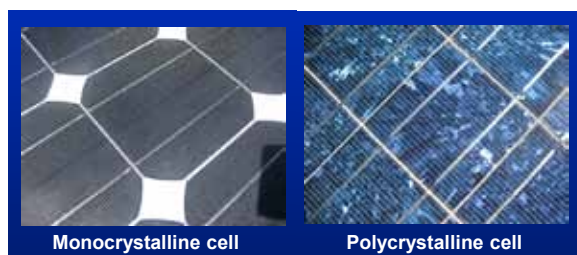


Figure 43. Silicon solar cells produce about 0.5 V to 0.6 volt independent of cell area, depending on temperature.

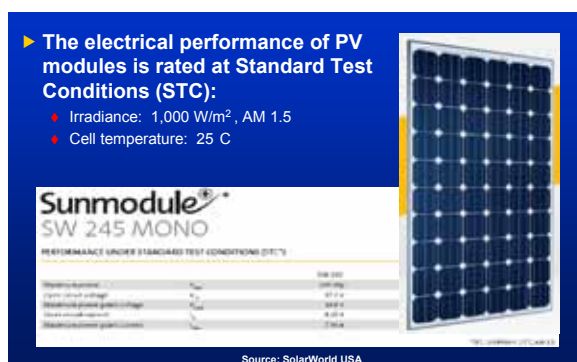


Figure 44. Standard Test Conditions (STC) is the universal rating condition for PV modules and arrays.

Solar Energy Fundamentals

The principles of solar radiation, the solar resource and its units of measure are very important for the PV designer and installer to understand, especially as it concerns the performance of PV modules and arrays. This includes quantifying the amount of solar power incident on a PV array at any given point in time, as well as estimating the total solar energy received on monthly and annual basis. Solar radiation is the basic source of energy that drives a PV system. It must be accurately measured and quantified to make reasonable performance estimates in the design, in order to verify the proper operation of modules, arrays and complete systems.

Solar radiation is electromagnetic radiation ranging from about 0.25 μm to 4.5 μm in wavelength, including the near ultraviolet (UV), visible light, and near infrared (IR) portions of the spectrum. The sun produces immense quantities of

electromagnetic radiation as a product of fusion reactions at its core. The tiny fraction reaching the earth's surface amounts to approximately 170 million gigawatts (GW), many thousands of times greater than all of the electrical power used on earth.

Reference: U.S. Energy Information Administration, Annual Energy Outlook 2011:
[http://www.eia.gov/forecasts/aeo/pdf/0383\(2011\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf)

Solar irradiance (solar power) is the sun's radiant power incident on a surface of unit area, commonly expressed in units of kW/m^2 or W/m^2 . Due to atmospheric effects, typical peak values of terrestrial solar irradiance are on the order of $1000 \text{ W}/\text{m}^2$ on surfaces at sea level facing the sun's rays under a clear sky around solar noon. Consequently, $1000 \text{ W}/\text{m}^2$ is used as a reference condition for rating the peak output for PV modules and arrays. This value of solar irradiance is often referred to as *peak sun*. However, higher values of irradiance are common at higher altitudes and on exceptionally clear days during winter months when the sun is closest to earth. In these cases, solar irradiance can reach $1250 \text{ W}/\text{m}^2$ or higher for continuous periods.

For south-facing fixed (non-tracking) tilted surfaces on a clear day, the incident solar irradiance varies along a bell-shaped curve, peaking at solar noon when the surface faces most directly toward the sun. Local weather patterns and cloud cover affect the receivable radiation accordingly. See Fig 45.

Solar irradiation (solar energy) is the sun's radiant energy incident on a surface of unit area, commonly expressed in units of kWh/m^2 . Solar irradiation is sometimes called *solar insolation*. Similar to electrical power and energy, solar power and solar energy are related by time. The amount of solar energy received on a surface over a given period of time is equal to the average solar irradiance multiplied by the time. Graphically, solar irradiation (energy) is the area under the solar irradiance (power) curve. See Fig 46.

For example, if the solar irradiance (power) averages $400 \text{ W}/\text{m}^2$ over a 12 hour period, the total solar irradiation (energy) received is $400 \text{ W}/\text{m}^2 \times 12 \text{ hr} = 4800 \text{ Wh}/\text{m}^2 = 4.8 \text{ kWh}/\text{m}^2$. Conversely, if the total solar energy received over an 8 hour period is 4 kWh, the average solar power would be $4 \text{ kWh} \div 8 \text{ hr} = 0.5 \text{ kW}/\text{m}^2 = 500 \text{ W}/\text{m}^2$.

Solar Energy Powers the World

The U.S. currently has just over 1000 GW of peak electrical power generation capacity, supplying a total annual electrical consumption of about 3,700 billion kWh. To produce this much energy would require about 2,500 GW of peak PV generation distributed throughout the U.S. Using a reference PV module efficiency of 15% (power density $150 \text{ W}/\text{m}^2$), the total array surface area required would be about 4 million acres (about 6400 square miles), or about 0.2% of the continental U.S. land area. Considering over 50% of U.S. land area is already dedicated to the extraction of natural resources and fossil fuels, including agriculture, forestry, mining and public lands, a significant contribution from PV in meeting our national energy needs is not an unrealistic expectation.

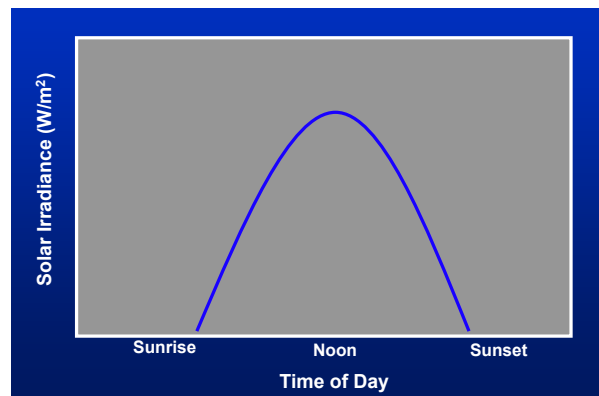


Figure 45. For fixed south-facing surfaces on a clear day, the incident solar irradiance varies in a bell-shaped curve, peaking at solar noon.

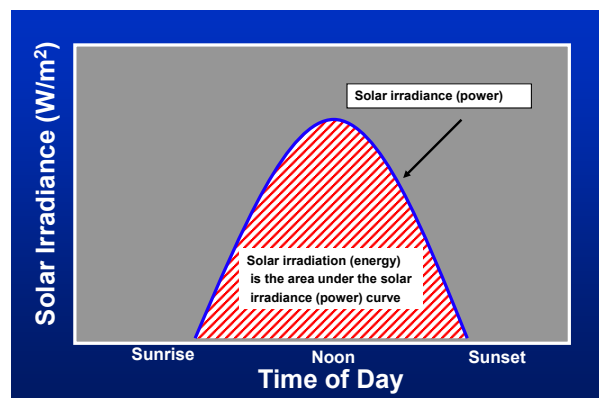


Figure 46. The amount of solar energy received on a surface over a given period of time is equal to the average solar power multiplied by the time.

Solar Constant

The *Solar Constant* is the average value of solar irradiance outside the earth's atmosphere on a surface facing the sun's rays, at the average earth-sun distance of 1 Astronomical Unit (AU), equal to about 93 million miles. The Solar Constant represents the average value of extraterrestrial solar irradiance, which is approximately 1366 W/m^2 . Due to the earth's slightly elliptical orbit around the sun, the actual values for extraterrestrial irradiance vary from the average value by about 7% between the aphelion and perihelion (points in the earth's orbit furthest and closest to the sun, respectively). Approximately 30% of the extraterrestrial irradiance is reflected or absorbed by the atmosphere before it reaches the earth's surface.

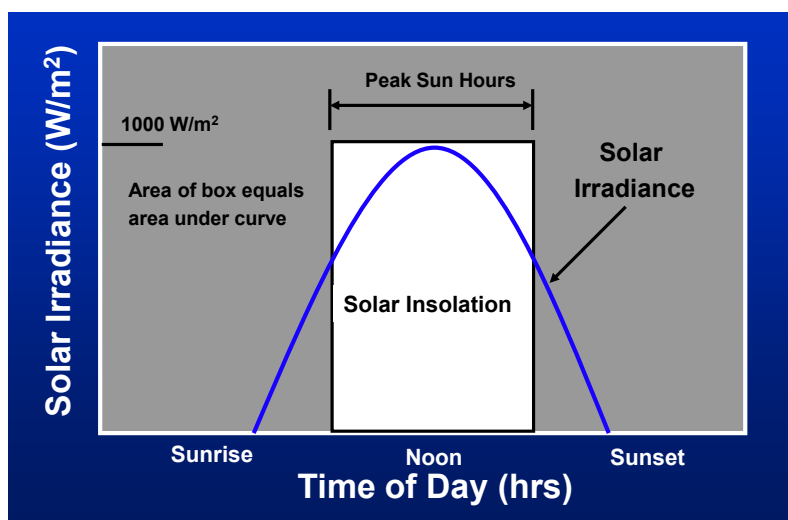


Figure 47. Peak sun hours (PSH) represents the average daily amount of solar energy received on a surface, and equivalent to the number of hours that the solar irradiance would be at a peak level of 1 kW/m^2 .

Solar irradiation (energy) can be represented as a total for the year ($\text{kWh/m}^2\text{-yr}$), or commonly on an average daily basis for a given month or annually ($\text{kWh/m}^2\text{-day}$). When solar energy is represented on an average daily basis, the total daily energy can be equivocated to the same amount of energy received at a peak irradiance level of 1 kW/m^2 , for a specific number of hours.

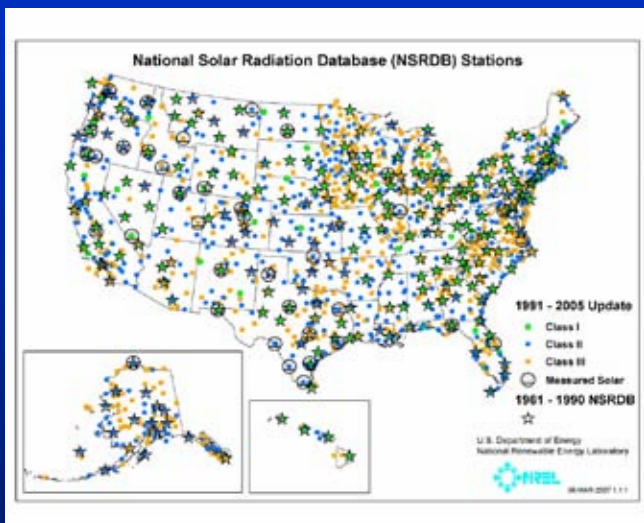
Peak Sun Hours (PSH) represents the average daily amount of solar energy received on a given surface, and is equivalent to the number of hours that the solar irradiance would need to be at a peak level of 1 kW/m^2 to accumulate the total amount of daily energy received. See Fig 47.

$$\text{Peak Sun Hours } \left(\frac{\text{hrs}}{\text{day}} \right) = \frac{\text{Avg. Daily Irradiation } (\text{kWh/m}^2 \cdot \text{day})}{\text{Peak Sun } (1 \text{ kW/m}^2)}$$

Since the power output PV modules and arrays are rated at 1 kW/m^2 solar irradiance, Peak Sun Hours simply represents the equivalent number of hours that a PV module or array will operate at its peak rated output. For example, consider a PV array that produces a peak power output of 6 kW when exposed to 1 kW/m^2 irradiance, at average operating temperatures. If the array surface receives 5 PSH per day on average, the expected daily energy production for this array would be $6 \text{ kW} \times 5 \text{ hrs/day} = 30 \text{ kWh/day}$. Coincidentally, the average daily residential energy use in the U.S is about 30 kWh/day , and a 6 kW PV system is about the typical size that can be installed on an average residential rooftop.

Solar radiation measurements made over past years throughout the U.S. and around the world have been processed and archived in databases, and this data is used by designers to estimate the expected performance of PV systems based on historical information. See Fig 48. The Renewable Resource Data Center (RReDC) at the National Renewable Energy Laboratory (NREL) maintains an extensive collection of renewable energy data, maps, and tools for solar radiation, as well as biomass, geothermal, and wind resources.

Reference: The National Solar Radiation Database includes data for over 1,400 sites in the U.S. and its territories, and many other sites around the world, see: www.nrel.gov/rredc/



NREL

► NSRDB 1961-1990

- ◆ 30 years of solar radiation and meteorological data from 239 NWS sites in the U.S.
- ◆ TMY2 hourly data files

► NSRDB 1991-2005 Update

- ◆ Contains solar and meteorological data for 1,454 sites.
- ◆ TMY3 hourly data files

Figure 48. The National Solar Radiation Database includes data for over 1,400 sites in the U.S.

Solar radiation data can be represented in tables, databases or in graphical form. See Fig. 49. Standard solar radiation data tables give several key sets of data for different fixed and tracking surfaces. The major limitation of the data tables is that they only provide data for south-facing fixed surfaces. Other tools, such as PVWatts™ can be used to predict the solar energy received on fixed-tilt surfaces facing directions other than due south.

The standard format spreadsheets provide minimum and maximum data for each month and annual averages for the following solar resource data and surface orientations:

- Total global solar radiation for fixed south-facing flat-plate collectors tilted at angles of 0°, Lat-15°, Lat, Lat+15°, and 90°.
- Total global solar radiation for single-axis, north-south tracking flat-plate collectors at tilt angles of 0°, Lat-15°, Lat, Lat+15°.
- Total global solar radiation for dual-axis tracking flat-plate collectors.
- Direct beam radiation for concentrating collectors.
- Average meteorological conditions.

City:	DAYTONA BEACH													
State:	FL													
WBAN No:	12834													
Lat(N):	29.18													
Long(W):	81.05													
Elev(m):	12													
Pres(mb):	1017													
Stn Type:	Primary													
SOLAR RADIATION FOR FLAT-PLATE COLLECTORS FACING SOUTH AT A FIXED-TILT (kWh/m2/day), Percentage Uncertainty = 9														
Tilt(deg)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
0	Average	3.1	3.9	5.0	6.2	6.4	6.1	6.0	5.7	4.9	4.2	3.4	2.9	4.8
	Minimum	2.7	3.2	4.2	5.6	5.3	5.4	5.5	4.8	4.3	3.5	2.9	2.4	4.6
	Maximum	3.7	4.4	5.5	6.8	7.0	7.0	6.6	6.3	5.5	4.8	3.7	3.3	5.1
Lat - 15	Average	3.8	4.5	5.5	6.4	6.4	6.0	5.9	5.8	5.2	4.7	4.1	3.6	5.2
	Minimum	3.2	3.7	4.5	5.8	5.3	5.3	5.4	4.8	4.5	3.8	3.4	2.8	4.8
	Maximum	4.6	5.2	6.1	7.1	7.0	6.8	6.4	6.5	6.0	5.5	4.6	4.1	5.5
Lat	Average	4.3	4.9	5.7	6.3	6.0	5.5	5.5	5.6	5.3	5.0	4.6	4.1	5.2
	Minimum	3.6	4.0	4.6	5.7	5.0	4.9	5.1	4.6	4.5	4.0	3.8	3.1	4.9
	Maximum	5.4	5.8	6.3	7.0	6.6	6.3	6.0	6.3	6.1	5.9	5.2	4.9	5.7
Lat + 15	Average	4.6	5.1	5.6	5.9	5.4	4.8	4.9	5.1	5.1	5.1	4.8	4.4	5.1
	Minimum	3.8	4.1	4.5	5.3	4.5	4.3	4.5	4.2	4.3	4.0	3.9	3.3	4.7
	Maximum	5.8	6.0	6.3	6.5	5.8	5.5	5.3	5.7	5.9	6.0	5.6	5.3	5.5
90	Average	3.9	3.8	3.6	2.9	2.1	1.8	1.9	2.4	3.0	3.6	4.0	3.9	3.1
	Minimum	3.1	3.1	2.9	2.7	2.0	1.6	1.8	2.0	2.5	2.7	3.1	2.8	2.8
	Maximum	5.1	4.7	4.0	3.1	2.2	1.9	2.0	2.6	3.4	4.3	4.7	4.7	3.3

NREL

NREL

Figure 49. Solar radiation data tables gives the total global solar radiation for fixed south-facing flat-plate collectors tilted at angles of 0°, Lat-15°, Lat, Lat+15° and 90°.

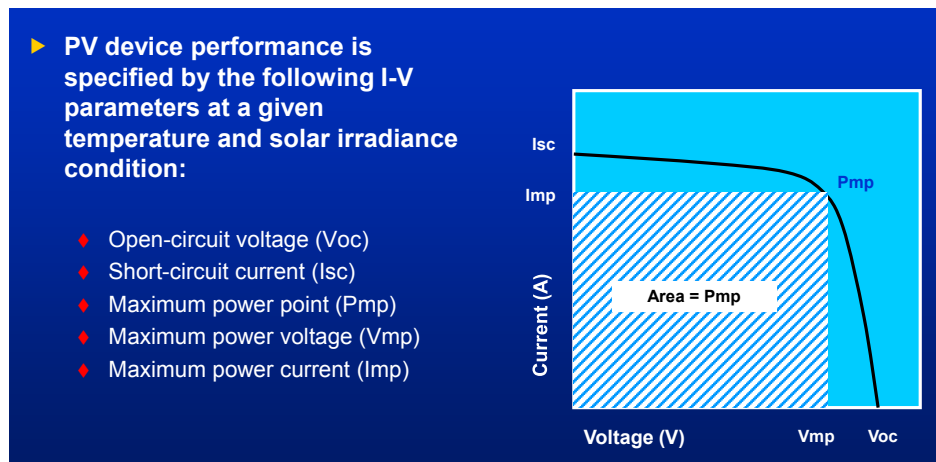


Figure 50. An I-V curve represents the electrical performance for PV modules and arrays.

PV Module Performance

Photovoltaic module electrical performance is characterized by its current-voltage (I-V) characteristic. I-V curves represent an infinite number of current and voltage operating point pairs for a PV device, at a given solar irradiance and temperature operating condition. Certain electrical parameters representing key points along the I-V curve are rated by the manufacturer at specified conditions, affixed on product labels, and are the basis for the designing the photovoltaic source and output circuits. See Fig. 50.

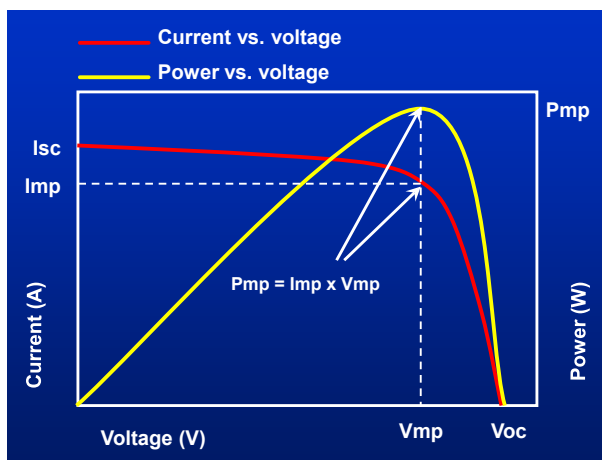


Figure 51. Current-voltage curves can also be expressed as power-voltage curves where the maximum power point (P_{mp}) is clearly shown.

PV module performance is sometimes represented by power versus voltage curves, which contain the same information as I-V curves. Power versus voltage curves provide a clearer illustration of how the power output is affected by the operating voltage, and where peak power output occurs. See Fig. 51.

Key Module Parameters

Open-circuit voltage (V_{oc}) is the maximum dc voltage on an I-V curve, and is the operating point for a PV device with no connected load. V_{oc} corresponds to an infinite resistance or open-circuit condition, and zero current and zero power output. Open-circuit voltage is independent of cell area and increases with decreasing cell temperature, and is used to determine maximum circuit voltages for PV modules and arrays. For crystalline silicon solar cells, the open-circuit voltage is typically on the order of 0.5 V to 0.6 V at 25°C. Thin-film technologies have slightly higher cell voltages and different temperature coefficients, but lower current density than crystalline silicon cells.

Short-circuit current (I_{sc}) is the maximum current on an I-V curve. I_{sc} corresponds to a zero resistance and short-circuit condition, at zero voltage and zero power output. Short-circuit current is directly proportional to solar irradiance, and rated values are used in calculations to size PV circuit conductors and overcurrent devices. Because PV modules are inherently current-limited, PV modules can be short-circuited without harming the modules using an appropriately rated shorting device. In fact, measuring the short-circuit current of a module or string when it is disconnected from the rest of the system is one way to test modules and strings. Some PV charge controllers regulate battery charging by short-circuiting the module or array. Note that short circuits for extended periods of time (greater than several minutes under high irradiance) may damage some thin-film modules. Manufacturers' data sheets provide applicable cautions.

The *maximum power point (P_{mp})* of a PV device is the operating point where the product of current and voltage is at its maximum. The *maximum power voltage (V_{mp})* is the corresponding operating voltage at P_{mp} , and is typically 70% to 80% of the open-circuit voltage. The *maximum power current (I_{mp})* is the operating current at P_{mp} , and typically 90% of the short-circuit current. The maximum power point is located on the "knee" of the I-V curve, and represents the highest efficiency operating point for a PV device under the given conditions of solar irradiance and cell temperature.

Operating Point

The specific operating point on an I-V curve is determined by the electrical load according to Ohm's Law. Consequently, the load resistance to operate a PV module or array at its maximum power point is equal to the maximum power voltage divided by the maximum power current (V_{mp}/I_{mp}). For example, consider a PV module with maximum power voltage (V_{mp}) = 35.8 V, and maximum power current (I_{mp}) = 4.89 A. The load resistance required to operate this module at maximum power is equal to $V_{mp} \div I_{mp} = 35.8 \text{ V} \div 4.89 \text{ A} = 7.32 \Omega$. The dc power produced is simply the product of the maximum power current and voltage. See Fig. 52.

In application, the operating point on the I-V curve is determined by the specific equipment connected to the output of the PV array. If the load is a battery, the battery voltage sets the operating point on the I-V curve, and sets the operating current. If the PV array is connected to an interactive inverter, the inverter circuits seek to operate the PV at its maximum power point as long as the array voltage operates within the inverter specifications. *Maximum power point tracking (MPPT)* refers to the process or electronic equipment used to operate PV modules or arrays at their maximum power point under varying conditions. MPPT circuits are integral to interactive inverters, some charge controllers and also available as separate equipment or part of PV array source circuit combiner boxes.

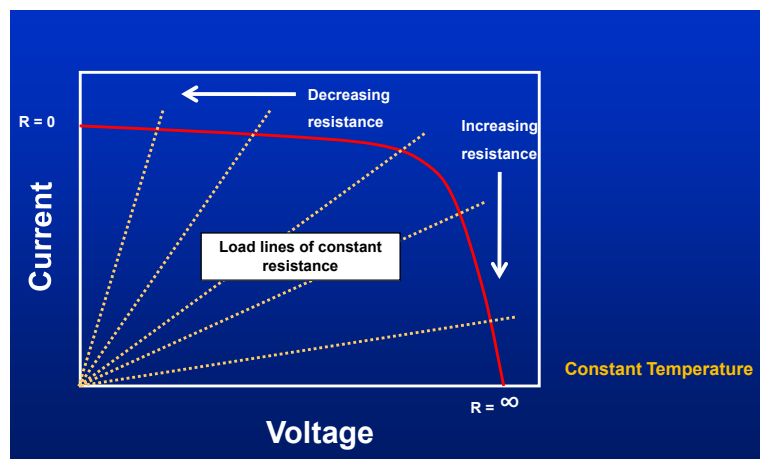


Figure 52. The specific operating point on an I-V curve is determined by the electrical load resistance according to Ohm's Law.

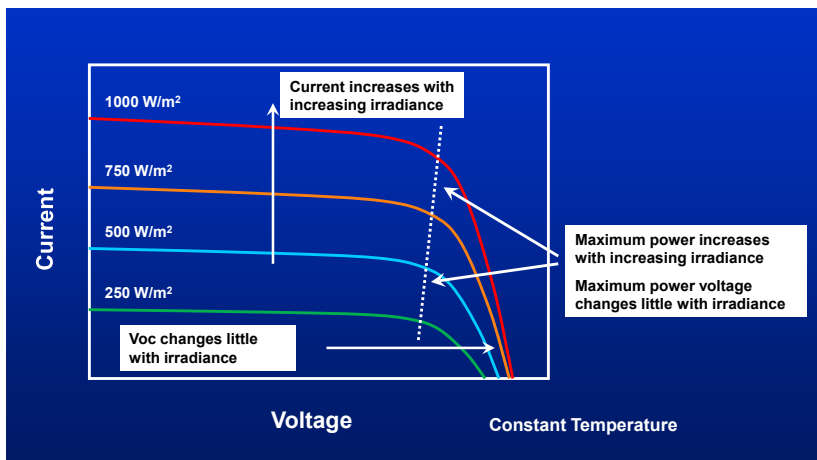


Figure 53. Changes in solar radiation have a direct linear and proportional effect on the current and maximum power output of a PV module or array.

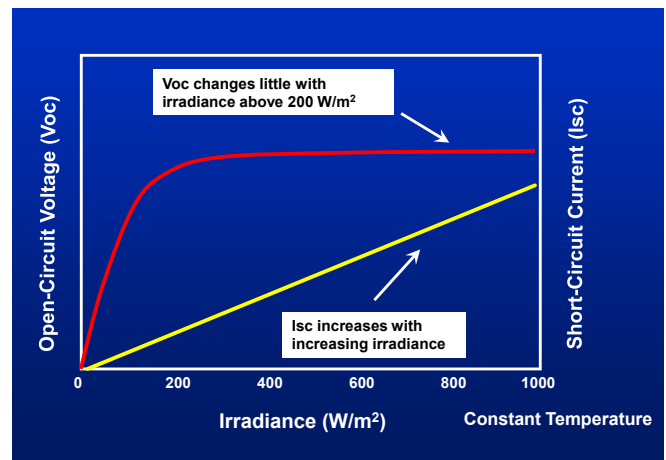


Figure 54. PV module current and voltage are affected differently by solar irradiance.

Response to Irradiance

Changes in solar radiation have a direct linear and proportional effect on the current and maximum power output of a PV module or array. See Fig. 53. Therefore, doubling the solar irradiance on the surface of the array doubles the current and maximum power output (assuming constant temperature). Changing irradiance has a smaller effect on voltage, mainly at lower irradiance levels. Because voltage varies little with changing irradiance levels, PV devices are well-suited for battery charging applications. See Fig. 54.

The short-circuit current (I_{sc}), maximum power current (I_{mp}), and maximum power (P_{mp}) at one condition of solar irradiance may be translated to estimate the value of these parameters at another irradiance level:

$$\begin{aligned} I_{sc_2} &= I_{sc_1} \times (E_2/E_1) \\ P_{mp_2} &= P_{mp_1} \times (E_2/E_1) \\ I_{mp_2} &= I_{mp_1} \times (E_2/E_1) \end{aligned}$$

where

I_{sc_1} = rated short-circuit current at irradiance E_1 (A)

I_{sc_2} = short-circuit current at new irradiance E_2 (A)

E_1 = rated solar irradiance (W/m^2)

E_2 = new solar irradiance (W/m^2).

P_{mp_1} = rated maximum power at irradiance E_1 (W)

P_{mp_2} = new maximum power at new irradiance E_2 (W).

I_{mp_1} = original maximum power current at irradiance E_1 (A)

I_{mp_2} = new maximum power current at new irradiance E_2 (A).

PV installers verify performance of PV systems in the field by measuring the solar irradiance incident on arrays with simple handheld meters, and correlating with the actual system power output. For example, if it has been established that the peak output of a PV array is 10 kW under incident radiation levels of $1000 W/m^2$ at normal operating temperatures, then the output of the array should be expected to be around 7 kW if the solar irradiance is $700 W/m^2$, assuming constant temperature.

Response to Temperature

The current and voltage output of a PV module are temperature dependent. For crystalline silicon PV devices, increasing cell temperature results in a measureable decrease in voltage and power, and a slight increase in current. Higher cell operating temperatures also reduce cell efficiency and lifetime. The temperature effects on current are an order of magnitude less than on voltage, and neglected as far as any installation or safety issues are concerned.

Temperature coefficients relate the effects of changing PV cell temperature on its voltage, current and power output. For crystalline silicon PV devices, the temperature coefficient for voltage is approximately $-0.4\%/^{\circ}\text{C}$, the temperature coefficient for short-circuit current is approximately $+0.04\%/^{\circ}\text{C}$, and the temperature coefficient for maximum power is approximately $-0.45\%/^{\circ}\text{C}$. Note that the power and voltage temperature coefficients are negative, as these parameters decrease with increasing temperature. Thin-film PV modules have different temperature coefficients than crystalline silicon modules. See Fig. 55.

Since PV modules achieve their highest voltages at the lowest temperatures, this voltage determines the minimum voltage ratings required for the modules and associated dc circuit components [NEC 690.7]. For crystalline silicon PV modules, the maximum voltage for PV systems is determined by multiplying the module rated open-circuit voltage (Voc) by the number of modules in series, and by a voltage correction factor [NEC Table 690.7]. See Fig. 56. Where other than crystalline silicon (thin-film) PV modules are used, or if temperature coefficients are provided with manufacturer’s instructions, those coefficients must be used to calculate maximum system voltage.

The following three methods are used to calculate temperature correction factors used in the NEC to establish maximum system voltage. The example uses a PV module with open-circuit voltage (Voc) = 37.3 V, installed in a location with a -12°C lowest expected ambient temperature.

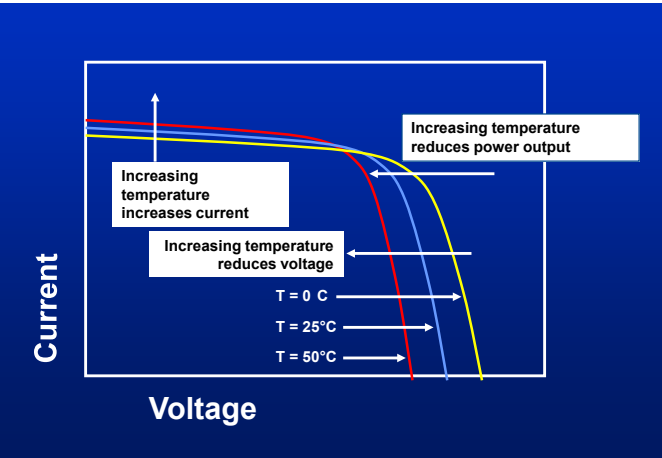


Figure 55. For crystalline silicon PV devices, increasing cell temperature results in a decrease in voltage and power, and a small increase in current.

Minimum Ambient Temperature ($^{\circ}\text{C}$)	Correction Factor
24 to 20	1.02
19 to 15	1.04
14 to 10	1.06
9 to 5	1.08
4 to 0	1.10
-1 to -5	1.12
-6 to -10	1.14
-11 to -15	1.16
-16 to -20	1.18
-21 to -25	1.20
-26 to -30	1.21
-31 to -35	1.23
-36 to -40	1.25

Adapted from NEC Table 690.7

Figure 56. Voltage-temperature correction factors for crystalline silicon PV modules increase with decreasing temperatures.

Maximum System Voltage

The maximum system voltage is the PV array open-circuit voltage at the lowest expected ambient temperature at a site. The NEC defines lowest expected ambient temperature in an informational note in Art. 690.7 as the Extreme Annual Mean Minimum Design Dry Bulb Temperature from the ASHRAE Handbook—Fundamentals. A table of these values for the United States is available in the appendix of the Expedited Permit Process: www.solar-abcs.org/permitting.

The ASHRAE temperatures represent statistically valid expected low temperatures, and fall midway between the record low and the average low for a location. The record low temperature for a location is overly conservative to use for PV module voltage-temperature corrections, and module voltage really doesn't reach its maximum until irradiance levels exceed 200 W/m², well after the record low temperature has occurred. Most PV module manufacturers now publish the temperature coefficient for Voc in their specifications.

Method 1 —

Module Manufacturer's Temperature Correction Factor—Percentage Method

$$\begin{aligned} \text{Temperature Coefficient for } V_{OC} &= \alpha V_{OC} = -0.37\%/^{\circ}\text{C} = -0.0037/^{\circ}\text{C} \\ \text{Temperature Correction Factor} &= 1 + \alpha V_{OC}(\%) \times (\text{Temp}_{\text{LOW}} - \text{Temp}_{\text{RATING}}) \\ &= 1 + (-0.0037/^{\circ}\text{C}) \times (-12^{\circ}\text{C} - 25^{\circ}\text{C}) \\ &= 1 + 0.0962 = 1.1369 \\ V_{\text{MAX}} &= 37.3\text{V} \times 14 \times 1.1369 = 593.7 \text{ Volts} < 600 \text{ Volts (compliant for a } 600V_{\text{MAX}} \text{ inverter)} \end{aligned}$$

Method 2 —

Module Manufacturer's Temperature Correction Factor—Voltage Method

$$\begin{aligned} \text{Temperature Coefficient for } V_{OC} &= \alpha V_{OC} = 137\text{mV}/^{\circ}\text{C} = 0.137 \text{ V}/^{\circ}\text{C} \\ \text{Temperature Correction Factor} &= 1 + [\alpha V_{OC}(\text{V}) \times (\text{Temp}_{\text{LOW}} - \text{Temp}_{\text{RATED}}) \div \text{VOC}] \\ &= 1 + [0.137 \text{ V}/^{\circ}\text{C} \times (-12^{\circ}\text{C} - 25^{\circ}\text{C}) \div 37.3\text{V}] \\ &= 1 + [5.069\text{V} \div 37.3\text{V}] = 1.1359 \\ V_{\text{MAX}} &= 37.3\text{V} \times 14 \times 1.1359 = 593 \text{ Volts} < 600\text{Volts (compliant for a } 600V_{\text{MAX}} \text{ inverter)} \end{aligned}$$

Method 3 —

Table 690.7 Temperature Correction Factor

From row for ambient temperature = -11°C to -15°C → 1.16
 $V_{\text{MAX}} = 37.3\text{V} \times 14 \times 1.16 = 605.8 \text{ Volts} > 600\text{Volts (this is less accurate and yields a value that exceeds the allowable } 600V_{\text{MAX}} \text{ for the inverter)}$

Rating Conditions

Standard Test Conditions (STC) is a universal rating condition for PV modules and arrays, and specifies the electrical output at a solar irradiance level of 1000 W/m² at AM 1.5 spectral distribution, and 25°C cell temperature. The conditions are conducive to testing in a manufacturing environment but tend to overestimate actual field performance, as the cell temperature is rarely at a temperature of 25°C and an irradiance of 1000 W/m² at the same time. An operating temperature of 50°C is much more common when the module is at mild ambient temperatures. See Fig. 57.

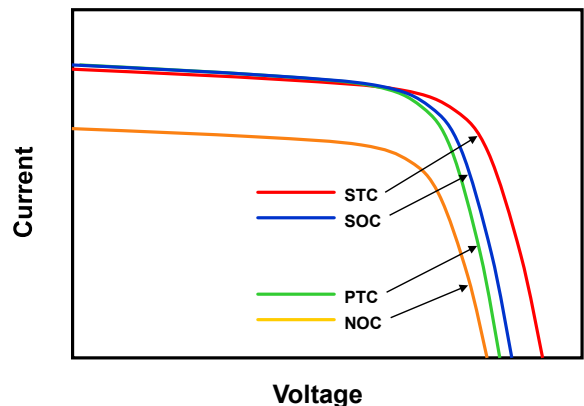


Figure 57. The differences between rating conditions can be clearly shown by the I-V curves.

PV module performance is sometimes represented at other test conditions, including:

- Standard Operating Conditions (SOC)
Irradiance: 1,000 W/m²
Cell temperature: NOCT
- Nominal Operating Conditions (NOC)
Irradiance: 800 W/m²
Cell temperature: NOCT
- Nominal Operating Cell Temperature (NOCT)
Irradiance: 800 W/m²
Ambient Temp: 20°C
PV Array: open-circuit
Wind Speed: 1.0 m/s
- PVUSA Test Conditions (PTC)
1000 W/m², 45°C, 1 m/s

A number of standards have been developed to address the safety, reliability and performance of PV modules. PV modules are classified as electrical equipment, and hence must conform to accepted product safety standards, and according to the NEC, they must be listed or approved by a recognized laboratory.

In the U.S., PV modules are listed for electrical safety to UL1703 *“Safety Standard for Flat-Plate Photovoltaic Modules and Panels”*. These requirements cover flat-plate photovoltaic modules intended for installation in accordance with the NEC and for use in systems with a maximum system voltage of 1000 volts or less. The standard also covers components intended to provide electrical connections and for the structural mounting of PV modules. The corresponding international standard is IEC61730, which has been harmonized with UL 1703.

PV Module Labels

Certain key I-V parameters at Standard Test Conditions are required to be labeled on every listed PV module [NEC 690.51]. These nameplate electrical ratings govern the circuit design and application limits for the module, and must include the following information and ratings:

- polarity of terminals
- maximum overcurrent device rating for module protection
- open-circuit voltage (Voc)
- short-circuit current (Isc)
- maximum permissible systems voltage
- operating or maximum power voltage (Vmp)
- operating or maximum power current (Imp)
- maximum power (Pmp)

Air Mass

Air mass (AM) is the relative path length of direct solar radiation through the atmosphere. Air mass affects the amount and spectral content of the solar radiation reaching the earth's surface, and varies with sun position and altitude (barometric pressure).

AM 1.5 defines the spectral irradiance characteristic for testing and rating the electrical performance of PV cells and modules, and is representative of a solar altitude angle of about 42°. Air mass is equal to $1/\cos\theta_z$, where θ_z is the zenith angle (90°-altitude angle). AM 0 is taken outside the earth's atmosphere, and represents extraterrestrial radiation. When the sun is directly overhead in the tropics, air mass is equal to one (AM 1). Air mass is also corrected for higher altitudes by average pressure ratios. See Fig 58.

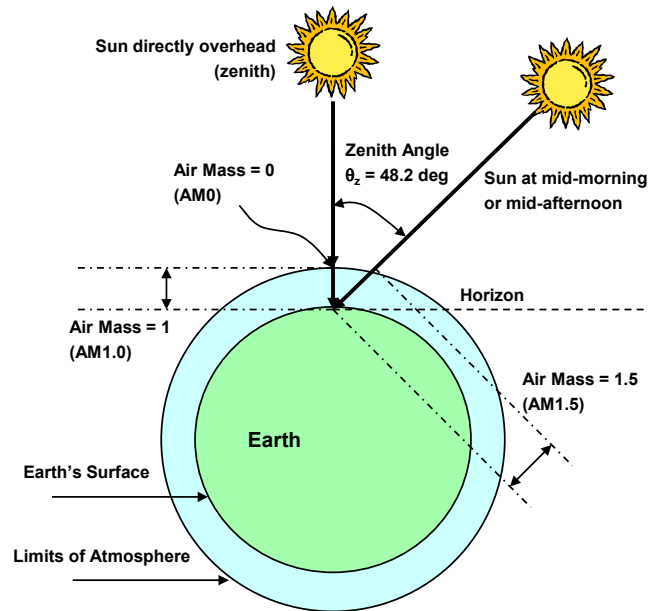


Figure 58. Air mass (AM) 1.5 defines the spectral irradiance characteristic for testing and rating the electrical performance of PV cells and modules.

Air mass is calculated by the following:

$$AM = \frac{1}{\cos \theta_z} \left[\frac{P}{P_o} \right]$$

where
 AM = air mass
 θ_z = zenith angle (deg)
 P = local pressure (Pa)
 P_o = sea level pressure (Pa)

Other items found on PV modules labels include fire classification ratings, minimum conductor sizes and ratings, and additional design qualification and type testing certification [IEC 61215 or IEC 61216]. Additional information related to PV module installation is found in the installation instructions included with listed PV modules. All installers should thoroughly read this information before working with or installing any PV modules or arrays [NEC 110.2]. See Fig. 59.

PV modules may be evaluated for external fire exposure for building roof covering materials. The fire class is identified in the individual Recognitions as class A, B or C in accordance with UL's Roofing Materials and Systems Directory. Modules not evaluated for fire exposure are identified as NR (Not Rated), and cannot be installed on buildings.

► All PV modules must be marked with the following information [690.51]:

- Open-circuit voltage
- Short-circuit current
- Operating voltage
- Operating current
- Maximum power
- Polarity of terminals
- Maximum overcurrent device rating
- Maximum permissible system voltage



Figure 59. PV module nameplate electrical ratings govern the circuit design and application limits for the product.

Series/Parallel Connections

PV arrays consist of building blocks of individual PV modules connected electrically in series and parallel to achieve the desired operating voltage and current. PV modules are connected in series to build voltage suitable for connection to DC utilization equipment, such as interactive inverters, batteries, charge controllers or DC loads. PV source circuits are connected in parallel at combiner boxes to build current and power output for the array.

A *string* is a series connection of PV devices. PV cells or modules are configured electrically in series by connecting the negative terminal of one device to the positive terminal of the next device, and so on. For the series connection of similar PV modules, the voltages add and the resulting string voltage is the sum of the individual module voltages. The resulting string current output remains the same as the current output of an individual module. See Figs. 60 & 61.

Connecting PV modules in series with dissimilar current ratings results in loss of power, similar in effect to partially shading an array, or having parts of a series source circuit located on surfaces facing different directions and receiving different solar irradiance. The resultant current output for a string of dissimilar current output devices is ultimately limited to the lowest current output device in the entire string, and should be avoided. However, it is perfectly acceptable to connect PV modules with different voltage output in series, as long as each module has the same rated current output. See Fig. 62.

Series strings of PV modules are configured electrically in parallel by connecting the negative terminals of each string together and the positive strings together. Usually, an overcurrent device is required in each string. For the parallel connection of strings, the string currents add and the resulting string voltage is the average of the individual string voltages. Parallel connections of string with different current output, or from string in different planes are acceptable, but may require different circuit sizing. See Figs. 63, 64 & 65.

Monopole PV arrays consist of two output circuit conductors, a positive and negative. Bipolar PV arrays combine two monopole arrays with a center tap.

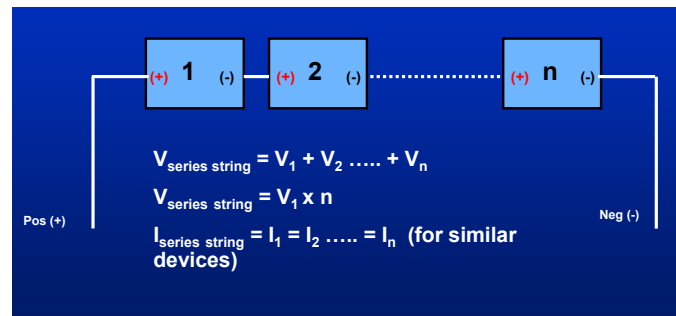


Figure 60. PV cells or modules are configured electrically in series by connecting the negative terminal of one device to the positive terminal of the next device, and so on.

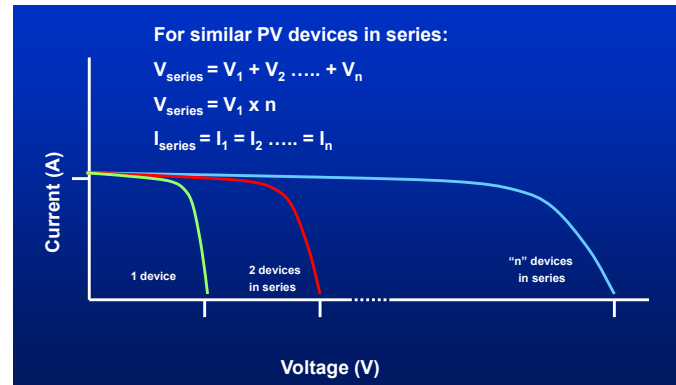


Figure 61. Connecting similar PV devices in series increases voltage while current stays the same.

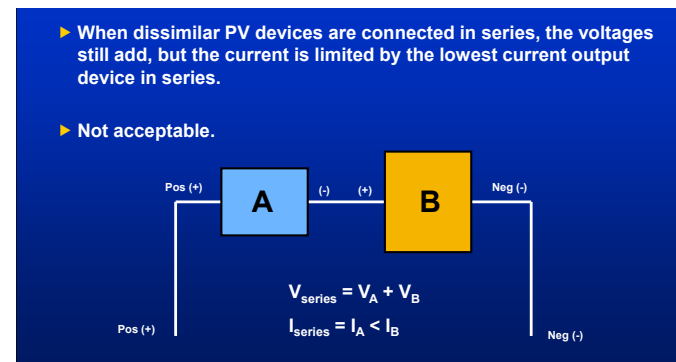


Figure 62. Connecting dissimilar PV devices in series must be avoided.

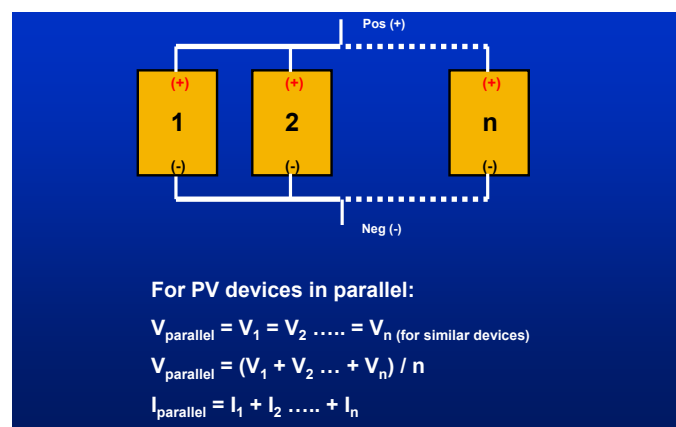


Figure 63. PV cells or modules are connected in parallel by connecting the negative terminals together and the positive terminals together at a common point.

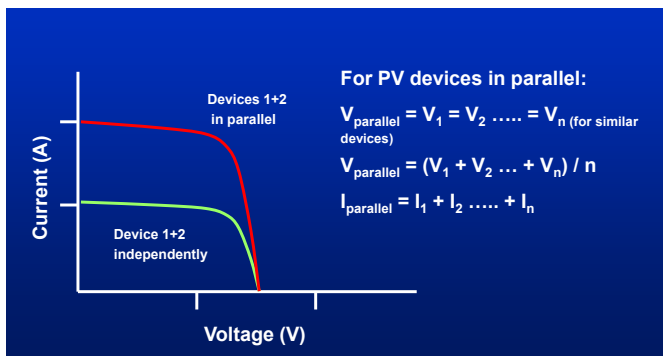


Figure 64. Connecting similar PV devices in parallel increases current while voltage stays the same.

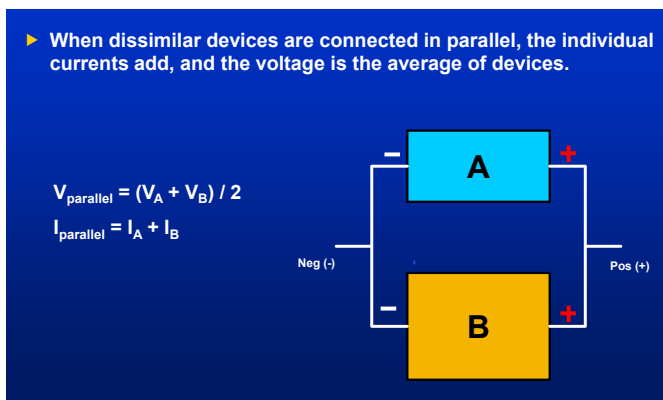


Figure 65. Dissimilar current PV modules and strings having similar voltage may be connected in parallel.

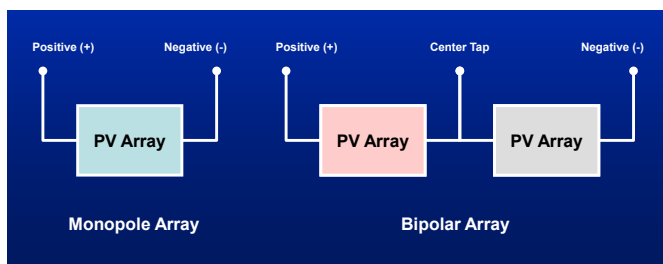


Figure 66. Monopole PV arrays consist of two output circuit conductors; bipolar PV arrays combine two monopole arrays with a center tap.

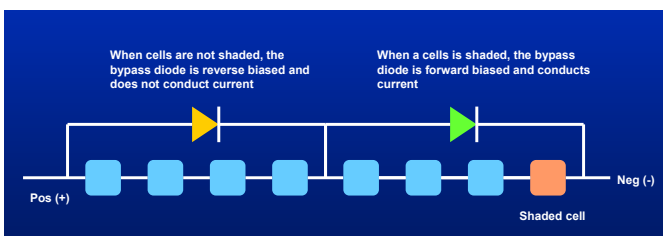


Figure 67. Bypass diodes are connected in parallel with series strings of cells to prevent cell overheating when cells or parts of an array are shaded.

Certain inverters require the use of bi-polar arrays. See Fig. 66.

Bypass diodes are connected in parallel with series strings of cells to prevent cell overheating when cells or parts of an array are shaded. See Fig. 67. Bypass diodes are essentially electrical check valves that permit the flow of current in only one direction. When modules in series strings are partially shaded, it may cause reverse voltage across the shaded cells or modules. The bypass diode shunts current around the shaded area and prevents cells overheating. Most listed PV modules are equipped with factory installed bypass diodes. Bypass diodes may or may not be serviceable via module junction boxes in the field. See Fig. 68.

PV Inverters

Inverters are used in PV systems to produce ac power from a dc source, such as a PV array or batteries. Inverter sizes range from module-level inverters rated a few hundred watts to utility-scale inverters 1 MW and larger. Similar to the way PV systems are classified, types of PV inverters are also defined based on their application in stand-alone, utility-interactive, or a combination of both types of systems.

Stand-alone inverters operate from batteries and supply power independent of the electrical utility system. These inverters may also include a battery charger to operate from an independent ac source, such as a generator. See Fig 69.

Utility-interactive or grid-connected inverters operate from PV arrays and supply power in parallel with an electrical production and distribution network. They do not supply PV array power to loads during loss of grid voltage (energy storage is required). See Fig. 70.

Bi-modal inverters are a type of battery-based interactive inverter that act as diversionary charge controllers by producing ac power output to regulate PV array battery charging, and send excess power to the grid when it is energized. During grid outages, these inverters transfer backup loads off-grid, and operate in stand-alone mode. They can operate either in



Figure 68. Bypass diodes are often located in module junction boxes.

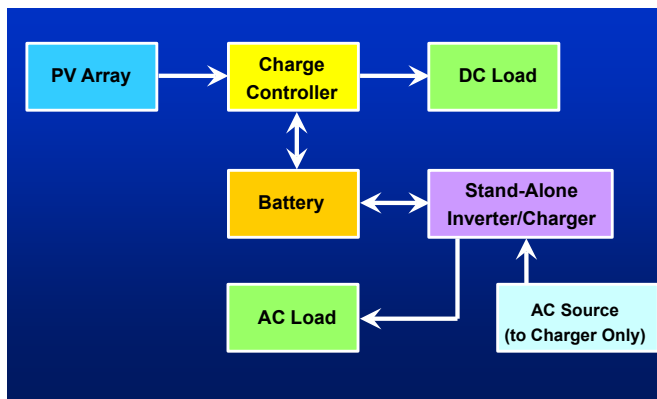


Figure 69. Stand-alone inverters supply power to ac loads isolated from the grid, and the inverter power rating dictates the maximum load.

interactive or stand-alone mode, but not simultaneously.

Although stand-alone and interactive PV inverters both produce ac power from dc power, they have different applications and functions. See Fig. 71.

The following list different types of utility-interactive inverters and their applications:

Module-level inverters include *AC modules* and *micro inverters*. AC modules and micro inverters are small inverters installed integral to or adjacent to individual PV modules. These inverters are rated 200 W to 300 W maximum ac power output, which is consistent with standard PV module sizes. The ac outputs of multiple inverters are connected in parallel to a dedicated branch circuit breaker. Advantages of module-level inverters include individual module MPPT and better energy harvest from partially shaded and multi-directional arrays. They also minimizes field-installed dc wiring and source circuit design issues, and they are inherently safer as the maximum dc voltages on the array are for a single module (35-60 V) as opposed to a series connection of several hundred volts for string inverters. See Fig. 72.

String inverters are small inverters in the 1 kW to 12 kW size range, intended for residential and small commercial applications. They are generally single-phase, usually limited to 1 to 6 parallel-connected source circuits. Some integrate source circuit combiners, fuses and disconnects into a single unit. Larger systems using multiple string inverters offer a number of advantages in systems design and installation. Multiple inverters can be distributed at

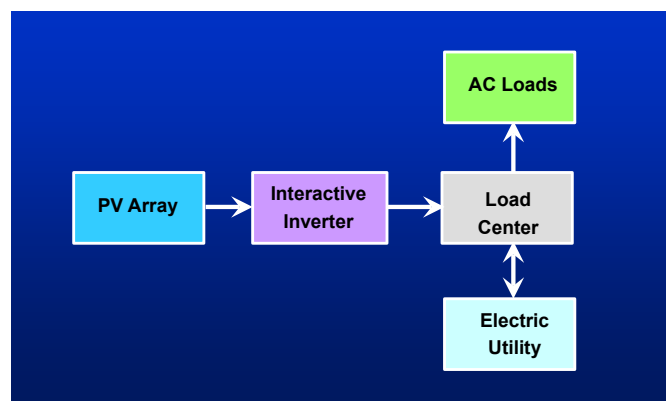


Figure 70. Interactive inverters use PV arrays for dc power input, and supply synchronized ac output power in parallel with the utility grid, supplementing power to the local ac distribution system.

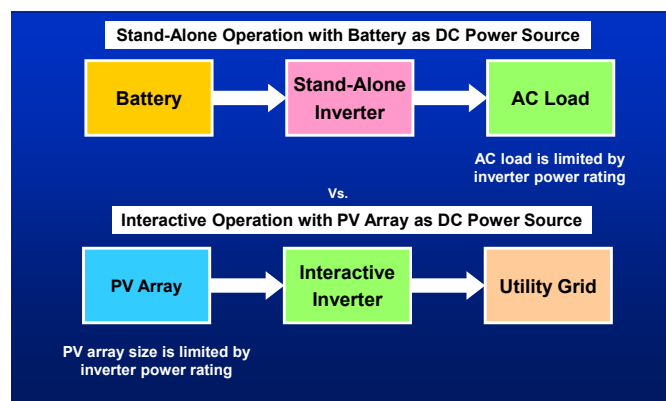


Figure 71. Stand-alone inverters use a battery for the dc power source, while interactive inverters use a PV array as the dc source.



Enphase Micro Inverter

Figure 72. AC modules and micro inverters are small inverters installed integral to or adjacent to individual PV modules.



Figure 73. String inverters are small inverters in the 1 to 12 kW size range, intended for residential and small commercial applications.

subarray locations, avoiding long DC circuits, and can be interconnected at distributed points in an electrical system. Multiple inverters also provide redundancy in the event of an individual inverter or subarray failure, and provide MPPT and monitoring at the subarray level, facilitating fault finding and optimizing the output of individual subarrays of different size, type, orientation or partially shaded. The AC output of multiple string inverters can be distributed equally across the three phases networks to avoid phase imbalance. See Fig. 73.

Central inverters start at 30 kW to 50 kW up to 500 kW, and interconnect to 3-phase grids. They are best suited for homogeneous PV arrays having all the same modules and source circuit configurations, and aligned and oriented in the same direction with no shading.

Utility-scale inverters are very large equipment with power ratings 500 kW to 1 MW and higher, designed for solar farms. These types may also include MV transformers and switchgear, and are interconnected to the grid at distribution voltages up to 38 kV. For utility-controlled sites, certain variances with the NEC and product listing requirements may apply. Both utility-scale and central inverter installations require heavy equipment handling, larger conduit and switchgear, and should be installed by competent individuals having experience with the installation of large electrical equipment. See Fig. 74.

Special controls may be used for utility-scale inverters that differ from smaller inverters due to their impact on grid operations. Smaller inverters are designed for near unity power factor output with tighter anti-islanding and power quality controls. Utility-scale inverters may be designed to deliver reactive power or low voltage ride through (LVRT), or provide other dynamic controls for grid support.

Bimodal inverters are battery-based interactive inverters that provide grid backup to critical loads, typical with rated ac power output 2 kW to 10 kW. They can operate in either interactive or stand-alone mode, but not simultaneously, and many can interface and control auxiliary source, such as generators for hybrid system applications. These types

of inverters and systems are used where a backup power supply is required for critical loads. Under normal circumstances when the grid is energized, the inverter acts as a diversionary charge controller, limiting battery voltage and state-of charge. When the primary power source is lost, a transfer switch internal to the inverter opens the connection with the utility, and the inverter operates dedicated loads that have been disconnected from the grid. An external bypass switch is usually provided to allow the system to be taken off-line for service or maintenance, while not interrupting the operation of electrical loads. These inverters may also be used in hybrid system applications to control loads, battery charging, and generator starting.

Inverter circuits use high-speed switching transistors to convert dc to ac power. Large thyristors are used in high power applications up to several MW for HVDC power transmission at grid-interties. Most PV inverters use metal-oxide semiconductor field-effect transistors (MOSFETs) or insulated gate bi-polar transistors (IGBTs). Power MOSFETs operate at lower voltages with high efficiency and low resistance compared to IGBTs. They switch at very high speeds (up to 800 kW) and are generally used in medium to low-power applications from 1 kW to 10 kW. IGBTs handle high current and voltage, but switch at lower speeds (up to 20 kHz), and are more common for high-voltage, large power applications up to an over 100 kW. Switching elements are connected in parallel to increase current and power capability.

Sine waves, square waves and modified square waves are examples of common inverter ac waveforms. Listed interactive inverters produce utility-grade sine wave output. Some small, lower cost stand-alone inverters produce modified square wave or square wave output. See Fig. 75.



Figure 74. Utility-scale inverters use higher DC input and AC output voltages to reduce losses, and the size and costs of the conductors and switchgear required.

AC Waveforms

For a pure sine wave, the peak voltage is related to the RMS voltage by a factor of the square root of 2:

$$V_{\text{peak}} = V_{\text{rms}} \times \sqrt{2} = V_{\text{rms}} \times 1.414$$

$$V_{\text{rms}} = V_{\text{peak}} \times 0.707$$

For example, a typical AC voltage sine wave with peak voltage of 170 V has an RMS voltage of $170 \times 0.707 = 120$ V.

For pure sine waves, the average voltage is also related to RMS and peak voltage by:

$$V_{\text{rms}} = 1.11 \times V_{\text{avg}}, \text{ or } V_{\text{avg}} = 0.9 \times V_{\text{rms}}.$$

$$V_{\text{avg}} = 0.637 \times V_{\text{peak}}, \text{ or } V_{\text{peak}} = 1.57 \times V_{\text{avg}}.$$

For a square wave, V_{avg} , V_{rms} , and V_{peak} are all equal. See Fig. 76.

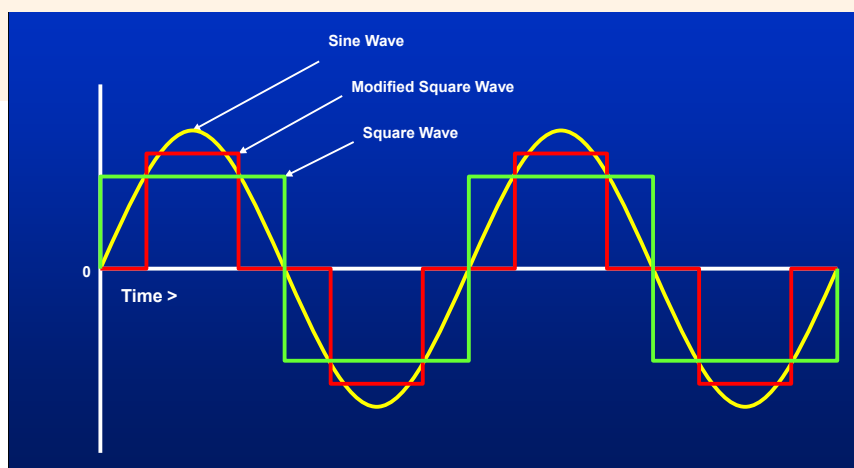


Figure 75. For a pure sine wave, the peak voltage is related to the RMS voltage by a factor of the square root of 2.

Selecting and specifying the best inverter for a given application involves considering the system design and installation requirements. Inverter specification sheets are critical. Inverter selection is often the first consideration in system design, and based on the type of electrical service and voltage, and the size and location of the PV array.

Specifications for inverters typically include:

DC Input

- Maximum array voltage (open-circuit, cold)
- Recommended maximum array power
- Start voltage and operating range (interactive inverters only)
- MPPT voltage range (Interactive inverters only)
- Maximum usable input current (interactive inverters)
- Maximum array and source circuit current
- Array ground fault detection

AC Output

- Nominal Voltage
- Maximum continuous output power
- Maximum continuous output current
- Maximum output overcurrent device rating
- Power conversion efficiency
- Power quality
- Anti-islanding protection

Performance

- Nominal and weighted efficiencies
- Stand-by losses (nighttime)
- Monitoring and communications interface

Physical

- Operating temperature range
- Size and weight
- Mounting locations, enclosure type
- Conductor termination sizes and torque specifications
- Conduit knockout sizes and configurations

Other Features

- Integral DC or AC disconnects
- Number of source circuit combiner and fuse/circuit ratings
- Standard and extended warranties

Inverter efficiency is calculated by the AC power output divided by the DC power input. Inverter efficiency varies with power level, input voltage and temperature, among other factors. For example, an inverter having an input power of 6000 W_{dc} and producing an output of 5700 W_{ac} has an efficiency of $5700 \div 6000 = 0.95 = 95\%$. See Fig 77.

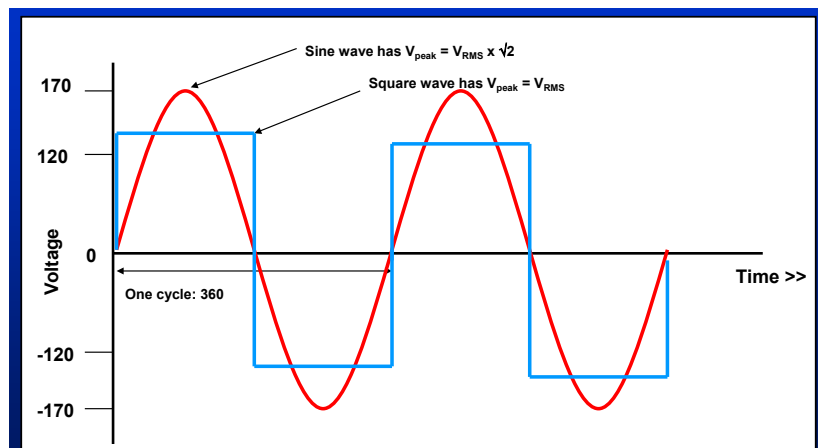


Figure 76. Sine waves, square waves and modified square waves are examples of common inverter ac waveforms.

Inverter Standards

The following standards apply to inverters used in PV systems, including requirements for product listing, installation and interconnection to the grid.

UL 1741 *Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources* addresses requirements for all types of distributed generation equipment, including inverters and charge controllers used in PV systems, as well as the interconnection of wind turbines, fuel cells, microturbines and engine-generators.

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, and IEEE 1547.1 Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems are the basis for UL 1741 certification for interactive inverters.

Inverter installation requirements are governed by the NEC Articles 690 and 705. These articles cover inverter installation requirement including sizing conductors and overcurrent protection devices, disconnect means, grounding, and for connecting interactive inverters to the electric utility grid.

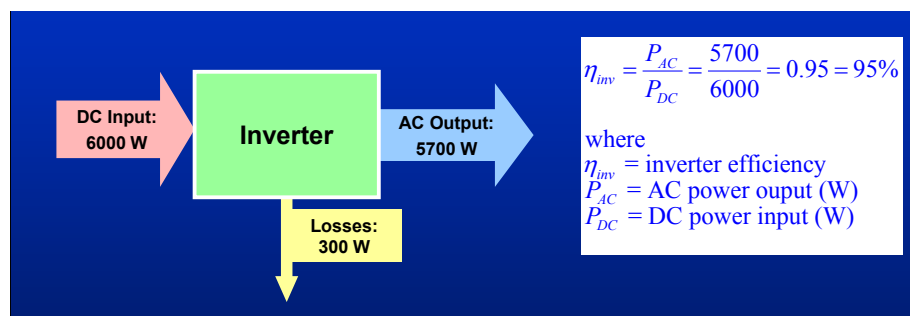


Figure 77. Inverter efficiency is calculated by the ac power output divided by the dc power input.

In addition to product safety testing and listing to the UL1741 standard, the California Energy Commission (CEC) has established requirements for independent inverter efficiency testing by an NRTL to be approved as eligible equipment. Incentive programs in other states also require the use of PV modules and inverters on the CEC list. A complete list of eligible inverters and test results are available online.

Inverter efficiency testing is conducted over the entire power range of the inverter, and at minimum, maximum and nominal dc operating voltages. Inverter efficiency rises quickly with a low power levels, and most inverters reach at least 90% efficiency at only 10% of their maximum continuous output power rating. See Fig 78.

Reference: List of Eligible Inverters per SB1 Guidelines, California Energy Commission:
<http://www.gosolarcalifornia.org/equipment/inverters.php>

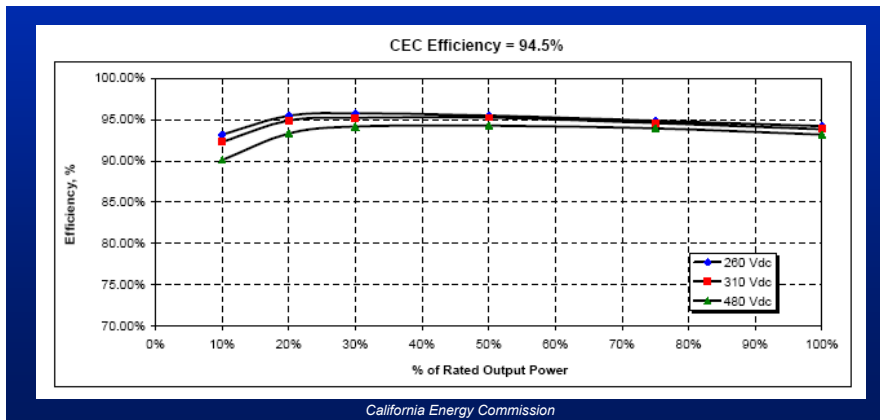


Figure 78. Inverter efficiency testing is conducted over a range of operating voltages and power levels.

2.7 Review Wiring and Conduit Size Calculations

There are several circuits in PV systems depending on the type of system installed. Some circuits are dc and others are ac, operating at different voltages and currents, and of varying length and environmental exposure. Some of these circuits have special requirements for sizing the circuit conductors and overcurrent protection. The PV installer should be able to clearly identify the different circuits in a PV system and their installation requirements [NEC 690.2]. See Figs. 79, 80 & 81.

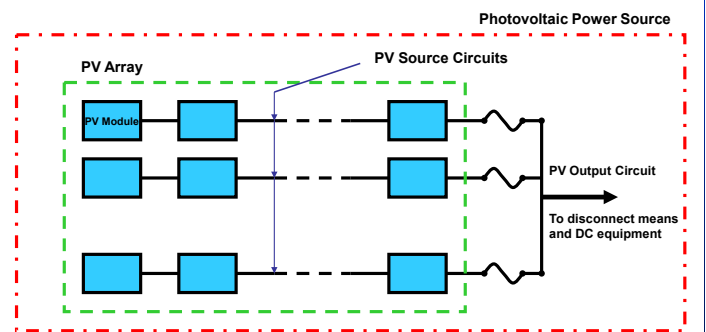


Figure 79. The PV power source consists of the complete PV array dc power generating unit, including PV source circuits, PV output circuits, and overcurrent protection devices as required.

Interactive System

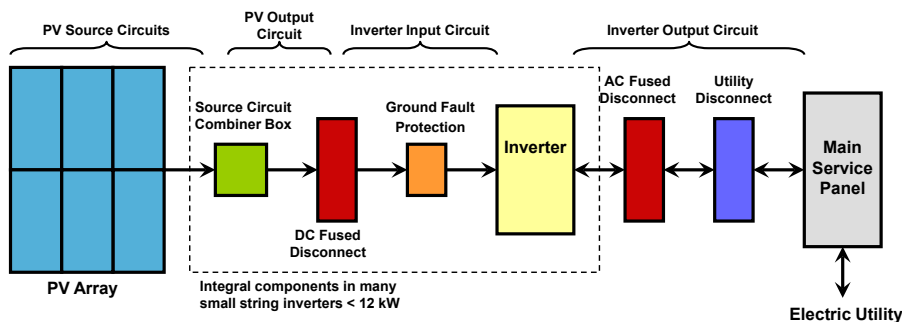


Figure 80. For simple interactive PV systems, the PV array is connected to the dc input of inverters, and there is no energy storage.

Stand-Alone System

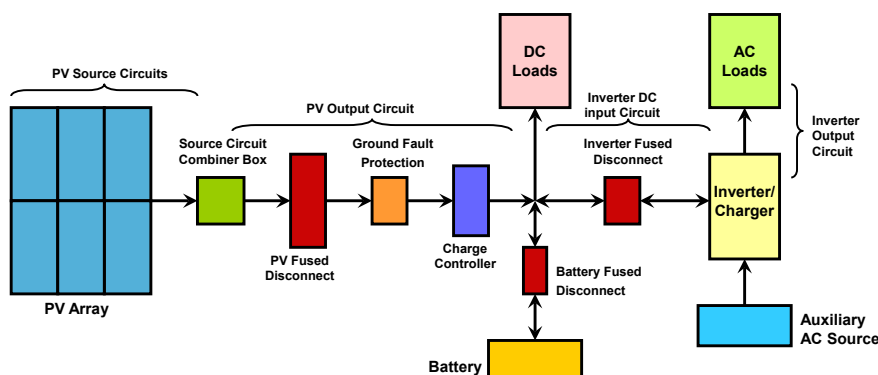


Figure 81. For stand-alone PV systems the PV array charges the battery, and the battery provides dc power to the inverter which can produce ac power output at any time.

2.7.1 Determine Circuit Currents

Source Circuit Maximum Current

The required ampacity of the source circuit wiring, or conductors from modules to source circuit combiner box, depends upon the rated PV module short-circuit current (I_{sc}). The *maximum current* for PV source circuits is determined by 125% of the sum of the module rated short-circuit currents in parallel [NEC 690.8(A)]. Since most crystalline silicon arrays only have one series string per source circuit, there is normally no need to account for parallel circuits in the source circuit calculation. The reason for the 125% factor is that in certain locations and times of the year, it is possible for the modules to operate at 125% of the STC short-circuit current rating for 3 hours or more around solar noon. The example shown in the Appendix has a module short circuit rating of 8.41 A. Thus, the maximum continuous current rating of that module is 125% of the STC short-circuit current rating, or $1.25 \times 8.41 \text{ A} = 10.5 \text{ A}$.

PV Power Source Maximum Circuit Current

The maximum current for the PV output circuit and the entire PV power source is the sum of all parallel source circuits supplying dc power. The maximum circuit current for a typical PV array with three series strings is the sum of the three source circuit maximum currents. For the example with a maximum source circuit current of 10.5 A, the maximum current for the PV output circuit having three of these source circuits in parallel would be $3 \times 10.5 \text{ A} = 31.5 \text{ A}$.

Inverter Output Circuit Current

The inverter output circuit is defined as the ac circuit from the inverter output to the utilization load. In the case of utility-interactive installations, the inverter output circuit is the ac output that connects to the interactive point of connection. This point of connection in residential PV systems is often a simple circuit breaker in a utility-fed service panel. The maximum current of the inverter output circuit is the continuous current capability of the inverter (continuous = 3-hour rating). The maximum continuous current of an inverter may be listed on the product specification sheet. If it is not available on the specification sheet, then the current can be calculated by taking the continuous power rating at 40°C and dividing that value by the nominal ac voltage. For example, the maximum current for an inverter with maximum continuous power of 7,000 W at 240 Vac would be 29 A.

Battery Circuit Current

Battery circuits are unique in that they carry not only the dc current required to run the inverter at full load continuously (for 3 hours), but they must also carry ac current. This may surprise some installers, but all inverters require an ac input in order to create and ac output. Since dc sources such as a PV array do not naturally provide these ac currents, a short-term storage device is necessary. In utility-interactive inverters, these storage devices are capacitors. Each time the ac power goes to zero, when the ac voltage goes to zero, the power from the PV array is stored in the capacitor. That energy is rereleased at the peak of the next waveform. Therefore current is stored and removed from the capacitor two times every cycle. When the required frequency is 60 Hertz, the frequency on the capacitors is 120 Hertz. This storage is sometimes called half-wave storage.

In battery-based inverters, rather than installing capacitors, the battery is used for half-wave storage. Current that is needed to create the sine wave is stored and removed from the battery. This means that additional current is travelling on the battery input conductors that must be accounted for.

2.72 Calculate Required Ampacity of Conductors

Temperature and Conduit Fill Corrections for Ampacity of Conductors

The required ampacity of conductors is based on the maximum circuit current, the size of the overcurrent protection device, the ambient temperature of the conductor, the type of conductor and insulation, the conduit fill of the conductor, and any limitations that the terminals may place on the conductor. PV systems are some of the most complex wiring systems to determine wire sizing due to the large number of factors that must be considered when choosing an adequate wire size. Fortunately, the 2011 NEC has some much clearer direction on this subject that should help installers and system designers more accurately specify wire sizes. To illustrate the proper code-approved method, it is beneficial to do an example using NEC 690.8 from the 2011 NEC.

EXAMPLE:

A residential rooftop PV system has 3 pairs of conductors in a sunlit raceway mounted 1½" above the roof surface in Palm Springs, California. The short-circuit current of each source circuit is 8.41 amps. What is the minimum size conductor for this scenario?

Answer:

Step 1: Calculate Maximum Circuit Current [690.8(A)(1)]: $I_{max} = I_{sc} \times 1.25 = 8.41A \times 1.25 = 10.5A$

Step 2: Calculate the minimum overcurrent protective device (OCPD) [690.8(B)(1)(a)]:

OCPD = $I_{max} \times 1.25 = 10.5A \times 1.25 = 13.1A \rightarrow 14A$ [690.9(C)]; since 14A fuses are not generally manufactured for 600Vdc, choose a 15A fuse as the smallest available fuse \rightarrow module maximum fuse rating is 15A so minimum and maximum are the same.

Step 3: Calculate minimum conductor size without conditions of use [690.8(B)(2)(a)]

Minimum conductor ampacity = $I_{max} \times 1.25 = 13.1A \rightarrow 14$ AWG (minimum bldg wire)

Step 4: Calculate minimum conductor size based on I_{max} with conditions of use [690.8(B)(2)(b)]:

Conditions of use include conduit fill, sunlit conduit temperature adder, and ambient temperature adjustment factors.

Conduit fill adjustment factor $\rightarrow 0.8$ according to Table 310.15(B)(3)(a)

Sunlit conduit temperature adder $\rightarrow 22^{\circ}C$ according to Table 310.15(B)(3)(c)

Ambient temperature adjustment factor $\rightarrow 22^{\circ}C + 44^{\circ}C = 66^{\circ}C \rightarrow 0.58$ [Table 310.15(B)(2)(a)]

Minimum conductor ampacity = $I_{max} \div \text{conduit fill adj factor} \div \text{temp adj factor} = 10.5 \div 0.8 \div 0.58 = 22.6$ Amps $\rightarrow 12$ AWG

Step 5: 15 Amp Overcurrent protection can protect the conductor [690.8(B)(2)(c)]

12 AWG \rightarrow ampacity = $30\text{amps} \times 0.8 \times 0.58 = 13.92$ amps (fails because of 690.9(C))

10 AWG \rightarrow ampacity = $40\text{amps} \times 0.8 \times 0.58 = 18.56$ amps (okay)

Source Circuit

Outside Conduit

Exposed outdoor cables are common in PV systems and in industrial conventional electrical systems, but they are less common in commercial and residential electrical systems. Conductors as single conductor cables, or bundles of three conductors or less, are commonly run in PV arrays from a few kilowatts up to megawatts. Since these conductors are often run for some distance in free air, it would be possible to claim free air ampacities for those exposed lengths of cables [NEC Table 310.15(B)(17)]. However, these exposed conductors are often run into raceways for physical protection and support. As long as the sections of raceway protection are not more than 10 ft or 10% of the circuit length, then free air ampacities can be used [NEC 310.15(A)(2)].

Bundled or Inside Conduit

In almost all cases, wiring behind modules will be exposed to elevated temperatures, sometimes as high as 75°C. The NEC also recognizes the fact that conductors installed in conduit exposed to direct sunlight, as is common in PV systems, can operate at temperatures that are 17°C or more above the ambient temperature [Table 310.15(B)(3)(c)]. This means that a conduit in an outdoor temperature of 40°C should actually be sized based on a 57°C operating temperature due to the sunlight exposure. Suppose the conductors are exposed to 57°C and that 14 AWG THWN, with insulation rated at 75°C, is being considered. According to NEC Table 310.15(B)(16), when THWN wire is operated at 30°C or less, its ampacity is 20 A. But the correction factor associated with Table 310.15(B)(2)(a) requires that the ampacity of the wire be derated to 58% of its 30°C value if it is operated at 57°C. This reduces the ampacity of the wire to $20 \text{ A} \times 0.58 = 11.6 \text{ A}$.

Although it may appear that this ampacity is just enough to satisfy the source-circuit ampacity requirement in our source circuit example, the conductors pass through conduit so the conduit fill adjustment factor must be applied. The conduit between the junction box (JB) and the source-circuit combiner box contains four current-carrying conductors. According to NEC Table 310.15(B)(3)(a), a further adjustment of 80% is needed for conduit fill. This reduces the ampacity of the 14 AWG THWN conductors to $11.6 \times 0.8 = 9.28 \text{ A}$. The ampacity of the conductor, after the application of these “conditions of use” factors must be equal to or greater than the continuous current of 9 amps. Since the “9.28” ampacity factor for the 14 AWG conductor is greater than the 9 amps of continuous currents, this conductor meets initial code requirements for ampacity.

However, the fuse protecting the conductors must also be rated at 1.25 times the continuous currents (1.56 I_{sc}), which is 11.23 amps, and that fuse must provide overcurrent protection for the conductor under its conditions of use. The fuse rating can be rounded up to the next higher standard value (12 amps), but this value of fuse will not protect the cable, which has a corrected ampacity of only 9.28 amps. The 14 AWG THWN conductor therefore is not acceptable due to the minimum size of the overcurrent protection.

If a 14 AWG THWN-2 copper wire is used, the 30°C ampacity of the wire is 25A. Furthermore, the temperature correction factor for 57°C operation is 0.71. The resulting ampacity of the 14 AWG THWN-2 conductor, when corrected for temperature and for conduit fill becomes $25 \times 0.71 \times 0.8 = 14.2 \text{ A}$, which is more than adequate to handle the continuous source circuit current (9 amps). It can also be appropriately protected with the 12-amp fuse.

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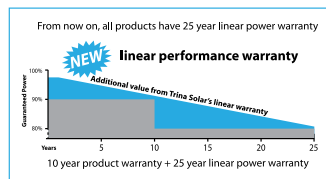


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When using conductors with insulation temperature ratings higher than the terminal temperature rating of the connected devices, a check must be made to ensure that the conductor temperature during normal operation does not exceed the maximum temperature rating of the terminals of these devices. In this case the module terminals are rated at 90°C and the fuse terminals are rated at 60°C or 75°C. The ampacity of the 14 AWG conductor taken from the 75°C or 60°C insulation column in NEC Table 310.15(B)(16) is 20 amps. The continuous current in this circuit is only 9 amps so it is assured that the 14 AWG conductor will operate at temperatures well below 60°C at the fuse terminals if the terminals are in an ambient temperature of 30°C. If the fuse terminals are in a 40°C environment, similar to conduit not exposed to sunlight, the maximum allowable current must be corrected by the 40°C correction factor of 0.82 or 16.4 amps ($0.82 \times 20 \text{ A} = 16.4 \text{ A}$). Fortunately, the maximum continuous current is only 9 amps which is well below the maximum of 16.4 A. If the terminals are in a box on the roof exposed to direct sunlight, they would have to be rated for 75°C minimum in order to not overheat on a hot sunny day since the temperatures could reach 57°C similar to the conduit.

PV Power Source Circuit

Bundled or Inside Conduit

PV power source circuits, similar to feeder circuits in conventional ac distribution in buildings are typically run inside conduit. Occasionally these circuits are bundled together and run in cable trays. In either case, adjustment factors must be applied to the allowable ampacity of the conductors to prevent the insulation from being damaged by overheating. Table 310.15(B)(3)(a) covers the adjustment factors required for conductors in raceways or multi-conductor cables. Bundles of single conductor cables would also be required to use these adjustment factors.

Inverter Output Circuit

The inverter output circuit is sized according to 690.8(A)(3), which states that the conductor shall be sized according to the maximum continuous current output of the inverter. The overcurrent device protecting the wire must be sized at least 1.25 times the continuous current. The chosen overcurrent device should be the sized according to the conductor ampacity after conditions of use or the next standard size above that ampacity. If the overcurrent device is sized larger than the next available size, when the max OCPD rating for the inverter allows a larger size, then the conductor size must be increased to match the OCPD rating.

Battery Circuit

To properly calculate the required ampacity of the inverter input circuit in a battery-based inverter system, the maximum input current needs of the inverter must be calculated and then the RMS ac current of the inverter operation must be numerically added. EXAMPLE: A 6000 Watt (Volt-Amp) inverter is connected to a large battery bank at 48 Volts. Inverter is operating at full capacity and lowest dc operating voltage of 44 Volts. What is the total current flowing through the inverter input circuit conductors for a 90% efficient inverter with 45 amps of ac ripple current on the battery?

Step 1: Calculate dc current: $I_{dc} = \text{inverter power} \div \text{inverter efficiency} \div \text{dc voltage at minimum operating voltage} = 6000\text{VA} \div 0.9 \div 44 \text{ Volts} = 152 \text{ Amps}$ [690.8(A)(4)]

Step 2: Total current = $I_{dc} + I_{ac \text{ ripple}} = 152 \text{ A} + 45 \text{ A} = 197 \text{ Amps}$

Size Equipment Grounding Conductor for Each Circuit

The equipment grounding conductor (EGC) for the dc side of the PV system is sized according to NEC 690.45. Since most PV systems related to residential and commercial buildings must have ground-fault protection systems [NEC 690.5]. NEC 690.45(A) requires the minimum size EGC to be based on Table 250.122. For systems without ground-fault protection, the EGC is sized according to 690.45(B) and must be a minimum of twice the rated short circuit current of the largest circuit it is protecting.

2.7.3 Calculate Voltage Drop

Voltage Drop for Circuits

In the above example, before deciding that 14 AWG THWN-2 is adequate, it is also necessary to check for voltage drop. It is wasteful to dissipate energy to heat wires when the cost of larger wires is usually minimal compared with the cost of PV modules. Voltage drop is often the determining factor in wire sizing particularly for systems operating below 100 Volts. Voltage drop is not a safety issue, therefore it is not covered in great detail in the NEC. However PV systems with excessive voltage drop are inefficient and can perform poorly.

Once the NEC requirements for ampacity have been met, the voltage drop must be verified that it is within acceptable limits for efficiency and quality performance. For any given wire size, voltage drop increases with increasing currents and/or increasing wire lengths. Therefore circuits with high current and/or long lengths deserve close scrutiny with respect to voltage drop. This is particularly true of systems operating at 12 V, 24 V, or 48 V, but even higher voltage systems can have significant voltage drop issues as a result of long circuits.

There is no specified code compliance limit for voltage drop in any given circuit. Generally accepted practices within the industry limit overall system voltage drop within a range of 2% to 5% of the circuit operating voltage. The PV system designer must use their best judgment considering performance and economics.

Five percent is generally considered a maximum overall acceptable voltage drop from source to load. In order to achieve this 5% limit you will have to limit intermediate runs within a circuit to a lesser percentage voltage drop. For instance, intermediate circuit runs such as “PV array to PV combiner box” and “PV Combiner box to PV charge controller” must be limited to less than 2 % each in order to stay within 5% overall.

Determining Voltage Drop

If the one-way distance between two points is expressed as length (d) in feet, recognizing that the total wire length of a circuit between these two points will be 2 x d. Ohm's Law ($V_d = I \times R$) provides the basic equation to find voltage drop in conductors, where V_d is the amount of voltage drop in the conductor at the highest expected current level. The Ω/kft term is the resistance of the conductor in ohms/1000 feet and is presented in the NEC Chapter 9, Table 8.

$$\begin{aligned}V_d &= I \times R \\R &= 2 \times d \times \frac{\text{kft}}{1000 \text{ f}} \left(\frac{\Omega}{\text{kft}} \right) \\V_d &= \frac{I \times 2 \times d}{1000 \text{ f} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right) \\\%V_{\text{drop}} &= \frac{V_d}{V_{\text{nom}}} \times 100\% = \frac{\frac{2 \times d \times I}{1000 \text{ f} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right)}{V_{\text{nom}}} \times 100\%\end{aligned}$$

Where I is the circuit current in Amperes, which for source circuits is usually taken as the maximum power current, I_{mp} , V_{nom} is the nominal system voltage, which, in this case, is 24V, and Ω/kft is found from NEC Chapter 9, Table 8, "Conductor Properties."

In this case, using 14 AWG stranded copper uncoated wire, Ω/kft is found to be 3.14. Assuming the distance from junction box to source circuit combiner box to be 40 ft, the $\%V_{\text{drop}}$ is found, after substituting all the numbers into the formula, to be

$$\%V_{\text{drop}} = \frac{\frac{2 \times 40 \text{ ft} \times 7 \text{ A}}{1000 \text{ ft} / \text{kft}} \times 3.14 \left(\frac{\Omega}{\text{kft}} \right)}{24 \text{ V}} \times 100\% = 7.3\%$$

Clearly a value of 7.3% is high and is well above the recommended target of 1-3%. Even though 14 AWG THWN wire meets the ampacity requirements of the NEC, it falls quite short of meeting the voltage drop requirements for system performance. If the target $\%V_{\text{drop}}$ is less than 2% from junction box to combiner box, what would be the correct conductor size? To find the correct conductor size, substitute in the Ω/kft values for other wire sizes until a size is found that will meet the voltage drop requirements. Substituting the value for Ω/kft for 12 AWG stranded copper gives $\%V_{\text{drop}} = 4.62\%$, which is still too high. For 10 AWG stranded copper, the result is $\%V_{\text{drop}} = 2.89\%$, and for 8 AWG stranded copper, the result is $\%V_{\text{drop}} = 1.82\%$, which meets the performance requirement.

The distance from source-circuit combiner box to charge controller also must be calculated. Assuming a distance of 10 feet, the $\%V_{\text{drop}}$ can be calculated using the equation below to be:

$$\%V_{\text{drop}} = \frac{\frac{2 \times 10 \text{ ft} \times 14 \text{ A}}{1000 \text{ ft} / \text{kft}} \times 1.24 \left(\frac{\Omega}{\text{kft}} \right)}{24 \text{ V}} \times 100\% = 1.45\%$$

This voltage drop is high for such a short wire run, and as 8 AWG is being used for the wire runs from the junction box to the source-circuit combiner box, it is recommended that 6 AWG be used between the combiner box and the charge controller. The voltage drop over this circuit will then be reduced to 0.9%. This exercise shows how large the conductors must be in 24 V systems to carry small amounts of current.

To achieve overall system voltage drops that are within 3% to 5%, individual circuits must have much lower voltage drops. To illustrate the need to keep these voltage drops at reasonable levels, the following table (Table 2) shows one way of tracking voltage drop to maintain it within appropriate levels. Not all systems will have all these different circuits, but it becomes easy to see how voltage drops can add up if care is not taken throughout the wire sizing process. The following table shows how a typical wire sizing exercise would proceed.

Table 2. Conductor voltage drop example.

Circuit Name	Total Distance(kft)	Current (amps)	Wire Size	Ω/kft	V_{drop}	$\%V_{\text{drop}}$
Dc circuits (@ 24 V)						
Module wiring	0.012	7	12AWG	1.98	0.166 V	0.69 %
Array to J-box	0.02	7	10AWG	1.24	0.174 V	0.72%
J-box to Combiner	0.08	7	8AWG	0.778	0.436 V	1.82%
Combiner to CC	0.01	21	6AWG	0.491	0.103 V	0.43%
CC to Disco	0.006	21	6AWG	0.491	0.062 V	0.26%
Disconnect to inverter	0.006	21	6AWG	0.491	0.062 V	0.26%
Dc V_{drop} total					1.003 V	4.18%
Ac Circuits (120 V)						
Inverter to disconnect	0.01	6 amps	10AWG	1.2	0.072 V	0.06%
Disconnect to Service Panel	0.05	6 amps	10AWG	1.2	0.36 V	0.3%
Ac V_{drop} total						0.36%
Overall V_{drop} total						4.54%

The example in this table is very typical of a well-designed, 24 V PV system. It also illustrates where increasing wire size will initially have the most impact—in the J-box to combiner circuit. By increasing this circuit size from 8 AWG to 6 AWG, the voltage drop will reduce by about 0.7% overall. However, the larger size wire will require the next size larger conduit to accommodate these circuits. An overall voltage drop of less than 5% for a 24 V system is a good target and getting voltage drop below 3% is extremely difficult for these very low voltage systems. A 48 V system will drop the dc voltage drop impact to 25% of that seen with 24 V systems for the same wire sizes shown in the table, yielding an overall system voltage drop near 1%. This is one of the main reasons why 48 V battery-based systems are generally recommended over 24 V systems. Other unavoidable voltage drops not calculated in this table include voltage drops in fuses, circuit breakers, and switches which can add up to 0.5% for a 24 V system. Additionally, charge controllers can cause another 1% to 4% voltage drop depending on the product.

If the wiring from the modules to the junction box is exposed, the NEC requires the wire must be listed as or marked “sunlight-resistant.” A suitable insulation type for this application is USE-2. Even if exposed wiring is used, the ampacities of NEC Table 310.15(B) (16) must still be used if the conductors terminate at equipment (PV modules). As a final note on voltage drop, it is common practice to use smaller wiring between modules and junction boxes, and then increase the wire size between the junction box and the string combiner box. As the wire size is increased to meet voltage drop requirements, then it is important to be sure that lugs or terminals in each of the boxes can accommodate the larger wire size. It is required that the box itself be large enough for the wire. If wire sizes in junction boxes are 6 AWG and smaller, the minimum box size is found from either NEC Table 314.16(A) or Table 314.16(B). If conductors larger than 6 AWG are in the box, then the installation must comply with NEC 300.4(F), and the box size should be determined in accordance with NEC 314.28(A). Listed PV combiner boxes will have terminals and wire bending space consistent with the current ratings of the device. Some will accommodate the larger wires necessary to address voltage-drop requirements.

2.7.4 Select Size and Type of Conductor Based on Location, Required Ampacity, and Voltage Drop

The previous sections have described how to determine the required size of a conductor based on the ampacity and voltage drop requirements. The NEC states that all conductors in conduit installed in exposed locations (outdoors, on rooftops), or underground must be rated for wet locations (NEC 300.9 and 300.5(B) respectively). A common misconception is that conductor in watertight conduit do not have to be wet rated. All outdoor and underground conduit systems have moisture in them that will condense under the right conditions.

When selecting conductors for conduit systems, the conductor should have a “W” in the wire designation for wet rating. Since rooftops are high temperature environments, it is often necessary to select 90°C rated conductors. The most commonly selected conductors for rooftop conduit in PV systems are THWN-2, XHHW-2, and RHW-2. The THHN designation, while rated for 90°C, is not rated for wet locations. The THWN and XHHW designations, while rated for wet locations are not rated for 90°C in wet locations. USE-2

often run from the PV modules to the inverter in conduit. This is acceptable as long as the conduit run is exterior to the building, or if run interior, the conductor carries an indoor conductor designation such as XHHW-2 or RHW-2. Most conductors carry multiple designations, which causes some confusion for installers. All that matters when reviewing conductor designations is that the one designation needed for the location is listed on the conductor insulation. Just because one designation, like USE-2, is prohibited indoors does not exclude the conductor from being installed indoors as long as the conductor has one of the allowed indoor designations.

2.7.5 Select Conduit for Conductors

Select Conduit Type Based on Application

When using conduit as the wiring method, the type of conduit selected is based on a variety of factors including physical protection, sunlight resistance, temperature extremes, and corrosion resistance. In tropical climates where the temperature differences are small and corrosion is severe, PVC conduit systems are common. PVC is also commonly used underground because of its corrosion resistance and the fact that ground temperature does not fluctuate as much as air temperature. However, in climates with large temperature swings and less corrosion concerns like desert areas, steel conduit systems are much more common such as EMT and IMC. Occasionally, the physical protection needs of the installation are high in places like parking garages and hospitals. These locations often require rigid steel RMC conduit. Locations with large expansion and contraction concerns due to long conduit runs may favor IMC over EMT since the pipe is threaded and less susceptible to compression fittings vibrating loose over time.

Ultimately, whatever wiring method is selected will require some maintenance over time (see section 7). The type and amount of maintenance will depend on the local conditions and the response of the selected conduit to those conditions. Life-cycle costs for conduit and wiring systems must be considered when selecting the most appropriate conduit for a PV project.

Select Conduit Size Based on Type and Conductor Fill

The NEC states that the maximum fill for a conduit based on the ratio of the sum of the cross-sectional area of the wires to the inner cross-sectional area of the conduit can be no more than 40% (NEC Chapter 9, Table 1). There is no differentiation made based on conduit type or conductor type. However, conductors with rubberized insulation generally need more room than slicker thermoplastic insulations. Regardless of the conductor type, it is best for a goal of 25% conduit fill for easier pulling of conductors through conduit. This may be treated as a maximum for certain conductor/conduit combinations.

Select Expansion Joints Based on Type, Temperature, and Fixed Distance

Expansion fittings are required on straight runs between fixed points depending on the straight distance, the temperature fluctuations, and the type of conduit. PVC has the largest expansion rate of commonly used wiring methods having 5 times the expansion of steel conduit. Given the temperature changes in much of the United States, PVC rooftop conduit systems will require expansion fittings for all constrained straight runs over 20 feet (not a misprint) and require one 4 in expansion fitting every 75 ft in the run [Table 352.44]. Steel conduit, such as IMC, requires expansion fittings for all constrained runs over 100 ft and require one 4 in fitting every 375 ft in the straight run.

2.8 Review Overcurrent Protection Selection

Once the wire size from the junction box to the source-circuit combiner box has been determined, the source-circuit fuse sizes need to be determined. These fuses or circuit breakers (both known as overcurrent protective devices (OCPD)) are installed to protect the PV modules *and* wiring from excessive reverse current flow that can damage cell interconnects and wiring between the individual PV modules. The maximum size fuse is specified by the PV module manufacturer and approved as part of the module listing. The fuse size marked on the back of the module must be at least 156% ($1.25 \times I_{max}$) of the STC-rated module short-circuit current to meet NEC requirements for overcurrent protection. Hence, for the modules specified in Table 2, the smallest fuse size that could be marked on the back of the module would need to be at least 11.23 A. It can be larger if the module manufacturer has tested and listed the module with a larger value. The fuse will generally be a dc-rated cartridge-type fuse that is installed in a finger-safe pullout-type fuse holder. The finger-safe holder is necessary, as each end of the fuse holder will typically be energized at a voltage close to the maximum system voltage. These fuses are available in 1-amp increments from 1 A to 15 A, with other larger sizes as provided for in NEC 240.6(A). However, even though the code may state the standard fuse sizes, fuse manufacturers may not make all standard sizes. For example, rather than 1-amp increments being available from 10A to 15A, only 10A, 12A, and 15A sizes are available for most midsize fuse types.

2.9 Review Fasteners Selection

If the chosen design calls for installation on a sloped roof, most mounting systems are fastened solidly to the roof trusses or rafters rather than the roof decking. Depending upon the type of roof, the mounts need to be attached in a manner that will ensure that the roof will not leak at the penetrations. The residential building code now requires that all roof penetrations be flashed to address roof leakage. Products exist for flashing any roof type so compliance with this requirement is possible regardless of the roof type. Methods that do not attach directly to structural members require engineering and preferably product certification by the appropriate organization. For mounting systems, the ICC Evaluation Service is a typical choice for these types of certifications. Commercial rooftop PV systems often use ballasted mounting systems to secure the PV array on the roof. These ballasted systems require detailed engineering reports and evaluations to ensure that the wind loading and dead loading issues of the system have been properly addressed. Several companies that manufacture these systems provide professional engineering services to certify the drawings for submittal to the local jurisdiction. Some locations cannot use ballasted systems because of excess design wind speeds. Some designs allow for a combination of ballast and roof attachments to allow installation in high wind zones and high seismic zones.

Materials used for mounting structures and fasteners must be suitable for the environment and compatible with other materials they contact. In dry areas such as Southwestern United States, a plated steel fastener may not degrade much with time. In high corrosion environments, such as Florida, it is essential that fasteners be corrosion-resistant stainless steel. Manufacturers of commercial array mounts and racks generally supply the mounts with stainless steel hardware to be sure it will be adequate for specified installation locations and site conditions. This also precludes the aesthetic problem of discoloration of hardware that occurs in any climate.

Materials for array mounts can also vary widely depending upon environmental requirements. In some areas, painted wooden mounts may be acceptable, while other locations require mounts made of galvanized steel or aluminum. A common structural material used for commercial array mounts is corrosion resistant aluminum of various alloys such as 6061 or 6063 aluminum. Aluminum develops a thin oxide coating very quickly, and this coating prevents further oxidation. Anodizing is common with aluminum extrusions and can increase the corrosion resistance for aesthetics or for areas with high corrosion rates. Stainless steel is generally too expensive for structural materials, even though it is highly corrosion resistant. The combination of corrosion-resistant aluminum structural members and stainless steel fasteners is a practical solution to minimizing the cost while maximizing long-term structural reliability.

2.92 Lag Screw Fasteners

The withdrawal load is the force required to remove a screw by pulling in line with the screw. The pull strength increases as the diameter of the screw increases and is directly proportional to the length of the screw thread imbedded in the wood. When a lag screw must pass through a metal L-bracket, then roof shingles and roof membrane, nearly one inch of the length of the screw does not enter rafter or truss. Also note that many lag screws in lengths over one inch are not threaded the entire length of the screw. Pilot or lead holes must be drilled for lag screws, typically in the range of 67%-80% of the lag screw shank diameter. Larger pilot holes are required for hard woods than for soft woods. Note that actual pull strengths will vary depending upon the wood that is used, and this is why using safety factors of four or more is not unusual. A safety factor of four simply means that if withdrawal strength of X pounds is needed, then the design requires withdrawal strength of 4X pounds. The allowable withdrawal loads for various lag screw sizes driven into the side grain of four common types of kiln-dried wood can be easily calculated. See Fig. 82.

The minimal wind loading of a PV array occurs when the array is mounted parallel to the roof surface at height of 6 inches or less and at least three feet away from the edges of the roof. In regions with high design wind speeds, it is best to keep the modules away from the edges of the roof.

Some roof structures above cathedral ceilings have structural insulated panels (SIPS) and may require the mounting screws to penetrate a sandwich of foam insulation between two layers of decking before the screw will enter a support beam. Other cathedral roof structures are built over scissors trusses with the insulation above the ceiling rather than

Allowable Withdrawal Loads for Lag Screws (lb/in)			
Lumber Type >	Douglas Fir	Southern Yellow Pine	White Spruce
Screw Nominal Shank Diameter (in)	Specific Gravity		
	0.51	0.58	0.45
1/4	232	281	192
5/16	274	332	227
3/8	314	381	260
Includes a factor of safety of 4 X			

Figure 82. Allowable withdrawal loads for lag screws in lumber depend on the density and species of the wood, the diameter of the screw, and the thread penetration depth.

under the roof decking. If there is any uncertainty over the roof composition, roof loads, uplift loads, or roof materials, the installer should consult with a structural engineer, professional roofer, or building contractor.

2.10 Review Plan Sets

A complete plan set is a necessary component of an effective permit application. More complex projects require more detailed plan sets. Specific details need to be outlined to the extent that portions of the installation are not standard industry practice or require specific direction. The Expedited Permit Process, published by the Solar America Board for Codes and Standards has provided simple interactive pdf drawings (www.solarabcs.org/permitting) that allow installers to fill in blanks in the form and print good quality plans for residential-sized PV systems. These SolarABCs plans include several standard templates for string inverter systems, micro-inverter systems, and ac module systems. More complex systems may require structural drawings and more detailed electrical drawings. The U.S. Department of Energy is considering funding projects that may include standard drawing specifications and drawing templates for typical commercial PV systems.

3 Managing the Project

Project management is a key aspect of any construction project. Once a contract has been signed with the customer, the project schedule can commence for the construction of the PV system. Longer lead time system components such as modules, inverters, and combiner boxes can be ordered while drawings are being finalized and the permit package is being assembled for submittal. The construction foreman must be informed of the project plans and be given the opportunity to provide their input to the process to implement any necessary improvements to the construction process. A healthy feedback mechanism should be in place to make continual process improvements and learn from the mistakes of past projects. Failure to make process improvements when managing projects will lead to a loss of morale with the construction crew and ultimately result in high labor turnover rates.

In summary, planning a PV installation utilizes information gathered during a site survey, and includes the following considerations:

- Reviewing, completing and adapting the system design
- Submitting applications for permits, utility interconnection and incentives
- Defining the project schedule, manpower and equipment needs
- Identifying and resolving construction activity conflicts such as power outages or alterations to the site
- Coordinating other logistics with the customer such as site access, worker facilities, waste collection and storage areas

3.1 Secure Permits and Approvals

A complete permit package is critical to an expeditious permitting and approval process. When working with jurisdictions for the first time, it is always valuable to schedule a meeting with the building department and develop an understanding of the expectations of the jurisdiction on the contents of a permit package. Jurisdictions that are new to PV systems will require more time and effort in processing the paperwork for construction approval. While it is rarely a problem to provide too much information, the information must be relevant and well organized so the plan reviewer can perform their review as efficiently as possible.

The benefit of having a positive and helpful attitude when working with jurisdictional personnel is hard to understate. Most jurisdictional employees are overworked, underpaid, and underappreciated. Showing an appreciation for their role in the construction process can make big difference in how a permit package is received. Too often contractors get a bad attitude about having to work through the bureaucracy of local government. That attitude often comes across loud and clear to the jurisdictional employees causing them to lose any possible motivation they might have had to process the paperwork in a timely manner. For a plan checker with little or no PV experience, offering to be available for questions and clarifications can help move the process more quickly.

A high quality permit package is one of the most effective methods of establishing a good rapport with the local jurisdiction. The contents of a high quality permit package include:

- A title page with the project address, brief project description, list of project specifications, and a table of contents.
- Completed forms that the local jurisdiction requires to process a permit.
- A site plan that shows the location of major components on the property including array layout, location of access pathways for rooftop system for fire department review, setbacks to property lines for ground mounted systems, and location of the utility disconnect if required.
- Detailed electrical diagram showing and specifying all major components used in the electrical portion of the PV system. This diagram must show the configuration of the PV array, the location and ratings of overcurrent protection and disconnecting means, callout conduit and wire size, type, and ratings. The electrical diagrams should also include specifications and content for the required signs and labels.
- Mounting structure information including manufacturer, model, installation documentation and details.
- Specification sheets for all major electrical equipment including PV modules, inverters, combiner boxes, and any other unique components that are not common in conventional electrical installations.

Some jurisdictions may handle the entire approval process by submitting a single package of materials with multiple copies for distribution to several internal departments. Other jurisdictions may require separate submittals to be filed with the building department, planning and zoning department, fire department, and any other relevant department. Knowing and understanding how to navigate the approval process takes time and focus so that projects can work their way through the process as quickly as possible.

3.2 Preconstruction

The proper preparation for construction is as important as the actual construction process itself. Making sure all required material is on hand or procured to be available by the time it is needed on the site requires significant planning and project experience. All PV projects require a safety plan, and safety equipment must be on hand prior to construction. The safety equipment must be inspected to insure that it is in good repair and has no missing pieces. Any necessary equipment rentals need to be planned, budgeted, and deliveries scheduled. Often large amounts of materials may need to be staged and moved into position in preparation for construction, requiring special equipment. A number of software tools are available to assist construction manager in planning and allocating project resources.

3.3 Project Labor

Determining the amount and proper allocation of project labor is critical to a smooth and efficient construction project. In the pressure and busyness of project preparations, a commonly overlooked aspect of the construction process is good communication with the construction crew as to their roles and reasonable expectations. A key component of that process is training the crew for the specific job needs of the project. Even experienced project labor needs continuing education on aspects of the project that may slightly different than previous projects. Since materials, mounting systems, modules, and inverters are constantly changing in the dynamic PV world, some level of personnel training will be involved in each project, including site-specific safety hazards, at a minimum.

Assuming that a crew has all the knowledge and materials to carry out the project is an all too common mistake in a construction project. This requires checking with project labor to make sure they are comfortable with their responsibilities and making sure that they are comfortable expressing recommendations for process improvement. Managing the morale of project labor requires a good understanding of the personalities in the crew and good motivational skills so that laborers are recognized and appreciated for a job well done.

3.4 Adapting System Design

In the early stages of a construction project it is often necessary to make adjustments to the project plan to address discrepancies between the site and system design, and unforeseen project obstacles. This may require adaptations to the system design. It is rare for a project to go completely as planned. Even with the best preplanning, issues beyond the control of the project manager invariably arise that require flexibility, such as making material substitutions due to product availability.

3.5 Implement a Site Safety Plan

A safe PV system is installed according to applicable building codes and standards. PV installer safety includes considerations for a safe work area, safe use of tools and equipment, safe practices for personnel protection, and awareness of safety hazards and how to avoid them. The installation of PV systems involves a number of safety hazards, principally electrical and fall hazards.

Working safely with PV systems requires a fundamental understanding of electrical systems and the safety hazards involved, in addition to normal work site and construction hazards. The common sense aspects for jobsite safety can be summarized as follows:

- If the workplace is cluttered, the possibility of tripping over something is significantly increased.
- If the workplace is a sloped roof with clutter, the possibility of falling off the roof is significantly increased.
- If tools are left lying out on a roof, the chance of the tools falling off the roof and injuring someone below is increased.
- If the workplace is a rooftop in bright sunshine, the chance of sunburn and heat exhaustion is increased, so workers should take appropriate precautions like using sunscreen, keeping well-hydrated and wearing light-colored clothing.

There are the usual subtle hazards, as well. These include nicks, cuts, and burns from sharp or hot components. Gloves should be used when handling anything that might be sharp, hot, rough, or that might splinter. Special insulating gloves are required for working with live voltages. There is always the possibility of dropping tools or materials on either oneself, someone else, or on sensitive equipment or materials. Dropping conductive tools across battery terminals is an especially dangerous hazard. When a PV system is being assembled, it presents the possibility of shock to personnel. Proper procedure during installation can reduce, and often eliminate hazards including electrical shock. Improperly installed systems may result in shock or fire hazards developing over time due to wiring or arcing faults.

3.5.1 OSHA Regulations

All individuals working on or contracting installation services for PV systems should be familiar with standards established by the Occupational Safety and Health Administration (OSHA), contained in Volume 29 of the U.S. Code of Federal Regulations (29 CFR). OSHA regulations are applicable in all U.S. states and territories and enforced by federal or local authorities. States with OSHA-approved programs must set standards at least as effective as federal standards. These standards apply to private employers and general industry, construction, maritime, agricultural and other occupations. The broad scope of OSHA regulations includes health standards, electrical safety, fall protection systems, stairways and ladders, hand and power tools, cranes and lifts, excavations, scaffolding, and other potential hazards likely to be encountered in constructing PV systems.

OSHA regulations require that employers provide a safe and healthful workplace free of hazards, and follow the applicable OSHA standards. Employers must provide safety training addressing all probable hazards on a construction site, and employers of 11 or more employees must maintain records of occupational injuries and illnesses. All em-

ployers must display the OSHA poster, and report to OSHA within 8 hours any accident that results in a fatality or hospitalization of three or more employees. Workers are responsible for following the employer's safety and health rules and wear or use all required safety gear and equipment, reporting hazardous conditions to OSHA if employers do not fix them, and cooperating with OSHA inspectors. Large construction projects often require workers to complete 10 hour training on OSHA regulations and have a valid course completion card for insurance purposes.

Safety and Health Regulations for Construction (29 CFR Part 1926) applies to general construction, including several subparts applicable to the installation of PV systems:

- Subpart C - General Safety and Health Provisions
- Subpart D - Occupational Health and Environmental Controls
- Subpart E - Personal Protective and Life Saving Equipment
- Subpart I - Tools, Hand and Power
- Subpart K - Electrical
- Subpart M - Fall Protection
- Subpart X - Stairways and Ladders

10-HOUR CONSTRUCTION INDUSTRY REQUIRED COURSE TOPICS	
* OSHA subject references are provided for informational purposes; training should emphasize hazard awareness	
Mandatory – 4 hours	Elective – 2 hours
One Hour Introduction to OSHA, including: <ul style="list-style-type: none"> ■ OSH Act, General Duty Clause, Employer and Employee Rights and Responsibilities, Whistleblower Rights, Recordkeeping basics ■ Inspections, Citations, and Penalties ■ General Safety and Health Provisions, Subpart C ■ Competent Person, Subpart C ■ Value of Safety and Health ■ OSHA Website and available resources ■ OSHA 800 number 	Choose at least two of the following elective topics: These topics must add up to at least two hours: - Minimum One-half hour each -
Two Hours (minimum 15 minutes on each of four areas) OSHA Focus Four Hazards <ul style="list-style-type: none"> ■ Fall Protection, Subpart M ■ Electrical, Subpart K ■ Struck by (e.g., falling objects, trucks, cranes) ■ Caught in/between (e.g., trench hazards, equipment) 	Materials: Handling, Storage, Use and Disposal, Subpart H Tools - Hand and Power, Subpart I Scaffolds, Subpart L Cranes, Derricks, Hoists, Elevators, & Conveyors, Subpart N Excavations, Subpart P Stairways and Ladders, Subpart X
30 Minutes Personal Protective and Lifesaving Equipment, Subpart E	Optional – 4 hours For the remaining four class hours: Teach any other construction industry hazards or policies and/or expand on the mandatory or elective topics
30 Minutes Health Hazards in Construction (e.g., noise, hazard communication and crystalline silica)	

Figure 83. The OSHA 10-Hour Construction Industry Training Program is strongly recommended and may be required for PV installers.

OSHA 10

The OSHA 10-Hour Construction Industry Training Program is intended to provide entry-level construction workers with a general awareness on recognizing and preventing hazards on a construction site. Many projects require all construction workers on a jobsite to have a current OSHA 10 training. Workers must also receive additional training on hazards specific to their job. See Fig. 83.



Figure 84. Fall protection is a primary safety concern for PV installers.



Figure 85. Skylights must be protected from fall hazards by barriers or covers.

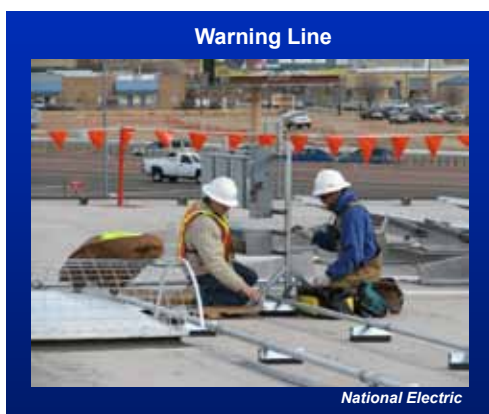


Figure 86. Warning lines designate safe areas in which work may take place without the use of PFAS.

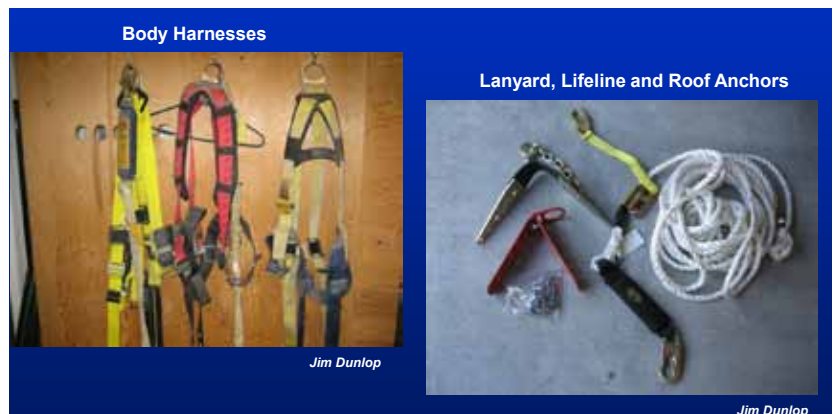


Figure 87. A personal fall arrest system (PFAS) consists of an anchorage and connectors, a body harness, and a lanyard/deceleration device.

3.5.2 Fall Protection

Falls are the leading cause of deaths in the construction industry. Because most PV systems involve climbing ladders, or working on rooftops, it is essential that PV installers are familiar with OSHA fall protection regulations. Most fatalities occur when employees fall from open-sided floors and through floor openings. Consequently, OSHA requires that fall protection be used for walkways and ramps, holes and excavations, roofs, wall openings or skylights where an employee or worker can fall 6 feet or more. Employers must provide training to employees on how to recognize and minimize fall hazards, and the use of fall protection systems and devices. See Figs. 84, 85 & 86.

Fall protection options include Personal Fall Arrest Systems (PFAS), guardrails and safety nets, and must be in place before work commences. See Figs. 87 & 88. Train-



Figure 88. Safety line anchorages must be independent of any platform anchorage and capable of supporting at least 5,000 pounds per worker.

ing is required on how to properly use and maintain PFAS, including the anchorages, lifelines and body harnesses. Guardrails used to protect open-sided floors and platforms must have top rails between 39 and 45 in tall, a mid-rail, and toe boards at least 3-1/2 in high. Safety nets must be deployed no further than 30 ft below where work is performed, preferably closer. In certain applications, the use of designated safety monitors and warning lines may meet the requirements, but is the least desirable of all fall protection systems. In any case, it is best practice to perform work at ground level if possible, such as pre-assembly of PV panels and arrays.

3.5.3 Stairways and Ladders

OSHA requires that a stairway or ladder be used at points of access where there is an elevation break of 19 in or more on a jobsite. See Fig. 89. Stairways with four or more risers, or higher than 30 in, must be equipped with at least one handrail, capable of withstanding a force of 200 pounds. See Fig. 90. Stairways with four or more risers or more than 30 in high must have a stair rail along each unprotected side or edge. Stairs must be installed between 30 and 50 degrees, must have uniform riser height and tread depth, with less than a 1/4-in variation. Stairways landings must be at least 30 in deep and 22 in wide at every 12 ft or less of vertical rise. Unprotected sides of landings must have standard 42 inch guardrail systems. Where doors or gates open directly on a stairway, a platform must be used that extends at least 20 in beyond the swing of the door.

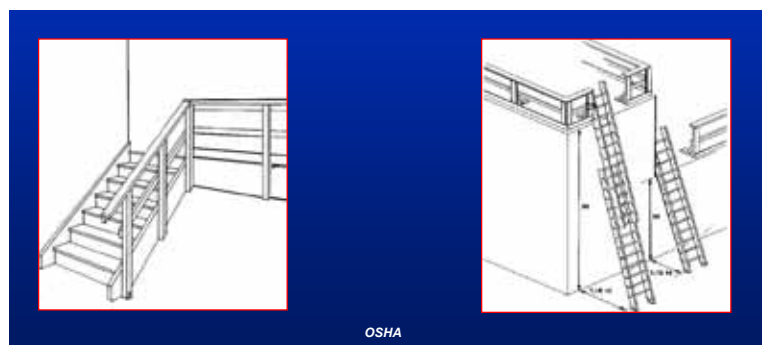


Figure 89. A stairway or ladder is required at points of access to a construction site where there is a break in elevation of 19 inches or more.

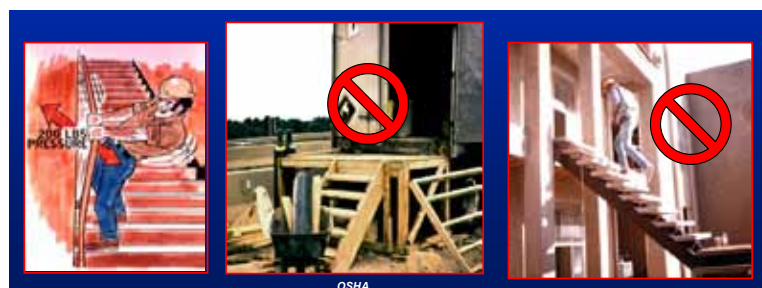
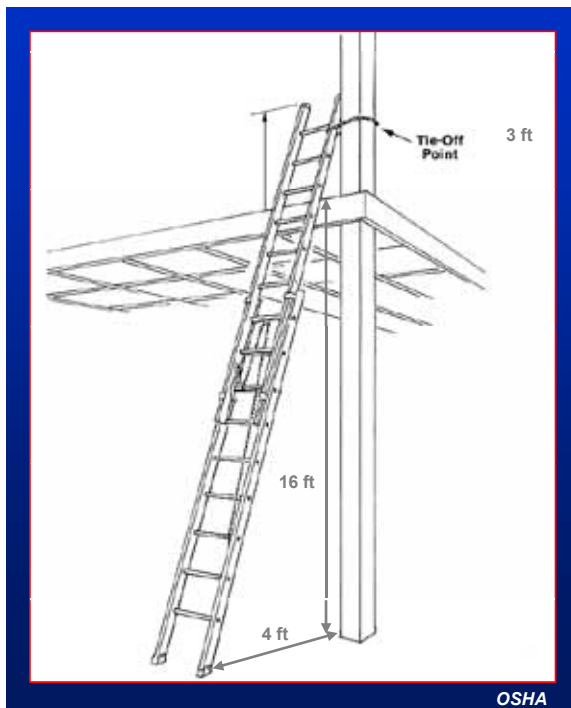


Figure 90. Stairrails and handrails must be able to withstand 200 pound force.

Ladders must be kept in a safe working condition. Keep the area around the top and bottom of a ladder clear, and ensure rungs, cleats, and steps are level and uniformly spaced 10 in to 14 in apart. Use ladders only for their designed purpose. Never tie ladders together to make longer sections, or load ladders beyond the maximum load for which they are rated. A competent person must inspect ladders for visible defects, like broken or missing rungs, and if a defective ladder is found, immediately mark it defective or tag it “Do Not Use”, and withdraw defective ladders from service until repaired.

Ladders should be used on stable and level surfaces, and secured to prevent accidental movement due to workplace activity. Do not use ladders on slippery surfaces unless secured or provided with slip-resistant feet. Ladders, particularly wooden ones, should never be painted. A double-cleated ladder (with center rail), or two or more ladders are required when ladders are the only way to enter or exit a working area with 25 or more employees, or when a ladder will serve simultaneous two-way traffic.

Non-self-supporting ladders (those that lean against a wall or other support) must be positioned at an angle where the horizontal distance from the top support to the foot of the ladder is $\frac{1}{4}$ the working length of the ladder. See Fig. 91. For example, if a 20 ft ladder is used to access the rooftop of a 16 ft building, the base of the ladder should be one-quarter the height, or 4 ft away from the building. When using a portable ladder for access to an upper landing surface, the side rails must extend at least 3 ft above the upper landing surface. For step ladders, the top and top step should never be used as a step, and never use crossbracing on the rear of a stepladder for climbing — unless the ladder is designed for that purpose. Tall fixed ladders 24 ft or longer must be equipped with either: a ladder safety device; self-retracting lifelines with rest platforms every 150 ft or less; or cage or well, and multiple ladder sections, each section not exceeding 50 ft.



If using ladders where the employee or the ladder could contact exposed energized electrical equipment, such as transformers or overhead services, ladders must have nonconductive side rails such as wood or fiberglass. Face the ladder when going up or down, and use at least one hand to grab the ladder when going up or down. Do not carry any object or load that could cause you to lose balance while climbing ladders.

Figure 91. Ladders must be used with the proper angle and secured at the appropriate height.

3.5.4 Hand and Power Tools

Power tools are extremely hazardous when used or maintained improperly. Workers using hand and power tools may be exposed to a number of hazards, including objects that fall, fly, are abrasive, or splash; harmful dusts, fumes, mists, vapors, and gases; and frayed or damaged electrical cords, hazardous connections and improper grounding. Eye protection is usually always required.

All hand and power tools and similar equipment, whether furnished by the employer or the employee, shall be maintained in a safe condition. All power tools must be fitted with factory guards and safety switches, and hand-held power tools must be equipped with a constant pressure switch or on-off switch. Hazards are usually caused by misuse and improper maintenance.

Additional guidelines and precautions for using power tools include the following:

- Follow manufacturers' instructions
- Use the proper PPE
- Disconnect tools when not in use, for cleaning, and when changing accessories
- Secure work with clamps or a vise, freeing both hands to operate the tool
- Inspect tools regularly before use and maintain in sharp, clean condition
- Do not wear loose clothing and jewelry that can get caught in moving parts
- Do not use electric cords to carry, hoist or lower tools
- Keep cords and hoses away from heat, oil, and sharp edges
- Remove damaged electric tools & tag them: "Do Not Use."

3.5.5 Personal Protective Equipment (PPE)

Personal protective equipment (PPE) includes protective clothing, gloves, footwear, helmets, goggles, respirators, aprons or other garments designed to protect workers from injury to the body by impacts, electrical hazards, heat and chemicals, and other job-related safety hazards. PPE is the last measure of control when worker exposure to the safety hazards cannot be totally eliminated by feasible work practices or engineering control.

Responsibilities of the employer include assessing the workplace for hazards, providing PPE, determining when to use it, and providing training for affected employees. Employee responsibilities include using PPE in accordance with training received and other instructions, and inspecting daily and maintaining the PPE in a clean and reliable condition.

The employer shall ensure that each affected employee wears a protective helmet when working in areas where there is a potential for injury to the head from falling objects, or exposure to electrical hazards. See Fig. 92. Type I hard hats provide protection from blows only to the top of the head. Type II hard hats have a full brim and provide protection from blows to the top or sides of the head. Class G (General) hardhats are intended to reduce the danger of contact exposure to low voltage conductors and are proof tested to 2,200 volts. Class E (Electrical) hardhats are intended to reduce the danger of exposure to high voltage conductors and are proof tested to 20,000 volts. Class C (Conductive)



Figure 92. Hard hats protect the head from blows and energized electrical conductors.



Figure 93. Types of eye and face protection include safety glasses, goggles and face shields.

hardhats provide no electrical insulation and not intended to provide protection against contact with electrical conductors.

Eye protection must be provided to protect against hazards such as dust and other flying particles, corrosive gases, vapors, and liquids, and welding operations. See Fig. 93. The selection of eye protection is based on protection from a specific hazard, its comfort, and must not restrict vision or movement, or interfere with other PPE. Types of eye and face protection include:

- **Safety glasses:** Single or double lens; close and comfortable fit important. Prescription lenses available.
- **Goggles:** Offer the most complete protection from impacts, chemicals and vapors by sealing around the eye area. Vented types allow air flow and reduce the chance for fogging, but protect from impacts only. Non-vented and indirect-vent types protect from impacts as well as splash, vapors or particles; use lens coatings for better anti-fog performance. Many types fit over prescription eyeglasses.
- **Face shields:** A supplementary, secondary protective device to protect a worker's face from certain chemical and welding radiation hazards. Must use with safety glasses for impact protection. Special lenses and shade number required for specific welding operations.

Hearing protection must be used whenever an employee's noise exposure exceeds an 8-hour time-weighted average (TWA) sound level of 90 dBA. Noise levels above 115 dBA require control measures for any duration. OSHA also recognizes an 85 dBA TWA as an action level to monitor noise levels. Noise levels likely exceed 85dBA if one has to raise their voice to converse with another person 3 feet away. Hearing protection options include earmuffs that fit over the ear and seal against the side of the head, disposable and reusable earplugs inserted directly into the ear canal, or hearing bands. See Fig 94. All approved hearing protectors have an assigned Noise Reduction Rating (NRR) in decibels.

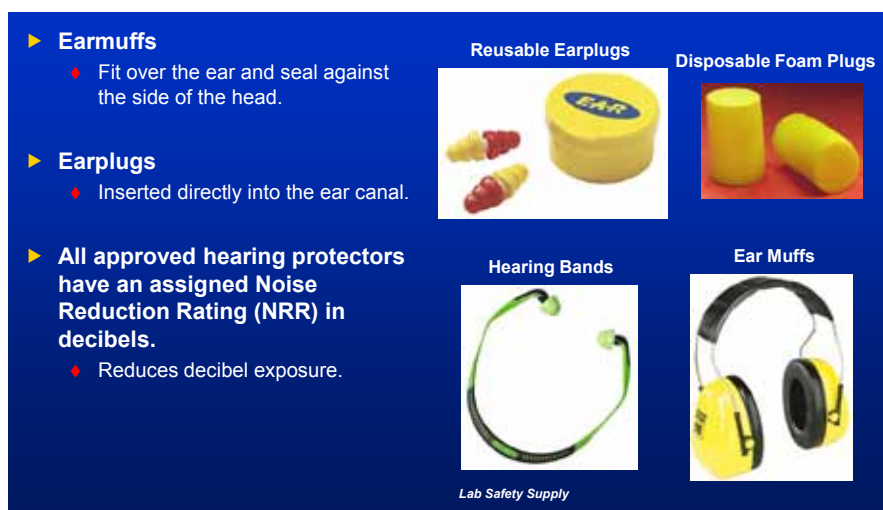


Figure 94. Hearing protection should be used whenever using machinery or power tools with noise levels exceeding 85 dB.

When employees are exposed to harmful atmospheres, dust or vapors, the employer shall provide respirators which are applicable and suitable for the purpose intended. Although not generally required, certain construction tasks related to a PV installation may require respiratory protection, such as working in insulated attics.

Foot protection must be used when any of the following conditions are present: heavy objects such as barrels or tools that might roll onto or fall on employees' feet; sharp objects such as nails or spikes that might pierce ordinary shoes; molten metal that might splash on feet; hot, wet or slippery surfaces. Safety shoes have impact-resistant toes and heat-resistant soles, and may be electrically conductive for use in explosive atmospheres, or nonconductive to protect from electrical hazards.

All types of protective footwear must include an identification label listing the applicable standard, manufacturer, and specifications. All protective footwear must provide impact and compression resistance. Impact resistance (I) is rated for 75, 50 or 30 foot-pounds. Compression resistance (C) is rated for 75, 50 or 30 which correlates to 2500, 1750 or 1000 pounds of compression resistance.

Protective footwear may also meet the following specifications as labeled:

- Metatarsal resistance (Mt) is rated for 75, 50 or 30 foot-pounds.
- Conductive (Cd) footwear is used to dissipate static electricity in explosive environments.
- Electrical hazard (EH) footwear has non-conductive soles and provides secondary protection from live electrical equipment.
- Puncture resistant (PR) footwear provides integral protection from sharp objects penetrating the sole.
- Static dissipative (SD) footwear reduces the accumulation of excess static electricity for electronics environments.
- Chain saw cut resistant (CS) footwear.
- Dielectric insulation (DI) footwear is designed to provide additional insulation for contact with energized electrical conductors.

Employers shall select and require employees to use appropriate hand protection when employees' hands are exposed to hazards such as harmful substances; severe cuts or lacerations; severe abrasions; punctures; chemical burns; thermal burns; and temperature extremes. See Fig. 95. Employers shall base the selection of the appropriate hand protection on an evaluation of the performance characteristics of the hand protection relative to the tasks to be performed, conditions present, duration of use, and the hazards and potential hazards identified.

Types of gloves vary widely in materials and application, including:

- Durable gloves made of mesh, leather or high-performance materials like Kevlar® to protect from cuts, burns and heat.
- Chemical-resistant rubber gloves to protect from burns and irritation
- Electrical insulating gloves for exposure to live voltages

Correct glove size and fit is important for comfort and dexterity. Glove size is determined by diameter of the hand at its widest point. Common men's sizes are: Small: 7½-8", Medium: 8½-9", Large: 9½-10", and Extra Large: 10 ½-11".



Figure 95. Gloves are rated for six levels of abrasion, cut and puncture resistance tested to ANSI/ASTM standards.

4 Installing Electrical Components

4.1 Mitigate Electrical Hazards

About 5 workers are electrocuted every week in the U.S., causing 12% of all young worker workplace deaths. It takes very little electrical energy to cause personal injury; and electrical hazards also pose a significant fire danger — further compounding the risk to life and property. Electrical accidents are caused by a combination of three factors:

1) unsafe equipment and/or installation, 2) workplaces made unsafe by the environment, and 3) unsafe work practices.

Preventing electrical hazards on the job involves the following practices:

- Wearing nonconductive Class E hardhat
- Wearing electrical hazard (EH) rated foot protection
- Using properly grounded or double-insulated power tools maintained in good condition
- Avoiding overhead power lines and buried electrical conductors
- Working on electrical equipment and circuits in a de-energized state
- Maintaining an orderly job site and cautious work flow

Lockout and tagging is used to prevent unknowing individuals from energizing electrical circuits or other hazardous machinery while they are being serviced or maintained. See Fig 96. Lockout refers to the physical locking of the power source disconnect with a padlock in the “off” or open position. Tagging refers to the labeling of deactivated controls, de-energized equipment and circuits at all points where they can be energized, and must identify equipment or circuits being worked on. When working on energized equipment is unavoidable, use the appropriate PPE, including helmets, face shields, gloves and flame-resistant clothing.

To protect workers from electrical hazards use barriers and guards to prevent passage through areas of exposed energized equipment; pre-plan work, post hazard warnings and use protective measures; and keep working spaces and walkways clear of cords. Test GFCIs regularly, and check switches and insulation. Flexible extension cords for temporary use on construction projects must be 3-wire type (with ground) and designed for hard or extra-hard use.



Figure 96. The employer must provide policies, procedures, documentation, equipment, training, inspection and maintenance for lock out and tag out programs to authorized employees.

Electrical Injuries

There are four main types of electrical injuries. Direct types of injuries include electrocution (death due to electrical shock), electrical shock, and burns. Indirect electrical injuries include falls due to electrical shock. Other common electrical injuries include concussions resulting from arcing explosions, as well as eye damage due to arc flash. Working on or near exposed energized conductors or electrical equipment requires special personal protective equipment (PPE). Means to assess the electrical hazards that exist, and the PPE and other precautions required are addressed in NFPA 70E, *Electrical Safety in the Workplace*.

The severity of the shock depends on the path of current flow through the body, the amount of current, and the duration of the exposure. Low voltage does not mean low hazard. Currents above 10 mA can paralyze or “freeze” muscles. Currents of more than 75 mA ac can cause a rapid, ineffective heartbeat, and can result in death in minutes unless a defibrillator is used. 75 mA is not much current — a small power drill uses 30 times as much. Electrical burns are the most common shock-related injury, which can occur by touching electrical wiring or equipment that is improperly used or maintained, and typically occurs on the hands. Electrical burns are often very serious injuries and require immediate attention.

4.2 Install Electrical Equipment

The installer should pay careful attention to the location of module junction boxes so the lengths of electrical wiring can be minimized and organized into source circuits as needed, once modules are mounted. Modules are normally installed in groups that produce the desired source-circuit voltage. Junction boxes do not have to be readily accessible, but must permit ready access by temporarily removing modules connected by flexible wiring methods [NEC 690.34].

The layout of BOS components should be done in a neat and professional manner that provides for convenient access, testing, and disconnecting of system components. If the array is on a residential roof, it is generally preferable to install combiner boxes containing source-circuit fuses or circuit breakers in a more accessible location. Because most PV modules carry warranties of 20 years or more, any other components installed on the roof should be also be capable of operating for 20 years without significant maintenance. The BOS layout should minimize distances for dc wiring if the system operates at 48 V or less. However, residential PV arrays operating at more than 300 V dc will longer dc runs without significant voltage drop. Keeping the ac voltage drop as low as reasonably possible will improve system performance by reducing the likelihood of inverters tripping offline due to high utility voltage.

4.2.1 Working Space for Electrical Systems

Working spaces must be allowed for maintenance personnel to safely work on electrical equipment [NEC 110.26]. Proper working spaces are the first priority when locating balance of system hardware for a PV system. Generally, clearances in front of equipment that is services in an energized state must be at least 3 ft, but several qualifiers determine the appropriate clearance to use. Voltages from 150 V to 600 V require greater clearances if live parts are on one side and grounded parts on the other or if live parts are on both sides of the working space. The width of working spaces must be the width of the equipment or 30 in, whichever is wider. For dc voltages less than 60 V, smaller working spaces may be permitted by special permission of the AHJ. Although this is allowed in the code, permission must be secured prior to mounting equipment should smaller clearances be sought.

Some PV installations may involve working in attic spaces, which usually requires wearing a breathing mask, eye protection, and clothing that will protect skin from irritating insulation. Ensure that the attic floor will support the weight of a worker, and take care to step only on structural members to prevent falling through the ceiling. Attics can be extremely hot and workers should limit their exposures and maintain hydration. Additional lighting is also usually required when working in attics or other confined spaces.

4.3 Install Wiring Methods

Wiring methods include all conductors, cables, conduits, raceways, fittings, connectors, terminals, junction boxes and other equipment used for electrical connections between system components. The installation requirements for wiring methods are covered in Chapter 3 of the NEC: Wiring Methods and Materials. Manufacturers provide additional product-specific instructions, and installation of many wiring methods requires specialized training and experience.

Much of the installation work in all electrical systems is mechanical in nature. Conduit systems are the most common wiring methods for circuits leaving the vicinity of PV arrays. Conduit is used to support and protect string conductors and to install the PV output circuits from combiner boxes to inverters. Each type of conduit or raceway system has specific application and installation requirements [NEC Chap 3].

Conduit runs must be supported properly at the intervals required by the specific conduit type. While the NEC does not require conduit to be held at any specific distance above the roof surface, the building code does not permit items on a rooftop that could cause damming of leaves and other debris. Although the building code does not specifically address electrical conduit systems, it is wise to keep a minimum of 0.75in of airspace beneath conduit runs, to help prevent smaller debris from being trapped under the conduit. The 0.75 in airspace also has the advantage of reducing the conduit temperature [NEC Table 310.15(B)(3)(c)].

Since in conventional ac systems it is uncommon to have long rooftop feeders, like those in large PV systems, there exists little field experience from electrical workers on installing these wiring methods on rooftops. Setting up a conduit run with multiple expansion fittings is not trivial and requires painstaking adherence to manufacturer's directions that account for the conduit temperature and where in the expansion process that temperature falls. Expansion joints must be held in place so that the conduit moves relative to the joint. In addition to the concerns over the conduit system, the conductors inside the conduit also move relative to the conduit system and the end terminations. Several systems in recent history have not properly accounted for this relative motion which has caused significant conductor insulation damage resulting in fires in some cases. Since this type of damage is likely in large conduit systems, operation and maintenance programs must periodically check for this damage.

4.4 Install Grounding Systems

Proper grounding of PV systems reduces the risk of electrical shock to personnel and the effects of lightning and surges on equipment. There are two basic types of grounding. System grounding connects a current-carrying conductor in an electrical system to ground, or earth potential. Equipment grounding connects non-current carrying metal parts to ground, such as PV module frames, racks, enclosures, junction boxes, conduit and other metallic components. Bonding is electrically connecting metal parts together so that they stay at the same voltage. All PV systems require equipment grounding, and most also require system grounding. The grounding and bonding requirements for PV systems are covered in NEC Article 690 Part V and Article 250.

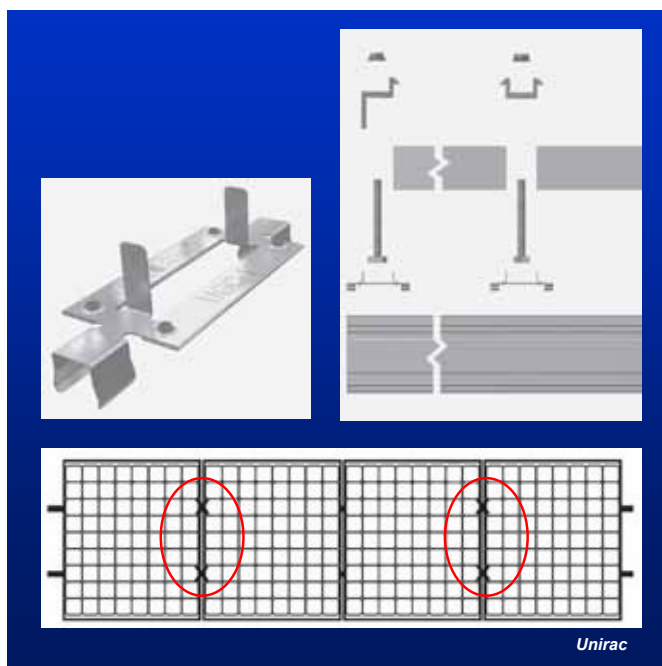


Figure 97. Devices listed and identified for bonding the exposed metallic frames of PV modules to grounded mounting structures are permitted, but are not approved for all modules and mounting structures.

System grounding is the intentional connection of a current-carrying conductor in an electrical system to ground (earth). Commonly, this connection is made at the supply source, such as a transformer or at the main service disconnecting means. For PV arrays, one conductor of a 2-wire system, or the center tap conductor of a bipolar system must be grounded if the maximum PV system voltage is over 50 V [NEC 690.41]. The dc system grounding connection must be made at a single point on the PV output circuit [NEC 690.42]. Locating this connection point as close as practicable to the photovoltaic source better protects the system from voltage surges due to lightning. Typically, for PV systems requiring ground-fault protection, the single point of grounding for a dc current-carrying conductor is usually made internal to a ground-fault protection device or utility-interactive inverters, and additional external bonding connections are not permitted.

Equipment grounding is the connection of normally non-current carrying metal parts to ground. Equip-

ment grounding requires electrical bonding of PV module frames, racks, enclosures, junction boxes, conduit and other metallic components. This ensures that metal components in the system will be at equipotential, thus reducing the risk of electrical shock. The installation of an equipment grounding conductor (EGC) is required for all metal framed PV module systems and any PV array that has exposed conductors in contact with metal support structures, regardless of system voltage [NEC 250, 690.43]. The EGC can be a conductor, busbar, metallic raceway, or structural component. EGCs must be installed in the same raceway as the PV circuit conductors upon leaving the vicinity of an array. System grounding and equipment grounding conductors are separate and only connected together (bonded) at the source of supply.

Several methods are permitted to provide equipment grounding for PV modules. Traditional methods use self-tapping screws and cup washers, or lay-in lugs attached to the module frames to connect the EGC. Other methods include using bonding washers or clips between module frames and supports, and the EGC is connected to the support structure. EGCs smaller than 6 AWG must be protected from physical damage, and copper grounding conductors should never be allowed to touch aluminum module frames or supports. Refer to PV module and mounting system manufacturer's installation instructions for specific grounding requirements. See Fig. 97.

For most utility-interactive systems, the grounded dc conductor, the dc equipment grounding conductor, and the ac equipment grounding conductor are terminated in the inverter. The EGC is connected to the dc grounded circuit conductor through the GFID circuit. The premises grounding system serves as the ac grounding system, and the dc GEC is combined with the ac EGC.

PV arrays are permitted to have ungrounded source and output circuits only when the following conditions are met [NEC 690.35]:

- Both ungrounded conductors (positive and negative) must have a disconnecting means and overcurrent protection.
- Array ground fault-protection for all conductors must be provided.
- All PV source and output circuit conductors must be either installed in raceways, use jacketed multi-conductor cables, or use listed and labeled PV wire where used for single-conductor exposed PV module connections.

Inverters or charge controllers used with ungrounded PV arrays must be listed and identified for use with ungrounded arrays. The PV power source must be marked at each disconnect, junction box or other device that may be serviced with the following label:

**“WARNING - ELECTRIC SHOCK HAZARD.
THE DIRECT CURRENT CIRCUIT CONDUCTORS
OF THIS PHOTOVOLTAIC POWER SYSTEM ARE
UNGROUNDING BUT MAY BE ENERGIZED WITH
RESPECT TO GROUND DUE TO LEAKAGE PATHS
AND/OR GROUND FAULTS.”**

The proper and safe grounding of PV systems has been the subject of much discussion in recent years, especially the grounding of PV module frames to support structures. Consequently, PV module manufacturers are now required to provide details for equipment grounding in their listed installation instructions per the UL 1703 standard.

While indoor grounding means are plentiful in the electrical industry, products designed for outdoor use are not nearly as available. Couple this issue with the fact that much of the electrical industry uses steel for wiring methods and support structures, as opposed to aluminum in the PV industry and now the usable products are much less. Grounding and bonding of steel is relatively straightforward since bolted connections and welding accomplishes the bonding requirements. Readily available copper lugs can be mounted to steel structures for connecting to equipment grounding conductors. Aluminum, on the other hand, is a different story. Simple bolting of aluminum structures will not necessarily create effective bonding. This is due to the fact that aluminum either has an anodized coating to reduce corrosion or a thick layer of oxidation as in the case of non-anodized aluminum. In either case, simple bolting of modules to structures, or lugs to modules or structures, will not necessarily provide the necessary bonding and grounding. The NEC generally requires that the installer remove non-conductive coatings prior to making electrical connections. This means that in order to call two aluminum surfaces electrically connected, one must remove the non-conductive coating on both surfaces.

Using a grinder on an array of 500,000 modules, or even a few dozen modules is not very practical. Alternative means exist, but these means must be compatible with the products being installed. One common method of electrically connecting two aluminum structural

pieces is to have stainless fasteners with serrations. Stainless star washers can also be used to break through the non-conductive coatings and establish effective bonding. The typical PV module has an aluminum frame that must be bonded and grounded. Module manufacturers may provide hardware and fasteners for making electrical connections to the frame metal. Some modules will simply have directions on how to make such connections. Some modules have multiple methods available for grounding while others may only specifically mention a single method (more common). According to the UL safety standard for modules (UL1703), the manufacturer is required to provide information on all approved grounding methods. Since it can be expensive to specifically test each grounding method, many module manufacturers limit the number of options to reduce testing costs.

Generic grounding methods that bond adjacent modules together and bond modules to their support structures is specifically mentioned in NEC Article 690 as of the 2005 edition. See Fig. 98. Products exist that can perform these functions and many module manufacturers list these options in their installation manuals. While these methods work well with most PV modules manufactured today, problems arise when module instructions do not specifically mention these options. Many jurisdictions take a strict interpretation of the requirement that all products must be installed according to the supplied manufacturer's instructions [NEC 110.3(B)]. For those jurisdictions, only the specifically mentioned methods will likely be allowed. Many module installation manuals will allow any code-approved grounding method. The UL1703 module standard and a new standard UL2703 for module racking systems are being revised to allow better accommodation of generic grounding systems.

A grounding electrode system consists of a rod, pipe, plate, metal water pipe, building steel or concrete-encased electrode, and includes all grounding electrodes at a building or structure that must be bonded together. The grounding electrode conductor (GEC) connects the grounded system conductor or the equipment grounding conductor (EGC) to a grounding electrode system. The GEC must be a continuous length without splices except for irreversible connections. A 6 AWG GEC may be secured to and run along building surfaces where protected from damage. GECs smaller than 6 AWG must be in metal raceways or use armored cables [NEC 250].

Specific requirements are given for the grounding electrode system used for PV installations [NEC 690.47]. The requirements are given ac systems, dc systems, and system with both ac and dc grounding requirements. The existing grounding electrode system should



Figure 98. Special bonding jumpers, stainless-steel bonding washers and lay-in lugs may be used to electrically connect separate components or attach equipment grounding conductors.

be checked as part of any PV installation, particularly for older facilities that may have degraded grounding systems. Verify that all available grounding electrodes at the facility are bonded together, and that the grounding electrode conductors are properly installed and sized.

Battery systems are considered to be grounded when the PV power source is grounded [NEC 690.71, 690.41]. Battery systems over 48 volts are permitted without grounding a current-carrying conductor have several requirements [NEC 690.71(G)]. First, the PV source and output circuits must have a grounded current-carrying conductor or meet the requirements for ungrounded arrays and have overcurrent protection for each ungrounded conductor [NEC 690.35]. The dc and ac load circuits for the system must also be solidly grounded. Both the positive and negative ungrounded battery circuit conductors must have a switched disconnect means and overcurrent protection, or dc-rated circuit breaker. A ground-fault detector-indicator is also required for ungrounded battery systems over 48 V.

Utility Interconnection

Interconnection refers to the technical and procedural matters associated with operating interactive PV systems and other distributed generation sources in parallel with the electric utility system. Technical interconnection issues include safety, power quality, and impacts on the utility system, and are addressed in national codes and standards. Interconnection procedures are based on state and utility policies, and include the application process and schedule, customer agreements, and permitting and inspection. Contractual aspects of interconnection policies include fees, metering requirements, billing arrangements, and size restrictions on the distributed generator.

IEEE 1547 Standard for Interconnection of Distributed Resources with Electrical Power Systems establishes the technical requirements for interconnecting all types of distributed generation equipment, including photovoltaics, fuel cells, wind generators, reciprocating engines, microturbines, and larger combustion turbines with the electrical power system. It also establishes requirements for testing, performance, maintenance and safety of the interconnection, as well as response to abnormal events, anti-islanding protection and power quality.

The focus of IEEE 1547 is on distributed resources with capacity less than 10 MVA, and interconnected to the electrical utility system at primary or secondary distribution voltages. The standard provides universal requirements to help ensure a safe and technically sound interconnection. It does not address limitations or impacts on the utility system in terms of energy supply, nor does it deal with procedural or contractual issues associated with the interconnection.

UL 1741 Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources addresses requirements for all types of distributed generation equipment, including inverters, charge controllers and combiner boxes used in PV systems, as well as equipment used for the interconnection of wind turbines, fuel cells, microturbines and engine-generators. This standard covers requirements for the utility interface, and is intended to supplement and be used in conjunction with IEEE 1547. The



Figure 99. Inverters and ac modules used in utility-interactive PV systems must be listed and identified for interactive operations.

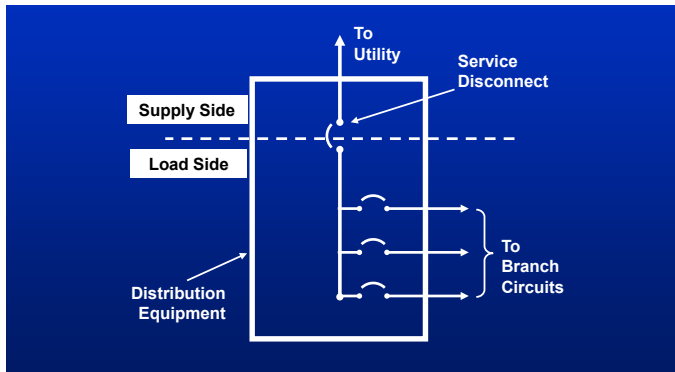


Figure 100. Interactive inverters may be connected to either the load side or the supply side of the service disconnecting means.

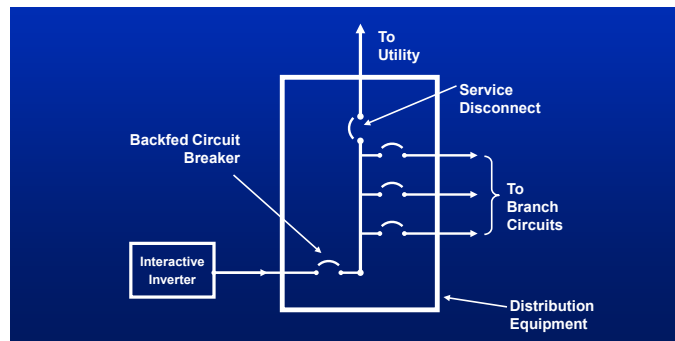


Figure 101. Many small residential and commercial PV systems can be interconnected by adding backfed circuit breakers to distribution panels as long as certain conditions are met.

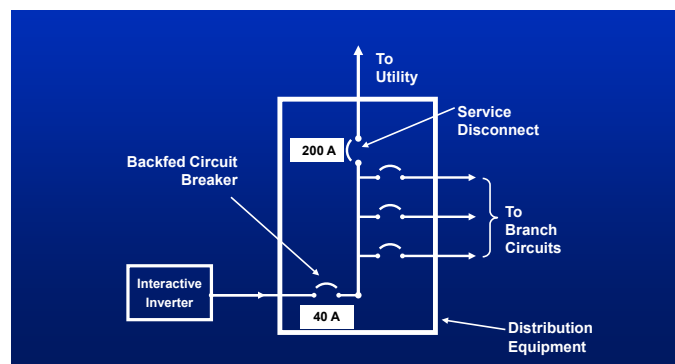


Figure 102. Load side connections require that the sum of the ampere ratings of overcurrent devices supplying power to a busbar or conductor does not exceed 120% of busbar or conductor rating.

products covered by the UL 1741 listing are intended to be installed in accordance with the National Electrical Code, NFPA 70.

All inverters and ac modules that are specifically intended to be used in utility-interactive PV systems must be listed and identified for interactive operations, and this information must be marked on the product label. Battery-based inverters intended only for stand-alone off-grid applications do not have these special identification markings, and may not be used for grid-connected applications. However, all inverters used in PV systems must be listed to the UL 1741 standard, whether they are used for stand-alone or interactive systems. See Fig 99.

NEC Article 690 Part VII addresses the connection of PV systems to other power sources, and applies to all interactive PV systems connected to the utility grid. For the 2011 NEC, many of the common interconnection requirements applicable to all distributed generators, including PV systems, fuel cells and wind turbines were moved to Article 705.

The *point of connection*, or *point of common coupling*, is the point where a distributed generator interfaces with the electric utility system. The point of connection may be located on the load side or the supply side of a facility service disconnecting means. See Fig. 100.

The output of interactive PV inverters may be connected to either the supply side or load side of the service disconnecting means [NEC 690.64, 705.12].

For many smaller systems, the point of connection is usually made on the load side of the service disconnect at any distribution equipment on the premises, usually at a panelboard. See Fig 101.

For load side connections, where the distribution equipment is supplied by both the utility and one or more utility-interactive inverters, and where the distribution equipment is capable of supplying multiple branch circuits or feeders, or both, load side connections must comply with the following seven requirements [705.12(D)]: See Fig 102.

1. Each source (inverter) must have a dedicated disconnect and overcurrent protection. This can be a fusible disconnect or circuit breaker and need not be service rated. PV systems using more than one inverter are considered multiple sources, and require a dedicated disconnect and overcurrent device for each inverter. A single disconnecting means can be additionally provided for the combination of multiple parallel inverters connected to subpanels. This requirement does not apply to modules or micro inverters where the output of multiple inverters is permitted for one disconnect and overcurrent device.

2. Load side connections require that the sum of the ampere ratings of overcurrent devices supplying power to a busbar or conductor does not exceed 120% of busbar or conductor rating. For a typical 200 A residential service with a 200 A panel busbar, up to 40 A of backfed PV breakers would be allowed, allowing a maximum inverter continuous output current rating of 32 A. For interactive PV systems with energy storage intended to supply backup load during grid outages, the bus or conductor loading is evaluated at 125% of the inverter maximum continuous current output rather than the overcurrent device rating.

EXAMPLE:

What is the highest rated inverter continuous AC output current that can be interconnected to a 125 A panel supplied from the grid by a 100 A overcurrent device?

The OCP devices supplying power to the panel (PV and grid) cannot exceed 120% of the panel bus rating. The allowable OCP devices is $1.2 \times 125 \text{ A} = 150 \text{ A}$. The allowable PV breaker would then be $150 \text{ A} - 100 \text{ A} = 50 \text{ A}$. Since the PV OCP device needs to be 125% of the inverter maximum continuous output current ratings, the maximum inverter continuous output current would be $50 \text{ A} / 1.25 = 40 \text{ A}$.

3. Interactive inverters must be interconnected on the line side of all ground-fault protection equipment. Most ground-fault protection breakers are not listed for backfeeding, and may damage them and prevent proper operation. Supply side interconnections are usually required for larger facilities incorporating ground-fault protection devices at the service if they are not listed and approved for backfeeding.

4. Distribution equipment used for interconnecting inverters must have markings to identify the connection for all sources. This requires labels for backfed PV breaker and main supply breaker.

5. Circuit breakers used for inverter connections must be suitable for backfeeding. Breakers without “Line” and “Load” side marking have been evaluated in both directions, and considered to be identified as suitable for backfeeding.

6. Fastening normally required for supply breakers is not required for breakers supplied by interactive inverters. Bolt-in connections, or panel covers normally render breakers not readily accessible for removal. The requirement for listed interactive inverters to de-energize output upon loss of utility voltage also makes these breakers safer for removal and service.

7. If the sum of the overcurrent device ratings supplying a panelboard is greater than 100% of the bus rating, the inverter output breakers must be installed at the opposite end of the bus from the utility supply breaker, and have a permanent label stating: WARNING: INVERTER OUTPUT CONNECTION – DO NOT RELOCATE THIS OVERCURRENT DEVICE.

EXAMPLE:

Consider a 7 kW PV inverter with 240 V output. Can this inverter be connected to a 150 A panel bus supplied by a 150 A main service breaker?

The inverter maximum continuous output current is:

$$7,000 \text{ W} \div 240 \text{ V} = 29.2 \text{ A}$$

The required overcurrent device rating is:

$$29.2 \text{ A} \times 125\% = 36.5 \text{ A rounded up to next standard breaker size, 40 A}$$

The 150 A panelboard permits $120\% \times 150 \text{ A} = 180$ of supply breakers:

$180 \text{ A} - 150 \text{ A main leaves } 30 \text{ A maximum allowable PV supply breakers.}$

A 7 kW inverter requires a 40 A breaker and may not be connected to this panel.

To allow the load side connection of a 7 kW inverter for the previous example, possible solutions include:

- Upgrading the panel rating to 200 A with a 200 A main breaker would allow a 40 A back-fed breaker from the PV systems.
- Keeping the main breaker at 150 A would allow even more PV capacity to be interconnected, and not require a utility service upgrade.
- Ultimately, the ratings of distribution equipment and overcurrent protection devices limit the size of load side interconnections.

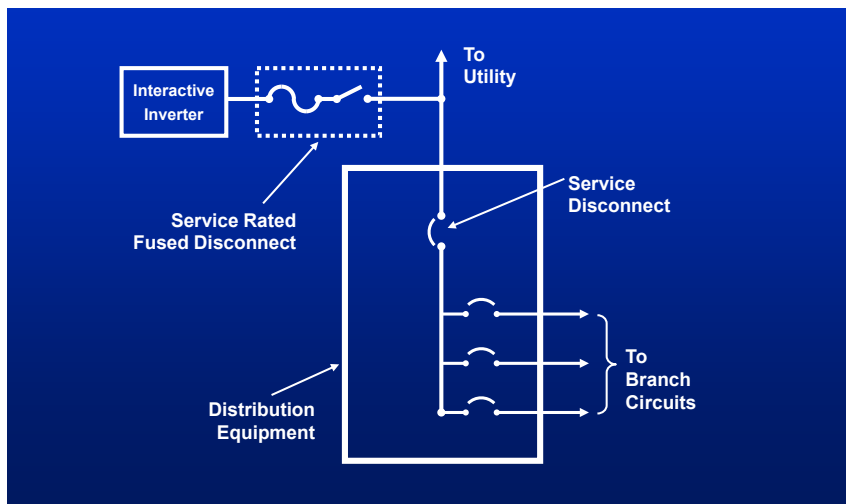


Figure 103. Supply side connections are made on the utility side of the service disconnecting means.

When the requirements for load side connection become impractical, interactive PV systems and other interconnected power sources may be connected to the supply side of the service disconnecting means [NEC 705.12(A), 230.82(6)]. These requirements are similar to installing another service, which involves tapping service conductors or bus, or installing new service equipment. Supply side interconnections are often required for larger installations. The sum of the ratings for overcurrent devices supplying a service must not exceed the service ratings. See Fig 103.

Supply side connections must have a service-rated disconnect and overcurrent device, with a minimum rating of at least 60 A, and have an interrupt rating sufficient for the maximum available fault current. The connection can be made by tapping the service conductors at the main distribution panel prior to the existing service disconnect, or it may be made on the load side of the meter socket if the terminals permit. Additional pull boxes may be installed to provide sufficient room for the tap. Service equipment for larger commercial facilities often has busbars with provisions for connecting tap conductors.

In cases of very large PV installations, existing service conductor ampacity or distribution transformers may not be sufficient and separate services may be installed. Power flow can occur in both directions at the point of connection, and the interface equipment and any metering must be sized and rated for the operating conditions.

Systems larger than 100 kW may be interconnected at other points in a facility provided qualified persons operate and maintain the systems, and that appropriate safeguards, procedures and documentation are in place [NEC 705.12(C)].

5 Installing Mechanical Components

PV modules and array mounting systems are installed in accordance with manufacturer's instructions. Not following these instructions may void product warranties or listings. Specialized training and experience may be required for certain products and systems, such as large area modules, building-integrated products or large tracking arrays.

5.1 Install Mounting System

PV arrays are constructed from building blocks of individual PV modules, panels and sub arrays that form a mechanically and electrically integrated dc power generation unit. The mechanical and electrical layout and installation of PV arrays involves many interrelated considerations and tradeoffs. Some of the many factors to consider include:

- Module physical and electrical characteristics
- Array electrical design and output requirements
- Mounting location, orientation and shading
- Type of mounting surface (roof or ground mount)
- Access and pathways for installation, maintenance and fire codes
- Structural loads on modules, mounting structures and attachments
- Thermal characteristics of modules and effects of mounting system
- Weathersealing of building penetrations and attachments
- Materials and hardware compatibilities with the application environment
- Aesthetics

Mounting system designs have a strong effect on average and peak array operating temperatures. Higher operating temperatures reduce array voltage, power output and energy production, and accelerate degradation of modules and their performance over many years.

Rack mounted arrays have the greatest passive cooling and lowest operating temperatures, with temperature rise from 15°C to 25°C above ambient temperatures under solar irradiance levels of 1000 W/m². Direct mounts have the highest operating temperatures, with temperature rise coefficients of 35 to 40°C/kW/m². Standoff mounts have moderate operating temperatures, depending on the standoff height. Maximum passive cooling gains are generally achieved with the tops of PV modules 3 to 6 inches above the roof surface.

Common standoff PV arrays are mounted slightly above and parallel to rooftops. PV modules are typically bolted or clamped with their long dimension across two structural rails or beams for support. The rails are then fastened and weathersealed to the building structure at defined points along the rails with special brackets designed for a specific type of roof. PV arrays installed in higher wind regions require stronger rails, or smaller spans between rail attachments (more attachment points) to avoid excessive rail and module deflections. These brackets support the entire structural loads on the PV array at

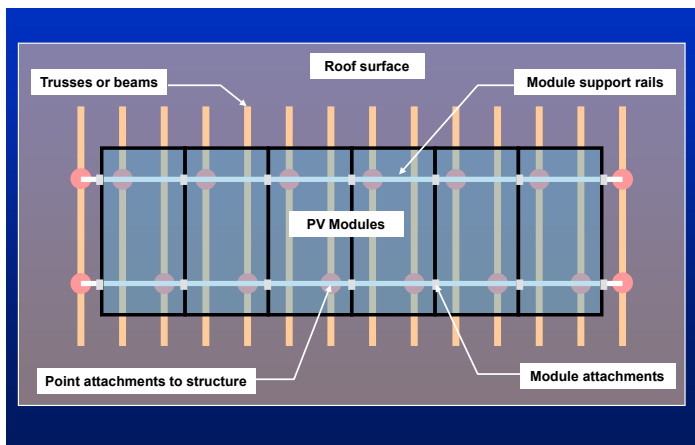


Figure 104. Structural considerations for PV arrays include attachments of modules and supports to structures.



Figure 105. Point attachments connect the array assembly to a building or structure at distributed locations, and are usually the critical design point of the entire mounting system.

the attachment points, which are either screwed or bolted to the roof trusses or structure. Lag screws are commonly used for screwed attachments to residential roof types.

The point attachments must be installed properly to structural members. See Figs. 104 & 105. Where lag screws are used, they must be centered into a truss generally only 1-1/2 inches in width. To find the exact center of trusses, special deep-penetrating stud finders can be used. With practice, the trusses on a shingled residential roof can usually be located by hitting the roof with a hammer. The center of the truss can be located by driving a small nail through the roof covering, deck and into the truss, then moving over 1/8 inch or so at a time until the nail does not penetrate into the truss, locating the truss edge. Backing up 3/4 in then defines the center of the truss. A drill alignment tool can help center the appropriate size pilot holes prior to screw installation.

When structural members are not present or cannot be located for array attachment points, the installer may be required to add additional blocking in the attic between the roof trusses. This is commonly required toward the edges of hip roofs. Typically a solid anchor between trusses can use pairs of 2x6 boards that are attached between rafters or trusses. The 2x6 pairs provide three inches of wood into which a lag screw can penetrate, as well as a relatively large area for mounting the bracket on top of the roof. In order to provide proper support for the array, the boards must be nailed or screwed securely onto the rafters or trusses with at least two fasteners on each side of each board. See Fig. 106.



Figure 106. Additional blocking may be required for some installations to adequately secure point attachments to the structure.

PV array mounting system designs and all components must be able to withstand the maximum forces expected in any given application. Oftentimes, independent engineering or test results may be required to certify PV array structural designs for local building code compliance. The critical design area is usually the point attachments of the array mounting system to a structure.

A number of pre-engineered standoff mounts are available commercially. When installed according to the manufacturer's directions, engineers or test laboratories certify these mounts to be capable of withstanding specified wind loads. If engineered mounting systems are used, it is necessary to follow the instructions to ensure that the system is installed properly to address the design wind load requirements. During inspection, it should be pointed out that the directions were followed to meet the loading requirements.

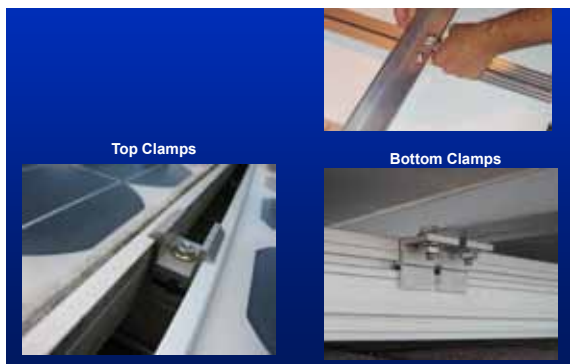


Figure 107. PV modules are commonly attached to underlying rails or beams using bolted attachments or clamps to the module frame.

5.2 Install PV Modules

Most standard flat-plate PV modules are glass laminates enclosed in an aluminum frame. The frame provides mechanical support for the laminate, and a means to structurally attach the module to a mounting system and for electrical grounding. PV modules are either bolted with fasteners or clamped to supporting rails or beams. See Fig. 107.

In common sloped rooftop applications, the rails are usually laid out with the length in an east-west direction across the roof, which permits variable width attachments to the underlying roof structural members, such as rafters or trusses. As the spacing between rafters or trusses is usually fixed, this may constrain the installation of rails up and down the roof slope (in a north-south direction). This is because PV modules require the support rails to be located at certain points on the module frame to support

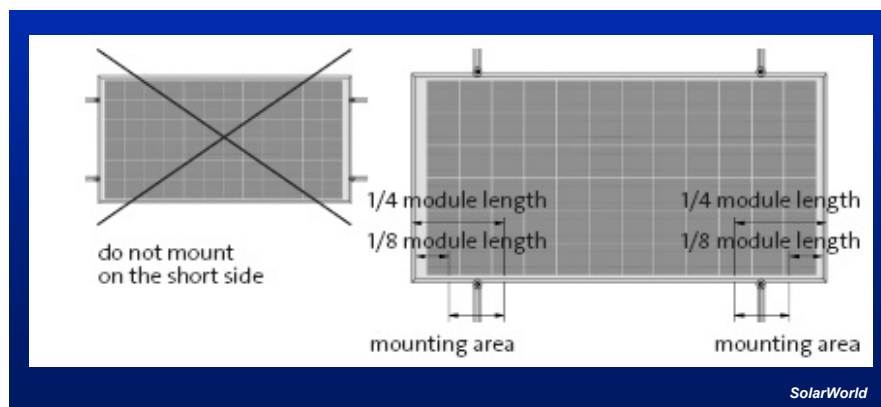


Figure 108. PV module specifications give the maximum mechanical loads that the module can support using specified supports and attachments.

the specified mechanical loads. Refer to mounting hardware manufacturer's data on maximum allowable loads and deflection on module support beams.

Manufacturer's instructions should be carefully followed whenever handling or installing PV modules. See Fig. 108. Although PV modules are designed to withstand environmental extremes for many years, they can be damaged if improperly stored, handled or installed. Some modules are more durable than others, but care should be taken to ensure that the module edges are not chipped or impacted. Unframed laminates are particularly susceptible to edge damage and require significantly more care in construction handling. Small chips or nicks in the glass result in high stress points that become cracks that destroy the module. Since clamps are commonly used to fasten PV modules, it is important to install the proper clamps for the modules used, and torque to the proper values so that the clamps stay firmly in place but do not crush the module frame. Follow the PV module manufacturer's installation instructions for the allowable mounting points to meet the maximum design loads.

Working safely with PV modules involves taking precautions to avoid electrical shock from potentially high dc voltages, especially when several modules are connected in series. Wiring faults may also lead to hazardous conditions and high voltages on metal components.

Care in handling, transporting, storing and installing PV modules includes the following:

- Leave modules in packaging until they are to be installed.
- Carry modules with both hands, do not use connectors as a handle
- Do not stand modules on hard ground or on their corners
- Do not place modules on top of each other or stand on them
- Do not mark or work on them with sharp objects
- Keep all electrical contacts clean and dry
- Do not install modules in high winds

General safety precautions for installing PV modules include the following:

- Use the appropriate safety equipment (insulated tools/gloves, fall protection, etc.)
- Never insert electrically conducting parts into the plugs or sockets
- Never connect non-load break connectors under load or if dirty or wet
- Never use damaged modules
- Do not dismantle modules.
- Do not remove any part or label fitted by the manufacturer
- Never treat the rear of the laminate with paint, adhesives or mark it using sharp objects
- Do not artificially concentrate sunlight on modules

6 Completing System Installation

Once PV systems are installed, they are inspected and commissioned to verify the installation matches the plans and code requirements, and to verify that performance expectations are met.

6.1 Commission the System

Commissioning of PV systems follows similar requirements to any electrical installation, involving visual observations, testing and measurements to verify the safety and quality of the installation in accordance with the plans and applicable codes and standards, and to verify the proper operation and performance of the system.

Key steps of a commissioning procedure include:

- Completing final installation details
- Completing a system checkout and visual inspections
- Verifying wiring insulation integrity and proper termination torques
- Completing system documentation and labeling requirements
- Perform initial start-up and operations
- Demonstrate and verify shutdown and emergency procedures
- Verifying expected output and performance
- Conducting user training and orientation

A final checkout confirms that the installation is complete before beginning operations. A punch list can help check off items as they are completed, and should include the following items:

- Verifying disconnects are open and lockout/tagout procedures are in place
- Visually inspecting all components and connections (structural and electrical)
- Verifying terminal torque specifications and insulation integrity
- Verifying consistency of overall installation with system design
- Identifying and completing any unresolved items

Numerous markings, labels and signs are required to identify PV systems and their components, and to warn operators, service personnel or emergency responders of hazardous conditions. Manufacturer markings and labels identify the size, type, specifications and ratings for PV modules, inverters, controllers, combiner boxes, conductors, raceways, overcurrent devices, switchgear and all other electrical components. These markings are placed on the product at the time of manufacture, and include listing marks from the approval agency (NRTL), such as UL. Code officials may verify these markings during final inspections, and use them for the basis of their approval.

Additional markings and labels are required for the overall system and certain components, and are to be provided and placed by the installer. These include additional labels on conductors, connectors, conduits, disconnecting means, and at the point of utility connection. Special labeling is also required for bipolar arrays, ungrounded PV arrays, battery storage systems, and stand-alone inverters providing a single 120-volt supply.

The initial startup for a PV system is conducted after all inspections and checks have been completed with all outstanding items resolved. Typical startup procedures include:

- Installing overcurrent devices
- Closing all DC and AC disconnects and turning on inverter
- Verifying output

6.2 Visual Inspection

Visual inspections should be performed as part of commissioning and routinely over the system lifetime to verify and ensure that the system remains in a satisfactory condition for use. Prior to operation, PV systems should be inspected for full compliance with the many NEC requirements, including verifying appropriate:

- Circuit voltages and currents
- Conductor and overcurrent device sizes and ratings
- Disconnecting means
- Wiring methods and connectors
- Equipment and system grounding
- Markings and labels
- Connections to other sources
- Battery and charge controller installation

An inspection checklist is an indispensable tool for contractors and regulators, and provides an organized process to review and help ensure code compliance for PV installations. The basic purposes for an inspection checklist include:

- Verification of appropriate equipment listings and labeling, intended for the conditions of use, and installed in accordance with instructions.
- Verification of appropriate sizes and ratings for major components and balance-of-systems equipment.
- Verification of proper grounding and bonding.
- Verification that all equipment and the overall installation is completed in a workmanlike manner in compliance with all applicable codes.

Some sources for PV system inspection checklists include:

www.nmsu.edu/~tdi/Photovoltaics/Codes-Stds/Codes-Stds.html

irecusa.org/wp-content/uploads/2010/07/PV-Field-Inspection-Guide-June-2010-F-1.pdf

www.jimdunlopsolar.com/vendorimages/jdsolar/PVInspectionChecklist.pdf

6.3 Test the System

Testing PV systems requires qualified persons with knowledge of electrical systems measurements, the test equipment used, and the specifications and characteristics of the equipment or systems under test. PV systems should be thoroughly tested at the time of commissioning and periodically over the system life to ensure proper and safe operations.

Electrical testing on interactive PV systems includes the following measurements and verifications:

- Test ac circuits for continuity, phasing, voltage
- Test dc circuits for continuity of grounding conductors
- Verify correct dc polarity
- Test string open-circuit voltage
- Test string short circuit current
- Verify system functionality
- Insulation resistance testing of PV arrays source and output circuits

Insulation Resistance Testing

Insulation resistance testing measures the resistance from ungrounded circuits to ground, and is used to verify and demonstrate integrity of wiring systems [NEC 110.7]. These tests can be used to identify damage or insulation faults for PV modules and interconnect wiring, to locate ground faults, or to assess the degradation of array wiring, PV modules and other system circuits. The insulation tester can be a variable dc power supply or megohmmeter that provides a test voltage of 500 V.

Damage to wiring insulation can be due to improper installation, or from vermin chewing the wires. Older PV arrays may have significantly higher leakage current than when they were new. Proper insulating gloves and other applicable PPE should be used whenever touching a PV array or associated conductive surfaces to protect against electrical shock, especially when ground-fault conditions are indicated.

Insulation resistance testing measures the resistance between the system circuits and ground. Insulation resistance for large PV arrays is generally measured at source circuit combiner boxes, where the individual source circuits can be accessed for disconnection and testing. The tests can be conducted dry, or a wetting agent can be sprayed on portions of an array to better pinpoint fault locations.

All circuits must be isolated from others for testing and grounding or bonding connections are left connected. Any surge suppression equipment must be removed from the circuits. Connect the positive and negative output leads of the array together, and to the positive terminal of the insulation tester. A short-circuiting device is required suitable for the source circuit or array maximum current. Connect the negative terminal of the insulation tester to the grounding point for the array or source circuit. Apply a dc test voltage of 500 V and wait for capacitive effects to subside and readings to stabilize. Measure and record the insulation resistance in megohms. Observe and listen to the array during the tests for evidence of arcing or flashover. Generally, when a fault exists, resistance measurements will decrease significantly. Tests conducted during system commissioning may be used as a baseline for which later measurements can be compared.

6.3.1 Complete System Documentation

Adequate documentation for PV systems is an essential part of the approval process, and helps ensure safe and reliable operation over decades of operation. Complete documen-

tation is particularly important for safety concerns, routine maintenance, later modifications, and for systems having a change in ownership or those responsible for operating and maintaining the system. In most jurisdictions, system documentation is required by the building officials for the plan review and permitting process, and also for interconnection approval from the local utility. In some cases, incentive programs may require additional documentation, such as a shading analysis and system performance estimates. Final system documents should always be provided to the owners and caretakers and should be accessible at the system site for future reference. The installation contactor should also keep a copy of the system documentation materials for their records and follow-on service as required.

A complete system documentation package is a well-organized collection of all relevant documents depicting the as-built system design, major components and relevant information on safety, operations, and maintenance. While the details may vary with the size and scope of specific projects, key components of a final PV system documentation package should include the following:

- General information should include the system dc and ac power ratings; the manufacturer, model and quantity of PV modules, inverters, batteries, controllers and all other major components, as applicable. The dates of the system installation, commissioning and inspection should also be noted.
- Contact information should include the names, postal addresses, phone numbers and email addresses for the customer/owner, system designer, installation contractor and any other responsible parties or subcontractors.
- A site layout drawing is often required by local jurisdictions for permitting purposes, to identify equipment locations on buildings or relative to property lines or easements. In some cases, a shading analysis and performance estimates may be provided with project proposals, and should also be including with the final system documents.
- A single line diagram should be provided depicting the overall system design, including the types of modules, total number of modules, modules per string and total number of strings; the types and number of inverters; and any other major components. For larger projects, complete as-built electrical and mechanical drawings are usually required at project close out.
- The types, sizes and ratings for all balance-of-system components should also be annotated on the single line diagram, or noted and provided in a separate table, including specifications for all conductors, raceways, junction boxes, source circuit combiner boxes, disconnects, overcurrent protection devices, and grounding equipment, as applicable.
- Data sheets and specifications should be provided for PV modules, inverters and other major components, including module mounting systems. For most inverters, installation and user/operator manuals are available and provide important information regarding the safe operation and maintenance of the equipment.
- Operation and maintenance information should include procedures for verifying proper system operation and performance, and how to determine if there is a problem and what to do. Procedures for isolating/disconnecting equipment and emergency shutdown procedures should also be provided. A maintenance plan and intervals should be provided for all routine (scheduled) system maintenance, such as

array cleaning as required. Operating and maintenance guidelines should differentiate what tasks can be performed by the owner or caretakers, from those that require professional service due to the complexity of the tasks, special equipment needs, or safety concerns. Maintenance agreements, plans and recordkeeping forms or sheets should also be provided to document maintenance activities over time.

- Warranty details on major components should be clearly identified, indicating the terms and conditions, and how the warranty process is handled and by whom. System warranties should also be addressed, including quality of workmanship, roof weathersealing or performance warranties as applicable.
- Copies of all commissioning test reports and verification data shall be provided as applicable.
- Contracting and financial details are also an important part of system documentation, and may be included with the technical items discussed above or under a separate file. These documents would include construction contracts, invoices and payments for materials and labor, building permits, inspection certificates, interconnection agreements, and applications and approvals from incentive programs, such as rebates and tax forms.

7 Conducting Maintenance and Troubleshooting Activities

PV systems require periodic maintenance to ensure safe and reliable operations over the long-term, and to maximize performance. Although most PV systems usually require little maintenance, a maintenance plan ensures that essential service is performed on a regular schedule. Maintenance helps identify and avoid potential problems that affect system functions, performance, or safety. When problems do occur, a systematic troubleshooting process is used to diagnose and identify the problems, and take corrective actions.

All PV systems require some maintenance. A maintenance plan includes a list and schedule for all required system maintenance and service:

- Inspections of components and wiring systems
- Evaluation of structural attachments and weathersealing
- Cleaning and removing debris around arrays
- Performing battery maintenance
- Conducting electrical tests and verifying performance
- Replacement of damaged or failed system components

7.1 Perform Visual Inspection

Visual inspections of the complete system should be performed with regular maintenance, similar to the initial inspection prior to commissioning. The main difference is that during maintenance inspections, the code compliance aspects of the system do not necessarily need to be evaluated, as the equipment would not normally have been changed. However, the integrity of the electrical installation must be carefully evaluated for deteriorating effects over time, due to the site conditions, or even for poor quality components or damage for outside influences. Visual inspections and observations are supplemented with electrical tests and measurements to fully verify system integrity and performance.

PV modules should be visually inspected for signs of any physical damage, including bent frames or broken glass. See Fig. 109. Modules with fractured or damaged laminates will eventually admit moisture and develop high leakage currents, and should be removed from the array and replaced. Most PV modules use tempered glass, which shatters in small pieces when stressed or impacted. Physical damage may be quite obvious in the case of impacts, but fractured glass in a PV module may not be clearly evident from a distance.



Figure 109. Inspect PV arrays for any signs of physical damage, such as impacts or fractures.



Figure 110. PV modules should be carefully inspected for any signs of discoloration, corrosion or delamination.

More subtle signs of module degradation include delamination, moisture or corrosion within modules, particularly near cell busbar connections and edges of laminates. Discolorations inside module laminates may be an indicator of a failing edge seal, or damage to the back of the module laminate. Degradation of solder bonds at internal cell connections can lead to hot spots and ultimately burn through the back of the module, resulting in module failure, reduced system performance and creating a fire hazard. See Fig.110. Burned bus bars, delaminated modules and damaged wiring systems are likely to show faults during insulation resistance testing. Thermal imaging can be a useful diagnostics tool for identifying faults in wiring systems or poor connections, especially for PV arrays.



Figure 111. Operating parameters in PV systems are measured to verify expected performance.

7.2 Verify System Operation

Performance data can be used to verify output expectations and identify problems that require service or maintenance. See Fig. 111. Most inverters and charge controllers provide some indication of performance and operating status, such as power output or energy production, and fault or error indications. This information is extremely helpful in verifying proper system operation. Also ensure that the system can be disconnected and shut down safely and that it starts properly. Knowledge of the specific equipment used and the product installation and operation instructions are crucial to verifying their safe and proper operation.

For simple interactive PV systems without energy storage, the key indicators for system performance are ac power output (kW) and ac energy production (kWh). The ac power output for an interactive system is determined by the rated dc power output of the array, the inverter efficiency and systems losses, and is proportional to solar irradiance on the array. Measurement of ac power output is usually given on inverter output display, or can be recorded over time and accessed remotely. Power measurements may be an instantaneous (snap-shot) measurement, or averaged over a certain interval.

The ac power output of an interactive PV system at any moment can be compared with expectations, using the basic translation formulas for solar irradiance and temperature. AC power output can be read from inverter displays or by additional power meters, and the array temperatures and solar radiation in the plane of the array can be measured with simple handheld meters without working on energized equipment. AC power verification can be done any time when the system is operating under steady sunlight conditions, preferably at higher irradiance levels.

Generally, the maximum ac power output for interactive systems can be related to the rated maximum dc power output rating for the array and adjusted by a number of derating factors. The factors include several types of dc and ac system losses and power conversion efficiencies, which in combination result in ac power output varying between 70% to 85% of the PV array dc rating at Standard Test Conditions (STC), depending on temperature.

The ac energy production (kWh) for grid-connected PV systems is measured over periods of months and years to compare with sizing and long-term performance expectations. The ac energy production for grid-connected PV systems with no energy storage can be estimated using popular tools such as PVWATTS. PVWATTS first estimates the system ac power output rating at STC based on user-supplied inputs and derating factors. AC power is then estimated on an average hourly basis energy production is the based on the user selected array tilt and azimuth angles are selected. PVWATTS then performs an hour-by-hour simulation for a typical year to estimate average power output at for each hour and totals energy production for the entire year. PVWATTS uses an overall dc to ac derate factor to determine the rated ac power at STC. Power corrections for PV array operating temperature are performed for each hour of the year as PVWATTS reads the meteorological data for the location and computes the performance. A power correction of $-0.5\%/^{\circ}\text{C}$ for crystalline silicon PV modules is used.

Actual solar irradiation (insolation) and array temperatures can be used to more precisely compare with the ac energy produced. The average daily ac energy production divided by the product of the PV array dc peak power rating at STC and peak sun hours is a key indicator of system performance:

$$\text{ac kWh} / (\text{dc kW} \times \text{PSH}) = 0.7 \text{ to } 0.85$$

The installer must be capable of making a good estimate of what the PV array should produce instantaneously based on the system design and environmental conditions. Knowing the array size and inverter efficiency, these parameters can be adjusted by the irradiance on the array and the temperature of the PV modules. System adjustment factors for module mismatch and dc and ac wire losses vary based upon the actual installation. Another factor that can limit irradiance



Figure 112. Handheld solar meters use a small PV cell to measure solar irradiance.

Solar Radiation Measurements

A pyranometer measures total global solar irradiance (solar power). Irradiance measurements are used in the field to translate the actual output of PV array and systems to a reference condition to verify performance. Small inexpensive meters using calibrated PV cells as sensors are available from \$150 and up. See Fig 112. A small PV module with calibrated short-circuit current can also be used to approximate solar radiation levels.

is soiling on the array. This is particularly important in climates in the western U.S. that can go for several months without rain.

Example:

How much power should a 4,800 Watt (STC) crystalline silicon array produce when the array temperature is 45°C and the irradiance is 840 W/m²? The inverter efficiency is 95%; module mismatch and the dc and ac wiring losses are 2% and 3% respectively, and soiling is minimal.

System Adjustment Factors:

1. Temperature: $[1 - (45^{\circ}\text{C} - 25^{\circ}\text{C}) \times (-0.005/^{\circ}\text{C})] = 0.90$
2. Irradiance: $(\text{IRR} \div 1000\text{W/m}^2) = 840/1000 = 0.84$
3. Inverter Efficiency: 0.95
4. Mismatch and dc and ac wire losses: 5% total = 0.95
5. Soiling: 0% = 1.0

Inverter Output Power = 4800 X (0.9) X (0.84) X (0.95) X (0.95) X (1.0) = 3275 W

STC array rating ————↑

Temperature ————↑

Irradiance ————↑

Inverter Efficiency ————↑

Mismatch and wiring ————↑

Soiling ————↑


For a utility-interactive system with battery backup, the calculation of expected voltages, currents, and powers is more complicated. The difference between a battery backup system and a system without batteries is that the PV array does not operate at its maximum power voltage unless a MPT charger is used. The battery also requires constant charging to remain fully charged. The output power of the system can be estimated when the system is operating in utility-interactive mode, and if the batteries are fully charged.

Typical max power tracking controlled battery-based systems will lose 2% (0.98) for maximum power tracking losses and about 5% (0.95) for additional inverter losses. These systems will operate at about 93% of the same size PV systems without batteries. Battery-based systems without max power tracking controllers will lose another 5-10% instantaneous power due to operation off the maximum power point. All battery-based systems will lose energy keeping the battery fully charged. This charging can reduce the annual energy production by 2-5%. It is arguable whether the PV system should be held accountable for this loss factor since all standby power systems have these battery charging losses.

Watt-hour meters measure electrical power and energy, and are commonly used at electrical service entrances by utility companies for customer billing purposes. Watt-hour

meters essentially measure current, voltage and their phase angle to determine ac power and energy. They can be electronic or electro-mechanical types. Advanced electronic types use microprocessors to can measure directional and time of use power flows and other electrical properties such as reactive power, power factor and peak power demand. See Fig 113.

- ▶ The watt-hour constant (K_h) indicates the watt-hours accumulated per revolution of the meter disk.
- ▶ Multiply K_h by the disk revolution rate to calculate average power through the meter.



$$P_{avg} = K_h \times N_{rev} \times 3600$$

where

P_{avg} = average power (W)

K_h = meter constant ($\frac{Wh}{rev}$)

N_{rev} = disk revolution rate ($\frac{rev}{sec}$)

Figure 113. A standard watt-hour meter can be used to measure average power over brief intervals.

Standard utility watt-hour meters are often used to record the energy produced by PV systems over time, but can also be used to measure average power over brief intervals. The watt-hour constant (K_h) indicates the watt-hours accumulated per revolution of the meter disk. Most residential meters have $K_h = 7.2$. The smaller the constant, the faster the meter spins for a given amount of power passing through it. Multiply K_h by the disk revolution rate to calculate average power through the meter. The disk has markings on the top and sides with a scale of 0 to 100. Electronic meters use progressing LCD hash marks to simulate disk revolutions and the rate of energy flow.

For example, the average power through a meter with $K_h=7.2$ that makes 10 complete revolutions in 40 seconds is calculated by:

$$P_{avg} = 7.2 \text{ Wh/rev} \times 10 \text{ rev} / 40 \text{ sec} \times 3600 \text{ sec/hr} = 6480 \text{ W.}$$

Performance verification for stand-alone systems with battery storage is more complex, and involves measurements of:

- Battery voltage, amp-hours and state-of-charge
- PV array, battery and load currents
- Load availability and other factors

Battery health is the key to stand-alone PV systems, and battery failure is often the indicator of many other system problems. Many battery charge controllers and inverters monitor and record certain battery data, such as voltage, current and amp-hours. Closely monitoring and evaluating this data can be an invaluable tool to those operating and maintaining stand-alone systems.

Usually, stand-alone systems are designed to produce a specified amount of energy on an average daily basis to meet system loads. Measurements of daily energy consumption can be used by the system owner/operators to control their loads and manage the available energy, to maintain battery charge, or to minimize or eliminate the requirement for using a backup source, such as a generator. Measurements of daily minimum daily battery voltage can be used as an indicator of state-of-charge. The net amp-hours delivered to and withdrawn from a battery can also be used to assess whether the battery is receiving enough charge. Deficit charging will usually be indicated by declining minimum battery voltages. The performance of electrical loads can be verified by measuring their current or power consumption, and if the function as intended.

7.3 Perform Maintenance Activities

Maintenance activities include scheduled maintenance and other maintenance needs identified from visual inspections, electrical testing or performance measurements. Basic maintenance for PV arrays includes the following:

Debris Removal

Any leaves, trash or other debris that collects around PV arrays should be removed during routine maintenance. These materials can present a fire hazard, as well as a problem for proper drainage and can lead to mildew and insect problems that can ultimately lead to degradations of wiring systems or other components.

Shading Control

Because a relatively small amount of shading can significantly reduce array output, any conditions that contribute to increased shading of PV arrays should be evaluated during routine maintenance. Trees and vegetation present ongoing shading concerns, and may require trimming and maintenance to prevent excessive array shading. Ground-mounted PV arrays may also be susceptible to shading from shrubs or long grass near the array. Where visual observations cannot determine the extent of shading problems, a solar shading evaluation tool can be used.

Soiling

PV arrays become soiled over time, particularly in arid and dusty regions with infrequent rainfall. Soiling may result from bird droppings, emissions, dust or dirt that settles and accumulates on the array surface. Extensive soiling can reduce array output by 10 to 20% or more. Generally, cleaning PV array on buildings involves climbing ladders and working at heights where personal fall arrest systems are required. Electrical shock hazards may also exist for higher voltage arrays with existing faults. See Fig. 114.

Weathersealing and Structural

The weathersealing of all attachment points and building penetrations should be routinely inspected for signs of water leakage, and repairs made as required. All structural attachments should be inspected for security and signs of degradation.



Figure 114. Cleaning soiled PV arrays is a common maintenance need.

Battery Maintenance

Batteries can be one of the more maintenance-intensive components in a PV system. Regular care and service is important to maximizing battery life, and to mitigate any hazardous conditions. All battery maintenance should be conducted using proper procedures and safety precautions. Battery maintenance includes checking and replenishing electrolyte, cleaning, re-tightening terminals, measuring cell voltages, specific gravity and any other periodic maintenance or testing recommended by the manufacturer.

Battery maintenance involves various tasks depending on the type of battery and manufacturer requirements, including:

- Inspecting and cleaning battery racks, cases trays and terminations
- Inspecting battery disconnects, overcurrent devices and wiring systems
- Checking termination torques
- Measuring voltage and specific gravity
- Adding water
- Inspecting auxiliary systems
- Load and capacity testing

Observe all safety precautions and wear appropriate PPE when conducting any battery maintenance. Personal safety precautions for battery maintenance include:

- Wearing face shields, aprons and rubber gloves when dealing with electrolytes
- Providing eye wash facilities, water and baking soda for flushing and neutralizing spilled electrolyte
- Providing disconnecting means to isolate battery system
- Fire protection equipment

Battery test equipment includes:

- DC voltmeters are used to measure battery and cell voltages
- DC ammeters (clamp-on type) are used to measure battery currents
- Hydrometers are used to measure electrolyte specific gravity
- Load testers discharge the battery at high rates for short periods while the voltage drop is recorded
- Impedance and conductance testers may be used on some VRLA batteries

Battery terminals are made of soft lead alloys, and connections may become loose over time. This can lead to increased resistance and voltage drop within the battery bank, resulting in unequal charge and discharge currents among individual cells. In severe cases, loose terminals can cause accelerated corrosion, and overheat to a point where the battery post or cable connection deforms or even melts, creating a fire hazard. Regular battery maintenance should include checks of all terminals for corrosion and proper torque. Terminals may be coated with petroleum jelly, grease, or special battery terminal corrosion inhibitors to retard corrosion. See Fig. 115.



Figure 115. Periodic battery maintenance should include checks of all terminals for corrosion and proper torque.

Specific gravity should be checked for open-vent flooded lead-acid batteries as part of annual maintenance, and may be used to estimate battery state-of-charge. Abnormally low readings may indicate failing or shorted cells.

A fully charged lead-acid cell has a typical specific gravity between 1.26 and 1.28 at room temperature. Specific gravity decreases with increasing electrolyte temperature, and measurements must be corrected to a reference temperature for comparison. Four “points” of specific gravity (0.004) are added for every 5.5°C (10°F) increment above a reference temperature and four points are

subtracted for every 5.5°C (10°F) decrease in temperature. For example, at 90°F (32°C) a hydrometer reading of 1.250 would be corrected to 1.254 at 80°F. See Fig 116.

Hydrometers measure electrolyte specific gravity (SG). Archimedes hydrometers use a float and buoyancy principles to measure SG. Refractive index hydrometers use a prism and optics to measure SG by the angle that light refracts through a droplet of electrolyte. See Fig. 117.

Open-circuit voltage may also be measured and used independently or in conjunction with specific gravity to estimate battery state-of-charge. The voltage readings must be taken when the battery has not been charged or discharged for at least 5 to 10 minutes.

For typical lead-acid battery at 25°C		
State-of-Charge	Specific Gravity	Open-Circuit Voltage (V)
100%	1.265	12.6
75%	1.225	12.4
50%	1.190	12.2
25%	1.155	12.0
0	1.120	11.8

Figure 116. Battery specific gravity and open-circuit voltage are measured during maintenance to evaluate battery health and estimate state-of-charge.



Figure 117. Hydrometers measure electrolyte specific gravity (SG).

Flooded, open-vent batteries require frequent water additions to replenish water lost through electrolyte gassing. Distilled water is recommended. Electrolyte levels must not be allowed to decrease below the tops of the battery plates, which can oxidize and reduce capacity. Because electrolyte expands with increasing concentration, batteries should only be completely filled or “topped off” when they are fully charged. Otherwise, the battery may overflow electrolyte from the cell vents.

The frequency and amount of watering required depends on charge rates, temperature, regulation voltage and age of the battery among other factors. Watering intervals may be extended where batteries have reserve electrolyte capacity. Advanced multi-stage charge control methods and temperature compensation also reduce water loss. Higher water loss should be expected in hot, arid climates. Excessive electrolyte loss may be due to a faulty charge controller, failed temperature compensation or improper regulation set point. Comparatively low water consumption in individual cells may indicate a weak or failing cell, or need for equalization charge. Specific gravity is also likely to be lower in cells with lower water loss.

Battery load testing applies very high discharge rates for a few seconds, while measuring the decrease in battery voltage. Weak or failed cells are indicated by significantly greater voltage drop. Battery capacity testing involves discharging the battery at nominal discharge rates to a prescribed depth-of-discharge. This test evaluates available energy storage capacity for the system during normal operations.

Appendixes

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References

Introduction to Resources Section

The following pages list additional sources of information on the topics that are covered in the NABCEP PV Installer Job Task Analysis. The list of sources was assembled by a committee of subject matter experts and represents their considerable efforts to offer additional study materials. The list is not complete, nor could it ever be complete, as additional material in the form of books, videos, articles and web sites are continually being produced.

The reader will note that some sub topic areas do not have recommended additional study references. This is because the Committee did not find a reference for that particular topic area that met their standards of usefulness and accuracy. NABCEP encourages dialogue and input at all times and invites readers who identify potential references for any topic areas covered in this guide to send them to NABCEP for review by the Committee for possible inclusion in future editions of this Guide. Please send reference recommendations to info@nabcep.org with the subject line "PV Resource Guide Reference Submission".

Color Key:

Task Steps and Knowledge in each Category Level

CATEGORY / LEVEL	DESCRIPTION
● Critical	Absolutely essential for a PV installer. Installers do these tasks most frequently.
● Important	Very important, but not of the highest level of criticality. These tasks are done with less frequency by installers yet have been identified as important to the knowledge base of installers.
● Useful	Might be useful; can inform education and training to add richness and depth. Installers do these tasks infrequently.

1. Verify Client Needs

• Confirm desired location of equipment	
• Address aesthetic concerns	Photovoltaic Systems; Chapter # 10/Page# 259-260; Mechanical Intergration - Aesthetics; J.P. Dunlop; Home Power Magazine; Issue #142/Pgs# 44-51; Architectural PV Design Considerations; M. Welch
• Address legal concerns	
• Confirm loads assessment	Photovoltaic Systems; Chapter # 9/Pgs# 233-240; System Sizing - Load Analysis; J.P. Dunlop; PV Design & Installation man.; Chapter # 4/Pgs# 38-40; Electric Load Analysis; S.E.I.
• Confirm critical loads	Photovoltaic Systems; Chapter # 4/Pgs# 96-97; System Components & Config. - Electric Loads; J.P. Dunlop; Solar Pro Magazine; Issue # 3.3; Stand alone System Design - 5 rules for Load analysis
• Confirm system matches client expectation	Photovoltaic Systems; Chapter # 3/Pgs# 84-85; Site Survey and Preplanning - Prep Proposals/Install Planning

Additional useful references

• Determine client's energy expectations	Photovoltaic Systems; Chapter # 3/Pg# 82; Site Survey and Preplanning - Energy Audit; J.P. Dunlop; Solar Pro Magazine; Issue# 4.4; PV Performance Guarantees (Part 1): Managing Risks & Expectations; Mat Taylor, David Williams
• Determine client's financial expectations	Photovoltaic Systems; Chapter # 15/Pgs# 399-416; Economic Analysis; J.P. Dunlop
• Obtain utility bills	Photovoltaic Systems; Chapter # 4/Pgs# 105-107; System Components & Config - Utility interactive Systems; J.P. Dunlop
• Determine client budget	Photovoltaic Systems; Chapter # 15/Pgs# 394-398; Economic Analysis - Incentives/Rebates/Grants/Tax Incentive; J.P. Dunlop

2. Review Site Survey

• Evaluate roof conditions	Photovoltaic Systems; Chapter #3/Pgs# 78-80; Site Survey and Preplanning - Roofing Evaluation; J.P. Dunlop; Solar Pro Magazine; Issue # 2.3; Quality Assurance: Aerial Site Surveys Save Time and Resources; Tim Harvey
• Evaluate desired array and equipment locations	Photovoltaic Systems; Chapter # 3/Pgs# 66,67,80; Site Survey and Preplanning - Array Loc./Equipment Loc.; J.P. Dunlop; Home Power Magazine; Issue # 115/Pgs# 98-100; Considerations for PV Site Surveys; J. Wiles; Home Power Magazine Issue # 130/Pgs# 52-56; Optimizing a PV array with Orientation and Tilt; D. DelVecchio
• Locate solar equipment	Photovoltaic Systems; Chapter # 3/Page# 80; Site Survey and Preplanning - Equipment Locations; J.P. Dunlop
• Locate conduit paths	
• Evaluate roof structure	Solar Pro Magazine; Issue # 3.2; Pitched Roof PV Mounting: Design and Engineering considerations; Yun Lee
• Determine obstructions	Photovoltaic Systems; Chapter # 3/Pages# 70 - 77; Site Survey and Preplanning - Shading Priority/Alt. Angle method; J.P. Dunlop
• Conduct a site hazard assessment (existing hazards)	Photovoltaic Systems; Chapter # 3/Pages# 60 - 64; Site Survey and Preplanning - Survey Safety; J.P. Dunlop
• Identify staging/lifting/access locations	Photovoltaic Systems; Chapter # 10/Pgs# 256 - 257; Mechanical Integration - Mech. considerations/Accessibility

• Confirm accuracy of shading analysis	Photovoltaic Systems; Chapter # 3/Pgs# 69-77; Site Survey and Preplanning; Shading Analysis; J.P. Dunlop; Home Power Magazine; Issue # 121/Pgs# 88-90; Solmetric Suneye Solar Site; Evaluation tool; J. Schwartz; Home Power Magazine, Issue # 115/Pgs# 30-33; Choose the right Site to Maximize your Solar Investment; Tehri Parker; Solar Pro Magazine; Issue # 1.1; Solar Site Evaluation: Tools & Techniques to Quantify & Optimize Production; Mark Galli, Peter Hoberg
• Evaluate existing electrical equipment	Photovoltaic Systems; Chapter # 3/Page# 80; Site Survey and Preplanning - Electrical Assessment; J.P. Dunlop
• Determine true South	Photovoltaic Systems; Chapter # 3/Page# 68; Site Survey and Preplanning - Magnetic declination; J.P. Dunlop
• Evaluate wall structure	PV Design & Installation man.; Chapter # 3/Page# 32-33; The Solar Resource - Orientation; S.E.I.; Home Power Magazine; Issue # 116/Page# 12-13; Ask the Experts: Finding True South; R. Perez
• Confirm existing roof tilt and orientation (pitch and azimuth)	Photovoltaic Systems; Chapter # 3/Pages# 66 - 70; Site Survey and Preplanning - Array Loc. / Equipment Loc.; J.P. Dunlop; Home Power Magazine; Issue # 137; Pages #74-80; Modern PV Roof Mounting; Rebekah Hren
• Confirm accuracy of site drawings	Photovoltaic Systems; Chapter # 3/Pages# 81; Site Survey and Preplanning - Site Layout Drawings; J.P. Dunlop
• Evaluate wind exposure	Photovoltaic Systems; Chapter # 10/Page# 271-272; J.P. Dunlop
• Evaluate soil conditions	Solar Pro Magazine; Issue # 3.4; Ground Mounted PV - Soil Properties; Charly Bray
• Confirm solar resource	Photovoltaic Systems; Chapter # 2/Pages# 33 - 53; Solar Radiation - Sun Path, Tilt angle, Azimuth Angle, Data sets; J.P. Dunlop; Home Power Magazine; Issue # 135/Page# 128; Irradiance & Insolation; E. Weliczko

3. Confirm System Sizing

• Arrange modules in mounting area	Solar Pro Magazine; Issue # 1.1; Pitched Roof Racking: Layout, Flashing & Sealing for the Life of the System; Steve Fain, David Brearley
• Determine topography of mounting area	
• Confirm utility/authority having jurisdiction (AHJ) restrictions	

Other references

• Maximize the incentives	Photovoltaic Systems; Chapter # 15/Pages# 394-395; Economic Analysis - Incentives; J.P. Dunlop
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4. Review Design of Energy Storage Systems

• Verify appropriate energy storage system location	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Verify ventilation requirements	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Verify circuit design for critical loads	
• Verify access requirements	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt

• Verify loads analysis	Photovoltaic Systems; Chapter # 9/Pgs# 233-240; System Sizing - Sizing Calc./ Load analy./Critical Design analysis; J.P. Dunlop; Solar Pro Magazine; Issue #3.3; Stand alone System Design - The art of load analysis; Phil Undercuffler
• Inspect existing wiring	NFPA 70 NEC; NEC Chapters 1 - 4; Understanding NEC Requirements for PV Systems; Mike Holt
• Identify multi-wire branch circuits	NFPA 70 NEC; Article 210; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm battery bank is appropriate to inverter requirements	Photovoltaic Systems; Chapter # 9/Pgs# 243 - 245; System Sizing - Battery Bank Sizing; J.P. Dunlop ; Home Power Magazine; Issue # 76/Pgs# 96-100; Measuring Energy Usage for Inverter & Battery Bank Sizing; M. Patton; Solar Pro Magazine; Issue # 3.1; Understanding and Optimizing Battery Temperature Compensation; Jim Goodnight; Solar Pro Magazine; Issue # 3.3; Optimizing Array Voltage for Battery-Based Systems; Jim Goodnight
• Confirm battery bank is appropriate to other charging sources	Photovoltaic Systems; Chapter # 7/Pgs# 195 - 199; Charge Controllers - Battery & array Size / Mult. Battery banks; J.P. Dunlop
• Confirm that battery technology is appropriate to usage	Photovoltaic Systems; Chapter # 6 / Pgs# 161 - 165; Batteries - Battery types / Battery Classifications / etc.; Photovoltaic Systems; Chapter # 9 / Pgs# 243 - 247; System Sizing - Battery Bank Rated Capacity / Battery Selection; J.P. Dunlop

5. Confirm String Size Calculations

• Confirm highest and lowest design temperature	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm module Voc at lowest design temperature	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm temperature corrected voltage	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm voltage limits of system	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 3.6; Array Voltage Considerations; Bill Brooks
• Configure appropriate string diagram	Photovoltaic Systems; Chapter # 9 / Pgs# 249 -252; System Sizing - Array Rate Output/Module Selection, J.P. Dunlop
• Determine Vpmax at highest design temperature	NFPA 70 NEC; Article 705; Understanding NEC Requirements for PV Systems; Mike Holt

Additional useful references

• Account for module degradation	Photovoltaic Systems; Chapter # 5 / Pgs# 141 - 144; Cells,Modules, and Arrays - Module Std.s / Performance ratings; Home Power Magazine; Issue # 140 / Page# 41; Ask the Experts: Module Degradation; J. Davidson
• Determine inverter MPPT	NFPA 70 NEC; Article 705; Understanding NEC Requirements for PV Systems; Mike Holt

6. Review System Component Selection

• Confirm component compatibility	
• Confirm the selected module mounting system is appropriate for the application	Photovoltaic Systems; Chapter # 10 / Pgs# 260 - 267; Mechanical Integration - Array Mounting Systems; J.P. Dunlop; Home Power Magazine, Issue # 124 / Pgs# 58-64, Rack & Stack - PV Array Mounting Options; R. Mayfield; Home Power Magazine; Issue # 130 / Pgs# 74-80; Pitched Roof Mounting; R. Hren; Home Power Magazine; Issue # 142 / Pgs# 80-85; PV Rack Strategies; G. McPheeters; Solar Pro Magazine; Issue # 3.2; Racking Equipment Guide; Ryan Mayfield, David Brearley; Solar Pro Magazine; Issue # 4.1; Tile Roofing Systems: Materials & Methods for Flashing Penetrations; Johan Alfsen
• Confirm the selected grounding method is appropriate for the application	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 1.1; Equipment Grounding Conductors: Sizing and Methods; Ryan Mayfield; Solar Pro Magazine; Issue # 2.5; PV System Ground Faults; Paul Mync, John Berdner
• Confirm the selected combiner boxes are appropriate for the application	Home Power Magazine; Issue # 78 / Pgs# 52-56; Build your own PV Combiner Box; D. Scanlin, Home Power Magazine, Issue # 132 / Pgs# 68-75, Combiner Boxes; L. Wilensky
• Confirm the number and type of inverters are appropriate for the application	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm the number and type of charge controllers are appropriate for the application	Photovoltaic Systems; Chapter # 7 / Pgs# 181-186; Charge Controllers - Charge Controller Types; J.P. Dunlop
• Confirm that all overcurrent protection devices are appropriate for the application	NFPA 70 NEC; Article 240; Mike Holt; Solar Pro Magazine; Issue # 3.6; Surge Protection Devices for PV Installations; Robert Schlesinger
• Confirm DC disconnect (s) are appropriate for the application	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm the AC disconnect(s) are appropriate for the application	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm maximum allowable number of unprotected parallel strings	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm GFP devices are appropriate for the application	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
<i>Additional useful references</i>	
• Match modules to inverters	Solar Pro Magazine; Issue # 1.1 ; Grid-Direct PV String Inverter Guide; David Brearley, Joe Schwartz; Solar Pro Magazine; Issue # 2.1; Array to Inverter Matching: Mastering Manual Design Calculations; John Berdner
• Determine number of strings	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Select string combiners	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 2.3; Strategies for Making Common Connections in PV Power Circuits; Tommy Jacoby, David Brearley; Solar Pro Magazine; Issue # 4.2; DC Combiners Revisited; Marvin Hamon

7. Review Wiring and Conduit Size Calculations

• Confirm conductor ampacity calculations	NFPA 70 NEC; Articles 240, 310, and 690; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 4.3; Code-Compliant Conductor Sizing; Jason Sharpe
• Confirm conduit fill calculations	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm conductor run distance	Photovoltaic Systems; Chapter # 11 / Pgs# 290 - 295; Electrical Integration - Conductor Ampacity/Voltage Drop; J.P. Dunlop
• Confirm appropriate conduit type(s)	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm appropriate conductor insulation type(s)	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm continuous current calculations	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm continuous load calculations	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm conditions of use calculations	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm temperature de-rate calculations	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm conductor de-rate calculations	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 4.3; Code-Compliant Conductor Sizing; Jason Sharpe
• Confirm voltage drop calculations	Basic Electrical Theory, Mike Holt; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 3.2; Voltage Drop in PV Systems; Blake Gleason
• Confirm power loss calculations	Basic Electrical Theory; Mike Holt; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm appropriate grounding conductor type(s)	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm circuit current calculations	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm conduit size calculations	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm grounding conductor sizing calculations	NFPA 70 NEC; Articles 250 and 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm thermal expansion calculations	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
<i>Additional useful references</i>	
• Determine environmental condition of conduit	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt

8. Review Overcurrent Protection Selection

• Confirm voltage specifications	NFPA 70 NEC, Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm compatibility with conductor size and type	NFPA 70 NEC; Article 240; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm circuit currents calculations	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm characteristics of existing electrical distribution system	NFPA 70 NEC; Chapter 1 - 4; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm selection of overcurrent protection device enclosures	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm equipment limits of overcurrent protection	NFPA 70 NEC; Article 240; Understanding NEC Requirements for PV Systems; Mike Holt; Solar Pro Magazine; Issue # 2.3; Load Side Point of Interconnection - Bus or Conductor Rating; John Wiles
• Confirm available fault currents	NFPA 70 NEC, Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm voltage compatibility	NFPA 70 NEC, Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm disconnecting means type	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm disconnecting means amperage rating	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm temperature rating of device	NFPA 70 NEC, Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm terminal temperature limits of device	NFPA 70 NEC, Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm enclosure rating of device	
• Confirm wire size limitations of device	NFPA 70 NEC; Article 310; Understanding NEC Requirements for PV Systems; Mike Holt
<i>Additional useful references</i>	
• Determine disconnecting means location	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt

9. Review Fastener Selection

• Confirm fastener sizes	Photovoltaic Systems; Chapter # 10 / Pgs# 274 - 277; Mechanical Integration - Attachment Methods - Lags/Bolts/J Bolt; J.P. Dunlop; Home Power Magazine; Issue # 100 / Pgs# 100-103; The Nuts and Bolts of Fasteners; M. Brown
• Confirm environmental conditions assessment	Solar Pro Magazine; Issue # 3.4; Lag Screws in Residential PV Installations Mark Shelly
• Confirm compatibility of fasteners to system	
• Confirm fastener types	Photovoltaic Systems; Chapter # 10 / Pgs# 274 - 277; Mechanical Integration - Lag Screw/Bolts/J-Bolts/Self Balasting; J.P. Dunlop; Solar Pro Magazine; Issue # 3.4; Lag Screws in Residential PV Installations; Mark Shelly

• Confirm pilot hole specifications	Solar Pro Magazine; Issue # 3.4 Page# 74; Lag Screws in Residential PV Installations; Mark Shelly; Home Power; Issue # 144 Page# 94-99; Prepping for PV; Johan Alfsen
• Confirm fastener assembly	Home Power Magazine; Issue # 144 Page# 94-99; Prepping for PV; Johan Alfsen
• Confirm structural characteristics of substrate	
• Confirm fastener pull-out strengths	
• Confirm fastener removal	
• Confirm mounting method	Solar Pro Magazine; Issue # 3.4; Lag Screws in Residential PV Installations; Mark Shelly; Solar Pro Magazine; Issue # 4.1; Tile Roofing Systems; Johan Alfsen; Home Power Magazine; Issue # 144 Page# 94-99; Prepping for PV; Johan Alfsen
• Confirm torque values	
• Confirm usage of appropriate auxiliary materials	
• Confirm weatherproofing materials for building penetrations	Solar Pro Magazine; Issue # 1.1; Pitched Roof Racking; S. Fain, D. Brearley; Solar Pro Magazine; Issue # 4.3; Low-Slope Roofs As PV System Platforms; James R. Kirby; Solar Pro Magazine; Issue # 4.1 Page# 62-68; Tile Roofing Systems; Johan Alfsen
• Confirm pull-out loads	Photovoltaic Systems; Chapter # 10 / Page# 274; Mechanical Integration - Allowable Withdrawl Loads; J.P. Dunlop
• Confirm wind loading	Photovoltaic Systems; Chapter # 10 / Page# 280 - 281; Mechanical Integration - Structural Analysis; J.P. Dunlop
• Confirm shear loads	
• Confirm shear strengths	
• Confirm types of loads	
• Confirm accuracy of bill of materials	

10. Review Plan Sets

• Confirm AHJ requirements	Photovoltaic Systems; Chapter # 12 / Pgs# 344 - 346; Utility Interconnection - Interconnect agreements, J.P. Dunlop
• Confirm accuracy of electrical one- or three-line diagram	
• Confirm accuracy of site plan	Solar Pro Magazine; Issue # 2.5; Project Plan Sets; Ryan Mayfield
• Confirm accuracy of system design	
• Generate a safety plan	Solar Pro Magazine; Issue # 4.6; Implementing a successful safety program; Karl Riedlinger
• Assemble manufacturer's data sheets	
• Create labeling schedule	Photovoltaic Systems; Chapter # 13 / Pgs# 363 - 366; Permitting and Inspection - Lables and Marking; J.P. Dunlop; Solar Pro Magazine; Issue # 4.2; PV System Labeling; NEC, OSHA and ANSI Codes and Standards; Gernon Harvey
• Assemble manufacturer's instructions	
• Note and address structural concerns	
• Complete commissioning forms	Solar Pro Magazine; Issue # 2.6; PV System Commissioning; Blake Gleason
• Generate string diagram	
<i>Additional useful references</i>	
• Clarify design and OEM manuals	Solar Pro Magazine; Issue # 3.3; Avoiding and Resolving PV Permitting Problems; Tobin Booth; Solar Pro Magazine; Issue # 4.1; PV Systems and Firefighter Safety: A Proactive Approach; Dan Fink

1. Conduct Pre-Construction Meetings

• Plan weather contingencies	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE
• Verify site conditions match design	Project Management for Construction: Fundamental Concepts for Owners, Engineers, Architects and Builders; Chris Hendrickson & Tung Au; 3.8 Construction Site Environment
• Assemble workforce, including other trades as appropriate	Electrical Pre-Construction Planning Process Implementation Manual; Section 4.2; Awad S. Hanna, Ph.D., PE
• Determine daily construction goals	Electrical Pre-Construction Planning Process Implementation Manual; Section 4.9; Awad S. Hanna, Ph.D., PE;
• Communicate construction strategy to customer	Electrical Pre-Construction Planning Process Implementation Manual; Section 6.3; Awad S. Hanna, Ph.D., PE;
• Provide customer orientation	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE
• Communicate target pull-off time for crew	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE
• Document safety plan	OSHA CFR 29 1926; Subpart C; SolarPro 4.6 Implementing a Successful Safety Plan; Karl Riedlinger; “Elements of a Successful Safety Program” Section
• Resolve scheduling conflicts	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE; Section 4.9
• Ensure pre-construction commitments by customer are complete	
• Determine community issues	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE
• Determine customer requirements	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE

2. Secure Permits and Approvals

• Coordinate inspections	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Schedule inspections	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Confirm job permits	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3; Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Resolve AHJ conflicts	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3; Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Submit plans to utilities	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13 p. 357-359; SolarPro 2.5 Project Plan Sets; Ryan Mayfield; “Purpose and Benefits” Section
• Resolve utility conflicts	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 12 p. 342-346; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Obtain sign-off final building permit	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth
• Determine additional agency permits (e.g., zoning, solar access, HOA, historic district)	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3; Avoiding and Resolving PV Permitting Problems; Tobin Booth; “Common Permitting Problems” Section

Additional useful references

	Taking the Red Tape out of Green Power: How to Overcome Permitting; Obstacles to Small-Scale Distributed Renewable Energy; Network for New Energy Choices, September 2008.
• Secure written record of approval to interconnect	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 12 p. 344-346
• Submit plans to building department	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 2.5 Project Plan Sets; Ryan Mayfield; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth; “Effective Solutions” Section
• Submit plans to fire department	Photovoltaic Systems, Second Edition, 2010; J.P. Dunlop; ch. 13; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth; “Effective Solutions” section; SolarPro 3.3 Avoiding and Resolving PV Permitting Problems; Tobin Booth; “Effective Solutions” Section

3. Manage Project Labor

• Coordinate with subcontractors	SolarPro 3.6; Operations Management for Solar Integrators; Darlene McCalmont; “Improving the Bottom Line” Section
• Determine order of tasks	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; C.3 Sequenced Project Schedules
• Allocate resources	SolarPro 3.6; Operations Management for Solar Integrators; Darlene McCalmont
• Supervise project crews	
• Communicate aspects of safety plan	SolarPro 4.6 Implementing a Successful Safety Plan; Karl Riedlinger; “Elements of a Successful Safety Program” Section
• Coordinate with other trades	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; A.1 Guideline on General Contractor-Subcontractor Relations
• Orient contractors to job site conditions	
• Track man hours	
• Conduct toolbox talks	
• Resolve disputes	

Additional useful references

• Confirm insurance compliance	SolarPro 3.4 Large-Scale PV Operations and Maintenance; Dave Williams; Section on “Insurance”
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4. Adapt System Design

• Identify potential conflicts in design	
• Document changes to proposed design	
• Maintain as-built documentation	SolarPro 3.6; Operations Management for Solar Integrators; Darlene McCalmont “Improving the Bottom Line” Section; SolarPro 2.6; PV System Commissioning; Blake Gleason; “Commissioning Tasks” Section
• Submit modification proposals	Electrical Pre-Construction Planning Process Implementation Manual; Awad S. Hanna, Ph.D., PE; Section 4.4
• Acquire approvals to change design	
• Submit any change orders	

5. Manage Project Equipment

• Take delivery of components	Project Management for Construction: Fundamental Concepts for Owners, Engineers, Architects and Builders; Chris Hendrickson & Tung Au
• Schedule deliveries	Project Management for Construction: Fundamental Concepts for Owners, Engineers, Architects and Builders; Chris Hendrickson & Tung Au
• Identify lifting and handling areas	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; C.4 Guideline on Site Logistics
• Perform equipment inspection	
• Perform equipment maintenance	
• State site equipment	
• Schedule machinery	Project Management for Construction: Fundamental Concepts for Owners, Engineers, Architects and Builders; Chris Hendrickson & Tung Au
• Ensure equipment operator certification	
• Install pedestrian barriers	
<i>Additional useful references</i>	
• Prepare site storage facilities	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; C.4 Guideline on Site Logistics
• Obtain temporary facilities	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; C.4 Guideline on Site Logistics
• Maintain temporary facilities	Guidelines for a Successful Construction Project; The Associated General Contractors of America, 2008; C.4 Guideline on Site Logistics

6. Implement a Site Specific Safety Plan

• Perform hazard analysis	SolarPro 4.6 Implementing a Successful Safety Plan; Karl Riedlinger “Elements of a Successful Safety Program” Section; Solar Construction Safety Oregon Solar Energy Energy Industries Association, 2006; “General Jobsite Safety” Section
• Identify job site hazards	SolarPro 4.6 Implementing a Successful Safety Plan; Karl Riedlinger; “Elements of a Successful Safety Program” Section; Solar Construction Safety; Oregon Solar Energy Energy Industries Association, 2006. “General Jobsite Safety” Section
• Implement ladder safety	OSHA CFR 29 1926; Subpart X; laddersafety.org; American Ladder Institute Solar Construction Safety; Oregon Solar Energy Energy Industries Association, 2006. “Ladder Safety” Section
• Implement fall protection plan	OSHA CFR 29 1926; Subpart M (1926.500 to 1926.503). Dunlop, Jim: Photovoltaic Systems, Second Edition, 2010, J.P. Dunlop, Ch. 3 p. 62-63; Solar Construction Safety; Oregon Solar Energy Energy Industries Association, 2006; “Fall Protection and Jobsite Trip Hazards” Section
• Execute electrical safety	OSHA CFR 29 1926; Subpart K; “NFPA 70E Electrical Safety in the Workplace”; NFPA; Solar Construction Safety; Oregon Solar Energy Energy Industries Association, 2006; “Solar Electrical Safety” Section
• Select personal protective equipment (PPE)	OSHA CFR 29 1926; Subpart E
• Develop site specific safety plan	OSHA CFR 29 1926; Subpart C; The Importance of Site Specific Safety and Health Management Plans; Garcia, Gabe. 2010; SolarPro 4.6 Implementing a Successful Safety Plan; Karl Riedlinger

• Implement vehicle safety	OSHA CFR 29 1926; Subpart O
• Install site safety barriers	OSHA CFR 29 1926; Subpart M
• Identify access points to site	
• Identify site evacuation points	OSHA CFR 29 1926; Subpart P; Emergency Exit Routes Fact Sheet; OSHA, 2003
• Post hospital map routes	
• Post emergency contact numbers	
• Ensure material safety data sheets (MSDS) are on-site	OSHA CFR 29 1926; 1910.1200(g)
• Post contingency plan	

1. Mitigate Electrical Hazards

• Implement the site safety plan	
• Implement the lock-out, tag-out procedures	
• Determine voltage levels of interconnections	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Maintain clear work area	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Clarify the maximum working voltage	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Select required PPE based on system design (arc flash, shock, burn, voltage, etc.)	
• Disconnect all unnecessary live circuits	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Determine working clearances	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Demonstrate situational awareness	
• Measure voltage on equipment before proceeding with work	
• Inspect safety equipment	
• Inspect test equipment	
• Maintain safety equipment	
• Inspect hand and power tools	
• Measure current on equipment before proceeding with work	
• Maintain hand and power tools	

2. Install Grounding Systems

• Install module grounding	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install inverter grounding	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install mounting system grounding	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Ground all noncurrent-carrying metal parts	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Bond metallic raceways	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Install grounding electrode conductor	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Bond all electrical equipment	NFPA 70 NEC; Article 250 and 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Apply antioxidant material	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Prepare surfaces for electrical connections	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Make grounding electrode connection	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt

• Install grounding electrode(s)	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Install supplementary ground electrode	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Install system grounds	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Determine grounding conductor size	NFPA 70 NEC; Article 250 and 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install DC ground-fault protection	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Locate underground hazards	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt

3. Install Conduit and Raceways

• Plan conduit routing	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Penetrate building envelope	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Support and secure conduit	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Tighten all fittings	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Select fittings according to application	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Install above ground electrical raceways	NFPA 70 NEC; Article 225; Understanding NEC Requirements for PV Systems; Mike Holt
• Install conduit bushings	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Make knockouts in electrical raceways	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Install underground electrical raceways	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Remove sharp edges (deburr)	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Install service entry mast	NFPA 70 NEC; Article 230; Understanding NEC Requirements for PV Systems; Mike Holt
• Locate underground utilities	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Create underground trenches	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Backfill underground trenches	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Mark underground cables	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Mark underground trenches	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt

4. Install Electrical Components

• Select location of DC disconnect	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Mount electrical enclosures	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Install DC combiner	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Label equipment	NFPA 70 NEC; Article 690 and 705; Understanding NEC Requirements for PV Systems; Mike Holt
• Install PV system disconnects	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install inverter disconnects	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install utility required disconnects	NFPA 70 NEC; Article 404; Understanding NEC Requirements for PV Systems; Mike Holt
• Install array wiring transition box	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Install inverter	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Install underground electrical components	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Install AC combiner	NFPA 70 NEC; Article 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install meter bases	NFPA 70 NEC; Article 312; Understanding NEC Requirements for PV Systems; Mike Holt
• Select label materials	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Install junction boxes in the attic	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt

5. Install Circuit Conductors

• Pull conductors	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Label conductors	NFPA 70 NEC; Article 690 and 705; Understanding NEC Requirements for PV Systems; Mike Holt
• Terminate conductors	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Wire the inverter	NFPA 70 NEC; Articles 110, 300, 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Wire modules	NFPA 70 NEC; Articles 110, 300, 310; Understanding NEC Requirements for PV Systems; Mike Holt
• Select the correct wire type, color, and gauge	NFPA 70 NEC; Table 310.104, 200.6, Table 310.15(B); Understanding NEC Requirements for PV Systems; Mike Holt
• Secure conductors	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt

• Measure wires	
• Set up the wire installation (tugger, fish tape, rope)	
• Test conductor installation	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Test DC source circuits	
• Test DC currents	
• Set up pull stations	NFPA 70 NEC; Chapter 3; Understanding NEC Requirements for PV Systems; Mike Holt
• Clear the electrical raceway	
• Splice electrical conductors	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt

6. Install Utility Interconnection

• Install over current protection device (OCPD)	NFPA 70 NEC; Article 240; Understanding NEC Requirements for PV Systems; Mike Holt
• Install disconnects	NFPA 70 NEC; Article 404; Understanding NEC Requirements for PV Systems; Mike Holt
• Test utility voltage	
• Coordinate AHJ inspection	
• Verify fill rates	
• Terminate conductors	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Implement lock-out, tag-out procedures	
• Evaluate existing service entrance equipment	NFPA 70 NEC; Article 230; Understanding NEC Requirements for PV Systems; Mike Holt
• Install generation metering	NFPA 70 NEC; Article 312; Understanding NEC Requirements for PV Systems; Mike Holt
• Test conductor insulation	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt
• Select connection location	
• Coordinate utility shutdowns	
• Coordinate with customers and other regarding shutdowns	
• Move existing circuits	NFPA 70 NEC; NFPA 70E; Understanding NEC Requirements for PV Systems; Mike Holt

7. Install System Instrumentation

• Test system	
• Install power and energy metering	NFPA 70 NEC; Articles 312; Understanding NEC Requirements for PV Systems; Mike Holt
• Install data communication cables	NFPA 70 NEC; Article 800; Understanding NEC Requirements for PV Systems; Mike Holt
• Install communication systems	NFPA 70 NEC; Article 800; Understanding NEC Requirements for PV Systems; Mike Holt
• Install environmental sensors	
• Install controllers	

• Install electrical sensors	
• Install inverter interface	
• Install power supply	
• Install battery temperature sensors	
• Install outlet for monitoring system	NFPA 70 NEC; Chapters 1 - 4; Understanding NEC Requirements for PV Systems; Mike Holt

8. Install Battery Components

• Test each unit before placement (voltage, specific gravity, polarity)	
• Terminate fine stranded cables	NFPA 70 NEC; Articles 110 and 690; Understanding NEC Requirements for PV Systems; Mike Holt
• Install maintenance disconnect	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Confirm battery bank location	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Install battery enclosure	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Install battery enclosure venting	
• Install battery spill containment	
• Install batteries	
• Prepare battery terminals (e.g., clean)	
• Install battery interconnection conductors	
• Install battery units	
• Apply antioxidant compounds	
• Calculate ampacity	NFPA 70 NEC; Article 480; Understanding NEC Requirements for PV Systems; Mike Holt
• Install charge controller	
• Seal conduit entry to battery box	
• Label battery units	
• Label battery enclosure	
• Label battery room	
• Establish maintenance schedule	
• Test final assembled battery polarity and voltage	
• Install safety station	

1. Install Equipment Foundation

• Locate center points of holes	Concrete Principles; Chapter 5 page 136; Thomas P. Fahl
• Place anchor hardware	
• Install grounding equipment conductor (GEC)	NFPA 70 NEC; Article 250; Understanding NEC Requirements for PV Systems; Mike Holt
• Excavate to design specifications	Concrete Principles; Chapter 10 page 293; Thomas P. Fahl
• Build concrete forms	Concrete Principles; Chapter 4 page 98; Thomas P. Fahl
• Coordinate foundation inspections	See Local Jurisdiction (City or County) Development Services
• Identify location of underground utilities	www.callbeforeyoudig.com, www.bluestake.com
• Add structural reinforcement	Concrete Principles; Chapter 4 page 93; Thomas P. Fahl
• Install wire raceways	NECA 101-2006 Standard for Installing Steel Conduit (Rigid, IMC, EMT) (ANSI) Published 2006
• Place concrete to design specifications	Concrete Principles; Chapter 7 page 182; Thomas P. Fahl
• Place anchor hardware	Geotechnical Engineering Foundation Design; page 210; John N. Cernica
• Install driven posts	Concrete Principles; Chapter 5 page 119; ; Thomas P. Fahl; Installation specification for Driven Piles PDCA Specification; 103-07; Pile Driving Contractors Association
• Strip concrete forms	Concrete Principles; Chapter 7 page 197; Thomas P. Fahl
• Backfill excavation	Geotechnical Engineering Foundation Design; page 150; John N. Cernica
• Place mounting posts	Concrete Principles; Chapter 5 page 136; Thomas P. Fahl; Ground Trac Installation Manual; Professional Solar Products

2. Install Mounting System

• Install roof attachments	Installing Solar Power; Gary Gerber; Journal of Light construction, Article
• Weatherproof penetrations	Sealing and flashing metal roofs; Rob Haddock; Journal of Light construction, Article
• Locate structural roof members	SolarWedge XD Installation Manual; Professional Solar Products; Page 3
• Determine array attachment locations	SolarWedge XD Installation Manual; Professional Solar Products; Page 3
• Install structural attachments	SolarWedge XD Installation Manual; Professional Solar Products; Page 4
• Install module support frame	RoofTrac Installation Manual; Professional Solar Products
• Install rack components	RoofTrac Installation Manual; Professional Solar Products
• Locate array footprint	RoofTrac Installation Manual; Professional Solar Products
• Confirm compatibility with existing roofing system	Roofing Instant Answers; ISBN: 0071387129; Terry Kennedy
• Plumb array structure	Ground Trac Installation Manual; Professional Solar Products
• Level array structure	Point to Point Lasers; David Frane; Journal of Light construction, Article Ground Trac Installation Manual; Professional Solar Products
• Apply corrosion protection to cut surfaces	NECA 101-2006 Standard for Installing Steel Conduit (Rigid, IMC, EMT) (ANSI); Published 2006
• Install tracking apparatus	wattsun.com, Installation Guide AZ-225; Array Technologies; Pg. 6 zomeworks.com, Zomeworks F-series Track Rack installation manual; zomeworks
• Install actuator motors	wattsun.com, Installation Guide AZ-225; Array Technologies, Pg. 9
• Install supplementary structural supports	ewpa.com
• Confirm row spacing	Renewable and Efficient Electric Power Systems; pg. 391 - 408; Gilbert M. Masters

• Confirm structural analysis has been performed	Should I Call an Engineer; Harris Hyman; Journal of Light construction, Article
• Install structural members	Framing Flaws; Donald Cohen; Journal of Light construction, Article
• Locate ballast for mounting system	See Racking Manufacturer.
• Install seismic and wind loading	Special Design Provisions for Wind and Seismic (SDPWS), 2005 Edition, with Commentary American Wood Council

3. Install PV Modules

• Unpack PV modules	
• Stage PV modules	
• Secure module wiring	NFPA 70 NEC; Article 300; Understanding NEC Requirements for PV Systems; Mike Holt
• Inspect module for physical damage	
• Fasten modules to structure	
• Torque module fasteners	
• Confirm module frame grounding	
• Align modules aesthetically	
• Determine project workflow	
• Test PV modules	
• Prep PV modules	

1. Test the System

• Verify mechanical connection integrity	Field Inspection Guidelines for PV Systems; Section 1-e, Section 2-a, and Section 2-d; Inspector Guidelines for PV Systems, Version 2.1, March 2006 Brooks Engineering; Section: Inspection Guidelines for all PV systems; A Guide to Photovoltaic (PV) Design and Installation, June 2001; California Energy Commission (CEC); Section 4: Solar Electric (PV) System Installation Checklist
• Verify system grounding	NFPA 70 NEC; Article 690.41; Understanding NEC Requirements for PV Systems; Mike Holt
• Verify electrical connection torque	NFPA 70 NEC; Article 110; Understanding NEC Requirements for PV Systems; Mike Holt; Article 110.3(B); SUNNY BOY 8000TL-US/9000TL-US/10000TL-US - Installation Guide version 1.1; SMA; Section 6.5.2, Section 6.5.3, Section 6.6.2
• Verify polarity	Photovoltaic Systems, Second Edition, 2010; Chapter 14; Commissioning, Maintenance, and Troubleshooting; J.P. Dunlop A Guide to Photovoltaic (PV) Design and Installation, June 2001; California Energy Commission (CEC) Section 4: Solar Electric (PV) System Installation Checklist; “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section: 5.4.3
• Measure DC voltages (string, output)	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 5.4.4; A Guide to Photovoltaic (PV) Design and Installation, June 2001; California Energy Commission (CEC); Section 4: Solar Electric (PV) System Installation Checklist
• Verify inverter operation	Inverter Manufacturer’s Instructional Manual; “Grid connected photovoltaic systems – Minimum requirements for system; documentation, commissioning tests and inspection, Edition 1.0, 2009-05”, IEC, Section 5.4.6, A Guide to Photovoltaic (PV) Design and Installation, June 2001; California Energy Commission (CEC); Section 4: Solar Electric (PV) System Installation Checklist
• Measure DC currents	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 5.4.5
• Compare measured values with expected values	SP2.6-34 PV System Commissioning; Section: Performance Verification; Blake Gleason; “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 5
• Measure AC system values	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05” IEC; Section 5.4.1
• Perform physical inspection	Field Inspection Guidelines for PV Systems; Inspector Guidelines for PV Systems, Version 2.1, March 2006; Brooks Engineering; Section: Inspection Guidelines for all PV systems; A Guide to Photovoltaic (PV) Design and Installation, June 2001 California Energy Commission (CEC); Section 4: Solar Electric (PV) System Installation Checklist
• Verify conduit fitting tightness	NFPA 70 NEC; Article 110.3(B), Article 110.12
• Verify conduit and wiring supports	Field Inspection Guidelines for PV Systems; Section 1-b, Section 1-e; NFPA 70 NEC; Chapter 3
• Verify workmanship	NFPA 70 NEC; Article 110.12

• Measure environmental levels	SP2.6-34 PV System Commissioning; Section: Expected Performance; Blake Gleason
• Measure irradiance levels	SP2.6-34 PV System Commissioning; Section: Expected Performance; Blake Gleason
• Calculate expected electrical parameters	NFPA 70 NEC; Article 690; SP3.6-68 Array Voltage Considerations; Bill Brooks Expedited Permit Process (www.solarabcs.org OR www.brooksolar.com); Brooks Engineering; Section 5, Section 6, Section 7
• Verify anti-islanding system	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Annex C, Model PV array test report
• Test for ground fault	SP2.5-60 PV System Ground Faults; Mync & Berdner
• Measure insulation resistance	SP2.5-66 PV System Ground Faults, Mync & Berdner, Insulation Resistance Testing - Application Note Fluke http://support.fluke.com/find-sales/Download/Asset/1579160_6115_ENG_C_W.PDF ; “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 5.4.7
• Measure environmental levels	
• Confirm phase rotation	Satcon Installation Manual - PowerGate Plus 100; Satcon

2. Commission the System

• Turn on system	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting; J.P. Dunlop; A Guide to Photovoltaic (PV) Design and Installation, June 2001, California Energy Commission (CEC); Section 4: Solar Electric (PV) System Installation Checklist; SUNNY BOY 8000TL-US / 9000TL-US / 10000TL-US - Installation Guide version 1.1; SMA Section 7
• Initiate startup procedures per manufacturer instructions	Photovoltaic Systems, Second Edition, 2010; Chapter 14; Commissioning, Maintenance, and Troubleshooting; J.P. Dunlop; Satcon Installation Manual - PowerGate Plus 100; Satcon; SUNNY BOY 8000TL-US / 9000TL-US / 10000TL-US - Installation Guide version 1.1; SMA; Section 7
• Program variable set points	Inverter Manufacturer’s Instructional Manual; Outback Power GTFX and GVFX Inverter/Charger Programming Manual
• Measure all electrical parameters	Photovoltaic Systems, Second Edition, 2010, Chapter 14, Commissioning, Maintenance, and Troubleshooting - Measured Parameters; J.P. Dunlop; SP2.6-34 PV System Commissioning, Blake Gleason; Section: Expected Performance; “Grid connected photovoltaic systems – Minimum requirements for system; documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section: 5.4
• Compare measured values to expected values	SP2.6-34 PV System Commissioning; Section: Performance Verificaiton “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; Blake Gleason; IEC; Section: 5.4.5.3
• Monitor startup process	SUNNY BOY 8000TL-US / 9000TL-US / 10000TL-US - Installation Guide version 1.1, SMA, Section 7
• Record anomalous conditions	SP2.6-34 PV System Commissioning; Section: Commissioning Tasks; Blake Gleason
• Document design changes	Field Inspection Guidelines for PV Systems; Section 1-a; SP2.6-34 PV System Commissioning; Section: Commissioning Tasks; Blake Gleason
• Verify as-built documentation	Field Inspection Guidelines for PV Systems; Section 1-a; SP2.6-34 PV System Commissioning; Section: Commissioning Tasks; Blake Gleason

• Verify labeling accuracy	NFPA 70 NEC; Articles 690 and 705; Field Inspection Guidelines for PV Systems Section 3; Brooks Engineering
• Note data and time of system startup	Maintenance and Operation of Stand-Alone Photovoltaic Systems, December 1991 Section: 3.0 Inspection; SolarPro_2009_PV_Commissioning_Form; SolarPro
• Repair anomalous conditions	
• Record environmental conditions	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Measured Parameters; J.P. Dunlop; SP2.6-34; PV System Commissioning; Section: Expected Performance; Blake Gleason
• Record prior values on inverter	
• Measure voltage of energy storage system	Maintenance and Operation of Stand-Alone Photovoltaic Systems, December 1991; Section: 3.0 Inspection
• Verify calculation of Total Solar Resource Fraction	http://energytrust.org/trade-ally/programs/solar/resources/ ; Energy Trust of Oregon Solar Resource Tools; Solar Site Assessment: http://www.oregon.gov/ENERGY/RENEW/Solar/docs/SunChart.pdf?ga=t ; State of Oregon
• Verify polarity of energy storage system	Maintenance and Operation of Stand-Alone Photovoltaic Systems, December 1991 Section: 3.0 Inspection; Photovoltaic Systems, Second Edition, 2010 Chapter 14, Commissioning, Maintenance, and Troubleshooting; J.P. Dunlop
• Verify anti-islanding performance	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Annex C, Model PV array test report
• Record voltage of energy storage system	Maintenance and Operation of Stand-Alone Photovoltaic Systems, December 1991 Section: 3.0 Inspection

3. Complete System Documentation

• File project photographs	SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
• Record component serial numbers	SolarPro_2009_PV_Commissioning_Form; SolarPro; SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
• Deliver as-built documents	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection; Edition 1.0, 2009-05” IEC; Section 4, SP3.6-82 Operations Management for Solar Integrators; Darlene McCalmont; Section: Process Management
• File permits	Photovoltaic Systems, Second Edition, 2010; Chapter 13, Permitting and Inspection; J.P. Dunlop; SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
• Record certificates of inspection	
• File inspection forms	SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
• File commissioning forms	SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
• File data sheets	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 4.4
• File proof of system test results	“Grid connected photovoltaic systems – Minimum requirements for system; documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 4.7

• Complete equipment warranty registration	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Complete installation warranty registration	Photovoltaic Systems, Second Edition, 2010, Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop

Additional useful references

• Complete O&M documentation	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Maintenance; J.P. Dunlop; “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 4.6; SP3.4-48 Large-Scale PV Operations & Maintenance
• Compile customer operations manual	“Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 4.6; SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont

4. Orient Customer to System

• Explain startup and shutdown procedures	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Answer customer questions	
• Explain safety procedures to customer	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Explain maintenance procedures	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Address customer concerns	
• Train customer on maintenance and operation procedures	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Explain equipment clearance requirements	NFPA 70 NEC; Article 110; Photovoltaic Systems, Second Edition, 2010; Chapter 13, Permitting and Inspection - Inspection; J.P. Dunlop
• Perform customer walk-through	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop
• Provide contact information to customer	
• Explain normal operational performance	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop

Additional useful references

• Deliver O&M documentation to customer	Photovoltaic Systems, Second Edition, 2010; Chapter 14, Commissioning, Maintenance, and Troubleshooting - Commissioning; J.P. Dunlop; “Grid connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection, Edition 1.0, 2009-05”; IEC; Section 4.6; SP3.6-82 Operations Management for Solar Integrators; Section: Process Management; Darlene McCalmont
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1. Perform Visual Inspection

• Verify equipment grounding	NFPA 70 NEC; Article 690.43; Photovoltaic Systems 2nd ed., Chapter 11 pgs. 311-313; J.P. Dunlop; IAEI NEWS; “Connecting to Mother Earth, May/June 2010”; John Wiles
• Inspect module mounting system	Mounting System Safety and Installation Instructions; Unique to each manufacturer; Field Inspection Guidelines for PV Systems v1.1 June 2010; Section 1e, 2a,2d IREC/ B. Brooks
• Identify hazards	NFPA 70E NEC; Chapter 1; OSHA
• Inspect weatherproofing systems	Weatherproofing/Flashing System Safety and Installation Instructions; Unique to each manufacturer; Field Inspection Guidelines for PV Systems v1.1 June 2010; Section 1e, 2d; IREC/ B. Brooks; The NRCA Waterproofing Manual; http://www.nrca.net
• Inspect for wiring damage	NFPA 70E NEC; Article 100-250; Field Inspection Guidelines for PV Systems v1.1 June 2010; Section 1b; IREC/ B. Brooks
• Inspect module integrity	NFPA 70E NEC; Chapter 1; PV Module listed Safety and Installation Instructions Unique to each manufacturer; Photovoltaic Systems 2nd ed.; Chapter 14 pg. 374-6; J.P. Dunlop
• Check inverter status	Inverter Installation and Operation Manual; Unique to each manufacturer Photovoltaic Systems 2nd ed.; Chapter 14 pg. 385; J.P. Dunlop
• Inspect electrical equipment	NFPA 70 NEC; Chapter 1-4, Article 690; Understanding NEC Requirements for PV Systems; Mike Holt; Photovoltaic Systems 2nd ed.; Chapter 13; J.P. Dunlop; NFPA 70E NEC; Article 100-250
• Identify damage due to corrosion	Photovoltaic Systems 2nd ed., Chapter 14 pg. 374; J.P. Dunlop
• Identify array shading	Photovoltaic Systems 2nd ed.; Chapter 3 pg. 69-77; J.P. Dunlop
	Home Power Magazine; Issue# 121 / Pgs# 88-90: Solmetric Suneye Solar Site Evaluation tool; J. Schwartz
• Identify array soiling	PV Module listed Safety and Installation Instructions; Unique to each manufacturer; Photovoltaic Systems 2nd ed.; Chapter 14 pg. 373; J.P. Dunlop
• Inspect cells for discoloration	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 374-6; J.P. Dunlop PV Module datasheet; Unique to each manufacturer
• Verify grounding system integrity	NFPA 70 NEC; Article 690.41; Understanding NEC Requirements for PV Systems; Chapter 6; Mike Holt; Photovoltaic Systems 2nd ed.; Chapter 13 pg. 362-363; J.P. Dunlop
• Look for unsupported wiring	NFPA 70 NEC; Articles 110, 300, 310, 338, 690; Field Inspection Guidelines for PV Systems v1.1 June 2010; Section 1b; IREC/ B. Brooks; Understanding NEC Requirements for PV Systems; Mike Holt
• Identify damage to module glazing	Photovoltaic Systems 2nd ed., Chapter 14 pg. 374-6; J.P. Dunlop
• Document findings	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 390; J.P. Dunlop
• Identify mismatched equipment	System Labels, Manuals, As-built documents; Equipment and Job specific Field Inspection Guidelines for PV Systems v1.1 June 2010; Section 4; IREC/ B. Brooks; Solar Pro Magazine; “Array to Inverter Matching: Mastering Manual Design Calculations, Dec/Jan 2009 (Issue 2.1)””; J. Berdner
• Inspect for working clearances	NFPA 70 NEC; Article 110.26; Understanding NEC Requirements for PV Systems Chapter 1; Inverter Installation and Operation Manual; Unique to each manufacturer; Mike Holt

• Identify electrical connections damage due to overheating	“Tests and measurements for electrical fire prevention”; Fluke “Application Note http://www.fluke.com/fluke/user/community/fluke-news-plus/articlecategories/safety/electrical+fire+prevention.htm ”
• Confirm equipment serial numbers	As-built Documents; Job specific
• Inspect module back skin	PV Module listed Safety and Installation Instructions; Unique to each manufacturer
• Check conduit fitting tightness	NFPA 70 NEC; Chapter 3
• Inspect for evidence of animals	Solar Pro Magazine, J. Berdner, P. Mync, PV System Ground Faults, Aug/Sep 2009 (Issue 2.5)
• Identify vegetation growth	
• Identify water ponding	
• Identify ice damage	

2. Verify System Operation

• Measure system electrical parameters	NFPA 70E NEC; Article 100-250; Solar Pro Magazine; “PV System Commissioning” Oct/Nov 2009; B. Gleason
• Document found electrical parameters	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 390; J.P. Dunlop
• Calculate expected electrical parameters	Solar Pro Magazine; “PV System Commissioning” Oct/Nov 2009; B. Gleason
• Compare expected parameters with as-found parameters	Solar Pro Magazine; “PV System Commissioning” Oct/Nov 2009; B. Gleason
• Note anomalous conditions	
• Test system electrical equipment operations	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Recommend corrective actions	
• Verify source circuits are connected	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Interview customer	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Document customer’s concerns	
• Compare historical kWh performance against expected kWh performance	Solar Pro Magazine; “PV System Commissioning” Oct/Nov 2009; B. Gleason
• Measure equipment temperatures	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Note inter-annual weather variability	
• Measure terminal temperatures	NFPA 70E NEC; Article 100-250; Standard for Infrared Inspection of Electrical Systems & Rotating Equipment; Infrasppection Institute, 425 Ellis Street, Burlington, NJ 08016 http://www.infrasppection.com/useful_guidelines.html Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Verify operation of battery venting systems	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop
• Verify battery auxiliary systems	Photovoltaic Systems 2nd ed.; Chapter 14; J.P. Dunlop

3. Perform Corrective Actions

• Replace defective modules	
• Check equipment variable set points	Original System Labels, O&M Manual, As-built documents; Job Specific Equipment Installation and Operation Manuals; Unique to each manufacturer
• Perform scheduled maintenance	Owners and Operations Manual; Job Specific
• Replace frayed wires	NFPA 70E NEC; Article 100-250; American Electricians’ Handbook, Division 2, 8, 9
• Replace blown fuses	NFPA 70E NEC; Article 100-130, 225; Equipment Installation and Operation Manual; Unique to each manufacturer

• Replace faulty components	NFPA 70E NEC; Article 100-250; Equipment Installation and Operation Manual Unique to each manufacturer
• Locate ground faults	NFPA 70E NEC; Article 100-250; Solar Pro Magazine; PV System Ground Faults, Aug/Sep 2009 (Issue 2.5); J. Berdner, P. Mync
• Repair ground faults	NFPA 70E NEC; Article 100-250; Solar Pro Magazine; The Bakersfield Fire: A Lesson in Ground-Fault Protection, Feb/Mar 2011 (Issue 4.2); B. Brooks
• Locate line to line faults	NFPA 70E NEC; Article 100-250
• Repair line to line faults	NFPA 70E NEC; Article 100-250
• Document corrective actions	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 390; J.P. Dunlop
• Clean arrays	PV Module listed Safety and Installation Instructions; Unique to each manufacturer
• Service ventilation systems	NFPA 70E NEC; Article 240, 300-320; Home Power Magazine; John Meyer, Joe Schwartz; Battery Box Basics, John Meyer, Joe Schwartz, Jun/Jul 2007 (#119) pp. 50-55; Photovoltaic Systems 2nd ed.; Photovoltaic Systems 2nd ed.; Chapter 14; J.P. Dunlop
• Clean batteries	NFPA 70E NEC; Article 240, 300-320; Home Power Magazine; Flooded Lead-Acid Battery Maintenance, Dec/Jan 2004 (#98) pp. 76-79; Richard Perez
• Recalibrate equipment variable set points	Equipment Installation and Operation Manuals; Unique to each manufacturer Original System Labels, O&M Manual, As-built documents; Job Specific
• Wipe down power conditioning equipment	
• Clean heat sinks	Inverter Installation and Operation Manual; Unique to each manufacturer
• Schedule manufacturer onsite service call	
• Seal compromised weatherproofing systems	The NRCA Waterproofing Manual; NRCA; http://www.nrca.net ; Roof manufacturer's maintenance and warranty requirements; Manufacturer specific
• Perform battery maintenance	NFPA 70E NEC; Article 240, 300-320; Photovoltaic Systems 2nd ed.; Chapter 14 pg. 376-380; J.P. Dunlop
• Perform controlled overcharge	Home Power Magazine; Flooded Lead-Acid Battery Maintenance, Dec/Jan 2004 (#98) pp. 76-79; Richard Perez
• Clean system labeling	
• Replace system labeling	NFPA 70 NEC; Articles 690 and 705; Photovoltaic Systems 2nd ed.; Chapter 13 pg. 363-366; J.P. Dunlop; Original System Labels, Manuals, As-built documents Equipment and Job specific

4. Verify Effectiveness of Corrective Actions

• Retest system operations	Solar Pro Magazine; "PV System Commissioning" Oct/Nov 2009; B. Gleason
• Retest electrical parameters	Solar Pro Magazine; "PV System Commissioning" Oct/Nov 2009; B. Gleason
• Retest environmental conditions	Solar Pro Magazine; "PV System Commissioning" Oct/Nov 2009; B. Gleason
• Compare pre-maintenance values to post-maintenance values	
• Retest weatherproofing system	The NRCA Waterproofing Manual; NRCA http://www.nrca.net ; Roofing/flashing system installation and maintenance manuals; Manufacturer specific
• Reorient customer to system	Photovoltaic Systems 2nd ed.; Chapter 14 pg. 372; J.P. Dunlop

NABCEP

PV Installer Certification Eligibility Requirements

This document sets forth the eligibility requirements for the NABCEP PV Installer Certification as revised and approved by the Directors of the North American Board of Certified Energy Practitioners (NABCEP) on December 12, 2011. The following requirements will apply to all applications to sit for NABCEP PV Installer Exam received by NABCEP **after January 13, 2012**. Candidates that have been accepted to sit for the exam under the previous requirements will have until September 2013 to complete and pass the exam without having to re-apply using the new requirements.

The table below summarizes the Installation and Education Requirements for the NABCEP Certified PV Installer Exam. Following the table are the complete requirements.

Requirements for all applicants	Be at least 18 years of age and Document a minimum of 10 hours of OSHA approved Construction Industry safety training by presenting a 10 OSHA card (or state or provincial equivalent).		
Track	Who	Installation Experience	Education
A	Any PV Installer	Five (5) PV Systems	58 Hours
B	An existing licensed contractor in good standing in solar or electrical construction-related areas	Three (3) PV Systems	
C	Someone with four (4) years of electrical construction-related experience working for a licensed contractor (includes licensee or owner/operator)		
D	Someone with three (3) years experience in a U.S. Dept. of Labor-approved electrical construction trade apprentice program		
E	Holder of a two (2) or four (4) year electrical construction-related, electrical engineering technology, renewable energy technology/technician degree, or a four (4) year degree in mechanical, structural or civil engineering		

Solar PV Installer Certification Requirements

Eligibility Requirements for the Solar PV Installer Certification

To become certified and maintain certification, the applicant must minimally

- Be at least 18 years of age
- Meet prerequisites of related experience and/or education as outlined in Section 1.2 below
- Complete an application form documenting requirements
- Sign and agree to uphold a code of ethics
- Pay application and exam fee
- Pass a written exam
- Complete continuing education and installation requirements within the recertification timeframe

Qualifications for the Solar PV Installer Certification Examination

To qualify to sit for the NABCEP PV Installer Certification Examination, every applicant will need to provide documentation as defined in sections 1.6 to 1.10 to demonstrate

- 1) A minimum of 10 hours of OSHA approved Construction Industry safety training by presenting a 10 OSHA card (or state or provincial equivalent) **AND**
- 2) That he/she meets at least **one** of the following minimum entry requirement tracks:
 - A. Track A
 - i. Completion of 58 cumulative hours of training as defined in section 1.5 below; **AND**
 - ii. Installation of five (5) PV systems in compliance with the requirements of section 1.4 below;

OR

B. Track B

- i. Licensure as a contractor in good standing in solar or electrical construction-related areas; **AND**
- ii. Installation of three (3) PV systems in compliance with section 1.4 below; **AND**
- iii. Completion of 58 cumulative hours of training as defined in section 1.5 below;

OR

continued

NABCEP PV Installer Certification Eligibility Requirements - page 3

C. Track C

- i. Four (4) years of electrical construction-related experience working for a licensed contractor; **AND**
- ii. Installation of three (3) PV systems in compliance with section 1.4 below; **AND**
- iii. Completion of 58 cumulative hours of training as defined in section 1.5 below;

OR

D. Track 3

- i. Three (3) years experience in a U.S. Dept. of Labor-approved electrical construction trade apprenticeship program **AND**
- ii. Installation of three (3) PV systems in compliance with section 1.4 below **AND**
- iii. Completion of 58 cumulative hours of training as defined in section 1.5 below. *NOTE:* training does not need to be in addition to apprenticeship training coursework if requirements of Section 1.5 are met within the curriculum;

OR

E. Track 4

- i. Two (2) or four (4) year degree in a field related to electrical construction, electrical engineering technology, or renewable energy technology; **OR**
- ii. Four (4) year degree in a field related to mechanical, structural, or civil engineering technology; **AND**
- iii. Installation of three (3) PV systems in compliance with section 1.4 below; **AND**
- iv. Completion of 58 cumulative hours of training as defined in section 1.5 below. *NOTE:* training does not need to be in addition to degree coursework if requirements of Section 1.5 are met within the curriculum.

OSHA 10 Hour Requirements

All applicants must show proof of completion of an OSHA 10 Hour Construction Industry class or its equivalent. To find an OSHA class near you, go to (www.osha.gov/dte/outreach/courses.html)

NOTE: NABCEP strongly recommends the completion of an OSHA 30 Hour Construction Industry course. OSHA states that “the 10-hour class is intended for entry level workers” and “the 30-hour class is more appropriate for supervisors or workers with some safety responsibility.” *Additional note:* 18 out of the 20 additional hours of training in the 30-hour class may be applied to the 58 hour training qualification requirements in all Tracks as described in section 1.5.1.d

continued

Solar PV Installation Requirements

Installation and System Requirements

The applicant shall perform the role of the individual responsible for the installation of the solar PV systems as the foreman, supervisor, site manager, or experienced worker performing all aspects of PV installation work **without direct supervision**. Please see Section 1.7 on how to document experience.

Systems submitted with the application must meet the following minimum criteria:

- All installations must have occurred within the two calendar years prior to the application start date.
- At least 50% (fifty percent) of the submitted systems must have an inverter rated 2 kW AC or greater continuous.
- All systems submitted must have a minimum rating of 1 kW DC (STC).

Solar PV Training Requirements

Training must meet the following criteria to be accepted in an application:

- a) The training was completed in the three calendar years prior to the start of the application.
- b) All training must have a formal training format, with a teacher-learner structure. This implies a connection between a learner and a learning source. This can include web-based-training in which he/she is separated from faculty and other students but where the learner receives some sort of feedback and the learner's progress is monitored. All hour requirements are based on "contact hours" between the teacher and the learner.
- c) A minimum of 40 of the 58 prescribed hours must cover the NABCEP PV Installer Job Task Analysis and address advanced solar PV installation and design principles and practices.

All advanced PV training must be offered by one of the following education providers:

- I. Institutions accredited by an agency recognized by the federal Department of Education, or Canadian equivalent (Universities, Community Colleges etc.)
- II. Apprenticeship training programs (e.g. National Joint Apprenticeship Training Committee Department of Labor approved apprenticeship programs)
- III. Training programs accredited or instructors certified by the Interstate Renewable Energy Council to IREC or IREC ISPQ Standards (www.irecusa.com)
- IV. Those approved by State Contractor Licensing Boards (or Provincial equivalents)
- V. Vocational/Technical training programs (e.g. Board of Cooperative Educational Services/New York)

NOTE: Courses offered by private training organizations that are not accredited or taught by instructors certified by a recognized third party will not be accepted for the minimum 40 hours of advanced solar PV installation and design training.

continued

NABCEP PV Installer Certification Eligibility Requirements - page 5

d) Up to 18 of the 58 prescribed hours may be obtained through:

- Courses covering building and electrical codes relevant to the installation of solar PV systems
- “Entry Level” coursework by a NABCEP Registered PV Entry Level Provider, provided a passing score achievement was obtained on the NABCEP PV Entry Level Exam
- Additional OSHA or equivalent workplace safety courses above and beyond the required 10 hours
- Manufacturers Training that is registered with NABCEP as Continuing Education
- Any other coursework that addresses topics included in the NABCEP PV Installer Job Task Analysis (Note: the applicant will need to submit a course outline and a signed letter from the training provider detailing how many hours were spent covering the NABCEP Solar PV Installer Job Task Analysis)

The NABCEP Entry Level Exam

Applicants that have successfully achieved a passing score on the NABCEP PV Entry Level Exam may submit their passing score achievement in their application. The entry level coursework taken to qualify for the Entry Level Exam will subsequently count for (18) hours of training out of the fifty eight (58) hours prescribed.

NOTE: Courses leading to the NABCEP Entry Level Exam do not qualify for the minimum 40 hours of training on advanced solar PV installation and design principles and practices.

Manufacturers Training

Eighteen (18) of the prescribed 58 hours can be gained by attending training programs /courses offered by product manufacturers that are registered with NABCEP as Continuing Education but not accredited as defined above.

Documenting Training

When documenting training, the applicant will be required to submit a certificate of completion or a transcript for each completed training program or course.

All certificates of completion and transcripts must clearly state that the course covered subject matter directly related to advanced PV or National Electric Code. If the subject matter covered in the course is not clearly stated in the title of the course, then the applicant must provide a course outline and a signed letter from the training provider detailing how many hours were spent covering the NABCEP Solar PV Installer Job Task Analysis or relevant building and electrical codes.

Documentation Requirements for Solar PV System Installations

All systems must be supported with permits, inspections reports and documentation that the applicant was the senior person responsible for the job. In regions where neither permit nor inspection reports are issued, the applicant may hire a qualified electrician recognized by the Authority Having Jurisdiction (AHJ) to write an inspection report.

continued

NABCEP PV Installer Certification Eligibility Requirements - page 6

- To document experience, applicants are asked in the Application Form to provide a concise description of work performed at the job site for each of the qualifying installed systems, including;
 - the system size
 - a list of components
 - the level of their responsibility on the jobsite
 - number of full-time equivalent workers supervised
 - any other pertinent information.
- To show that the applicant held a responsible role in the installation of the system, the applicant must submit the following documentation for each system:
 - Electrical permitting and inspection documents for the system installed
 - If the applicant's name is not on the permit and/or inspection report, then the individual who is named or the employer must provide a signed letter on company letterhead that verifies the applicant was the lead installer for that system.
- To document the system size and inverter capacity, the applicant must submit plans and/or bills of materials for each installation.

NOTE: NABCEP reserves the right to contact system owners/operators, permitting authorities, and responsible contractors to verify work listed in this section.

Documenting Employment

Applicants applying under qualifying category (B), (C) or (D), must submit documentation for the required experience, starting with most current employment. The Applicant will need to submit a job description, a summary of the number and type of solar PV systems they helped install (if applicable), and provide contact information for their supervisor.

In addition, a signed letter from the most recent supervisor or employer is required to verify the applicant's employment.

If the applicant is self-employed, they must provide a detailed description of the work that they do. The self-employed applicant's installation documentation will provide additional "proof of employment".

Documenting Education

If the applicant's qualifying category requires a college education or apprenticeship program, copies of official transcripts or diplomas attesting to the completion of the degree or certificate earned will need to be attached to the application form.

Documenting Licensure

If the applicant's qualifying category requires that you they hold a specific license, or if a license for solar installation is required in the jurisdiction in which the work is performed, applicants must submit copy of their license with their application.

Case Study Examples

Example 1: Grid-Direct String Inverter PV System Connected to Load Side of Service Panel.

Module Ratings:

MODULE MAKE	AMERICAN SOLAR	
MODULE MODEL	AS 230	
MAX POWER-POINT CURRENT (I_{MP})		7.79 A
MAX POWER-POINT VOLTAGE (V_{MP})		29.5 V
OPEN-CIRCUIT VOLTAGE (V_{OC})		37.3 V
SHORT-CIRCUIT CURRENT (I_{SC})		8.41 A
MAX SERIES FUSE (OCPD)		15 A
MAXIMUM POWER (P_{MAX})		230 W
MAX VOLTAGE (TYP 600V _{DC})		600 V
VOC TEMP COEFF (mV/°C <input type="checkbox"/> or %/°C <input checked="" type="checkbox"/>)		-0.37
IF COEFF SUPPLIED, CIRCLE UNITS		

Inverter Ratings:

INVERTER MAKE	AMERICAN INVERTER	
INVERTER MODEL	AI-7680	
MAX DC VOLT RATING		600 V
MAX POWER @ 40°C		7680 W
NOMINAL AC VOLTAGE		240 V
MAX AC CURRENT		32 A
MAX OCPD RATING		50 A

Location: Newark, New Jersey

- 1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP -15 °C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE 34 °C

Design questions:

1. What does the NEC consider the maximum voltage of this PV module at this location?

Temperature Coefficient for $V_{OC} = \alpha V_{OC} = -0.37\%/^{\circ}\text{C} = -0.0037/^{\circ}\text{C}$

Temperature Correction Factor = $1 + \alpha V_{OC}(\%) \times (\text{Temp}_{\text{LOW}} - \text{Temp}_{\text{RATING}})$

$$= 1 + (-0.0037/^{\circ}\text{C}) \times (-15^{\circ}\text{C} - 25^{\circ}\text{C})$$

$$= 1 + 0.148 = 1.148$$

Answer: $V_{OC} \times \text{Temp. Corr. Factor} = 37.3\text{V} \times 1.148 = \mathbf{42.8V}$

2. What is the maximum number of modules that may be installed in series where all dc equipment is rated for 600Vdc?

Answer: Max. Number of Modules = $600V \div 42.8 = 14.02 \rightarrow \mathbf{14 \text{ modules}}$

3. What is the Maximum System Voltage as defined by NEC 690.7?

Answer: $V_{\max(\text{module})} \times \# \text{ of modules in Series} = 42.8V \times 14 = \mathbf{599.2 \text{ Volts}}$

4. If the module degradation is -0.5%/year, minimum voltage of the inverter is 300 Vdc, and the module Vmp temperature coefficient is -0.5%/°C, what is the minimum number of modules in series that will keep the Vmp above 300Vdc in 20 years at a module temperature of 65°C?

Step 1: What is the adjustment factor for Vmp after 20 years of degradation?

20 years of voltage loss @ -0.5%/year = $1 + (20 \times (-0.5\%)) = (1 - 0.1) = \mathbf{0.9}$

Step 2: What is the adjustment factor for Vmp from STC to 65°C?

Vmp Loss due to temperature @ 65°C = $1 + [(65^\circ\text{C} - T_{\text{STC}}) \times (-0.5\%/^\circ\text{C})] = 1 + [(65^\circ\text{C} - 25^\circ\text{C}) \times (-0.5\%/^\circ\text{C})] = 1 + [40^\circ\text{C} \times (-0.5\%/^\circ\text{C})] = 1 - 0.2 = \mathbf{0.8}$.

Step 3: Apply both adjustment factors to Vmp

Vmp @ 20 years and 65°C = $V_{\text{mp}} \times 0.9 \times 0.8 = 29.5V \times 0.9 \times 0.8 = \mathbf{21.24V}$

Step 4: Divide adjusted Vmp into 300V to determine minimum number of modules.

Min. # of Modules = $300V \div 21.24V = 14.12 \rightarrow \mathbf{14 \text{ modules}}$ (min & max the same)

5. The inverter recommend maximum STC Watts of modules is 9600 W_{STC}, what is the maximum number of modules that can be installed on this inverter?

Answer: $9600W \div 230W = 41.74 \rightarrow \mathbf{42 \text{ modules}}$

Note: the recommended max is not a hard limit—for low altitude coastal climates like New Jersey, the amount of power loss from the array is small. Also, as the array degrades, the amount of power limiting will be small.

6. What array configuration provides for the best utilization of the array and inverter power?

Answer: **3 strings of 14**, which is 42 modules \rightarrow 9660 Watts_{STC} of modules

Note: This is right at the recommended limit of array size for the inverter. Since the inverter should only be configured with strings of 14 modules, an array with 2 strings of 14 modules only has a 6440 Watt array that would be more suited to between a 5kW and 6 kW inverter. A location at higher elevation would favor a 6kW inverter with 2 strings of 14 modules.

7. The PV array is on detached garage structure so it is decided that a combiner box and disconnect be mounted outside the garage accessible at ground level before proceeding to the house where the inverter is mounted next to the main panel. What is maximum current of the photovoltaic power source and what size wire should be run underground to the inverter?

Answer: $I_{\text{max}} = I_{\text{sc}} \times 3 \times 1.25 = 8.41 \text{ A} \times 3 \times 1.25 = 31.54 \text{ Amps} \rightarrow$ Minimum conductor ampacity according to NEC 690.8(B)(2)(a) is $I_{\text{max}} \times 1.25 = 31.54 \text{ A} \times 1.25 = 39.4 \text{ A}$
Since the circuit is run underground \rightarrow 8 AWG will work for all terminal types.

8. At what distance does the wire run voltage drop equal 2% for maximum operating current so that a larger size conductor should be considered for the wire run?

The maximum operating current = $I_{mp} \times 3 = 7.79 \text{ Amps} \times 3 = 23.37 \text{ Amps} = I$ in equation. Solve for “ d ” in the equation below.

$$\%V_{drop} = 2\% = \frac{V_d}{V_{nom}} \times 100\% = \frac{\frac{2 \times d \times I}{1000 \text{ ft} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right)}{V_{nom}} \times 100\%$$

$$0.02 \times V_{nom} = \frac{2 \times d \times I}{1000 \text{ ft} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right)$$

$$20 \times 240V = 2 \times d \times 23.37A \times (0.778\Omega / \text{ft})$$

$$\left(\frac{20 \times 240V}{2 \times 23.37A \times 0.778\Omega / \text{ft}} \right) = d = 132 \text{ feet}$$

9. What is the minimum ac breaker allowed for this inverter?

Answer: Min. Breaker = Inverter Max AC Current $\times 1.25 = 32 \text{ A} \times 1.25 = \mathbf{40 \text{ A}}$

10. What is the minimum size conductor before considering ambient temperature or voltage drop issues?

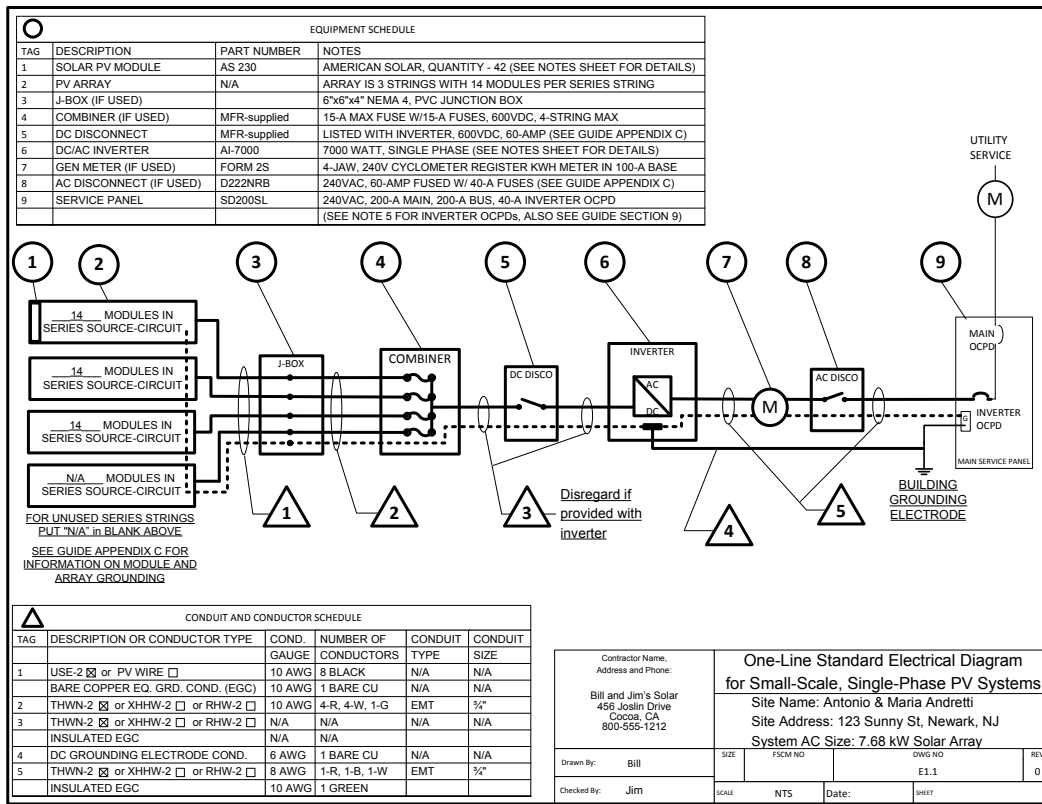
Answer: Table 310.15(B)(16) \rightarrow **8 AWG** has 40 Amp ampacity at 60°C and 50 Amp ampacity at 75°C depending on the temperature rating of the circuit breaker. 10 AWG will not work in either case.

11. How much annual energy is the PV system expected to produce if the system factor is 0.77, the average daily irradiation is 4.21 kWh/m²/day?

Answer: Annual PV system production = Peak Sun Hours \times Total Module STC rating \times System Factor

Annual solar irradiation = average daily irradiation \times 365 days = 4.21 kWh/m²/day \times 365 days/year = 1536.65 kWh/m²/year \rightarrow equivalent to 1536.65 Peak Sun Hours @ 1000W/m²

Total Module STC rating (in kilowatts) = (230W_{STC} \times 42) \div (1000W/kW) = 9.66 kW_{STC}
 = 1536.65 hours \times 9.66 kW_{STC} \times 0.77 = **11,430 kWh** (check answer using PVWatts)



PV MODULE RATINGS @ STC (Guide Section 5)	
MODULE MAKE	AMERICAN SOLAR
MODULE MODEL	AS 230
MAX POWER-POINT CURRENT (I_{mp})	7.79 A
MAX POWER-POINT VOLTAGE (V_{mp})	29.5 V
OPEN-CIRCUIT VOLTAGE (V_{oc})	37.3 V
SHORT-CIRCUIT CURRENT (I_{sc})	8.41 A
MAX SERIES FUSE (OCPD)	15 A
MAXIMUM POWER (P_{max})	230 W
MAX VOLTAGE (TYP 600VDC)	600 V
VOC TEMP COEFF (mV/°C <input type="checkbox"/> or %/°C <input checked="" type="checkbox"/>)	-0.37
IF COEFF SUPPLIED, CIRCLE UNITS	

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS (NEC XXX.XX)

INVERTER RATINGS (Guide Section 4)	
INVERTER MAKE	AMERICAN INVERTER
INVERTER MODEL	AI-7000
MAX DC VOLT RATING	600 V
MAX POWER @ 40°C	7680 W
NOMINAL AC VOLTAGE	240 V
MAX AC CURRENT	32 A
MAX OCPD RATING	50 A

SIGNS-SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT	
PHOTOVOLTAIC POWER SOURCE	
RATED MPP CURRENT	19.6 A
RATED MPP VOLTAGE	430 V
MAX SYSTEM VOLTAGE	599 V
MAX CIRCUIT CURRENT	26.5 A
WARNING: ELECTRICAL SHOCK HAZARD—LINE AND LOAD MAY BE ENERGIZED IN OPEN POSITION	

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)	
SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	29 A
NOMINAL AC VOLTAGE	240 V
THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)	

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix E):

- 1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP 15 °C
- 2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE 34 °C
- 2) 2005 ASHRAE FUNDAMENTALS 2% DESIGN TEMPERATURES DO NOT EXCEED 47°C IN THE UNITED STATES (PALM SPRINGS, CA IS 44.1°C). FOR LESS THAN 9 CURRENT-CARRYING CONDUCTORS IN ROOF-MOUNTED SUNLIT CONDUIT AT LEAST 0.5' ABOVE ROOF AND USING THE OUTDOOR DESIGN TEMPERATURE OF 47°C OR LESS (ALL OF UNITED STATES).
 - a) 12 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH I_{sc} OF 7.68 AMPS OR LESS WHEN PROTECTED BY A 12-AMP OR SMALLER FUSE.
 - b) 10 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH I_{sc} OF 9.6 AMPS OR LESS WHEN PROTECTED BY A 15-AMP OR SMALLER FUSE.

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

- 1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒
- 2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒
- 3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT
- 4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)
- 5) TOTAL OF 1 INVERTER OCPD(s). ONE FOR EACH INVERTER. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES ☒ NO ☐

Contractor Name, Address and Phone: Bill and Jim's Solar 456 Joslin Drive Cocoa, CA 800-555-1212		Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems Site Name: Antonio & Maria Andretti Site Address: 123 Sunny St, Newark, NJ System AC Size: 7.68 kW Solar Array	
Drawn By: Bill	SIZE: FSCM NO	DWG NO: E1.2	REV: 0
Checked By: Jim	SCALE: NTS	Date:	SHEET

Example 2: Grid-Direct Micro-Inverter PV System Connected to Load Side of Service Panel.

Module Ratings:

MODULE MAKE	AMERICAN SOLAR
MODULE MODEL	AS 230
MAX POWER-POINT CURRENT (I_{MP})	7.79 A
MAX POWER-POINT VOLTAGE (V_{MP})	29.5 V
OPEN-CIRCUIT VOLTAGE (V_{OC})	37.3 V
SHORT-CIRCUIT CURRENT (I_{SC})	8.41 A
MAX SERIES FUSE (OCPD)	15 A
MAXIMUM POWER (P_{MAX})	230 W
MAX VOLTAGE (TYP 600V _{DC})	600 V
VOC TEMP COEFF (mV/°C <input type="checkbox"/> or %/°C <input checked="" type="checkbox"/>)	-0.37
IF COEFF SUPPLIED, CIRCLE UNITS	

Inverter Ratings:

INVERTER MAKE	AMERICAN INVERTER
INVERTER MODEL	AI-200
MAX DC VOLT RATING	60 V
MAX POWER @ 40°C	200 W
NOMINAL AC VOLTAGE	240 V
MAX AC CURRENT	0.83 A
MAX OCPD RATING	20 A

Location: Chattanooga, Tennessee

1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP -12 °C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE 34 °C

Design questions:

1. What does the NEC consider the maximum voltage of this PV module at this location?

Temperature Coefficient for $V_{OC} = \alpha V_{OC} = -0.37\%/^{\circ}\text{C} = -0.0037/^{\circ}\text{C}$

Temperature Correction Factor = $1 + \alpha V_{OC}(\%) \times (\text{Temp}_{\text{LOW}} - \text{Temp}_{\text{RATING}})$

$$= 1 + (-0.0037/^{\circ}\text{C}) \times (-12^{\circ}\text{C} - 25^{\circ}\text{C})$$

$$= 1 + 0.1369 = 1.1369$$

Answer: $V_{OC} \times \text{Temp. Corr. Factor} = 37.3\text{V} \times 1.1369 = \mathbf{42.4V}$

2. What is the maximum number of modules that may be installed in series where all dc equipment is rated for 60Vdc?

Answer: Max. Number of Modules = $60\text{V} \div 42.4 = 1.41 \rightarrow \mathbf{1 \text{ module (microinverter)}}$

3. What is the Maximum System Voltage as defined by NEC 690.7? Answer to #1

Answer: $V_{\text{max(module)}} \times \# \text{ of modules in Series} = 42.4\text{V} \times 1 = \mathbf{42.4 \text{ Volts}}$

4. What is the maximum number of microinverters per 20-amp ac breaker allowed?

Answer: 20 Amp circuit breaker → Maximum continuous current = 20A x 0.8 = 16A
 Number of inverters = 16A ÷ I_{max} = 16A ÷ 0.83 A = 19 inverters

5. What is the minimum size ac conductor for 19 inverters where an 11-foot length of conduit from the array contains 4 current carrying conductors, is mounted 1½” above the roof, and is in direct sunlight?

Answer:

Conduit fill adjustment factor: Table 310.15(B)(3)(a) → 4-6 conductors → 0.8

Sunlit conduit temperature adder: Table 310.15(B)(3)(c) → ½” to 3½” → 22°C

Temperature adjustment basis: 34°C (2% ASHRAE value) + 22°C = 56°C ambient temp.

Temperature adjustment factor: Table 310.15(B)(2)(a) → 0.71 (90°C Column)

Table 310.15(B)(16) → **12 AWG** has 30 Amp ampacity at 90°C: With correction factors, the ampacity of 12 AWG is: 30A x 0.8(conduit fill) x 0.71(ambient temp) = 17.04 Amps
 It is permissible to protect this conductor with a 20-amp circuit breaker according to NEC 240.4(B). A larger conductor should be considered unless the run is extremely short.

6. At what distance does the wire run voltage drop equal 1% for maximum operating current so that a larger size conductor should be considered for the wire run?

The maximum operating current = I_{mp} x 19 = 0.83 Amps x 19 = 15.83 Amps = I in equation. Solve for “d” in the equation below.

$$\%V_{drop} = 1\% = \frac{V_d}{V_{nom}} \times 100\% = \frac{\frac{2 \times d \times I}{1000 \text{ ft} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right)}{V_{nom}} \times 100\%$$

$$0.01 \times V_{nom} = \frac{2 \times d \times I}{1000 \text{ ft} / \text{kft}} \times \left(\frac{\Omega}{\text{kft}} \right)$$

$$10 \times 240V = 2 \times d \times 15.83A \times (1.98\Omega / \text{ft})$$

$$\left(\frac{10 \times 240V}{2 \times 15.83A \times 1.98\Omega / \text{ft}} \right) = d = 38 \text{ feet}$$

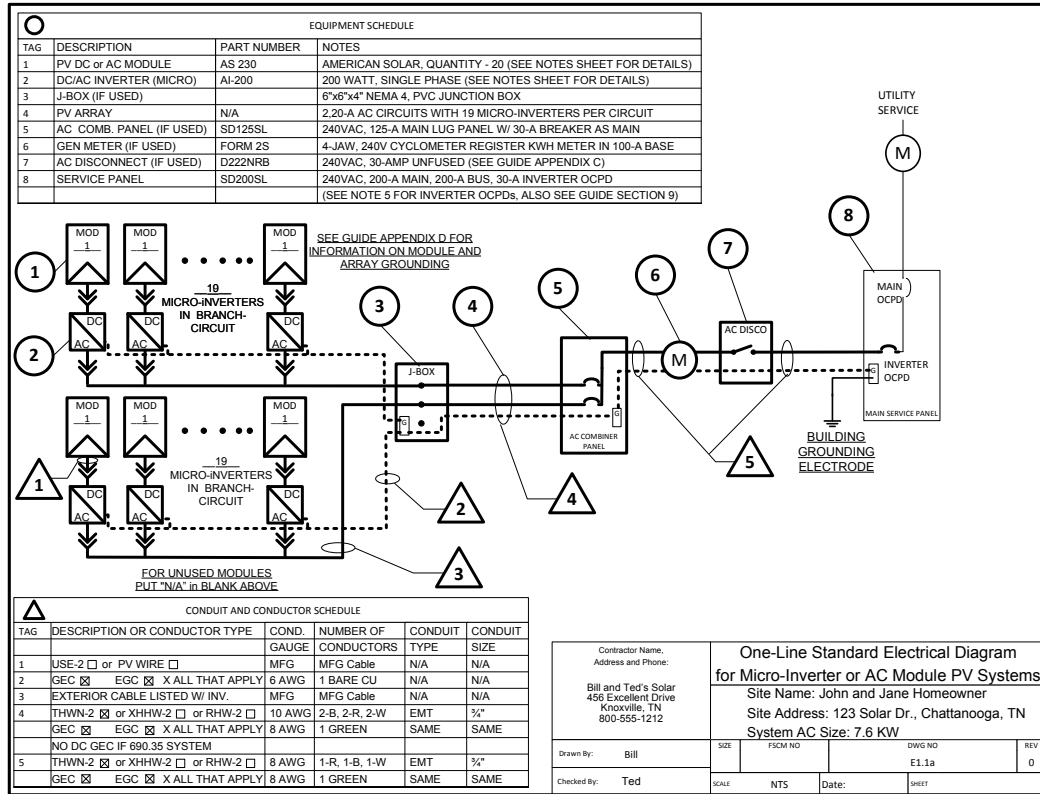
38 feet for 12 AWG; 61 feet for 10 AWG; and 97.4 feet for 8 AWG

7. If the house can handle 38 modules, two full branch circuits, how much annual energy is the PV system expected to produce if the system factor is 0.8, the average daily irradiation is 4.75 kWh/m²/day?

Answer: Annual PV system production = Peak Sun Hours x Total Module STC rating x System Factor

Annual solar irradiation = average daily irradiation x 365 days = 4.75 kWh/m²/day x 365 days/year = 1733.75 kWh/m²/year → equivalent to 1733.75 Peak Sun Hours @ 1000W/m²

Total Module STC rating (in kilowatts) = (230W_{STC} x 38) ÷ (1000W/kW) = 8.74 kW_{STC}
 = 1733.75 hours x 8.74 kW_{STC} x 0.8 = **12,122 kWh** (check answer using PVWatts)



PV MODULE RATINGS @ STC (Guide Section 5)	
MODULE MAKE	AMERICAN SOLAR
MODULE MODEL	AS 230
MAX POWER-POINT CURRENT (I_{mp})	7.79 A
MAX POWER-POINT VOLTAGE (V_{mp})	29.5 V
OPEN-CIRCUIT VOLTAGE (V_{oc})	37.3 V
SHORT-CIRCUIT CURRENT (I_{sc})	8.41 A
MAX SERIES FUSE (OCPD)	15 A
MAXIMUM POWER (P_{max})	230 W
MAX VOLTAGE (TYP 600V _{DC})	600 V
VOC TEMP COEFF (mV/°C <input type="checkbox"/> or %/°C <input checked="" type="checkbox"/>)	-0.37
IF COEFF SUPPLIED, CIRCLE UNITS	

INVERTER RATINGS (Guide Section 4)	
INVERTER MAKE	AMERICAN INVERTER
INVERTER MODEL	AI-200
MAX DC VOLT RATING	60 V
MAX POWER @ 40°C	200 W
NOMINAL AC VOLTAGE	240 V
MAX AC CURRENT	0.83 A
MAX OCPD RATING	20 A

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS (NEC XXXXX)

SIGNS—SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT

No sign necessary since 690.51 marking on PV module covers needed information

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)

SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	31.7 A
NOMINAL AC VOLTAGE	240 V
THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)	

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix E):

- 1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP -12 °C
- 2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE 34 °C

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

- 1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☒ NO ☐ N/A ☐
- 2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒
- 3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT
- 4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)
- 5) TOTAL OF 2 INVERTER OUTPUT CIRCUIT OCPD(s), ONE FOR EACH MICRO-INVERTER CIRCUIT. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES ☒ NO ☐

Contractor Name: Address and Phone: Bill and Ted's Solar 456 Excellent Drive Knoxville, TN 800-555-1212		Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems Site Name: Joe and Jane Homeowner Site Address: 123 Solar Dr., Chattanooga, TN System AC Size: 7.6 kW Solar Array	
Drawn By: Bill	SIZE	FSM NO	DWG NO
Checked By: Ted	SCALE	NTS	E1.2a
		Date:	REV 0

Sample NABCEP Exam Questions

The following questions are representative of the difficulty and scope of the type of questions that are on the NABCEP PV Installer Exam. These questions are provided to give those preparing for the exam an understanding of the type of questions that are on the exam. There is no guaranty that any problems on the NABCEP exam will match these questions.

1. A family of four is purchasing a 5 kW net-metered utility interactive PV system for their house which is located at 30°N latitude. The family members are out of the home regularly during the following hours:

Father: 9 am - 5 pm

Mother: 8:30 am - 12:00 pm

Children: 8:00 am - 3:00 pm

While the home is unoccupied, the energy use goes to near zero. There are no shade issues at the property; competing installation costs are equal, and the year round utility rate remains constant. Which of the following orientations will produce the most annual utility savings?

- a.) true south
- b.) true southeast
- c.) true southwest
- d.) magnetic south

2. A PV array for a utility-interactive system is to be ground mounted on a hill 1,000 feet from the point of utility connection. The single string of PV modules operates between 300 and 550 volts dc. The inverter is a 240 V inverter. There is a small building halfway between the array location and the utility point of connection. To minimize wire size, increase performance, and ensure consistent operation, where should the inverter be installed?

- a.) At the PV array
- b.) At the midpoint building
- c.) At the utility point of connection
- d.) Midway between the PV array and the building

3. Of the following site assessment tools, which are MOST OFTEN NEEDED to determine optimal array placement?

- a.) compass, level, and anemometer
- b.) compass, inclinometer, and irradiance meter
- c.) compass, digital camera, and multimeter
- d.) compass, inclinometer, and sun path analyzer

4. What is the MOST IMPORTANT consideration for mounting PV arrays on residential rooftops with regard to energy production?

- a.) Cooling
- b.) Shading
- c.) Tilt angle
- d.) Stand-off height

5. A homeowner wants a roof mounted solar array that produces 90% of the annual household energy consumption of 6900 kWh. The roof has a pitch of 26° and is facing true south. The array is mounted parallel to the roof. Given an 80% system efficiency, and the information contained in the table below, what is the array STC rating required to achieve 90% of the annual energy needs?

Average Daily Solar Irradiation for Des Moines, IA LAT 41.53 N LONG 93.65 W					
Tilt Angle	0	Latitude – 15	Latitude	Latitude + 15	90
Solar Irradiation	4.1	4.8	5.0	4.6	3.3

- a.) 4.25 kW
- b.) 4.43 kW
- c.) 4.92 kW
- d.) 5.15 kW

6. Which characteristic of a 500 V dc PV array gives it an advantage over a 48 V dc array of the same wattage?

- a.) Only one device is required for GFDI protection.
- b.) Under low light conditions, the single source circuit configuration produces more power.
- c.) Smaller conductors can be used between the array and inverter.
- d.) The maximum power tracking capability of the inverter is increased.

7. The battery bank for a battery backup utility-interactive PV system is located in a harsh environment with temperature and humidity extremes. The system charge controller has a provision for temperature compensation, but it is not connected. What is the MOST LIKELY result on the battery state of charge?

- a.) Overcharged in both hot and cold weather.
- b.) Undercharged in both hot and cold weather.
- c.) Overcharged in cold weather and undercharged in hot weather.
- d.) Undercharged in cold weather and overcharged in hot weather.

8. What is the required minimum working space width in front of a 48 V lead acid battery bank?

- a.) 24" where all live exposed parts are less than 60 V dc.
- b.) 30" inches or the width of the battery bank, whichever is greater.
- c.) 36" from the right and left edges of the battery bank.
- d.) 36" from the top of the ungrounded battery terminal.

9. A single inverter system requires 9 or 10 modules in series and one or two series strings in parallel. If the southeast roof is large enough for 8 modules and the southwest roof is large enough for 15 modules, which of the following array configurations results in the MOST EFFICIENT use of the PV modules installed?

- a.) 15 modules on southwest roof and 5 modules on southeast roof
- b.) 12 modules on southwest roof and 8 modules on southeast roof
- c.) 10 modules on southwest roof and 5 modules on southeast roof
- d.) 10 modules on southwest roof and 0 modules on southeast roof

NABCEP Sample Questions: (1) a, (2) c, (3) d, (4) b, (5) b, (6) c, (7) d, (8) b, (9) d



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