Initial Release, February 2015; Updated December 2017

Cooperative Utility PV Field Manual

Volume II

Planning, Design, Installation/Interconnection, and Commissioning

Prepared by:

National Rural Electric Cooperative Association

under the SunShot Initiative, SETO, U.S. Department of Energy

Volume I: Business Models and Financing Options
Volume II: Planning, Design, Installation/Interconnection, and Commissioning
Volume III: Operations, Maintenance, and Monitoring

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About this Series

Many co-ops are interested in solar PV, but only a few have deployed utility-scale (1 MW or more) systems because of industry gaps in standardized designs; cost-benefit analysis tools; assistance with finance, procurement, and permitting; and training and best practices for operations and maintenance.

NRECA's Cooperative Utility PV Field Manual is a three-volume series designed to support electric cooperatives as they explore and pursue utility-scale, utility-owned solar PV deployments. It is a product of the Solar Utility Network Deployment Acceleration (SUNDA) project, a four-year, multi-state 23-MW solar installation research project and collaboration among U.S. electric cooperatives, the National Rural Utilities Cooperative Finance Corporation (NRUCFC/CFC), Federated Rural Electric Insurance Exchange, PowerSecure Solar, and the National Rural Electric Cooperative Association (NRECA). The SUNDA project is funded in part by the U.S. Department of Energy's SunShot program; its overarching goal is to address the barriers to utility-scale, utility-owned solar PV systems faced by co-ops. Participating cooperatives include the following:

Anza Electric Cooperative	Anza, CA
Brunswick Electric Membership Corporation	Shallotte, NC
CoServ Electric	Corinth, TX
Eau Claire Energy Cooperative	Fall Creek, WI
Great River Energy	Maple Grove, MN
Green Power Electric Membership Corporation/Oglethorpe	Tucker, GA
North Arkansas Electric Cooperative	Salem, AR
Oneida-Madison Electric Cooperative	Bouckville, NY
Owen Electric Cooperative	Owenton, KY
Pedernales Electric Cooperative	Johnson City, TX
Sandhills Utility Services	Fort Bragg, NC
Sussex Rural Electric Cooperative	Sussex, NJ
Tri-State G&T Association	Westminster, CO (serving UT, WY, NM, & NE)
Vermont Electric Cooperative	Johnson, VT

The standardized products for evaluation, implementation, and operation of utility-scale solar PV at co-ops are discussed in detail in this Cooperative Utility PV Field Manual:

Volume I: Business Models and Financing Options

Volume II: Planning, Design, Installation/Interconnection, and Commissioning

Volume III: Operations, Maintenance, and Monitoring

This document is the final project release of Volume II

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Acknowledgments

This is Volume II of the Cooperative Utility PV Field Manual, prepared for the Solar Utility Network Deployment Acceleration (SUNDA) project. This manual was prepared by staff at NRECA's Cooperative Research Network with very significant technical support from its authors, Jim Dunlop, P.E.; Doug Danley, Principal Investigator for SUNDA; and the engineering staff at PowerSecure.

We would also like to thank the following reviewers:

- Christine Hallquist, former CEO, Vermont Electric Cooperative, Johnson, VT
- Keith Pitman, CEO, Oneida-Madison Electric Cooperative, Bouckville, NY
- Blake Beavers, Renewable and Distributive Energy Manager, Pedernales Electric Cooperative, Johnson City, TX
- Kevin Short, General Manager, Anza Electric Cooperative, Anza, CA
- Dustin Brown, Energy Engineering Manager, CoServ Electric, Corinth, TX
- Jonathan Beyer, Member Relations Manager, Tri-State G&T, Westminster, CO
- Andy Bergrud, Senior Engineering Project Manager, Great River Energy, Maple Grove, MN
- John Aiton, Engineering Project Manager, Great River Energy, Maple Grove, MN

Executive Summary

This manual provides general information on the design and installation of large-scale solar photovoltaic (PV) systems and is intended as a guide for electric utility personnel considering such projects. The content is based on the best information available to the National Rural Electric Cooperative Association (NRECA) and input from various experts and consultants knowledgeable in the field.

This manual provides recommendations on typical design and installation practices and is based on best industry practices and applicable standards. It is not intended to provide full training in the design and installation of large-scale PV systems. Rather, it is intended to familiarize utility staff who will be involved in this type of project as to the technical issues and basic processes involved. Readers are advised to seek counsel and advice from technical experts before undertaking any project or investment.

1 Introduction

This is Volume II of the Cooperative Utility PV Field Manual prepared for the Solar Utility Network Deployment Acceleration (SUNDA) project (part of DOE's SUNRISE-B program). This volume covers the options and typical steps involved in designing and installing utility-owned solar PV generation projects. It will use the SUNDA template design for a 1-MW-AC PV system as the basis for all discussion.

Volume I of the Utility PV Field Manual covers business and financing topics, and Volume III covers operations and maintenance.

1.1 Markets and Applications

The market for PV systems in the U.S. and has accelerated dramatically since the beginning of the SUNDA project, with 53 GW of solar now installed in the United States[1] (Some U.S. solar deployments are shown in Figure 1.) Total U.S. PV installations in 2017 were approximately 10.8 GWp. There are an estimated 53 GWp cumulative total installed grid-connected systems operating in the U.S.[2]

Factors contributing to the accelerated market growth for solar PV systems include lower prices for components and systems, availability of financing and incentives, and consumer demand. Installed prices for PV systems dropped dramatically as installations have increased. The federal Investment Tax Credit (ITC) and Renewable Portfolio Standards (RPSs) have resulted in PV systems achieving financial viability and, in many cases, currently competing with conventional generation sources. Furthermore, PV system installation practices are being improved continually, and components have attained exceptionally high levels of reliability and performance.

[1] https://www.seia.org/solar-industry-research-data.
[2] PV capacity is typically given in MWp or GWp, which represent the PV array peak-rated DC power output.

Eau Claire Energy Cooperative - 750 kW AC

CoServ Electric – 2 MW AC

Middle Tennessee EMC – 7.2 MW AC

Figure 1: Co-op Deployments

In 2017, the utility market was 59% of industry total installations. Growth in solar among co-ops has also grown dramatically, with 443 co-ops in 43 states reporting solar projects totaling 723 MW as of early 2018.

1.1.1 Utility Challenges

Over the past few years, there has been little growth in U.S. electricity consumption, due in part to a poor economy and increasing energy efficiencies. Consequently, additions of PV capacity to the grid generally have not supported a growth in consumption; rather, they have been offset by the retirement of older power plants or reduced generation from existing plants. Naturally, increasing PV penetration levels will require careful planning for grid integration and also will offer increasing opportunities for utility ownership and investments in solar PV generation.

1.2 Introduction to SUNDA Reference Designs

The SUNDA reference designs include pre-engineered drawings and construction documents for utility-scale PV systems, ranging from 250 kW to 1 MW peak AC output. (See Figure 2 for an overview of the SUNDA 1-MW reference design.) The design packages include a cover sheet that provides a list of drawing sheets, six site plans (equipment layouts, trenching and grounding), single-line diagrams, schedules, labels, partial plans for inverter pads, conduit details, and stringing plans for arrays. The following four design packages are currently available on the SUNDA website:

- 250 kW 600 V, Single Inverter, fixed tilt
- 250 kW 1,000 V, String Inverters, fixed tilt
- 500 kW 1,000 V, Single Inverter, fixed tilt
- 1,000 kW 1,000 V, Two 500-kW Inverters, fixed tilt
- 1,000 kW 1,000 V, Two 500-kW Inverters, fixed tilt
- 1,050 kW 1,500 V, Single Inverter, fixed tilt
- 1,000 kW 1,000 V, String Inverters, single axis tracking

The reference designs are intended to reduce the engineering time required to implement projects, achieve the lowest possible cost, and maximize land use, and can be replicated and expanded for larger systems. The designs use fixed non-tracking arrays, centrally located inverters, and optimized combiner locations to reduce trenching and wiring costs and facilitate maintenance.

In most cases, the reference designs will need to be adjusted for the particulars of a field site, including electrical string length (based on minimum site temperatures), climatic conditions (such as wind and snow loads), row spacing (based on latitude), land contours, shading, and other factors. The typical engineering time for such adjustment is intended to be under 100 hours for site-specific modifications.

Although significant effort has been made to incorporate all applicable standards and ensure good engineering and correct practice in the development of the reference designs, and these designs have been used to develop actual field-deployed, utility-scale solar PV systems, no warranty or guaranty is made on these designs for their fitness, suitability, safety, or applicability for any purpose. Utilities must employ a trained engineer to interpret and adjust the reference designs for the specific requirements of their application.

Features of the standard SUNDA reference designs include maximizing land use and ease of replication and expandability to achieve the lowest possible cost. The reference designs provide details for modular racking, grounding, and surge protection, and all other configuration details.

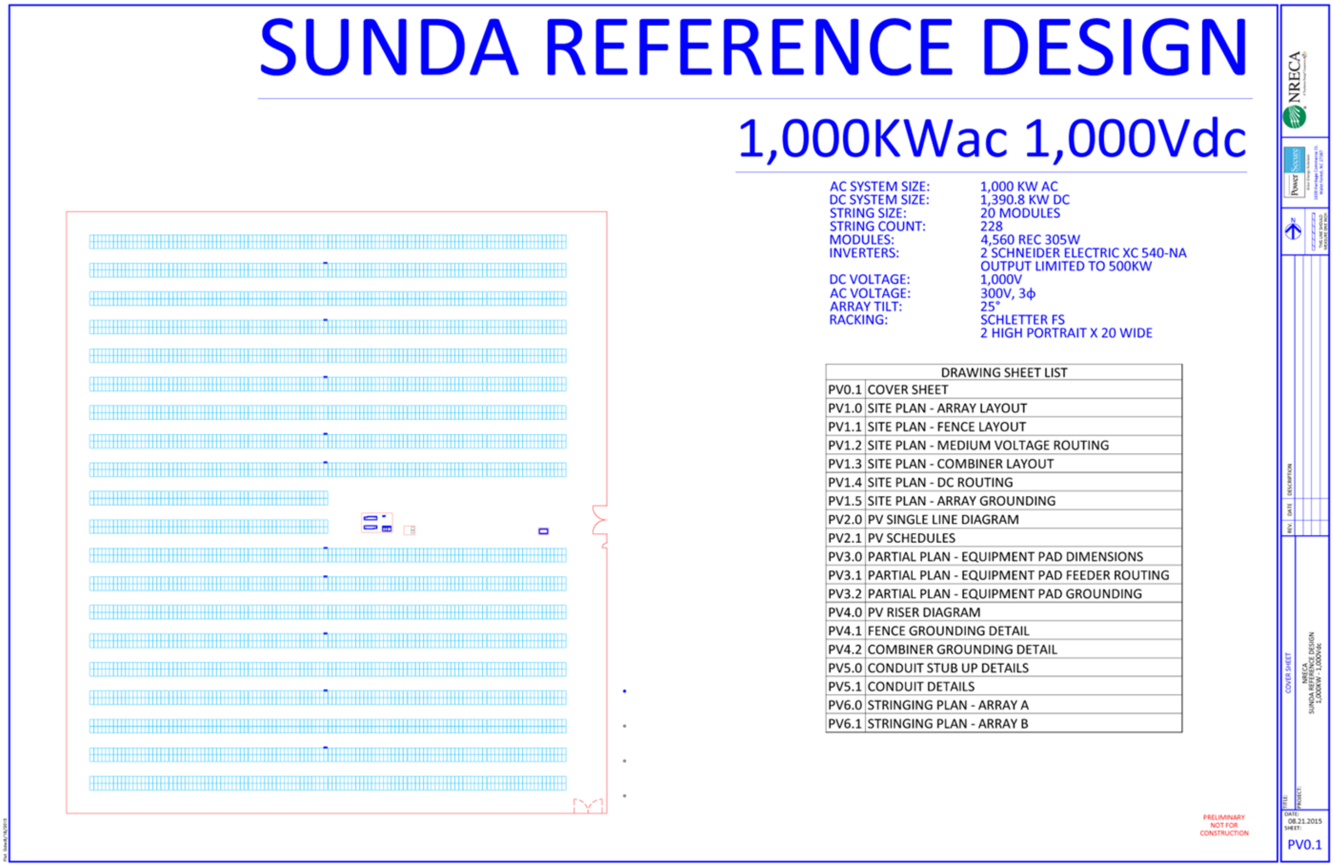


Figure 2: Overview of the SUNDA 1-MW Reference Design

2 Planning, Permitting, and Performance Prediction

2.1 Defining Goals

The first step in any PV system project is to determine the goals to be accomplished by that project. Typical goals for an electric cooperative may include the following:

- Implement renewable generation as part of an integrated resource plan
- Meet renewable portfolio requirements imposed by state, local, or utility officials, or others
    - Energy-based requirements (percentage of energy usage)
    - Capacity requirements (percentage of generation nameplate capacity)
- Contribute to peak reduction, typically in the afternoon
- Implement a “community solar” program
- Act as a generation resource for a micro-grid
- Test a “new” technology for potential future scaling
- Use a system for research into advanced utility functions
- Increase member satisfaction or respond to member requests

Once these goals are determined, the utility can move forward to determine the size and cost of the system and plan the best path toward implementation.

2.1.1 Implementation Options

There are two primary methods to add solar generation to a utility:

1. Contract with a developer and sign a power purchase agreement (PPA) to purchase a specific amount of electricity over a defined period
2. Construct the project, with full utility ownership as a goal

In addition to these primary options, there may be other methods for operation of solar at co-ops, including partnerships with commercial members.

The SUNDA project focuses on the second option, so all discussion within this volume will assume this method.

Within the second option, a number of choices exist on how to proceed, including the following:

1. Develop a specification, issue a request for proposals (RFP), and hire an engineering procurement construction contractor (EPC) to design and install the system.
2. Engineer the system (using SUNDA design templates as a basis, for example), procure primary materials through the utility, and hire one or more contractors to procure additional materials and install the system.
3. Engineer the system, procure all materials through the utility, and manage the project using internal utility engineering and installation resources.

There are also many variations on these three main sub-options. For example, in sub-option 1, a utility could act as general contractor but hire various subcontractors to provide engineering, site preparation, and installation services.

The choice of which sub-option to use depends on the specific utility implementing the project. For example, a small distribution co-op with limited staff and engineering resources might choose sub-option 1 or possibly 2, whereas a larger co-op or a G&T might choose to implement some form of sub-option 2 or 3.

The second and third sub-options (in which the utility procures basic materials) offer the greatest ability to reduce costs, since the three major hardware components (PV modules, inverters, and racking) make up nearly three-quarters of the cost of a utility-scale PV system. The remainder is split between site prep, installation and engineering, project management, and design costs.

Co-ops in particular may have access to very favorable financing through the Rural Utilities Service (RUS) or a co-op-affiliated bank, such as the National Rural Utilities Cooperative Finance Corporation (NRUCFC) or CoBank. Use of co-op employees to provide some or all of the installation labor also could result in savings, especially if the project can be scheduled to absorb unallocated time for these resources.

2.2 Planning and Documentation

Planning PV installations involves establishing all details concerning the project financing and size; acquiring and permitting land use; developing the site; completing the system design; obtaining engineering and construction documents; specifying and procuring equipment; executing the installation, commissioning, and inspections; and obtaining approvals.

Organizing documentation is a critical part of planning and executing PV installations. Key components of a system documentation package should include the following:

- System design and equipment specifications
- Site layout drawings and equipment locations
- Manuals and specifications for the overall system and major components
- Electrical and mechanical drawings
- Civil drawings, including road access, water management, and retention ponds (these will need to be finalized after the specific site has been selected)
- Installation, operating, and maintenance procedures
- Warranties and service contracts
- Permitting documents

2.2.1 Resources for Evaluating Solar Projects

NRECA has developed a series of webinars, papers, and online training modules to assist co-ops in evaluating solar projects. The following are some of the resources currently available from the SUNDA website; additional materials will be added as they become available.

Webinars:

Best Practices for Effective Community Solar Communications, September 10, 2015 (Public): This 90-minute webinar offers practical, experiential advice on how to communicate effectively with your members about the features and benefits of your co-op's community solar projects.

Cooperative Experiences with Community Solar, August 2015 (Public): Hear from three co-ops already implementing community solar and learn about NRECA's community solar resources.

How Electric Cooperatives Are Integrating Solar, June 2015 (Public): Presentation on solar programs and policies that co-ops have chosen and why they made the choices they did.

Tools for Utility-Scale PV at Your Co-op, March 2015 (Public): Overview of the tools and resources available to cooperatives through the SUNDA project, including the financial and cost models, the PV field manual, and engineering designs.

Community Solar: How Cooperatives Are Implementing Community Solar Projects, December 2014 (Public): This 90-minute webinar discusses the experiences of two co-ops in implementing community solar.

Technical Workshop on Residential & Utility-Scale Solar Trends, July 2014 (Public): This webinar provides a technical overview of residential and utility-scale solar.

State of the Solar Market: Knowing the Facts and Understanding the Trends, June 2014 (Co-op Resource): This 90-minute webinar offers a review of the basics of solar, explores the state of the residential and utility-scale solar market, and discusses information being developed through SUNDA.

The Business of Solar: Owning Utility-Scale PV, July 2014 (Public). This webinar focuses on the current financial opportunities in and barriers to installing utility-scale PV, including the current business models and the utility's role in system operation, assets and ownership, and different financing options.

Documents:

Case Study: Kauai Island Utility Cooperative—The Impact of Extensive PV Penetration (July 2015). This article provides a case study of KIUC, which has experienced dramatic growth in solar photovoltaic systems, and shares lessons learned about issues related to significant solar PV growth.

Solar PV Fact Sheet, January 2014 (Co-op Resource). This fact sheet provides a quick reference regarding the basics of the solar market today, including pertinent definitions, market components, and the impact on cooperatives.

Consequences of High Solar Penetration on a Co-op's Load Profile: A Look at the Not-So-Distant Future, April 2013 (Co-op Resource). This article looks at a study performed by CoServ Electric of Texas and NRECA to look at the impacts of large-scale distributed solar generation.

SUNDA PV Maturity 2014 Survey Results, September 2014 (Public). This report analyzes the results of an NRECA survey of electric cooperatives to help evaluate the current PV market and co-ops' involvement in PV projects. The survey asked 584 cooperatives that indicated they have or expect solar PV on their systems in the next three to five years a series of questions regarding co-op generation resources and resource planning; membership engagement; utility, community solar, and member-owned solar PV; technical/engineering issues related to solar PV; and related behavioral and financial issues.

The Changing Cost of Solar Power—Financing Options for Electric Cooperatives, October 2013 (Co-op Resource). This article explores options for electric cooperatives to leverage their unique financial advantages to finance PV solar projects and discusses approaches to electricity rates.

Solar Leasing and Solar PPA Programs: The Increase in Residential Photovoltaic Solar Deployment, November 2013 (Co-op Resource). This article explores the basic business model and solar leasing program offered by SolarCity—the largest vertically integrated and only publicly traded solar leasing company at this time.

The Best Places to Build Solar Power Plants, September 2013 (Co-op Resource). This article explains the variety of factors that in combination determine the effectiveness and economic favorability for PV projects.

Impact of Large Penetrations of Moderate Renewables on Distribution Systems, May 2013 (Co-op Resource).

2.3 Site Selection

Selection of a site for a PV array is one of the first and most important of the many decisions a co-op must make. Land use planning is an important step in qualifying a potential site, such as for a site presenting environmental concerns.

Utility-scale PV systems typically use 6–10 acres per MW-AC, depending primarily on parcel shape, latitude, slope, and shading. The land should be relatively level and have a good southern exposure without significant shading. (Note: different racking manufacturers provide specific allowances for how level a site needs to be.) Sites that are flat or slope toward the south are ideal, whereas those with a north-facing slope will require additional space to minimize inter-row shading.

The site should be well drained, not within any potential flood zones, and accessible to construction and maintenance vehicles, including large commercial delivery trucks.

New fire codes in the International Fire Code (IFC) and from the National Fire Protection Association (NFPA 1) require a 10-foot clear area around ground-mounted PV arrays for emergency vehicle access. Additional vehicle/equipment access also should be considered throughout the array field to facilitate installation and maintenance.

The lowest-cost array racking structures use "driven-pier" designs, so land with deep soil and minimal inclusions is desirable. There can be some cost advantages with helical pile/screw anchors as well, depending on the contractor's equipment and what is cheapest for the contractor to install.

This list of features indicates a requirement for prime agricultural land, so cooperatives should be careful to ensure that they meet local zoning requirements. As an alternative, PV systems can be sited on "brownfield" land (such as reclaimed heavy industrial sites), or even on landfills, using a "ballasted" structure rather than driven piers.

A typical specification for a pad-mounted transformer is included in Appendix I to show the level of detail that must be considered in a PV system.

2.3.1 Land Acquisition

One major but often overlooked part of solar PV projects is acquiring and permitting land for the project. Although the purchase price of land typically accounts for only 3 to 4 percent of total project cost (assuming 6 to 10 acres for a 1-MW solar array at a cost of $10,000/acre), land acquisition challenges can delay a solar project for months if not handled appropriately. To facilitate the process, attorneys, land brokers, and commercial real estate professionals should be retained to address property transactions, including title searches, negotiations with owners/sellers and the Authority Having Jurisdiction (AHJ), leases, and lien satisfaction, as applicable.

See the SUNDA White Paper on land acquisition and siting challenges for more information: *Solar Project Land Acquisition and Permitting: A Case Study of Four Cooperatives Participating in the Solar Utility Network Deployment Acceleration Project*.

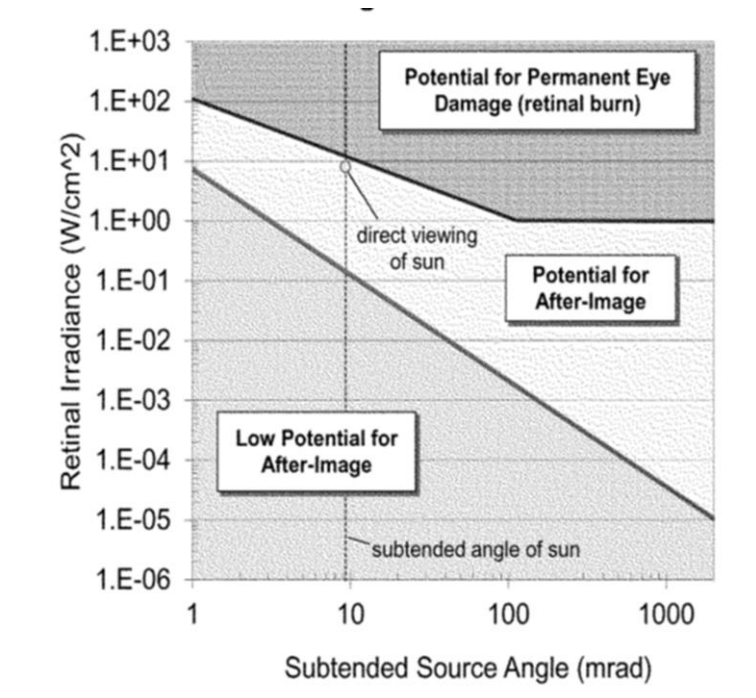
Building a solar project on land that a cooperative already owns is ideal because it avoids the land acquisition process. When land acquisition is required, due diligence is critical to complete transactions in a timely manner and not delay project construction. The estimated time to acquire land and secure permits can vary considerably. In the best case, with no issues, the complete process can take 3 to 9 months. Permitting matters can take 1 to 3 months and preliminary engineering and site development an additional 1 to 2 months. Land use or rezoning variances can take an additional 2 to 4 months. Permitting, variances, engineering, and site development also apply to land a co-op already owns. Land acquisition and permitting may also require community impact studies or evaluations of wetlands, streams, hydrology, archeological sites, and endangered species.

A summary of issues to consider in the land acquisition process includes the following:

- Who is the Authority Having Jurisdiction (AHJ) for code compliance?
- Do you need a conditional or special-use permit?
- Are there setbacks, easements, encroachments, or right-of-ways?
- Are there landscaping or tree screening requirements?
- Are there any liens on the land?
- How is the land zoned?
- What is the Storm Water/Erosion Control Plan?
- What is the wetland assessment and stream determination?
- Does your project require a Phase I Environmental Study?
- Is a traffic study required?
- What site prep does the land require?
- Is access to the site required?
- If applicable, what are the lease-term rules?

FAA Ocular Impact Study

The FAA requires the use of the Solar Glare Hazard Analysis Tool (SGHAT) to demonstrate compliance for solar energy installations on federally regulated airport properties. This online tool determines whether a proposed solar energy project would result in the potential for ocular impact, as depicted on the Solar Glare Hazard Analysis Plot.



See: https://share.sandia.gov/phlux/.

2.4 Permitting

Once a site has been identified for a PV system, it must be permitted through the local AHJs for proper use. In some cases, utilities may be exempted from certain local government building permits and inspections for power generation facilities on their properties, as these common regulatory/construction approvals do not generally apply. However, most utilities will construct PV plants using the latest industry standards and electrical codes, such as the National Electrical Code (NEC).

The utility must determine the regulations that apply to the site, which may include the following:

- Local (municipal, county) site plan approval and building and electrical permits
- Zoning and land use regulations
- Appearance, landscaping, and buffer requirements
- Water quality-related permitting
- Soil disturbance, sedimentation, and erosion control permitting
- Environmental Impact Statements and Endangered Species Act compliance
- Transportation planning and permitting: driveways, right-of-ways, and roadway improvements.
- Historical or archaeological concerns
- FAA ocular impact studies, if the project is located near an airport

In addition, utilities may have to deal with regulatory considerations imposed by their local public utility commissions (or equivalent).

It is important to allow sufficient time for all permitting and regulatory processes. Note that "sufficient time" can vary dramatically from site to site, so it is important that the permitting and regulatory approval process begin immediately upon project initiation, as many issues may arise that can and will affect design constraints and decisions.

A representative permitting checklist is included in the appendices of Volume III.

2.5 Impacts on Feeder

The point of interconnection to the utility distribution system needs to be established early in the project. Considerations include proximity to existing feeders, distribution lines, or substations, and the capacity and load on the substation and local network. Co-ops also must consider the need for line extensions, re-conductoring, additional transformers, and other equipment. System size at co-ops usually is limited to an amount that will not provide backfeeding into the transmission network. Backfeeding along segments of a distribution feeder may occur, so load flow calculations should be performed before the final size/system size is finalized.

From a utility perspective, an ideal site should be located near a "stiff" electrical connection point, such as a substation. If a large PV system is placed at a random point on a distribution feeder, it would require extra study to determine whether the variability might have effects on the voltage of the feeder because of the load conditions or the amount of PV generation. NRECA is working on extending the capabilities of its Open Modeling Framework (OMF) tool to accommodate this sort of modeling directly from utilities' network topology files (WindMil or Cyme) and SCADA data. It should be noted that some siting locations are simply too disruptive to a system; the costs to mitigate these disruptions can render the PV system not economically viable.

2.6 Yield Projection

Estimating the electrical output of a PV system is a very different exercise than that for traditional generation resources. The output of a PV system depends heavily on the location of the system.

Different parts of the country have dramatically different amounts of solar resources available. This sometimes is offset by the fact that PV modules typically have a negative temperature coefficient for power, so they can be more efficient in colder climates. For example, Bismarck, North Dakota has only about 80 percent of the measured solar insolation of Tallahassee, Florida, but a 1.39 MWp/1.0 MW-AC system in Bismarck theoretically would produce 99 percent as much annual electricity as the same system in Tallahassee. The output would be less evenly spread over the year, producing more in the summer up north, but the annual energy is very close in the two locations. The North Dakota system would present other challenges (such as dealing with snow) but would also provide other benefits (reflection from the snow once the array is cleared would increase system output). Figure 3 shows the relative output of systems across the United States.

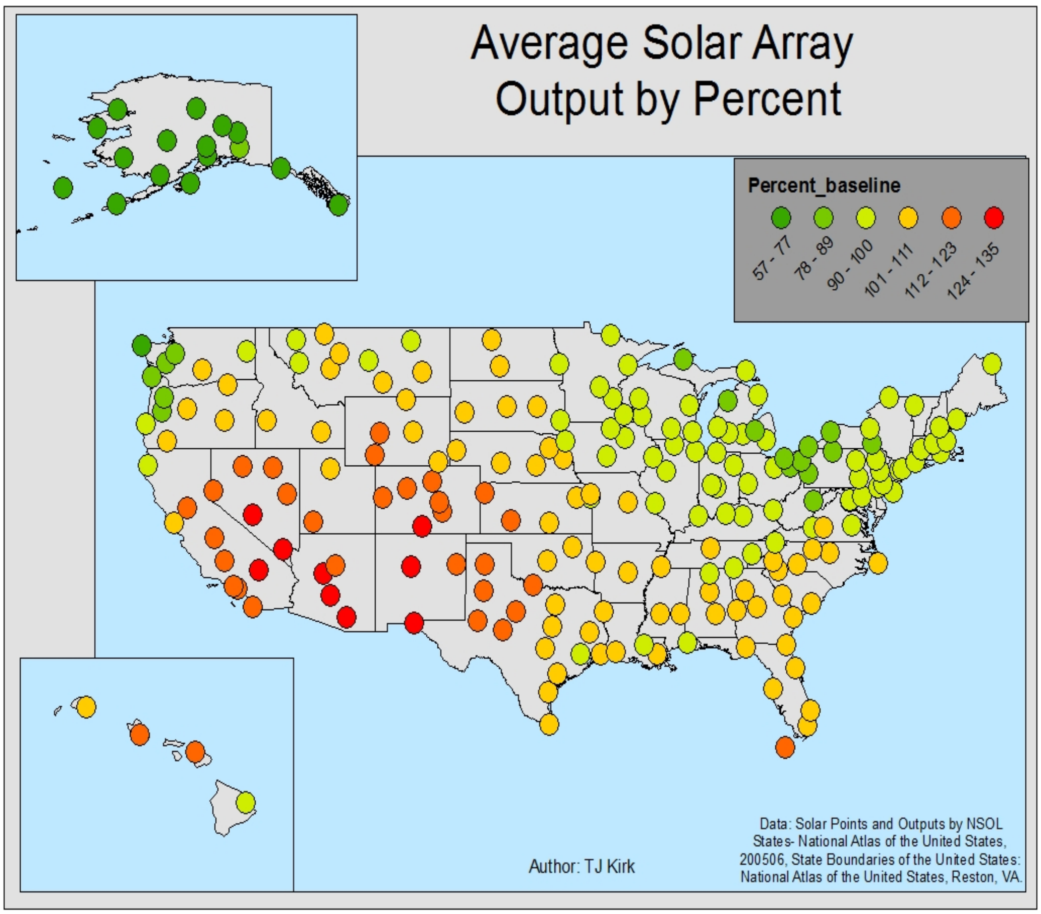


Figure 3: Relative Output of PV Arrays Across the United States

Time of Peak Production

The time of peak production for a PV system may be more important to electric utilities than the total amount of energy produced. The example in Figure 4 shows a typical co-op load profile for the month of August, superimposed on the average daily solar energy collected on 40º tilted arrays, oriented at azimuth angles of 180º (due south), 225º (southwest), and 270º (due west). Compared to a south-facing array (4.96 PSH), orienting the array southwest (225º) shifts the PV system peak output by about two hours later in the afternoon; however, there is a 5.6 percent reduction in the amount of annual solar energy received (4.68 PSH). The effects are more pronounced at higher tilt angles and higher latitudes.

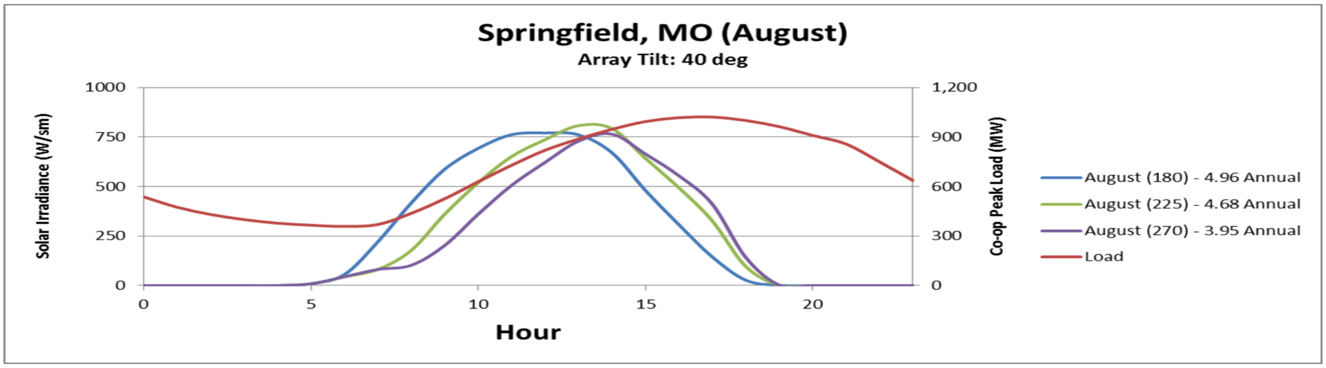


Figure 4: Solar Output vs. Co-op Load Profile in Missouri in August

Array tilt and azimuth are also important values to consider. In general, arrays in the northern hemisphere should be aimed toward the south for maximum energy production, as shown in Figure 5. Since the sun rises lower in the sky at higher latitudes, arrays typically are tilted at higher angles the farther north they are installed. Maximum annual output typically is achieved by tilting the array at an angle near latitude.

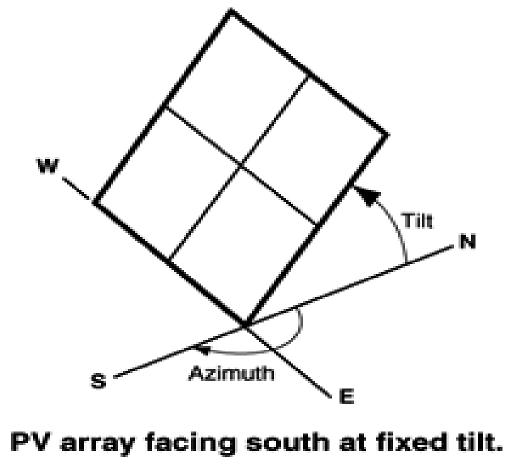


Figure 5: Tilt and Azimuth (image courtesy of NREL)

In practice, however, there are many exceptions to this rule. In utility-scale PV systems with many rows of PV modules, inter-row shading is a significant issue. Arrays at steeper tilts cast longer shadows, which require increased spacing between rows and thus more land area for a given system size. Utility-scale arrays typically are tilted at shallower angles than true optimum, with the lost theoretical production being countered by reduced shading and increased land density.

Off-azimuth arrays also are increasingly common among utility systems. Although there is a performance penalty, it is relatively small, especially at shallower tilts (see above). Aiming arrays toward the west can also produce more energy during the afternoon, which often has value in matching utility demand peaks.

2.6.1 Shading Analysis

A shading analysis evaluates and quantifies the impacts of shading on PV arrays. Shading may be caused by any obstructions near PV arrays that interfere with the solar window. Ideally, there should be no shading on arrays between 9 a.m. and 3 p.m. solar time over the year, since most solar radiation and peak system output occurs during this period. 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. Such a chart shows the portion of the solar window 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.

Several devices and software tools have been developed commercially to simplify shading evaluations. These devices project or record obstructions on sun path diagrams 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. Most system design and performance-estimating tools also incorporate shading factors to derate the system output accordingly.

For larger PV systems with multiple parallel rows one in front of another in the array, one row of modules can shade another in back during winter months if the rows are too closely spaced (see Figure 6). Multiple rows of PV arrays can be spaced more closely at lower latitudes and use lower tilt angles. The minimum required separation distances between PV array rows and other obstructions depends on latitude, the height of the obstruction, and the desired time of day and year for shading 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.

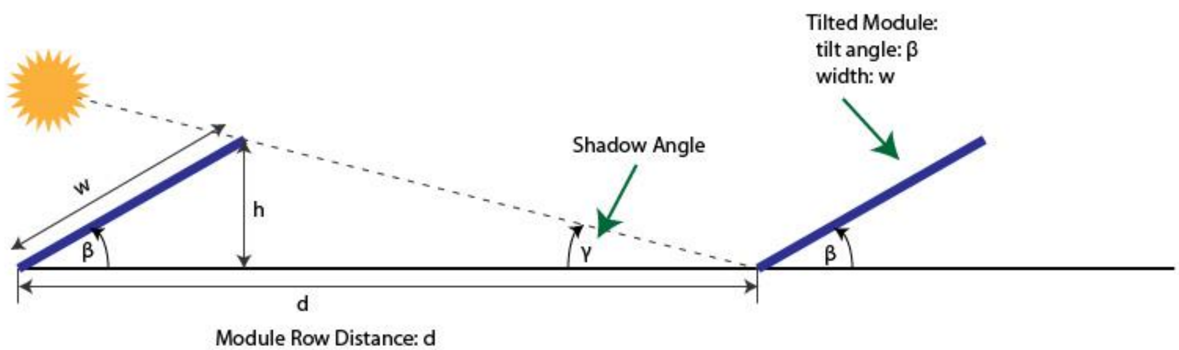


Figure 6: Spacing Between Array Rows in PV System

2.7 Software Tools

Several public domain and commercial software tools are available for evaluating, planning, developing, designing, and executing PV projects. In addition, NRECA has developed a screening tool to evaluate the costs and financing for utility-scale PV projects, intended for use by co-op planners and decision makers to explore the viability of potential projects. This comprehensive tool allows developers and designers to provide their location and inputs to optimize the sizing, design, performance, financial considerations, and many other factors for PV projects (see Figure 7). (Refer to: https://www.dropbox.com/s/piyh2qc806c7ab2/SUNDA%20Solar%20Costing%20%20Financing%20Screening%20Tool%20-%20released.xlsm?dl=0.)

Cooperative	XYZ, EC		
Zipcode	64735	Clinton, MO	
System Size (MWac):	1.00	2,038,775	System Output (first year, kWhac)
Land	Owned	5	Acres of land (min)
Cost/acre	$ -		
Module Cost ($/Wp)	$ 0.650		
Racking Cost ($/Wp)	$ 0.115		
Inverter Type	Central		
Inverter unit cost	$ 107,000	2	Inverters required for this size system
Project Mgmt	$ 15,000		
EPC Markup %	3%		
Mechanical Install Labor ($/hr)	$ 35.00		These labor rates should reflect the going local rate in your area, or your rates,
Electrical Install Labor ($/hr)	$ 50.00		including overhead, for your own people if you are building the system yourself
Development Costs	2%	$ 41,899	Consulting, Legal and Banking fees to set up the system (set to 5% for Tax-Equity Flip)
Interconnect Costs	$ 25,000		
Distribution Adder ($/MWh)	$ -		
Total System Costs	**$ 2,161,873**	$ 2,094,974	Installed Equipment Costs

Duration		
Expected System Life (years)	25	Note: This number more than any other drives the return on the system!

Financing Information		
Discount Rate	2.32%	Note: Mouse over the values for explanations and limitations
Loan Interest Rate	2.00%	Please also see "Additional Input" sheet for more parameters.
NCREB Tax Credit Rate	4.06%	
Lease Buyback rate	-4.63%	
Targeted Tax-Equity Return	8.50%	

PPA Information (for comparison purposes)		
First year energy cost ($/MWh)	$ 56.00	Use this to compare Utility-owned facilities to 3rd party PPA offerings
Annual Escalation Rate	3.00%	
PPA Duration (yrs)	20	

Legend:

(yellow)	These items must be adjusted by the user
(green)	May be adjusted, but have good default numbers
(blue)	These value are calculated from the inputs, but can be modified if needed
(grey)	These values are calculated from inputs and should not be changed, they appear here as they are inputs to other sections
(orange)	These values are entered in another worksheet and should not be modified here

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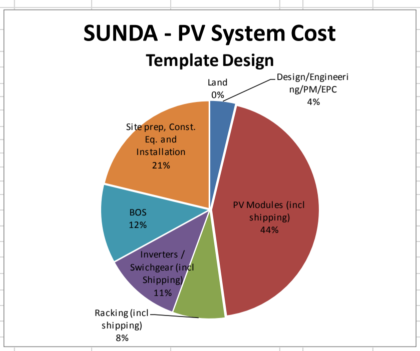
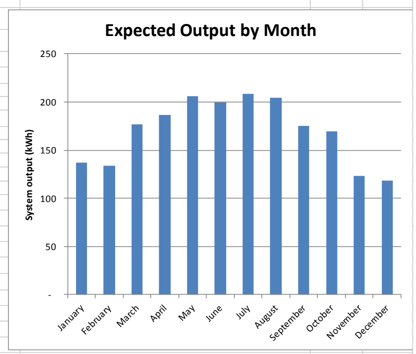
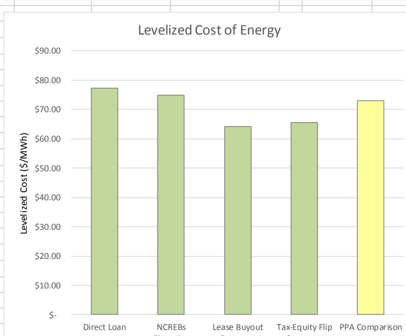
SUMMARY RESULTS
XYZ, EC
Re-Calculate

Installed System Cost:	$ 2,161,873
$/Wdc Installed:	$ 1.55
Capacity Factor:	23%
First Year System Output (MWh_{ac})	2,039
Direct Loan	
Levelized Cost of Energy ($/MWh)	$ 77.25
Community Solar Project:	
Cost per 305W Panel (prepay)	$ 583.08
Cost per 10W of Panel (lease)	$ 19.12
NCREBs Financing	
Levelized Cost of Energy ($/MWh)	$ 74.83
Community Solar Project:	
Cost per 305W Panel (prepay)	$ 564.80
Cost per 10W of Panel (lease)	$ 18.52
Lease Buyout Structure	
Levelized Cost of Energy ($/MWh)	$ 64.33
Community Solar Project:	
Cost per 305W Panel (prepay)	$ 485.53
Cost per 10W of Panel (lease)	$ 15.92
Tax-Equity Flip Structure	
Levelized Cost of Energy ($/MWh)	$ 65.61
Community Solar Project:	
Cost per 305W Panel (prepay)	$ 495.21
Cost per 10W of Panel (lease)	$ 16.24
PPA Comparison	
Levelized Cost of Energy ($/MWh)	$ 72.99
First Year Cost/MWh	$ 56.00
Yearly Escalation	3.00%







Expected Output by Month	kWhr
January	137
February	134
March	176
April	187
May	206
June	200
July	209
August	204
September	175
October	170
November	123
December	118

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Figure 7: NRECA Cost and Financing Screening Tool for Utility-Scale PV Projects

2.7.1 Public Domain Tools

These tools are free to use. Many have been developed in conjunction with the National Renewable Energy Laboratory (NREL), Sandia National Laboratory, and other government agencies.

2.7.1.1 PVWatts®

PVWatts® is an easy-to-use web-based application, developed by NREL, which estimates the energy production and basic economic factors for utility-interactive PV systems.

http://pvwatts.nrel.gov/

PVWatts can be used for preliminary studies of non-concentrating PV systems using crystalline silicon or thin-film PV modules. However, PVWatts is not a complete design tool, and more detailed engineering, financial analysis, and design tools should be employed to address site factors not considered in its estimates.

To execute PVWatts, the user begins by specifying the proposed system location, either by address, zip code, or coordinates. Other locations, including international sites, can also be selected from an interactive map. The calculator estimates the monthly and annual electricity production of a photovoltaic system, using an hour-by-hour simulation over a period of one year. To represent the system's physical characteristics, PVWatts requires values for six inputs:

- System DC size
- Module type
- Array type
- System losses
- Array tilt angle
- Array azimuth angle

You can refine the system design assumptions with three optional advanced inputs:

- DC to AC size ratio
- Inverter efficiency
- Ground coverage ratio

PVWatts produces the cost of electricity estimates based on assumptions about the economics of the system, including system installation cost and average annual retail cost of electricity.

2.7.1.2 System Advisor Model®

The System Advisory Model® (SAM) combines PVWatts with economic analysis to provide a more detailed look at system performance. SAM is currently a stand-alone tool.

https://sam.nrel.gov/

2.7.1.3 Solar Prospector

The Solar Prospector is a mapping and analysis tool designed to provide access to geospatial data relevant to the solar industry in general and for siting utility-scale solar plants in particular. The application provides easy access to solar resources; land ownership; and environmental, administrative, and infrastructural data to help assess solar development potential within the United States. The Solar Prospector also allows users to download solar resource data in a variety of formats for further exploration and analysis.

http://maps.nrel.gov/prospector

2.7.2 Commercial Software Tools

Commercial software tools are available for more detailed design and analysis of PV systems. These programs can be purchased from the companies listed. Up-to-date pricing can be found on their websites. This is not a complete list of tools – there are many others available

2.7.2.1 *PVSyst™*

PVSyst™ is the industry standard for utility-scale system design; it provides a deeper level of analysis than PVWatts, including detailed shading models based on CAD drawings. PVSyst is a stand-alone tool.

http://www.pvsyst.com/en/

2.7.2.2 *HelioScope™*

HelioScope™ is a relatively new program from Folsom Labs, developed with help from a DOE SunShot Initiative grant. It integrates Google Earth and detailed performance analysis to allow designers to evaluate options rapidly. It is a web-based tool.

http://www.folsomlabs.com/

2.7.2.3 *Helios 3D™*

Helios3D™ is a solar array layout program developed by the racking manufacturer Schletter. It does detailed analysis of array layouts to calculate shading. Designs can be imported into PVSyst for performance analysis.

http://www.schletter.us/helios-3d.html

2.7.3 Tools for String Sizing and System Design

Free online string sizing and system design tools are also available from many inverter manufacturers and contain databases of specifications for commercially available PV modules. These tools determine allowable array configurations based on the location, user inputs, and module and inverter specifications and limits of operation. Some tools provide circuit design features, including sizing for PV source and output circuit conductors and overcurrent devices, DC combiner boxes, and other plant equipment.

2.8 System Economics

Traditional generation systems have the following four main cost categories:

1. Capital cost (typically described as $/kW or $/MW)
2. Recurring fuel costs (tied closely to the plant efficiency/fuel rate and plant capacity factor)
3. Recurring maintenance costs
4. Non-recurring maintenance costs

Two of the attractive features of PV systems—no fuel costs and low maintenance costs—make it more challenging to compare them directly to traditional generation systems with high operations costs. Merely looking at capital costs is misleading. Rather, total system lifetime costs and revenues need to be examined. However, comparing two or more different PV options can be done rationally by capital costs alone ($/Wp-DC or $/kWp-DC). It is important to note that these are based on the size of the DC array, not on the AC rating of the inverter.

The majority of the costs in a PV system include three components—PV modules, racking, and power electronics—as shown in the representative cost breakout in Figure 9 below.

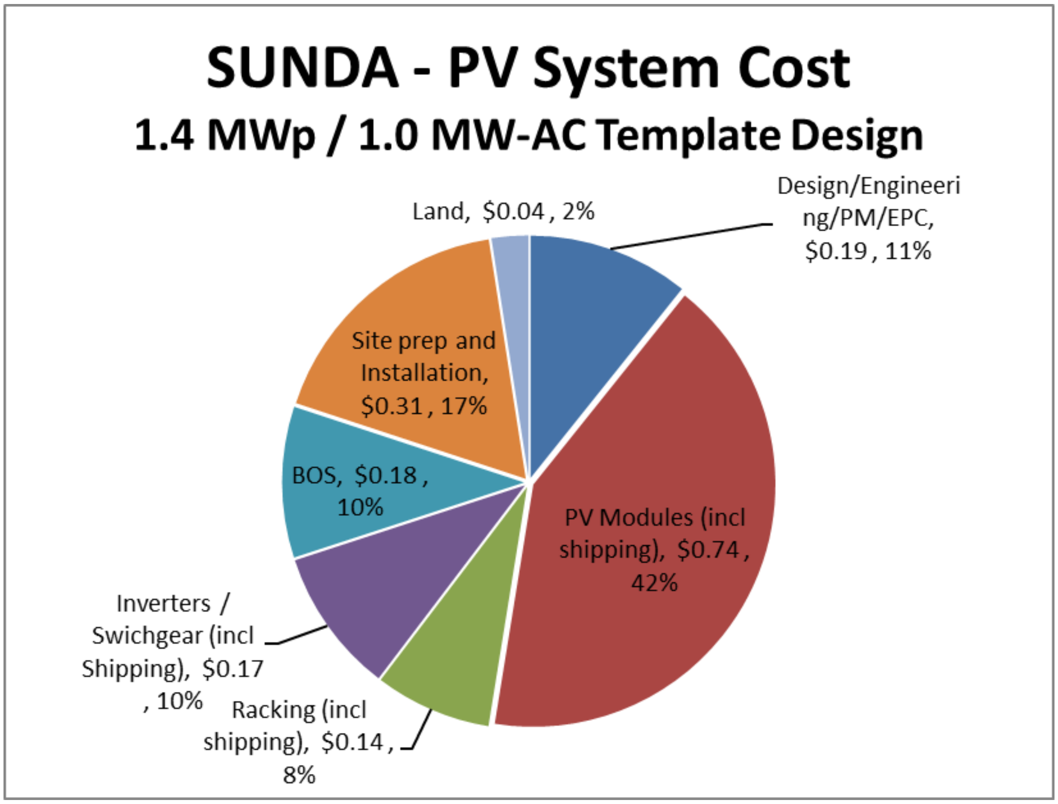


Figure 9: Primary Capital Costs for PV Systems Include Modules, Inverters, and Support Structures

These representative costs are based on an analysis of the 1-MW template design provided as part of the SUNDA project. The cost of an individual project may vary significantly based on location, choice of components, and contracting method used to implement the system.

The cost of energy from a PV system can be calculated using a "levelized cost of electricity" (LCOE) formulation, which combines the capital cost (including financing) with discounted costs for maintenance and repairs. LCOE typically is calculated for the life of the system, which is 25 years or longer for modern PV systems. The following formula shows a simplified LCOE calculation:

$$LCOE = \frac{Project\ Cost + \sum_{n=1}^{N} \frac{AO}{(1+DR)^n} - \frac{RV}{(1+DR)^n}}{\sum_{n=1}^{N} \frac{Initial\ KWh\ X\ (1 - System\ Degradation\ rate)^n}{(1+DR)^n}}$$

- Project cost = initial capital cost for the project, including engineering, permitting, land, equipment, installation, and commissioning; this is currently $1.60–$2.20 per Wp-DC for utility-scale systems
- AO = annual operations, i.e., the cost of maintaining the system. This is currently $15–20/kWp/yr
- RV = residual value
- Initial kWh = first-year system performance as calculated by PVWatts or a similar program
- System degradation = rate at which a system degrades; this is typically 0.5–1.0 percent per year and can be modeled as linear without too much error
- DR = discount rate
- n = year of operation
- N = life of system

Example:

- 1.39 MWp/1 MW-AC System in Jackson, MN
- Initial cost = $1,800 per kWp = $2,500K
- Initial output = 2.026 MWh/yr
- AO = $25/kWp = $34.8K/yr
- System degradation = 0.8%/yr
- DR = 3%
- RV = $0
- N = 25 years
- LCOE = $0.093/kWh

It is important to note that the energy from a PV array is both intermittent (it varies according to the amount of sun and clouds at the site) and non-dispatchable (it cannot be turned on to a fixed power at will), so it cannot be compared directly to traditional generators without additional considerations.

Tax incentives and financing terms can dramatically affect the economics of PV systems. Volume I of this manual discusses system economics in more detail.

The SUNDA project has developed a simplified cost model for each of its template designs to allow quick estimation of the costs involved in installing a system of this type. There are four versions of the cost model, each tied to one of the template designs. These models are available at www.nreca.org/SUNDA.

3 Systems and Components

Solar PV systems are an assembly of components and equipment that produce electrical power. They are modular and versatile power generators and can be designed to produce DC or AC power to supply any type of electrical load at any service voltage. PV systems can be designed to independently power very small DC loads on the order of a few watts up to large-scale power plants of tens of megawatts or more that interface with utility T&D systems such as other generators. The configurations and components required depend on the functional and operational requirements of the system.

3.1 Types of PV Systems

PV systems are categorized based on the loads they are designed to power or their connections with other electrical systems.

3.1.1 Grid Interactive Systems

Grid Interactive PV systems operate in parallel and are interconnected with the utility grid. When installed on buildings or facilities, these systems supplement utility-supplied energy to the site loads. Sometimes called grid-connected or utility-interactive PV systems, these systems do not commonly use any energy storage. The primary component in interactive PV systems is the inverter, which directly interfaces between the PV array and the electric utility network, converts DC output from a PV array to AC power, and synchronizes with the grid. For safety reasons, interactive PV systems are required to disconnect from the grid during utility outages or disturbances.

Distributed interactive PV systems make a bi-directional interface at the point of utility interconnection, typically at the site distribution panel or electrical service entrance. This allows the AC power produced by the PV system either to supply on-site electrical loads or backfeed the grid when the PV system output is greater than the site load demand.

3.1.2 Stand-Alone Systems

Stand-alone PV systems operate independently of other electrical systems and are commonly used for off-grid remote power applications. Applications include street or sign lighting, water pumping, transportation safety devices, communications, off-grid homes, and many other electrical loads. Stand-alone systems may be designed to power DC and/or AC electrical loads; with few exceptions, they use batteries for energy storage. A stand-alone system may use a PV array as its only power source or also may use wind turbines and/or an engine-generator as additional energy source(s) in hybrid applications. Stand-alone systems are not intended to produce output to interface with the electric utility system and are not addressed in this manual.

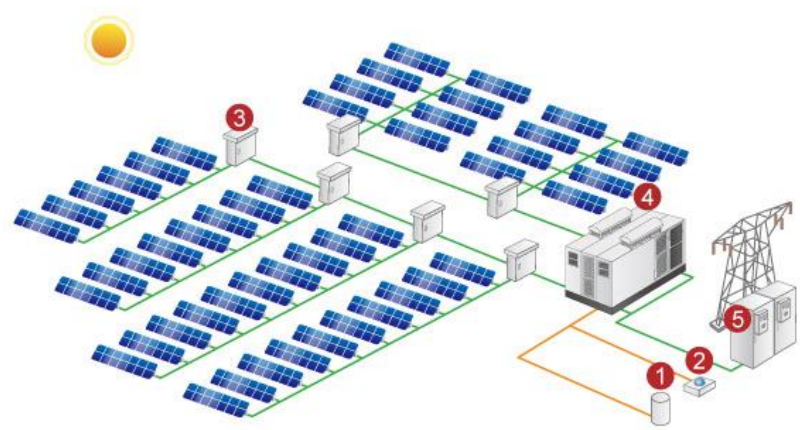
3.1.3 Multimode Systems

Multimode PV systems are utility-interactive PV systems that use battery storage and can also operate in stand-alone mode. These types of systems are used by homeowners and small businesses when a backup power supply is required for critical loads, such as computers, refrigeration, water pumps, and lighting.

Multimode PV systems operate in a manner similar to uninterruptible power supplies and have many similar components. 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; the inverter operates dedicated loads that have been disconnected from the grid. An external bypass switch usually is provided to allow the system to be taken off-line for service or maintenance while not interrupting the operation of electrical loads. Larger multi-mode systems often are classified as "micro-grids."

3.2 Major Components

PV systems include an array of PV modules and other equipment required to conduct, control, convert, distribute, and utilize the energy produced by the array. The major components of a utility-scale PV system include the PV modules and array, and power conditioning equipment, such as inverters, transformers, and interconnection equipment, as shown in Figure 10. Additional hardware, including support structures, foundations, wiring methods, disconnecting means, overcurrent protection, and protective and safety equipment are required to assemble and connect major components to construct a complete power generating unit.



❶ System Performance Monitoring and Communications

❷ Weather Monitoring

❸ String Combiner Box

❹ Inverter

❺ Interconnect Transformer

Figure 10: Major PV System Components Include an Array of PV Modules and Power Conditioning Equipment

The box below and Figure 11 give the components and a pictorial display for the SUNDA 1-MW reference design.

Major Components and Specifications for the SUNDA 1-MW Reference Design

AC System Size:	1,000 KWac
Inverters:	2 Schneider Electric Conext XC 540-NA
DC System Size:	1,390.8 KWdc
Total Modules:	4,560 REC 305 W
DC String Size:	20 modules in series
String Count:	228
Maximum array voltage:	1,000 Vdc
Array racking:	Schletter FS
Array tilt angle:	25°

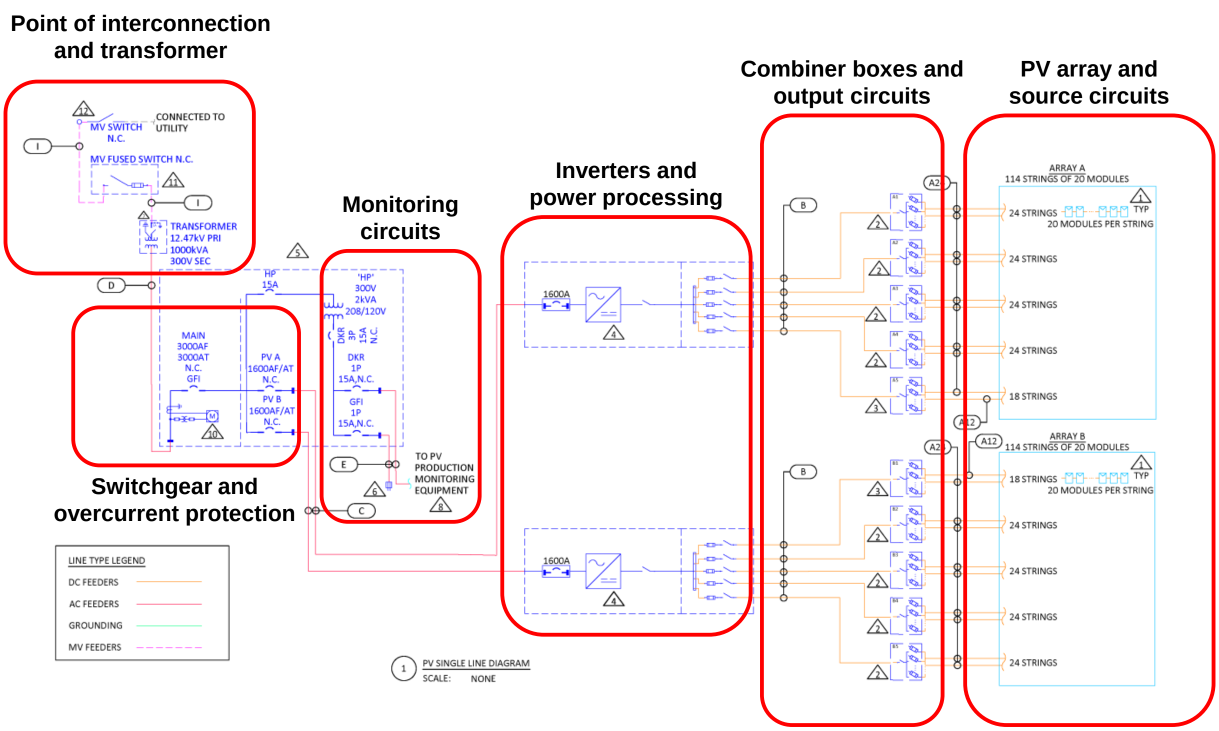


Figure 11: SUNDA 1-MW Reference Design

3.2.1 PV Cells, Modules, and Arrays

Solar cells convert solar radiation into DC electricity and are the basic element of PV modules. Modern solar cells are created by junctions between different semiconductor materials—most commonly silicon. A typical crystalline silicon solar cell, as shown in Figure 12, is a junction between boron-doped silicon (P-type) and phosphorus-doped silicon (N-type) semiconductors. N-type semiconductors are materials having excess electron charge carriers. P-type semiconductors are materials having a deficiency of electron charge carriers or excess electron voids (holes). Photons in sunlight impart their energy to the charge carriers, allowing them to move freely about the material. An electrical field created at the junction provides momentum and direction to the free charge carriers, resulting in the flow of electrical current when the cell is connected to an electrical load.

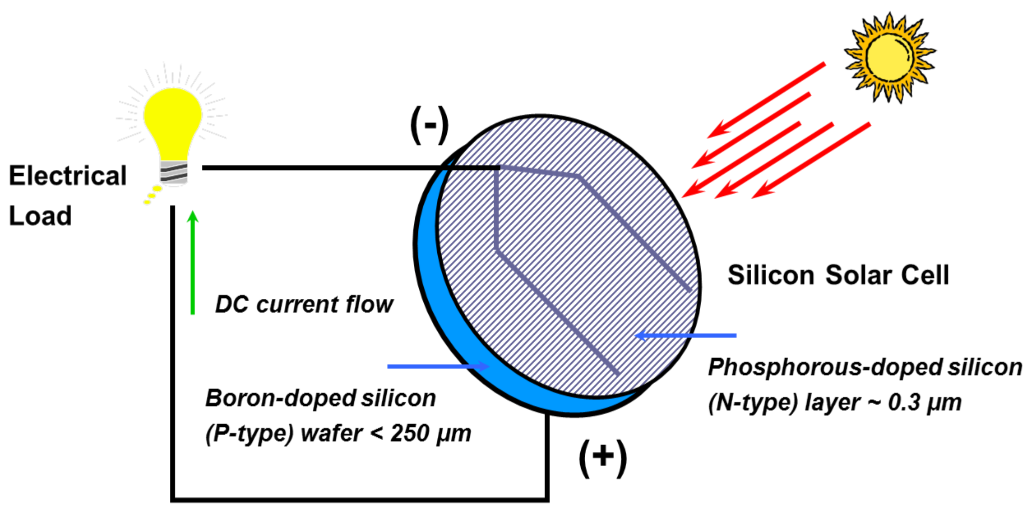


Figure 12: A Typical Silicon Solar Cell Consists of a Junction Between P-Type and N-Type Semiconductor Materials

Modules are complete field-installable DC generating units, consisting of multiple solar cells encapsulated in an environmentally protected laminate, including a frame for structural mounting and electrical connection points. Commercial PV modules are available in a variety of technologies, power ratings, and sizes. **Arrays** are a complete DC power generating unit, consisting of multiple individual modules and circuits assembled and configured to provide a desired electrical output. **Subarrays** are electrical subsets of arrays. An individual solar cell, including these components, is depicted schematically in Figure 13.

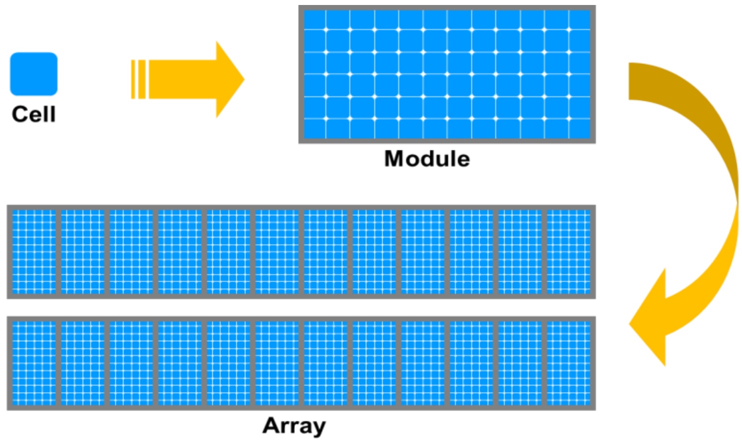


Figure 13: Individual Solar Cells Are the Basic Element of PV Modules; Modules Are Used to Build PV Arrays

3.2.1.1 Crystalline Silicon Modules

Crystalline silicon is the oldest and most mature component of all PV technologies. First deployed for terrestrial applications in the mid-1970s, silicon wafer-based PV modules accounted for approximately 90 percent of the worldwide market in 2013. Modern silicon solar cells are manufactured in sizes greater than 50 in^2 area and can produce more than 4 watts and 8 amps each under full sunlight. A silicon solar cell produces about 0.6 V independent of cell area and decreases with increasing temperatures. There are two basic types of crystalline silicon solar cells, primarily distinguished by the wafer manufacturing process, as shown in Figure 14.

Monocrystalline wafers are produced by growing a single crystal ingot, known as the Czochralski process. A seed crystal is rotated and drawn from a bath of molten polysilicon containing a small amount of boron. As the silicon cools, it forms a cylindrical ingot, typically up to 8 inches (approx. 200 mm) in diameter and up to 80 inches (approx. 2 m) in length. Using diamond wire saws, the edges of the ingot are cropped to form a more rectangular shape, and individual wafers are sawn from along its length. The edge cropping allows cells to be packed more densely in a given module area, and the slightly rounded edges result in visible diamond-shaped patterns between these cells in a module.

Polycrystalline wafers are produced by the cast-ingot or ribbon method. The cast-ingot method involves pouring the molten polysilicon and boron mixture into a crucible and cooling it at controlled rates. This casting and cooling process creates a rectangular-shaped ingot with a multigrain polycrystalline structure. Rectangular-shaped wafers then are sawn from the cast ingot. The ribbon method produces rectangular polycrystalline wafers by drawing molten silicon between dies and allowing it to cool in a continuous process. Ribbon technology avoids the additional casting steps and wafer sawing involved in the cast ingot process.

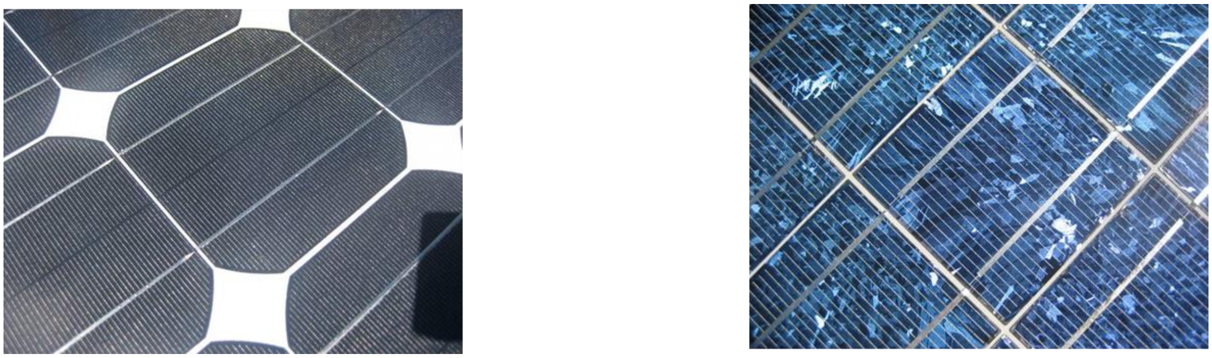


Figure 14: Typical Silicon Solar Cells Include Monocrystalline (left) and Polycrystalline Types (right)

Mono and polycrystalline wafers are subsequently processed in similar manufacturing steps to produce complete solar cells. The wafers are etched in a sodium-hydroxide solution to create an irregular surface that absorbs more solar radiation and allows better adhesion for the N-type layer and anti-reflective coatings. The N-type silicon layer is created by passing the wafers through a furnace and diffusing phosphorous gas onto their outer surfaces. The edge layer is removed and an anti-reflective coating of titanium oxide is applied to the top surface. Metallic grid patterns are screen printed on the front and back surfaces of the cells to conduct current. The back aluminum contact alloys with silicon and neutralizes the N-type layer on the back of the cell. Each cell is electrically tested and sorted based on its current output.

72-Cell Polycrystalline PV Modules

The SUNDA 1-MW reference design uses 72-cell/300 Wp-class modules. Mono and polycrystalline modules of this type are ideal for building large-scale commercial and utility projects while reducing balance-of-system costs. See Figure 16.

Crystalline silicon PV modules are assembled from individual cells that are “tabbed” together into a series of strings and laminated with an EVA encapsulation between a sheet of tempered glass and a Tedlar backing sheet. A junction box on the back of the laminate is used to connect the cells’ circuits for bypass diodes to protect them from overheating during partial shading and to make external connections. The module assembly is completed with a rigid aluminum frame to provide mechanical support for the laminate and the means for electrical grounding and structural attachments. PV modules produced from mono and polycrystalline silicon cells are comparable in costs, reliability, and performance, with monocrystalline having slightly higher efficiencies.

Most listed modules can be connected in series up to a maximum limit of 1,000 volts DC, although the industry is now moving toward a 1,500-VDC standard. Although the industry has developed some standardization in the physical characteristics and electrical ratings for crystalline silicon modules, there still are small differences between similar modules from different manufacturers. Most modules used in utility-scale PV systems consist of either 60 (6x10) or 72 (6x12) individual 156-mm cells, as shown in Figure 15. A typical 60-cell module measures approximately 1,700 x 1,000 mm. A typical 72-cell module measures 2,000 x 1,000 mm. Modules with 60 cells often are referred to as “250-W class” modules, whereas 72-cell modules are referred to as “300-W class” modules. Within these classes, manufacturers typically will produce a range of products with slightly different power ratings, resulting from the cell-sorting process.

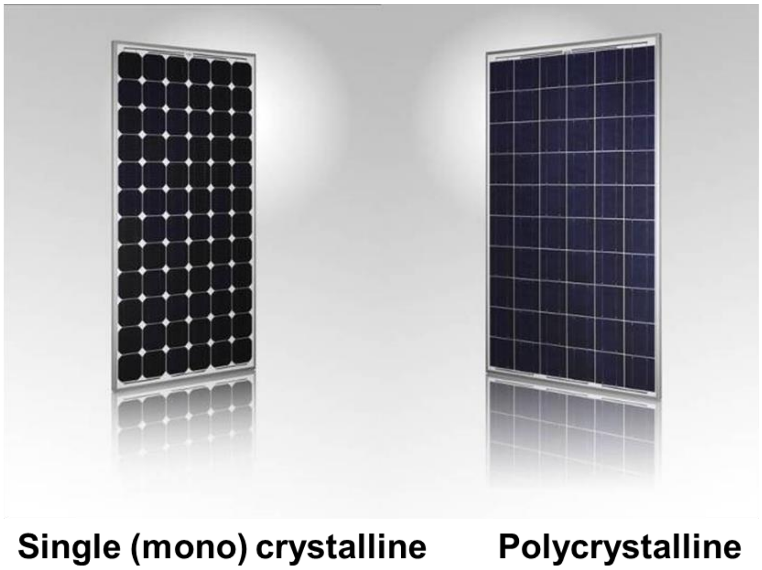


Figure 15: PV Modules for Power Applications Typically Include Either 60 or 72 Series-Connected Cells (Source: SolarWorld)

Figure 16: Polycrystalline REC Peak Energy 72 Series Modules

3.2.1.2 Thin-Film Modules

Thin-film PV modules use a module-based continuous manufacturing process involving the deposition of ultra-thin layers of semiconductor materials on a flexible or rigid substrate. The primary advantage of thin-film PV modules is their potential for significant reductions in raw materials, manufacturing costs, and weight. However, these advantages have eroded somewhat in recent years due to lower materials use and cost reductions for silicon wafer-based modules. Thin-film PV modules are currently under 10 percent of the market and mostly deployed for larger utility-scale applications.

Although efficiencies and reliability for thin-film modules have been increasing in recent years, they are generally less efficient than crystalline silicon modules, and hence require larger surface areas to generate the same amount of power. This fact also increases costs for the balance-of-system components, such as racking and support structures for the array; also, more wiring and connections are required per unit array size.

The physical and electrical characteristics of thin-film modules typically are different than those of crystalline silicon products. Many thin-film modules have low current output and voltages as high as 100 volts DC, and may use parallel connections of modules before they are connected in series in array source circuits. Temperature coefficients for thin-film modules also typically are lower than for crystalline silicon products, resulting in smaller decreases in voltage and power output with increasing temperatures.

Thin-film PV modules are considered second-generation devices and include cadmium telluride (CdTe), copper indium gallium selenide (CIS or CIGS) (both shown in Figure 17), and amorphous silicon (a-Si). Some of the characteristics of these products are described below.

Cadmium Telluride (CdTe) is the leading thin-film PV technology; it accounted for about 5 percent of the worldwide market and half of all thin-film module production in 2013. Record lab efficiencies for CdTe are about 20 percent—comparable with CIGS and polycrystalline silicon cells. The temperature coefficients for voltage and power for CdTe are roughly one-third of those for crystalline silicon, yielding more energy production per rated power at typical operating temperatures. Due to the use of toxic cadmium, CdTe modules must be recycled properly at end of life. Tellurium is also a scarce and expensive element, which could limit the mass commercialization of CdTe technology.

First Solar, based in Tempe, Arizona, is a leading manufacturer of CdTe modules, with a primary focus on the utility-scale market and integrated system solutions. The First Solar Series 4™ PV module is listed for applications up to 1,500 V, weighs 12 kg, and has dimensions of 600 mm x 1200 mm. These modules are available in power outputs ranging from 92 to 105 Wp at standard test conditions (STC), corresponding to peak efficiencies of 14.6 percent. These modules are frameless glass laminates and require specialized mounting structures.

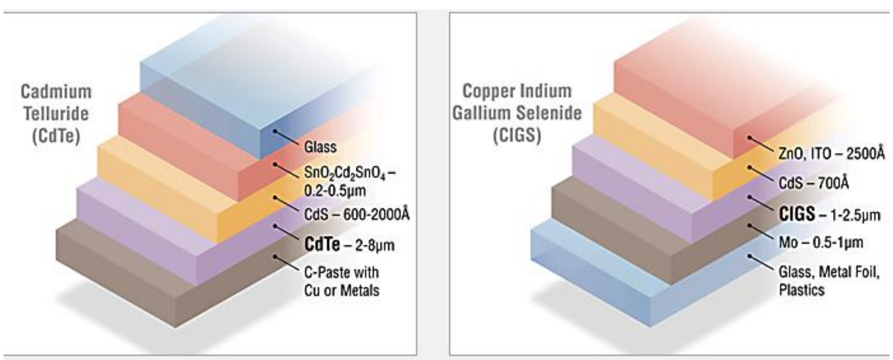


Figure 17: CdTe and CIGS Thin-Film Technologies Use Ultra-Thin Layers of Semiconductor Materials (Source: NREL)

Copper Indium Gallium Selenide (CIGS or CIS) is a competing thin-film technology that accounted for 2 percent of the thin-film PV module market in 2013. Many CIGS manufacturers have left the market due to decreasing costs for crystalline silicon products, although there are still some suppliers. Similar to CdTe, temperature coefficients for CIGS are about one-third lower than for crystalline silicon.

Amorphous silicon (a-Si) modules were the first thin-film PV module technology to be commercially deployed for power generation in the early 1990s, having achieved wide success in consumer electronic devices since the late 1970s. The first a-Si modules were single-junction devices, and such products were offered by several leading manufacturers. Triple-junction and tandem a-Si modules subsequently were developed and improved efficiencies.

Initial and long-term degradation rates are generally higher for a-Si than CdTe, CIGS, or silicon wafer technologies, and this must be considered in systems design. Specifically, a-Si suffers an initial 10–30 percent efficiency loss during the first several months of exposure, known as the Staebler-Wronski effect. Although this efficiency loss is recoverable by annealing at temperatures above 150°C, these conditions do not normally exist in the field. For this reason, most a-Si module manufacturers have factored this initial degradation into their guaranteed product ratings. Beginning in 2010, many major a-Si module manufacturers either have left the market or shifted focus to crystalline silicon products. In 2013, a-Si modules accounted for about 2 percent of market share.

3.2.1.3 Concentrating PV Modules

Concentrating PV (CPV) modules are special designs that use glass/plastic lenses, mirrors, or other optical means to focus solar radiation through a larger aperture area onto a smaller area of highly efficient solar cells. Concentrator designs use less solar cell material per unit collector area and take advantage of increasing solar cell efficiencies at higher levels of solar irradiance. Since concentrating PV modules utilize only the direct component of solar radiation (about 60–70 percent of the total global), they are installed on sun-tracking (dual-axis) structures. Depending on the design, concentrating PV modules can have concentration ratios of up to 1,000x normal non-concentrated sunlight and achieve cell efficiencies of up to 40 percent. Major design challenges include thermal management of the module and conducting very high DC currents. CPV projects have been relatively limited and are generally custom designs requiring special product installation methods.

3.2.2 PV Arrays

PV arrays are constructed from building blocks of individual PV modules, panels, and subarrays that form a mechanically and electrically integrated DC power generation unit. The mechanical and electrical layout and installation of PV arrays involve many interrelated considerations and trade-offs affected by the system design, the equipment used, and the site conditions.

Types of PV arrays can be classified broadly according to their electrical characteristics, the types of PV modules used, or by the way that PV arrays are mechanically integrated with buildings and other structures. PV arrays also are characterized by their surface orientation toward the sun and whether they are installed on fixed or movable structures.

The size of PV arrays usually is described by their peak rated DC power output, which is the data sheet STC rating multiplied by the number of modules in the array. PV array sizes can range from individual modules of a few watts to large fielded arrays of hundreds of megawatts using tens of thousands of individual PV modules. The array's electrical parameters dictate the system design and installation requirements, and must be matched appropriately to and compatible with the input ratings of inverters, charge controllers, or any other DC power-processing hardware with which PV arrays are interfaced. (As a corollary, utilities usually describe their PV systems based on their AC output (inverter) rating rather than the DC array rating.)

3.2.3 PV Module Performance

Current-voltage (I-V) characteristics are used to describe the electrical performance of photovoltaic cells, modules, or arrays. A specific I-V curve (shown in Figure 18) represents only one operating condition for a PV device, based on a specified level of solar radiation and device temperature. A single I-V curve represents an infinite number of current and voltage operating points at which a PV device can operate, depending on its electrical load.

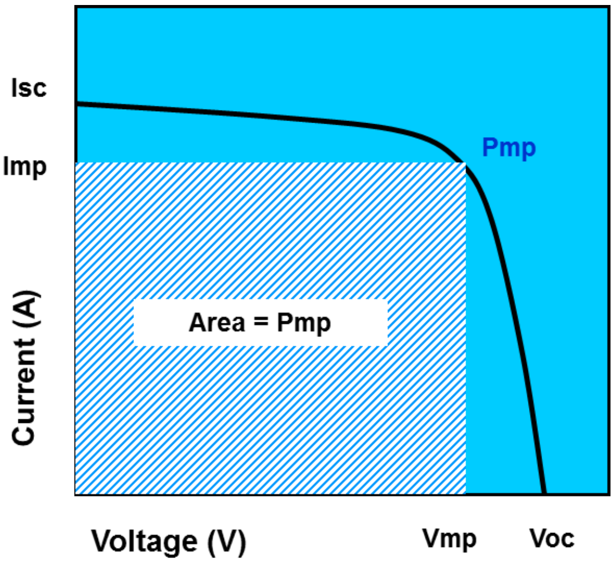


Figure 18: I-V Curves Represent the Electrical Performance of PV Devices at Specified Solar Irradiance and Temperature Conditions

Module manufacturers use certain key I-V parameters to describe the performance of their products at rated conditions and as the basis for circuit designs. These parameters include the following:

Open-circuit voltage (Voc) is the maximum voltage on an I-V curve and the operating point for a PV device with no connected load. Voc corresponds to an infinite resistance or open-circuit condition and zero current and power output. Open-circuit voltage is independent of cell area, decreases with increasing 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 0.6 V at 25°C. Module-level Voc will be specified on the data sheet. The array Voc is the module Voc times the number of modules in the series.

Short-circuit current (Isc) is the maximum current on an I-V curve. Isc corresponds to a zero resistance and short-circuit condition with zero voltage and power output. Short-circuit current is directly proportional to solar irradiance and is used to determine maximum circuit design currents for PV modules and arrays. Array Isc is the module Isc times the number of strings in parallel for an individual circuit.

Maximum power point (Pmp) of a PV device is the operating point at which the product of current and voltage (power) is at its maximum.

Maximum power voltage (Vmp) is the corresponding operating voltage at the maximum power point. Vmp is typically 70 to 80 percent of the open-circuit voltage.

Maximum power current (Imp) is the operating current at the maximum power point. Imp is typically about 90 percent 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.

Maximum power point tracking (MPPT) refers to the process or electronic equipment used to operate PV devices at their maximum power point under varying operating conditions. MPPT functions are integral to interactive inverters and some battery charge controllers in maximizing PV array efficiency and energy production.

3.2.4 PV Module Rating Conditions

Standard Test Conditions (STC) is the universal rating condition for PV modules and arrays, and specifies a solar irradiance level of 1,000 W/m^2 at air mass 1.5 spectral distribution and a cell operating temperature of 25°C. The electrical codes require all listed PV modules to have labeling that lists the key I-V parameters at STC for systems design purposes, and manufacturers specify these parameters, as shown in Figure 19.

GENERAL DATA	
Cell Type:	72 REC PE multicrystalline 3 strings of 24 cells with bypass diodes
Glass:	5/32" solar glass with anti-reflection surface treatment
Back Sheet:	Double layer highly resistant polyester
Frame:	Anodized aluminum (silver)
Junction Box:	IP67 rated 4 mm² solar cable, 47" + 47"
Connectors:	MC4 connectable (4 mm²)
Origin:	Made in Singapore
MAXIMUM RATINGS	
Operational Temperature:	-40 ... +85°C
Maximum System Voltage:	1000 V
Design Load:	75.2 lbs/ft² (3600 Pa)* 33.4 lbs/ft² (1600 Pa)* *Refer to installation manual
Max Series Fuse Rating:	20 A
Max Reverse Current:	20 A
MECHANICAL DATA	
Dimensions:	77 1/2 x 39 x 1 3/4 in
Area:	21 ft²
Weight:	59 1/2 lbs

Note! All specifications are subject to change without notice at any time.

ELECTRICAL DATA @ STC	REC295PE72	REC300PE72	REC305PE72	REC310PE72	REC315PE72
Nominal Power - P_{MPP} (Wp)	295	300	305	310	315
Watt Class Sorting - (W)	0/+5	0/+5	0/+5	0/+5	0/+5
Nominal Power Voltage - V_{MPP} (V)	36.1	36.4	36.6	36.7	36.8
Nominal Power Current - I_{MPP} (A)	8.23	8.33	8.42	8.53	8.62
Open Circuit Voltage - V_{OC} (V)	44.5	44.9	45.1	45.3	45.5
Short Circuit Current - I_{SC} (A)	8.80	8.86	8.95	9.02	9.09
Panel Efficiency (%)	15.1	15.4	15.6	15.9	16.2

Analysed data demonstrates that 99.7% of modules produced have current and voltage tolerance of ±3% from nominal values.
Values at standard test conditions STC (airmass AM 1.5, irradiance 1000 W/m², cell temperature 25°C).
At low irradiance of 200 W/m² (AM 1.5 and cell temperature 25°C) at least 95,5% of the STC module efficiency will be achieved.

Figure 19: Specifications and Ratings for REC PV Modules Used for SUNDA 1-MW Reference Design

Other conditions of solar irradiance and cell temperature sometimes are used for PV module and array ratings. Temperature and irradiance translations can be used to convert one rating condition to another. These rating conditions include the following:

Standard Operating Conditions (SOC)

- Irradiance: 1,000 W/m^2
- Cell temperature: NOCT

Nominal Operating Conditions (NOC)

- Irradiance: 800 W/m^2
- Cell temperature: NOCT

Nominal Operating Cell Temperature (NOCT)

- Irradiance: 800 W/m^2
- Ambient Temp: 20°C
- PV Array: Open-circuit
- Wind Speed: 1.0 m/s

PVUSA Test Conditions (PTC)

- Irradiance: 1,000 W/m^2
- Cell temperature: 45°C
- Wind speed: 1 m/s

Certain key I-V parameters at STC are required to be labeled on every listed PV module, as shown in Figure 20. 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)

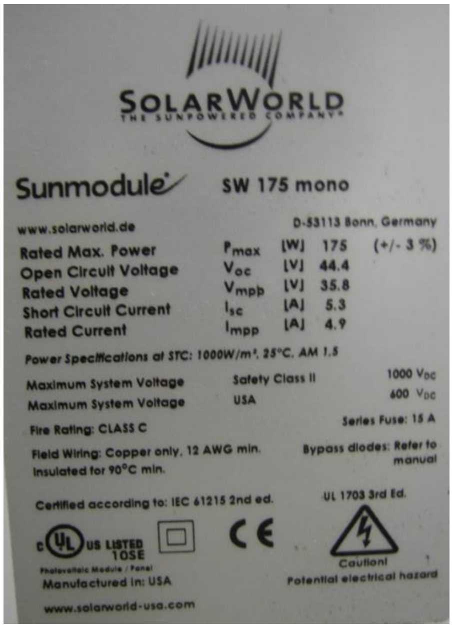


Figure 20: PV Module Labels Contain Important Information on Ratings and Design Application

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

3.2.5 PV Module Efficiency

Efficiency of a PV device is the ratio of the electrical power output and the solar irradiance input over the device area, expressed as a percentage. The efficiency of a PV device defines the area required to generate a given amount of power under a specified level of solar irradiance. PV modules with higher efficiencies require less surface area to produce a given amount of power, thus saving on costs for raw materials, mounting structures, and the balance-of-system equipment. However, higher efficiency modules generally are more expensive than less efficient modules per rated power output. Efficiency depends on temperature and the operating point on an I-V curve, and increases with increasing irradiance.

The efficiency of a PV cell, module, or array represents how effectively the device converts solar radiation to electricity. New record laboratory efficiencies for emerging technologies are reported routinely and compared with the theoretical limits and status of commercial development to assess the technology potential. However, module or array efficiency is not a direct indicator of PV system performance or value. Other factors and performance ratios are better suited to evaluate system performance, as discussed later in this manual.

PV module or array efficiency is defined by the ratio of DC power output to the solar power input, where the solar power input is simply the product of the plane-of-array (POA) irradiance and the module or array surface area.

For example, the efficiency of a 2-m^2 PV module producing 300 Wp-DC at 1 kW/m^2 irradiance would be:

Eff = 300 Wp/(2m^2 * 1,000 W/m^2) = 15%

The operating efficiency of a PV module or array in the field is not constant because power output is affected by temperature and how close the device operates in relation to its true maximum power point.

Efficiency also increases with higher irradiance levels (for constant temperature), an advantage utilized by concentrating PV module designs.

PV module manufacturers often report efficiencies in their specifications based on the module peak rated DC power output (Pmp) at STC. Using PV module manufacturers' data at STC, the estimated peak power output per unit area can be determined by multiplying the rated efficiency by an STC irradiance of 1 kW/m^2.

3.2.6 Response to Solar Irradiance

Solar irradiance 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 1,000 W/m^2 on surfaces at sea level facing the sun's rays under clear sky conditions around solar noon. Consequently, 1,000 W/m^2 is used as a solar irradiance reference condition for rating the peak output for PV modules and arrays.

Changes in solar radiation have a direct linear and proportional effect on the current and maximum power output of a PV module or array, as depicted in Figure 21. Thus, doubling the solar irradiance on the surface of an 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**.**

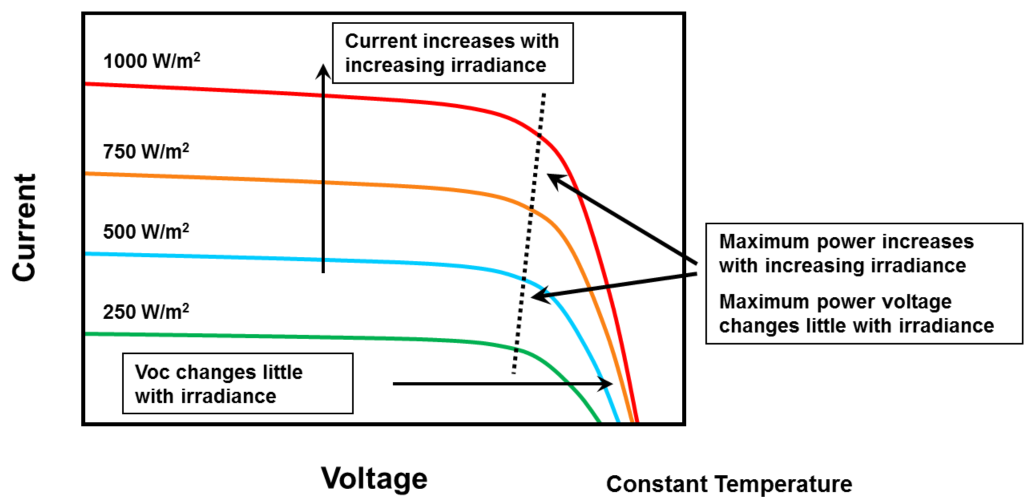


Figure 21: PV Module Current and Power Output Increase Proportionally with Solar Irradiance; Voltage Changes Little

PV installers using simple handheld meters may verify the performance of PV systems in the field by measuring the solar irradiance incident on arrays and correlating with the actual system power output. For example, if it has been established that the peak output rating for a PV array is 10 kW under incident radiation levels of 1,000 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, as shown in Figure 22.

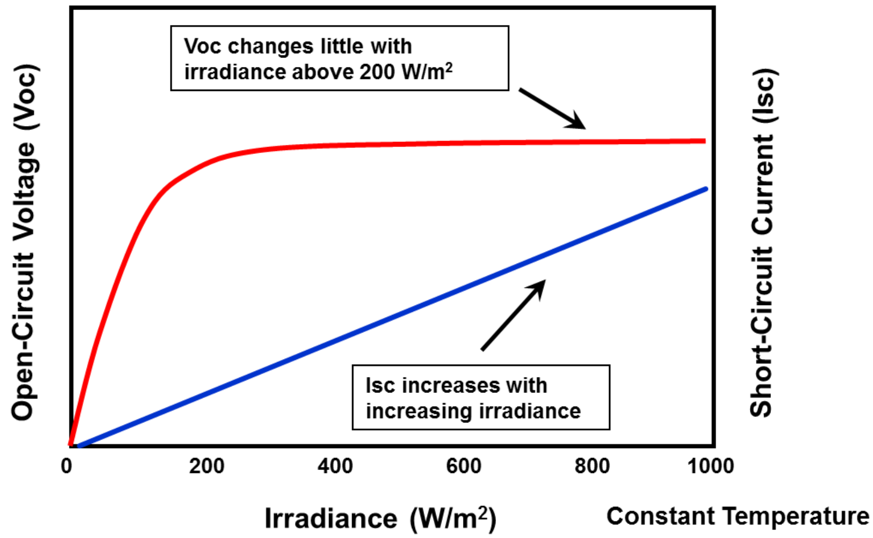


Figure 22: Open-Circuit Voltage Increases at Low Irradiance Levels, then Remains Relatively Constant as Irradiance Increases

The short-circuit current (Isc), maximum power current (Imp), and maximum power (Pmp) at one condition of solar irradiance may be translated to estimate the value of these parameters at another irradiance level:

$$Isc_2 = Isc_1 \times \frac{E_2}{E_1} \qquad Pmp_2 = Pmp_1 \times \frac{E_2}{E_1} \qquad Imp_2 = Imp_1 \times \frac{E_2}{E_1}$$

where

- Isc_1 = rated short-circuit current at irradiance E_1 (A)
- Isc_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)
- Pmp_1 = rated maximum power at irradiance E_1 (W)
- Pmp_2 = new maximum power at new irradiance E_2 (W)
- Imp_1 = original maximum power current at irradiance E_1 (A)
- Imp_2 = new maximum power current at new irradiance E_2 (A)

3.2.7 Response to Temperature

At nighttime, when there is no solar irradiance incident on a PV array, the array temperature is very close to the ambient air temperature and can even be somewhat cooler than ambient under clear sky conditions, due to night sky radiation losses. As irradiance increases, the difference between the array and ambient air temperature increases in proportion to the irradiance level and depends on the array mounting system configuration and natural airflow around the array. At peak sun during summertime, rack-mounted arrays may operate at 20–25°C above ambient temperature, whereas standoff roof-mounted arrays may operate as high as 30–40°C above ambient.

For crystalline silicon PV devices, increasing cell temperature results in a 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. The effects of temperature on current and voltage are depicted in Figure 23.

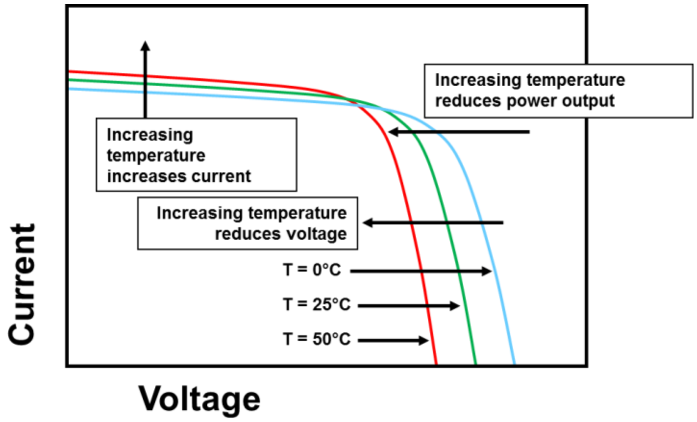


Figure 23: Lower Operating Temperature Increases the Voltage and Power Output from PV Arrays

Temperature coefficients relate the effects of changing PV cell temperature on device performance, such as voltage, current, and power. Temperature coefficients may be expressed either as a unit or a percentage change in a parameter. Unit temperature coefficients must be multiplied by the number of cells in series for the voltage and by the number of cells in parallel and the cell area for current.

Percentage change temperature coefficients are used more commonly. For crystalline silicon PV devices, the percentage change temperature coefficient for voltage is approximately -0.4%/°C (negative), the temperature coefficient for short-circuit current is approximately +0.04%/°C, and the temperature coefficient for maximum power is approximately -0.45%/°C (negative). Note that the power and voltage temperature coefficients are negative, as these parameters decrease with increasing temperature. Temperature coefficients for current are an order of magnitude less than for voltage and power and are not used for any system design calculations. Other PV materials have varying temperature coefficients; the manufacturer's coefficients should be used for voltage calculations.

$$V_{trans} = V_{ref} + [V_{ref} \times C_v \times (T_{cell} - T_{ref})]$$

$$P_{trans} = P_{ref} + [P_{ref} \times C_p \times (T_{cell} - T_{ref})]$$

where

- V_{trans} = translated voltage at T_{cell} (V)
- V_{ref} = reference voltage at T_{ref} (V)
- P_{trans} = translated power at T_{cell} (W)
- P_{ref} = reference power at T_{ref} (W)
- C_v = voltage-temperature coefficient (% per ºC)
- C_p = power-temperature coefficient (% per ºC)
- T_{cell} = cell temperature (ºC)
- T_{ref} = reference temperature (ºC)

For example, consider a 72-cell crystalline silicon PV module with a rated open-circuit voltage of 44.4 V at 25°C and a voltage-temperature coefficient of -0.33%/°C. The open-circuit voltage at a cell temperature of 60°C can be estimated by using the following:

$$V_{trans} = 44.4 + [44.4 \times 0.0033 \times (60 - 25)] = 39.2\ V$$

If the same PV module operates at -10°C (35°C lower than the reference temperature), the translated voltage is:

$$V_{trans} = 44.4 + [44.4 \times 0.0033 \times (-10 - 25)] = 49.6\,V$$

3.2.8 Bypass Diodes

Bypass diodes are connected in parallel with series strings of cells to prevent cell overheating when cells or parts of an array are shaded. 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 from overheating, as shown in Figure 24.

Most listed PV modules are equipped with factory-installed bypass diodes. When sealed junction boxes are used, as in Figure 25, bypass diodes are not serviceable in the field.

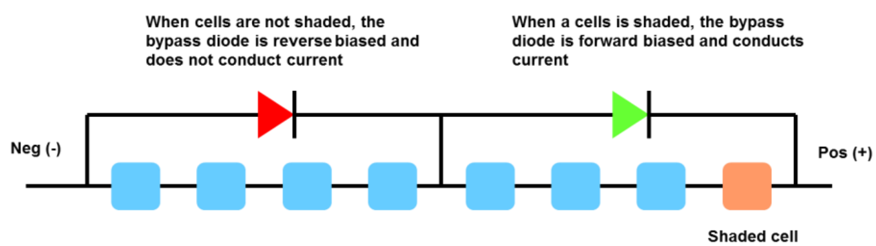


Figure 24: Bypass Diodes Protect Partially Shaded Cells from Overheating

Figure 25: Bypass Diodes Are Typically Located in Module Junction Boxes

3.2.9 PV Module Standards

Several standards have been developed to address the safety, reliability, and performance of PV modules. These modules are classified as electrical equipment and must conform to accepted product safety standards. According to the NEC, they must be listed or approved by a nationally recognized testing laboratory (NRTL).

In the U.S., PV modules are listed for electrical safety in UL1703, "Safety Standard for Flat-Plate Photovoltaic Modules and Panels." These requirements cover flat-plate PV modules intended for installation in accordance with the NEC and for use in systems with a maximum system voltage of 1,000 volts or less. The standard also covers components intended to provide electrical connections and for the structural mounting of PV modules. A similar international standard, IEC 61730, is published by the International Electrotechnical Commission (IEC) and harmonized with the UL 1703 standard.

3.2.9.1 Design Qualification

PV modules produced by leading manufacturers may be type tested for design qualification according to IEC standards, which increasingly are being required for module procurements. The first, IEC-61215, covers "Crystalline Silicon Terrestrial Photovoltaic (PV) Modules – Design Qualification and Type Approval"; the second, IEC 61646, covers "Thin-film Terrestrial Photovoltaic (PV) Modules – Design Qualification and Type Approval." The following are tests to which modules are subjected in design qualification: thermal cycling tests; humidity and freezing tests; impact and shock tests; immersion tests; cyclic pressure, twisting, vibration, and other mechanical tests; wet/dry hi-pot tests; and excessive and reverse current electrical tests.

Design qualification has important implications for product warranties offered by manufacturers. As a result, most major module manufacturers currently offer warranties of 20 years and longer that guarantee module peak power output to be within 80 percent of initial nameplate ratings, which equates to a degradation rate of no more than 1 percent per year.

PV modules may also be evaluated for fire classification, based on similar tests for determining fire exposure resistance for roofing 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 not suitable for installation on buildings. New requirements in the International Building Code require coordination of module fire class ratings with those of the roofing materials. However, the effects of PV arrays on roofing material fire class ratings are not well understood and are being investigated.

3.2.10 PV Array Configurations

PV arrays consist of building blocks of individual PV modules connected electrically in series and parallel. 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. Series strings of modules, or source circuits, are connected in parallel at combiner boxes to build current and power output for the array.

There are numerous ways in which PV arrays can be electrically and mechanically configured. The first objective is to create an array electrical configuration that meets the voltage, current, and power requirements for the system. The electrical requirements establish the number of PV modules required and the physical size of the PV array. The mechanical configuration then depends on the dimensions of the individual modules and the structure or foundation to which the array attaches.

Strings are series connections of PV modules. 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 up, 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 Figure 26 for a depiction of how array voltage is built.

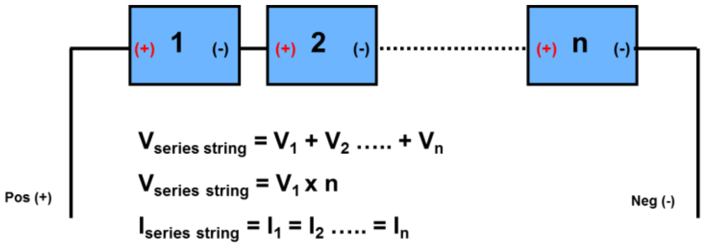
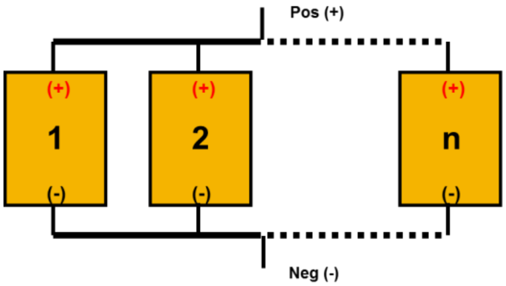


Figure 26: PV Array Voltage Is Built by Connecting Series Strings of PV Modules

Strings of PV modules are connected in parallel by connecting the positive terminals and the negative terminals together in a combiner box. For the parallel connection, the string voltage remains the same, and the string currents are the sum of the individual string currents, as shown in Figure 27**.**



$$V_{parallel} = V_1 = V_2 \ldots.. = V_{n\ \text{(for similar devices)}}$$

$$V_{parallel} = (V_1 + V_2 \ldots + V_n) / n$$

$$I_{parallel} = I_1 + I_2 \ldots.. + I_n$$

Figure 27: Connecting PV Source Circuits in Parallel Builds Array Current and Power Output

Monopole PV arrays have a single pair of positive and negative output circuit conductors. Monopole arrays are most common. **Bipolar PV arrays** are two monopole arrays connected together and used for large inverter applications. Bipolar arrays are used with certain inverters designed employing insulated gate bi-polar transistor (IGBT) switching elements or push-pull inverter topologies. Both types of arrays are shown in Figure 28**.**

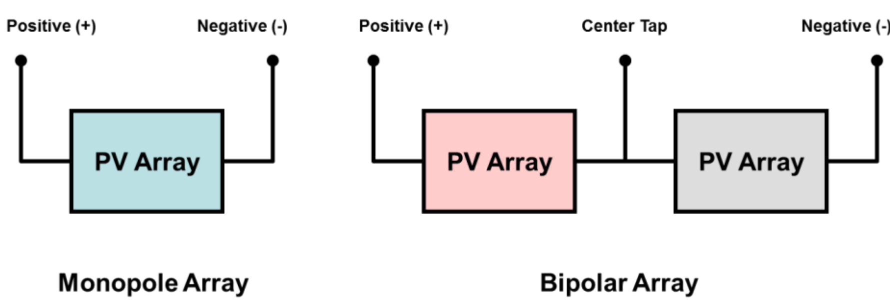


Figure 28: PV Arrays Can Be Configured as Monopole or Bipolar Arrays, Depending on Inverter Requirements

3.3 Power Conditioning Equipment

Power conditioning equipment is used to convert, control, or process the DC power produced by PV arrays to make it suitable for interfacing with electrical loads or utilization equipment. Power conditioning equipment includes inverters, chargers, DC-DC converters, battery charge controllers, and MPPTs. Power conditioning equipment interfaces between PV arrays, batteries, loads or other electrical systems, and primary components of PV systems.

Inverters convert DC power to AC power; they are characterized by the DC power source they use (PV array or battery), their power output, operating voltages, power quality, and efficiency. 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 at a few hundred watts to utility-scale inverters 1 MW and larger.

Modern electronic inverters used in PV systems are microprocessor-based power conditioning units (PCUs) that convert DC power input from a battery or PV array into AC power output suitable for utilization loads or connection to other electrical systems. Inverters also are used to produce AC power from fuel cells and some wind turbines with DC generators. Large inverters and rectifiers are used for high-voltage DC power transmission across grid interties. Inverters are also an integral part of devices that produce variable or high-frequency output, such as electronic lighting ballasts, induction heaters, and variable-frequency drives. Inverters often are used in conjunction with DC-DC converters and other power conditioning equipment components in high-speed microturbine generators.

Charge controllers are used in stand-alone systems to regulate battery-charging current from a PV array and protect from overcharging. Almost every PV system that uses a battery requires a charge controller for safe charging operations. Charge controllers are intended to optimize system performance and battery life; they are characterized by their method of charge regulation, set points, voltage and current ratings, and other features. Advanced charge controllers are microprocessor based and include PV array MPPT functions.

Load controllers regulate battery discharge current to electrical loads and protect a battery from overdischarge. Load controllers may also control the timing or duration of electrical loads, such as lighting. **Diversion charge controllers** regulate battery charge by diverting power to a diversion load. The diversion load may be DC load or an inverter that produces AC power and is interconnected to the utility grid. Systems using a diversionary charge controller as a primary means of control must have a second independent means of charge control to protect the battery if the diversion load fails or becomes unavailable to dump power from the battery.

Maximum power point trackers (MPPTs) are a type of DC-DC converter that operates PV modules or arrays at their maximum power output. All interactive inverters as well as some battery charge controllers contain MPPTs to optimize array output. MPPTs also can be utilized for water pump loads or located at the PV source circuit or module level to optimize output of the array.

Transformers are used with most large-scale PV systems for interfacing the inverter AC output with different utility service or distribution voltages. Most modern PV inverters do not use transformers, and many have non-standard AC output voltages. Transformers also are used to transition from delta-wye and wye-delta grid configurations.

Buck-boost transformers often are used as autotransformers to externally convert inverter output voltages to different load or utility voltages. These transformers can carry loads in excess of their nameplate rating and are an economical, compact means of slightly adjusting voltage up or down. For example, a buck-boost autotransformer may be used to convert an inverter’s 240-V output to a 208-V grid, or a 208-V output to a 240-V grid. Because the same winding is used for the primary and secondary sides, autotransformers do not provide isolation.

3.3.1 Grid Configurations

Larger inverters (30–50 kW and higher) typically are interconnected to three-phase power systems. An understanding of different types of electrical services and their compatibility with inverter output specifications is an important aspect of designing and installing utility-interactive PV systems.

Wye "Y" configurations are a type of three-phase electrical system characterized by the connection of three voltage sources (or phases) separated by 120° phase angle, with one pole of each source connected at a common point. The phase currents are always the same as the line currents, regardless of load balance. For a balanced load, the line voltage between any two phases is equal to the phase voltage times the square root of 3. For example, a typical Y-connected system with 120-V phases (sources) with a balanced load has line-to-line voltage of 120 V x 1.73 = 208 V. A Y-connected system with 277-V sources has a line-to-line voltage of 480 V. Wye configurations commonly are used for utility networks (see Figure 29) and Delta configurations for commercial services (Figure 30)**.**

A four-wire Y configuration uses a neutral conductor connected to the common point, whereas a three-wire Y configuration does not. The four-wire configuration with a neutral connection provides for 120-V loads and keeps the other phase voltages the same if one phase opens, which is important for connecting motors and inverters.

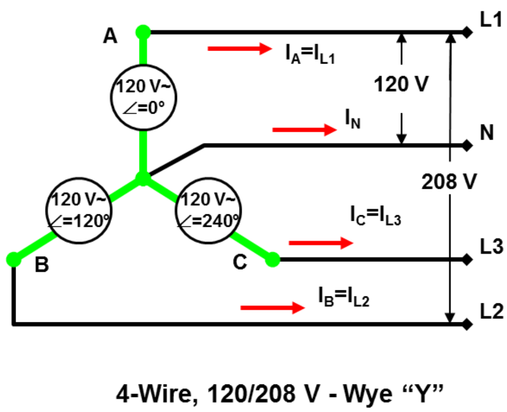
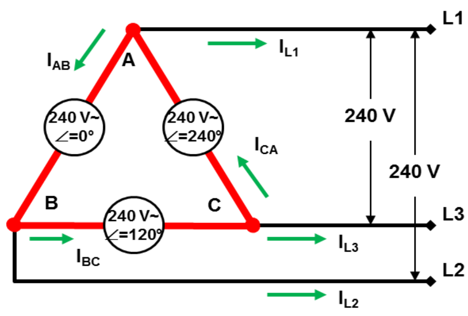


Figure 29: Wye Configurations Are Commonly Used for Utility Networks

Delta "Δ" configurations are a type of three-phase electrical system network characterized by the connection of three voltage sources separated by 120° phase angle, with each source connected in series with the other to form a triangular loop. There is no common connection point for the three sources. In Δ-configurations, the line-to-line voltage is equal to the phase voltage regardless of load, since the loads are connected in parallel with each phase. For a balanced load, the line current is equal to the phase current times the square root of 3. For example, a typical Δ-connected system with 240-V phases (sources) also has line-to-line voltage of 240 V.



3-Wire, 240 V Delta "Δ"

Figure 30: Delta Configurations Are Commonly Used for Commercial Services

A high-leg delta configuration center taps one winding for a ground and neutral connection. This allows a single service to supply 120 V for lighting, 240 V single-phase, and 240 V three-phase for motor loads. Two of the phases are 120 V to neutral; the third phase or "high leg" is 208 V to neutral.

3.3.2 Inverter Circuit Designs

3.3.2.1 Basic Inverter Design

Inverter circuits use high-speed switching transistors to convert DC to AC power. Most PV inverters use metal-oxide semiconductor field-effect transistors (MOSFETs) or 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 kHz) and generally are used in medium- to low-power applications.

IGBTs handle high current and voltage, but switch at lower speeds (up to 20 kHz) and are more common for larger high-voltage power applications. Switching elements are connected in parallel to increase current and power capability.

The AC output voltage of a utility-scale inverter bridge is a function of the DC input voltage and various other design choices. To provide a standard output voltage and prevent injection of DC onto the grid, inverters traditionally have used a step-up isolation transformer to bring the 60-Hz output voltage to 480 V, with a second transformer used to bring the voltage to distribution levels (e.g., 13.2 kW).

Some modern inverters have eliminated the need for this 60-Hz isolation inverter by incorporating a small high-frequency transformer between a DC/DC converter connected to the array and the bridge used to generate AC. The non-standard output then is brought directly to distribution voltage using a custom transformer. This eliminates both the cost and losses for the extra transformer.

There are also inverter designs that use bipolar and ungrounded PV arrays.

Bipolar inverters use two monopole PV subarrays for the DC input, with a positive and negative pole, and a center tap ground. For example, +600 VDC and -600 VDC ground-referenced PV output circuits can be used to provide 1,200 VDC maximum voltage to the inverter bus. Conductors and equipment need only be rated for 600 V if the PV output circuits for each monopole arrays are run in separate raceways and terminate within the inverter.

Most interactive inverters allow configurations for grounding either the positive or negative pole of the PV array. Performance enhancements are achieved with certain PV modules (Sunpower and some thin-film products) with a positive ground reference. A high-impedance ground connection can be used to allow these systems to operate with ungrounded inverters.

All interactive inverters manufactured for the U.S. market prior to 2010 ground either the positive or negative DC output circuit conductor from the array. DC faults are detected and interrupted by inverter ground-fault indication/detection (GFID) circuits. However, smaller faults below the rating of the GFID fuse may go undetected, and faults between the grounded circuit conductor and ground are not detected and may circulate within the array. This situation has occurred at a few larger PV sites, resulting from poor installation workmanship.

Ungrounded PV arrays do not use a grounded DC current-carrying conductor. Ungrounded PV arrays are permitted by NEC (2017) 690.41 and commonly used throughout Europe. These designs have additional requirements over grounded PV arrays, but offer certain advantages for fault protection. Inverters used with ungrounded arrays are required to be listed and approved for ungrounded operations. Ungrounded arrays require overcurrent protection and disconnect means in both the positive and negative circuits, and special double-insulated cabling or conduit is required for DC source circuits. With ungrounded arrays, ground faults are measured between each pole of the array and ground. Circulating fault paths within the array are not possible, and faults can be measured at much lower levels. All systems still must have equipment grounding, whether they use grounded or ungrounded arrays.

Power and Voltage Considerations

Interactive inverters can usually handle PV array DC power input levels 110–150 percent 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, so as not to damage the inverter. The PV array also must not exceed the maximum DC input current limits for the inverter.

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

Interactive inverter manufacturers offer online string sizing tools to determine the appropriate PV module configurations for their products. Inverter specifications define the operating limits for PV array DC current, voltage, and power. PV module specifications and site temperature extremes are used to estimate the range of array voltage and power output for specific series and parallel module configurations appropriate for the inverter. All tools include a disclaimer and strongly recommend that calculations should be made independently and verified by system designers, using actual application conditions and module temperature coefficients. A string sizing tool for evaluating PV array voltage compatibility is shown in Figure 31.

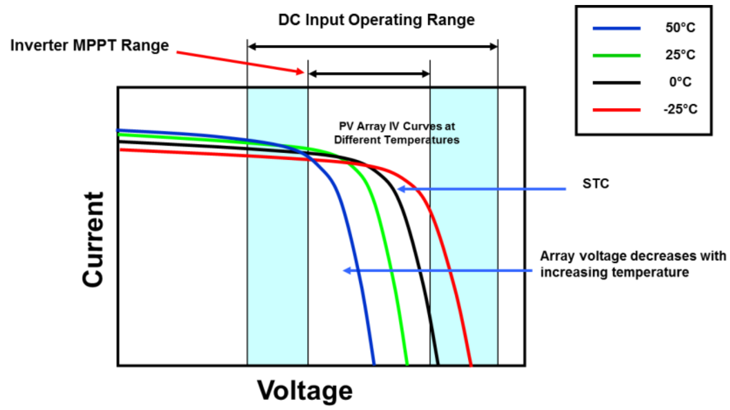


Figure 31: String Sizing Evaluates PV Array Voltage Compatibility with Inverter Input Requirements

3.3.2.2 Module-Level Inverters

Module-level inverters are installed integrally or adjacent to individual PV modules and include AC modules and micro inverters. These small inverters typically are rated from 200 to 300 W and are compatible with common PV module sizes. **Micro inverters** are module-level inverters installed to support structures behind individual PV modules as separate equipment, as shown in Figure 32. **Alternating-current (AC) modules** are a factory-integrated listed assembly consisting of a PV module and inverter that produces AC power.

Figure 32: Micro Inverters Are Installed Adjacent to Individual PV Modules

Module-level inverters offer several advantages over string inverters for smaller systems, including individual module maximum power tracking and better energy harvest from partially shaded and multi-directional arrays. They are inherently safer than a string inverter system, as the maximum DC voltages on the array are only for a single module, presenting less risk to first responders. By producing AC power at the module level, they also eliminate DC circuit design issues and costs. The AC output of multiple inverters is connected in parallel to a dedicated branch circuit breaker, similar to a load circuit.

Other module-level electronics include maximum power trackers and DC-DC converters/optimizers, which achieve similar performance benefits as module-level inverters, although they still require DC circuits. Module-level inverters and electronics also meet existing and anticipated new fire codes that may require module-level rapid shutdown provisions for all PV systems installed on buildings.

Presently, micro inverters and other module-level electronics are used primarily for residential and small commercial applications. However, the costs and reliability of these products have been improving considerably over the past few years, and these products may receive wider use in large commercial and even utility-scale projects.

3.3.2.3 Single-Phase String Inverters

Single-phase string inverters are small inverters in the 1- to 12-kW size range, intended for residential and small commercial applications. These inverters are generally single phase, usually limited to one to six parallel-connected PV source circuits or strings of up to 15 series-connected modules, as shown in Figure 33. Some string inverters integrate source circuit combiners, fuses, and disconnects into a single unit.

Modules in series-connected strings should be identical and located in the same plane so they receive the same amount of solar radiation and produce the same current output to avoid mismatch losses. Strings are connected in parallel at combiner boxes to build higher array voltage and power outputs. Source circuit strings of 8–12 modules in series typically are 1.5–3 kW and operate at voltages of 300–600 VDC, although the NEC now allows 1,000 VDC so some inverters now allow that string voltage.

Larger systems using multiple string inverters offer some advantages in systems design and installation. Multiple inverters can be distributed at subarray locations, thus avoiding multiple combiner boxes and long DC circuit runs, 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 MPPT and monitoring at the subarray level, facilitating fault finding and optimizing the output of individual subarrays of different sizes, types, orientations, or those that are partially shaded. The AC output of multiple single-phase string inverters can be distributed equally across the three phases in groups of three to avoid phase imbalance.

Figure 33: String Inverters Use Series-Connected Array Designs

3.3.2.4 Three-Phase String Inverters

Three-phase string inverters are inverters in the 10- to 100-kW size range, intended for commercial and utility-scale applications. These inverters use one or more strings as input, with three-phase AC as output. This means that much of the wiring across the array field can be three-phase AC instead of high-voltage DC. Other potential advantages are modularity in design and "soft-failure" modes—if an inverter fails, only a small section of the array output is affected, and it can be replaced in the field and then repaired. This advantage is at least partially offset by the fact that with multiple inverters experiencing the same failure rate, there will be more inverter failures.

3.3.2.5 Multimode Inverters

Multimode inverters are utility-interactive inverters that use battery storage and can operate in either an interactive or stand-alone mode. These types of inverters are often used where a backup power supply is required for critical loads. Multimode inverters are available in sizes ranging from 2 to 10 kW and primarily intended for residential and small commercial applications.

Under normal circumstances when the grid is energized, a multimode inverter acts as a diversionary charge controller, limiting battery voltage and state of charge by diverting excess energy to the grid. 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 without interrupting the operation of electrical loads. These inverters may also be used in hybrid system applications to control loads, battery charging, and generator starting.

3.3.2.6 Central Inverters

Central inverters (see Figure 34) are designed for commercial applications. These inverters interconnect to three-phase networks at typical commercial service voltages. Central inverters are intended for homogeneous PV arrays having all the same model modules and source circuit configurations, and oriented in the same direction with no shading. Central inverter installations require heavier handling equipment and larger conduit and switchgear than for string inverters.

In common practice, 3-phase string inverters have replaced this size of central inverter for commercial applications.

Figure 34: Central Inverters Are Used in Medium to Large Commercial Installations

3.3.2.7 Utility-Scale Inverters

Utility-scale inverters are industrial power conditioning units ranging in size from 500 kW to 2.5 MW with multi-inverter skid mounts at 5 MW and larger, and designed for utility PV plants. These inverters typically operate with PV array DC voltages up to 1,500 V, and may include transformers and MV switchgear to allow interconnection to the grid at distribution voltages up to 38 kV. Large projects (20 MW or larger) are typically connected to the transmission grid and must adhere to NERC interconnection rules.
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. These large inverters are typically installed at sites with restricted access and under the exclusive control of an electric utility.

Figure 35 shows the Schneider Electric Conext Core XC Series Inverter.

Schneider Electric Conext Core XC-NA Series Inverters

The SUNDA 1-MW reference design uses the Schneider Electric Conext Core XC-NA Series inverter. This 500-kW central inverter for utility-scale PV systems includes integrated grid management functions, switchgear, and monitoring systems. It uses a transformerless design and operates from PV arrays up to 1,000 VDC. The output is 300 VAC/3-phase, which is intended to be interconnected to distribution systems through a transformer. For additional information on the inverters specified for the SUNDA 1-MW reference design, including installation manuals, operating instructions, monitoring systems, specifications, and certifications, see the manufacturer's website: http://solar.schneider-electric.com/.

Figure 35: Schneider Electric Conext Core SC-NA Series Inverters

3.3.3 Inverter Specifications

Selecting and specifying inverters for a given application involves considering the system design and installation requirements. Inverter specification sheets provide the physical characteristics and operating parameters for the PV array and circuit designs.

All inverters are rated for their maximum continuous AC power and current output over a specified temperature range. Inverter power ratings are limited by the temperature of their switching elements; many larger inverters use cooling fans. Interactive inverters limit their maximum power output by tracking the PV array off its maximum power point. This protective feature is integral to all listed interactive inverters.

All interactive inverters employ MPPT algorithms in the inverter circuitry to load PV arrays at their maximum output condition. Some smaller inverters use independent MPPT on each source circuit input. Larger systems may incorporate MPPT for source circuits or subarrays at distributed combiner boxes throughout the array. This allows the maximum output to be extracted from larger arrays with multiple source circuits that may have different I-V characteristics. These different characteristics may be due to using dissimilar modules or numbers of modules in series strings, having parts of the array orientated in different directions, temperature variations, or partial shading within the array.

Typical inverter specifications include the following DC and AC parameters and features:

DC Input

- Maximum array voltage (open-circuit, coldest expected conditions)
- Recommended maximum array power
- Start voltage and operating range
- MPPT voltage range
- Maximum usable input current
- Maximum array and source circuit current
- Ground fault and arc fault detection

AC Output

- Maximum continuous output power
- Maximum continuous output current
- Maximum output overcurrent device rating
- Power quality factors
- Anti-islanding protection

Additional information covered in inverter specifications and installation manuals usually includes the following:

- Nominal and weighted efficiencies
- Stand-by losses (nighttime)
- Monitoring and communications interface
- Operating temperature range
- Size and weight
- Mounting locations, enclosure type
- Conductor termination sizes and torque specifications
- Conduit knockout sizes and access
- Integral DC or AC disconnects
- Number of source circuit combiner and fuse/circuit ratings
- Standard and extended warranty provisions

Inverter selection is often the first consideration in system design, based on the type of electrical service and voltage, and the size and layout of the PV array. For interactive inverters, STC DC ratings for the PV array are typically 120–150 percent of the inverter maximum continuous AC power output rating.

Figure 36 shows the features of the Schneider Conext Core XC-NA Series.

Conext Core XC-540-NA Specifications

DC Input	
Input voltage range, MPPT	440-800 V (at PF=1)
Input voltage range, operating	440–885 V
Static and dynamic MPPT accuracy	>99.9% 5% to 100% of nominal power Entire MPP (maximum power point) range; PV generator Fill Factor from 60-80%
Max. input voltage, open circuit	1,000 V
Max. input current	1,280 A
Max. input short circuit current at STC	1,600 A
Max. input short circuit current under any condition	2,000 A
AC Input	
Nominal output power	540 kVA
Power factor settable range (Ppf dispatch)	0.8 to 1 leading and lagging
Power factor range (PQ dispatch)	0 to 1 leading and lagging
Real power	540 kW (at PF=1)
Reactive power range	+/- 540kVAR
Output voltage	300 V
Frequency	60 Hz
Nominal output current	1,040 A
Harmonic distortion (THDi)	<3% at rated power

Efficiency	
Maximum	98.2%
CEC	97.5%

General Specifications

Power consumption, night time	< 210 W
Degree of protection	Enclosure type 3R, suitable for use in class 4S2 according to IEC 60721-3-4
Enclosure material	Steel with 3 layer coating (zinc primer, epoxy powder coat, polyester powder coat)
Seismic	IEEE-693-2005 Moderate performance level*, IBC certification ICC-ES AC156-2012**
Product weight (includes DC combiner)	2240.0 kg (4938.0 lb)
Product dimensions (H x W x D) (includes DC combiner)	227.3 x 321.4 x 85.8 cm (89.5 x 126.5 x 33.8 in)
Ambient air temperature for operation	-20°C to 50°C (-4°F to 122°F) full power. Power derating to 55°C (low temperature option to -35°C)
Operating altitude	1000 m, derating for higher altitudes
Relative humidity	0 to 100% condensing

Features

Type of cooling	Forced convection cooling
Display type	LCD multifunction removable display standard
Communication interface	RS485/Modbus standard, Modbus over TCP/IP optional
AC/DC disconnect	Load break rated DC disconnect and AC circuit breaker standard - meets the requirements of NEC 690.17
Ground fault detection/interruption	Pre-connection isolation monitoring relay with GFDI (negative or positive grounding), or isolation monitor (floating configuration)
Sub-array combiner	Integrated sub-array combiner - up to 10 poles with fuse sizes from 250 A to 400 A, optional string monitoring, optional disconnects

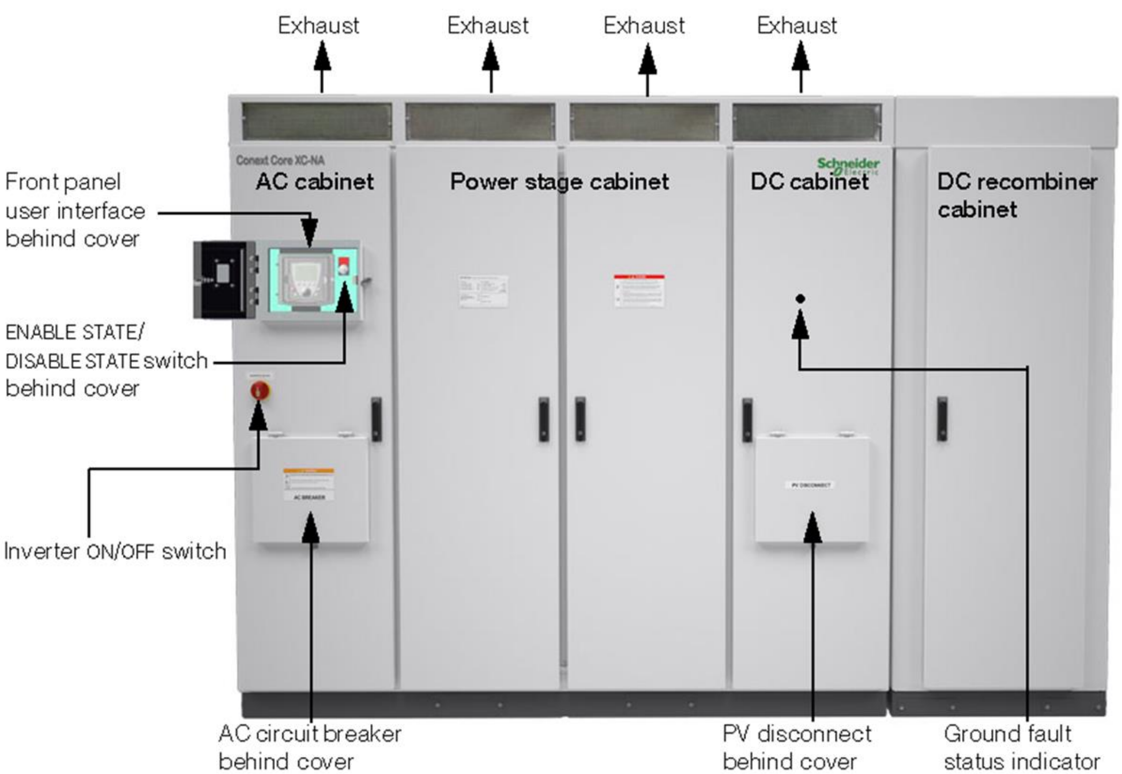


Figure 36: Schneider Electric Conext Core XC-NA Series Features

3.3.4 Inverter Standards

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

The following key standards apply to PV system inverters:

- UL 1741, "Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources", addresses product safety requirements for all types of distributed generation equipment. This standard has been updates to UL-1741SA. UL 1741 SA is a product safety standard that lays out the manufacturing (including software) and product testing requirements with the goal of producing inverters more capable of riding through grid excursions or even actively managing grid reliability functions. Although it is currently applicable on in California and limited other markets, it addresses many of the same areas as the new IEEE 1547 standards and will form the basis for a future nationwide standard.
- UL 62109-1, "Standard for Safety of power converters for use in photovoltaic power systems - Part 1: General requirements", which has been harmonized with IEC 62109.
- IEEE Std 1547-2018 – "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" is the basis for UL 1741 certification for interactive inverters. This is part of a family of standards which includes additions information on testing, monitoring, microgrid applications and many other subjects. This standard has been revised to accommodate new inverter functions such as voltage and frequency ride-through, VAR sourcing / sinking, ramp rates, and controlled curtailment.

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 for state incentive programs. 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 is available online.[3]

Inverter efficiency is calculated as the AC power output divided by the DC power input and varies with power level, input voltage, and temperature, among other factors. 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 low power levels; most inverters reach at least 90 percent efficiency at only 10 percent of their maximum continuous output power rating. Most large interactive inverters have weighted efficiencies of 95 percent or higher, as shown in Figure 37.

[3] List of Eligible Inverters per SB1 Guidelines, California Energy Commission: http://www.gosolarcalifornia.org/equipment/inverters.php.

Input Voltage (Vdc)		Power Level (%; kW) 10% 54.00	20% 108.00	30% 162.00	50% 270.00	75% 405.00	100% 540.00	Wtd
Vmin	439	95.26	97.47	97.91	98.14	98.14	97.57	97.93
Vnom	529	95.20	97.17	97.62	97.82	97.80	97.34	97.63
Vmax	800	93.24	96.14	96.85	97.24	97.22	96.77	96.95

CEC Efficiency of Inverter and ABB Transformer = 97.5%

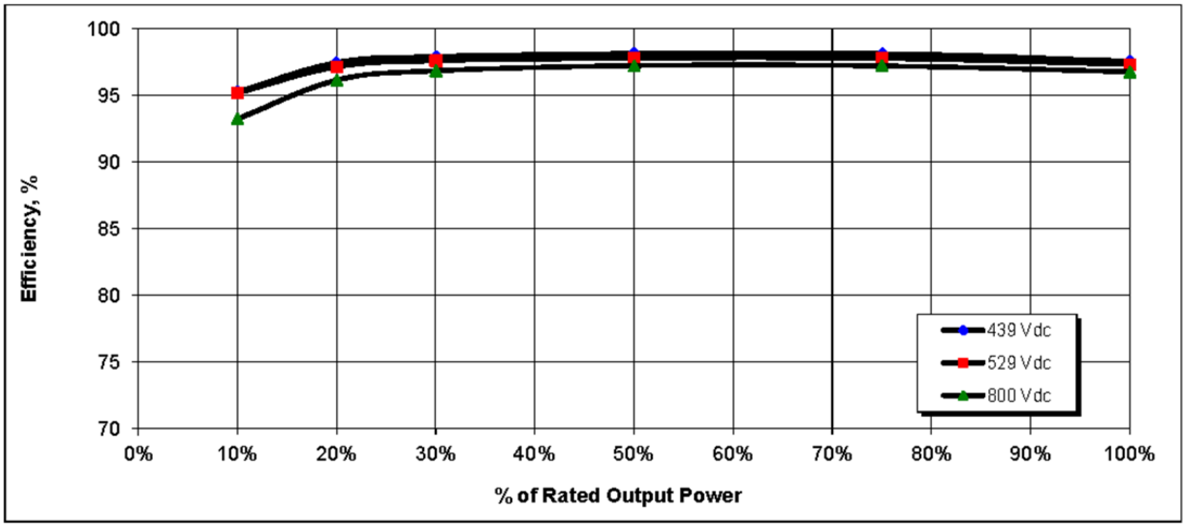


Figure 37: Inverter Efficiency Curves Show Power Conversion Efficiencies over a Range of Power and Voltage Levels (Conext Core XC-540-NA)

PV modules are wired into strings based on the input voltage limitations of the inverter, which are paralleled in combiner boxes mounted on the array structure. Large amperage "home run wiring" then goes to disconnects before being input to the inverter.

Modern inverters are required to conform to IEEE 1547 to prevent "islanding" of the PV system in a power outage. However, more advanced functions are available in today's inverters, including ramp-rate control, controllable curtailment (turning the array down, not just turning it off), and low-voltage and low-frequency ride-through to help provide temporary system support during grid interruption events.

All interactive inverters include integral monitoring and communications interfaces to record, display, and retrieve key operating and performance information, including the following:

- DC input operating parameters (array voltage, current, and power)
- AC output parameters (grid voltage, current, and power)
- Energy production (daily and cumulative)
- Fault conditions and error codes

Data and operating status may be indicated on the inverter panel and/or retrieved remotely through communications interfaces. Additional sensors for temperatures and solar radiation may be added to some inverters and aftermarket monitoring systems.

3.4 PV Array Mounting Structures

PV arrays can be mounted on the ground or attached to buildings or other structures using a variety of methods. PV array mounting orientations can also be classified as fixed-tilt, adjustable, or sun-tracking mounts.

Fixed-tilt arrays are non-movable structures that position the PV array in a constant orientation relative to the sun. Fixed PV arrays installed in northern latitudes are tilted up from the horizontal and oriented toward the south, and away from shading obstructions to maximize the solar energy received. Most PV arrays installed on buildings and ground mounts use fixed-tilt PV arrays.

Adjustable-tilt arrays use mounting structures with removable fasteners, telescoping legs, or other manual means to allow for seasonal adjustments of the array tilt angle. Adjusting the tilt angle of PV arrays twice per year, around the time of the equinoxes in the spring and fall, can marginally improve system output, but is generally not practical for most installations due to the added structural complexities and labor requirements.

Ground-mounted arrays, as shown in Figure 38, are detached from buildings and include racks, pole mounts, and sun-tracking arrays. Ground-mounted arrays usually permit the greatest flexibility in mounting and orienting the array. Ground mounts require anchoring to foundations such as concrete, setting poles, anchoring directly in the soil, or by self-ballasting means. The site conditions and the methods and materials specified by the mounting system manufacturer usually dictate the best installation practices.

Since ground-mounted arrays are typically at lower elevations, shading from nearby trees, fences, buildings, towers, power lines, and other obstructions may be a concern. Ground-mounted PV arrays generally require restricted access by fencing or elevating the array to reduce safety hazards.

Figure 38: Ground-Mounted PV Arrays Often Use a Combination of Pole and Racking Designs for Simplicity

Rack-mounted arrays are commonly used on the ground and commercial buildings, and offer the greatest flexibility in mounting the array at specific tilt angles. Small rack-mounted arrays can be installed on poles, and larger racks can be installed in multiple rows for larger arrays. Rack-mounted arrays can be fixed tilt or adjustable.

Self-ballasted arrays rely on the weight of the PV modules, support structure, and additional ballast material to secure the array. Self-ballasted arrays are intended to reduce or eliminate direct structural connections to a building or foundation, thereby avoiding additional labor and weather-sealing concerns. This type of mounting system may also be used for some ground-mounted systems. Typical ballast materials include sand and concrete blocks installed in trays at the bottom of the racks. Self-ballasted arrays usually require additional restraints in seismic and high-wind load regions.

Pole-mounted arrays use either fixed, adjustable, or sun-tracking arrays on racks installed on a rigid metal pipe or wooden pole. Pole-mounted designs allow the arrays to be elevated to protect them from harm and avoid shading; most allow the array azimuth angle to be rotated for optimal orientation. Pole mounts have larger foundation loads than distributed supports as well as limitations on the size of the array they can support, based on the size of the pole and foundation.

Tracking arrays use mounting structures that automatically and continually move the array surface to follow the sun's position throughout the day. Sun-tracking arrays are characterized by their tracking mode and whether they track the sun on one or two axes, as shown in Figure 39. Most single-axis trackers are designed to move the array surface east to west on a north-south tracking axis tilted from the horizontal. Sun-tracking arrays can receive up to 30 percent more solar radiation than fixed south-facing arrays. Single-axis trackers do not face the sun directly at all times, but generally receive 15–30 percent or more solar radiation than do south-facing fixed-tilt surfaces. Marginal performance benefits are achieved with two-axis tracking over single-axis designs but they seldom justify the additional equipment and expense involved. Point-focus concentrating PV modules require two-axis sun tracking to capture the direct-beam solar radiation component, whereas linear-focus concentrators can use single-axis tracking.

Tracking arrays can be controlled by passive or active means. Passive means use solar heating of working fluids in the tracker's internal structure to create a weight shift and move the tracker or pressurize piston actuators to move the structure (see Figure 40). Active trackers use computers to control motors or other devices to keep the array aimed towards the sun.

North-south axis, zero-tilt single-axis trackers are the most common type of tracker used today. There are three primary types of design in common use. The first design uses a single motor and a mechanical linkage to control multiple rows of modules. A great deal of engineering has been done in recent years to reduce the costs of this design and to improve the reliability through use of flexible joints and sealed bearings. The second design uses a separate motor for each row of modules. Similar to the drive towards distributed string inverters rather than central inverters, the idea is that if a single motor fails, it affects only a small portion of the array and can be rapidly swapped out by a small crew due to its limited size. A new tracker design by Sunfolding uses pneumatic actuators to tilt arrays.

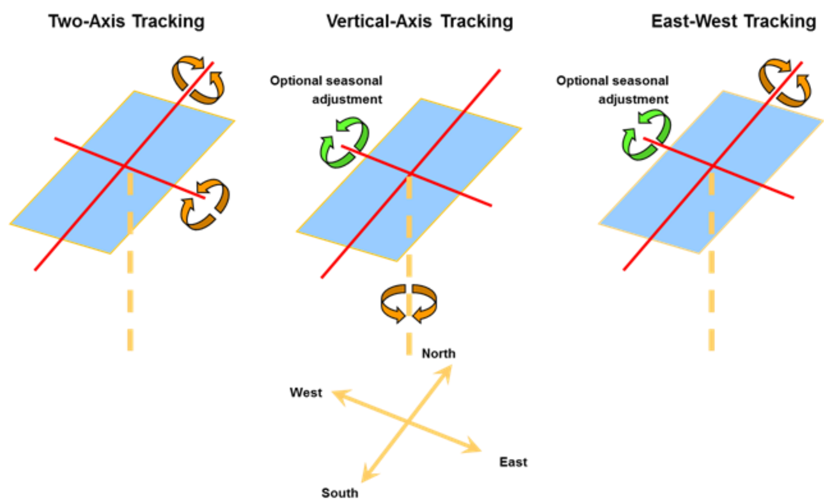


Figure 39: Sun-Tracking Arrays Receive Higher Levels of Solar Radiation than Fixed Arrays but Require Larger Areas

Figure 40: Active Sun-Tracking Arrays Use Hydraulic Pistons, Pneumatic Pistons or Motors to Drive the Tracking Mechanism for Single Rows or Multiple Subarrays

Tracking PV arrays are usually installed on the ground rather than on top of buildings due to the large structural loads at the foundations. Tracking systems usually require more land than fixed arrays as well as sufficient spacing between individual rows to avoid shading. Most single-axis tracker designs use a backtracking approach to limit the tracker movement early in the morning and late in the afternoon and sacrifice some solar energy gain to permit closer spacing of individual trackers and avoid shading. Trackers also use a "safe stow" mode which can be activated when high winds are anticipated.

The trade-off for tracking systems involves balancing the additional initial costs and recurring maintenance versus the cost of additional modules on a fixed array to achieve similar energy performance. Single axis trackers currently cost about 10% more than fixed tilt systems, but produce between 20-30% more energy, especially during summer months.

In addition to energy benefits, the output of trackers provides more power earlier in the day and later in the afternoon than a south-facing fixed tilt system. This can provide significant peak reduction benefits which can provide additional value to co-ops. Similar peak reduction benefits can be achieved by orienting the array more towards the west and at a steeper tilt. However, this results in reduced energy production, which may offset

Roof-mounted array designs include standoff mounts and rack mounts that can be retrofitted to existing rooftops. Rooftops often have large areas of unused space and are popular locations for installing PV arrays. Rooftop locations provide higher elevations that help avoid shading and offer additional protection and safety for the array. Most roof-mounted PV arrays use fixed-tilt support structures retrofitted to existing rooftops. Roof mounts may also be classified according to the type of roof structure or roof covering to which the array attaches, such as sloped or flat roofs; or asphalt shingle, metal, tiles, or composition roofing materials. Because of practical and structural considerations, roof mounts generally do not use movable sun-tracking arrays or pole mounts.

Standoff-mounted arrays are the most common method for attaching PV arrays to sloped rooftops. Standoff mounts typically locate the PV modules 3–5 inches above and parallel to the roof plane. They usually are not tilted at a different angle than the roof surface because the added complexity and costs of installing mounting structures obliquely with respect to the roof surface usually do not justify the marginal increases in solar energy gain and system performance. Several manufacturers provide standard mounting hardware for roof-mounted standoff arrays that meet the structural loads for most applications.

Building-integrated PV (BIPV) arrays include direct mounts and integral mounts integrated with building components and cladding materials, such as windows, awnings, and roofing tiles. The advantage of BIPV arrays is that the PV array replaces conventional building materials, thus saving on materials and construction costs. Most BIPV arrays are designed into the original building architecture, use custom-designed modules, and require special installation procedures.

3.5 Balance-of-System Components

Balance-of-system (BOS) components include mechanical and electrical equipment, and other hardware used to assemble and integrate major components, and conduct, distribute, and control the flow of power in the system. Typical BOS components include the following:

- Conductors (wiring)
- Raceways (conduit)
- Junction and combiner boxes
- Disconnect switches
- Overcurrent fuses and circuit breakers
- Terminals and connectors
- Safety and protective equipment
- Array mounting hardware

It is important that all electrical balance of system equipment be rated for the proper voltage, especially on the DC size of the system where array voltages of 1,000 VDC and 1,500 VDC have become commonplace and 2,000 VDC systems are being proposed for the near future.

4 System Design

The design of solar PV plants involves many factors and trade-offs, ranging from regulatory and compliance matters to the electrical, mechanical, and civil engineering details. The design process begins with the project development and financial considerations addressed in Volume I, which establish some of the initial design options and constraints, such as the proposed location and size of the system. A preliminary design study then can be conducted to help assess the project's feasibility.

The following are the design objectives:

- Utilize the allocated land area effectively
- Maximize the electrical output per unit of land area and cost
- Maximize the energy production of the plant per unit of land area and the unit DC size of the PV array
- Prepare construction drawings/prints for installation

4.1 Preliminary Design Considerations

Topographical and land-cover information is evaluated using available geographical resources (NREL's Solar Prospector, for example). These data are used to develop a 9 a.m. to 3 p.m. shading model, which generally indicates areas to avoid when considering PV. The target modules, array structure, and inverter typically are chosen at this time to allow a physical representation of the array.

Taking these shading models into consideration, engineers then define the array layout to scale on a boundary survey, aerial photo, or both, as available. The array configuration design will balance the electrical string size requirements for minimum and maximum voltage with the physical space requirements for shading, spacing between rows of panels, and desired system size.

The land should be surveyed for suitability as to drainage, wetlands protection, endangered species protection, and other factors.

The land should also be evaluated for land-use permitting and requirements for road access, both for construction and normal operation.

A basic interconnection to medium voltage should be analyzed at this stage, including a plan for any lines necessary to reach the point of interconnection with the medium-voltage grid.

A sizing program such as PVWatts or PVSyst™ then is used to calculate energy output from the PV system as designed; it can be used to identify shading issues and the potential value of off-south orientation.

A geotechnical study is recommended to analyze soil types and determine the embedment requirements for driven piles or helical screw anchors.

4.2 Design Considerations

Site considerations include the following:

- Offsets to frontage, property lines, and environmental features
- Site work needed.
- Soil quality – will embedded rocks affect the types of foundations that can be used.
- Reflection issues if located near an airport
- Equipment pad location and accessibility
- Access roads and driveways

- Future expansion plans
- Telecommunications available at the site
- Ground cover – gravel vs. grass vs. ag-friendly crops such as prairie or pollinator crops

Hardware considerations include the following:

- Crystalline modules versus thin-film modules
- Tracking versus fixed tilt
- Array tilt and azimuth for fixed-tilt systems
- Array elevation
  - For ease of mowing if live ground cover is used
  - for snow accumulation in front of the panels
- DC/AC ratio
- Ground coverage ratio (row spacing) and shading considerations
- Array DC voltage – 1000 V DC versus 1500 V DC (or future higher-voltage options)
- Inverter configuration – string inverters vs. utility-scale inverters
- Combiner box sizes and locations
- Racking and wire management systems
- Driven-pile vs ballasted array structure foundations
- Grounding and surge protection equipment
- Modularity and expandability of designs
- Suitability for adding energy storage on either the DC side or AC side of the inverters.

Interconnection, control, and monitoring issues include the following:

- Interconnection voltage (480 V AC versus medium-voltage distribution voltages)
- Immediate transformation to reduce costs of AC MV conductors
- Protective relays and system coordination
- Advanced inverter control (per IEEE 1547-2018), including low-voltage ride-through, low-frequency ride-through, controllable curtailment, and ramping control—"smart inverter"
- Monitoring allowance for a utility system or public view website
- Remote troubleshooting through a monitoring solution
- Metering location, type, and data requirements paired with telecommunication availability at the site

4.2.1 The DC/AC Ratio

PV systems are designed with a higher DC rating for the array compared to the AC rating of the inverter. There are several reasons for this design, including the following:

- The official rating of the modules at STC, which is not always achievable in field conditions
- Losses within the DC wiring and inverter
- The variability of solar means that peak hours are relatively infrequent
- Modern inverters can handle larger DC sizes, "clipping" the output when the DC power exceeds inverter capacity
- The array power output will degrade between 0.5 and 1.0 percent per year, depending on the manufacturer, so any clipping that happens initially will decrease as the system ages

The current rule of thumb is for the DC rating of a fixed array to be from 1.3–1.5 times the AC rating of the inverter. Although this might result in clipping at different times during the year, the annual effect is minimal and gradually reduces due to module degradation.

Tracking systems sometimes use a lower DC to AC ratio of around 1.2 since they operate near design peak more of the day. The proper value can vary based on latitude and climate as well as on the exact equipment selected. Performance and optimization can be verified through a full sizing run using a program such as PVSyst.

4.2.2 Final Design

The preliminary design is iterated, along with site considerations, until all issues have been addressed. At this point, a final design package can be completed, land use and construction permits acquired (prior to site prep), site preparation started, and all components ordered and scheduled for delivery.

The final design should also include the following safety documentation:

- Corporate health and safety plans
- Site-specific safety procedures
- Definition of local emergency assistance contacts
- Site-specific safety package

4.3 Mechanical Design

The mechanical integration of PV arrays requires an understanding of the site conditions, the physical and electrical characteristics of the PV modules chosen, the desired electrical output for the array, and the mounting system and structural attachments. It also involves consideration of the installation, maintenance, and accessibility of equipment, and its architectural integration. The objective is to produce the least-cost mechanical installation that is safe, secure, and appropriate for the application.

PV arrays are constructed from building blocks of individual PV modules, panels, and subarrays 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 trade-offs, which are affected by the system design, the equipment used, and the site conditions, including the following:

- 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 the effects of the mounting system
- Weather sealing of building penetrations and attachments (where applicable)
- Materials and hardware compatibilities with the application environment
- Aesthetics and appearance
- Costs

The electrical performance of PV arrays is affected by several mechanical integration issues, including the following:

- Orienting PV arrays for maximum solar energy gain and avoidance of shading
- Optimizing array orientation for afternoon energy capture when applicable
- Maximizing air flow around the array to minimize operating temperatures
- Installing all modules in series source circuits in the same plane
- Facilitating access to the array for maintenance and cleaning

4.3.1 Thermal Considerations

Operating temperatures for PV arrays are strongly dependent on the mounting system design and airflow around the array. Higher operating temperatures reduce array voltage, power output, and energy production, and accelerate degradation of modules and their performance over many years. Mounting system designs have a strong effect on average and peak array operating temperatures.

Rack-mounted arrays have the greatest passive cooling and lowest operating temperatures, with temperature rise coefficients from 15 to 25°C/kW/m^2. Direct mounts have the highest operating temperatures, with temperature rise coefficients of 35 to 40°C/kW/m^2. Standoff mounts have moderate operating temperatures, depending on the standoff height. Maximum passive cooling gains generally are achieved with the tops of PV modules protruding 3–6 inches above the roof surface, as long as air flow is not impeded underneath the array.

4.3.2 Layout

The required electrical configuration and available mounting areas will often dictate the best mechanical layout for PV arrays. PV source circuits are usually grouped together with series-connected modules adjacent to one another on a common support structure. Source circuit combiner boxes are strategically located throughout the arrays to minimize the length of conductors and trip hazards around them.

Preferably, PV modules in source circuits are installed in a single row or rack, with each module adjacent to the other and the module junction boxes aligned on the same sides to facilitate wiring connections. Note that PV module connector leads are manufactured only to a certain length; additional cabling and connectors may be required for non-standard installations.

Materials and components used for a PV array support structure and other equipment attachments should be corrosion and UV resistant, suitable for the application environment, and have life expectancies compatible with PV systems. Structural members used are typically hot-dip galvanized steel or aluminum. Fasteners are usually stainless steel or galvanized. Any weather sealants used should be resistant to UV and temperature extremes and maintain flexibility for long service life.

Practices to minimize the cost of installing PV arrays include the following:

- Using array layouts consistent with the electrical design requirements and providing the shortest possible routing for conductors
- Using MC4 plug/receptacle connectors to wire modules together
- Minimizing the number of structural attachment points
- Using standardized mounting hardware
- Creating a process-oriented installation approach

4.3.3 Array Support Structures

PV modules must be mounted on structures within a system. These structures are made of combinations of extruded aluminum and galvanized steel, and often provide integrated cable management and simplified ground bonding. The three most popular designs for utility-scale systems are “driven pier,” screw anchor, and self-ballasted racking.

In a driven-pier design, a vertical structural member is driven into the ground 5–30 feet (1,500 mm to 9,000 mm) deep, depending on site conditions and other variables, without any concrete foundations. The horizontal support structures then are bolted onto these vertical members. Figure 43 shows the process of driving piers, which requires specialized equipment that typically can be leased for the installation phase. A typical design might include two rows of modules arranged in “portrait” orientation.

Figure 43: Foundations for PV Array Structures May Use Driven Piles or Anchors (Source: Schletter)

A screw-anchor system uses helical screw anchors, which are screwed into the ground. The upper support structure then is attached to the screw-anchor base.

A self-ballasted system, shown in Figure 44, is used when soil conditions preclude the other anchoring types. Individual ballast materials (sized to support the array under maximum wind loads) are pre-manufactured or cast in place; the upper racking structure then is attached to these anchors. Self-ballasted systems often are used on landfills, capped brownfield sites, and other areas where penetrating the upper few feet of soil is not allowed. Self-ballasted systems can also be a viable option for areas having very rocky soil.

Figure 44: Self-Ballasted Racking Systems Can Avoid Buried Foundation Requirements (Source: GameChange)

In any of these designs, it is important to incorporate adequate ground clearance to allow for grounds maintenance, and for snow to slide off the modules without piling up. Typical minimum ground clearance is 2 feet (600 mm) in moderate climates and 3–5 feet (1,000–1,500 mm) in high snow areas.

4.3.4 Structural Loads

The structural attachment of PV arrays is governed by the ASCE 7 standard, Minimum Design Loads for Buildings and Other Structures, which is adopted into most building codes throughout the U.S. However, it does not specifically address the installation of ground- or roof-mounted arrays. PV array mounting structures must be designed to meet all anticipated loads and ensure that allowable loads on existing structures, mounting systems, and foundations are not exceeded.

PV arrays must be designed and secured to withstand the maximum possible mechanical loads. Typical mechanical loads experienced by PV modules and arrays include the following:

- **Dead loads (D)** are static loads due to the weight of the array and mounting hardware. Dead loads are typically about 4–5 pounds per square foot (psf) for most PV arrays. Self-ballasted arrays can have substantially higher dead loads.
- **Live loads (L)** are loads from temporary equipment and personnel during maintenance activities. These loads generally are small for PV arrays, on the order of 3 psf. Typical flat and pitched roofs

must be designed for a minimum uniformly distributed live load of 20 psf. All roofs subject to use by maintenance workers must be designed for a minimum concentrated point load of 300 pounds.
- **Wind loads (W)** are loads due to wind forces acting on structural surfaces. Wind loads are typically the highest of all loads experienced by PV arrays, and can act in an upward, downward, or lateral direction on any surface.
- **Snow loads (S)** are loads due to the weight of snow accumulation. Snow loads can be up to and greater than 20 psf in northern climates.
- **Hydrostatic loads (H)** are loads due to the lateral pressure of the earth (soil) or groundwater pressure on an underground or buried structural member.
- **Seismic loads (E)** are loads due to anticipated earthquake events and based on region-specific seismic design categories. Special heavy equipment mounting considerations are required in seismic regions, as well as flexible wiring methods.

Mechanical loads act in combination with one another to produce the resultant net loads on structural members. **Allowable stress design** is a method used to determine the design loads for structural materials based on the maximum allowable elastic stress limits for the structural materials used. Consequently, it includes a factor of safety for unfactored loads. Allowable stress design considers various load combinations and uses the most unfavorable loading condition for structural design.

Key points of the structural evaluation for PV array mounting systems include the following:

- PV module allowable loads
- Allowable methods and locations for module attachments
- Strength of module attachment points
- Allowable deflections and stresses for support members (beams)
- Structural attachments to foundations or building members

4.3.5 Wind Loads

Wind loads are usually the most significant concern for PV array mounting structure designs.
Most PV modules are listed to handle wind loads of 2,400 Pa (50 psf); some are tested for loads up to 5,400 Pa (112 psf). Generally, PV modules must be supported in certain positions to achieve maximum load capability. Refer to specific PV module manufacturer's installation instructions for allowable mounting configurations and maximum loads.

Three methods can be used to determine the design wind loads for buildings and other structures: (1) a simplified procedure, (2) an analytical procedure, and (3) a wind tunnel procedure. The design loads for components and cladding can be computed using the simplified method if certain conditions are met. The building must be enclosed and have a regular shape, and a flat roof or a gable roof with a slope of no more than 45 degrees; or a hip roof sloped no more than 27 degrees. The mean building height must be no more than 60 feet, and the building or site must not have unusual characteristics or wind responses.

For ground-mounted arrays, wind loads can be evaluated by considering the array to be an open structure, like a carport.

The simplified procedure for calculating design wind loads for components and cladding involves determining the following:

- Basic wind speed (V)
- Structure classification and importance factor (I)

- Exposure category (B, C, or D)
- Height and exposure adjustment coefficient (λ)
- Topographic factor (K_{zt})
- Roof type, slope, and pressure coefficient zones (a)
- Effective wind area (A) and mean roof height (h)
- Net design wind pressures for h = 30 ft and I = 1.0 ($P_{net}30$)
- Net design wind pressures (P_{net})

Net design wind pressures (P_{net}) are applied normally (perpendicular) to each surface to evaluate structural loads:

$$P_{net} = \lambda \times K_{zt} \times I \times P_{net30}$$

where

- λ = height and exposure adjustment factor at mean roof height (1.0 for h ≤ 30 ft in exposure B)
- K_{zt} = topographic factor (1.0 for normal terrain; no escarpments)
- I = importance factor (1.0 for Category II structures)
- P_{net30} = net design pressure for exposure B, h = 30 ft, and I = 1.0
- If λ, K_{zt}, and I all equal 1.0, then: $P_{net} = P_{net30}$

Basic wind speed maps show the maximum design wind speed by location to be used for structural calculations. Many jurisdictions provide local wind speed maps based on the ASCE 7 standard. Higher basic wind speeds exist on the coasts, in mountain areas (special wind regions), or around large lakes. Higher exposure factors would also be considered in the immediate vicinity of lakes, due to open terrain. Figure 45 shows a wind map for the U.S.

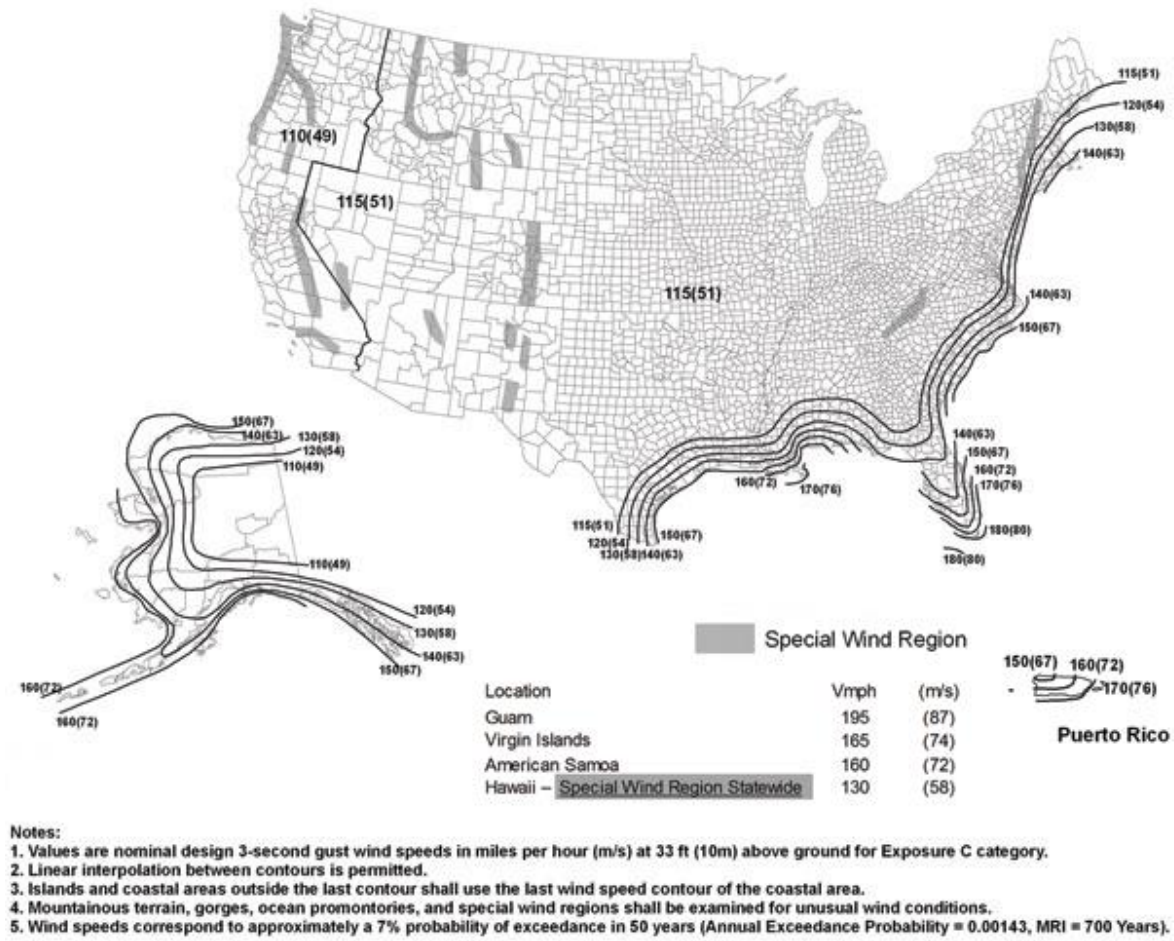


Figure 45: U.S. Wind Map (Source: ASCE 7)

Buildings and other structures are classified in categories, based on the consequences of their failure. Buildings and structures classified in higher-risk categories must be designed for greater loads.

- **Category I:** Buildings and structures that represent a low hazard to human life in the event of failure, including agricultural, temporary, and storage facilities.
- **Category II:** All buildings and other structures except those listed in Categories I, III, and IV—applies to most residential and commercial facilities.
- **Category III:** Buildings and other structures that represent a substantial hazard to life in the event of failure, including schools and congregation areas.
- **Category IV:** Buildings and other structures designated as essential facilities, including hospitals, emergency services and shelters, public utilities, and transportation centers.

Structures for utility-scale PV plants may fall under Category I or Category IV, depending on the critical nature of the application. A Category IV application increases the design loads by a factor of 1.15 for a wider margin of safety.

Importance factor (I) adjusts design wind loads based on the structure category classification. The importance factor considers the degree of the hazard and is based on the structure category and whether the application is in a hurricane-prone region with basic wind speed greater than 100 mph or not. For both hurricane and non-hurricane prone regions: for category II structures, the importance factor = 1.0; for category III and IV structures, the importance factor = 1.15.

Exposure category defines characteristics of the surrounding terrain for each wind direction considered. Exposure A applies to large city centers with at least 50 percent of the buildings having a height in excess of 70 feet (21,336 mm). Exposure B applies to areas with obstructions, such as trusses and buildings, with exposed areas that prevail for at least 2,630 feet (800 m) or 10 times the structure height, whichever is greater. Exposure C applies to open terrain with obstruction heights of 30 feet or less. Exposure D applies to flat, unobstructed areas and water surfaces where the terrain prevails for at least 5,000 feet (1,524 m) or 10 times the structure height, whichever is greater. Exposure D extends inland from the shoreline for 660 feet (200 m), or 10 times the structure height, whichever is greater.

Height and exposure adjustment coefficient (λ) is a factor used to adjust design wind pressures for mean roof height and exposure category. Adjustment factors increase wind loads for building heights above 30 feet and for exposure category. For a mean roof height h = 30 ft or less in exposure B, $\lambda = 1.0$; for h = 30 ft in exposure C, $\lambda = 1.4$; and for exposure D, $\lambda = 1.66$. The adjustment factor increases for all exposure categories for heights above 30 feet.

Topographic factor (K_{zt}) accounts for increased wind loads due to hills, ridges, and escarpments with abrupt elevation changes near the site. The topographic factor is considered whenever the terrain is unobstructed by similar features for 100 times the height of the feature, and the feature is two times or more the height of any other obstruction within a 2-mile radius. When these conditions do not apply, $K_{zt} = 1.0$.

4.3.6 Module Attachments

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 either are bolted with fasteners or clamped to supporting rails or beams. Cooperatives should follow the PV module manufacturer's installation instructions for the allowable mounting points to meet the maximum loads (see Figure 46).

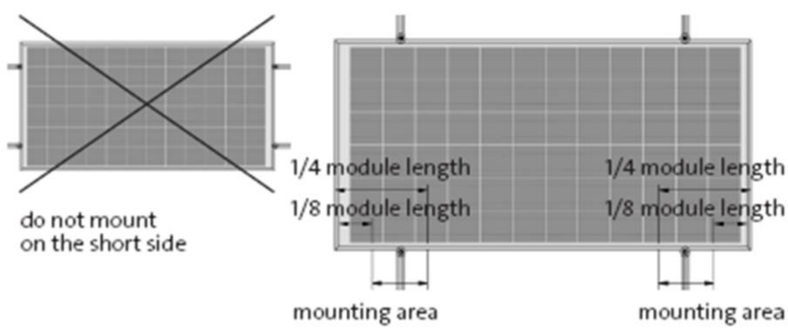


Figure 46: PV Module Specifications Provide the Maximum Mechanical Loads the Module Can Support Using Specified Supports and Attachments (Source: SolarWorld)

PV modules usually are installed with the long module dimension perpendicular to support rails (beams) to minimize the length of rails required. Cooperatives should refer to the mounting hardware manufacturer's data on maximum allowable loads and deflection on module support beams.

Point attachments connect the array assembly to the underlying structure (building or ground) at specified intervals. Point attachments produce concentrated loads on a structure or foundation. They connect the array assembly to a building or structure at distributed locations and usually are the critical design point of the entire mounting system. Increasing the number of point attachments decreases concentrated point loads, beam loading, and deflections but requires more labor to install than using fewer attachment points.

4.3.7 PV Site Groundcover

There are several options available to the utility when considering what sort of ground cover to maintain on the solar site. A basic consideration for all options is that you do not want to do anything that would cause shading of the solar array. Any groundcover needs to be kept short enough, or the height of the array needs to be such as to preclude any shaving of the PV panels.

Gravel / Split Rock / Aggregate

This ground cover option has the benefit of not needing to have any ongoing mowing service thus reducing O&M costs. It also can help stabilize loose soils. However, to achieve either of these ends the layer of gravel needs to be thick enough to prevent weeds from growing and to prevent erosion. This option also can be very expensive but can be put in place quickly.

Use of gravel also introduces the possibility of gravel being thrown up and damaging module backing if vegetation management is done carelessly – e.g. indiscriminate use of “weed-whackers” causing gravel to be thrown towards the arrays at high speeds. This can cause nearly invisible damage that may result in premature failure.

Natural Vegetation

Another option that can sometimes be implemented, depending of site, soil, and vegetation specifics, is to not disturb the existing vegetation more than necessary during the installation. For largely level sites that have an existing groundcover of primarily grass-type vegetation, this may be a desirable low-impact approach. Care should be given to the array height to ensure there is sufficient clearance to mow even several feet under the lower edge of the array.

Soil Stabilization Plantings

Many developers and contractors are used to planting a simple seed mixture to stabilize soils disturbed during construction. There are several commonly used varieties that include perennial turf grasses, and perennial and annual ryegrasses. Annual ryegrass is perhaps the most common of these and can quickly stabilize soils when planted at an appropriate time of year to facilitate germination. Cereal rye, winter rye, barley, oats, and millet are all other commonly available seed that work well to stabilize the soil under the PV array. Any of these seed plantings will behave differently depending on where under the array the seed falls. The degree of shading and the amount of rainfall will significantly impact the growth of any monoculture seeding. Depending on array height, these seed mixes will likely need at least annual mowing to control.

Wildflower and Pollinator Seed Mixes

The building of a PV array offers the utility an opportunity to mix things up a bit and provide additional agricultural and ecological benefits to the area. DOE and NREL have conducted multiple studies to determine the types of native grasses and flowering plants that will thrive under and around PV arrays. These have the added benefits of not only enhancing the aesthetics of the array but providing habitat for beneficial pollinators. Numerous studies have shown that agricultural crops can have substantial yield increases when they are located nearby pollinator habitats. As with tall grasses, these plantings will need the array to be positioned high enough to prevent shading and also may need to be mowed semi-annually.

Wildlife Habitat

Some work has been done on planting native grasses and low growing plants that provide habitat and sanctuary for many terrestrial and avian species under PV arrays. These plantings can offer a needed counter-balance to loss of habitat from agricultural and residential uses. Since many of the plants that may be part of such a habitat may grow to 6-feet, the array height will need to be at fairly high, which does increase the cost of the racking somewhat to accommodate potentially higher wind loads. Mowing for this type of habitat should be staggered by row each year to allow the vegetation to reach appropriate size to provide sufficient cover and habitat; mowing every third row each year.

4.4 Electrical Design

The electrical integration of PV systems involves the design and assembly of the various components into a complete power generation unit. The requirements for non-utility PV system installations are governed by the NEC, NFPA 70. Although utilities are not required to adhere to the NEC, it is generally a good design practice to comply.

The NEC provides for the safety of persons and property relative to the use of electricity and applies to nearly all electrical installations; notable exceptions include most vehicles, boats, trains, and certain utility-controlled properties. Although large-scale solar PV plants operated by electric utilities under their exclusive control may be exempted from many local building codes, best practices covered in the NEC should be followed for any PV installations.

NEC Article 690, Solar Photovoltaic Systems, addresses PV system requirements. Chapters 1–4 of the NEC apply generally to all electrical installations. Chapters 4–6 of the NEC supplement or modify requirements in the earlier chapters. Many articles in the first four chapters of the NEC also apply to PV installations, including but not limited to the following:

- Article 110 Requirements for Electrical Installations
- Article 230 Services
- Article 240 Overcurrent Protection
- Article 250 Grounding and Bonding
- Article 300 Wiring Methods
- Article 310 Conductors for General Wiring
- Article 705 Interconnected Electric Power Production Sources

Other articles that may apply to PV installations include the following:

- Article 314 Outlet, Device, Pull, and Junction Boxes; Conduit Bodies; Fittings; and Handhole Enclosures
- Article 338 Service-Entrance Cable: Types SE and USE
- Article 344 Rigid Metal Conduit: Type RMC
- Article 356 Liquidtight Flexible Nonmetallic Conduit: Type LFNC
- Article 358 Electrical Metallic Tubing: Type EMT
- Article 400 Flexible Cords and Cables
- Article 408 Switchboards and Panelboards
- Article 445 Generators
- Article 450 Transformers
- Article 480 Storage Batteries
- Article 706 Energy Storage Systems

Article 690 in the NEC 2017, Solar Photovoltaic Systems, includes seven parts addressing the following areas of PV installations:

I. General

II. Circuit Requirements

III. Disconnecting Means

IV. Wiring Methods

V. Grounding and Bonding

VI. Marking

VII. Connection to Other Sources

The 2014 section on storage has been moved to a new section 706 in NEC 2017. Section 691, which is also new, discusses large-scale PV Electric Power Production Facilities. The 2014 Section on EV Charging has been moved to Section 625.

Figure 47 shows the single-line diagram for the SUNDA 1-MW design.

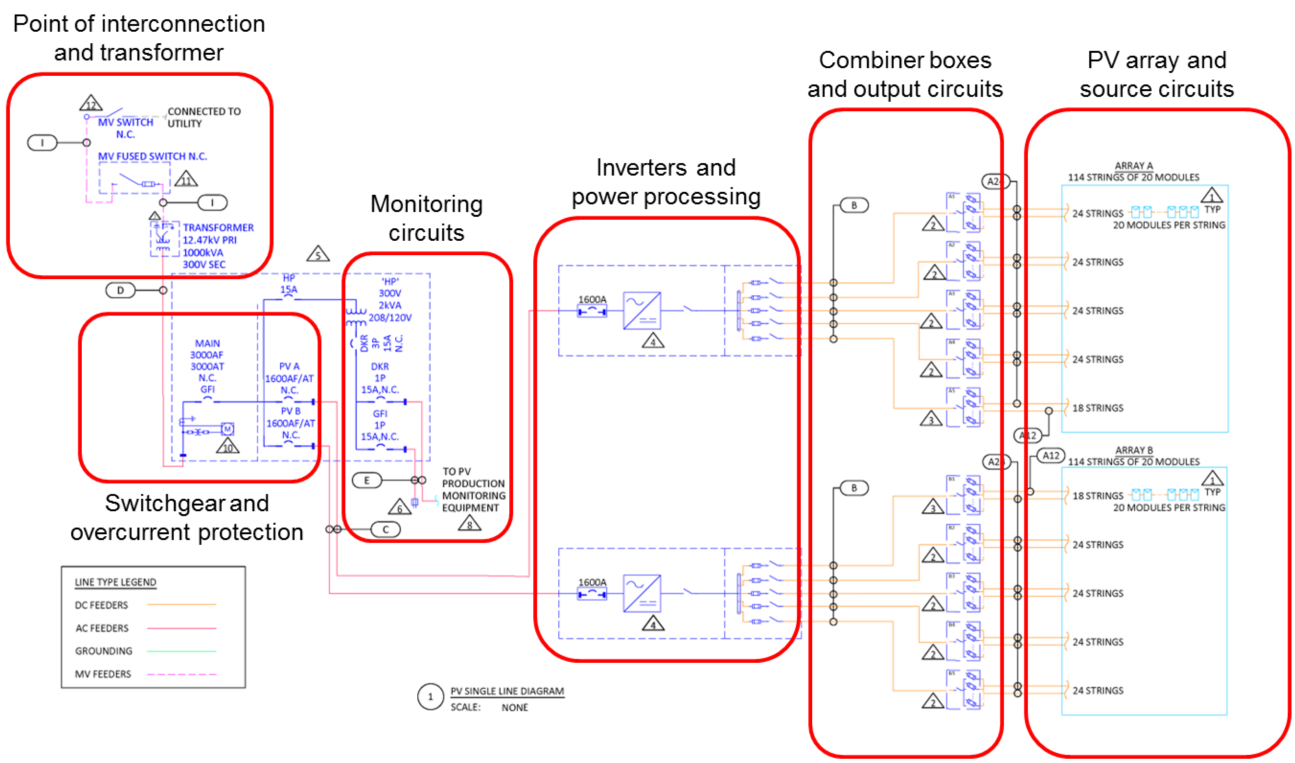


Figure 47: Single-Line Diagram for the SUNDA 1-MW Design

4.4.1 General Requirements

All equipment used in PV systems must be listed and identified for the application. Listing, labeling, and identifying equipment helps verify the proper application and code compliance for PV installations. Listed equipment has been evaluated to the applicable standards by an NRTL. Labels provide recognizable markings, ratings, and specifications for listed products, and are used to establish circuit requirements. Identified equipment is listed and labeled for a specific application, such as for inverters intended for use in utility-interactive systems or with ungrounded PV arrays. The NEC requires qualified persons to install any PV system equipment and all associated wiring and interconnections.

Fire safety, especially in buildings, is a principal concern of the NEC. A number of requirements address system fault protection features and considerations for wiring methods, labeling, and emergency disconnecting means.

Both ground-fault and arc-fault protection are required for PV systems located in or on buildings. These protective features are intended to limit or interrupt fault currents to prevent fire hazard risks. Most interactive inverters incorporate these functions internally and provide monitoring and notification of fault conditions.

4.4.2 Circuit Terminology

Certain PV system circuit definitions are provided in the NEC. These circuits are defined to establish the requirements for conductor sizing, overcurrent protection, disconnecting means, permitted wiring methods, grounding, and labeling.

Photovoltaic source circuits include the DC circuits and connections between individual PV modules to the point where they are connected together. PV source circuits usually are terminated at a combiner box or within smaller inverters. PV modules usually are connected in series to form source circuits and build voltage (sometimes called strings). Individual source circuits then are connected in parallel at combiner boxes to build current and power output. PV source circuits are sized for the voltage requirements of the DC utilization equipment, such as interactive inverters.

Photovoltaic output circuits include the DC conductors between the PV source circuits and DC utilization equipment. PV output circuits are the collection of parallel source circuits; they typically use larger conductors and different wiring methods.

Photovoltaic power sources form the complete DC generating source, including PV source circuits, PV output circuits, and associated equipment, as shown in Figure 48. Larger PV systems essentially are building blocks of many parallel-connected source circuits and output circuits.

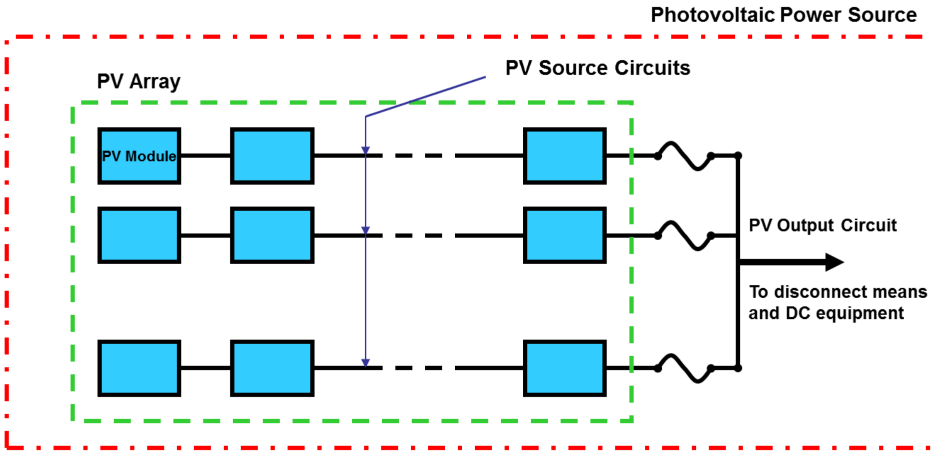


Figure 48: PV Power Sources Comprise PV Source and Output Circuits

For interactive PV systems, the PV array is connected to the DC input of inverters; there is no energy storage. The inverter input circuit includes the conductors between the DC photovoltaic output circuits and the inverter DC input terminals. For simple interactive PV systems without energy storage, the PV output circuit is connected to the line terminals of a DC disconnect; the inverter input circuit then runs from the load terminals of the disconnect means to the inverter DC input. The inverter produces AC power based on the array output only when the array is exposed to sunlight. For interactive-only inverters, the inverter rating and efficiency limits the size of PV array that can be connected to its DC input. In an interactive system, the PV output circuits and inverter input circuit are essentially the same circuit, separated by a disconnect means. The inverter output circuit connects the inverter AC output to the utility grid. An interactive PV system is depicted in Figure 49.

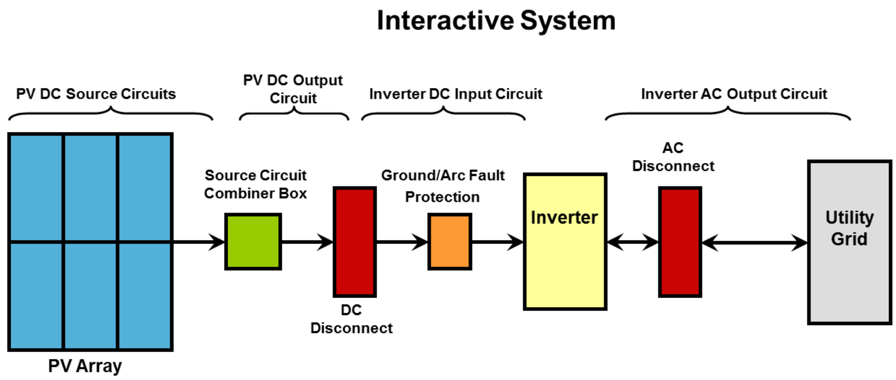


Figure 49: Interactive PV Systems Comprise Specific DC and AC Circuits

4.4.3 Circuit Design

The conductors, overcurrent devices, disconnect means, and other equipment used in PV system circuits are selected and sized based on the maximum circuit voltages and currents. Specifications and ratings for major components, including PV modules and inverters, are required to determine the appropriate circuit parameters for sizing the conductors and overcurrent protection. The circuit layout for SUNDA's 1-MW reference design is depicted in Figure 50.

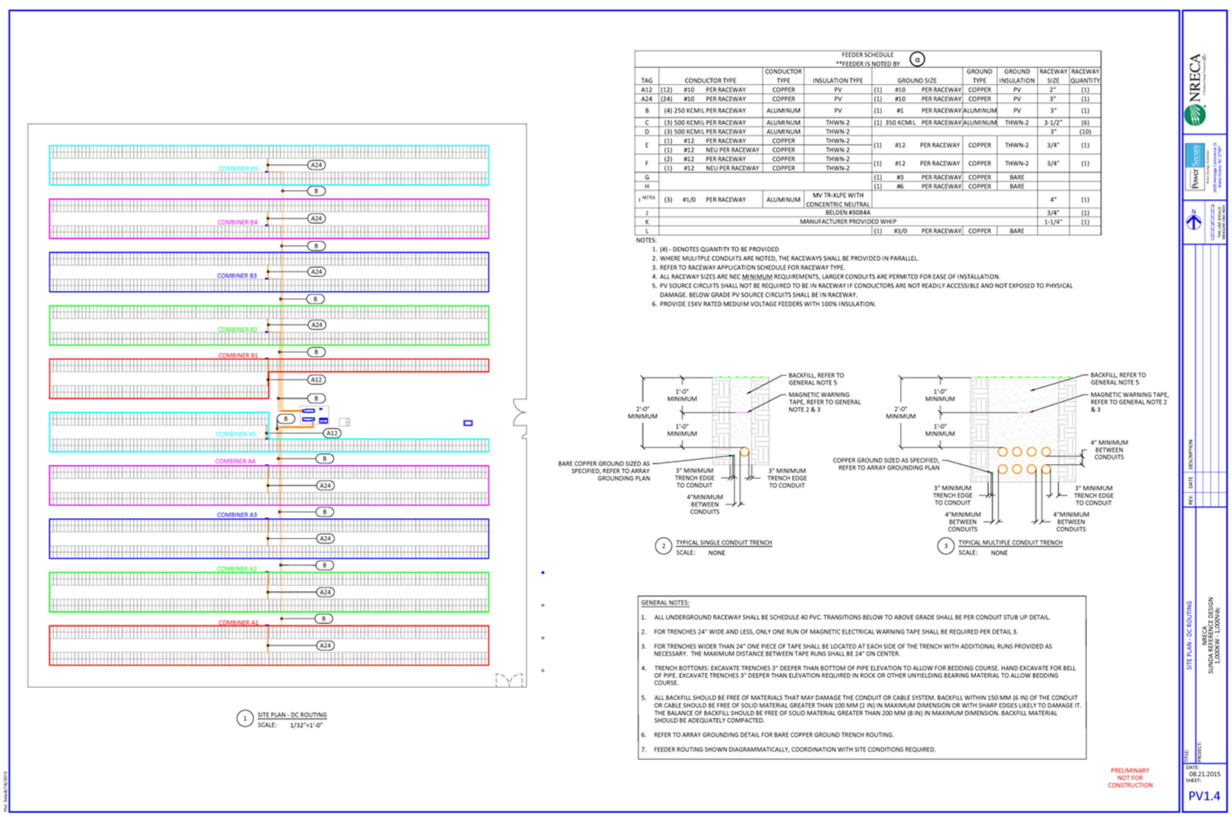


Figure 50: DC Circuit Layout for SUNDA 1-MW Reference Design

4.4.3.1 Maximum Voltage

Maximum photovoltaic system voltage is the array open-circuit voltage, adjusted for lowest expected ambient temperature, because PV modules have a negative voltage temperature coefficient—a higher open circuit and operating voltage at colder temperatures. This maximum possible voltage dictates the minimum voltage ratings for cables, disconnects, overcurrent devices, and other equipment used in the PV source circuits and output circuits.

PV arrays for one- and two-family dwellings were formerly limited to 600 VDC or less but the 2017 NEC now allows 1,000V systems. However, commercial and utility applications may use arrays configured to 1,000 to 1,500 VDC or higher when module and inverter voltage ratings permit.

The maximum system voltage is determined for the specific site temperatures and array configuration, and the calculated value must be labeled by the installer at or near the DC disconnecting means. The rated array open-circuit voltage is multiplied by a temperature correction factor to determine the maximum system voltage and minimum equipment ratings.

$$V_{max} = V_{oc} \times n_m \times C_T$$

where

- V_{max} = maximum photovoltaic system voltage (V)
- V_{oc} = module rated open-circuit voltage (V)
- n_m = number of series-connected modules
- C_T = low-temperature adjustment factor

Voltage-temperature corrections for crystalline silicon PV modules must use the factors provided in NEC Table 690.7 unless the lowest temperatures are below -40°C or the coefficients are provided with listed module instructions. In those cases, and for thin-film modules, manufacturers' coefficients are used. Traditionally, the site record low temperatures have been used to determine the maximum systems voltage. Guidance in the NEC suggests using the Extreme Annual Mean Minimum Design Dry Bulb Temperatures from the ASHRAE Fundamentals Handbook. These data provide a more realistic minimum temperature for determining maximum systems voltage and minimize the chances that array voltage will be too low to operate inverters during the hottest operating conditions.

For example, consider a source circuit using 12 series-connected crystalline silicon modules with a rated open-circuit voltage of 38.4 V each. The extreme annual mean minimum temperature for the site is –25°C (-14°F), which corresponds to a voltage correction factor of 1.20. The maximum system voltage is calculated in this way:

$$V_{max} = 38.4\,V \times 12 \times 1.20 = 553\,V$$

At 25°C, the rated array Voc is 461 V. Table 690.7 adjusts the voltage using a coefficient of

-0.004/°C. This equates to an increase in voltage of 4 percent for every 10°C decrease in temperature below 25°C. Figure 51 shows an example of a PV array design.

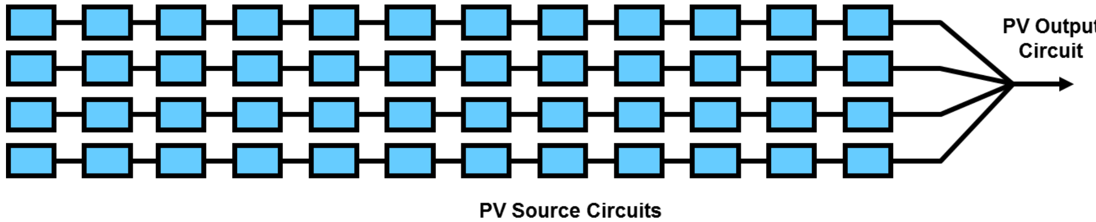


Figure 51: PV Array Design Example

Voltage drop in all PV system circuits should be limited to no more than 2–3 percent. Excessive voltage drop in DC circuits is a particular concern for large PV arrays located at long distances from combiner boxes and inverters; it results in power loss and reduction in performance ratio. Excessive voltage drop in AC circuits may cause loads to operate improperly or hinder an interactive inverter's ability to remain connected to the grid.

4.4.3.2 Maximum Currents

Calculating the maximum circuit currents is the first step in determining conductor ampacity and overcurrent protection requirements for the circuit.

Maximum PV source circuit current is determined by multiplying the short-circuit current of the source circuit by 125 percent. When PV source circuits consist only of series-connected modules, the short-circuit current for the source circuit is the same as for a single module. If parallel connected modules are used in source circuits, the source circuit maximum current is the short-circuit current of an individual module multiplied by the number of parallel-connected modules. This factor is required to account for the fact that PV modules can produce more than their rated short-circuit currents for continuous periods during the middle of the day, especially at high altitudes and on very clear days when the solar irradiance may exceed 1,000 W/m^2 for several hours.

$$I_{max,pv} = I_{sc} \times 1.25$$

where

$I_{max,pv}$ = maximum PV source circuit current (A)

I_{sc} = source circuit short-circuit current (A)

PV output circuits consist of one or more parallel connected source circuits. **Maximum PV output circuit current** is the sum of parallel-connected source circuit maximum currents.

Consider the PV array in the previous example, where the modules have rated short-circuit current (I_{sc}) of 9.5 A. The source circuit maximum currents are:

$$I_{max,pv} = 9.6\ A \times 1.25 = 12\ A$$

Since the output circuit consists of four parallel source circuits, the PV output circuit maximum current is simply 12 A x 4 = 48 A.

The maximum inverter AC output circuit current is the maximum continuous output current rating from the inverter nameplate label. The maximum continuous current can also be calculated by dividing the inverter maximum rated power output by the AC output voltage for unity power factor inverters. Some utility applications may require a reactive power component; in that case, the power factor would need to be considered in calculating maximum current based on the inverter power rating and voltage.

Inverter DC input circuits are a continuation of the PV output circuits for interactive systems; the same circuit calculations apply.

4.4.4 Conductor Ampacity

PV system currents are considered to be continuous for the purpose of sizing conductors. The conductors in any PV system circuit must be sized for the greater of the following:

1. 125 percent of the maximum circuit current before the application of adjustment and correction factors or
2. The maximum circuit current after the application of adjustment and correction factors

Adjustment and correction factors often account for more than a 20 percent reduction in allowable conductor ampacity and, where applicable, include the following:

- **Ambient temperature correction factors** reduce allowable conductor ampacity below 30°C.
- **Adjustment factors for more than three current-carrying conductors** reduce allowable conductor ampacity when more than three such conductors are bundled together or installed in the same raceway for more than 24 in.
- **Ambient temperature adjustment for raceways or cables exposed to sunlight on or above rooftops** provides an ambient temperature adder based on the raceway distance above a rooftop, to determine which ambient temperature correction factor to use. This adjustment does not apply to ground-mounted systems.

Ampacity Tables

Tables 310.15(B)(16) and 310.15(B)(17) in the NEC give allowable ampacities at 30°C for insulated conductors rated up to 2,000 V for insulation temperature ratings of 60°C, 75°C, and 90°C. Adjustment factors then are applied to determine allowable ampacities for maximum operating temperatures greater than 30°C [Table 310.15(B)(2)(a)].

Table 310.15(B)(16) applies to no more than three current-carrying conductors in a raceway, cable, or directly buried. Adjustments are applied to derate allowable ampacities when more than three current-carrying conductors are installed in a single conduit or raceway. (Table 310.15(B)(3)(a)]. Table 310.15(B)(17) applies only to individual conductors installed in free air, not bundled or installed in raceways.)

To determine the minimum conductor ampacity and size required, consider a maximum PV output circuit current of 48 A. Four source circuits (eight current-carrying conductors) are installed in the same raceway and exposed to a maximum ambient temperature of 40°C. The adjustment factor for more than three current-carrying conductors is 70 percent. The ambient temperature correction factor for 90°C-rated conductors at 40°C is 0.91. The conductor sizing is based on the greater of the following:

1. 1.25 x 48 A = 60 A or
2. 48 A / (0.70 x 0.91) = 75 A

In this example, the application of adjustment factors results in the greater design current of 75 A. A minimum size 6 AWG 90°C-rated copper conductor would be required. The same calculations apply to sizing the conductors for the PV output circuits and all other PV system circuits.

4.4.4.1 Overcurrent Protection

Overcurrent devices protect the circuit conductors from overheating. Overcurrent devices in PV system circuits may be fuses or circuit breakers that may also serve as disconnecting means. For DC PV source circuits and PV output circuits, only special listed PV overcurrent devices are permitted to be used; they must have the appropriate voltage, current, and interrupt ratings. Supplementary fuses are permitted to protect PV module source circuits and are available in integer-size increments from 1 to 15 A. Overcurrent devices used in PV source circuits must have no greater than the maximum allowable overcurrent device (or fuse) rating on the module label.

Overcurrent devices in PV system circuits must be sized for at least 125 percent of the maximum circuit currents. For DC PV source and output circuits, this 125 percent factor is in addition to the 125 percent factor applied to I_{sc} to calculate maximum PV circuit currents. This results in a combined factor of 1.25 x 1.25 = 1.56. If overcurrent devices are operated at over 40°C, manufacturer's temperature correction factors must be used to determine the overcurrent device rating.

In the preceding example, the PV source circuit maximum current was calculated to be 48 A. The minimum overcurrent device rating then must be 48 A x 1.25 = 60 A. The next higher standard size overcurrent protection device may be used as required.

The temperature ratings for terminals and overcurrent devices may limit the ampacity of connected conductors. The conductor ampacity is selected at a temperature rating no greater than the temperature ratings of a terminal or device to which it is connected. Using terminals rated for 90°C usually avoids this problem, and the 90°C conductor ampacities may be used.

Overcurrent protection for a transformer with a power source on each side, such as a PV system and the utility, is determined in accordance with NEC 450.3 by considering first one side and then the other side of the transformer as the primary.

4.4.4.2 Disconnecting Means

All ungrounded current-carrying DC conductors of a PV system require a disconnecting means to isolate the circuits from all other conductors and equipment. A switch must not be installed in the circuit with a grounded conductor unless it is part of an arc-fault or ground-fault protection circuit or used only for maintenance, accessible to qualified persons only, and rated for the maximum DC voltage and current in the circuit.

PV array DC disconnects are not required to be service-rated equipment or installed at the array location. However, source circuit switches and overcurrent devices are permitted on the PV array side of the disconnecting means. A maximum of six disconnects are allowed, and they must be grouped with other disconnecting means for the system, suitable for use, readily accessible, and each marked to identify them as a PV system disconnect.

All PV system equipment must have a means to disconnect from ungrounded conductors from all sources. The disconnecting means must be grouped and identified if equipment can be energized from more than one source [690.15]. These disconnect requirements apply to PV arrays, charge controllers, batteries, inverters, and chargers. Single AC disconnecting means are permitted for one or more AC modules or micro inverters.

Switches or circuit breakers used for the disconnecting means must have the following characteristics:

- Readily accessible
- Manually and externally operable, and protected from live parts
- Plainly indicating an open or closed position
- Rated for sufficient fault current interrupting and maximum system voltage

PV system DC disconnects in interactive systems may be energized on one side from the PV array and on the other side from residual voltage on inverter input circuit capacitors for several minutes after the disconnecting means has been opened and the inverter turns off. Warning signs are required when both sides of a disconnecting means may be energized in the open position.

Combiner boxes for PV DC source circuits located on buildings (shown in Figure 52) must have a load-break disconnecting means located in the combiner or within 1.8 m (6 feet) of the combiner. The disconnecting means may be remotely controlled but also must be manually operable when control power is not available. Disconnecting combiner boxes commonly are used for large PV arrays to facilitate safe maintenance practices and troubleshooting.

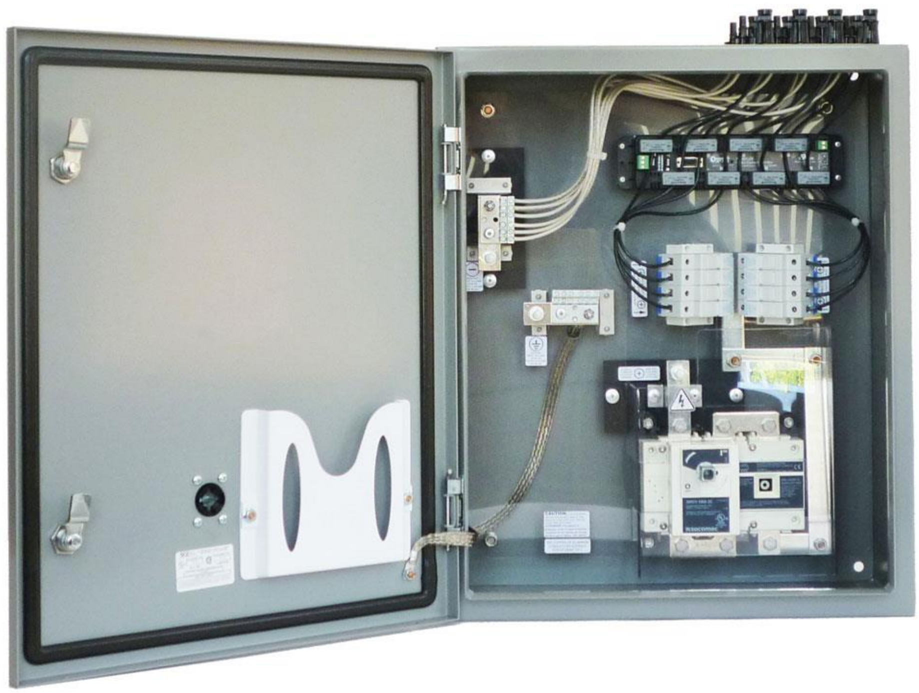


Figure 52: Combiner Box (courtesy of Solar Professional Magazine)

Fuses used in PV source circuits must be able to be disconnected independently of other source circuit fuses [690.16]. Fuses must have disconnects to isolate them from both sides if they are so energized. Fuse pull-outs or holders that are not load-break rated must not be used to disconnect fuses under load; a separate load-break rated disconnecting means is required. PV output circuits must have disconnecting means within 6 feet of fuses if the fuses cannot be isolated from energized circuits. If more than 6 feet away, a directory identifying the disconnect locations is required.

4.4.4.3 Wiring Methods

PV array wiring methods and materials are subjected to harsh environmental conditions and must have appropriate ratings for the application. Wiring methods used in PV systems include standard types of conductors, raceways, and fittings used in building electrical systems, in addition to special cables, connectors, and other methods specifically identified for use in PV systems. Environmental exposure requires PV array conductors to have their insulation rated for high temperatures, wet locations, and sunlight resistance.

Listed and labeled PV wire is allowed for use in exposed outdoor locations for PV module source circuit interconnections within the PV array and provided with factory-installed leads on many PV modules.

Exposed single-conductor wiring is permitted only for module interconnections within PV array source circuits and must transition to other approved wiring methods and raceway systems at junction boxes at the array. The wiring must be neatly tied and concealed beneath the array to prevent movement, chafing, or other damage to the conductors or connectors.

USE-2 conductors are sunlight resistant and rated for 90°C in wet locations. Transitions for exposed conductors to junction boxes or raceways must use appropriate fittings, connectors, or strain reliefs.

The following are basic requirements for terminating electrical conductors [110.3, 110.14]:

- All terminating devices must be listed and identified for the proper conductor material and conditions of use and installed according to manufacturer's instructions.
- Conductors or materials made of dissimilar metals must not be allowed to touch each other, and any solders or corrosion inhibitors used must be suitable for the application.
- The ampacity of any connected conductors must be evaluated at the lowest termination temperature rating.
- Crimped lugs must use the proper crimping tool.
- Terminals using set screws must be torqued to the proper specifications.
- Fine-stranded cables require special terminals intended for their use.

For any PV systems with a maximum system voltage of over 30 V, PV source and output circuit conductors must not be readily accessible to ensure physical protection and reduce electrical hazards [690.31]. This requirement means that conductors must be installed in conduit, enclosures, or other raceways. Most PV modules do not permit direct attachment of raceways; consequently, the conductors must be made so as not to be readily accessible through elevation, fencing around the array, or guarding of exposed conductors with barriers. This requirement usually is not applied to a utility-scale application with restricted access.

Connectors are used in PV systems for PV module connections and other equipment as applicable, and must be as follows [690.33]:

- Polarized and non-interchangeable
- Guarded against contact with live parts
- Latching or locking type
- Requiring a tool for opening if readily accessible and operating at over 30 volts
- First to make and last to break grounded conductors
- Load-break rated for interrupting the maximum circuit current or requiring a tool for opening, and should be marked "Do Not Disconnect Under Load" or "Not for Current Interrupting"

The connectors must also be weather sealed and otherwise appropriate for their conditions of use (outdoor and wet locations). Special connector mating and crimping tools are required for their fabrication and assembly with conductors (see Figure 53).

It is important to use high quality certified quick-terminals since some low-cost "clones" may not mate properly and could cause arc-faults and other issues over time.

Figure 53: Multi-Contact MC4 Connectors Include a Locking Sleeve and Assembly/Opening Tool and Are Used for PV Module Connections

4.4.5 Grounding and Bonding

A complete grounding system complying with NEC, NFPA 70, and UL Standard 1741 is essential for the safety of the PV system and all personnel in contact with it. The means and methods used to install the grounding system shall minimize deteriorating electrical connections for the life of the PV system. Grounding conductor shall be bare Cu, insulated direct burial, or run-in heavy wall PVC conduit of the size shown in construction drawings or required by NEC.

The equipment grounding conductor (EGC) properly bonds all exposed or accessible non-current-carrying metal parts of the PV system together and to earth. Bonding shall be done with insulated bonding bushings and mechanical or compression-type lugs.

Raceways shall not be used as EGCs. NEC 110.12 requires that good workmanship be used in the installation of the system. This is crucial because of the extreme changes in the environment in which it is installed.

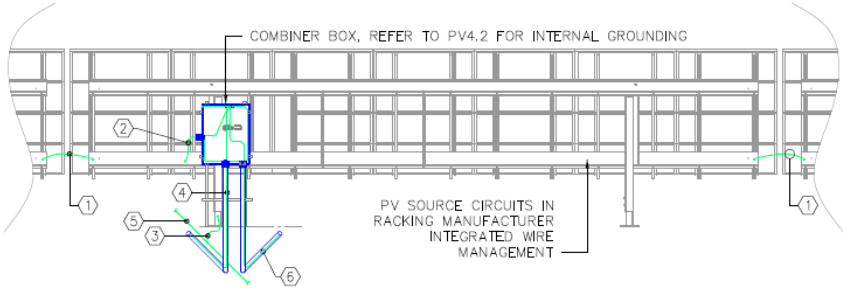
Reference installation requirements that can be considered or reviewed during the site-specific design and/or by the engineer of record are as follows:

- The main service ground clamp shall be attached to a ground rod system or the metallic cold water main at an accessible point and before its size is reduced immediately after it enters the building. The clamp shall be accessible after construction is complete. The grounding conductor shall be without splice when run into the service enclosure, where it shall be connected to the ground bus or in a 4-W system with the main service neutral.
- Two means of grounding will be required. The grounding conductor shall be continuous and sized as shown on the plans. The grounding conductor conduit, if required, shall be fastened to the service enclosure with double locknuts and bonding bushings.
- The metal frame of the building shall be bonded to the grounding electrode system using a conductor that is sized the same as the main grounding conductor on the plans.
- Upon completion of installation of the grounding electrode and bonding system, the ground resistance shall be tested with a ground resistance tester. Resistance to ground shall be less than 25

ohms. If the test indicates a greater resistance, appropriate measures shall be taken, including driving additional ground rods, to reduce the resistance to less than 25 ohms. The contractor shall provide test reports indicating that the ground resistance test has been performed and stating the resistance measured.

- Any raceway anywhere in the system that enters a box or cabinet through part of a concentric or oversized knockout shall be fitted with an insulated bonding bushing and jumper. These bushings also shall be used wherever conduits stub into switchboards or transformer cabinets. Grounding-type insulated bushings shall always be used on one end of the conduits feeding panelboards. The bonding jumper shall be sized according to NEC Section 250 and lugged to the box.
- EMT couplings and connectors shall be a compression-gland type of malleable steel, either galvanized or sherardized. Set screw, indentor, or cast-type fittings are not acceptable.
- Attach rigid metal conduits with double locknuts—one inside and one outside—and fiber bushings.
- The raceway system shall not be relied upon for ground continuity. A green grounding conductor, properly sized per NEC Table 250.122, shall be run in ALL raceways except for telecommunications, data, and audio conductor raceways.

Figure 54 shows details of a typical array mount grounding.



2 TYPICAL GROUND MOUNT RACKING GROUNDING DETAILS
SCALE: NONE

GENERAL NOTES TO PV 1.5

1. THE RACKING SYSTEM IS LISTED PER UL 2703 FOR GROUNDING CONTINUITY. COMPONENTS WITHIN THE RACKING SYSTEM FORM AN ELECTRICALLY BONDED UNIT AND REQUIRE ADDITIONAL BONDING FROM ONE INDIVIDUAL RACK SECTION TO ADJACENT SECTIONS.

2. REFER TO GROUNDING RISER DIAGRAM FOR SYSTEM GROUNDING.

3. REFER TO SINGLE LINE DIAGRAM AND SCHEDULES FOR SPECIFICATIONS

4. WIRE TYPE G (BARE COPPER #2) SHALL BE RUN IN TRENCH WITH COMBINER DC WIRES.

KEYED NOTES TO PV1.5:

1 PROVIDE GROUND BRAID BETWEEN RACKING SECTIONS PER RACKING MANUFACTURER INSTRUCTIONS.

2 PROVIDE #6 BARE COPPER BONDING JUMPER (WIRE TYPE H) FROM THE COMBINER BOX GROUND BAR TO THE WIRE TRAY.

3 PROVIDE #6 BARE COPPER BONDING JUMPER (WIRE TYPE H) VIA IRREVERSIBLE CRIMP FROM #2 GROUND (WIRE TYPE G) IN TRENCH TO ONE PIER PER ROW OF RACKING. IRREVERSIBLE CRIMP SHALL BE UL LISTED FOR GROUNDING AND BONDING. ENSURE ALL CONNECTIONS ARE TORQUED TO MANUFACTURER'S RECOMMENDED TORQUE VALUE.

4 PROVIDE EQUIPMENT GROUND CONDUCTOR (REFER TO SINGLE LINE DIAGRAM AND SCHEDULES FOR EGC SIZE) FROM COMBINER BOX GROUND BUS BAR TO ASSOCIATED INVERTER BUS BAR. EQUIPMENT GROUND CONDUCTOR SHALL BE RUN IN CONDUIT WITH ASSOCIATED PV OUTPUT CONDUCTORS.

5 PROVIDE #2 BARE COPPER (WIRE TYPE G) LENGTH OF ARRAY AS SHOWN.

6 PROVIDE #6 BARE COPPER BONDING JUMPER (WIRE TYPE H) FROM THE COMBINER BOX GROUND BAR TO THE WIRE TRAY ON ADJACENT ROW SUPPLIED BY ASSOCIATED COMBINER.

Figure 54: Typical Ground-Mount Racking Grounding Details

5 System Documentation

All PV installations should have adequate documentation that provides details of the system design and all components and materials used in its construction. The documentation should also include safety information and procedures for operating and maintaining the system.

IEC 62446 describes the minimum documentation that shall be provided to the customer following installation of a grid-connected PV system. All PV installations should have adequate documentation, providing details of the system design and all components and materials used in its construction. A complete documentation package for PV systems contains essential information for system approvals, installation, and O&M. Documentation requirements and details may vary for different purposes or types of PV systems.

IEC 62446 requires the system documentation to include basic system information and specifications; contact information for the system designers and installers; detailed wiring diagrams; component manuals and data sheets; structural design information; and procedures for system operations, maintenance, and safety.

Proper system documentation helps ensure safe and reliable system operations and generally is required for the following purposes:

- Plan review and permitting process with local building officials
- Interconnection approval from the local utility
- Installation and maintenance contractors
- Owners and caretakers

The system documentation is a permanent record associated with a PV installation, including maintenance and testing records. This information is critical for the effective maintenance and evaluation of the system over time. Key components of a PV system documentation package should include the following:

- 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; and the dates of the system installation, commissioning, and inspection.
- 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 identifying 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 included with the final system documents.
- A single-line diagram 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 usually are required.
- The types, sizes, and ratings for all balance-of-system components 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 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, including procedures for verifying proper system operation and performance, how to determine if there is a problem, and what to do about it. 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 as opposed to those requiring professional service due to their complexity, special equipment needs, or safety concerns. Maintenance agreements, plans, and recordkeeping forms or sheets should also be provided for documenting maintenance activities over time.
- Warranty details on major components 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 weather sealing, or performance warranties, as applicable.
- Copies of all commissioning test reports and verification data.
- 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 pertaining to incentive programs, such as rebates and tax forms.

6 Procurement and Installation

6.1 Quality Assurance and Quality Control

It is important to establish a quality assurance and quality control (QA/QC) plan to effectively manage the construction and commissioning of solar PV plants. Inspections are a key part of a QA/QC plan and help ensure that the installation process is on schedule and following approved plans and construction documents.

Minimum requirements for a QA/QC plan include the following:

- Definition of those people responsible for QA
- Definition of a QA program
- Development of procedures necessary for a QA/QC plan's success
- Documents control
- Construction process control
- Calibration and control of measurement and testing equipment
- Inspections and testing for in-process and completed work
- Guidelines for materials—receipt, storage, and handling
- Processes for nonconforming items and corrective actions
- Subcontractor management plans
- Recording of quality information
- Evaluation of the quality program for effectiveness

6.2 Installation Safety

Working with PV systems involves exposure to energized circuits carrying high voltages and potentially lethal currents, thus presenting electrical shock hazards. When these electrical hazards are combined with other hazards, such as working at heights and in difficult locations exposed to the elements, it is imperative for those installing and servicing PV systems to follow all applicable safety standards and guidelines.

Qualified Person

The NEC defines a *qualified person* as "one who has skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training to recognize and avoid the hazards involved." However, the NEC is not very specific about the extent of safety training required relative to the levels of hazards and types of work involved, presuming that individuals may be qualified for certain tasks but not others. Generally, individuals installing or servicing PV installations should have appropriate experience in working with PV systems and electrical systems, and safety training consistent with the requirements outlined in NFPA 70E-2009, Standard for Electrical Safety in the Workplace.

The Occupational Safety and Health Administration (OSHA) issues and enforces standards in the U.S. for worker safety and health. In particular, OSHA regulations covered in CFR 29 Part 1926, Safety and Health Regulations for Construction, address a broad spectrum of safety hazards likely to be encountered in constructing and maintaining PV installations. The standards can be freely downloaded from the OSHA website, [www.osha.gov.](http://www.osha.gov)

OSHA regulations require that employers provide a safe and healthy workplace free of hazards and follow the applicable OSHA standards. Employers must provide safety training to affected employees addressing all probable hazards on a construction site. Workers are responsible for following the employer's safety and health rules, and wearing and maintaining safety gear as instructed. An OSHA 10-Hour Construction Industry Training Program covers the requirements for avoiding and mitigating a number of job site safety hazards addressed in 29 CFR 1926, including electrical safety, personal protective equipment (PPE), fall protection systems, stairways and ladders, hand and power tools, cranes and lifts, excavations, scaffolding, and others.

Best practices for preventing electrical hazards and other common safety hazards associated with PV installations include the following:

- Working on electrical equipment and circuits in a de-energized state using documented lockout and tagout (LOTO) procedures
- Wearing the appropriate PPE, including protective clothing, nonconductive Class E hardhat, electrical hazard (EH)-rated foot protection, and safety glasses at all times
- Using electrically insulated hand tools and properly grounded or double-insulated power tools maintained in good condition
- Avoiding contact with overhead power lines and buried electrical conductors
- Using ladders with wooden or fiberglass rails when working on or near energized conductors
- Mitigating fall hazards and using personal fall arrest systems (PFAS) whenever working at unprotected heights of 6 feet or more
- Maintaining an orderly work site and cautious approach to the work

In some cases, working on energized equipment is unavoidable—for example, when making measurements on PV arrays that always are energized when exposed to sunlight. Certain test equipment, such as megohmmeters and insulation testers, also produce high test voltages; appropriate safety precautions must be observed when using this equipment. Proper electrical insulating gloves and other applicable PPE should always be worn when working on or testing energized circuits. The level of PPE required depends on the voltage levels and fault currents for the circuits under test. Particular care should be exercised whenever touching a PV array or associated conductive surfaces to protect against electrical shock, especially when faults are suspected.

6.3 Basic Installation Steps

A utility-scale PV system is a relatively simple system by utility standards. It consists of an array of DC PV modules mounted on metal support structures. These are wired into one or more DC/AC inverters. The inverters are bussed together and run through a step-up transformer and protective equipment for interconnection with the electrical grid.

The basic steps for system installation are as follows:

1. Complete engineering design and permitting tasks
2. Procure materials
3. Site preparation (can be done in parallel with procurement)
4. System installation
    a. Mechanical installation (foundations, racking, conduit runs, grounding, module physical installation)
    b. Electrical installation (wiring modules to combiner boxes, combiner boxes to inverter, inverter to transformers and AC switchgear, and interconnection with electric grid)
5. Test and commission the system

6.4 Procurement

A large majority of the equipment cost of a PV system consists of three components—the modules, the racking system, and the inverter subsystem so careful attention should be paid to these items. Procurement can be bundled together with engineering and construction using an "EPC" contractor. Alternatively, a co-op may choose to hire separate engineering and construction contractors (or do portions of the work in-house) and manage procurement itself.

In general, PV modules should be sourced from a high-quality supplier. Bloomberg New Energy Finance has developed a "Tier" system to identify suppliers with high "bankability" (and thus an implication of high quality). A Tier 1 solar manufacturer is defined as a "those which have provided products to five different projects which have been financed non-recourse by five different (non-development) banks in the past two years."

Choice of a structure vendor needs to take into account the type of structure desired (tracking or fixed, driven-pier or ballasted. Attention should also be paid to installation efficiency -- it may be worth it to pay a little more for a system which has fewer parts and can be installed more quickly.

Inverter suppliers should also be chosen based on their track record showing that they have the ability both to produce and to support the project over the 25-year typical life of a system.

Aside from these three high-cost items, the next most critical part is the monitoring system. Once again, the equipment and associated software must be maintained for the full life of the system, so it is important to choose a vendor which has shown that it can support the project over its projected life.

A "Solar Bid Evaluation Form" and a "Fixed Racking Bid Evaluation Form" are provided on the SUNDA website as a sample of a form to compared technical bids for a project. A similar spreadsheet can be used to compare construction details, financing, and project management plans.

6.5 Site Preparations

Site preparation includes general leveling of the land, improving access roads and drainage as necessary, and trimming specified vegetation. This can be done significantly in advance of actual site work. The perimeter fence usually can be installed once the site grading is completed.

6.5.1 Construction Site and Schedule Management

Developing and constructing a PV project can often take a year or more from start to finish, but the actual installation time can be much shorter. A 1-MW-AC system typically takes approximately six weeks for actual installation (after site prep is completed and not counting final interconnection and commissioning).

The following sections list the basic tasks needed to install a PV system; see Volume III appendices for a more detailed checklist.

6.6 Mechanical Installation

1. Survey and install support foundations (e.g., driven piers, helical screw anchors, ballasted foundations)
2. Install racking structures
3. Install conduits for "home run" wiring from combiner boxes to inverter DC switchgear
4. Prepare inverter pad, including conduit stub-outs
5. Install grounding system for metal structure and inverter pad
6. Install modules on racking
7. Install combiner boxes on racking structures

8. Install weather station, which, along with system monitoring, will be used to verify proper operation of the system

Example -- Schletter FS Racking Installation

The Schletter FS racking system is a pre-engineered racking design intended to reduce costs, materials, and installation time for large-scale PV arrays. This system uses a pier-driven array foundation with integrated equipment grounding. Geotechnical and proof testing are required for all project sites to determine the number of posts and embedment depth. Proof testing includes vertical pull-out tests and lateral load tests. Soil samples and classifications to determine load-bearing capacity, corrosion potential, gradation, and soil plasticity are also required for the pre-engineered design.

There are five simple installation steps for the Schletter FS racking system:

- Drive the post into the ground
- Mount the head assembly
- Place the support on the post attachment head and bolt the lower strut
- Insert the locking plate at the attachment head
- Install the cross beams (purlins)

For additional information, see Figures 55 and 56 as well as the FS System installation manual:

http://www.schletter.us/support/FS-System-Install-Manual.pdf

FS System installation video:

https://www.youtube.com/watch?v=X6xtRPZc2Bc

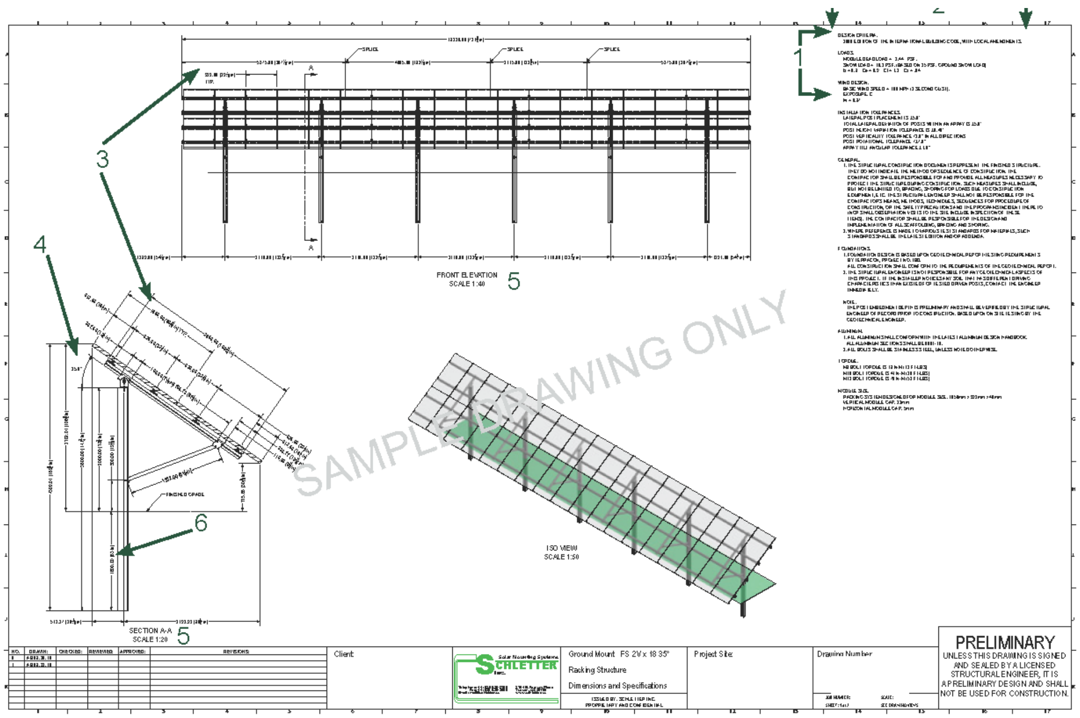


Figure 55: Schletter RS Racking System

Most manufacturers' literature states that module installation should be done by qualified, licensed electrical professionals. Listed PV modules must be installed in accordance with instructions provided (shipped) with the product. These instructions include information on safety, working with PV modules during sun hours (energized electrical equipment), mounting configurations, and electrical wiring and grounding instructions. Some of the basic safety and handling precautions for PV modules include the following:

- Do not insert electrically conducting parts into the plugs or sockets.
- Do not wear metallic jewelry while performing installation.
- Do not fit solar modules and wiring with wet plugs and sockets. Tools and working conditions must be dry.
- Exercise caution when carrying out work on wiring and use the appropriate safety equipment (insulated tools/gloves, fall protection, etc.).
- Do not use damaged modules. Do not dismantle modules. Do not remove any part or label fitted by the manufacturer. Do not treat the rear of the laminate with paint or adhesives, or mark it using sharp objects.
- Do not artificially concentrate sunlight on standard modules.

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 and 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 during high wind conditions.

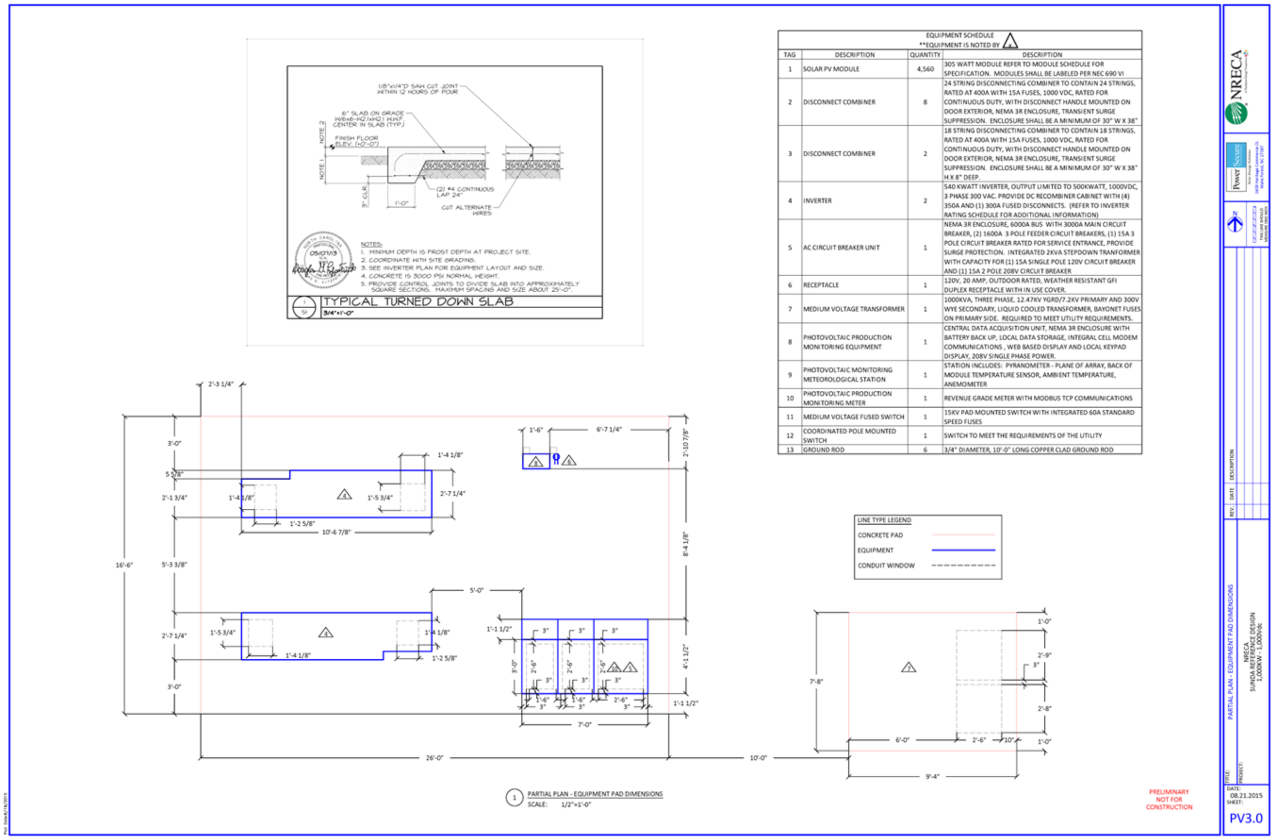


Figure 56: Inverter Installation Details for SUNDA 1-MW Reference Design

6.7 Electrical Installation

The NEC, NFPA 70 governs the requirements for most non-utility electrical installations in the U.S., including solar PV systems. When adopted into their building codes by states or local jurisdictions, the NEC becomes the basis for inspections and approvals of electrical installations.

Although the NEC is not typically required for utility-owned installations, it is an excellent body of safety-based knowledge and procedures that forms the foundation for any safe PV system design and installation.

Chapters 1–4 of the NEC generally apply to all electrical systems, covering installation requirements, wiring and protection, wiring methods and materials, and equipment for general use. Article 690 of the NEC covers special installation requirements for solar PV systems, although many other articles also apply. Additionally, Article 705 covers requirements for interconnecting PV systems and other distributed generation equipment to other sources, such as the utility grid.

The NEC does not specifically address PV system performance, but it does establish requirements for the overall quality and safety of electrical installations. Many of these requirements can be verified through visual inspections and a review of the system design and installation documents. However, certain NEC requirements can be validated only by electrical tests and measurements. These include verifying the continuity of grounding systems, verifying system voltages and currents, and measuring insulation resistance to determine wiring integrity.

Other standards also apply to PV system testing and commissioning. Compliance with these additional codes or standards may be required by local authorities or requested by buyers, lenders, or underwriters to help ensure the highest levels of safety, quality, and performance for PV installations.

The following steps comprise the PV electrical installation process for a system with central inverters (the process is similar for string inverters):

1. Wire modules in series and wire to combiner boxes.
2. Install inverter(s), lightning protection/surge arrestors (if utilized), and associated DC and AC switchgear.
3. Install metering cabinet and associated telecommunications.
4. Run DC “home run” wires from combiner boxes to inverter DC switchgear.
5. Connect inverter to interconnection transformer and associated switchgear, including CTs and PTs, and a revenue-grade bi-directional meter.
6. Connect inverter and associated equipment to grounding system and protection equipment.
7. Connect monitoring system to the utility SCADA system.
8. Connect the system to the electric grid.

See Figure 57 for a depiction of the electrical installation of the SUNDA 1-MW reference design.

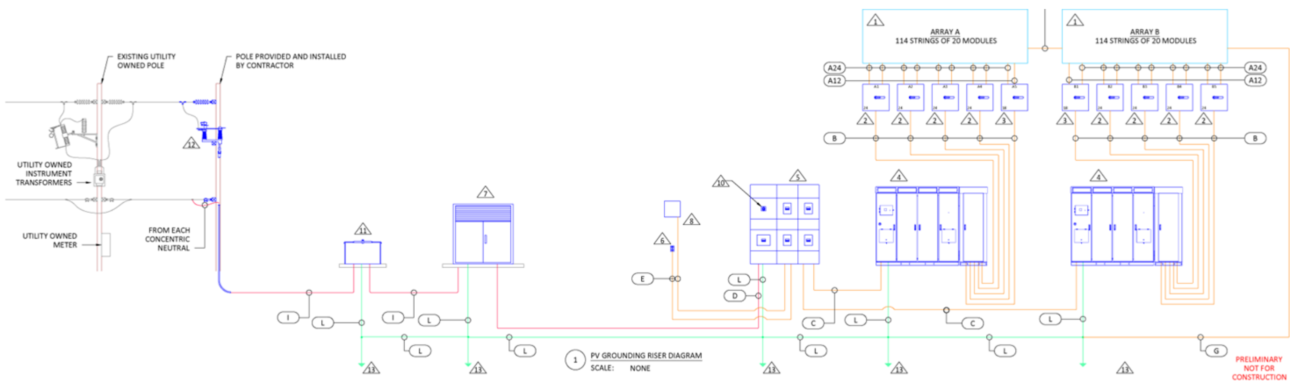


Figure 57: Electrical Installation Details for SUNDA 1-MW Reference Design

6.8 Labels and Markings

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. Local inspection officials may verify these markings during inspections and rely on them for their approvals [110.2, 110.3, 100.21].

Additional markings and labels are required for the overall system and certain components in PV systems, and are to be provided and placed by the installer. These include additional labels on DC conductors and raceways [690.4, 690.31], connectors [690.33], disconnecting means [690.14, 690.17], and at the point of utility connection [690.54, 705.10, 705.12]. Labels and markings also are required on PV modules [690.51], alternating-current modules [690.52], the PV power source [690.53], ground-fault protection equipment [690.5], and battery storage systems [690.55]. Special labeling also is required for bipolar arrays [690.7], ungrounded PV arrays [690.35], a facility with either stand-alone systems or multiple power sources [690.56], and stand-alone inverters providing a single 120-volt supply [690.10].

It is important to use high quality materials for all labels and marking, since the outdoor location on many labels will require periodic replacement.

7 Interconnection

Interconnection refers to the technical and procedural matters associated with connecting and operating interactive PV systems and other distributed generation sources in parallel with the electric utility system. Distributed generation technologies can be classified as using either rotating generators or static electronic inverters. The type of equipment used has important considerations for interconnecting these systems to the electric utility grid.

> **Changes to IEEE 1547**
>
> A completely new version of IEEE 1547 is being released in April/May of 2018. IEEE 1547-2018 will have significant changes beyond those described in this document. Please check for additional articles on the changes in this standard and effects on PV system design.

Mechanical rotating generators and electronic inverters have very different characteristics, which affect their protective features and how they are synchronized with the utility system. Traditional rotating generators act as a voltage source and can deliver high fault current. This mechanical equipment uses separate equipment for synchronization and protection. On the other hand, electronic inverters act as a current source, produce limited fault current, and include synchronization and protective features integral to the inverter circuitry.

7.1 General Requirements

Technical interconnection issues include safety, power quality, and impacts on the utility system; these are addressed in national codes and standards. Interconnection procedures are based on regulatory and utility policies, and different requirements apply to customer-owned versus utility-owned systems.

Interconnection agreements for customer-owned systems typically include an application process, customer agreements, permitting, and inspection. Contractual aspects of interconnection policies for customer-owned systems include fees, type of metering and billing arrangements, and possibly size restrictions. Most customer-owned PV systems are interconnected at service voltage levels.

Different interconnection procedures apply to utility-owned systems. These larger systems are generally installed on utility-controlled property with restricted access and are operated and maintained by qualified persons. In the case of distribution cooperatives, interconnection policies are usually governed by their G&T supplier. Typically, these interconnection agreements preclude distribution cooperatives from back-feeding the transmission system.

Utility-owned systems are usually interconnected at distribution voltage levels to substation feeders and are often exempted from local AHJ inspections and approvals. The interconnection equipment for a utility-scale PV system typically includes transformers with CT metering, switchgear, and a three-phase recloser.

Some utility-scale inverters (include three-phase string inverters) have standard 480-V three-phase outputs that allow interconnection at normal service voltages or to the distribution system through a standard distribution transformer. However, most new utility-scale inverters do not include an integral transformer and have non-standard AC output voltage—for example, 380–420 V—requiring special order distribution transformers. Some inverter manufacturers provide integrated solutions, with the inverters, distribution transformer, and switchgear mounted to a skid for easier installation.

7.2 IEEE 1547

IEEE 1547, Standard for Interconnection of Distributed with Electrical Power Systems, establishes the technical requirements for interconnecting all types of distributed generation equipment with the electrical power system, including PV systems, fuel cells, wind generators, reciprocating engines, microturbines, and larger combustion turbines. It also establishes requirements for the testing, performance, maintenance, and safety of the interconnection, as well as responses to abnormal events, anti-islanding protection, and power quality. IEEE 1547 consists of a series of standards and guidelines dealing with various aspects of interconnecting distribution power sources to the utility system.

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

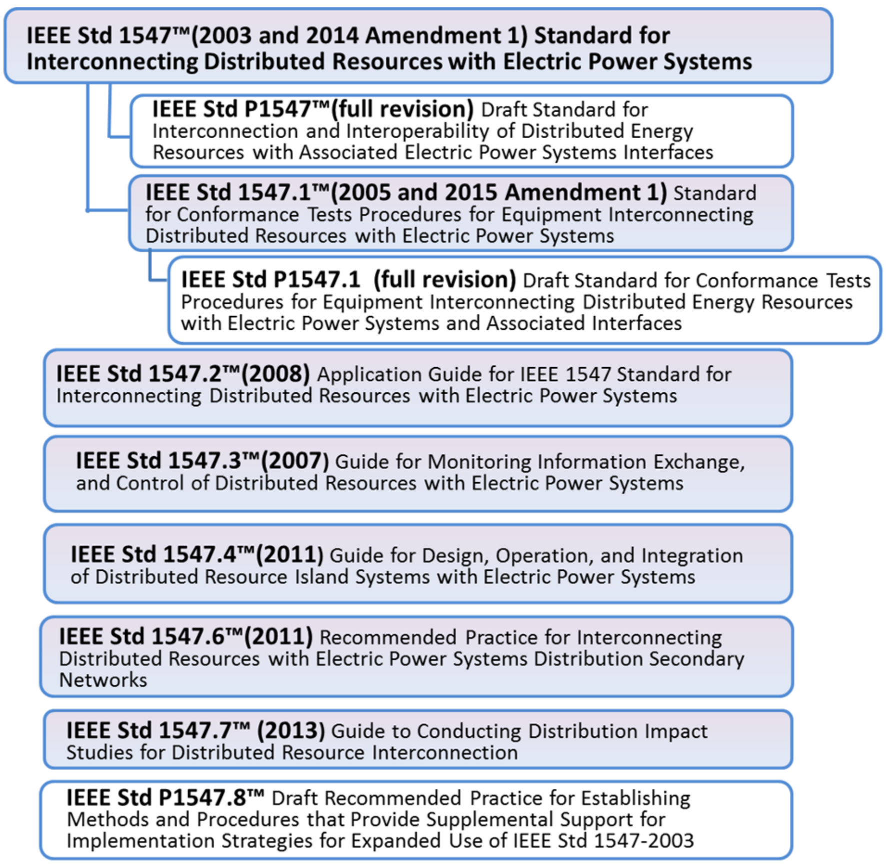


Figure 58: IEEE 1547

7.2.1 Anti-Islanding Protection

Islanding is a condition in which part of a utility system containing both load and generation is isolated from the remainder of the utility system but remains energized. Islanding of PV systems and other distributed generation is an undesirable condition, presenting two basic problems for electric utilities regarding safety and operation of the utility system. First, utilities have no control over the voltage and frequency if an islanding condition develops. Equipment damage may occur and can also interfere with the utility's normal procedures for bringing its system back into service following an outage. Second, the creation of an island can present safety hazards to linemen working to restore power after an outage.

For these reasons, IEEE 1547 requires PV systems and other distributed generation sources to be able to detect when an island is forming and stop supplying power to the grid until the utility system returns to its normal operating limits. Unlike rotating generators that require additional protective relaying equipment to prevent islanding, anti-islanding functions are integral to inverter circuitry. Interactive inverters monitor grid voltage and frequency, and must disconnect their output to the grid within 2 seconds when an islanding condition is detected. Inverters must remain disconnected until the utility has been re-energized to acceptable voltage and frequency limits for a period of 5 minutes.

7.2.2 Voltage/Frequency Regulations and Power Quality

IEEE 1547 requires certain voltage and frequency regulation and power quality for DG systems, consistent with utility standards. The distributed generation (DG) system must not cause the service voltage to go outside of the requirements of ANSI C84.1, Range A. The system also must not cause the service voltage to fluctuate more than ±5 percent when interconnecting, and the service voltage must be within ANSI C84.1, Range B for 5 minutes before reconnection. The DG system must de-energize its output within a specified time under abnormal voltage conditions, as follows:

- < 50 percent of nominal voltage (V), 0.16 sec (~10 cycles)
- 50–88 percent of nominal V, 2 sec (120 cycles)
- 110–120 percent of nominal V, 1 sec (60 cycles)
- 120 percent of nominal V, 0.16 sec

IEEE 1547 requires frequency to be maintained within acceptable limits. For DG systems under 30 kW, a system must de-energize its output within 0.16 seconds if the frequency falls outside of the range of 59.3–60.5 Hz (57–60.5 Hz for DG systems larger than 30 kW). Frequency must remain in the range of 59.3–60.5 Hz for 5 minutes prior to interconnection.

IEEE 1547 also requires DG systems to conform to certain power quality standards. DC current injection must be less than 0.5 percent. Current harmonics are limited to a specified percentage, depending on the harmonic order. Total demand distortion (TDD) for current must be less than 5 percent.

7.2.3 UL 1741

UL 1741 "Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources" addresses the requirements for all types of DG 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 products covered by the UL 1741 listing are intended to be installed in accordance with the NEC, NFPA 70.

Synchronizing is the process of connecting a generator to an energized electrical system. Synchronizing also is called paralleling a generator or bringing it on line. The prerequisites for synchronizing a rotating electrical generator with the grid are extremely critical, involving the following four important steps before the interconnection can be made:

1. The phase sequence of the generator must be the same as other generators already operating on the electrical system. This means it must be rotating in the same direction. A phase-sequence indicator is used to determine in what order the phases reach their maximum voltage.

2. The synchronizing generator must be operating at the same frequency as other generators on the system. Frequency is controlled by the rotating speed of the generator and based on the number of field poles.
3. The voltages of the generator and grid at the point of connection must be the same. Voltage is controlled by varying the generator field current and magnet strength.
4. The generator and grid voltages must be in phase.

Modern electronic inverters perform all synchronizing and protective functions internal to the inverter circuitry.

7.3 Point of Connection

Point of connection or **point of common coupling** is the location at which a DG system interfaces with the electric utility system. For smaller distributed PV systems on buildings, the point of connection may be located on the load or supply side of a service disconnecting means. For utility-scale systems not associated with buildings, the point of connection is usually a dedicated connection to the local distribution feeder through a transformer.

Supply-side interconnections are made on the utility side of a facility disconnecting means by tapping the service conductors. Supply-side connections must have disconnecting means and overcurrent protection, as well as requirements similar to installing a new service. For supply-side interconnections, the sum of inverter AC output overcurrent devices supplying the service must not be greater than the service rating.

Load-side interconnections permit the output of utility-interactive inverters to be connected on the load side of the service disconnecting means of a facility at any distribution equipment on the premises, such as a panelboard or feeder. Load-side connections must meet several requirements, including each inverter having dedicated overcurrent protection and disconnecting means. Additionally, overcurrent devices (including inverter output and utility supply breakers) must not exceed 120 percent of the bus or conductor rating of the distribution equipment it supplies. Backfed breakers must be listed for such use and labeled as PV supply breakers. If the supply breakers exceed 100 percent of the bus rating up to the allowed 120 percent limit, the PV system overcurrent devices must be located at the opposite end of the bus or conductor from the utility supply and marked "Do Not Relocate This Overcurrent Device." This helps ensure that the bus or conductor will not be overloaded at any point. Many small residential and commercial PV systems can use load-side interconnections if these requirements can be met.

Large utility-scale PV systems not installed on buildings are usually interconnected at distribution substations or feeders and may require additional transformers and protective equipment.

7.3.1 Point of Connection Markings

Markings are required for interconnected PV power sources at the disconnecting means and must indicate the following:

- A PV power source
- Nominal AC operating voltage
- Maximum AC current

Facilities supplied by both utility services and PV systems must have a permanent plaque or directory showing the location of the service disconnecting means and the PV system disconnecting means, if not co-located (see Figure 59). A directory of power sources and the location of disconnecting means are required for safety and access to emergency responders (see Figure 60).

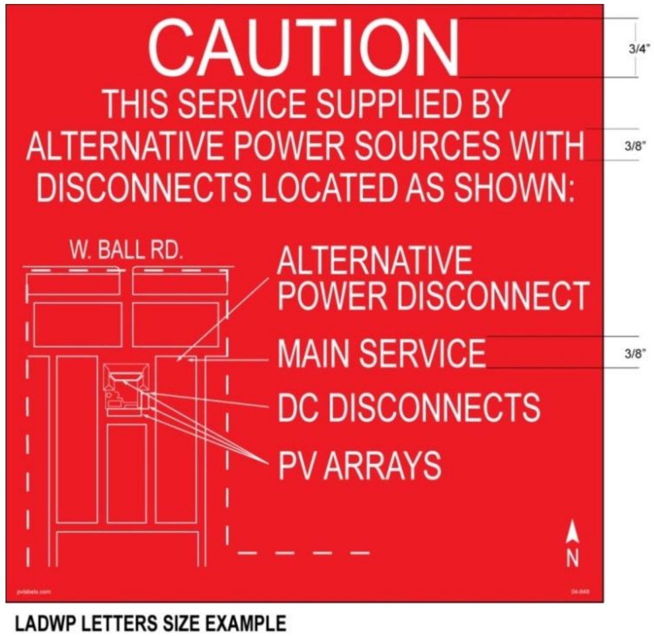


Figure 59: Label at AC Disconnect (courtesy pvlabels.com)

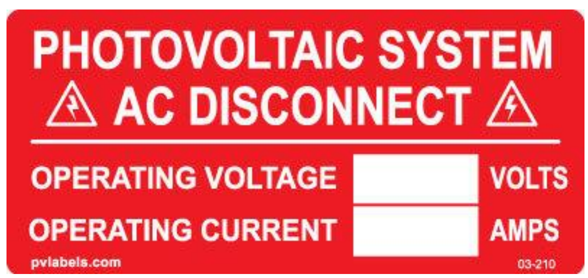


Figure 60: PV System Directory and Location of Disconnecting Means

All inverters and AC modules specifically intended to be used in utility-interactive PV systems must be listed and identified for interactive operations; this information must be marked on the product label.

7.4 Interconnection Hardware

The interconnection equipment for a PV system typically includes transformers with CT metering, switchgear, and a three-phase recloser.

Figure 61 shows a one-line diagram for a typical three-phase medium-voltage interconnection. Figure 62 shows a sample physical layout.

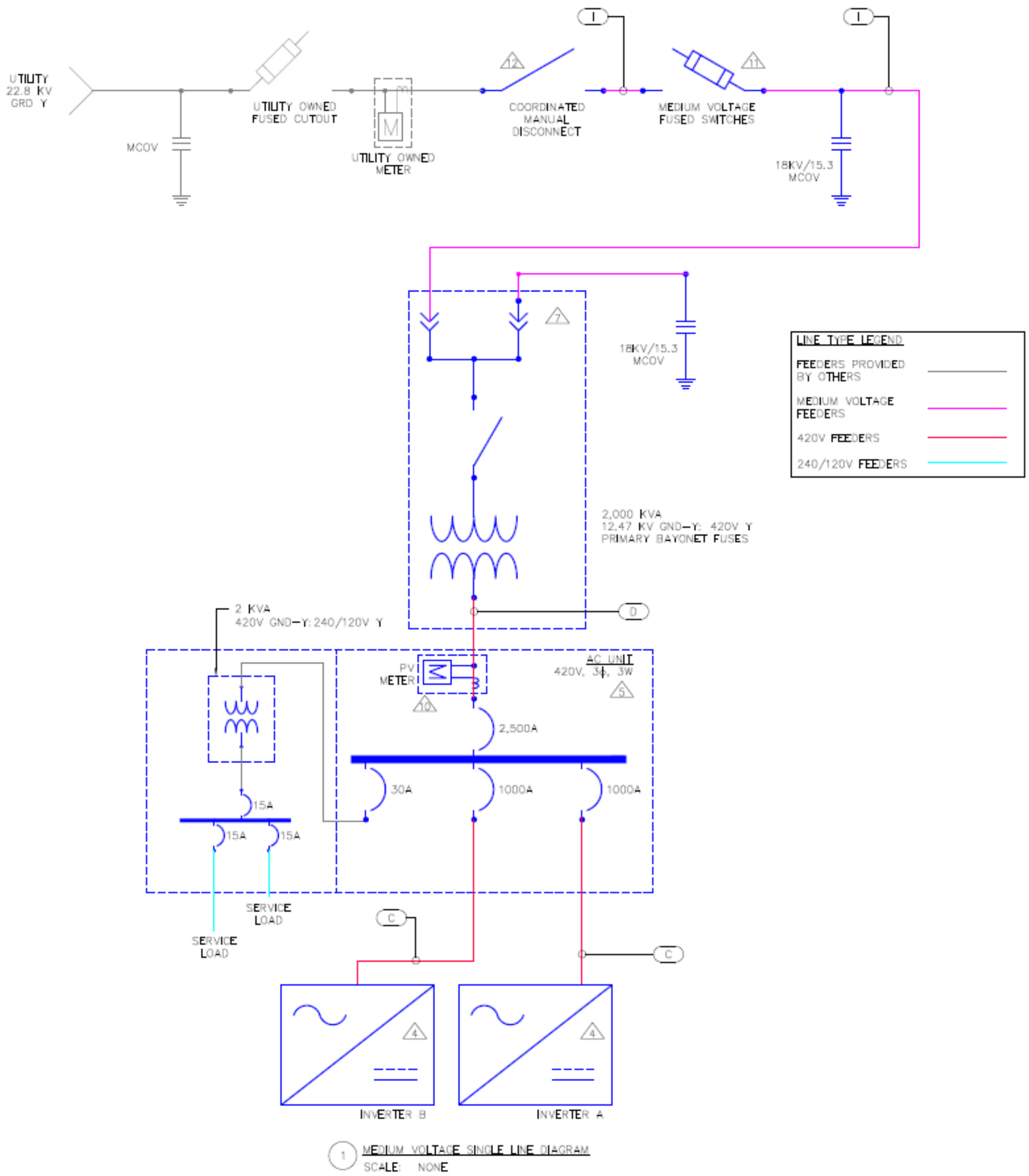


Figure 61: Sample One-Line Interconnection

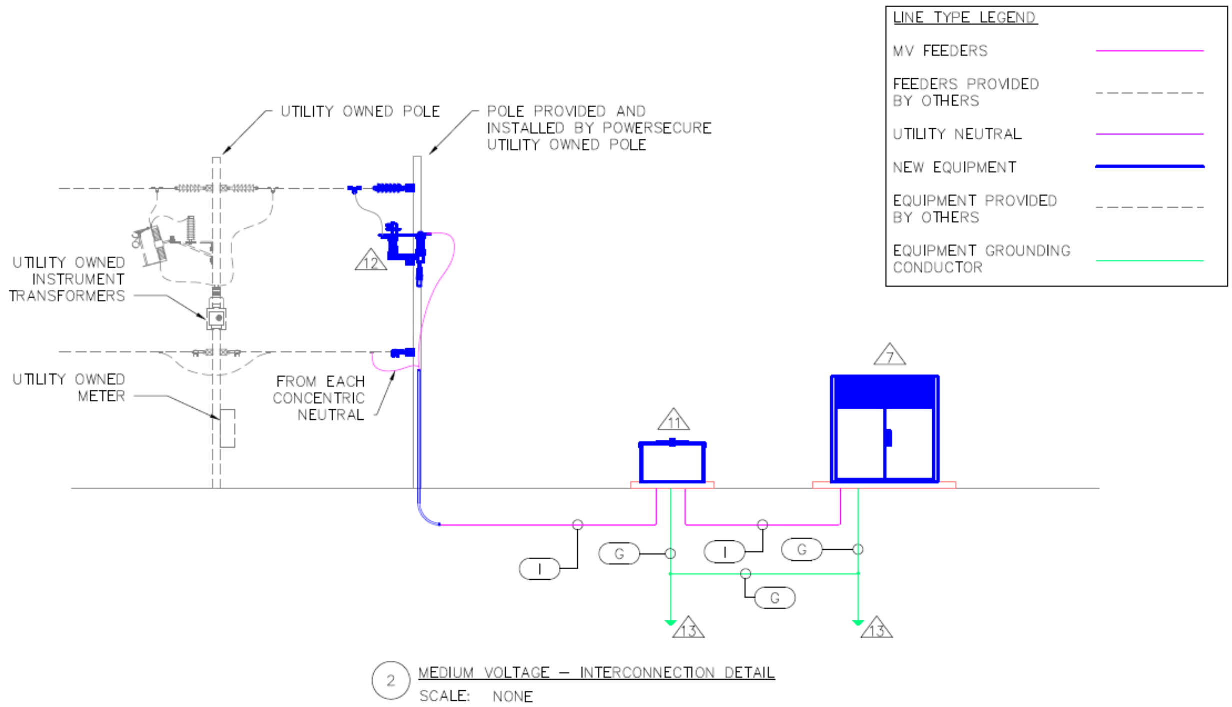


Figure 62: Sample Interconnection Physical Layout

7.5 Transformer

A transformer is required between the inverter AC output and the medium-voltage distribution line. This transformer may be supplied by the system integrator as part of an inverter assembly or by the interconnecting utility.

The transformer should be a new, complete, and satisfactorily liquid-filled pad-mounted step-up transformer, as indicated on the system drawings. The exact transformer specifications and protective equipment depend on the type of inverter selected and the point of common coupling with the grid. This is one of the areas that will require additional engineering beyond the template designs provided by this project.

All items of equipment -- hardware, raceway, wiring, and so on -- required for a complete installation should be furnished and installed whether or not

Distribution transformers are used to step up inverter AC output voltages to distribution voltages of up to 35 kV, often referred to as the AC collection system. Substation transformers are used for larger solar plants that step up the AC collection system voltage to transmission-level voltages of up to 115 kV.

The standard winding connection options on both the primary and secondary sides of the transformer are delta, ungrounded wye, and grounded wye. Low-voltage windings must conform to the inverter manufacturer's requirements. Multiple inverters connected to a single transformer may require galvanic isolation between the inverters. Utility interconnection standards typically govern the high-voltage winding connections on the primary side of the transformer.

Dry-type distribution transformers are generally larger, heavier, and more expensive than liquid types, and generally used only for indoor applications. Most utility-scale PV systems use liquid-filled pad-mounted distribution transformers. Manufacturers typically build transformers for solar applications to order, so plan for appropriate lead times.

every item is specifically mentioned. The transformer and installation must comply with the following standards:

Standards ANSI C57.12.00 and C57.12.27 (general)

- ANSI C57.12.70 and C57.12.80 (connections and terminology)
- ANSI C57.12.90 (test code)
- ANSI/IEEE C57.109 (transformer damage curves and protection)
- ANSI C57.12.26 (dead-front high-voltage bushings)
- ANSI/IEEE 386 (separable connectors)

Figure 63 shows a typical medium-voltage transformer installation. Figure 64 shows details of a pad-mounted distribution transformer.

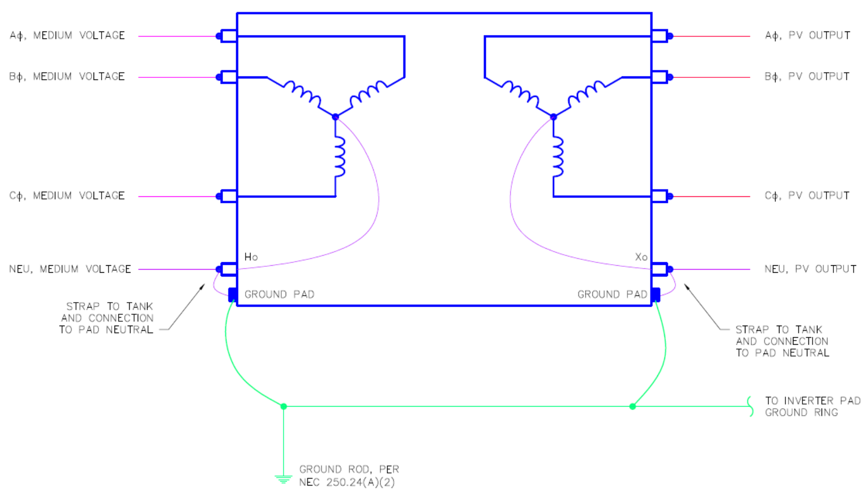


Figure 63: Sample Transformer Installation

A sample transformer specification is included in Appendix I.

The 1.0- and 0.5-MW PV systems described in this manual are designed to be connected at distribution voltage (13.2 kV, for example). The output of the inverters has a 420 VAC, three- phase output, so they need a special interconnection transformer, typically supplied as part of the inverter skid.

The 250-kW systems both have 480 V, three-phase output, so they can be connected either through a low-voltage circuit or supplied with a standard distribution transformer.

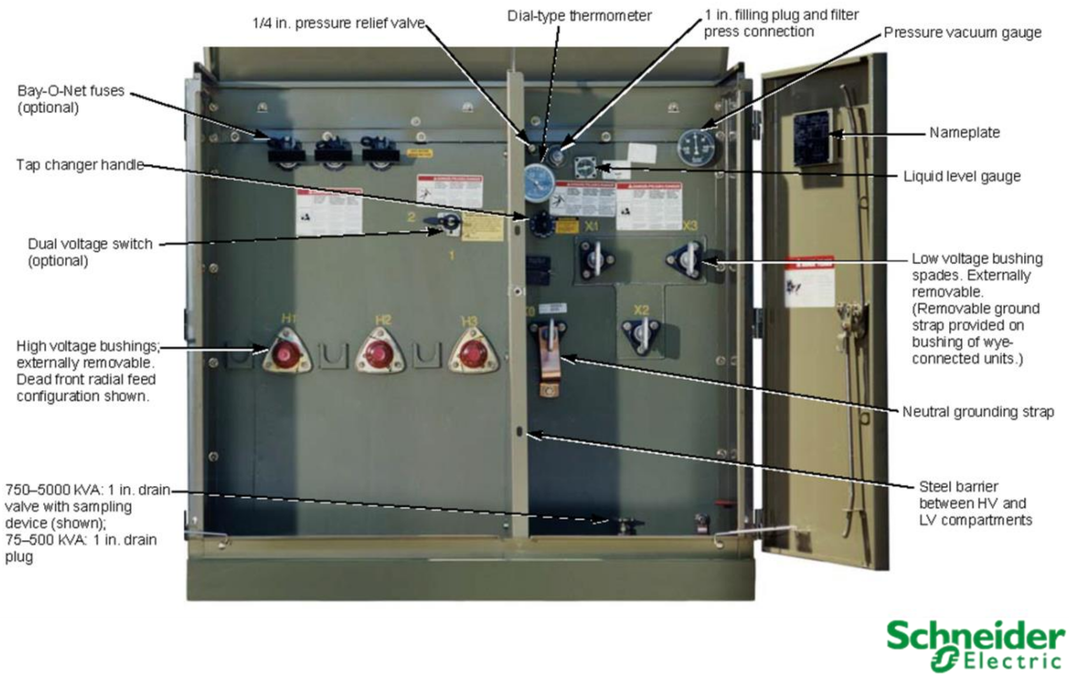


Figure 64: Typical Pad-Mounted Distribution Transformer Details

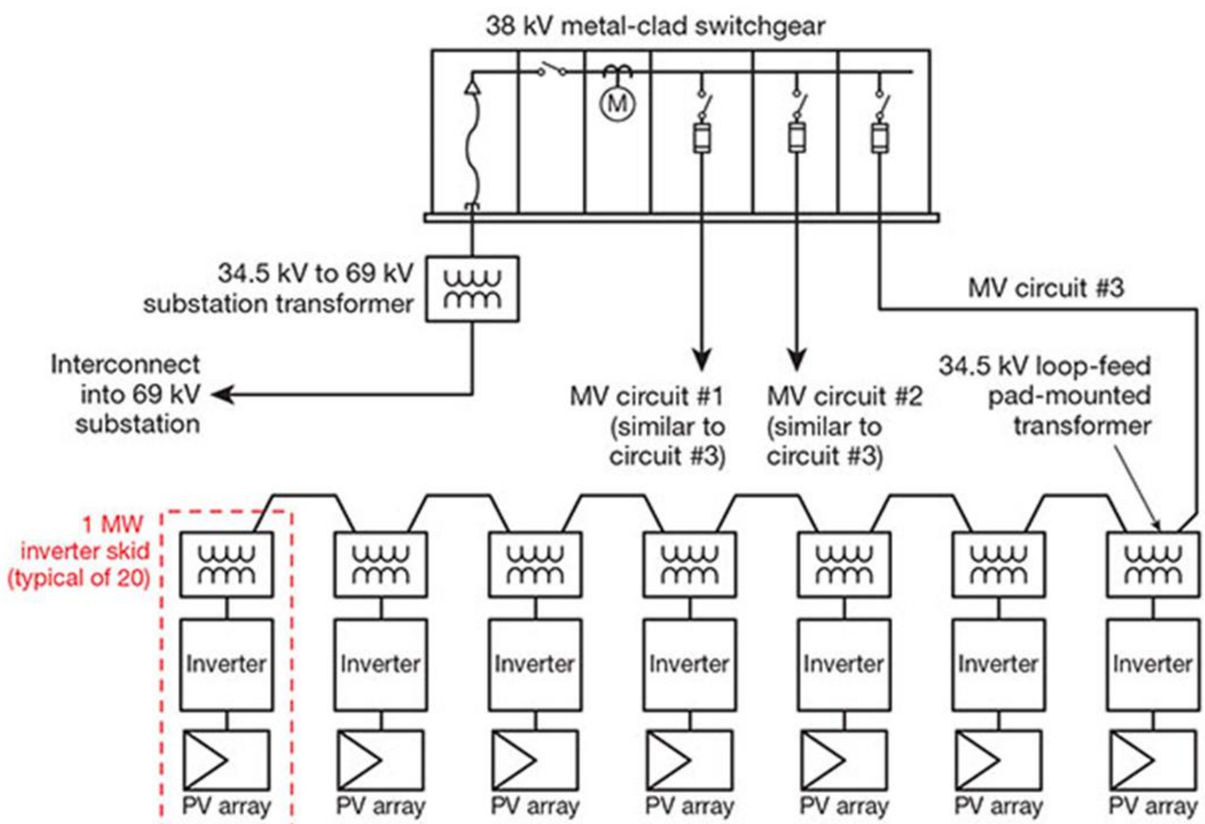


Figure 65: AC Collection Systems for Large Utility-Scale PV System

The AC collection systems for large utility-scale PV systems may have a number of distribution transformers coupled through switchgear to substation transformers for interconnection to the transmission network, as shown in Figure 65.

7.5.1 Overcurrent Protection

A short-circuit and protective device coordination study encompasses portions of an electrical distribution system. In addition to a normal power source or sources, it includes fuses in medium-voltage service entrance switchgear, fuses in medium-voltage distribution switchgear, the main breaker in sub-distribution panels, and the main breaker in each panelboard or the upstream breaker serving each panelboard.

A part of the coordination study must provide an arc-flash analysis in accordance with IEEE 1584 and labeling in accordance with NFPA 70-2008, Article 110.16, and meeting the requirements of NFPA 70E-2009, Article 130.

7.5.1.1 Short Circuit and Protective Device Coordination Study to Meet Requirements of NFPA 70

The coordination study must be prepared before ordering distribution equipment to verify the equipment ratings required.

The study should be performed with the aid of a computer software program. If applicable, obtain actual settings for the packaged air conditioning unit, motor characteristics, and variable-frequency drive information for the equipment subject to the study.

Calculate short-circuit interrupting and, when applicable, momentary duties for assumed three-phase bolted fault short-circuit current, and phase to ground-fault short-circuit current at each of the following:

- Medium-voltage switchgear
- Pad-mounted transformer
- Low-voltage switchgear
- Switchboards
- Distribution panelboards
- Branch-circuit panelboards
- Any other significant equipment located throughout the system
- DC combiner boxes
- Inverters

Also reference the report contents or specifications determined by the engineer of record as follows:

- Calculation methods and assumptions
- Base per unit value selected
- One-line diagram
- Source impedance data, including power company system available power and characteristics
- Typical calculations
- Fault impedance
- X to R ratios
- Asymmetry factors
- Motor-fault contribution
- Short-circuit kVA
- Symmetrical and asymmetrical phase-to-phase and phase-to-ground fault currents
- Tabulations of calculation quantities and results

- One-line diagram, revised by adding actual instantaneous short circuits available
- Conclusions and recommendations

Supply other information, including device characteristic curves at the point reflecting maximum symmetrical fault current to which the device is exposed. Include the following on curve sheets:

- Medium-voltage equipment overcurrent device characteristics
- Low-voltage equipment circuit breaker trip device characteristics
- Low-voltage equipment fuse characteristics
- Cable damage point characteristics

Include pertinent transformer characteristics, such as the following:

- Transformer full load current
- Transformer magnetizing inrush
- ANSI transformer withstand parameters
- Significant symmetrical fault current
- Pertinent motor characteristics
- Other system load protective device characteristics

The study should be performed in accordance with IEEE 242, and the arc flash test in accordance with IEEE 1584 equations presented in NFPA70E-2004, Annex D. The study must be done under the direct supervision of a professional engineer experienced in the design of this type of work and licensed in the state in which the project is being constructed.

7.5.2 MV Power Cable

The physical properties and thickness of the insulation and sheath, as well as the testing methods, shall comply with the requirements of ICEA and AEIC specifications, ICEA Standard S-93-639 (NEMA Publication No. WC74), and IEEE Standard 241, and shall be UL listed as MV-105.

Conductors shall be soft-drawn Type MV-105 Class "B" concentric compact or compressed, stranded copper or aluminum, single-conductor cable, with an extruded semi-conducting cable shield. The cable shall be capable of operating at a normal continuous conductor temperature of 105°C, an emergency overload conductor temperature of 130°C, and a short-circuit conductor temperature of 250°C.

The cable shall be shielded with uncoated metallic, uncoated copper, or aluminum tape, applied helically.

The overall jacket or sheath shall be a PVC compound resistant to oil, acid, alkali, and sunlight, rated for use in conduit, direct burial, cable tray, or aerial construction. The cable identification must be printed on this jacket using indelible ink.

The primary cable rating shall be a nominal 220-mill thickness. The cable shall meet or exceed AEIC or ICEA requirements and have 100 or 133 percent insulation, or as required by the site-specific specification or engineered drawings. The cable shall meet or exceed the following standards: ICEA S-93-639, NEMA WC 74, AEIC CS-8, ASTM B-496, UL-1072 (type MV-105) for all cables, and IEEE 383 for cables.

7.5.3 Monitoring

The SUNDA template system designs include a PV monitoring system. This system must be connected to the inverter, the weather monitoring equipment, and any additional metering installed in the PV system by the utility; the resulting data connection must be routed back to the utility offices and connected to the SCADA system. It is important to coordinate any SCADA mapping early in the design/installation process to ensure that the proper information is available to the utility. A utility sometimes will use both a SCADA connection and a vendor-provided data acquisition site to gather information on system performance.

8 Commissioning

Any electrical system can be tested to verify performance and evaluate the condition of the wiring systems and equipment. This testing is particularly important for PV installations, which are subjected to extreme environmental conditions and the deteriorating effects of the elements over many years. To help ensure the long-term safe operation of these systems, all PV installations should have a thorough commissioning process, followed by a regular periodic testing and maintenance program. These practices can help promote safety and optimize performance, and provide essential information required to effectively troubleshoot, diagnose, and remedy potential problems with the system.

Commissioning of PV systems involves visual observations as well as tests and measurements to verify the safe and proper operation of the system. Commissioning is performed immediately after PV installations are completed but before being operated and put into service for the first time. A thorough commissioning process helps improve safety and quality control and provides verification that the installation matches the plans and code requirements, and is performing as expected. Some of the tests conducted during commissioning may be repeated during periodic routine maintenance to help ensure that the system remains in a satisfactory operating condition over its lifetime.

Key steps of a PV system commissioning procedure typically include the following:

- Completing final installation details
- Completing visual inspections
- Verifying compliance with NEC requirements
- Conducting electrical verification tests
- Verifying system functionality, including start-up, operations, shut-down, and emergency procedures
- Verifying that system power output and energy production meet performance expectations
- Completing system documentation, including changes for as-built drawings
- Conducting user orientation and training on system operations and safety

The IEC 62446 standard defines minimum documentation, commissioning tests, and inspection criteria for grid- connected PV systems. It is intended to verify the safe and proper operation of PV systems, and serve as a guide for designers, installers, and service personnel. Compliance with IEC 62446 provides buyer assurances and correlates with requirements for the verification of safety for all electrical systems.

The requirements of IEC 62446 are covered in two parts: (1) system documentation and (2) verification. Additionally, the standard’s annex provides sample verification and testing report templates as well as alternative testing methods. Compliance with this standard is highly recommended and provides the best assurances for the owner’s investment.

8.1 Final Installation Checkout

A final checkout confirms that the installation is complete before conducting any testing and beginning system operations. Typically, the installation contractor will perform the final checkout before formal inspections by building officials. With the exception of the PV array, all circuits should be de-energized whenever possible in preparation for system testing. A punch list can be used to help check off items as they are completed; it typically includes the following items:

- Verifying that all structural and electrical components are installed and secured properly
- Verifying that all components are installed in a neat and workmanlike manner, including wire management practices
- Verifying proper connections and terminations, including terminal torque specifications
- Verifying that all required system and equipment labels, markings, and placards are correct and in the proper locations
- Verifying that any calibrations or adjustments for inverters, charge controllers, or other equipment are set or programmed properly
- Verifying that all disconnects are open, fuses are removed, and LOTO procedures are in place
- Identifying and completing any unresolved items
- Completing site clean-up and restoring the site to original conditions

8.2 Visual Inspection

Visual inspections of PV systems should be performed as part of commissioning and routinely over the system lifetime to verify and ensure that the system remains in a safe and properly functioning condition. There are many areas to evaluate through visual inspections, with the frequency and level of detail depending on the type and size of the system involved. Visual inspections are supplemented with other observations, test measurements, and performance data to fully evaluate the safety and condition of PV systems.

Initial inspections are used primarily to identify unfinished installation details and verify compliance with the applicable code requirements. Visual inspections conducted after installation or during periodic routine maintenance tend to look for physical damage or degradation of equipment from temperature extremes, moisture, or other environmental conditions.

Before initial operation, all PV systems should be inspected for compliance with the many NEC requirements. Checklists often are used to review and verify these requirements at the time of inspection for examination and approval by local authorities. Among the key NEC requirements covered in Article 110, Requirements for Electrical Installations, are the following:

- All equipment shall be properly listed, identified, and labeled suitable for the conditions of use and installed according to the listed product instructions [110.3].
- All equipment shall be installed in a neat and workmanlike manner, consistent with quality craftsmanship standards in the electrical construction industry [110.12].
- All equipment shall be mechanically secured and provided with adequate ventilation or cooling, as required [110.13].
- All electrical terminations and connections shall be made using approved products and installation methods [110.14]. This includes consideration of conductor and terminal materials, temperature ratings, and specially approved terminals for use with fine-stranded conductors or more than a single conductor. Pressure connectors using a set screw have required tightening torques; these values should be recorded and verified at commissioning.
- All electrical equipment shall be marked with the manufacturer’s identification and applicable specifications and ratings [110.21].
- Sufficient working spaces shall be provided around any electrical equipment likely to be serviced or maintained while energized [110.26]. Clear spaces and dedicated spaces are also required around certain electrical equipment, such as panelboards or switchgear.

NEC requirements covered in Article 690, Solar Photovoltaic Systems, also should be evaluated and verified during inspections. These requirements address the following areas:

- Circuit voltages and currents
- Conductor and overcurrent device sizes and ratings
- Disconnecting means
- Wiring methods
- Equipment and system grounding
- Marking
- Connections to other sources (also Article 705)

Some sources for PV system inspection checklists and guidelines include the following:

- https://dept-wp.nmsu.edu/swtdi/files/2015/10/INSPECTOR-InstallerCHECKLIST6-30-2011.pdf
- http://brooksolar.com/files/PV-Field-Inspection-Guide-June-2010-F-1.pdf
- http://www.jimdunlopsolar.com/vendorimages/jdsolar/PVInspectionChecklist.pdf
- https://webstore.iec.ch/publication/24057 (IEC 62446-1:2016)

8.3 System Testing and Measurements

PV systems should be tested thoroughly at the time of commissioning and periodically over their lifetimes to ensure proper performance and safe operation. Baseline measurements at the time of system commissioning are compared to the system ratings and expectations for acceptance and serve as a baseline for comparison with future measurements. Changes in test results over time are used to track system degradation and identify problems that require attention or service for safety or performance reasons. Circuits or components that are modified or replaced should be retested accordingly.

Several types of electrical tests conducted on PV systems are used to verify NEC requirements and system performance. Many of these tests can be conducted with common electrical test equipment, whereas some measurements require special meters and instruments. In many cases, system performance information is measured, recorded, and displayed by inverters and other power processing equipment, and can be used to verify system functions and proper operation.

The following summarizes common types of testing conducted on PV systems, and what information it provides:

- **Continuity and resistance testing** verifies the integrity of grounding and bonding systems, conductors, connections, and other terminations.
- **Polarity testing** verifies the correct polarity for PV DC circuits and proper terminations for DC utilization equipment.
- **Voltage and current testing** verifies that PV array and system operating parameters are within specifications.
- **Insulation resistance testing** verifies the integrity of wiring and equipment, and is used to detect degradation and faults to wiring insulation.
- **Performance testing** verifies that system power and energy output are consistent with expectations. These tests also require measurements of array temperature and solar irradiance.

Figure 66: The Seaward PV100 Handheld Meter

Multi-function PV system testers are now available to conduct many of the recommended tests, including continuity and resistance tests, polarity tests, voltage and current tests, and insulation resistance tests. By combining these test functions into a single instrument (see Figure 66), testing personnel avoid having to purchase, carry, and maintain multiple meters. These instruments can also store data into the commissioning test reports that become part of the system documentation record for later retrieval and processing.

8.3.1 Testing Safety

Conducting electrical testing on any PV system should be performed by qualified individuals having knowledge of and experience with electrical systems measurements, the test equipment used, the equipment or systems being tested, and an awareness of the hazards involved. General safety recommendations for using electrical test equipment include the following:

- Follow manufacturer's instructions for the safe operation of any test instruments.
- Use test instruments only for their intended purpose and within their established limits and ratings.
- Carefully inspect test equipment and leads before each use.
- Properly maintain test instruments and recommended calibrations.
- Plan and review all testing, safety, and emergency procedures in advance.
- Use appropriate PPE, including electrical insulating gloves.
- Work with a partner.

8.3.2 Continuity Testing

Continuity testing is commonly used to verify grounding and bonding connections in electrical systems. These tests also verify the proper operation of disconnecting means and the function of overcurrent protection devices, such as fuses and circuit breakers. Measurements of resistance can also be used for estimating voltage drop in conductors, terminations, and other connections, and for evaluating windings in motors and transformers.

Proper grounding of PV systems reduces the risk of electrical shock to personnel and the effects of lightning and surges on equipment. The grounding requirements for PV systems can be quite complex to understand, and installation practices and hardware are continually evolving and improving. 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. All PV systems require equipment grounding; most also require system grounding. Specific grounding requirements for PV systems are addressed in NEC Article 690, Part V; general grounding and bonding requirements are covered in NEC Article 250.

Most legacy PV arrays in the U.S. today have been installed with a grounded DC circuit conductor—either the positive or negative conductor or the center tap of bipolar arrays [690.41]. This connection must be made at a single point on the PV output circuit [690.42]. For interactive inverters with ground-fault protection [690.5], this connection usually is made internal to the inverter at dedicated terminals according to the manufacturer's instructions. The connection between the grounded conductor and grounding electrode system is made through the ground-fault protection device. When a ground-fault condition is detected by current flow in this conductor, the circuit is opened and the inverter displays a ground-fault indication. Special labels are required to warn that normally grounded conductors may be ungrounded and energized. Appropriate safety precautions should be exercised around any PV array when ground faults are suspected.

Ungrounded PV arrays are permitted by the NEC but require specially listed inverters designed for use with ungrounded arrays, special cabling, or protection for wiring, and require disconnecting means, overcurrent protection, and ground-fault protection in both ungrounded array DC conductors. Ungrounded PV arrays are common in Europe; expect to see more of these designs installed in the U.S. in coming years, due to lower inverter costs and capability for better array fault detection.

Equipment grounding for PV systems is particularly challenging, due to the large numbers of individual PV modules in arrays and their multiple connections to metallic support structures. PV module manufacturers are required to provide details of acceptable equipment grounding methods and components in their listed installation instructions, according to the UL 1741 standard for module safety. However, different mounting structures supplied by different manufacturers often require specialized grounding practices and hardware. Be sure to follow module and mounting system manufacturers' instructions for proper equipment grounding practices.

Electrical resistance and continuity testing can be used to confirm the following NEC requirements:

- Verify that the finish or anodizing on aluminum or other metallic components has been satisfactorily removed or penetrated for equipment bonding connections [250.12, 250.96].
- Verify that all available grounding electrodes in a building are bonded together and form a single grounding electrode system [250.50]. This includes underground metallic water pipes; building structural steel; concrete-encased electrodes; ground rings; and rod, pipe, and plate electrodes, as available.
- Verify that the grounding electrode conductor is continuous, and the viability of any irreversible splices, welds, or other connections are made using approved means, where permitted [250.64]. Also verify the connection of the grounding electrode conductor to the grounding electrode.
- Verify that metal raceways, enclosures, frames, fittings, and other components serving as equipment grounding conductors are bonded together properly [250.86, 250.96]. Circuits operating at over 250 volts to ground require special bonding methods to ensure electrical continuity of metallic raceways, such as the use of listed bonding lock nuts and bushings [250.97].
- Verify that the continuity of the equipment grounding conductor is first-make, last-break for any plug and receptacle equipment, and is not opened by any disconnect device [250.124].
- Verify that metallic raceways and enclosures are joined into a continuous electrical conductor [300.10]. Loss of mechanical continuity due to improper installation or inadequate support can also lead to loss of electrical continuity [300.11, 310.12].

- Verify that metal parts of all PV module frames, support structures, and other equipment are bonded to the equipment grounding system [690.43]. Special equipment bonding devices, listed, and identified for bonding grounding module frames to support structures, are allowed when approved for specific types of modules and mounting structures. Refer to PV module and mounting system manufacturers' instructions for additional information.
- Verify the continuity of equipment grounding connections and bonding jumpers when PV modules or inverters are removed from a circuit for service [690.47]. Similar requirements also apply to maintaining the continuity of equipment grounding conductors to metallic boxes containing receptacles, luminaires, and other devices that may be removed for service [250.148].
- Verify that continuity between the grounded PV array source circuit and output circuit conductors remain bonded to the grounding electrode conductor whenever an inverter or other equipment is removed for service [690.47].

Continuity tests can be conducted using a conventional ohmmeter capable of measuring low resistances. Most digital multimeters also include continuity test features that produce an indication of pass or fail, such as an audible alarm when continuity is verified. Extra-long test leads often may be required to verify the continuity of grounding connections in PV systems due to the long separation distances between components. For accurate readings, the resistance of the test leads is accounted for or nulled by zeroing the ohmmeter prior to any resistance measurements. A clean surface and reliable test lead connection to the circuit under test also is crucial. Continuity and resistance testing should be performed only on de-energized circuits and conductors.

8.3.3 Polarity Testing

As for any DC circuits, the polarity of array wiring and DC equipment is a critical concern for PV installations. The polarity of every source circuit and the entire PV power source must be verified before connecting to any DC utilization equipment, such as batteries, charge controllers, inverters, or electrical loads. Without required PV array source and output circuit overcurrent protection [690.9, 240], reversing the polarity of an array connection to a battery can lead to disastrous results and damage PV modules or source circuit wiring. A reversed polarity array can also act as a load, discharging current from a battery without some form of reverse current protection such as a blocking diode. Some inverters have rectifiers on their DC input to protect them from reverse polarity connections; many do not, however, and can be damaged by inadvertently reversing the connections.

Reversing the polarity of a PV module within a given series source circuit can occur for hard-wired connections, although this problem largely has been eliminated by factory-installed PV module connectors and the requirement for them to be polarized, marked, and non-interchangeable [690.33]. For PV modules using bypass diodes, reversing module polarity within a series source circuit will force that module to operate at reverse voltage, limited by the voltage drop across the blocking diodes, usually around 0.7 V for each diode. The result is that the current from other modules in the series string will "bypass" the reversed module, and the net voltage output for the entire string will be reduced by the voltage of the reversed module plus the voltage drop across the bypass diodes. Bypass diodes prevent PV modules from operating at large reverse voltages that can result in high power dissipation and damage to the module.

Reversing the polarity of an individual PV source circuit within a combiner box will simply cancel the current output from other parallel-connected strings wired with proper polarity. For larger PV installations with dozens of source circuits terminating at several combiner boxes throughout the PV array, keeping track of each source circuit and its polarity can be a challenge. To help reduce confusion and promote better wire management practices, the NEC now requires all PV circuit conductors to be identified clearly by labeling, grouping, or color coding at all terminations, connections, or splices [690.4]. All source circuit fuses and module bypass diodes should be checked if modules or strings are ever connected in reverse polarity.

Polarity is verified by measuring the voltage on energized circuits before closing disconnects and operating the system for the first time. Most digital multimeters can be used for this purpose, as can specialized PV array testing equipment capable of measuring DC voltage over the appropriate range. Electronic meters typically indicate the polarity of DC voltage measurements with a plus (+) or minus (-) symbol on the display, according to the connections of the positive and negative test leads. Analog voltmeters are not used for polarity testing, as the meter movements on these instruments can be damaged by connecting them in reverse polarity.

Polarity should be verified on the following DC components and circuits in a PV system:

- PV modules
- PV source circuits
- PV output circuits
- Disconnecting means
- Inverter DC input terminations

8.3.4 Voltage and Current Testing

Basic voltage and current tests are conducted on both DC and AC circuits in PV systems to verify that these parameters are within acceptable limits before closing disconnects and beginning system operations. Detailed voltage and current tests may also be conducted on PV source circuits and arrays for performance verification purposes. Testing for performance verification requires additional measurements of solar irradiance and array temperatures, and translation of test results to a reference test condition.

Before operations, voltage should be verified for the following circuits and sources in PV systems:

- Verify AC voltage and correct phasing at utility supply, inverter AC terminals and disconnects, and electrical generators, as applicable.
- Verify DC voltage and correct polarity for PV array source and output circuits, and at DC disconnects and inverter input.
- Verify DC voltage and correct polarity for battery, charger, and charge controller subsystems.

Many PV inverters have integral data monitoring that measures many system parameters on the DC and AC sides of the inverter, including DC voltage, current, and power. Usually, source circuit measurements need to be made at combiner boxes located throughout the array field in larger systems, where the source circuits can be isolated and identified for testing.

8.3.4.1 Open-Circuit Voltage Testing

Before closing the PV array DC disconnects, the Voc for each PV array source circuit should be tested and compared with expectations. This test can also be used to verify proper polarity. These tests simply verify correct installation and are not intended to verify performance. Open-circuit voltage tests require a suitable voltmeter capable of reading AC and DC voltages of 600–1,500 V.

Most PV systems have identical strings consisting of the same number of series-connected modules. In these cases, similar open-circuit voltage readings should be expected under the same testing conditions—typically within 5 percent of each other. Lower than expected voltage can be due to improper array wiring, failed modules, or shorted bypass diodes. The string open-circuit voltage measurements should also be verified to operate within the DC voltage limits for inverters, charge controllers, or any other DC utilization equipment.

If average cell temperatures also are measured, the open-circuit voltage measurements can be easily translated to a reference temperature condition for comparison with system specifications. Based on a standard -0.4 percent/°C voltage-temperature coefficient for crystalline silicon PV modules, the corresponding voltage change should be 2.5 percent for every 10°C change in module temperature.

8.3.4.2 **Short-Circuit Current Testing**

Short-circuit current tests are conducted on PV array source circuits to verify proper readings and ensure that they are clear of major faults. Similar to the open-circuit voltage tests, these tests are intended only to verify proper system operation, not performance. Suitable test equipment, capable of safely short-circuiting high-voltage DC circuits, is required. Most digital multimeters can measure DC current up to 10 A but require a suitable shorting device to safely measure the current. Clamp-on ammeters also are available for DC current measurements; they require an external shorting device as well. Some circuit breakers and disconnect switches may have appropriate DC current and voltage load-break ratings for shorting array source circuits.

Short-circuit current is directly proportional to the solar irradiance incident on the array. Consequently, these tests must be done quickly under steady clear sky conditions at as close to the same irradiance level as possible. Make sure the array is not shaded or particularly soiled before testing. Short-circuit current readings taken under steady conditions typically should be within 5 percent of one another for acceptance. If irradiance measurements also are made simultaneously with short-circuit current measurements, the results can easily be translated to a reference irradiance condition—for example 1,000 W/m^2—to compare with specifications.

8.3.5 Insulation Resistance Testing

Insulation resistance tests are used to verify and demonstrate the integrity of electrical wiring systems and equipment, as required by the NEC [110.7]. These tests can be used to assess degradation or damage to wiring insulation and to locate faults within PV arrays and other system circuits. Insulation tests are an important element of commissioning, acceptance testing, and preventative maintenance for PV systems.

Electrical conductors usually are insulated with an outer covering to protect them from coming into contact with personnel, equipment, or other conductors. Where conductors are exposed at termination points or on busbars, the terminal spacing and air gaps provide insulating properties. Compared to conductors that have very low resistance—on the order of a few ohms or less—insulators have very high resistance, as measured in megohms (MΩ).

The quality of conductor insulation can be determined by measuring its resistance. Insulation resistance is determined by applying a constant test voltage to a conductor and measuring the current flow between the conductor and ground, or between other de-energized system conductors. This is analogous to pressure testing a plumbing system for water leaks. As wiring insulation degrades, its resistance decreases and the small current flow through the insulation increases. The higher its resistance value, the better the conductor insulating quality. Excessive leakage current can present an electrical shock hazard, damage equipment, and degrade system performance.

Damage to wiring insulation can result from improper installation or any number of environmental factors, including from impacts or vibration; animals or insects; or deterioration from temperature, sunlight, or other adverse conditions. Due to the degradation of PV modules and wiring systems over many years of direct exposure to the elements, older PV arrays naturally will have lower insulation resistance than when they were new. Insulation resistance tests are recommended on a three-year maintenance interval or more frequently, as circumstances dictate.

Insulation resistance is measured between the conductors under test and ground, or between other conductors. Insulation resistance and leakage current testing are used to verify the integrity of the following PV system circuits and components:

- Verifying integrity of PV modules and array source and output circuit conductors
- Measuring the leakage current through overcurrent and disconnect devices, including fuses, switches, and circuit breakers
- Measuring the insulation resistance for any equipment with windings, such as motors, generators, transformers, and inductors
- Testing the grounding electrode resistance

To maintain safety and avoid damaging components during testing, the following guidelines and precautions apply to insulation testing of PV system circuits and associated equipment:

- Always use insulated rubber gloves with leather protectors when conducting insulation tests. Make sure the test area and equipment are protected from access by unauthorized persons.
- Never connect insulation testers to energized circuits. Some testers may signal an alarm or revert to voltage measurement when connected to energized circuits.
- Isolate circuits for testing by opening disconnects and verify that circuits are de-energized using LOTO procedures before connecting insulation testers. The exception is for PV DC source circuits, which are always energized when exposed to light.
- A grounded test lead should always be the first to make and last to break any circuit measurement. Never use insulation testers in an explosive environment or around combustible materials.
- Never use insulation testers on circuits with any electronic equipment, including inverters, charge controllers, instrumentation, or surge suppression equipment, as the application of high test voltages can damage this equipment.
- Never conduct insulation tests on batteries or other energy storage systems.
- Always ensure that circuits are discharged properly before and after insulation tests, either through the test equipment or externally with a load resistor. This is particularly important for PV modules, motor windings, and parallel wiring methods with capacitive characteristics.

8.3.5.1 **Test Equipment**

Insulation resistance testing usually is measured with a megohmmeter. A megohmmeter is a special type of ohmmeter that measures very high values of resistance by applying high test voltages between conductors and measuring the leakage current. Megohmmeters may be powered by an external source, internal batteries, or a hand crank. Test voltages range from 50 Vdc to 5,000 Vdc, depending on the instrument and its purpose.

Insulation resistance testing may also be performed using a hipot tester. Similar to a megohmmeter, a hipot tester also supplies a high-test voltage but measures leakage current rather than resistance and is used for higher voltage insulation resistance testing. The insulation resistance then can be calculated using Ohm's Law by dividing the test voltage by the leakage current. A high-voltage DC power supply can also be used as a source for insulation resistance tests, using ammeters to measure leakage current.

Handheld insulation multimeters often combine insulation test functions with voltage, resistance, and continuity measurements. This test equipment is lightweight and easy to use and can accommodate a variety of electrical system testing requirements. Specialized multi-function insulation multimeters purposely designed for testing PV arrays are available.

8.3.5.2 Testing Considerations

Insulation resistance varies with the type of insulation and is inversely proportional to the volume of insulation tested. For example, a 500 foot insulated conductor would typically have one-fifth of the insulation resistance as the same insulated conductor that is only 100 feet in length. Insulation resistance also decreases with age as the insulation degrades and is affected by temperature and moisture. Insulation resistance is inversely proportional to temperature; as temperature decreases by 10°C, insulation resistance effectively doubles. For example, a conductor having an insulation resistance of 4 MΩ at 20°C would have a resistance of 1 MΩ at 40°C. Consequently, it is important to measure and evaluate insulation resistance readings at constant temperatures and record this information with the test results. To avoid condensation and moisture effects, dry insulation resistance tests should be conducted only when the conductor temperature is above the dew point.

Spot insulation resistance tests are taken as one reading after a defined period of time (usually 60 seconds) under the applied test voltage. These short-time tests are used primarily to compare with previous measurements or expected values. Step insulation tests compare insulation resistances measured under different test voltages.

Time-based insulation resistance tests use multiple measurements recorded over time and can completely evaluate the quality of insulation without the benefit of previous testing results. The resistance of good insulation will increase slightly over several minutes, whereas the resistance of cracked or contaminated insulation will remain steady or even decrease slightly. This is because the current flow through the conductor insulation changes over time. The total current flowing through insulation includes the following three time-based components:

1. Capacitive current, which starts very high as voltage is first applied and then drops quickly
2. Absorption current, which also starts high but decreases at a lower rate due to voltage build-up across the insulation
3. Leakage current, which is a steady current that decreases over time as insulation degrades and insulation resistance increases

There are two common time-based insulation resistance measurements. The Polarization Index (PI) is the ratio of the 10-minute insulation resistance to the 1-minute insulation resistance. The Dielectric Absorption Ratio (DAR) is the ratio of the 1-minute insulation resistance to the 30-second insulation resistance. Some special insulation testers automatically calculate and display PI and DAR results. PI values should be 2.0–4.0 or higher; DAR values should be 1.5 or higher. Lower values indicate damaged insulation.

8.3.5.3 Test Procedures

Insulation resistance testing is conducted by applying high voltages to conductors and equipment and determining the resistance by measuring the leakage current. All circuits must be isolated from others for testing and discharged before and after testing. Grounding or bonding connections are left connected. Any surge suppression equipment must be removed from the circuits. The test leads must make a reliable connection with the circuit under test and may require filing or grinding of some coated metal components.

The test voltage depends on the circuits or equipment tested. It usually is higher than the operating voltages for the circuits or equipment under test, but not higher than the voltage ratings of the equipment or conductor. Higher test voltages may be used for proof testing of equipment by manufacturers rather than for field tests. Note that the maximum system voltage rating for most PV modules in the U.S. market is 1500 V.

Insulation resistance and other electrical tests on PV arrays generally are measured at source circuit combiner boxes, where the individual array circuits can be accessed. The tests can be conducted dry, or a wetting agent can be sprayed on portions of an array to better pinpoint fault locations. Insulation tests may be performed using either of the following two methods:

1. Between the positive DC conductor and ground, and between the negative DC conductor and ground.
2. Between the shorted positive and negative DC conductors and ground. This method requires an appropriate shorting device rated for circuit current and voltage.

IEC 62446

The international standard IEC 62446-1:2016, Grid Connected PV Systems – Minimum Requirements for System Documentation, Commissioning Tests, and Inspection, defines minimum documentation, commissioning tests, and inspection criteria for grid-connected PV systems. Information derived from this standard is intended to verify the safe and proper operation of PV systems, and serve as a guide for designers, installers, and service personnel. This standard covers specific requirements for testing and commissioning PV systems. Many of the testing procedures outlined in this standard correlate directly with NEC requirements for the verification of safety for all electrical systems.

The grounding connection is made to metallic module frames or support structures, the building grounding electrode systems, or directly to earth. Some modules and supports structures may not have a metallic support structure or frames. For spot testing, apply the desired test voltage 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, insulation resistance measurements will decrease significantly.

The IEC 62446 standard recommends 0.5 MΩ as an acceptable minimum insulation resistance value for PV arrays operating at less than 120 V. For system voltages higher than 120 V, 1 MΩ or higher is considered acceptable. Tests conducted during system commissioning may be used as a baseline to which later measurements can be compared to evaluate wiring condition and degradation.

ASTM E2047, Standard Test Method for Wet Insulation Integrity Testing of Photovoltaic Arrays, provides guidelines on test procedures and the interpretation of results for wet insulation resistance testing of PV arrays. This standard can be used in conjunction with the IEC 62446 standard for conducting insulation resistance testing on PV arrays.

8.4 System Functional Testing

System functional testing verifies proper system operation, including start-up, shut-down, and nominal operating conditions. These tests confirm that system operating parameters are within expected and nominal limits but are not intended to verify system ratings in accordance with specifications or warranty provisions. Additional detailed testing, using additional measurements and normalizing data, are required to verify performance with system ratings.

Knowledge of the specific equipment used and the product installation and operation instructions are crucial in verifying their safe and proper operation during functional tests. Most inverters and charge controllers provide some indication of performance and operating status, such as power output or energy production, as well as fault or error indications, such as out-of-limit parameters or array ground faults. This information is extremely helpful in verifying proper system operation and may reduce the need to make hand measurements on energized circuits.

System functional tests ensure that the system starts and operates properly and can be disconnected safely. Among the types of functional tests conducted on PV systems are the following:

- Verifying the proper operation of disconnecting means and component connection and disconnection sequences.
- Verifying that interactive inverters and AC modules de-energize their output to the utility grid upon loss of grid voltage. This is a safety requirement to prevent interactive inverters from operating as an islanded electrical system without voltage or frequency control and preventing them from back-feeding de-energized electrical systems. These functions are performed internally by all utility-interactive inverters listed according to the IEEE 1547 and UL1741 standards.
- Verifying that interactive inverters automatically reconnect their output to the grid once the voltage has been restored for at least 5 minutes.
- Verifying that battery-based interactive inverters disconnect AC loads from the utility source when operating in stand-alone mode [690.61].
- Verifying the proper grid voltage and frequency to operate inverters, including evaluating voltage drop between the inverter AC output and point of connection to the grid.

8.5 Test Reports

Measurements and test results for PV systems should be summarized clearly in a test report that includes the following information:

- System information
- Visual inspection record and observations
- Identification of circuits tested, tests performed, and record of measurements
- Interpretation and summary of results, identifying special maintenance needs or corrective actions
- Signatures of responsible person(s) and date(s) of tests

An example test report format is presented in the annex of the IEC 62446 standard.

8.6 System Performance Testing

PV systems are designed to produce a specified electrical output under certain operating conditions. Performance testing verifies that the system power output and energy production are as expected, based on component and system ratings and the given operating conditions. Performance data can also help identify problems that require service or maintenance and be used for determining system financial revenues and warranty provisions.

8.6.1 Verifying Power and Energy Production

Power and energy production are the fundamental metrics for PV system performance. The methods and procedures to verify PV system performance are based on the principles of PV device operation, and accounting for the effects of temperature and solar radiation. Many parameters may be monitored automatically and displayed by meters, inverters, controllers, or other power processing equipment in the system.

For interactive PV systems, the key indicators for system performance are AC power output (kW) and energy production (kWh). Measurement and verification of AC power output can be done at any time when the system is operating under steady sunlight conditions near peak output levels. Energy production is measured over longer periods of months and years to compare with expectations and the available solar resource.

Performance verification for stand-alone PV systems is inherently more complex, involving more measurements and multiple interactions between energy storage, charge control, and system loads that affect PV system production. Battery health is the key to stand-alone PV system performance, and battery failure is often the indicator of many other system problems. Usually stand-alone PV 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 owners/operators to control their loads and manage the available energy. Measurements of daily minimum battery voltage and 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 usually will be indicated by declining minimum battery voltages. The performance of electrical loads can be verified by measuring their current or power consumption and if they function as intended.

8.6.2 Verifying AC Power Output

The AC power output for interactive systems is related to the rated maximum DC power output of the array, adjusted by a number of derating factors. The factors include several types of AC and DC system losses and the inverter power conversion efficiency; in combination, they result in AC power output that is normally 70–85 percent of the PV array DC rating at STC. The actual AC output of an interactive PV system at any moment can be compared with expectations by using the basic translation formulas for solar radiation and temperature.

Array temperatures and solar radiation in the plane of the array must be measured simultaneously with power measurements and are used to translate measured data to a reference rating condition, usually STC. Module and array temperatures can be estimated using low-cost and widely available non-contact infrared (IR) thermometers. Some of these meters are capable of averaging several temperature measurements.

The typical procedure for verifying the expected AC power output for interactive PV systems begins with noting the nameplate DC ratings for the PV array and then applying applicable derating factors. The array DC rating is usually taken as the sum of all individual module nameplate maximum power ratings (Pmp) at STC. The product of the derating factors and DC rating give the estimated system AC power output. Translations for temperature and solar radiation provide an estimate for actual operating conditions.

Following are the primary derating factors used to estimate the AC power output of PV systems under given operating conditions:

- **Nameplate Ratings:** This derating factor accounts for the accuracy of the manufacturer's power rating and guaranteed performance. Manufacturing tolerances result in most PV modules producing less than their rated power at STC; the UL 1703 module listing standard requires module power to be within only ±10 percent of the module rating. Additional design qualification tests covered in IEC 61215 may establish power tolerance within 3 percent of nameplate ratings. A derate factor of 0.95 represents that the array power output at STC is 5 percent less than the manufacturer's nameplate rating.
- **Inverter and Transformer:** The derate factor for the inverter and transformer is their combined efficiency in converting DC power to AC power. Modern interactive inverters have weighted efficiencies on the order of 95 percent. The efficiencies of transformers separate from inverters also need to be considered. This factor should also include the array maximum power point tracking efficiency for the inverter, which is generally around 98–100 percent.
- **Module Mismatch:** The derating factor for PV module mismatch accounts for manufacturing tolerances that yield PV modules with slightly different current-voltage characteristics. Consequently, when connected together electrically, usually in series, the modules do not operate at their respective peak efficiencies. A derating factor of 0.98 represents a loss of 2 percent due to mismatch and is a reasonable assumption. PV systems using AC modules or micro inverters would not have any module mismatch, because PV modules are individually connected to maximum power point tracking inverters.
- **DC Wiring:** This derating factor accounts for losses in the DC circuits from the PV array to the inverter. It includes voltage drops in wiring, connections, fuses, diodes, switches, or any other components, as applicable. These losses can be determined in the field by measurements of the current and voltage drops through the entire DC circuit. Losses in DC circuit conductors can be easily calculated from Chapter 9, Table 8 in the NEC. Total DC wiring and connection losses usually will be on the order of 2 percent for most PV systems, resulting in a derating factor of 0.98. Systems using AC modules or micro inverters have insignificant DC wiring and connection losses, and AC modules are rated for AC, not DC, specifications.
- **AC Wiring:** This derating factor accounts for losses in the AC circuits from the inverter to the point of utility interconnection, or where the system output is measured. It includes voltage drops in wiring, fuses, and disconnects, and usually is on the order of 1 percent or less for most PV systems, resulting in a derating factor of 0.99.
- **Soiling:** This factor accounts for the accumulation of dirt, snow, and other foreign matter on the surfaces of PV modules that reduces the amount of solar radiation received. PV arrays located in arid, dusty areas with infrequent rain can experience soiling losses of 20 percent a year or higher. Routine maintenance and array cleaning as required can largely eliminate soiling losses; a default derating factor of 1.0 may be used for clean arrays.
- **Age:** The derate factor for age accounts for losses in performance over time, due primarily to degradation of the PV modules. The loss in performance is typically 0.5–1 percent per year for most crystalline silicon PV arrays.

8.6.3 Example: Verifying AC Output for Interactive PV Systems

The following worksheet can be used to estimate the expected AC power output for interactive PV systems without energy storage. This procedure is valid only for interactive systems using flat-plate crystalline silicon PV arrays (no special bifacial modules or concentrating modules). The entire PV array must be oriented in the same direction and unshaded. The inverter must be operating the array at its maximum power point and not exceeding inverter ratings within prescribed voltage limits. Measurements of solar radiation, temperature, and power output must be done simultaneously. For best results, measurements should be within ±2 hours of solar noon, with incident solar radiation levels of 800 W/m^2 or higher and under clear sky conditions.

INTERACTIVE PV SYSTEM PERFORMANCE WORKSHEET	
Estimating and Verifying System AC Power Output	
PV Array DC Power Rating at STC – 1,000 W/m^2, 25 °C (kW)	1,000
Derating Factors	
Nameplate Ratings	0.95
Inverter and Transformer	0.95
Module Mismatch	0.98
DC Wiring	0.98
AC Wiring	0.99
Soiling	1.00
Age	1.00
Combined Derating Factors	0.86
Estimated System AC Power Output at STC – 1,000 W/m^2, 25 °C (kW)	860
Temperature Adjustments	
Array Power-Temperature Coefficient (%/°C)	-0.5
Measured Array Operating Temperature (°C)	55
Estimated System AC Power Output at 1,000 W/m^2 and Operating Temperature (kW)	731
Solar Radiation Adjustments	
Measured Solar Irradiance in Plane of Array (W/m^2)	850
Estimated System AC Power Output at Operating Temperature and Solar Irradiance (kW)	621

8.6.3.1 Verifying AC Energy Production

A key metric for PV system performance is the AC energy (kWh) it produces over time. Energy production for interactive PV systems depends on many factors, including the size of the array, the local solar energy resource, and the array operating temperatures. It also depends on inverter efficiencies in converting DC to AC power; its effectiveness in tracking array maximum power; and other losses in the system, including voltage drop, shading, and soiling of the array. Energy production is measured over periods of months and years to compare with sizing and long-term performance expectations.

Watt-hour meters measure electrical energy and are commonly used by utility companies for revenue purposes. They are also used to record energy produced by PV systems and are integral to most interactive inverters. Traditional electro-mechanical types are being replaced by electronic types having the capability for many additional power system measurements, including multi-directional and time-of-use power flows, and other electrical properties, such as reactive power, power factor, and peak power demand.

PVWATTS™

The AC energy production for interactive PV systems can be estimated using the popular online tool PVWATTS. This program uses historical solar radiation and temperature data for a site, along with user-supplied data on the system size, array orientation, and several derating factors. PVWATTS then performs an hour-by-hour simulation for a typical year to estimate average hourly power output and monthly and annual energy production. See: http://pvwatts.nrel.gov/.

However, it is important to note that the PVWatts performance estimate is based on long-term averages of solar energy irradiance. Actual solar irradiance (and thus system production) in any given year will not necessarily match the long-term average.

8.6.3.2 Example: Estimating and Verifying AC Energy Production

NRECA has developed a cost and finance screening tool (https://www.cooperative.com/programs-services/bts/sunda-solar/Pages/Cost-Finance-Screening-Tool.aspx) that uses the PVWatts engine to help co-ops estimate the output and system costs for a solar PV installation. The system is both flexible and easy to use. At the most basic level, a co-op just puts in its zip code and the AC size of the system it is contemplating, and the tool will quickly give the expected energy output, the expected installed costs, and the levelized cost of the energy produced by the system under varying financing structures. That said, the tool is also quite flexible and has two dozen or more additional inputs that will allow the co-op to fine tune its predictions based on details like site prep costs, state grants, array tilt and azimuth, EPC rates, and much more. If further refinement is called for, the tool is developed in Microsoft Excel and can be easily modified to suit any eventuality a co-op might want to include in its estimations.

Cooperative	XYZ, EC		
Zipcode	64735	Clinton, MO	
System Size (MWac):	1.00	2,038,775	System Output (first year, kWh
Land	Owned	5	Acres of land (min)
Cost/acre	$ -		
Module Cost ($/Wp)	$ 0.650		
Racking Cost ($/Wp)	$ 0.115		
Inverter Type	Central		
Inverter unit cost	$ 107,000	2	Inverters required for this syste
Project Mgmt	$ 15,000		
EPC Markup %	3%		
Mechanical Install Labor ($/hr)	$ 35.00		
Electrical Install Labor ($/hr)	$ 50.00		
Development Costs	2%	$ 41,899	
Interconnect Costs	$ 25,000		
Distribution Adder ($/MWh)	$ -		
Total System Costs	**$ 2,161,873**	$ 2,094,974	Installed Equipment Costs

Figure 67: NRECA's Solar PV Cost and Finance Screening Tool

8.6.4 Performance Ratio

The following describes normalized energy parameters for interactive PV systems. These parameters may be used to compare the performance of PV systems of the same and different ratings, in similar or different locations, over any evaluation period (day, month, or year). These data may also be used in part for verification of system performance.

Data measurements required to calculate the parameters include DC and AC energy production, plane-of-array solar irradiation, the array area, and the module manufacturer's nameplate DC power rating. Variations in the calculated values may be due to system problems or excessive losses in a particular system or temperature variations. Temperature coefficients also can be applied to the normalized parameters to account for temperature differences.

Normalized DC and AC Energy Production per Unit Irradiation: kWh/(kWh/m^2)

This parameter normalizes the DC or AC energy output of a system per 1 kWh/m^2 unit of solar irradiation received, often referred to as one Peak Sun Hour. Solar radiation data are commonly represented in units of Peak Sun Hours, which translates to the equivalent number of hours a day at a peak irradiance level of 1 kW/m^2 and the equivalent number of hours per day a PV array would be producing its peak rated output. This parameter can be used to compare the performance of similar systems in different locations with a different solar resource and to track performance trends.

Normalized DC and AC Energy Production per Unit Array Rating: (kWh/kWp)

This parameter normalizes the DC or AC energy output for a PV system per unit array size. When based on the DC energy production, this factor can be interpreted as the number of hours per day the system operates at its peak DC kWp rating. This parameter can be used to compare similar systems with different ratings in the same location and to track performance trends.

Normalized DC and AC Energy Production per Unit Array Rating and Unit Irradiation: (kWh/kWp/kWh/m^2)

This parameter normalizes the DC or AC energy output for a PV system per unit array size and unit solar irradiation received. When this parameter is calculated using the actual AC energy production for a system, it often is referred to as the system's performance ratio (PR), an indicator of how effectively the rated array

DC energy is converted into AC energy. The PR for typical PV systems has improved steadily over the past 15 years, from around 70 percent prior to 2000 to more than 80 percent today, primarily due to improved inverter efficiencies.

Capacity Factor

Although many of the above parameters are of interest to the solar engineer, the one most used by utilities is the **Capacity Factor**. In solar PV production, this is the actual annual AC output of the system divided by the nameplate capacity of the inverters for the year. Typical values for a modern solar PV system will be in the range of 17–29 percent, depending primarily on location.

8.6.5 Array I-V Measurements

To fully evaluate the performance of PV modules and arrays for rating purposes, their I-V curves need to be measured. This requires specialized test equipment that can load the module or array over the full range of the I-V curve, from short-circuit (zero resistance load) to open-circuit condition (infinite resistance load). The array can be loaded with any device rated for the voltage and power of the PV device under test and can vary the load. The load can be a variable resistor or a variable DC power supply that can sink current from the PV device. Typically, array I-V testers use a capacitive load that quickly charges from zero voltage up to the array open-circuit voltage while the current and voltage point are recorded with a high-speed data acquisition system. Concurrent with the I-V measurements, the cell temperature for the PV device under test and the incident solar irradiance also are recorded. I-V data points then are processed and normalized to a reference rating condition for comparison with module or array ratings.

In addition to obtaining all of the current and voltage data discussed previously, detailed I-V curves can help evaluate the following for PV modules and arrays:

- Determine the true array maximum power point in relation to the operating voltage for inverters, battery systems, and other DC utilization equipment
- Determine voltage and power degradation rates from baseline measurements and subsequent measurements over time
- Determine changes in array series and shunt resistance over time
- Identify array wiring problems or module failures
- Analyze the effects of shading on electrical output
- Evaluate losses due to module mismatch and array wiring methods
- Establish module or array ratings for performance guarantees or warranty purposes
- Locate open bypass diodes; this requires an I-V curve test or DC power supply that reverses biases (applies negative voltage) to the module under test

I-V testers are rated for maximum current and voltage inputs from PV arrays, and measure and record the I-V data points for each curve. I-V data or the I-V curve may be displayed on the tester; the data usually can be downloaded to personal computers for translation to reference rating conditions. Most I-V testers use four-wire test lead measurements; one set of leads simply measures voltage, whereas the other set measures the current, thus eliminating measurement errors due to voltage drop in the test leads. Additional resistance in the test circuit from conductors and connections ultimately will affect the I-V curves for arrays. Caution should be taken never to coil the test leads, as the inductance may clamp the voltage during the high-speed I-V measurement.

Until recently, most I-V testers were large and priced out of reach for most PV installation contractors. Today, however, a few small I-V testers are available for field testing modules and PV array source circuits. This equipment can be used to assess array problems that cannot be detected through common electrical measurements.

The solar irradiance in the plane of the array and the array temperature are measured concurrent with the I-V measurements and are used to translate the actual output of PV arrays and systems to a reference condition so as to verify performance. Some I-V testers can make these measurements from external sensors attached to the I-V tester and include these parameters with the recorded I-V data, or they may be measured by separate instruments and the data entered separately.

A pyranometer measures total global solar irradiance (solar power). There are different types of solar radiation instruments, some much more expensive and accurate than others for scientific measurements. Since PV device short-circuit current is directly proportional to solar irradiance, a small PV module can also be used to approximate solar radiation levels. Small, inexpensive meters using calibrated PV cells as sensors are available from approximately $200 and up.

One manufacturer has produced an excellent handbook about interpreting IV curve measurements. This is available online at: http://resources.solmetric.com/get/Guide%20to%20Interpreting%20I-V%20Curves.pdf.

8.6.5.1 I-V Test Procedures

Accurate I-V measurements in the field require ideal test conditions and an organized testing approach. For best results and to minimize errors in data translations, measurements should be made at solar irradiance levels on the array at over 800 W/m^2 under steady clear sky conditions near solar noon, with minimal wind speed.

ASTM E1036, Standard Methods for Testing Electrical Performance of Nonconcentrator Terrestrial PV Modules and Arrays Using Reference Cells, provides guidelines for making I-V measurements on PV modules and arrays in the field, and specifically for normalizing the results to STC. This standard addresses only performance, not safety. The translation methods prescribed are quite complex and typically are used in spreadsheets or computer programs to produce the results.

8.6.6 Other Tests

Special testing may also be conducted on PV systems for preventative maintenance or to troubleshoot specific problems. These tests require the use of specialized equipment.

8.6.6.1 Power Quality Analysis

Power analyzers are multi-function test instruments used to diagnose issues with electrical systems. In addition to a basic digital multimeter, power quality analyzers have data acquisition capabilities and oscilloscope functions to evaluate waveforms. They can be used to monitor grid conditions, such as voltage sags and surges, power factor and phase angles, harmonics, and other conditions over time. They can also be used to measure AC ripple currents on DC circuits that may need to be considered for conductor sizing and selection of overcurrent protective devices.

These devices are available both as handheld tools for spot checking system problems (e.g., http://en-us.fluke.com/products/power-quality-analyzers/fluke-434-series-ii-power-quality.html) and as longer-term data acquisition systems for tracking intermittent problems (e.g., http://en-us.fluke.com/products/power-quality-analyzers/fluke-1750-power-quality.html).

8.6.6.2 Thermal Imaging

IR thermography is becoming a very popular tool for the evaluation of electrical systems, and particularly PV arrays. Thermal imaging can identify hot spots or overheating equipment and thermal gradients within PV arrays, and can help locate developing problems internal to individual PV modules before failure. Common problems that can be identified with thermal imaging include bad module connectors, shorted or failing bypass diodes, or module busbar failures. Thermal imaging can also identify bad or loose circuit breakers, fuses, or switchgear, or connections to terminals, batteries, or other equipment. A variety of thermography instruments and thermal imaging cameras are available beginning at around $2,000.

8.6.6.3 Inverter Efficiency Tests

Inverter efficiency is the ratio of the AC power output to the DC power input. Inverter efficiency varies with power level and input voltage, and is affected by inverter temperature. Most commercial utility-interactive inverters have weighted power conversion efficiencies of 95 percent and higher over most of their operating range. Sample efficiency measurement can be made in the field by simultaneously measuring the DC power input and AC power output at the inverter terminals. Many inverters measure and display these data, or they can be measured with separate equipment. The DC input voltage and current can also be measured to determine inverter input power; for inverters with unity power factors, the AC power can be determined by measuring the inverter AC voltage and current output as well. True watt-hour meters or power analyzers are needed to determine power for reactive circuits and components.

8.6.6.4 Maximum Power Point Tracking (MPPT) Tests

The effectiveness of MPPT circuits can be evaluated as part of I-V testing. This measurement requires operating the PV system under steady conditions and recording the operating voltage and power output for the array, and then immediately disconnecting the array and measuring its I-V curve to determine the true maximum power. The ratio of the operating power to the true maximum power defines the MPPT efficiency.

A sample PV Solar Site Commissioning Checklist is included in Appendix I of Volume III, which incorporates a section on inverters. Appendix II, the PV Solar Site Inspection Checklist, also includes an item regarding the performance of inverter inspection.

9 Reference Design Packages

The SUNDA reference designs include pre-engineered drawings and construction documents for utility-scale PV systems ranging from 250 kW to 1 MW peak AC output. The design packages include a cover sheet that provides a list of drawing sheets, six site plans (equipment layouts, trenching and grounding), single-line diagrams, schedules, labels, partial plans for inverter pads, conduit details, and stringing plans for arrays.

The reference designs are intended to reduce the engineering time required to implement projects, achieve lowest possible cost, and maximize land use, and can be replicated and expanded for larger systems. The can also be used as a comparison to designs received under competitive bids. The initial designs used fixed non-tracking arrays, centrally located inverters, and combiners to reduce trenching and wiring costs, and facilitate maintenance.

Features of the initial SUNDA reference designs include the following:

- Maximized ground coverage ratio, expandable symmetric block
- Fixed, non-tracking design for cost-effective construction and low O&M costs
- Efficient design, allowing for most of the array construction to be duplicated
- Combiner box locations optimized to reduce DC conductors, avoiding jumpers or other pull boxes in unusual locations
- Equipment pad centrally located, driving feeder cost and transformation of local to solar inverters—configurable with other variations
- Immediate transformation drives lower cost of AC MV conductors
- Access roads can be on either side
- Grounding and surge protection: metallic array parts, pad halo grounding, fence grounding, surge arrestors in gear
- MV switch is used as site AC disconnect, reducing pad footprint
- Racking system is ETL listed for grounding, thus reducing significant bonding requirements and on-site labor
- Racking has integrated wire management, is very modular and fast to install, and its accessible height is good for installation
- AC switchgear contains the AC bus, the step-down transformer for local 120 V power, and the revenue meter for DAS
- Using 500-kw inverters allows for a centralized electrical equipment pad
- Electrical equipment pad is conveniently accessible: designed to provide easy service access, minimize use of concrete, optimize feeder stub-ups; 1-MW pad is cost effective and provides ability to use shared transformer

Additional designs were added to the toolkit to include designs with three-phase string inverters and tracking systems. These designs were also optimized for efficient installation, good ground-cover-ratio and ease of replication.

In some cases, the reference designs may need to be adjusted for a particular field site, including electrical string length (based on minimum site temperatures), climatic conditions (such as wind and snow loads), row spacing (based on latitude), land contours, shading, and other factors. Typical engineering time for such adjustment is intended to be, and historically has been, under 100 hours for site-specific modifications.

A significant effort has been made to incorporate all applicable standards and ensure good engineering and correct practice in the development of the reference designs, and these designs have been used to develop actual field-deployed, utility-scale solar PV systems. However, no warranty or guaranty is made on these designs for their fitness, suitability, safety, or applicability for any purpose. Utilities must employ a trained engineer to interpret and adjust the reference designs for the specific requirements of their application.

9.1 Design Templates

The SUNDA project has developed a set of six template designs for co-ops to use as the basis for PV system projects. Systems larger than 1 MW usually can be designed as multiples of the 1-MW template. Because of the widely varying sizes and needs of rural co-ops, we have included two separate 250-kW designs—one using a single 250-kW central inverter and the other using multiple three-phase distributed "string inverters." The four designs are as follows:

- 1.0 MW-AC / 1.4 MWp-DC ground mount, fixed tilt, using 2 x 500 kW / 1,000V-DC central inverters
- 0.5 MW-AC / 0.7 MWp-DC ground mount, fixed tilt, using 1 x 500 kW / 1,000V-DC central inverter
- 0.25 MW-AC / 0.375 MWp-DC ground mount, fixed tilt, using 1 x 250 kW / 600V-DC central inverters
- 0.25 MW-AC / 0.375 MWp-DC ground mount, fixed tilt, using distributed 1,000V-DC 3-phase AC string inverters
- 1.05 MW-AC / 1.47 MWp-DC fixed tilt using single 1,500V-DC central inverter
- 1.0 MW-AC / 1.26 MWp-DC single axis tracker using distributed 1,000V-DC 3-phase AC string inverters

The majority of systems up to 2 MW-AC currently use string inverters. Systems 2-5 MW may use string inverters or central inverters. For systems larger than a 5 MW, the economics and system maintenance issues favor central inverters. The central inverter is a pad-mounted piece of equipment, quite robust, and typically slightly more efficient. The string inverter system has a few more pieces of equipment that have the potential to fail, but the entire system does not go down if one piece does. String inverters are small and inexpensive enough to keep one as a spare that can be installed by the utility.

The standard system design practice for utility scale systems has moved to from 600V to 1,000V-DC for smaller systems (5 MW and under) and larger scale systems have moved to 1,500 V-DC with multiple central inverters.

Systems under 5 MW-AC may use fixed tilt or single axis tracker designs. Larger systems (5 MW-AC and above) typically use single axis trackers, and tracker technology (including pneumatic trackers) has now been developed to make tracking economical for smaller systems. There are currently three main types of single axis trackers. The design used in the template drawings uses a single motor to move multiple rows, controlling up to about 300 kWp sections per motor. Other designs use a separate tracker motor for each row (so the granularity of design can be smaller) or pneumatics instead of electrical motors.

9.2 Typical Drawing Package Contents

A drawing package for each of these designs has been drawn up and full AutoCAD files are available on request from the NRECA project staff. PDF versions of the drawings are available for free on the project website. The standard 1 MW, 100 V-DC fixed tilt package consists of the following drawings (other packages are similar, but differ in some details):

- PV0.1 COVER SHEET: Provides an overview of the site plan, a drawing sheet list, and general specifications of the solar PV system.

- PV1.0 SITE PLAN – ARRAY LAYOUT: Locates equipment, including modules, combiners, fence, inverter pad, switch pad, pole-mounted switch, and point of interconnection.
- PV1.1 SITE PLAN – FENCE LAYOUT: Gives detailed information about the fence, including location and size of vehicle gates, pedestrian gates, and temporary vehicle gates. Dimensions and distances of each section of fence are also noted.
- PV1.2 SITE PLAN – MEDIUM-VOLTAGE TRENCHING: Detail 1 shows the location of medium-voltage feeders, transformers, and switches; Detail 2 is an unscaled riser diagram showing the interconnection elements; and Detail 3 provides information about the medium-voltage transformer.
- PV1.3 SITE PLAN – COMBINER LAYOUT: The goal of this sheet is to clearly mark the specific modules connected to each combiner.
- PV1.4 SITE PLAN – DC TRENCHING: Detail 1 shows the types and locations of each DC feeder, Detail 2 shows the requirements for a single conduit trench, and Detail 3 shows the details of an eight-conduit trench.
- PV1.5 SITE PLAN – ARRAY GROUNDING
- PV2.0 MEDIUM-VOLTAGE SINGLE-LINE DIAGRAM
- PV2.1 PV SINGLE-LINE DIAGRAM
- PV2.2 PV SCHEDULES
- PV2.3 PV LABELS
- PV3.0 PARTIAL PLAN – INVERTER PAD DIMENSIONS
- PV3.1 PARTIAL PLAN – INVERTER PAD FEEDER ROUTING
- PV3.2 PARTIAL PLAN – INVERTER PAD GROUNDING
- PV4.0 PV RISER DIAGRAMS
- PV5.0 CONDUIT STUB-UP DETAILS
- PV5.1 CONDUIT DETAILS & COMBINER DETAIL
- PV5.1 GROUND FAULT DETECTION WIRING DIAGRAM
- PV6.0 STRINGING PLAN – ARRAY A
- PV6.1 STRINGING PLAN – ARRAY B

9.3 SUNDA Template Designs

Table 1 compares characteristics of the various template designs.

PV System Size/Inverter Type	**Template 1: 1.0 MWAC, 1 kV-DC Solar PV System, Fixed Array, central Inverters**	**Template 2: 0.5MWAC, 1kVDC Solar PV System with Central Inverter**	**Template 3: 0.25MW-AC, 600 VDC Solar PV System with Central Inverter**	**Template 4: 255 kW-AC, 1kVDC Solar PV System with String Inverters**	**Template 5: 1.05 MWAC, 1.5 kVDC Solar PV System with Central Inverter**	**Template 6: 1.0 MW-AC, 1 kVDC Solar PV System with single axis tracking**
AC System Size	1,000 kWAC	500 kWAC	250 kWAC	255 kWAC	1,050 kWAC	1,000 kWAC
DC System Size	1,391 kWpDC	695 kWpDC	349 kWpDC	313 kWpDC	1,472 kWDC	1,260 kWpDC
String Size	20 Modules	20 Modules	11 Modules	20 Modules	30 Modules	20 Modules
String Count	240 Strings	114	104 Strings	54 Strings	156 Strings	200 Strings
Modules	4,560 x 305 Wp	2,280 x 305 Wp	1,144 x 305 W	1,026 x 305 W	4,680 x 315 Wp	4,000 x 315 W
Inverter	2 x 500 kW central inverters	1 x 500 kW central inverter	1 x 250 kW central inverter	11 x 23.2 kW string inverters	1 x1050 kW central inverter	40 x 250 kW string inverters
DC Voltage	1,000 Volts	1,000 Volts	600 Volts	1,000 Volts	1,500 Volts	1,000 Volts
AC Voltage	300 Volts, 3ϕ	300 Volts, 3ϕ	480 Volts, 3ϕ	480 Volts, 3ϕ	565 Volts, 3ϕ	480 Volts, 3ϕ
Array Tilt	25°	25°	25°	25°	25°	0°
Racking	Fixed	Fixed	Fixed	Fixed	Fixed	Single Axis Tracker

Appendix I – Glossary of Terms

A

Adjustable-tilt arrays use mounting structures with removable fasteners, telescoping legs, or other manual means to allow for seasonal adjustments of the array tilt angle.

Allowable Stress Design is a method used to determine the design loads for structural materials based on the maximum allowable elastic stress limits for the structural materials used.

Alternating-Current (AC) modules are a factory-integrated listed assembly, consisting of a PV module and inverter, that produces AC power.

Amorphous silicon (a-Si) modules were the first thin-film PV module technology to be commercially deployed for power generation in the early 1990s, having achieved wide success in consumer electronic devices since the late 1970s.

Arrays are a complete DC power generating unit, consisting of multiple individual modules and circuits that are assembled and configured to provide a desired electrical output.

B

Balance-of-system (BOS) components include mechanical and electrical equipment and other hardware used to assemble and integrate major components, and to conduct, distribute, and control the flow of power in the system.

Basic wind speed maps show the maximum design wind speed by location to be used for structural calculations.

Bipolar inverters use two monopole PV subarrays for the DC input, with a positive and negative pole and a center tap ground.

Bipolar PV arrays are two monopole arrays connected together and used for large inverter applications.

Building-integrated PV (BIPV) arrays include direct and integral mounts integrated with building components and cladding materials such as windows, awnings, and roofing tiles.

Bypass diodes are essentially electrical check valves that permit the flow of current in only one direction and connected in parallel with series strings of cells to prevent cell overheating when cells or parts of an array are shaded.

C

Cadmium Telluride (CdTe) is the leading thin-film PV technology; it accounted for about 5 percent of the worldwide market and half of all thin-film module production in 2013.

Central inverters are designed for commercial applications and range from around 30 to 500 kW.

Charge controllers are used in stand-alone systems to regulate battery-charging current from a PV array and protect from overcharging.

Concentrating PV (CPV) modules are special designs that use plastic lenses, mirrors, or other optical means to focus solar radiation through a larger aperture area onto a smaller area of highly efficient solar cells.

Continuity and resistance testing verifies the integrity of grounding and bonding systems, conductors, connections, and other terminations.

Copper Indium Gallium Selenide (CIGS or CIS) is a competing thin-film technology that accounted for 2 percent of the thin-film PV module market in 2013.

Current-voltage (I-V) characteristics are used to describe the electrical performance of photovoltaic cells, modules, or arrays.

D

Dead loads (D) are static loads due to the weight of the array and mounting hardware.

Delta "Δ" configurations are a type of three-phase electrical system network characterized by the connection of three voltage sources separated by a 120° phase angle, with each source connected in series with each other to form a triangular loop.

Diversion charge controllers regulate battery charge by diverting power to a diversion load.

E

Efficiency of a PV device is the ratio of the electrical power output and the solar irradiance input over the device area, expressed as a percentage.

Exposure category defines characteristics of the surrounding terrain for each wind direction considered.

F

Fixed-tilt arrays are non-movable structures that position the PV array in a constant orientation relative to the sun.

G

Ground-mounted arrays are detached from buildings and include racks, poles mounts, and sun-tracking arrays.

H

Height and exposure adjustment coefficient (λ) is a factor used to adjust design wind pressures for mean roof height and exposure category.

Hydrostatic Loads (H) are loads due to the lateral pressure of the earth (soil) or ground water pressure on an underground or buried structural member.

I

Importance factor (I) adjusts design wind loads based on the structure category classification.

Insulation resistance testing verifies the integrity of wiring and equipment, and is used to detect degradation and faults to wiring insulation.

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.

Inverters are used in PV systems to produce AC power from a DC source, such as a PV array or batteries. They are characterized by the DC power source they use (PV array or battery), their power output, operating voltages, power quality, and efficiency.

Islanding is a condition in which part of a utility system containing both load and generation is isolated from the remainder of the utility system but remains energized.

L

Live loads (L) are loads from temporary equipment and personnel during maintenance activities.

Load controllers regulate battery discharge current to electrical loads and protect a battery from overdischarge.

Load-side interconnections permit the output of utility-interactive inverters to be connected on the load side of the service disconnecting means at any distribution equipment on the premises.

M

Maximum photovoltaic system voltage is the array open-circuit voltage, adjusted for lowest expected ambient temperature.

Maximum power current (Imp) is the operating current at the maximum power point. Imp is typically about 90 percent of the short-circuit current.

Maximum power point (Pmp) of a PV device is the operating point where the product of current and voltage (power) is at its maximum.

Maximum power point trackers (MPPTs) are a type of DC-DC converter that operate PV arrays or modules at their maximum power output.

Maximum power point tracking (MPPT) refers to the process or electronic equipment used to operate PV devices at their maximum power point under varying operating conditions.

Maximum power voltage (Vmp) is the corresponding operating voltage at the maximum power point. Vmp is typically 70 to 80 percent of the open-circuit voltage.

Maximum PV output circuit current is the sum of parallel-connected source circuit maximum currents.

Maximum PV source circuit current is determined by multiplying the short-circuit current of the source circuit by 125 percent.

Micro inverters are module-level inverters installed to support structures behind individual PV modules as separate equipment.

Module-level inverters are installed integral to or adjacent to individual PV modules; they include AC modules and micro inverters.

Modules are complete field-installable DC generating units, consisting of multiple solar cells encapsulated in an environmentally protected laminate, including a frame for structural mounting and electrical connection points.

Monocrystalline wafers are produced by growing a single crystal ingot, a method known as the Czochralski process.

Monopole PV arrays have a single pair of positive and negative output circuit conductors. Monopole arrays are most common.

Multimode inverters are utility-interactive inverters that use battery storage and can operate in either interactive or stand-alone mode.

O

Open-circuit voltage (Voc) is the maximum voltage on an I-V curve and the operating point for a PV device with no connected load.

P

Performance testing verifies that system power and energy output are consistent with expectations.

Point of connection or point of common coupling is the location at which a distributed generator interfaces with the electric utility system.
Polarity testing verifies the correct polarity for PV DC circuits and proper terminations for DC utilization equipment.
Pole-mounted arrays use fixed, adjustable, or sun-tracking arrays on racks installed on a rigid metal pipe or wooden pole.
Power conditioning equipment is used to convert, control, or process the DC power produced by PV arrays to make it suitable for interfacing with electrical loads or utilization equipment.

R

Rack-mounted arrays are commonly used on the ground and commercial buildings, and offer the greatest flexibility in mounting the array at specific tilt angles.
Roof-mounted array designs include standoff mounts and rack mounts that can be retrofitted to existing rooftops.

S

Seismic loads (E) are loads due to anticipated earthquake events and based on region-specific seismic design categories.
Self-ballasted arrays rely on the weight of the PV modules, support structure, and additional ballast material to secure the array.
Short-circuit current (Isc) is the maximum current on an I-V curve.
Snow loads (S) are loads due to the weight of snow accumulation.
Solar irradiance is sun's radiant power incident on a surface of unit area, commonly expressed in units of kW/m^2 or W/m^2.
Standard Test Conditions (STC) is the universal rating condition for PV modules and arrays, and specifies a solar irradiance level of 1,000 W/m^2 at air mass 1.5 spectral distribution and a cell operating temperature of 25°C.
Standoff-mounted arrays are the most common method for attaching PV arrays to sloped rooftops.
String inverters are small inverters in the 1 to 12 kW size range, intended for residential and small commercial applications.
Strings are series connections of PV modules.
Subarrays are electrical subsets of arrays.
Sun-tracking arrays use mounting structures that automatically and continually move the array surface so as to follow the sun's position throughout the day.
Synchronizing is the process of connecting a generator to an energized electrical system.

T

Thin-film PV modules use a module-based continuous manufacturing process involving the deposition of ultra-thin layers of semiconductor materials on a flexible or rigid substrate.
Topographic factor (K_{zt}) accounts for increased wind loads due to hills, ridges, and escarpments with abrupt elevation changes near the site.
Transformers are used to change voltage levels and transfer AC power from one circuit to another by magnetic coupling.

U

Ungrounded PV arrays do not use a grounded DC current-carrying conductor.
Utility-scale inverters are industrial power conditioning units, ranging in size from 500 kW to 1 MW and greater, and designed for utility PV plants.

V

Voltage and current testing verifies that PV array and system operating parameters are within specifications.

W

Wind loads (W) are loads due to wind forces acting on structural surfaces.
Wye "Y" configurations are a type of three-phase electrical system characterized by the connection of three voltage sources (or phases) separated by a 120° phase angle, with one pole of each source connected at a common point.

Appendix II – Reference Pad-Mounted Transformer Specification

SECTION 26 12 00

PAD-MOUNTED TRANSFORMER

PART 1 - GENERAL

1.1 REQUIREMENTS

A. The Electrical Contractor shall furnish and install a new complete and satisfactorily liquid-filled pad-mounted step-up transformer as specified herein and as indicated on the drawings. All items of equipment, hardware, raceway, wiring, etc., required for a complete installation shall be furnished and installed, whether or not every such item is specifically mentioned. This transformer may be included in a packaged inverter/transformer skid.

B. Standards ANSI C57.12.00 and C57.12.27 (general)
    1) ANSI C57.12.70 and C57.12.80 (connections and terminology)
    2) ANSI C57.12.90 (test code)
    3) ANSI/IEEE C57.109 (transformer damage curves and protection)
    4) ANSI C57.12.26 (dead-front high-voltage bushings)
    5) ANSI/IEEE 386 (separable connectors)

C. Transformer Ratings
    1) Size (kVA):
    2) Primary Voltage:
    3) Secondary Voltage:
    4) BIL:
    5) Windings:
    6) Impedance:

PART 2 - MATERIALS

2.1 PAD-MOUNTED TRANSFORMERS GENERAL

A. Each pad-mounted transformer shall be manufactured by Siemens, Square D, RTE, ABB, Cooper Power Systems, GE Prolec, HICO, Iljin, Delta Star, Waukesha, or Approved Equal.

B. Each transformer shall consist of a primary connection and protector cubicle, a liquid-filled transformer section, and a secondary connection cubicle—all enclosed in hinged, totally enclosed weatherproof construction.

C. Liquid shall be less flammable per NEC 450-23 non-PCB type (R-Temp or equivalent), made from renewable and biodegradable vegetable-based oil. The manufacturer is responsible for maintaining adequate documentation of the oil furnished in each unit and must provide copies upon request. Silicon is not acceptable.

D. The unit shall be tamper proof and suitable for padlocking. The doors shall be so arranged that access to the high-voltage compartment can be gained only after opening the low-voltage compartment.

E. Cables shall enter and leave the compartment sections through openings in the bottom.

F. The transformer tank, high-voltage compartment, and low-voltage compartment shall be constructed as an integral unit that will limit disassembly, breakage, and prying open of any of the doors, panels, and sills with the doors in the closed and locked position. There shall be no exposed screws, bolts, or other fastening devices that are externally removable.

G. There shall be no openings through which foreign objects, such as sticks, rods, or wires, might be inserted to contact live parts. Lifting eyes and jacking pads shall be provided as part of the transformer and shall be arranged to provide a distributed balanced fit.

H. The transformer tank shall be of a sealed-tank construction as specified in ANSI Standard C57.12.26. The tank shall be a minimum of 12 gauge sheet steel and strong enough to withstand a pressure of 7 psi without permitting distortion and 15 psi without rupturing or displacing of transformer components. A removable main cover may be provided over a bolted-on, tamper-proof handhole. Handholes shall be provided for access to high-voltage isolation links, three-phase switches, neutral connections, etc.

I. Construction shall conform to ANSI/IEEE Standard 386. Bushings shall be externally clamped and externally removable. High- and low-voltage winding lead lengths shall be long enough to permit field replacement of bushings or bushing wells. All gasketed joints are to afford a sealed tank, in accordance with industry standards. Gasket material must be durable and reusable. Parking stands shall be provided for mounting accessory equipment.

2.2 PRIMARY CUBICLES

A. The primary cubicle shall contain the following:

1. High-voltage bushings shall be universal well type, dead front, arranged to receive incoming medium-voltage cables utilizing loadbreak 600A elbows. Provide two bushing wells per phase (loop feed) and one loadbreak feed-thru insert for one bushing well per phase. Primary cubicle shall be completely dead-front construction, inclusive of switching, fusing, and lightning arresters. Provide with parking stands.

2. For each transformer, provide an externally operable no-load tap changer.

3. For each transformer, provide a liquid-filling connection.

4. For each transformer, provide a loop switch and on-off radial switch

5. For each transformer, provide tank grounding provisions in accordance with ANSI standards (primary and secondary cubicles). Bond primary and secondary neutrals internally to transformer ground and driven rod. The grounding provisions shall be capped before painting the unit.

6. For each transformer, provide lightning arresters (distribution type); dead-front construction M.O.V.E. type. Arrestor shall be loadbreak integral type, mounted on feed-thru insert (ANSI/IEEE Standard 386).

7. For each transformer, provide bayonet-type oil-immersed current-limiting fuses in series with bayonet oil-immersed, overload-sensing expulsion fuses accessible through the primary compartment. Provide welded oil dripshield under each fuse. Provide fuses with __________ interrupting rating.

8. Electrical contractor shall provide a spare set of fuses identical to those provided with transformer.

2.3 TRANSFORMER SECTIONS

A. The transformer sections shall be oil filled, self-cooled, and manufacturer's standard BIL values. Primary voltage shall match medium-voltage collector system with three phase, (3-wire) (4-wire) (grounded WYE) (ungrounded WYE) (DELTA), with four 2 ½ percent taps—two below-rated voltage and two above-rated voltage, with factory connections to tap changer in the primary cubicle. Secondary voltage shall be voltage to match inverter output, three phase, (4-wire grounded WYE) (3-wire ungrounded WYE) (3-wire DELTA). Other features of the transformer shall include the following:

1. A ground pad.

2. A nameplate.

3. Provisions for lifting and jacking.

4. One-inch drain, filler and sampling valves.

5. Filling and top-filter press connection drain.

6. Bottom-filter press (to drain completely).

7. A dial-type thermometer.

8. A liquid level gauge with alarm contacts.

9. A pressure-vacuum gauge with alarm contacts.

10. A bolted and gasketed tank handhole.

11. Fuses must be externally removable and field replaceable using a hotstick without having to remove transformer compartment top.

12. The terminal compartment shall be full height, air-filled, and with individual doors. The doors shall be constructed with sheet steel (minimum 13 gauge) and braced to prevent distortion. They shall be installed using lift-off type stainless steel hinges of a gauge equal to, or greater, than the door. A three-point latching mechanism with a cabinet-type handle, having provisions for the use of a single padlock, shall be provided on the low-voltage door. A ½-inch penta-head stainless steel spring-loaded captive bolt shall also be provided, with a blind bolt hole. Removal of the penta-head locking bolt may be accomplished only after removal of the padlock. This latching mechanism shall be designed and located to provide access to the high-voltage compartment only after the door to the low-voltage compartment has been opened. There shall be one more additional fastening device that must be removed before the high-voltage door can be opened. Door stops shall be provided to hold the doors open when working in the compartments. The doors and the front sill of the compartments shall be removable to allow for sliding the transformer into position over conduit stubs. The high- and low-voltage compartments shall be separated by a steel barrier. When facing the transformer, the low-voltage compartment shall be on the right.

13. Provisions must be made for opening the connection between high- and low-voltage neutral, and for a fully insulated neutral bushing, connected to the ground pad with a detachable strap sized to carry the maximum available fault current.

14. The core and coil assembly shall be of a five-legged design to provide adequate short-circuit strength and heat dissipation.

15. Internal leads shall be insulated, trained, and anchored to prevent phase-to-phase flashover.

16. Provide a pressure-relief device that shall automatically relieve pressure and effectively keep the transformer sealed with no leakage of air or oil, or any permanent distortion. The pressure-relief device shall exclude moisture from the transformer and have a life equal to that of the transformer.

17. The transformer shall be provided with a NEMA standard outside warning label on the outside high-voltage compartment door, and a NEMA standard inside “DANGER” label on the inside of the low-voltage compartment door.

18. The transformer shall be identified as a non-PCB oil-cooled unit, with the PCB content clearly and permanently marked on the nameplate.

19. The low-voltage bushing shall be of molded epoxy and capable of withstanding a load in a vertical direction of 800 inch-pounds without causing a deflection sufficient to produce a leak.

20. In preparation for painting the transformer, the metal shall be washed with a solvent to remove rust, oil, and grease. A minimum primer coat of 2 mils dry finish shall be applied. The finish coat of paint, with a minimum of 2-1/2 mils dry finish, shall be olive green munsel 7gy3.29/1.5.

21. Transformer overcurrent protection shall be a combination of oil-immersed current-limiting fuses in series with bayonet oil-immersed, overload-sensing expulsion fuses coordinated to provide full-range protection, with the expulsion fuse clearing low-current faults and the current-limiting fuses clearing high-current faults up to 50,000 amperes. The fuse assembly shall have an interrupting rating of 1800 A at 15.5 KV single phase and a loadbreak rating of 125A at 80 percent power factor for 15.5 KV single phase. The bayonet fuses must be accessible through the primary compartment. They must be externally removable and field replaceable using a hotstick. This operation must be accomplished without having to remove the transformer compartment top. A welded-on oil dripshield must be located under the bayonet fuse to protect the primary connections.

2.4 SECONDARY CUBICLE

A. The secondary cubicle shall have the following:

1. Low-voltage bushings: live front-molded epoxy type, 10-hole NEMA standard spacing, two (2) hole lugs (spade type), arranged for vertical take-off, capable of withstanding a load in a vertical direction of 800 inch-pounds without causing a deflection sufficient to produce a leak.

2. A permanently affixed stainless steel nameplate containing the transformer serial number, style number, plus other pertinent information.

PART 3 - EXECUTION

3.1 INSTALLATION

A. Provide "DANGER HIGH VOLTAGE – KEEP OUT" signage on the outside of the transformer.

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