CALIFORNIA
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GUIDELINES FOR CALIFORNIA'S SOLAR ELECTRIC INCENTIVE PROGRAMS PURSUANT TO SENATE BILL 1

DRAFT GUIDELINES

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Abstract

This document presents draft guidelines for solar energy system incentive programs throughout California in response to Senate Bill 1.

Senate Bill 1 is the culmination of the Governor's Million Solar Roofs Initiative, expanding upon the California Solar Initiative and the New Solar Homes Partnership. The statute requires the California Energy Commission to establish eligibility criteria, conditions for incentives and rating standards to qualify for ratepayer-funded incentives provided by the Energy Commission, the California Public Utilities Commission and local publicly owned electric utilities.

Senate Bill 1 establishes three specific expectations to be met to qualify for the incentives made available through the bill:

1. high quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar,
2. optimal system performance during periods of peak demand, and
3. appropriate energy efficiency improvements in the new and existing home or commercial structure where the solar energy system is installed.

Keywords

Senate Bill 1, SB 1, Million Solar Roofs Initiative, California Solar Initiative, CSI, New Solar Homes Partnership, NSHP, California Energy Commission, CEC, publicly owned utilities, California Public Utilities Commission, CPUC, solar, solar energy systems, electricity generation, photovoltaic, PV, PV Calculator, energy efficiency, guidelines, eligibility criteria, conditions for incentives, rating standards, benchmarking, retro-commissioning, HERS rating, field verification, energy audit, PMRS

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CHAPTER 1: Introduction

Senate Bill 1 (SB 1, Murray, Chapter 132, Statutes of 2006) directs the California Energy Commission (Energy Commission) to establish eligibility criteria, conditions for incentives and rating standards for projects applying for ratepayer-funded incentives for solar energy systems.[1] This document sets forth guidelines for solar incentive programs throughout California, including those managed by the Energy Commission, the California Public Utilities Commission (CPUC) and local publicly owned electric utilities (POUs). It is intended to specify the minimum guidelines for the above program administrators to implement their solar energy programs under SB 1. However, these minimum guidelines are not intended to serve as the sole requirements for solar energy programs. Other requirements and details, specific to the CPUC's or POU's programs will be specified by the program administrators addressed in the program guidebook or handbook.

Once these guidelines are adopted and take effect, the program administrators shall incorporate the guidelines as part of their respective program guidebooks or handbooks.

These guidelines cover:

- Program and legislative background, and basis for guidelines
- Schedule for implementing these guidelines
- Solar equipment component requirements
- System design and installation requirements
- Energy efficiency requirements
- Reporting requirements for California publicly owned utilities.

SB 1 directs the Energy Commission, in consultation with the CPUC, POUs and interested members of the public to establish eligibility criteria, conditions for incentives and rating standards for solar energy system incentive programs. **Solar energy system incentive programs funded by California electricity ratepayers must meet the requirements set forth in these guidelines.** This includes the California Solar Initiative, the New Solar Homes Partnership and programs administered by California's POUs.

These guidelines build upon and have been modified to reflect public comments received on the Energy Commission's Staff Report, *Eligibility Criteria and Conditions for Incentives for Solar Energy Systems, Senate Bill 1*.[2]

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[1] SB 1 (Murray), Chapter 132, Statutes of 2006, § 4, as codified in Public Resources Code sections 25780 – 25784. Senate Bill 1 is an extensive, multi-faceted legislation that covers many other matters besides the eligibility criteria, conditions for incentives and rating standards addressed in these guidelines. These guidelines do not address those other matters.

[2] California Energy Commission, CEC-400-2007-014, August 2007.

Background

SB 1 is the culmination of Governor Schwarzenegger's “Million Solar Roofs Initiative” and expands upon the CPUC’s California Solar Initiative (CSI) program and the Energy Commission’s New Solar Homes Partnership (NSHP). SB 1 directs the expenditure of up to $3,350,800,000 by 2017 with goals to install solar energy systems with a generation capacity equivalent of 3,000 megawatts, to establish a self-sufficient solar industry in which solar energy systems are a viable mainstream option for both homes and commercial buildings in ten years, and to place solar energy systems on 50 percent of new homes in 13 years. The overall goal is to help build a self-sustaining solar electricity market in conjunction with improved energy efficiency in the state’s growing number of solar-powered residential and non-residential buildings.

SB 1 establishes three specific expectations to be met for ratepayer funded incentives made available through the bill:

1. High quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar,
2. Optimal system performance during periods of peak demand, and
3. Appropriate energy efficiency improvements in the new and existing home or commercial structure where the solar energy system is installed.

To guide the state in developing a successful solar photovoltaic (PV) program that is consistent with the Governor’s Million Solar Roofs Initiative, the Energy Commission delineated several principles in the 2004 and 2005 Integrated Energy Policy Reports (IEPRs). These principles include:

- Leveraging energy efficiency improvements should be a primary consideration in deploying photovoltaics. To participate in the PV program, new buildings should be required to exceed the current building standards, while existing buildings should be required to improve their efficiency. Combining energy efficiency measures with PV will ensure proper sizing of PV systems, contribute to the state’s efficiency goals, and provide the maximum benefits to PV purchasers and electricity consumers.
- Rational targeting of PV deployment to achieve the greatest cost benefit should be a central feature of a large-scale solar program. Solar installations should be targeted to climate zones with high peak demands for air conditioning and where solar systems can provide the most benefit.
- Transitioning away from capacity-based incentives for performance-based incentives and integrating energy efficiency and time-of-use energy considerations should be a priority.

The IEPR also recognized the common policy vision of “the loading order” adopted by the state’s principal energy agencies in the Energy Action Plan and the 2003 Integrated Energy Policy Report (IEPR). The loading order establishes the following priority for the development of energy resources: 1) conservation and energy efficiency, 2) renewable energy resources and distributed generation, and 3) clean, fossil fuel, central-station generation. In the Governor's energy policy to the Legislature in response to the 2003 IEPR, he highlighted the importance of this Million Solar Roofs Initiative and the aggressive pursuit of all cost effective energy efficiency, consistent with the loading order.

There are also several other energy policy directives that are important to address as the Energy Commission responds to the SB 1 mandates:

- Assembly Bill 32 (AB 32, Nunez, Chapter 488, Statutes of 2006) and the Climate Action Initiative – Governor Schwarzenegger's Executive Order S-3-05 placed California in a global leadership position by establishing aggressive greenhouse gas emissions reduction targets. The Climate Action Team's 2006 Report to the Legislature highlighted the need for expansion of energy efficiency, coupled with increased penetration of photovoltaic systems. These policies were reinforced by AB 32.
- Energy Efficiency Goals and Resource Procurement – SB 1037 (SB 1037, Kehoe, Chapter 366, Statutes of 2005) and AB 2021 (AB 2021, Levine, Chapter 734, Statutes of 2006) directed electricity corporations subject to the CPUC's authority and local publicly owned electricity utilities, respectively, to first meet their unmet resource needs through all available energy efficiency and demand response resources that are cost effective, reliable and feasible.
- Green Building Initiative – Governor Schwarzenegger's Executive Order S-20-04 was his first concrete step to pursue the loading order. The Green Building Initiative (GBI) committed to aggressive action to reduce state building electricity use by 20 percent by 2015 by taking all cost-effective measures described in the Green Building Action Plan, and strongly encouraging commercial building owners to take aggressive action to reduce electricity usage in the same manner. The GBI urged the CPUC to apply its energy efficiency authority to improve commercial building energy efficiency by the 20 percent goal.

To pursue all of the above policy directives, the goal of the SB 1 program should be to create a self-sustaining market for solar buildings that incorporate high levels of energy efficiency and high performing solar energy systems. By combining high levels of energy efficiency and high solar energy system performance, California maximizes the major investment it is making in SB 1, the solar energy system market makes its maximum contribution to California's accomplishment of the greenhouse gas emissions reductions required to avoid global climate change, and the solar industry maximizes the value of its products and services to California consumers.

It is the intent of these guidelines to establish eligibility criteria, conditions for incentives and rating standards that align solar energy system incentive programs throughout California to meet these goals.

Schedule

Under SB 1, the Energy Commission must establish eligibility criteria, conditions for incentives, and rating standards, as described above, by January 1, 2008.

Separately, SB 1 also directs the CPUC and the POUs to implement solar energy system programs for ratepayers subject to their respective jurisdiction by January 1, 2008. The solar energy programs established by the CPUC and POUs must be consistent with the directives of SB 1 as well as meet these guidelines established by the Energy Commission.

As discussed in the Energy Commission's Staff Report, *Eligibility Criteria and Conditions for Incentives for Solar Energy Systems, Senate Bill 1*, a transition period is needed for the CPUC and POU solar energy incentive programs to transition to conformance with all of the eligibility criteria, conditions, and rating standards established in these guidelines.

Due to the challenges of implementing more than the minimum guidelines into solar energy incentive programs throughout the state, these guidelines provide a 12 month transition period for full compliance with all the eligibility criteria, conditions, and rating standards established by these guidelines (Chapters 3 through 6). All program administrators[3] shall adjust their programs to conform to these guidelines no later than January 1, 2009. Program administrators may voluntarily conform to the guidelines in advance of that date, and are encouraged to do so to the extent feasible.

The Energy Commission recognizes that some program administrators already have established solar energy programs in place, and that these administrators will continue to implement their programs subject to established program rules and requirements until such time as the administrators can properly transition to and implement all of the Energy Commission's guidelines and in no event later than January 1, 2009.[4] However, SB 1 expressly establishes minimum requirements for some elements of the solar energy system programs, and these requirements must be implemented by January 1, 2008, in accordance with SB 1. Specifically, the requirements described in Chapter 2 shall be met by the January 1, 2008 date established for program start-up in SB 1.

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[3] As used in these guidelines, "program administrators" refers to those entities required to implement a solar energy program under SB 1, including the Energy Commission, the CPUC and the POUs.

[4] For example, the CPUC has aleady established program rules and requirements for the specific customers of investor owned utilities, which have been in effect since January 1, 2007. Similarly, several POUs already have established programs or have completed program planning for a January 1, 2008 start-up, as required by SB 1.

CHAPTER 2: Minimum Program Requirements

This chapter describes the minimum solar program requirements established in statute and by the Energy Commission to be met by solar energy incentive program administrators no later than January 1, 2008 in order to comply with SB 1.[5]

Declining Incentives

Under SB 1, incentives must decline to zero by the end of 2016 with the goal of installing 3,000 MW of solar capacity and achieving a self-sufficient solar electric industry within 10 years.[6]

Solar Energy System Definition

Solar energy systems eligible for financial incentives are those solar energy devices that have the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity. Solar energy systems must produce at least one kilowatt (kW), and not more than five megawatts, alternating current (AC) rated peak electricity, accounting for all system losses, and meet or exceed the eligibility criteria established in these guidelines.[7]

Eligible solar technologies must primarily generate electricity. The statutory definition of “solar energy systems” includes other solar technologies such as solar thermal electric technologies. However, at this time, the Energy Commission’s guidelines address only solar photovoltaic (PV) technology. These guidelines will be revised in the future to include other solar technologies when appropriate to do so. Manufacturers of non-PV solar energy systems are directed to work with the Energy Commission staff to define comparably rigorous and appropriate requirements for such systems.

Solar technologies that do not primarily generate electricity, including, but not limited to solar systems whose primary purpose is for water heating, solar space heating and cooling, are not eligible.

[5] Beginning January 1, 2009, all solar energy system programs shall comply with the full eligibility requirements, standards and conditions for incentives covered in Chapters 3 through 6 in these guidelines.

[6] Public Resources Code, Section 25780 (a) and Public Utilities Code Section 2851(a)(1).

[7] Public Resources Code, Section 25781 (e).

Incentive Level for Publicly Owned Utilities

Local publicly owned electric utilities must offer incentives for the installation of solar systems beginning at no less than $2.80 per watt, or the equivalent in terms of kilowatt-hours (kWh), on or before January 1, 2008.

System Location and Grid Interconnection

The solar system must be located on the same premises where the consumer's own electricity demand is located. The system must be connected to the electrical distribution grid of the utility serving the customer's electrical load.[8]

Solar Energy System Components

All components in the solar energy system must be new and unused and have not previously been placed in service in any other location or for any other application.[9]

All major solar energy system components (PV and non-PV) eligible for ratepayer funding under SB 1[10] must be listed on the Energy Commission's Eligible Equipment List.[11] This includes PV modules, inverters and meters. Information on solar system components can be found at: [www.gosolarcalifornia.ca.gov]. For non-PV technologies, manufacturers are directed to work with the Energy Commission to define comparably rigorous and appropriate component standards for such equipment.

Chapter 3 of these guidelines establishes component standards, which are required to be complied with by January 1, 2009. In the interim, the Energy Commission recommends that program administrators strongly encourage applicants for solar incentives to follow these component standards to the maximum extent feasible.

[8] Public Resources Code, Section 25782 (a)(5) and (6).

[9] Public Resources Code, Section 25782 (a)(3).

[10] Public Resources Code, Section 25782 (c).

[11] Modules that do not appear on Energy Commission Eligible Equipment lists for the NSHP program or are not certified to the Commission to meet the component standards specified in Chapter 3 will not be eligible under programs complying with the requirements in Chapters 3, 4 and 5 of these guidelines without completion of the additional testing described in Chapter 3.

Performance Meter

All solar energy systems must be installed with a performance meter or an inverter with a built-in performance meter so that the customer can monitor and measure the system's performance and the quantity of electricity generated by the system.[12]

System Sized to Offset On-Site Electricity Load

The solar energy system must be intended primarily to offset part or all of the consumer's own electricity demand.[13] The minimum size of an eligible system is 1 kW AC, accounting for all system losses.[14] Systems sized between 1 KW AC and 5 KW AC, inclusive, shall be assumed to primarily offset the customer's annual electricity needs.

System Warranty

All solar energy systems must have a minimum ten-year warranty to protect against defects and undue degradation of electrical generation output.[15]

Installation

The solar energy system must be installed in conformance with the manufacturer's specifications and in compliance with all applicable electrical and building code standards.[16] Chapter 4 of this report establishes installation standards which shall be complied with by no later than January 1, 2009. In the interim, the Energy Commission recommends that program administrators strongly encourage applicants for solar incentives to follow these installation guidelines to the maximum extent feasible.

Energy Efficiency

Chapter 5 of this report establishes energy efficiency requirements, which shall be complied with no later than January 1, 2009. In the interim, the Energy Commission recommends that program administrators strongly encourage applicants for solar incentives to follow these efficiency requirements measures to the maximum extent feasible.

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[12] Public Resources Code, Section 25782 (a)(7).

[13] Public Resources Code, Section 25782 (a)(2).

[14] Public Resources Code, Section 25781 (e).

[15] Public Resources Code, Section 25782 (a)(4).

[16] Public Resources Code, Section 25782 (a)(8).

CHAPTER 3: Solar Energy System Component Standards

Under SB 1, the Energy Commission is directed to set rating standards for equipment, components, and systems to assure reasonable performance and develop standards that provide for compliance with the minimum ratings.[17] Setting rating standards and guidelines to ensure the quality of systems and components is critical to a successful solar incentive program and to ensure high performing systems are incentivized. The three main components that are subject to standards and ratings specific to PV installations are the modules, inverters and meters.

A description of the testing criteria and the criteria for reporting performance of eligible equipment is detailed in Appendix 1 - Criteria for Testing, Certification and Listing of Eligible Components.

These guidelines focus on component standards of photovoltaic (PV) systems. Manufacturers of non-PV solar energy systems are directed to work with the Energy Commission staff to define comparably rigorous and appropriate component standards for such systems.

The requirements in this chapter shall be implemented no later than January 1, 2009.

Photovoltaic Modules

Eligible PV modules shall be required to provide testing data from independent laboratories to ensure high quality data on module performance in the field. This data shall also be used to calculate the expected performance of the system. The eligible modules are listed with the Energy Commission.[18]

The PV module eligibility requirements are as follows:

- Modules shall be certified to UL 1703 by a Nationally Recognized Testing Laboratory (NRTL) to ensure safety and reliability.

- Detailed performance data shall be reported and certified using the subsections of International Electrotechnical Commission (IEC) Standard 61215 or 61646

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[17] Public Resources Code, Section 25782(c).

[18] Modules eligible under these requirements are currently listed under the NSHP eligible modules list [http://www.gosolarcalifornia.ca.gov/nshp/eligible_pv.html].

The modules on the following list will be eligible under programs complying with the requirements of Chapters 3, 4 and 5 once the requirements specified in Chapter 3 have been completed: [http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi].

(depending on the type of PV system) an International Laboratory Accreditation Corporation (ILAC) accredited laboratory.[19]

- The Normal Operating Cell Temperature (NOCT) for roof integrated building integrated photovoltaic (BIPV) products shall be determined using the specification described in Appendix 1, Criteria for Testing, Certification and Listing of Eligible Components.

All modules shall fulfill the eligibility criteria testing requirements by January 1, 2009 to qualify as eligible equipment.[20] *Between January 1, 2008 and December 31, 2008, performance data based on test procedures specified in UL 1703, Section 18.1 (in-house laboratory and flash test data) may be relied upon to list eligible modules.*

Inverters

The inverter test protocol developed by the Energy Commission to determine inverter performance data shall be used along with the UL certification for safety and reliability. The inverter test protocol ensures that the reported performance data of efficiency at the full range of operating conditions (power and efficiency at the full range of possible voltages) along with the night time tare loss for each inverter provides full performance information and enables hourly estimating of the overall performance of the system.

The eligible inverters are listed with the Energy Commission.[21]

The following are inverter eligibility requirements:

- Inverters shall be certified to UL 1741 standards by a Nationally Recognized Testing Laboratory (NRTL).

- Performance data (Maximum Continuous Output Power, Conversion Efficiency, and Tare Losses) tested in accordance with “Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems" by a NRTL shall be reported for each inverter.

[19] An ILAC laboratory inside or outside the United States may be used to conduct this testing and reporting.

[20] Modules that are of identical type can be grouped for testing purposes within a range of power ratings. Details for grouping modules are provided in Appendix 1.

[21] Inverters eligible under these requirements are listed with the Energy Commission at: http://www.consumerenergycenter.org/cgi-bin/eligible_inverters.cgi

Meters

Performance meters,[22] whether stand alone or integrated with the inverters, shall be required to meet the following eligibility criteria:

- Meters with ± 2 percent accuracy shall be installed for all Performance-Based Incentive applicants
- All ± 2 percent accuracy meters shall be tested according to all applicable ANSI C-12 testing protocols
- Meters with ± 5 percent accuracy (these are primarily inverter integrated) shall be allowed for expected performance incentive applicants
- All meters shall measure and display, both instantaneous (kW or W) and cumulative energy produced (kWh or Wh)
- All meters shall retain production data during power outages
- All meters shall be easy to read for the customer's benefit
- All meters shall have a communication port capable of enabling connection to remote performance monitoring and reporting service (PMRS).

The eligible meters are listed with the Energy Commission.[23]

[22] The CSI metering subcommittee is currently developing recommended requirements related to the following: a) testing standards for the ± 5 percent accuracy meters; b) metering requirements for non PV incentives; c) monitoring the interaction between the solar production meters, renewable energy credits, advanced meter and time of use meters and other metering applications.

Future updates of the guidelines will consider these recommendations.

[23] http://www.consumerenergycenter.org/cgi-bin/eligible_meters.cgi

CHAPTER 4. Solar Energy System Design and Installation Standards

SB 1 requires high quality design and installation of solar energy systems to promote the greatest energy production per ratepayer dollar, and directs the Energy Commission to establish design and installation standards or incentives. This chapter establishes guidelines needed to achieve these goals. Program administrators shall comply with these guidelines by **no later than January 1, 2009.**

High performance design and installation requires closely aligned incentive structures that reward attention to high performance and design and installation standards that enable and promote high performance.

Providing performance-based incentives (PBI) is one way to promote high performance of systems over the period during which the incentives are being paid, since the solar energy systems are incentivized based on their actual production (kWh) during that period. The PBI incentive payment is calculated by multiplying the incentive rate ($/kWh) by the measured kWh output. However, an expected performance-based incentive (EPBI) approach may be more appropriate for installations of smaller sized systems to serve newly constructed buildings or even existing buildings. The EPBI incentive approach pays an up-front incentive that is based on calculated expected performance, taking into account all major factors that affect performance of the particular installation in the given location.

Performance-Based Incentives

A performance-based incentive (PBI) approach shall be required for all systems greater than 50kW (AC) starting January 1, 2008. Beginning in January 2010, systems equal to or greater than 30 kW AC shall use the PBI approach. Projects below these size thresholds may voluntarily use the PBI approach.

The PBI payments shall be made over a minimum 5-year period following system installation, submission, and approval of incentive claim materials. *Program administrators may establish longer terms (more than 5 years) for PBI payments.* Payments shall be based on the per-kWh incentive rate and the actual energy (kWh) produced in time periods established by the program administrator.

Expected Performance Based Incentives

An expected performance-based incentive (EPBI) approach shall be used for systems that are below the PBI size threshold stated above and for projects that do not voluntarily use the PBI approach. The incentive calculation shall ensure all interactive component performance characteristics, determined by independent testing are used for establishing expected time dependent valuation (TDV)-weighted kWh performance.[24]

The EPBI calculation shall be based on hourly modeling of the interactive performance results of the combination of third-party tested performance characteristics (listed in Appendix 1 Table 1) of the specific modules and the inverter over the range of conditions that impact component performance, addressing all installation characteristics that are expected to have significant impacts on the performance of the components. The hourly performance of the system shall be based on the interaction of the components and be determined based on conditions that exist at that hour. The hourly production shall be weighted by factors (TDV) to account for the time-of-use value to the utility of that hour's production, and the results shall be summed to obtain the annual time of use weighted (TDV) energy results for the system (kWh_{TDV}) for incentive purposes.

Hourly photovoltaic production calculation

The PV production shall be calculated using a model that complies with the following minimum requirements:

1. The calculation model shall cover fixed flat plat collector technologies at a minimum and include single and dual axis tracking and concentrating solar collectors if the program administrators allow for these technologies to be incentivized under the EPBI approach.[25]
2. Use hourly weather data for one of the 16 climate zones in California, with the use of solar radiation (global horizontal, direct normal and diffused), dry bulb temperature and wind speed as minimum parameters in calculation to describe the conditions for the hour.
3. Determine the incident solar radiation on the modules based on the azimuth and tilt angle of the installation using the weather data and location longitude and latitude information.
4. Use the detailed performance characteristics data for modules (listed in Appendix 1, Table 1) in determining the hourly production at given conditions for the hour (both weather and electrical). This data shall be obtained from the library of eligible modules listed with the Energy Commission.[26]
5. Have the ability to determine the operating voltage of a system at a given hour by discerning the circuit design of the system in terms of the number of modules in series strings and the number of strings in parallel.

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[24] Information on TDV can be referenced at [http://www.energy.ca.gov/title24/2008standards/documents/E3/index.html].

[25] Tracking and concentrating solar collectors may be provided incentives using the PBI approach as an alternative to developing a calculation of expected performance for these systems.

[26] The list of eligible module referred here is the new list maintained by the Energy Commission under its New Solar Homes Partnership [http://www.gosolarcalifornia.ca.gov/nshp/eligible_pv.html].

6. Account for the mounting offset of the array from a surface below to assess the change in operating temperature (Normal Operating Cell Temperature (NOCT) impact). This is especially important to determine the performance of building integrated photovoltaics (BIPV), as compared to rack mounted modules.
7. Account for the height above the ground that the array is mounted, to capture the impact of wind speed on the module operating temperature.
8. Use detailed performance data for inverters (performance curves over range of voltage and power conditions applicable) in determining the hourly production at given conditions for the hour (both weather and electrical). This data shall be obtained from the library of eligible inverters listed with the Energy Commission.[27]
9. Limit the production of the system based on the size and voltage of the array and inverter voltage and power capacity.
10. Generate hourly estimates of PV production for the entire year, which can then be weighted by time dependent value (TDV) multipliers.
11. Determine the solar position for each hour of the year in terms of altitude and azimuth (used to determine the impact of shading from an obstruction).
12. Determine the hourly impact of shading on each string from obstructions that are outside of the minimal shading criteria definition (using shading protocol as described in Appendix 2, Section F).
13. Report the effective hourly production values for the entire year after factoring the impact of shading and applying the appropriate TDV multipliers for the climate zone and building type (residential or non residential).
14. Generate a performance verification table for each specific system that reports the expected production for the specific system and installation as a function of incident solar radiation and ambient temperature. This performance verification table shall enable field verification of actual vs. expected instantaneous production through the comparison of the output reported by the performance meter to the value in the performance verification table at the specific incident radiation and ambient temperature measured at the site at the time of the verification.
15. Generate a Certificate of Compliance form as a printable report which shall be used for incentive application and field verification purposes. The Certificate of Compliance shall include at a minimum the entire system description including installation specifics for the system, location, the shading details, echo all the inputs for the calculation, and the performance verification table.

The NSHP Energy Commission PV calculator[28] (completely or partially) can be used directly or as a reference program to demonstrate compliance with these requirements.

[27] The list of eligible inverters referred here is the list maintained by the Energy Commission [http://www.consumerenergycenter.org/cgi-bin/eligible_inverters.cgi].

[28] The NSHP Energy Commission PV calculator is a spreadsheet-based tool and runs the five-parameter PV model in the background to determine the hourly production. The calculator will be made available upon request by any program administrator.

Reference system and Location

The incentive calculation shall use a reference system and location established by the program administrator to determine the incentive payment for an actual system based on a comparison of the TDV-weighted kWh production of the actual system to that of the reference system/location. The reference system shall be used to convert an incentive level established in terms of \$/W to the $\$/kWh_{TDV}$ equivalent through the following calculation:

$$\$/\mathrm{kWh}_{\mathrm{TDV}} = \frac{\text{Reference System Watts}_{\text{CEC-AC}} \times \$/\text{Watt (incentive level)}}{\text{Reference System Annual kWh}_{\text{TDV}}}$$

The specification of the reference system should include:[29]

1. Location of the system to determine the weather data and corresponding applicable TDV factors to be used.
2. Size of a system that is representative of the median in the applicable utility program.
3. Selection of a reference module from the Energy Commission's Eligible Equipment List, along with all its performance characteristics, that is considered as a median for the applicable utility program.
4. Selection of an inverter from the Energy Commission's Eligible Equipment List that is considered a median for the applicable utility program.
5. The installation characteristics that comprehensively describe the system, including, but not limited to:
    a. Azimuth
    b. Tilt
    c. Mounting offset (BIPV or rack with specific height above substrate)
    d. Height above ground (one story or higher)
    e. Electrical circuit design (modules in series and parallel)
    f. Shading conditions (minimal shading)
    g. Other system losses (such as dirt, dust and wiring losses)

The $\$/kWh_{TDV}$ (or the \$/W before the above conversion) shall be chosen to insure that the full range of improvement in performance (in kWh_{TDV}) is provided with increasing incentives.

[29] For an example of a reference system specification, see the Energy Commission's NSHP Guidebook: [http://www.gosolarcalifornia.ca.gov/documents/CEC-300-2007-008-CMF.PDF]

Incentive calculation

The total incentive for the applicant system shall be determined by multiplying the TDV weighted annual kWh production with the $/kWh$_{TDV}$ determined in the previous step (using the reference system).

$$\text{Total Incentive}\,\$ = \text{Applicant System Annual kWh}_{\text{TDV}} \times \$/\text{kWh}_{\text{TDV}}$$

Shading

The methodology detailed in Appendix 2 - Field Verification and Diagnostic Testing of Photovoltaic Systems (Section F) shall be used as the minimum criteria for addressing shading.

Peak Load

For systems receiving incentives under the expected performance calculation approach, the incentive shall be based on weighting the hourly production with TDV factors to promote systems with higher performance at peak load conditions. TDV factors have been developed for the 16 Building Energy Efficiency Standards climate zones in California using the IOU generation, transmission and distribution cost data.[30]

POU program administrators may use either the TDV factors determined for the 16 climate zones or use hourly time of use weighting factors applicable for their service territories.

Field Verification

PV systems shall be required to successfully complete third party field verification on a sampling basis to be eligible for incentive payment. The field verification at a minimum shall include visually checking components, installation characteristics, shading conditions and verifying performance using the protocol described in Appendix 2 - Field Verification and Diagnostic Testing of Photovoltaic Systems.

The third party field verification shall be carried out on a minimum sample size of one in seven by a qualified Home Energy Rating System (HERS) rater or by the program administrator (or their designated qualified contractor) as determined by the program administrator.

[30] More information on TDV can be referenced at [http://www.energy.ca.gov/title24/2008standards/documents/E3/index.html].

Installation

All eligible systems shall be installed by individuals with a current A, B, C-10 or C-46 license. North American Board of Certified Energy Practitioners (NABCEP) certification of the installers is encouraged, though not required.

The installers shall certify all aspects of the installation using the protocol for field verification (Appendix 2). This includes the actual components used, the installation characteristics, shading conditions and the specified onsite instantaneous performance verification. The same protocol will be used by both the installer and the verifier, with the difference of the installer having better access to the installation in some cases. It will be the responsibility of the installer to document all proof for items that may be more easily observed and measured by the installer than by the verifier.

Performance Monitoring and Maintenance

All systems using the PBI approach shall have a five year service contract with a performance monitoring and reporting service (PMRS).[31]

For systems using the EPBI approach, a PMRS shall be required if the program administrator determines that it is economically reasonable, comparing the cost of available PMRS to the cost caps shown in the table below.

	5% accuracy meters	**2% accuracy meters**	**PMRS**
EPBI < 30kW	Required	Optional	Cost cap – 1% of entire system
EPBI 30kW and greater	Required	Optional	Cost cap – 0.5% of entire system
PBI	N/A	Required	Required

A maintenance plan shall be prepared for all systems over 10 kW. The maintenance plan shall be provided by the installer to the owner or facility manager of the property who has oversight of the system and to the program administrator. The maintenance plan shall include recommended periodic maintenance to address at a minimum the following considerations:

- Cleaning schedule for the array to remove dirt and dust build up.
- Periodic checking of electrical connections for corrosion.

[31] CSI metering subcommittee is currently developing requirements related to independence of the PMRS provider as well as the specification of the data streams that are minimum requirement. These requirements will be considered for possible future updates to these guidelines.

- Checking the inverter for instantaneous power, long term energy output and diagnosing and taking corrective action if production is significantly lower than expected.

- Checking for tree/plant growth or other obstructions that are causing shading on the array and advise on how to eliminate that shading.

CHAPTER 5: Energy Efficiency

Newly Constructed Residential Buildings

The New Solar Homes Partnership's (NSHP) Tier I and Tier II energy efficiency criteria shall be incorporated into the solar incentive programs operated by utilities and their program administrators for all newly constructed residential buildings statewide.[32]

For solar energy systems to be eligible for incentives under SB 1 when installed to serve a newly constructed residential building, the building shall achieve energy efficiency levels substantially greater than the requirements of the current Building Energy Efficiency Standards (Title 24, Part 6) in place at the time of the application.[33] The builder can choose to comply with either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the residential building's combined space heating, space cooling and water heating energy compared to the current Title 24 Standards.
- Tier II – 35 percent reduction in the residential building's combined space heating, space cooling and water heating energy and 40 percent reduction in the residential building's air conditioning energy compared to the current Title 24 Standards.

For either Tier I or II, each appliance provided by the builder shall be *Energy Star*[34] labeled if this designation is applicable for that appliance.

Solar thermal water heating may be used to assist in meeting the energy efficiency requirements of either Tier I or Tier II.

Field verification of energy efficiency measures shall be required and be consistent with current Title 24 Standards field verification procedures and protocols. The CF-1R form used to demonstrate Title 24 compliance with the current Building Energy Efficiency Standards shall be provided as proof of attainment of the Tier I or Tier II level. Compliance documents shall be completed by persons who are Certified Energy Plans Examiners (CEPE) by the California Association of Building Energy Consultants (CABEC).

Investor-owned and publicly-owned electric utilities should provide energy efficiency incentives for each Tier.

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[32] Solar energy systems are installed to serve newly constructed residential buildings when the building permit for the solar energy system is approved by the building code enforcement agency prior to the original occupancy of the newly constructed building.

[33] California Code of Regulations, Title 24, Part 6.

[34] The *Energy Star* designation is available for appliances that exceed minimum federal energy efficiency standards. For more information on the *Energy Star* designation, go to [www.energystar.gov].

Newly Constructed Commercial Buildings

For solar energy systems to be eligible for incentives when installed to serve a newly constructed commercial building,[35] the building shall achieve energy efficiency levels substantially greater than the requirements of the current Building Energy Efficiency Standards (Title 24, Part 6). The builder can choose to comply with either of the following two tiers of energy efficiency:

- Tier I – 15 percent reduction in the commercial building's combined space heating, space cooling, lighting and water heating energy compared to the current Title 24 Standards.

- Tier II – 30 percent reduction in the commercial building's combined space heating, space cooling, lighting and water heating energy compared to the current Title 24 Standards.

For either Tier I or II, any equipment or appliance provided by the builder must be *Energy Star* labeled if this designation is applicable to that equipment or appliance.

Solar water heating may be used to assist in meeting the energy efficiency requirements of either Tier I or Tier II.

- Compliance documents used to demonstrate Title 24 compliance, including the PERF-1 form and accompanying supporting forms, shall be provided as proof of attainment of the Tier I or Tier II levels. Compliance documents shall be completed by persons who are either a Certified Energy Plan Examiners (CEPE) by the California Association of Building Energy Consultants (CABEC).

- For newly constructed commercial buildings that are constructed in phases with the shell built first, and further energy systems installed in later phases as tenant improvements, an agreement shall made between the building owner and the tenant that obligates future tenant improvements to install lighting, HVAC and water heating equipment at efficiency levels necessary to meet the overall building Tier level that was committed to by the building owner.

Existing Buildings – Energy Audit, Information and Disclosure

For solar energy systems to be eligible for incentives when installed to serve an existing residential building or an existing commercial building, specific information shall be provided to the building owner, and specific information shall be disclosed by the building owner.

[35] For purposes of these guidelines "commercial buildings" include all non-residential buildings and structures.

For existing commercial buildings with conditioned floor area of 50,000 square feet or less and for existing residential buildings, an energy efficiency audit shall be conducted. The program administrator may allow online or telephone audits or may require onsite energy audits, as they specify for particular categories of customers. Building owners will be responsible for submitting a copy of the audit results with their solar incentive applications.

The program administrator shall provide information to the building owner prior to the installation of the photovoltaic system to enable the building owner to make informed decisions on energy efficiency investments. The building owner shall be required to sign a disclosure which certifies that this information was provided to them and identifies which, if any, energy efficiency measures will be taken. If measures are to be installed after the installation of the solar energy system, then the building owner shall declare on the disclosure when the measures will be installed. The disclosure shall also include the results of the energy audit that has been completed.

The information and disclosure shall be provided to the building owner via a web-based information portal or a paper format. The building owner shall complete and sign the disclosure form and submit it to the program administrator, along with the audit results.

Information to be provided to the building owner:

- most recent 12 months of energy consumption;
- list of building energy use assessment services and tools available for use by the building owner for further investigation;
- list of possible cost effective energy efficiency measures applicable to the building; and
- list of specific utility energy efficiency incentives that are available.

Disclosures to be provided by the building owner:

- certification that the building owner has received the above information;
- the energy use assessment services or tools the building owner used to identify cost effective energy efficiency measures that could be installed in the building;
- the energy efficiency measures that have been installed, or will be installed prior to or in conjunction with the installation of the solar energy system;
- if energy efficiency measures are planned to be installed at a later time, the date by which these measures are planned to be installed;
- energy audit report for existing residential buildings and commercial buildings 50,000 square feet or less; and
- additional energy use assessment services expected to be used to identify further energy efficiency measures and when those assessments are planned to occur.

Existing Commercial Buildings – Benchmarking, Retro-Commissioning and Efficiency Improvements

Benchmarking

For solar energy systems to be eligible for incentives when installed to serve an existing commercial building, the energy use intensity (EUI) shall be benchmarked[36] using Portfolio Manager or an equivalent benchmarking system for building types that cannot receive an *Energy Star* rating. Portfolio Manager can be accessed on the internet at: [https://www.energystar.gov/istar/pmpam/]

Building types that are not able to be benchmarked using Portfolio Manger, shall be benchmarked using the Energy Commission's equivalent benchmarking system.[37]

Smaller Commercial Buildings

Except as noted in the exceptions below, for commercial buildings 50,000 square feet or less in size, the benchmark rating shall be at 75 or above or retro-commissioning shall be completed. If the rating is at 75 or above, then no further action is required for the owner to receive the incentive for the solar energy system. Note: all existing buildings shall participate in the Information and Disclosure process described above.

Retro-Commissioning

Except as noted in the exceptions below, retro-commissioning[38] shall be required for all existing commercial buildings that are larger than 50,000 square feet and/or that have a benchmarking rating of less than 75.

Systems to be retro-commissioned include but are not limited to:

- heating, ventilation, and air conditioning systems and controls

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[36] Benchmarking is a process that compares the energy use of the building to the energy use of a population of similar buildings.

[37] The Energy Commission is preparing an equivalent system that can be used to benchmark commercial buildings not able to be benchmarked using Portfolio Manager.

[38] Retro-commissioning, is a process to identify how major energy using equipment are being operated and maintained and to identify specific improvements to the performance of those energy using systems. The process uses a whole building systems approach to identify problems and needed repairs or adjustments to achieve energy savings, occupant comfort and improved systems performance. A commissioning agent identifies and makes the necessary equipment adjustments and identifies energy efficiency projects that will improve overall building performance.

- lighting systems and controls
- daylighting systems and controls
- domestic hot water systems and controls
- renewable energy systems and associated equipment and controls
- process equipment and appliances specific to hospital, restaurant and hotel/motel operations
- refrigeration in supermarket and refrigerated warehouses.

Equipment repairs and adjustments and cost effective energy efficiency measures identified in the building retro-commissioning assessment shall be implemented up to those measures required to move the building's benchmarking rating up to a benchmarking rating of 75. If equipment/appliance replacement is recommended during the retro-commissioning process, the replacement shall be made with *Energy Star* equipment or appliances, or equipment or appliances that qualify for utility energy efficiency incentives, whichever is more efficient.

Utilities should provide energy efficiency incentives for the retro-commissioning and for the installation of cost effective efficiency measures.

Commitment Agreement

Equipment repairs and adjustments and energy efficiency improvements that are identified through retro-commissioning shall either be completed prior to or in conjunction with the installation of the solar energy system, or the building owner shall sign and submit a Commitment Agreement to make the repairs, adjustments and energy efficiency improvements by a specified date. The Commitment Agreement shall indicate what efficiency repairs and adjustments and cost effective improvements were identified in the retro-commissioning process, and shall commit the building owner to making the repairs and adjustments and installing the improvements by a specific date as a condition for receiving incentives for the solar energy system. The program administrator shall verify and ensure that the measures have been installed by the date established by the Commitment Agreement.

Energy Efficiency Exceptions for Existing Commercial Buildings

Specific energy efficiency requirements in these guidelines for existing commercial buildings are not required for the following:

- agricultural and industrial facilities which are not covered by Portfolio Manager or the Energy Commission's equivalent benchmarking system are not required to be benchmarked;
- energy efficiency is not required to be addressed when solar energy systems are not serving electricity to a building;
- retro-commissioning is not required for buildings that have complied with Title 24 requirements for newly constructed buildings in the past three years; proof of Title 24 compliance shall be included with the solar energy system incentive

application. While retro-commissioning is not required, the building still must be benchmarked.

Existing Residential Buildings

For solar energy systems to be eligible for incentives when installed to serve an existing residential building, the energy audit, information and disclosure requirements beginning on page 19 for all existing buildings shall be met.

Energy Audit Exception for Existing Residential Buildings

The energy audit is not required for buildings that have complied with Title 24 requirements for newly constructed buildings in the past three years; proof of Title 24 compliance shall be included with the solar energy system incentive application. There is no exception for the other information and disclosure requirements.

Alternative Portfolio Energy Savings

As an alternative to the requirements discussed above, program administrators may instead conduct a program which achieves a 20 percent energy efficiency savings over their entire SB 1 participation portfolio. This alternative enables program administrators to pursue different levels of energy efficiency with different customers over time. Program administrators shall provide the Energy Commission with a three year plan that describes the initiatives that they will take to achieve this level of energy efficiency savings. Program administrators shall report annually to the Energy Commission on progress in achieving a 20 percent energy efficiency savings over their entire SB 1 portfolio. Plans shall be reviewed by Energy Commission staff to determine that they will successfully achieve the 20 percent savings.

The Energy Commission may return the plan for further development if it deems necessary. Plans shall be considered for possible approval at a regularly scheduled Energy Commission Business Meeting, and once approved and implemented shall be used as an alternative to the specific energy efficiency requirements otherwise required in these guidelines. Alternative Portfolio Energy Saving Plans shall be approved by the Energy Commission in its discretion, and may be rejected if the Energy Commission determines the plan will not result in the requisite 20 percent energy efficiency savings. If a plan is approved, the program administrators shall be required to report annually on their progress of achieving the 20 percent savings. The Energy Commission may discontinue its approval of a plan or direct an expansion or modification of the plan if the Energy Commission determines that progress under the plan to achieve the 20 percent energy savings is not being achieved.

Program administrators may conform to the requirements in these guidelines for any of the building sectors (i.e., newly constructed residential buildings, newly constructed commercial buildings, existing commercial buildings, existing residential buildings) and establish an alternative portfolio energy savings plan covering just the remaining sectors. For example, a program administrator may conform to the requirements in these guidelines for newly constructed buildings, both residential and commercial, and establish an alternative portfolio energy savings plan just for existing buildings, both residential and commercial.

CHAPTER 6: Reporting Requirements

Under SB 1, local publicly owned electric utilities are required to make available key solar program information. This information must be made available, beginning June 1, 2008, to its utility customers, the California State Legislature and the Energy Commission.[39] This information must be made available no later than June 1 of subsequent years for the duration of the program. Except for 2008, the reporting period shall be from April 1 of the previous year through the following March 31. For 2008 only, the reporting period shall be January 1, 2008 through March 31, 2008.

Each publicly owned utility is required, at a minimum, to provide information on:

1. Solar program goals, including:
    a. Outreach and marketing,
    b. Any training or builder/installer assistance,
    c. Auditing of installed systems,
    d. Goals of installed systems (kW, AC) for each reporting period and total for program duration.

2. Number of submitted applications, including:
    a. Number of applications received,
    b. Number of applications approved and rejected,
    c. Key reasons for application rejections.

3. Total incentives awarded, including:
    a. Total public goods charge funds collected during reporting period,
    b. Total solar incentive expenditures,
    c. All other program expenses, by category.

4. The total number of systems installed, including:
    a. Breakdown by category type, including separate breakdown for installations serving newly constructed and existing buildings, for:
        i. Residential
            1. market-rate housing
            2. affordable housing
        ii. Commercial
        iii. Non profit
        iv. Government
        v. Industrial
        vi. Agricultural
    b. Discussion of any auditing of installed solar systems that has been undertaken during the reporting period.

5. Amount of added solar capacity installed and expected performance:

[39] Public Utilities Code, Section 387.5 (e).

a. Solar electric capacity (PV) and non-PV solar systems added,
    i. List and description of non-PV technologies
b. Estimated annual electrical generation (kWh) and savings as a result of solar energy systems,
c. Estimated annual electricity savings (kWh) as a result of program energy efficiency requirements,
d. Estimated annual natural gas (or propane where appropriate) savings (BTU) due to any program-specific energy efficiency requirements.

6. Solar system and energy efficiency implementation impacts:
    a. Costs and benefits evaluation of existing solar electric systems as a part of the utility's electrical system, and from projected solar electric systems anticipated during the term of the program,
    b. Impacts on the distribution, transmission, and supply of electricity.

7. Contribution toward program goals, including:
    a. Overview of program administration during reporting period.
    b. Problems identified and resolutions or recommended mitigation.
    c. Opportunities for the year ahead.

Each local publicly owned electric utility shall provide five copies of the report and an electronic version to the Energy Commission not later than June 1 of each program year. Electronic copies can be sent to: [renewable@energy.state.ca.us]; paper copies can be sent to:

California Energy Commission
Renewable Energy Office, MS 45
1516 Ninth Street
Sacramento, CA 95814

APPENDIX 1: Criteria for Testing, Certification and Listing of Eligible Components

This Appendix summarizes the criteria used for determining the components that can be used to create a photovoltaic (PV) system that is eligible for an incentive. Certified equipment (solar modules, inverters, and performance meters) is periodically added to and removed from the lists of eligible equipment.

The equipment shall be certified to meet nationally or internationally recognized standards, information submittal requirements, and other criteria specified by the Energy Commission to be listed. Until the equipment is listed, it is not eligible and no funding can be reserved or payment made.

Photovoltaic Modules

All flat plate PV modules shall be certified by a nationally recognized testing laboratory as meeting the requirements of and being listed to be in conformance to the Underwriters Laboratory (UL) Standard 1703 and any subsequent testing standard adopted by UL.

All flat plate PV modules shall also be tested by a laboratory accredited by the International Laboratory Accreditation Cooperation according to the following sections of either the International Electrotechnical Commission (IEC) Standard 61215, *Crystalline Silicon Terrestrial Photovoltaic (PV) Modules - Design Qualification and Type Approval, Second Edition 2005-04*, or the (IEC) Standard 61646, *Thin-film Terrestrial Photovoltaic (PV) Modules - Design Qualification and Type Approval, First Edition, 1996-11*, except as specified in Notes 3, 6 and 7 of Table 1 below.

IEC Standard 61215 Sections

- 10.2 Maximum Power Determination
- 10.4 Measurement of Temperature Coefficients
- 10.5 Measurement of Nominal Operating Cell Temperature (NOCT)
- 10.6 Performance at Standard Test Conditions (STC) and NOCT
- 10.7 Performance at Low Irradiance

IEC Standard 61646 Sections

- 10.2 Performance at STC
- 10.4 Measurement of Temperature Coefficients
- 10.5 Measurement of NOCT
- 10.6 Performance at NOCT
- 10.7 Performance at Low Irradiance
- 10.18 Light-Soaking

Grouping of modules for testing purposes

For testing and reporting of performance values by an accredited laboratory, families of similar modules shall have the option to be grouped based on type.

Multiple models may be included under a specific type, provided that the models are identical to the type, except for the STC power rating. Identical includes, but is not limited to, all structural components, materials, processes (including cell process), cell technology, encapsulation system, superstrate, backsheet/substrate, frame and/or mounting structure, junction box/electrical termination, cell interconnection materials and techniques, and internal electric circuitry.

For each type, the following tests shall be performed on the model with the highest STC power rating: Nominal Operating Cell Temperature (NOCT), temperature coefficient of short-circuit current, temperature coefficient of open-circuit voltage, temperature coefficient of maximum power current, temperature coefficient of maximum power voltage, and temperature coefficient of maximum power.

For each type, the models under that type shall be categorized into the smallest number of groups such that the STC power rating of the models within the group have a maximum range of ± 5 percent. For each of these groups, the model with the STC power rating closest to the average STC power rating of the models in the group shall be used for testing. If there are two models equally close to the average, the model with the highest STC power rating shall be selected. For each group, the following tests shall be performed on the model with the STC power rating closest to the average STC power rating of the group: short-circuit current, open-circuit voltage, maximum power current, maximum power voltage, maximum power, maximum power and low irradiance current, maximum power and low irradiance voltage, current at NOCT, and voltage at NOCT.

Each model shall be associated with the two types (groups) that have reported test values, if scaling of performance characteristics is applicable.

The factory measured maximum power of each production module, as specified in UL 1703, Section 44.1, and the lower bound of the manufacturer's stated tolerance range, pursuant to UL 1703, Section 48.2, shall be no less than 95 percent of the Maximum Power reported to the Energy Commission.

The following performance data and information shall be certified and provided to the Energy Commission.

Table 1. Module Performance Parameter Testing

Parameter	**Symbol**	**Units**	**Notes**
Maximum Power	P_{mp}	Watts	1, 7
Voltage at maximum power	V_{mp}	Volts	1, 7
Current at maximum power	I_{mp}	Amps	1, 7
Open Circuit Voltage	V_{oc}	Volts	1, 7
Short Circuit Current	I_{sc}	Amps	1, 7
Nominal Operating Cell Temperature	NOCT	°C	3, 7
Temperature Coefficients	β_{Voc} (at V_{oc}) β_{Vmp} (at V_{mp}) α_{Isc} (at I_{sc}) α_{Imp} (at I_{mp}) γ_{Pmp} (at P_{mp})	%/°C	2, 7
Voltage at maximum power and low irradiance	V_{low}	Volts	4, 6
Current at maximum power and low irradiance	I_{low}	Amps	4, 6
Voltage at NOCT	V_{NOCT}	Volts	5, 6
Current at NOCT	I_{NOCT}	Amps	5, 6

Notes:

1) Values shall be measured at Standard Test Conditions after Preconditioning according to IEC Standard 61215, Section 5, or after Light-soaking according to IEC Standard 61646, Section 10.18.
2) Values shall be measured and calculated according to IEC Standards 61215 and 61646, Section 10.4.
3) Values shall be measured according to IEC Standards 61215 and 61646, Section 10.5.2. For BIPV modules the measurements shall be made using the mounting specified below. Prior to January 1, 2009 manufacturers may provide NOCT values for BIPV modules that are not tested according to IEC Standards 61215 and 61646 with the mounting below; these values for performance calculations will be adjusted by adding 20 °C to be consistent with the Sandia National Laboratories Report, *A Simplified Thermal Model for Flat-Plate Photovoltaic Arrays* by Martin K. Fuentes, 1987, page 11, Table 4.
4) Values shall be measured at low irradiance according to IEC Standards 61215 and 61646, Section 10.7.
5) Values shall be measured at NOCT according to IEC Standards 61215 and 61646, Section 10.6.
6) Prior to January 1, 2009, the provision of this data is optional.
7) Prior to January 1, 2009 manufacturers will provide this data based on IEC Standard 61215 or IEC Standard 61646 if available or based on test procedures specified in UL 1703, Section 18.1 (in-house laboratory and flash test data is permissible prior to January 1, 2009), if testing for the module according to one of these IEC Standards has not been completed.

Mounting Specifications for NOCT testing for Building Integrated Photovoltaic (BIPV) Modules Intended for Roof Integrated Installations:

Tilt angle: the test modules shall be positioned so that they are tilted at $23^{o} \pm 5^{o}$ (5:12 roof pitch) to the horizontal.

Configuration: the test modules shall be located in the middle of an array that is at least four feet high and four feet wide. The array shall be surrounded on all sides with a minimum of three feet of the building system for which the BIPV system is designed to be compatible, and the entire assembly shall be installed and sealed as specified by the manufacturer for a normal installation.

Substrate and Underlayment: the test modules shall be installed on a substrate of oriented strand board with a minimum thickness of 15/32 inch that is covered by #30 roofing felt with a minimum R-10 continuous insulation under and in contact with the oriented strand board and include any other manufacturer-recommended underlayments.

Inverters

All inverters shall be certified as meeting the requirements of UL 1741. Each model of inverter shall be tested by a qualified Nationally Recognized Test Laboratory[40] to be eligible for this program. Performance ratings for each model will be determined according to sections of the test protocol entitled, *Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems*, prepared by Sandia National Laboratories, Endecon Engineering, BEW Engineering, and Institute for Sustainable Technology, October 14, 2004 version[41] and the "Guidelines for the Use of the Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems". This version of the test protocol and guidelines are available on the Energy Commission website at [http://energy.ca.gov/renewables/02-REN-1038/documents/2004-12-01_INVERTER_TEST.PDF]. The tests shall be performed in accordance with sections 3, 4, 5.1 and 5.2 of the test protocol, as further clarified in the guidelines. The following tests are required:

- **Maximum Continuous Output Power.** Section 5.4 shall be performed in its entirety for test condition A of Table 5-2 with the following exceptions: 1) the test

[40] Nationally Recognized Testing Laboratories shall be those laboratories that have been recognized by the U.S. Department of Labor, Occupational Safety & Health Administration (OSHA), in accordance with Title 29 of the Code of Federal Regulations, section 1910.7, and are approved to conduct test UL 1741 under the scope of their OSHA recognition. A list of all current Nationally Recognized Testing Laboratories is available on OSHA's web page at [www.osha.gov/dts/otpca/nrtl/index.html]. Please note, not all of the Nationally Recognized Testing Laboratories identified on OSHA's list are approved to conduct test UL 1741.

[41] This version of the test protocol is identified by the file name "InvertrTestProto_041014.doc" as shown in the left-hand side of the footer on each page of the protocol.

shall be performed at an ambient temperature of 40°C, rather than 45°C, and 2) the dc V_{nom} may be selected by the manufacturer at any point between V_{min} +0.25* (V_{max} -V_{min}) and V_{min} +0.75* (V_{max} –V_{min}). It is not necessary to perform Section 5.4 for test conditions B through E of Table 5-2.

- **Conversion Efficiency.** Section 5.5 shall be performed for test conditions A, B and C of Table 5.3, subject to the following: 1) the tests shall be performed with dc V_{nom} equaling the same voltage as selected above for the Maximum Continuous Power Output test, 2) steps 1 through 8 of the test procedure (Section 5.5.1) shall be performed at 25°C, and not at 45°C, and 3) to reduce time for each test condition, begin at the highest power level and go to the lower power levels. If done in this order it will only be necessary to wait for temperature stabilization at the 100 percent power level. In addition, the unit only needs to be operated at full output power for one hour, rather than 2.5 hours, and no preheating is necessary if the Conversion Efficiency test is performed within 1 hour of full operation under test 5.4 provided the unit has not been exposed to ambient temperature of less than 22°C.

- **Tare Losses.** Section 5.7.1 shall be performed in its entirety. It is not necessary to perform the tests under Section 5.7.2 or Section 5.7.3.

All of the above data will be used as inputs for the calculation of expected performance of the system.

The tests for Power Foldback (Section 5.8) and Inverter Performance Factor/Inverter Yield (Section 5.9) are NOT required.

The data and reports resulting from the tests for Maximum Continuous Output Power (Section 5.4), Conversion Efficiency (Section 5.5) and Tare Losses (Section 5.7.1) shall be provided to the Energy Commission and will be made public. The inverter tested shall utilize the same hardware and software configuration evaluated during the UL 1741 certification test.

Meters

All eligible meters shall comply with the requirements[42] stated below, to be listed as eligible equipment with the Energy Commission.

- Meter Measurement: Meters shall measure net generated energy output as well as instantaneous power.
- Meter Testing Standards: ± 2 percent meters shall be tested according to all applicable ANSI C-12 testing protocols. Testing protocols for ± 5 percent meters are being developed for the CSI Program and will be incorporated into future revisions of these Guidelines.

[42] The meter requirements listed here are based on the CSI Handbook, Appendix B.

- Meter Certification: The accuracy rating of ± 2 percent meters shall be certified by an independent testing body (i.e., a NRTL). Certification standards for ± 5 percent meters are being developed[43] and will be incorporated into future revisions of these Guidelines. Until these standards have been developed, the accuracy rating of all ± 5 percent meters shall be certified by the manufacturer of the ± 5 percent meter or an independent testing body. All test results or NRTL documentation supporting the certification shall be maintained on file for inspection by the Energy Commission.
- Meter Data Access: All meters shall provide the PMRS provider with the ability to access and retrieve the minimum required Solar Performance / Output Data from the meter using the Meter Communication / Data Transfer Protocols. In the event that the system is not required to have a PMRS provider, the System Owner shall have a means to retrieve the minimum required Solar Performance/Output Data from the meter.
- Meter Display: All meters shall provide a display showing measured net generated energy output and measured instantaneous power. This display shall be easy to view and understand. This display shall be physically located either on the meter, inverter, or on a remote device.
- Meter Memory and Storage: All meters shall have the ability to retain collected data in the event of a power outage. Meters that are reporting data remotely shall have sufficient memory to retain 60 days of data if their standard reporting schedule is monthly and 7 days of data if their standard reporting schedule is daily. Meters that do not remotely report their data shall retain 60 days of data. In all cases meters shall be able to retain lifetime production.

[43] The testing requirements for 5 percent accuracy meters are being developed by the CSI Metering subcommittee and will be review for possible inclusion in a future update of these guidelines.

APPENDIX 2: Field Verification and Diagnostic Testing of Photovoltaic Systems

Background

This appendix covers the minimum requirements of the field verification protocol to be followed for applicant systems using the EPBI approach. It addresses systems that use fixed flat plate collector technology at this time.[44] Third-party field verification shall be conducted on a minimum sample of 1 in 7 systems to ensure that the components of the solar system, its installation, and performance and shading estimation are consistent with the characteristics used to determine its estimated performance. The EPBI incentive amount is based on a determination of the expected performance of the solar system, which accounts for the tested and certified performance of the specific module and inverter, the mounting type and cell temperature, the orientation and tilt of the module and the extent to which the system is shaded. The PV calculator tool accounts for these parameters that are under the control of the owner and installer, as well as the solar and climatic conditions for the locale of the building to determine hourly estimated performance, which is weighted to account for the time-dependent valuation of the electricity that is produced. Third-party field verification shall be conducted to ensure that the components of the solar system and its installation are consistent with the characteristics used to determine its estimated performance. Field verification can be carried out by a HERS rater or the program administrator (or their designated qualified contractor) as determined by the program administrator.

The field verification and diagnostic testing procedures described in this Appendix are intended to ensure that the:

- PV modules and inverters used in the expected performance calculations are actually installed at the applicable site;

- PV modules are minimally shaded, or if shaded, that the actual shading does not exceed the shading characteristics that were included in the expected performance calculations; and

- Measured output power from the system matches that expected by the PV Calculator within the specified margin at the prevailing conditions at the time of field verification and diagnostic testing.

[44] Tracking and concentrating solar technologies may be addressed in a future update of these guidelines. Program administrators may specify a field verification protocol for such technologies.

Responsibilities

Field verification and diagnostic testing is the responsibility of both the PV system installer and with the verifier who completes the third-party field verification. The PV installer shall perform the field verification and diagnostic testing procedures in this document for every system that they install. The verifier then performs independent third-party field verification and diagnostic testing of the systems. For new housing developments, the builder may choose to have the verifier complete field verification using the sampling approach described in Section 7.5, including subsections 7.5.1, 7.5.2 and 7.5.3, of the *2005 Building Energy Efficiency Standards Residential Alternative Calculation Methods Approval Manual*.

The field verification and diagnostic testing protocol is the same for both the PV installer and the verifier. The protocol anticipates that the PV installer will have complete access to the system which the verifier may not have, due to constraints of liability and insurance of getting on top of a roof. The measurements required by this protocol are not required to be completed on the roof, but more accurate measurement techniques are possible with roof access. The measurements required by the protocol may be performed in multiple ways as described in the subsections below.

Field Verification and Diagnostic Testing Process

The field verification and diagnostic testing of solar systems follows the process described below. Note a solar system is one or more strings of PV modules connected to one inverter. Documentation of the process uses three forms that are counterparts to the compliance forms used for the *Building Energy Efficiency Standards*.

1. The applicant/builder's representative enters the necessary input data into the PV Calculator, which produces an output report **Certificate of Compliance Form** that documents the specific modules, inverters and meters that are used in each solar system that is installed on the building, the anticipated shading of each system (either the intent for the system to meet the minimal shading requirements or the actual shading that is anticipated), and a table of predicted electric power for each system for a range of solar irradiation and ambient air temperature. The Certificate of Compliance Form shall be provided to the program administrators at application time.

2. Once each solar system is installed, the PV installer completes the field verification and diagnostic testing protocol for each solar system on the building and documents the results on the **Installation Certificate**, verifying that the installation is consistent with the Certificate of Compliance. The PV installer documents and certifies that the PV system meets the requirement of this appendix and provides a copy of the Installation Certificate to the owner/builder and to the verifier.

3. The verifier completes independent third-party field verification and diagnostic testing of each solar system and documents the results on the **Certificate of Field Verification and Diagnostic Testing**, independently verifying that the installation is consistent with the Certificate of Compliance. The verifier provides a copy of the Certificate of Field Verification and Diagnostic Testing to the owner/builder (and the HERS provider in the case where HERS raters are used for field verification).

4. The payment claim shall be based on system characteristics that produce expected performance calculations that are no better than calculations based on the characteristics reported in the Certificate of Field Verification and Diagnostic Testing.

   In conjunction with the Installation Certificate, the applicant must provide to the installer and verifier a site plan that for each lot:

   a) identifies the species of all pre-existing, planted and planned trees and the location and height of any structures which will be built on the lot and neighboring lots of the building with the solar system; and

   b) shows the bearing of the property lines and the azimuth and tilt or roof pitch of each PV array.

The applicant shall also provide the verifier a product specification (cut-sheet) for the modules, inverter and meter for the specific system, along with an invoice or purchase document, which lists the make and model of PV modules installed in the project.

Relationship to Other Codes, Standards and Verification

The local jurisdiction must issue a building permit for the qualifying PV system, either as a separate permit or as part of the new construction building permit or retrofit application, and the PV system must meet all applicable electrical code, structural code and building code requirements. In addition, the local electric utility will have standards regarding interconnection to the electric grid and other matters which shall be complied with.

The field verification and diagnostic testing procedures described in this document do not substitute for normal electrical, structural or building plan check or field inspection. Nor do they substitute for field verification by the local utility regarding interconnection to the electric grid.

Field Verification Visual Inspection

The purpose of the visual inspection described in this protocol is to verify that the module, inverter and meter specified in the Certificate of Compliance for each residential building is properly installed in the field. The verifier shall use binoculars or another means to view the installation if access to the system is restricted due to insurance and liability reasons (sloping or unprotected roof top access for example), and shall verify the models and numbers of modules against the cut sheet/invoices. The verifier may rely on photographic evidence provided by the installer on the models and numbers of modules, standoff distance and shading, but in the absence of such evidence, must rely on a conservative determination based solely on their own observation.

Photovoltaic Modules

The PV installer and the verifier shall verify that the same number of each make and model number of PV modules used in the expected performance calculations are installed in the field. The PV installer and verifier shall also verify the module mounting type (flush mounted BIPV or rack mounted) and in the case of rack mounted modules, the standoff distance of the modules above the mounting surface. The PV installer and the verifier shall also observe and verify the mounting height of the modules (one story, two stories or measured minimum distance above the ground).

Inverters

The PV installer and the verifier shall verify that the make and model of inverters used in the expected performance calculations are installed in the field.

System Performance Meters

The PV installer and the verifier shall verify that either a separate system performance meter or an inverter with an integral system performance meter is installed that is the same make and model specified on the Reservation Application Form and meets all eligibility requirements for system performance meters.

Tilt and Azimuth

The PV installer and the verifier shall verify that the tilt and azimuth (orientation) of the PV modules installed in the field match the values that were used to determine the expected performance of each solar system, ***within ± 5 degrees***. In some systems, PV modules may be installed in multiple arrays with different tilts and azimuths; in these cases the tilt and azimuth of each array shall be verified.

Determining Tilt
The tilt angle of the PV modules is measured in degrees from the horizontal (e.g. horizontal PV modules will have a tilt of zero and vertically mounted PV modules will have a tilt of 90 degrees). The tilt of the PV modules may be determined in the following ways:

i. *Using the building plans*

The as-built or construction drawings for the building will state the slope of the roof, usually as the ratio of rise to run. If the PV modules are mounted in the plane of the roof then the slope of the PV modules is the same as the slope of the roof. Table 1 may be used to convert rise to run ratios to degrees of tilt.

Table 1 – Conversion of Roof Pitch to Tilt

Roof Pitch (Rise:Run)	Tilt (degrees)
2:12	9.5
3:12	14.0
4:12	18.4
5:12	22.6
6:12	26.6
7:12	30.3
8:12	33.7
9:12	36.9
10:12	39.8
11:12	42.5
12:12	45.0

ii. *Using a digital protractor*

A digital protractor may be used to measure either horizontal or vertical angles (see Figure 1). These devices when sighted up the slope of the PV modules from the ground will display the slope, relative to the horizontal.

Figure 1 – Digital Protractor

Determining Orientation (Azimuth)
The PV installer and the verifier shall determine the orientation by measuring the azimuth of the PV modules and verify that the azimuth is the same as that used to determine the expected performance of each solar system. The convention that is used for measuring azimuth is to determine the degrees of angle clockwise from north, e.g., north azimuth is zero degrees, east is 90 degrees, south is 180 degrees and west is 270 degrees (see Figure 2).

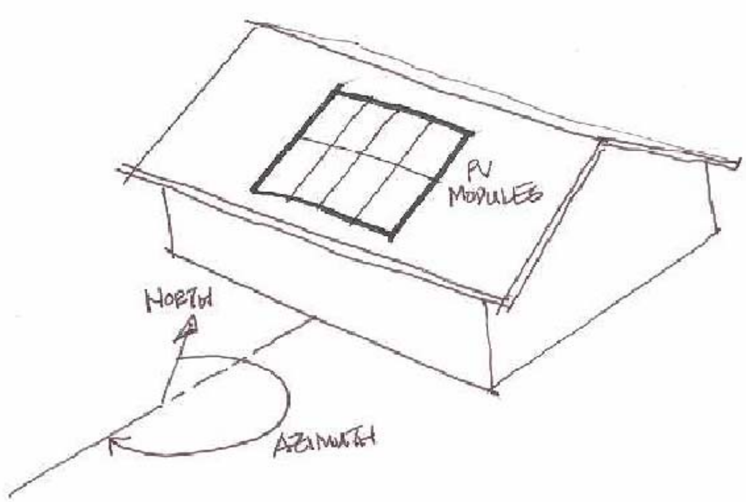


Figure 2 – Azimuth of the PV Array

The following methods may be used to determine the azimuth.

i. Using the Plot Plans

In new subdivisions, the house plans will often not show the property lines since the plans are used on multiple lots. However, the subdivision plot plan will show the property lines of the lots. The plot plan will show the bearing of the property lines, and from this information the azimuth of the roof surfaces where the PV modules are mounted may be determined from the position of the house on the lot relative to the bearings of the property lines.

Figure 3 shows an example plot plan with a house located on it. In this case, the house does not align with any of the property lines, but is rotated 15 degrees from the westerly property line as shown. Property lines on plot plans are typically labeled in terms of their bearing, which is the direction of the line. The westerly property line is labeled "North 12° East". If the house was aligned with this property line, the southerly exposure of the house would have an azimuth of 192° (180° plus the 12° bearing of the property line). Since the house is rotated an additional 15°, the azimuth of the southerly face of the house and the azimuth of the PV array is 207° (192° plus 15°). Usually, the house will be aligned with one of the property lines and the calculation described above will be simplified.

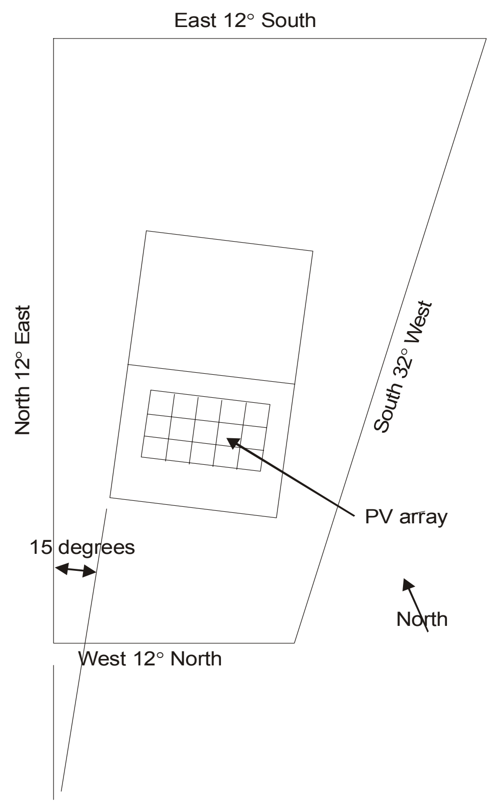


Figure 3 – Example Plot Plan

ii. *Using a Compass with a Sighting Feature and an Adjustment for Magnetic Declination.*

The installer and verifier shall ensure that the compass has a sighting feature. The compass may have an adjustment built in for magnetic declination so that the reading on the compass is true north or the installer and the verifier shall determine the magnetic declination using the tool available at [www.ngdc.noaa.gov/seg/geomag/jsp/Declination.jsp] and adjust the compass reading to account for the magnetic declination. Position the compass and determine the array azimuth angle between compass north and the direction that the PV modules face. It's usually convenient and most accurate to align the compass along the edge of the array using the sighting feature (see Figure 4).

Figure 4 – Compass with a sighting feature

Shading Verification

The PV installer and the verifier shall verify that the shading conditions on each string of the system in the field are consistent with those used in the expected performance calculations (Certificate of Compliance). The estimated performance calculations will be done either assuming that the “minimal shading” criterion is met or based on the specific shading characteristics of each string in the system.

Minimal Shading Criterion

The “minimal shading” criterion is that no obstruction is closer than a distance (“D”) of twice the height (“H”) it extends above the PV modules (see Figure 5 for an artistic depiction of “H” and “D”). As the figure illustrates the distance “D” must be at least two times greater than the distance “H.” Any obstruction that projects above any portion of the PV array must meet this criterion for the PV array to be considered minimally shaded. Obstructions that are subject to this criterion include:

i. Any vent, chimney, architectural feature, mechanical equipment or other obstruction that projects above the roof of the residential building;
ii. Any part of the neighboring terrain that projects above the roof;
iii. Any tree that is mature at the time of installation of the solar system;
iv. Any tree that is planted or planned to be planted as part of the landscaping for the residential building (the expected performance must be based on the expected mature height of any tree planted or planned to be planted as part of the landscaping for the residential building);
v. Any existing neighboring building;
vi. Any planned neighboring building; if the builder does not know what building or other structure is planned for construction on land that is neighboring the solar system, the shading must be based on the highest and closest dimensions of the building model and setbacks offered by the builder on that land or if the land is not planned for development by the builder, the highest and closest dimensions allowed by zoning.

vii. Any telephone or other utility pole that is closer than thirty feet from the nearest point of the array.

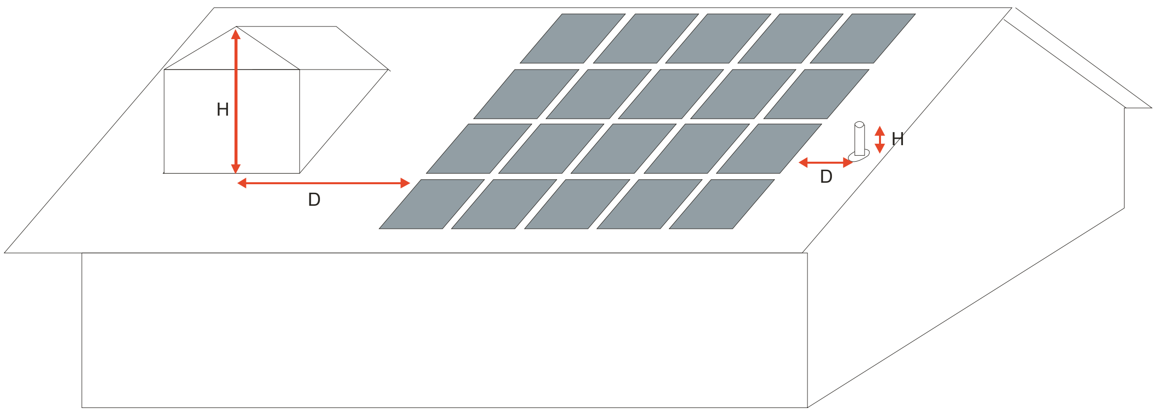


Figure 5 – The Minimal Shading Criterion - Artistic Depiction of "H" and "D"

Neither the PV array nor the shading obstruction are single points in space, so it is the responsibility of the PV installer and the verifier to determine the worst condition by determining the point on the array and the point on the obstruction that would result in the smallest ratio of distance from the obstruction point to the array point divided by the height of the obstruction point above the array point. Generally, the portion of the array that will most likely be shaded and thus represents the worst condition is the lower corner of the array that is closest to the obstruction and the portion of the obstruction that is the worst condition is the highest point of the obstruction, but this may not always be the case. *Obstructions that are located north of the array at azimuths between 305 degrees and 55 degrees from north relative to the most northerly points on the PV array need not be considered as shading obstructions*.

The PV installer and the verifier may verify through visual inspection that most obstructions above the roof meet the 2:1 criterion. For obstructions that visual inspection indicates potentially do not meet the criterion, the PV installer and verifier shall measure the height and distance of the obstruction(s) relative to the PV array as described above to verify that the 2:1 shading criterion is met. A tolerance of ± 5 percent will be permissible when determining the ratio.

Accounting for Actual Shading

When a PV installation does not meet the minimal shading criterion, it can still qualify for an incentive and participate in the program, but the shading conditions for each PV system at the site must be accounted for in the expected performance calculation as described in this section.

If shading (other than shading that meets the "minimal shading" criterion) is accounted for in the expected performance calculation, then the PV Calculator will produce on the Certificate of Compliance a table similar to Table 2 that shows the altitude angle between the PV array and obstructions that shade the PV modules. This table divides the compass into 22.5 degree segments, progressing clockwise around the compass from north. The altitude angle is the angle from the point on the lowest shaded point on the PV array to the highest point on the shading obstruction in each direction segment around the compass. The table also shows the distance-to-height ratio for existing obstructions including mature trees. This will be a number less than or equal to two, because if it is greater than two, the minimal shading criterion is satisfied in that direction and shading is not considered in the expected performance calculation for that segment. The table also shows the minimum distance to small, medium and large trees to meet the minimal shading criterion for trees that are not at their mature heights. The data in Table 2 is specific to a particular PV system installation on the specific residential building. In this example the minimal shading condition is exceeded for four segments of the compass, ESE, SSE, S and WNW.

The PV installer and the verifier shall verify that the shading conditions that exist (or are expected to exist in the case of the mature heights of trees in the landscaping plan or unbuilt residential buildings or structures on neighboring lots) at the site will not cause greater shading of the modules than the shading characteristics that were used in the expected performance calculations.

Table 2 – Example Certificate of Compliance Format for PV Shading

Orientation	Obstruction Type	Altitude Angle to Shading Obstruction	Distance to Height Ratio	Minimum Distance to Small Tree	Minimum Distance to Medium Tree	Minimum Distance to Large Tree
ENE (55 – 79)	NA	Minimal Shading	2.00	16	46	76
E (79 -101)	NA	Minimal Shading	2.00	16	46	76
ESE (101 – 124)	Neighboring structure	45 degrees	1.00			
SE (124 – 146)		Minimal Shading	2.00	16	46	76
SSE (146 – 169)	On roof obstruction	50 degrees	0.84			
S (169 – 191)	Tree (existing-mature)	70 degrees	0.36			
SSW (191 – 214)		Minimal Shading	2.00	16	46	76
SW (214 – 236)	Tree (existing-not mature)	30 degrees	1.5			
WSW (236 – 259)		Minimal Shading	2.00	16	46	76
W (259 – 281)		Minimal Shading	2.00	16	46	76
WNW (281 – 305)	Tree (planned)	65 degrees	0.49			

Measuring Heights and Distances or Altitude Angles

One of the following procedures may be used to measure heights and distances or altitude angles to obstructions.

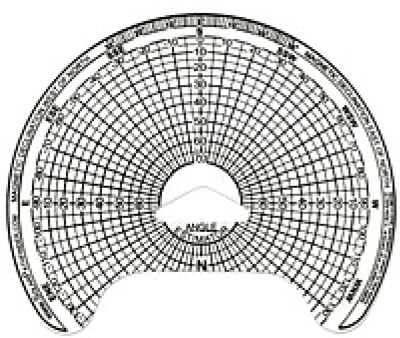
Using a Tape Measure
The simplest measurement technique is to use a tape measure or other measuring device to measure the distance from the point on the PV module to the worst shading condition point on obstructions in each 22.5 degree compass segment. The distance to a tree that has not reached its mature height is measured to the nearest edge of the trunk of the tree. Once the elevation difference (H) and distance (D) are determined in each compass segment, the ratio is calculated and must be greater than the value used in the expected performance calculation as reported on the Certificate of Compliance (see the third column in Table 2 labeled Distance to Height Ratio). This method can be employed from the ground without access to the roof, when factoring in the roof top dimensions from construction drawings.

Using a Digital Protractor
A digital protractor (see Figure 1) may be used to measure the altitude angle. The measured altitude angle must be smaller than or equal to that used in the expected performance calculation as reported on the Certificate of Compliance (see the second column of Table 2). To use the digital protractor measurement directly, the measurement must be made from the roof. Alternatively, the digital protractor measurement may be made from the ground and trigonometric adjustments will be required to adjust for the height difference between the ground where the measurements are made and the point of maximum shading of the PV modules in that compass segment.

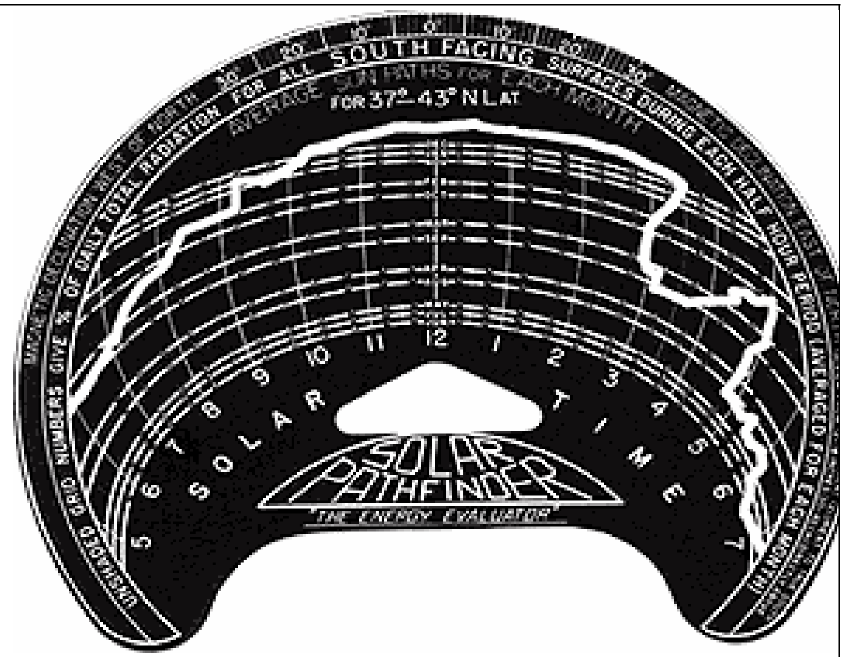
Using a Solar Access and Shading Analysis Instrument
For shading from existing obstructions, such as neighboring buildings or other structures, terrain or already mature trees, on-site shading conditions can be verified using an instrument such as the Solar Pathfinder (see Figure 6). This instrument shall be positioned at the point on the PV array that has the maximum shading. Generally, this will be one of the two lower corners of the array, but depending on the conditions of the site, other locations may be subject to more shading by adjacent buildings or structures, trees, terrain or other obstructions. This procedure will typically be used by the PV installer, but the verifier may not have direct access to the array on a roof top and would rely on the adequacy of documentation by the installer to verify the shading in this case..

Once the instrument is placed at the point on the PV array that has the maximum shading, it is leveled and oriented with true north. The orientation may be determined by using the site plan or a compass as described above. Once the instrument is properly positioned, objects that will cast a shadow on the PV modules will be shown for the month and time of day when shading will occur (see Figure 7). These results are then converted into the format used by the PV Calculator, shown in Figure 7(b) by using an Angle Estimator grid overlay (shown in Figure 6) to determine the altitude angle of an obstruction in each compass segment. The installer shall attach the diagram shown in Figure 7(b) to the Installation Certificate form, along with photographic evidence of the shading shown on the instrument, the location of the instrument on the array, and the shading obstructions that are indicated on the instrument, for the verifier to verify the results shown on the diagram. The results determined by the instrument are compared to the data that was used in the expected performance calculations to ensure that there is not greater shading at the site than was used in the expected performance calculations.

Solar Pathfinder

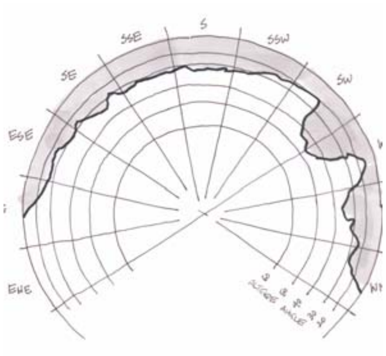


Angle Estimator grid overlay

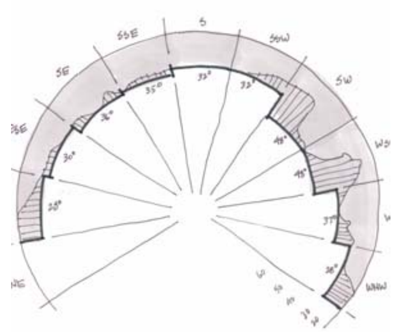


Traced obstruction outline example

Figure 6 – Example Solar Access and Shading Analysis Instrument



(a) This diagram shows the 22.5 ° compass segments used by the PV Calculator and the altitude angles.



(b) Within each compass segment, the highest altitude is selected and used for that entire segment. This data is input into the PV Calculator.

Figure 7 – Conversion of Results from Solar Pathfinder to PV Calculator Input

This method does not address expected shading resulting from the mature heights of planted or planned trees in the landscaping plan or expected construction of buildings or other structures on neighboring lots. Determining distances for planted trees should use a tape measure. Determining distances for planned trees should use the landscape plan provided by the builder. The height measurement for trees that are not yet mature shall be based on the Mature Tree Height discussed below. Determining the distances and heights of obstructions for buildings and structures that have not yet been constructed on neighboring lots shall be based on plans for those structures assuming that they will be located at the closest setbacks to the residential building that is being field-verified or the highest and closest dimensions allowed by zoning for future buildings on neighboring land.

Using a Digital Camera with Fisheye Lens
An electronic enhancement of the Solar Pathfinder uses a digital camera with a fisheye lens that is mounted looking up. An image is taken that is automatically processed to produce data similar to the solar pathfinder. The data must be converted to the format used for determining expected performance as described above for the Solar Pathfinder. Determining distances and heights for trees that are not yet at mature heights and unconstructed buildings and structures on neighboring lots must be addressed as described above for the Solar Pathfinder. The installer shall attach the diagram shown in Figure 7(b) to the Installation Certificate form, along with photographic evidence of the shading shown on the instrument, the location of the instrument on the array, and the shading obstructions that are indicated on the instrument, for the verifier to verify the results shown on the diagram. This method does not address expected shading resulting from the mature heights of planted or planned trees in the landscaping plan or expected construction of buildings or other structures on neighboring lots. Such shading shall be addressed separately.

Mature Tree Height

The expected performance calculations require the mature height to be used when accounting for the shading impact of planted and planned trees in the landscaping plan that have not yet reached their mature heights. This section provides guidelines for determining the mature height of such trees. Builders must identify the species of all planted and planned trees in the landscaping plans. That information shall be documented in conjunction with the Installation Certificate and provided to the verifier for verification.

All trees are classified as small, medium or large by species. Trees with a mature height of 20 feet or smaller are small trees. Trees with a mature height greater than 20 feet but less than 50 feet are medium trees. Trees with a mature height greater to or equal to 50 feet are large trees. If the type of tree is unknown, it must be assumed to be large. The mature heights of small, medium and large trees that must be used in the expected performance calculations are 20 feet, 35 feet, and 50 feet, respectively.

The Center for Urban Forestry Research of the U.S. Department of Agriculture's Forest Service has published tree guides for tree zones that are applicable to California. Table 3 shows the appropriate tree guide to use for each of California's climate zones for the expected performance calculations.

The guides provide tree selection lists for each tree zone. The lists provide either the mature height or the size category in that tree zone for each species. These tree guides are posted at [www.fs.fed.us/psw/programs/cufr/tree_guides.php].

For trees not listed in the tree selection tables of the tree guides, the Sunset Western Garden book should be consulted. This document provides the mature height range or maximum height for each species. If a range is given, the average of the maximum height range should be used to determine if the tree is large, medium or small.

Table 3 – Appropriate Tree Guide to Use for each California Climate Zone

CEC Climate Zones	Tree Regions	Tree Guide to Use	
1, 2, 3, 4, 5	Northern California Coast	Under Development (Use Sunset Western Garden Book)	
6, 7, 8	Southern California Coast	McPherson, E.G., et al. 2000. Tree guidelines for coastal Southern California communities. Sacramento, CA: Local Government Commission	Chapter 5, pages 57-65
9, 10	Inland Empire	McPherson, E.G., et al. 2001. Tree guidelines for Inland Empire communities. Sacramento, CA: Local Government Commission	Chapter 6, pages 65-82
11, 12, 13	Inland Valleys	McPherson, E.G., et al. 1999. Tree guidelines for San Joaquin Valley communities. Sacramento, CA: Local Government Commission	Chapter 5, pages 50-55
14, 15	Southwest Desert	McPherson, E.G., et al. 2004. Desert southwest community tree guide: benefits, costs and strategic planting. Phoenix, AZ: Arizona Community Tree Council, Inc.	Chapter 7, pages 51-53
16	Northern Mountain and Prairie	McPherson, E.G, et al. 2003. Northern mountain and prairie community tree guide: benefits, costs and strategic planting. Center for Urban Forest Research, USDA Forest Service, Pacific Southwest Research Station.	Chapter 5, pages 47-55

Table 4 shows the horizontal distance that trees of each mature height category would need to be located from nearest point of the PV modules in order to meet the condition of minimal shading.

Table 4 – Horizontal Distance Trees Would Need to be located from the Closest Point of a PV Array to Qualify for Minimal Shading

Mounting Location	Small Tree (20 ft)	Medium Tree (35 ft)	Large Tree (50 ft)
1 Story (Lowest Point of Array at 12 ft)	16	46	76
2 Story (Lowest Point of Array at 22 ft)	Any Distance	26	56
3 Story (Lowest Point of Array at 32 ft)	Any Distance	6	36

Verification of System Performance

The PV installer and verifier must verify that the AC output power from the PV system is consistent with that predicted by the PV Calculator. The PV Calculator will determine an estimate of system AC output power for a range of solar irradiance and outdoor air temperature conditions, and print a table on the Certificate of Compliance form. The values in the table will be 90 percent of the output estimated by the PV Calculator for each set of conditions in the table (the calculations also include the default adjustment of 0.88 for losses such as dirt, dust and mismatched wiring). An example of the data that will be produced is shown in Table 5. The data calculated by the PV Calculator is specific to each PV system.

Verification of system performance shall be performed after the PV system is installed and connected to the electricity grid. Measurements shall be made with a minimum irradiance of 300 W/m² in a plane parallel to the array. The PV installer and/or the verifier shall 1) measure the solar irradiance in a plane parallel to the array 2) measure the ambient air temperature and 3) determine the expected output power for the measured field conditions from the table on the Certificate of Compliance form. The PV installer or the verifier shall then observe the output AC power displayed on the inverter and verify that the output AC power is at least the amount shown in the table for the field measured conditions. To qualify for the NSHP, PV systems must have a performance meter or an inverter that has a built in meter that measures output AC power.

The PV installer and verifier shall observe the output AC power on the inverter after waiting for a five minute time period during which the measured solar irradiation level has stayed constant within ± 5 percent. If the solar irradiation level changes outside of these ranges during the five minute waiting period, the PV installer and verifier shall start over the five minute waiting period.

Table 5 – Example Table of Expected Output AC Power from PV Calculator (Watts)

(W/m^2)	T=15	T=20	T=25	T=30	T=35	T=40	T=45	T=50	T=55	T=60	T=65	T=70	T=75	T=80	T=85	T=90	T=95	T=100	T=105	T=110	T=115	T=120
300	614	606	599	591	584	576	568	560	553	544	536	528	520	512	504	496	487	479	471	463	454	446
325	665	657	648	640	632	623	615	607	598	590	581	572	564	555	546	537	528	519	510	501	492	483
350	716	707	698	689	680	671	662	653	643	634	625	616	606	597	588	578	569	559	550	540	530	520
375	766	757	747	738	728	718	708	699	689	679	669	659	649	639	629	619	609	598	588	578	568	557
400	817	807	797	786	776	765	755	745	734	723	713	702	691	681	670	659	648	637	626	615	604	593
425	868	857	846	835	824	813	802	790	779	768	757	745	734	722	711	699	688	676	664	653	641	629
450	918	907	895	883	872	860	848	836	824	812	800	788	776	764	752	739	727	715	702	690	677	665
475	967	955	943	931	919	907	894	882	869	856	843	831	818	805	792	779	766	753	740	727	714	700
500	1016	1004	991	978	966	953	940	927	913	900	887	873	860	846	832	819	805	791	777	763	750	736
525	1065	1052	1038	1025	1012	998	984	971	957	943	929	915	901	887	872	858	843	829	814	800	785	770
550	1113	1099	1085	1071	1057	1043	1029	1014	1000	986	971	956	942	927	912	897	882	866	851	836	820	805
575	1161	1147	1132	1117	1102	1088	1073	1058	1043	1027	1012	997	982	966	951	935	919	903	887	871	855	839
600	1209	1194	1178	1163	1147	1132	1116	1100	1085	1069	1053	1037	1021	1005	989	972	956	940	923	906	890	873
625	1256	1240	1224	1208	1192	1176	1159	1143	1126	1110	1093	1077	1060	1043	1026	1009	992	975	958	941	924	906
650	1302	1286	1269	1252	1236	1219	1202	1185	1168	1150	1133	1116	1098	1081	1063	1046	1028	1010	992	974	957	939
675	1348	1331	1314	1296	1279	1261	1244	1226	1208	1190	1172	1154	1136	1118	1100	1081	1063	1045	1026	1007	989	970
700	1394	1376	1358	1340	1322	1304	1285	1267	1248	1230	1211	1192	1174	1155	1136	1117	1098	1078	1059	1040	1021	1001
725	1439	1420	1401	1383	1364	1345	1326	1307	1288	1269	1249	1230	1210	1191	1171	1151	1132	1112	1092	1072	1052	1032
750	1483	1464	1444	1425	1405	1386	1366	1346	1327	1307	1287	1267	1246	1226	1206	1185	1165	1144	1124	1103	1082	1061
775	1526	1506	1487	1466	1446	1426	1406	1385	1365	1344	1323	1303	1282	1261	1240	1219	1198	1176	1155	1134	1112	1090
800	1569	1549	1528	1507	1486	1466	1445	1423	1402	1381	1360	1338	1317	1295	1273	1252	1230	1208	1186	1164	1141	1119
825	1611	1590	1569	1547	1526	1504	1483	1461	1439	1417	1395	1373	1351	1328	1306	1284	1261	1238	1216	1193	1170	1147
850	1653	1631	1609	1587	1565	1542	1520	1498	1475	1452	1430	1407	1384	1361	1338	1315	1292	1268	1245	1221	1198	1174
875	1693	1671	1648	1626	1603	1580	1557	1534	1510	1487	1464	1440	1417	1393	1369	1345	1322	1298	1273	1249	1225	1200
900	1733	1710	1687	1663	1640	1616	1593	1569	1545	1521	1497	1473	1449	1424	1400	1375	1351	1326	1301	1276	1251	1226
925	1772	1748	1725	1701	1676	1652	1628	1603	1579	1554	1529	1505	1480	1455	1430	1404	1379	1354	1328	1302	1277	1251
950	1811	1786	1762	1737	1712	1687	1662	1637	1612	1586	1561	1536	1510	1484	1459	1433	1407	1381	1354	1328	1302	1275
975	1980	1823	1798	1772	1747	1721	1696	1670	1644	1618	1592	1566	1540	1513	1487	1460	1434	1407	1380	1353	1326	1299
1000	1980	1980	1980	1807	1781	1755	1729	1702	1676	1649	1622	1595	1569	1542	1514	1487	1460	1432	1405	1377	1349	1322
1025	1980	1980	1980	1980	1815	1788	1761	1734	1706	1679	1652	1624	1597	1569	1541	1513	1486	1457	1429	1401	1372	1344
1050	1980	1980	1980	1980	1980	1820	1792	1765	1737	1709	1681	1653	1624	1596	1568	1539	1511	1482	1453	1424	1395	1365
1075	1980	1980	1980	1980	1980	1980	1823	1795	1767	1738	1709	1680	1652	1623	1593	1564	1535	1506	1476	1446	1417	1387
1100	1980	1980	1980	1980	1980	1980	1980	1825	1796	1766	1737	1708	1678	1648	1619	1589	1559	1529	1499	1468	1438	1407
1125	1980	1980	1980	1980	1980	1980	1980	1980	1824	1794	1764	1734	1704	1674	1643	1613	1582	1551	1520	1490	1458	1427
1150	1980	1980	1980	1980	1980	1980	1980	1980	1980	1822	1791	1760	1729	1698	1667	1636	1605	1573	1542	1510	1479	1447
1175	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1817	1786	1754	1722	1691	1659	1627	1595	1563	1530	1498	1466
1200	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1810	1778	1746	1714	1681	1649	1616	1583	1550	1517	1484

Measuring Solar Irradiance

Solar irradiance shall be measured by using a solar pyranometer. When making this measurement, the PV installer or verifier must place the pyranometer in a plane that is parallel to the PV modules. The PV installer should position the pyranometer on top of the PV modules or on the roof next to the PV modules. The verifier if they are not likely to be able to get on the roof shall position the pyranometer such that it is in full sun and is in plane that is parallel to the PV modules. Digital protractors or other instruments may be used to properly position the pyranometer.

Measuring Ambient Air Temperature

Ambient air temperature must be measured with a digital thermometer in the shade. The instrument must have an accuracy of ± 2^{o} C.

Observing Output AC Power at the Inverter

The PV installer and the verifier shall observe and record the reading within five minutes of the time the measurements of solar irradiation and ambient temperature were made. The inverter may cycle between multiple readings (total kWh of production, output power, etc.), so the PV installer or verifier will need to wait until the power is displayed and record this reading; several readings should be made to make sure that they are consistent and stable.

Multiple Orientation Arrays

For larger systems, PV modules connected to the same inverter may be installed with strings of equal numbers of modules connected in parallel in more than one orientation, each with its own tilt and azimuth (note that it is bad practice to install such strings in series or with a different number of modules in each string; either of these installations will lead to substantial reductions in performance). When strings are installed in multiple orientation arrays to the same inverter, separate Certificate of Compliance forms shall be prepared for each orientation, and solar irradiance shall be measured separately in a plane parallel to each string that has a different azimuth and tilt. The expected output AC power is determined separately for each condition and the sum is used for verification purposes.

For example a qualifying 3 kW PV system has 42 PV modules grouped in two parallel strings, one south (azimuth of 170 degrees) and one west (azimuth of

260 degrees). The south facing array has 21 PV modules and the west facing array has 21 PV modules connected in parallel to maintain system voltage. The verifier verified system performance at 11:30 AM in March and measured a solar irradiance of 950 W/m² in a plane parallel to the south array and 500 W/m² in a plane parallel to the west facing array. The ambient temperature at the time of the testing is 62^{o} F.

The expected AC output power table on the Certificate of Compliance indicates that the system should be producing 1,200 W at 950 W/m² and 700 W at 500 W/m² of solar irradiance. The expected output AC power to be compared to the inverter display is calculated to be 1,900 W based on the following equation.

$$\text{Expected AC Output Power (W)} = 1{,}200 + 700$$

$$= 1{,}900 \text{ W}$$

To test systems with multiple arrays the solar irradiance levels on all of the arrays must stay constant for the five minute waiting period discussed in Section G above.