CALIFORNIA
ENERGY
COMMISSION

GUIDELINES FOR CALIFORNIA'S SOLAR ELECTRIC INCENTIVE PROGRAMS (SENATE BILL 1)

SECOND EDITION

GUIDELINES

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Karen Douglas
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Melissa Jones
Executive Director

Smita Gupta
Payam Narvand
Supervisors

Bill Pennington
Smita Gupta
Patrick Saxton
Devorah Eden
Lynette Green
Joseph Fleshman
Principal Authors

Mark Hutchison
Manager
RENEWABLE ENERGY PROGRAM

Bill Pennington
Manager
BUILDINGS AND APPLIANCES

Valerie Hall
Deputy Director
EFFICIENCY AND RENEWABLE ENERGY

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Table of Contents

Abstract

According to Senate Bill 1, this document presents Guidelines for solar energy system incentive programs in California.

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. This legislation 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 publicly owned electric utilities.

Three specific expectations to be met to qualify for ratepayer-funded incentives are required by SB 1:

- High quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar.
- Optimal system performance during periods of peak demand.
- Appropriate energy efficiency improvements in new and existing homes and commercial structures where solar energy systems are installed.

Keywords

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

CHAPTER 1: Introduction

Senate Bill 1 (SB 1)[1] 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.[2] According to SB 1, this document establishes minimum guidelines to implement California's solar energy system incentive programs overseen by the Energy Commission, the California Public Utilities Commission (CPUC) and local publicly owned electric utilities (POUs). These Guidelines are not intended to serve as the sole requirements for solar energy system incentive programs.[3] Other requirements specific to the Energy Commission, CPUC and POU programs are expected to be addressed and delineated in their respective program guidebooks or handbooks.

The entities implementing these solar energy system incentive programs under SB 1 are referred to in this document, as "program administrators."[4] The solar energy system incentive program administrators must incorporate the requirements in this document as part of their respective program guidebooks or handbooks.

This document covers these topics:

- 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 electric utilities.

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[1] SB 1 (Murray, Chapter 132, Statutes of 2006, § 4) as codified in Public Resources Code sections 25780 – 25784. SB 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] Public Resources Code Section 25781(e) defines solar energy systems subject to these Guidelines as follows: "Solar energy system" means a solar energy device that has the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity, that produces at least 1 kilowatt (kW), and not more than 5 megawatts (MW), alternating current rated peak electricity, and that meets or exceeds the eligibility criteria established under Section 25782.

[3] These Guidelines do not apply to incentives for solar thermal and solar water heating devices covered by Public Utilities Code Section 2851(b).

[4] Note that the term "program administrator" is used by many to refer to the entity (generally a utility or third party) that is responsible for day-to-day processing of applications, payment requests, and related tasks.

SB 1 directs the Energy Commission, in consultation with the CPUC, POUs, and 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 directed in these Guidelines.** This includes solar energy system incentive programs established by the CPUC (California Solar Initiative), the Energy Commission (New Solar Homes Partnership) and programs administered by California's POUs.

Background

SB 1 is the culmination of Governor Schwarzenegger's "Million Solar Roofs Initiative" and builds on the CPUC's California Solar Initiative (CSI) program,[5] the Energy Commission's New Solar Homes Partnership (NSHP), and existing publicly owned utility solar energy system incentive programs. SB 1 directs total expenditures 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 that in 10 years solar energy systems are a viable mainstream option for homes and commercial buildings, and in 13 years to put 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 combined with improved energy efficiency in the state's residential and non-residential buildings.

Three specific expectations established by SB 1 must be met for the ratepayer-funded incentives:

- High-quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar.
- Optimal system performance during peak demand periods.
- 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, several principles were described in the *2005 Integrated Energy Policy Report* (IEPR). These principles include:

- Leveraging energy efficiency improvements should be a primary consideration in deploying PV systems. 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

[5] "California Solar Initiative" often refers to all of the various solar incentive programs in the state and addressed in SB 1, including programs administered by the CPUC, the Energy Commission, and the POUs. In this report, it is used to refer specifically to the CPUC's program that includes solar energy system incentives for new and existing commercial and existing residential customers served by San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company.

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 to 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 IEPR*. The loading order establishes the following priority for the development of energy resources: 1) energy efficiency and demand response, 2) renewable energy resources and distributed generation, and 3) clean, fossil fuel, central-station generation. The Governor highlighted the importance of the Million Solar Roofs Initiative and the aggressive pursuit of all cost-effective energy efficiency, consistent with the loading order in his energy policy to the Legislature.

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, Núñez, Chapter 488, Statutes of 2006) and the Climate Action Initiative – AB 32 reinforced Governor Schwarzenegger’s Executive Order S-3-05 placing 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 to expand energy efficiency, coupled with increased installation of photovoltaic systems.

- Energy Efficiency Goals and Resource Procurement – Senate Bill 1037 (SB 1037, Kehoe, Chapter 366, Statutes of 2005) and Assembly Bill 2021 (AB 2021, Levine, Chapter 734, Statutes of 2006) directed electricity corporations subject to the CPUC’s authority and local publicly owned electric utilities, respectively, to first meet their 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) directed agencies to reduce state building electricity use by 20 percent by 2015, using all cost-effective measures described in the Green Building Action Plan, and strongly encourage commercial building owners to take aggressive action to reduce electricity use with the same measures. The GBI urged the CPUC to apply its energy efficiency authority to improve commercial building energy efficiency by the 20 percent goal.

- The CPUC's October 18, 2007, Decision 07-10-032, reaffirmed the *Energy Action Plan* commitment to the loading order and states California's highest priority is to increase energy efficiency measures. Through this decision, the CPUC adopted goals for new residential construction to be net zero energy by 2020 and new commercial construction to be net zero energy by 2030. The CPUC concluded that energy efficiency must become "business as usual" if the state is to meet growing energy demand and combat global warming.

To meet all the policy directives, the goal of the SB 1 incentive programs is to create a self-sustaining market for solar buildings using high levels of energy efficiency and high performing solar energy systems. Combining high levels of energy efficiency and high solar energy system performance maximizes the major SB 1 investments, helps reduce greenhouse gas emissions, and maximizes the value of solar industry's products and services to California ratepayers and consumers.

These Guidelines establish eligibility criteria, conditions for incentives and rating standards that align California's solar energy system incentive programs to meet the SB 1 goals.

Schedule

Under SB 1, the Energy Commission must establish eligibility criteria, conditions for incentives, and rating standards, by January 1, 2008. SB 1 also directs the CPUC and the POUs to implement solar energy system incentive programs for ratepayers subject to their respective jurisdiction by January 1, 2008. The solar energy system incentive programs established by the CPUC and POUs must be consistent with the directives of SB 1, and meet these Guidelines.

As discussed in the Energy Commission's August 2007 staff report[6] *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 system incentive programs to conform with all of the eligibility criteria, conditions, and rating standards established in these Guidelines.

These Guidelines create minimum program requirements to be met by January 1, 2008 (Chapter 2) and allow for up to an 18-month transition period for full compliance with all the eligibility criteria, conditions, and rating standards described in Chapters 3 through 5. Chapter 6 applies only to publicly owned utilities and the requirement must be met annually beginning June 1, 2008. All program administrators must conform their programs as necessary to these Guidelines no later than July 1, 2009, except as noted. Program administrators may voluntarily conform to the Guidelines before that date and are encouraged to do so to the extent feasible. These requirements shall apply only to new incentive applications that are received on or after a program administrator has implemented these requirements. Applications submitted to solar energy system incentive programs for incentives before January 1, 2008, are not required to comply with these Guidelines.

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

POUs with peak demand of 200 MW or less as reported for calendar year 2006 are required to comply with Chapters 2, 3, and 6 only for 2008. These POUs may delay implementing the requirements in Chapters 4 and 5; however, they must comply with the requirements as described in Chapters 4 and 5 no later than January 1, 2010.

Audits

Senate Bill 1 requires the Energy Commission to conduct annual random audits of solar energy systems to evaluate their operational performance[7]. To carry out this requirement, the Energy Commission will work closely with the program administrators.

[7] Public Resources Code, Section 25783(d).

CHAPTER 2: Minimum Program Requirements

This chapter describes the minimum solar program requirements established in SB 1 and by the Energy Commission to be met by solar energy system incentive program administrators no later than January 1, 2008.

Program administrators shall comply with the requirements covered in Chapters 3 through 5 regarding solar energy system component standards, system design and installation standards, and energy efficiency requirements no later than July 1, 2009. POUs with peak demand of 200 MW or less as reported for calendar year 2006 shall comply with the requirements in Chapters 4 and 5 no later than January 1, 2010.

Solar Energy System Definition

As specified by the statutory definition,” solar energy systems” eligible for financial incentives covered by these Guidelines must have the primary purpose of providing for the collection and distribution of solar energy for electricity generation. Solar energy systems must produce at least 1 kilowatt (kW), and not more than 5 megawatts, alternating current(AC) rated peak electricity, accounting for all system losses, and meet or exceed the eligibility criteria established in these Guidelines.[8]

Eligible solar technologies must primarily generate electricity. For these Guidelines, “PV” refers to flat-plate non-concentrating photovoltaic modules and “other solar electric generating technologies” refers to all solar electric generating technologies except flat-plate non-concentrating photovoltaic modules.

These Guidelines do not apply to solar thermal and solar water heating devices that do not primarily generate electricity, but that qualify for the CPUC’s incentive program as specified in Public Utilities Code Section 2851(b).

Declining Incentives

Solar energy system incentives must decline at a rate of no less than an average of 7 percent per year and must be reduced to zero by the end of 2016.[9]

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

[9] Public Utilities Code, Section 387.5 (b), and Public Utilities Code Section 2851(a)(1).

Incentive Level for Publicly Owned Utilities

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

System Location and Grid Interconnection

The solar energy 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.[10]

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.[11] Additions to existing systems are only allowed for systems that met program requirements at the time of installation and were partially funded by program administrators in accordance with SB 1 and these SB 1 guidelines. For these existing systems, the program administrators have records and documentation identifying the equipment that was installed previously, the program warranty, and the system equipment standards and warranties that were met by the originally installed equipment. The newly added generating equipment shall be selected from the current lists of eligible equipment and meet the current requirements, including the requirement for a 10-year warranty. All of the current program eligibility criteria and documentation requirements apply to the added equipment.

All major solar energy system components eligible for ratepayer funding under SB 1[12] shall be included on the Energy Commission's Eligible Equipment Lists. This includes PV modules, other solar electric generating technologies, inverters, and meters. PV modules currently listed on the Energy Commission's Go Solar California website [http://www.GoSolarCalifornia.org/equipment/pvmodule.php] may be considered eligible for incentives only between January 1, 2008, and June 30, 2009. Beginning July 1, 2009, these PV modules will need to complete the testing requirements of Chapter 3 to continue eligibility. Requirements for other solar electric generating technologies are also in Chapter 3. Information on solar energy system components can be found at [http://www.GoSolarCalifornia.org].

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

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

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

Performance Meter

All solar energy systems shall 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.[13]

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.[14] The minimum size of an eligible system is 1 kW_{AC}, accounting for all system losses.[15] 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 10-year warranty to protect against defects and undue degradation of electrical generation output.[16] The 10-year warranty requirement is optional for stand-alone performance meters. Program administrators have discretion over how the 10-year warranty provisions are implemented under their respective solar programs.

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.[17] Chapter 4 of this report establishes installation standards which shall be complied with no later than July 1, 2009, except where noted. In the interim, the Energy Commission recommends that program administrators strongly encourage applicants for solar incentives to follow these installation Guidelines as much as possible.

All eligible systems shall be installed by individuals with a current A, B, C-10, or C-46 contractor license. Roofing contractors with a current C-39 license may place PV panels in accordance with the limitations of their license; however, electrical connections shall not be

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

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

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

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

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

made by a roofing contractor. North American Board of Certified Energy Practitioners (NABCEP) certification of installers is encouraged, though not required. Systems may be self-installed by the purchaser (owner).

Energy Efficiency

Chapter 5 of this report establishes energy efficiency requirements, which shall be complied with no later than July 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.

CHAPTER 3: Solar Energy System Component Standards

This chapter establishes rating standards for equipment, components, and systems to assure reasonable performance in accordance with SB 1.[18] Setting rating standards and guidelines to ensure the quality of systems and components is critical to a successful solar incentive program and to ensure incentives are given to high-performing systems. The three main components that are subject to standards and ratings specific to PV installations are the modules, inverters, and meters. Until the equipment is tested and listed by the Energy Commission, applications specifying the equipment are not eligible for incentive payment.

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.

The requirements in this chapter shall be implemented by solar energy system incentive program administrators no later than July 1, 2009.

Photovoltaic Modules

Eligible PV modules[19] shall be required to provide testing data from independent laboratories to ensure safety and high-quality data on module performance in the field. This data shall also be used to calculate the expected performance of the system. Eligible modules are listed with the Energy Commission.[20]

The PV module eligibility requirements are as follows:

- Modules shall be certified to UL 1703 by a Nationally Recognized Testing Laboratory[21] (NRTL) to ensure safety and reliability.

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

[19] For these Guidelines, "PV" refers to flat-plate non-concentrating photovoltaic modules.

[20] Modules currently eligible under these requirements are listed under the NSHP eligible modules list [http://www.GoSolarCalifornia.org/builders/equipment.html]. Modules previously listed as eligible with the Energy Commission on the following website [http://www.GoSolarCalifornia.org/equipment/pvmodule.php] must meet the testing requirements specified in Chapter 3 before July 1, 2009 to be eligible for programs implementing these Guidelines.

[21] 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 1703

- Detailed performance data shall be reported and certified using the subsections of International Electrotechnical Commission (IEC) Standard 61215 or 61646 (depending on the type of PV system) at an International Laboratory Accreditation Corporation (ILAC) accredited laboratory.[22]

- 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 currently listed photovoltaic modules shall fulfill the eligibility criteria testing requirements by July 1, 2009, to qualify as eligible equipment; thereafter, the listing will be updated monthly.[23] *Between January 1, 2008 and June 30, 2009, 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.*

Other Solar Electric Generating Technologies

Other solar electric generating technologies[24] shall be eligible for performance-based incentives (PBI) only.[25]

Eligible products shall provide a full safety certification with follow-up service or listing from a Nationally Recognized Testing Laboratory (NRTL).[26] Approval of products shall require an investigation to determine whether any existing standards or portions of existing standards are applicable, and/or whether development of new test protocols is necessary. Determination of applicability of existing standards and development of new test protocols shall be performed by

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under the scope of their OSHA recognition. A list of all current Nationally Recognized Testing Laboratories is available on OSHA's web page at [http://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 1703.

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

[23] 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.

[24] For these Guidelines, "other solar electric generating technologies" refers to all solar electric generating technologies except flat-plate, non-concentrating photovoltaic modules.

[25] Future updates of these Guidelines will consider inclusion of expected performance-based incentives (EPBI).

[26] Nationally Recognized Testing Laboratories must be approved to conduct test UL 1703 or UL 1741 under the scope of their OSHA recognition. Please note, not all of the Nationally Recognized Testing Laboratories identified on OSHA's list are approved to conduct test UL 1703 or UL 1741.

a NRTL. Manufacturers shall submit all new test protocols to the Energy Commission for review. The Energy Commission reserves the right to challenge the adequacy of test protocols for eligibility listing. If inadequacies are determined, the Energy Commission will consult the NRTL and manufacturer, but may ultimately not approve the eligibility listing if inadequacies are not resolved.

Additionally, each manufacturer shall work with the appropriate program administrator to determine suitable estimates of capacity and energy production before reserving funds.

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.

Eligible inverters are listed with the Energy Commission.[27]

The following are inverter eligibility requirements:

- Inverters shall be certified to UL 1741 standards by a Nationally Recognized Testing Laboratory (NRTL)[28].

- 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[29]" by a NRTL shall be reported for each inverter.

When an inverter is integral to and wholly contained within a solar electric generator, the inverter shall not be required to be separately certified to UL 1741 if UL 1741 testing is performed as part of a full safety certification by a NRTL for the solar electric generator.

[27] Inverters eligible under these requirements are listed with the Energy Commission at [http://www.GoSolarCalifornia.org/equipment/inverter.php].

[28] Nationally Recognized Testing Laboratories must be approved to conduct test UL 1741 under the scope of their OSHA recognition. Please note, not all of the Nationally Recognized Testing Laboratories identified on OSHA's list are approved to conduct test UL 1741.

[29] This document can be found at [http://www.energy.ca.gov/renewables/02-REN-1038/documents/2004-12-01_INVERTER_TEST.PDF].

Meters

Performance meters,[30] whether stand alone or integrated with the inverters, shall be required to meet the following eligibility criteria:

- Meters with ± 2 percent accuracy are required 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.
- Beginning January 1, 2010, inverter-integrated meters shall be tested to ± 5 percent accuracy in accordance with the "5% Accuracy Certification Requirements and Testing Procedures for Inverter-Integrated Meters"[31] by a NRTL.
- All meters shall measure and display both instantaneous power (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).

Eligible meters are listed with the Energy Commission.[32]

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[30] The CPUC's CSI Program is considering proposed requirements related to metering for solar electric displacing incentives and for 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 these Guidelines will consider these and subsequent recommendations.

[31] This test protocol can be found at [http://www.GoSolarCalifornia.org].

[32][http://www.GoSolarCalifornia.org/equipment/meter.php]

CHAPTER 4: Solar Energy System Design and Installation Standards and Incentives

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 the Guidelines for design and installation standards and incentives needed to achieve this mandate. Program administrators shall comply with these Guidelines by **no later than July 1, 2009.** POUs with peak demand of 200 MW or less as reported for calendar year 2006 shall comply with the requirements in this chapter no later than January 1, 2010.

To achieve high performing solar energy systems, the incentive structures shall be performance-based to reward performance. There are two acceptable performance-based approaches: the performance-based incentive (PBI) approach and the expected performance-based incentive (EPBI) approach. These are discussed further in this chapter.

Performance-Based Incentives

Providing a PBI[33] is the preferred way to promote high performing systems since the solar energy systems receive incentives based on their actual production (kWh) over the period during which the incentives are being paid. The PBI incentive payment is calculated by multiplying the incentive rate ($/kWh) by the measured kWh output.

The PBI payments shall be made over a minimum five-year period following system installation, submission, and approval of incentive claim materials. Payments shall be based on a $/kWh incentive rate and the actual electricity (kWh) produced in periods established by the program administrator.

Expected Performance-Based Incentives

The expected performance-based incentive (EPBI) approach pays an upfront 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. This incentive method may be more appropriate than a PBI approach for systems installed on newly constructed buildings or

[33] As an example, the CPUC's California Solar Initiative program requires larger solar energy systems (e.g., those 100 kW_{AC} or larger capacity beginning in 2007) to use PBI. The CSI program also requires PBI for systems 50 kW_{AC} and larger beginning January 1, 2008, and for systems 30 kW_{AC} and larger beginning January 1, 2010. Projects below these size thresholds may voluntarily use the PBI approach.

for smaller systems. The EPBI approach shall be used for systems that do not use the PBI approach.

To meet the expectations of SB 1 for optimal system performance during periods of peak demand and IEPR policy to target PV deployment to achieve the greatest cost benefit, EPBI shall be based on time-dependent value (TDV) weighted hourly generation.[34]

The EPBI calculation shall be based on hourly modeling of the interactive performance of solar energy systems using the third-party tested performance characteristics of the specific modules and the inverter over the range of conditions that impact component performance. This calculation addresses all installation characteristics that are expected to have significant impacts on the performance of the components and the solar radiation, ambient temperature, and wind conditions expected at the site.

The hourly performance of the system shall be based on the interaction of the components due to the expected conditions during each hour. The hourly production shall be weighted in each hour to account for the time-dependent value to the utility of that hour's production to obtain the annual time-dependent weighted energy results for the system (kWh_{TDV}). The total incentive for the solar energy system is based upon the annual kWh_{TDV} performance.

Hourly Photovoltaic Production Calculation

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

- The calculation model shall cover fixed flat-plate collector technologies at a minimum and include single- and dual-axis tracking if the program administrators allow for these technologies to be incentivized under the EPBI approach.[35]
- Use hourly weather data for one of the 16 climate zones in California, with the use of solar radiation (global horizontal, direct normal and diffuse), dry bulb temperature, and wind speed as minimum parameters in calculation to describe the conditions for the hour.
- 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.
- 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

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

[35] Systems employing tracking may be offered incentives using the PBI approach as an alternative to developing a calculation of expected performance for these systems.

weather and electrical). This data shall be obtained from the library of eligible modules listed with the Energy Commission.

- 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 each string and the number of strings.
- Account for the mounting offset of the array from a surface below to assess the change in operating temperature (Normal Operating Cell Temperature impact). This is especially important to determine the performance of building-integrated photovoltaics (BIPV), as compared to rack-mounted modules.
- Account for the height above the ground that the array is mounted to capture the impact of wind speed on the module operating temperature.
- 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.[36]
- Limit the production of the system based on the size and voltage of the array and inverter voltage and power capacity.
- Generate hourly estimates of PV production for the entire year, which can then be weighted by time-dependent value (TDV) multipliers.
- 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).
- Determine the hourly impact of shading from obstructions using a shading protocol as described in Shading Verification, Appendix 2.
- 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 nonresidential).
- 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.
- Generate a certificate of compliance form as a printable report[37]. The certificate of compliance shall include, at a minimum, the entire system description including installation specifics for the system, location, shading details, echo all the inputs for the calculation, and the performance verification table.

[36] The list of eligible inverters referred here is the list maintained by the Energy Commission at [http://www.GoSolarCalifornia.org/equipment/inverter.php].

[37] A program administrator may choose not to require the submission of this compliance certificate along with the incentive application.

Reference System and Location

The incentive calculation shall use a reference system and location established by the program administrator to convert an incentive level established in terms of \$/W to the $\$/kWh_{TDV}$ equivalent through the following calculation:

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

The specification of the reference system shall include:[38]

- Location of the system to determine the weather data and corresponding applicable TDV factors to be used.
- Size of a system that is representative of the median in the applicable utility program.
- 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.
- Selection of an inverter from the Energy Commission's Eligible Equipment List that is considered a median for the applicable utility program.
- The installation characteristics that comprehensively describe the system, including, but not limited to:
  - Azimuth
  - Tilt
  - Mounting offset (BIPV or rack with specific height above substrate)
  - Height above ground (one story or higher)
  - Electrical circuit design (modules per string and number of strings)
  - Shading conditions (minimal shading)
  - Other system losses (such as dirt, dust, and wiring losses)

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

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)[39].

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[38] For an example of a reference system specification, see the Energy Commission's *New Solar Homes Partnership Guidebook* at [http://www.GoSolarCalifornia.org/documents/CEC-300-2007-008-CMF.PDF]

[39] The program administrator may adopt a tolerance of ± 5 percent for approving total incentive payments. The program administrator may allow variations in incentives amount among the incentive application, field verified performance and payment claim requests up to this tolerance.

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

The basic structure of the Energy Commission's PV calculator[40] can be used to meet these requirements. The calculator can be modified or another calculator used, as long as it meets requirements 1 through 15 of the Hourly Photovoltaic Production Calculation. The reference system and location and the incentive level is specified by the program administrator. POU program administrators may use time of use multipliers that are applicable to their service territories instead of TDV.

EXCEPTION: The CPUC and POU Program Administrators are not required to comply with the above Hourly Photovoltaic Production Calculation requirements by July 1, 2009. The CPUC should determine whether it believes that changes should be made to the CPUC's CSI calculation methods and under what timeframe it would make changes. POU Program Administrators may choose to use a calculation method that complies with the Hourly Photovoltaic Production Calculation requirements or the expected performance based incentive calculation method used by the CPUC. The Energy Commission strongly encourages the CPUC's CSI program to upgrade its current methods for estimating the expected performance of solar electric generating systems to better promote high-quality solar energy systems with maximum system performance to promote the highest energy production per ratepayer dollar and to achieve optimal system performance during periods of peak electricity demand. The Energy Commission recommends that as the CPUC upgrades its calculation methods, it endeavors to meet the hourly photovoltaic production calculation provisions of these guidelines. POU Program Administrators who choose to use the CPUC's expected performance based incentives calculation method are expected to use improved versions that are updated to better meet the hourly photovoltaic production calculation provisions. The CPUC shall comply with the shading, performance verification, and field verification requirements of these guidelines.

Shading

The method that shall be used as the minimum criteria for addressing shading is detailed in Appendix 2-Field Verification and Diagnostic Testing of Photovoltaic Systems.

[40] The current implementation of the Energy Commission PV calculator is a spreadsheet-based tool and runs the five-parameter PV model to determine the hourly production. The calculator will be made available upon request to any program administrator.

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 IOU generation, transmission and distribution cost data.[41]

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

Field Verification

To be eligible for incentive payment, EPBI applicants and PBI applicants whose systems are smaller than 50 kW shall be required to successfully complete third-party field verification on a sampling basis. Field verification is encouraged for other PBI applicants. The field verification, at a minimum, shall include visual inspection of components, installation characteristics, and shading conditions. For EPBI systems only, performance shall be verified 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, the program administrator, or a designated qualified contractor, as determined by the program administrator.

Installation

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.

EXCEPTIONS: The program administrator may waive the installer requirement to follow the field verification protocol under any one of the following conditions:

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

1. The program requires field verification on 100 percent of the systems (without using sampling approach).
2. The installer follows the alternate protocol described in Installer System Inspection, Appendix 2, and signs a certificate of having completed the same.

Performance Monitoring and Maintenance

All systems using the PBI approach shall have a five-year service contract[42] with a performance monitoring and reporting service (PMRS).[43]

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

For all systems, it is recommended that program administrators ensure that information regarding system maintenance is provided to the owner or facility manager of the property who has oversight of the system. The information should address, at a minimum, the following considerations:

- Cleaning schedule for the array to remove dirt and dust buildup.
- Periodic checking of electrical connections (for corrosion, and so forth).
- 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 how to minimize or eliminate that shading.

[42] The applicant has the option of switching PMRS providers during this period, if necessary, but must demonstrate that the minimum five-year term of PBI payments is covered through one or another PMRS provider.

[43] The CPUC's CSI program is currently developing requirements related to the specification of the data streams. These requirements will be considered for possible future updates to these guidelines.

CHAPTER 5: Energy Efficiency

This chapter specifies energy efficiency requirements that shall be met as conditions for ratepayer-funded incentives for newly constructed and existing residential and commercial buildings. The chapter identifies separate energy efficiency requirements for each type of building. As an alternative to meeting these requirements for specific buildings, program administrators may choose to use the Alternative Portfolio Energy Savings Approach described at the end of this chapter. The energy efficiency requirements specified in this chapter are minimum requirements. Program administrators are encouraged to promote greater levels of energy efficiency as they find feasible.

Program administrators shall comply with the requirements in this chapter **no later than July 1, 2009.** Publicly owned utilities (POUs) with peak demand of 200 MW or less as reported for calendar year 2006 shall comply with the requirements in this chapter no later than January 1, 2010.

Newly Constructed Buildings

Minimum energy efficiency criteria beyond California's Building Energy Efficiency Standards (Title 24, Part 6) shall be conditions for the solar energy system incentive programs overseen by the CPUC, the Energy Commission, and POUs for all newly constructed buildings statewide.[44]

Residential Buildings

Newly constructed residential buildings shall achieve higher energy efficiency levels than the requirements of the Building Energy Efficiency Standards (Title 24, Part 6) in effect at the time the application for a building permit is submitted.

For building permits submitted before August 1, 2009 the applicant is required to meet 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 2005 Title 24 Standards.[45]

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[44] Newly constructed buildings are ones for which the building permit for the solar energy system is approved prior to the original occupancy of the newly constructed structure.

[45] Tier I was developed to match the energy efficiency requirements of the New Construction Programs for investor-owned utilities such as those implemented by PG&E, SCE, and SDG&E.

- 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 space cooling energy compared to the 2005 Title 24 Standards.[46]

For building permits submitted on or after August 1, 2009, the applicant is required to meet 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 2008 Title 24 Standards.[47]
- Tier II – 30 percent reduction in the residential building's combined space heating, space cooling, and water heating energy and 30 percent reduction in the residential building's space cooling energy compared to the 2008 Title 24 Standards.[48]

The Tier I level is a minimum condition for participation. Tier II is the Energy Commission's preferred level that builders are encouraged to meet. For either Tier I or II, each appliance provided by the builder shall be ENERGY STAR®[49] labeled if this designation is applicable for that appliance.

Solar water heating may be used to assist in meeting the energy efficiency requirements of either Tier I or Tier II.[50]

Field verification of energy efficiency measures shall be required and be consistent with Title 24 Standards field verification procedures and protocols in effect at the time the application for a building permit is submitted. The CF-1R[51] form used to demonstrate Title 24 compliance with the current Building Energy Efficiency Standards shall be provided with the solar incentive application to the program administrator as proof of attainment of the Tier I or Tier II level. Compliance

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[46] Tier II was developed to encourage builders to go beyond the minimum requirements of Tier I. Tier II efficiency level was developed to match the Building America program requirements.

[47] Tier I was developed to match the energy efficiency requirements of the California Green Building Standards (Title 24, Part 11).

[48] Tier II was developed to encourage builders to go beyond the minimum requirements of Tier I. Tier II efficiency level was developed to achieve energy efficiency best practices to align with the *Integrated Energy Policy Report (IEPR)* and the California Public Utilities Commission (CPUC) Strategic Plan initiatives.

[49] ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy. An ENERGY STAR designation is available for appliances that exceed minimum federal energy efficiency standards. For more information on the ENERGY STAR designation, go to [http://www.energystar.gov].

[50] For more information on using solar water heating to meet the energy efficiency requirements, please refer to the Go Solar California website [http://www.GoSolarCalifornia.org/builders/solar_water_heating.html].

[51] This Certificate of Compliance form summarizes the minimum energy performance specifications needed for compliance including the results of the heating and cooling load calculations.

documents shall be completed by persons who are Certified Energy Plans Examiners (CEPE) by the California Association of Building Energy Consultants (CABEC).
Investor-owned utilities (IOUs) fund energy efficiency programs through a public goods charge (PGC) with program oversight by the CPUC. POUs conduct and oversee their own energy efficiency programs. IOUs and POUs are strongly encouraged to provide energy efficiency incentives for each tier described in these Guidelines.

Commercial Buildings

Newly constructed commercial buildings[52] shall achieve higher energy efficiency levels than the requirements of the Building Energy Efficiency Standards (Title 24, Part 6) in effect at the time the application for a building permit is submitted.

For building permits submitted before August 1, 2009 the applicant is required to meet 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 2005 Title 24 Standards.[53]

- Tier II – 30 percent reduction in the commercial building's combined space heating, space cooling, lighting and water heating energy compared to the 2005 Title 24 Standards.[54]

For building permits submitted on or after August 1, 2009, the applicant is required to meet 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 2008 Title 24 Standards.[55]

- Tier II – 30 percent reduction in the commercial building's combined space heating, space cooling, lighting, and water heating energy compared to the 2008 Title 24 Standards.[56]

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[52] For these guidelines, "commercial buildings" include all non-residential buildings and structures.

[53] Tier I was developed as the minimum level of participation to match the Leadership in Energy and Environmental Design (LEED) New Construction Energy and Atmosphere prerequisite.

[54] Tier II was developed to encourage developers to go beyond the minimum requirements of Tier I. Tier II is in line with the 2030 Challenge [http://www.architecture2030.org].

[55] Tier I was developed as the minimum level of participation to match the energy efficiency requirements of the California Green Building Standards (Title 24, Part 11)

[56] Tier II was developed to encourage developers to go beyond the minimum requirements of Tier I. Tier II energy efficiency level was developed to achieve energy efficiency best practices to align with IEPR and CPUC Strategic Plan initiatives.

The Tier I level is a minimum condition of participation. Tier II is the Energy Commission's preferred level that builders are encouraged to meet. For either Tier I or II, any equipment or appliance provided by the builder shall 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.[57]

Compliance documents used to demonstrate Title 24 compliance, including the PERF-1 form[58] 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 Certified Energy Plan Examiners (CEPE) by the California Association of Building Energy Consultants (CABEC).

For 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 be made between the building owner[59] and the tenant. This agreement shall obligate future tenant improvements to install lighting, HVAC, and water heating equipment necessary to meet the overall building tier level that was committed to by the building owner. A copy of the agreement shall be included with the solar energy system incentive application.

Investor-owned and publicly owned electric utilities are strongly encouraged to provide energy efficiency incentives for each tier described in these Guidelines.

Existing Buildings

Energy Audit, Information, and Disclosure

Specific information about energy efficiency measures shall be provided to the building owner. The intent of the information is for the person who is responsible for paying the utility bill and the person who is responsible for building operations to receive information on: 1) their building's energy use, 2) energy efficiency investigation options for their buildings, and 3) possible energy efficiency improvements. These persons may not be the same entity for all applications. For these Guidelines, these persons are referred to as the building owner/manager/ratepayer.

[57] For more information on using solar water heating to meet the energy efficiency requirements, please refer to the Go Solar California website [http://www.GoSolarCalifornia.org/builders/solar_water_heating.html].

[58] The PERF-1 form is the Performance Certificate of Compliance that is produced by compliance software used to show compliance with Title 24.

[59] An agreement may be made with a developer/property manager and the tenant.

The program administrator or the utilities covered by the program administrators shall provide information to the building owner/manager/ratepayer before the design and installation of any proposed photovoltaic system to enable the building owner/manager/ratepayer to make informed decisions on energy efficiency investments. The building owner/manager/ratepayer shall sign and provide to the program administrator a copy of the signed disclosure that certifies that this information was provided to him 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/manager/ratepayer shall declare on the disclosure when the measures are expected to be installed.[60]

For existing commercial buildings with conditioned floor area of less than 100,000 square feet and for existing residential buildings, an energy efficiency audit shall be conducted. The program administrator may allow on-line or telephone audits or may require onsite energy audits, as they specify for particular categories of customers. Building owners, managers, and/or ratepayers shall be responsible for submitting a copy of the audit results with their solar incentive applications. The information and disclosure shall be provided to the building owner/manager/ratepayer via a Web-based information portal or paper format. The building owner/manager/ratepayer shall complete and sign the disclosure form and submit a copy to the program administrator.

Information to Be Provided to the Building Owner/Manager/Ratepayer:

- Most recent 12 months of the building's energy consumption—this information may be provided directly by the utility; if so, the program administrator is obligated to assure only that it was provided.
- List of building energy use assessment services and tools available for use by the building owner for further investigation—for commercial buildings this shall include information on available retrocommissioning services.
- List of possible cost-effective energy efficiency measures applicable to the building.
- List of current utility energy efficiency rebates and incentives that are available.

Disclosures to Be Signed by the Building Owner/Manager/Ratepayer and Submitted With the Solar Incentive Application:

- Certification that the building owner/manager/ratepayer has received the above information.
- The energy use assessment services or tools the building owner/manager/ratepayer used to identify cost-effective energy efficiency measures that could be installed in the building.

[60] The data gathered as a result of the information and disclosure process will be used to develop future energy efficiency requirements for solar energy system incentive programs.

- 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.
- A copy of the energy audit report for existing residential buildings and commercial buildings less than 100,000 square feet.

Existing Commercial Buildings – Benchmarking, Retrocommissioning 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[61] using Portfolio Manager or the equivalent energy performance rating for building types that cannot receive a rating by Portfolio Manager. Portfolio Manager can be accessed on the Internet at [https://www.energystar.gov/istar/pmpam/].

Building types that are not able to receive an energy performance rating using Portfolio Manager, shall be benchmarked using the Energy Commission's equivalent energy performance rating system.[62]

Retrocommissioning

Retrocommissioning[63] shall be required for all existing commercial buildings that are 100,000 square feet or larger and have a benchmark rating of less than 75, or an equivalent energy performance rating as determined by the Energy Commission. Retrocommissioning is required to

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

[62] The Energy Commission is working with US EPA on an equivalent rating system that can be used to benchmark commercial buildings not able to be rated using Portfolio Manager.

[63] Retrocommissioning is a process to identify how major energy using equipment is 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. For further information regarding the benefits of retrocommissioning, see the *California Commissioning Guide: Existing Buildings*, California Commissioning Collaborative, 2006 at [http://www.cacx.org/resources/documents/CA_Commissioning_Guide_Existing.pdf].

begin no later than one year after the completion of the installation of the PV system. Systems to be retrocommissioned include but are not limited to:

- Heating, ventilation, and air conditioning systems and controls.
- 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 retrocommissioning assessment shall be implemented to improve the building's energy performance rating. If a building is improved to exceed a rating of 75, further energy efficiency measures are not required. A building does not need to be re-benchmarked to receive an incentive. 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. IOUs and POUs are strongly encouraged to provide energy efficiency incentives for retro-commissioning and for the installation of cost effective energy efficiency measures, appliances and equipment.

Commitment Agreement

For buildings equal to or larger than 100,000 square feet and with a benchmark or equivalent energy performance rating of less than 75, retrocommissioning, equipment repairs and adjustments, and energy efficiency improvements that are identified through a retrocommissioning assessment shall either be completed prior to or in conjunction with the installation of the solar energy system. Alternatively, retrocommissioning shall be committed to be completed at a later date by the building owner/manager/ratepayer through a Commitment Agreement. The Commitment Agreement shall indicate when the retrocommissioning will begin, and commit the owner/manager/ratepayer to complete equipment adjustments, or cost-effective efficiency improvements identified in the retrocommissioning assessment. The retrocommissioning shall begin no later than one year after the completion of the installation of the PV system.

Energy Efficiency Exceptions for Existing Commercial Buildings

The 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 benchmark rating 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.
- The energy audit, benchmarking and retrocommissioning are not required for buildings that have complied with Title 24 requirements for newly constructed buildings during the last 12 months prior to applying for the solar energy incentive; proof of Title 24 compliance shall be included with the solar energy system incentive application.
- Retro-commissioning is not required for existing commercial buildings that have a current ENERGY STAR label.
- Retrocommissioning is encouraged but not required for PBI applicants.

Existing Residential Buildings

For solar energy systems serving an existing residential building, the energy audit, information, and disclosure requirements shall be met as discussed above.

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 before application for a solar energy incentive; 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 design and conduct a program that achieves a total 20 percent energy efficiency savings over the group of EPBI participants in their SB 1 participation portfolio. This alternative enables program administrators to pursue different levels of energy efficiency with different program participants 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 their progress in achieving a total 20 percent energy efficiency savings over the group of EPBI participants in their 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 to the program administrator 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 at 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 the previous sections of this chapter for any particular EPBI participating buildings in their SB 1 portfolio and establish an alternative portfolio energy savings plan covering just the remaining EPBI participating buildings. For example, a program administrator may conform to the requirements in the previous sections for newly constructed buildings, both residential and commercial, and establish an alternative portfolio energy savings plan just for existing EPBI participating 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 shall be made available, beginning June 1, 2008, to its utility customers, the California State Legislature, and the Energy Commission.[64] This information shall be made available no later than June 1 of **each** subsequent year for the duration of the 10-year program.

These reporting requirements will provide state officials the information needed to monitor how these programs are progressing, ensure consistent program design and implementation, and determine what changes may be needed to effectively meet goals and targets established under SB 1.

Reporting Requirements Beginning in 2009

For years 2009 and later, the reporting period shall be from January 1 to December 31 of the prior year. Each POU shall report the following information.

1. Solar program overview and contribution toward goals, including:
   a. Outreach and marketing, overview of program administration and activity during reporting period
   b. Problems identified and resolutions or recommended mitigation
   c. Opportunities for the year ahead

2. Number of submitted applications, including:
   a. Number of applications received
   b. Number of EPBI and PBI applications approved and rejected/cancelled
   c. Primary reasons for application rejections/cancellations

3. Total incentives awarded, including:
   a. Total solar funds collected for the life of the program
   b. Total solar incentive expenditures, by category (reserved/awarded, paid, administration, marketing)

4. The total number of systems installed, including:
   a. Breakdown for installations serving newly constructed buildings (Tier I vs. II, if available) and existing buildings
   b. Breakdown by category type, including:
      1. Residential

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

    a) Market-rate housing
    b) Affordable housing/low-income
2. Commercial
3. Nonprofit
4. Government
5. Industrial
6. Agricultural
7. Mixed-use

5. Amount of added solar capacity installed and expected generation:
    a. For PV systems, the solar electric capacity added in kilowatts (kW_{AC}) and the estimated annual electrical generation in kilowatt hours (kWh)
    b. For other solar electric generating systems, the solar electric capacity added in kilowatts (kW_{AC}), the estimated annual electrical generation in kilowatt hours (kWh), and a description of the specific technology deployed

6. Program support activities and goals, including:
    a. Any training or builder/installer assistance, if available
    b. Auditing of installed systems, if available
    c. Goals in kilowatts (kW_{AC}) for program duration, if available.

Each local publicly owned electric utility shall submit 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].

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.

Photovoltaic Modules

All flat plate PV modules shall be certified by a Nationally Recognized Testing Laboratory[65] as meeting the requirements of and being listed to be in conformance to the Underwriters Laboratory (UL) Standard 1703.

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

[65] Nationally Recognized Testing Laboratories must be approved to conduct test UL 1703 under the scope of their OSHA recognition. Please note, not all of the Nationally Recognized Testing Laboratories identified on OSHA's list are approved to conduct test UL 1703.

10.7 Performance at Low Irradiance
10.18 Light-Soaking

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, Under UL 1703, Section 48.2, shall be no less than 95 percent of the Maximum Power reported to the Energy Commission.

The performance data and information in Table 1 shall be certified and provided to the Energy Commission. This data may be made available to the public. For multiple model numbers, data may be grouped together as described below.

Table 1. Module Performance Parameter Testing

Parameter	**Symbol**	**Units**	**Notes**
Maximum Power	P_{max}	Watts	1, 7
Voltage at maximum power	V_{pmax}	Volts	1, 7
Current at maximum power	I_{pmax}	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_{Vpmax} (at V_{pmax}) α_{Isc} (at I_{sc}) α_{Ipmax} (at I_{pmax}) γ_{Pmax} (at P_{max})	%/°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 maximum power and NOCT	V_{NOCT}	Volts	5, 6
Current at maximum power and 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 July 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 July 1, 2009, the provision of this data is optional.
7) Prior to July 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 July1, 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.

Grouping of modules for testing purposes

For testing and reporting of performance values by an ILAC accredited laboratory, families of similar modules may be grouped together to reduce the required number of tests.

Multiple model numbers may be included in a group, provided that the models are identical except for the STC power rating. Identical applies to all of the following, but is not limited to: all materials, processes (including cell process), cell technology, cell size, encapsulation system, superstrate, backsheet/substrate, cell interconnection materials and techniques, and internal electric circuitry.

For each group, the following tests shall be performed on a model number that has a STC power rating that is within 95 percent (rounded to the nearest Watt) of the highest STC power rating in the group:

1. Nominal Operating Cell Temperature (NOCT) determination
2. Temperature coefficient of short-circuit current
3. Temperature coefficient of open-circuit voltage
4. Temperature coefficient of maximum power current
5. Temperature coefficient of maximum power voltage
6. Temperature coefficient of maximum power

Each group can be further categorized into subgroups where one model number will have further testing performed. All model numbers included in the subgroup shall have the same number of cells. The subgroup may contain model numbers such that the highest STC power rating in the subgroup is 105 percent (rounded to the nearest Watt) of the subgroup's tested model number's STC rating and the lowest STC power rating in the subgroup is 95 percent (rounded to the nearest Watt) of the subgroup's tested model number's STC rating. The tested model number in each subgroup shall be tested for:

At STC:

1. Short-circuit current
2. Open-circuit voltage
3. Current at maximum power
4. Voltage at maximum power
5. Maximum power

At maximum power and NOCT:

1. Current
2. Voltage

At maximum power and low irradiance:

1. Current
2. Voltage

Example: If a manufacturer has a family of identical modules with STC power ratings of 160 W, 165 W, 170 W, 175 W, 180 W, 185 W, 190 W, 195 W, and 200 W, the following testing is required. For the 190 W module, NOCT determination and temperature coefficient testing shall be performed. The results from these tests are applicable to the entire group of modules. Subgroups can then be created as follows:

185 W, 190 W, 195 W, and 200 W
170 W, 175 W, and 180 W
160 W and 165 W

For the 190 W, 175 W, and 160 W modules, the specified voltage, current, and maximum power testing at the following conditions shall be performed: STC, NOCT, and low irradiance. The results from these tests are applicable to the modules in the respective subgroup.

Inverters

All inverters shall meet the requirements of UL 1741. Certification to UL 1741 is required unless otherwise noted in Chapter 3. Each model of inverter shall be tested by a qualified Nationally Recognized Test Laboratory[66] to be eligible for this program. Performance ratings for each model will be determined according to sections of the test protocol titled *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

[66] Nationally Recognized Testing Laboratories must be approved to conduct test UL 1741 under the scope of their OSHA recognition. Please note, not all of the Nationally Recognized Testing Laboratories identified on OSHA's list are approved to conduct test UL 1741.

Technology, October 14, 2004, version[67] 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://www.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 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.

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[67] 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.

Meters

All eligible meters shall comply with the requirements 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. Beginning January 1, 2010, inverter-integrated meters shall be tested to ± 5 percent accuracy in accordance with the "5% Accuracy Certification Requirements and Testing Procedures for Inverter-Integrated Meters"[68] by a NRTL.

- Meter Certification: Meter accuracy ratings shall be certified by a NRTL. 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.

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[68] This test protocol can be found at [http://www.GoSolarCalifornia.org].

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. At this time, it addresses systems that use fixed flat plate collector technology.[69] 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, performance, and shading estimation are consistent with the characteristics used to determine the estimated performance. The EPBI incentive amount is based on the expected performance of the solar system, which accounts for the tested and certified performance of the specific modules and inverter, the mounting type, cell temperature, the orientation and tilt of the modules, and the extent to which the system is shaded. A calculator tool will account 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 production, 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 the estimated performance. Field verification can be carried out by a HERS rater or the program administrator (or their designated qualified contractor).

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

- PV array and inverters used in the expected performance calculations are actually installed at the applicable site.
- PV array is minimally shaded, or if shaded, that the actual shading does not exceed the shading characteristics that were included in the expected performance calculations.
- Measured AC power output from the system matches the expected AC power output table at the prevailing conditions at the time of field verification and diagnostic testing.

[69] 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 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. The third-party field verification shall be conducted on a minimum sample of 1 in 7 systems.

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. For rooftop systems, the measurements required by this protocol are not required to be completed on the roof, but more accurate measurements are possible with roof access. The measurements required by the protocol may be performed in multiple ways as described in the subsections below.

EXCEPTIONS: The program administrator may waive the installer requirement to follow the field verification protocol under any one of the following conditions:

1. The program requires field verification on 100 percent of the systems (without using sampling approach).
2. The installer follows the alternate protocol described in the Installer System Checkout section later in this appendix, and signs a certificate of having completed the same.

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[70]. Documentation of the process uses three forms that are counterparts to the compliance forms used for the *Building Energy Efficiency Standards*.

1. The applicant enters the necessary input data into a 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

[70] This definition of a solar system is applicable for field verification purposes as outlined in this appendix only and not for program administration purposes related to system size or program participation criteria. Multiple systems, such as micro-inverter-based systems, may be grouped for field verification using the sampling approach.

predicted AC power output for each system over a range of solar irradiance 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 either the field verification and diagnostic testing protocol or the alternate 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[71].

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 shall provide to the installer and verifier a site plan that for each lot:

   a) Identifies the height category (small, medium, or large) 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.

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

   EXCEPTIONS: A program administrator may exempt the following requirements for all retrofit projects (residential and non-residential):
   1. Site plan showing property lines.
   2. Identification of unknown future trees.
   3. Identification of neighboring structures that are not already constructed or that are unknown to be planned for construction in the future.

[71] The installer certificate shall be submitted to the program administrator if the field verification is the responsibility of the program administrator and assigned to a field verifier thereafter.

5. 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 modules, inverter, and meter specified in the Certificate of Compliance are 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, shall rely on a conservative determination based solely on their own observation.

Photovoltaic Modules

The PV installer and the verifier shall confirm 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 confirm 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 confirm 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 confirm 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 confirm 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***[72]. 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 confirmed.

Determining Tilt
The tilt angle of the PV modules is measured in degrees from the horizontal (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.

[72] Program administrators may choose a tighter tolerance for their program.

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 confirm 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; north azimuth is zero degrees, east is 90 degrees, south is 180 degrees and west is 270 degrees (see Figure 2).

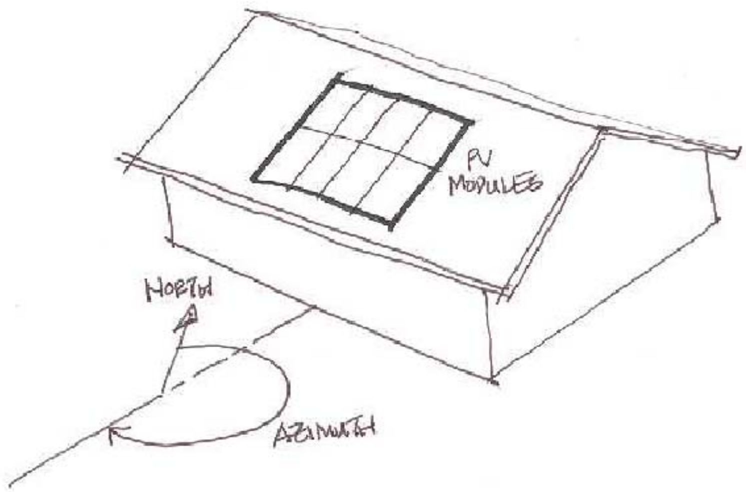


Figure 2 – Azimuth of the PV Array

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.

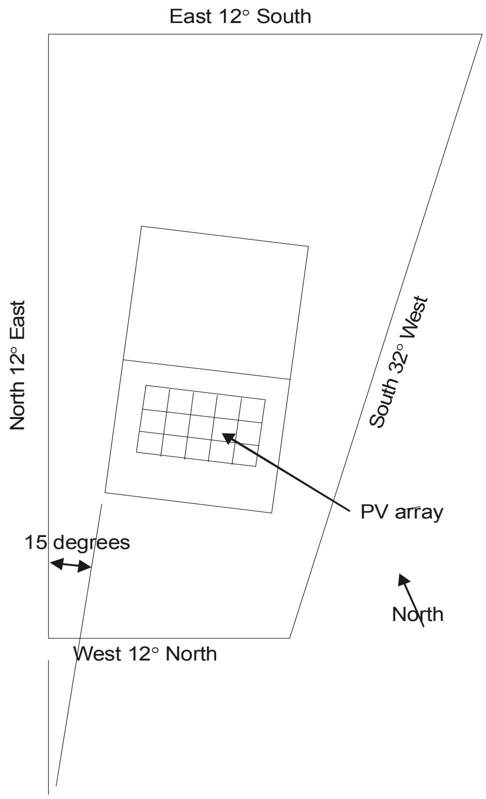


Figure 3 – Example Plot Plan

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 [http://www.ngdc.noaa.gov/geomagmodels/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

Shading of photovoltaic systems, even partial shading of arrays, can be the most important cause of failure to achieve high system performance. Significant shading should be avoided whenever possible. Shading can be avoided by careful location of the array at the point of installation or in some cases, particularly during the process of constructing buildings, by moving obstructions to locations where they do not cast shading on the array. Partial shading from obstructions that are relatively close to the array, particularly obstructions that are on the roof even if they are relatively small, can be particularly problematic because they cause partial shading of the array for longer time periods of the year. Shading caused in the future due to the maturing of trees that are immature at the time of installation of the PV System can also be a major cause of failure to achieve high performance over the life of the PV system.

The PV installer and the verifier shall confirm that the shading conditions on 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 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 array (see Figure 5 for an artistic depiction of "H" and "D"). As the figure illustrates the distance "D" shall be at least two times greater than the distance "H." Any obstruction that projects above the point on the PV array that is closest to the obstruction shall 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 is on the roof or any other part of the building.
ii. Any part of the neighboring terrain.
iii. Any tree that is mature at the time of installation of the solar system.
iv. Any tree that is planted on the building lot or neighboring lots or planned to be planted as part of the landscaping for the building (the expected shading shall be based on the mature height of the tree).
v. Any existing neighboring building or structure.
vi. Any planned neighboring building or structure that is known to the builder or building owner.
vii. Any telephone or other utility pole that is closer than 30 feet from the nearest point of the array.

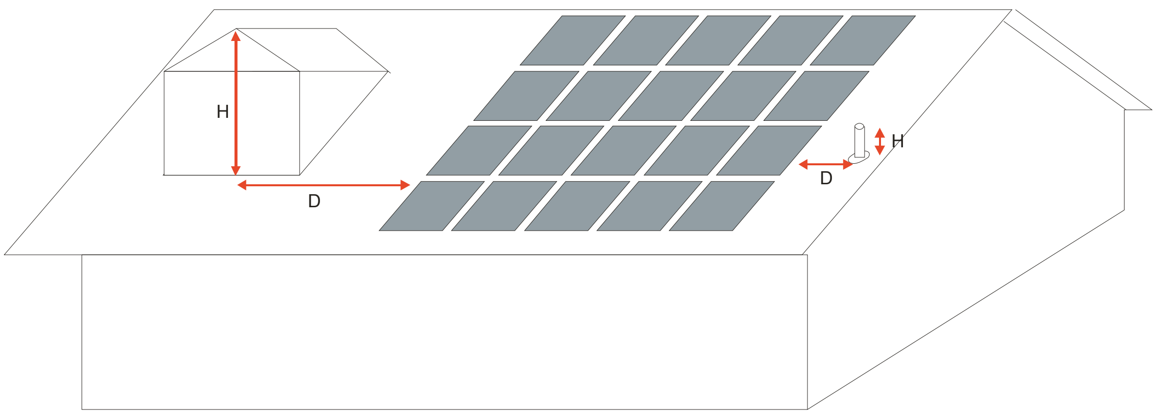


Figure 5 – The Minimal Shading Criterion - Artistic Depiction of "H" and "D"

To determine whether or not the minimal shading criterion is met, the PV installer and the verifier shall determine for each shading obstruction the smallest ratio of the horizontal distance from the obstruction to the array divided by the vertical height of the obstruction above that point on the array (this is the "closest point on the array"). Often the point on the obstruction that results in the smallest ratio is the topmost point of the obstruction, but in cases where the shape of the obstruction is complex, points on the obstruction that are not the topmost but are closer to the array may actually produce the lowest ratio. "H" is the vertical height of the shading obstruction point above the horizontal projection to the closest point on the array. "D" is the horizontal distance from the closest point on the array to the vertical projection from the point on the obstruction that results in the lowest ratio of "D" divided by "H." *Any obstruction located north of all points on the array need not be considered as shading obstructions*. When an obstruction is north of some parts of an array but east, south or west of other parts of the array, the minimal shading criterion shall be determined to the closest point on the array that is west, north or east of the obstruction.

The PV installer and the verifier may confirm through visual inspection that all obstructions meet the 2:1 criterion (note that an altitude angle of 26.5 degrees is equivalent to 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 (or a lower than 26.5 altitude angle through the same points on the obstruction and array) is met. A tolerance of ± 5 percent will be permissible when determining the ratio (or the altitude angle).

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 shall be accounted for in the expected performance calculation as described in this section. The basic method is used when the shading condition is measured using a tape measure or using a digital protractor. A different method is used when measurements are made with a solar assessment tool.

When a tape measure or digital protractor is used to measure shading obstructions that are accounted for in the expected performance calculation, the calculator will produce on the Certificate of Compliance a table similar to Table 2 that shows the distance to height ratio and altitude angle for the closest point on the array for each obstruction including mature trees that shades the PV array. This table divides the compass into 11 (approximately 22.5 degree) sectors, progressing clockwise around the compass from north. The table provides the distance to height ratio and altitude angle for each sector of the compass. When there is more than one obstruction in a sector, the information is reported for the obstruction with the lowest distance to height ratio (highest altitude angle). The distance to height ratio 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 sector. 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. In this example the minimal shading condition is not met for five sectors of the compass, ESE, SSE, S, SW and WNW.

The PV installer and the verifier shall confirm that the shading conditions that exist (or are expected to exist in the case of the mature heights of trees that are planted on the building lot or neighboring lots or planned to be planted as part of the landscaping for the building or planned buildings or structures on the building lot or neighboring lots that are known to the builder or building owner) at the site will not cause greater shading of the modules than the shading characteristics that were used in the expected performance calculations.

EXCEPTION: Program administrators may waive the requirement to account for future shade in the expected performance calculations for all solar projects on residential and nonresidential existing buildings on the condition that a copy of a disclosure statement is provided to the building owner and program administrator that identifies existing trees on the building site and adjoining sites that are smaller than 50 feet, which may cast potential future shade that would reduce future system performance.

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. Program administrators may determine the allowable tolerance related to field verification of these measurements for their specific programs. One reason for this tolerance is to account for the potential for user error when measurement tools are used.

Using a Tape Measure

A tape measure or other measuring device may be used to measure the distance ("D") from the point on the PV array corresponding to the lowest ratio of distance to height ("H") for each shading obstruction for each 22.5 degree compass sector. 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 height difference("H") and distance ("D") are determined in each compass sector, the ratio is calculated and shall be greater than the value used in the expected performance calculation as reported on the Certificate of Compliance (see the fourth 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.

The height measurement for trees that are immature shall be based on the Mature Tree Height discussed below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures.

Using a Digital Protractor

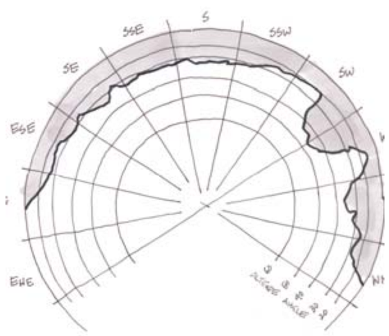
A digital protractor (see Figure 1) may be used to measure the highest altitude angle from the obstruction to the closest point on the array (using the same points on the array and on the obstruction that produce the lowest ratio of "D" to "H" if those dimensions were measured instead of the altitude angle). The measured altitude angle for each obstruction in each compass sector shall be smaller than or equal to that used in the expected performance calculation as reported on the Certificate of Compliance (see the third column in Table 2). To use the digital protractor measurement directly, the measurement shall be made from the roof. Alternatively, the digital protractor measurement may be made from the ground and trigonometric adjustments will be required to correct for the height difference between the ground where the measurements are made and the point of maximum shading of the PV array in that compass sector.

This method does not address expected shading resulting from the mature heights of planted immature trees or planned trees. To determine distances for planted immature trees a tape measure should be used. The height measurement for trees that are immature shall be based on the Mature Tree Height discussed below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures.

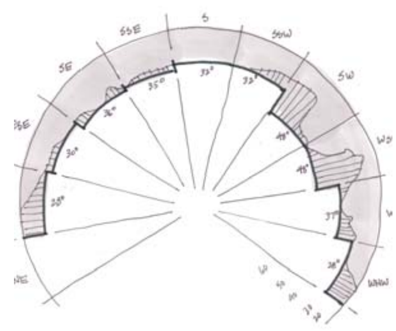
Using a Solar Assessment Tool

For shading from existing obstructions shading conditions may be verified using a solar assessment tool. This procedure will typically be used by the PV installer, but the verifier may not have direct access to the array and if not, would rely on the adequacy of documentation by the installer to confirm the shading conditions.

At each point of measurement, the tool is placed on the PV array, leveled and oriented consistent with the manufacturer's instructions. Once the tool is properly positioned, it will determine the obstructions that cast shade and the month and time of day when shading will occur. The tool will enable these determinations either through the use of a digital photograph or a manual tracing on an angle estimator grid overlay. These results for a single point of reference on the array are converted into a format that can be used by the calculator, either through software provided by the tool manufacturer or manually, as shown in Figure 6(b), to determine the altitude angle of an obstruction in each compass sector.



(a) This diagram shows the 22.5 ° compass sectors used by the PV Calculator and the altitude angles determined by a Solar Assessment Tool for a single point of reference on the array.



(b) Within each compass sector, the highest altitude angle is selected and used for that entire sector. This data is shown for a single point of reference on the array.

Figure 6 – Conversion of Results from Solar Assessment Tool for a Single Point of Reference on the Array

Measurements shall be made at all the major corners of the array with no adjacent measurement being more than 40 feet apart (see example in Figure 9). The points of measurement shall be distributed evenly between two major corners if they are more than 40 feet apart such that the linear distance between any sequential points is no more than 40 feet. However, if any linear edge of the array has no obstructions that are closer than two times the height they project above the closest point on the array, then the intermediate measurements along that edge do not need to be made.

1. The altitude angles measured at each major corner shall be overlapped onto a single diagram or processed with the tool manufacturer's software. The maximum altitude angles measured at any of the major corners of the array within a given sector shall be applied to the entire sector. This creates a set of 11 values which are used in the PV calculation (see Figure 7).

Azimuth	Altitude angle
ENE (55 – 79)	64
E (79 -101)	58
ESE (101 – 124)	40
SE (124 – 146)	27
SSE (146 – 169)	28
S (169 – 191)	34
SSW (191 – 214)	32
SW (214 – 236)	30
WSW (236 – 259)	17
W (259 – 281)	15
WNW (281 – 305)	50

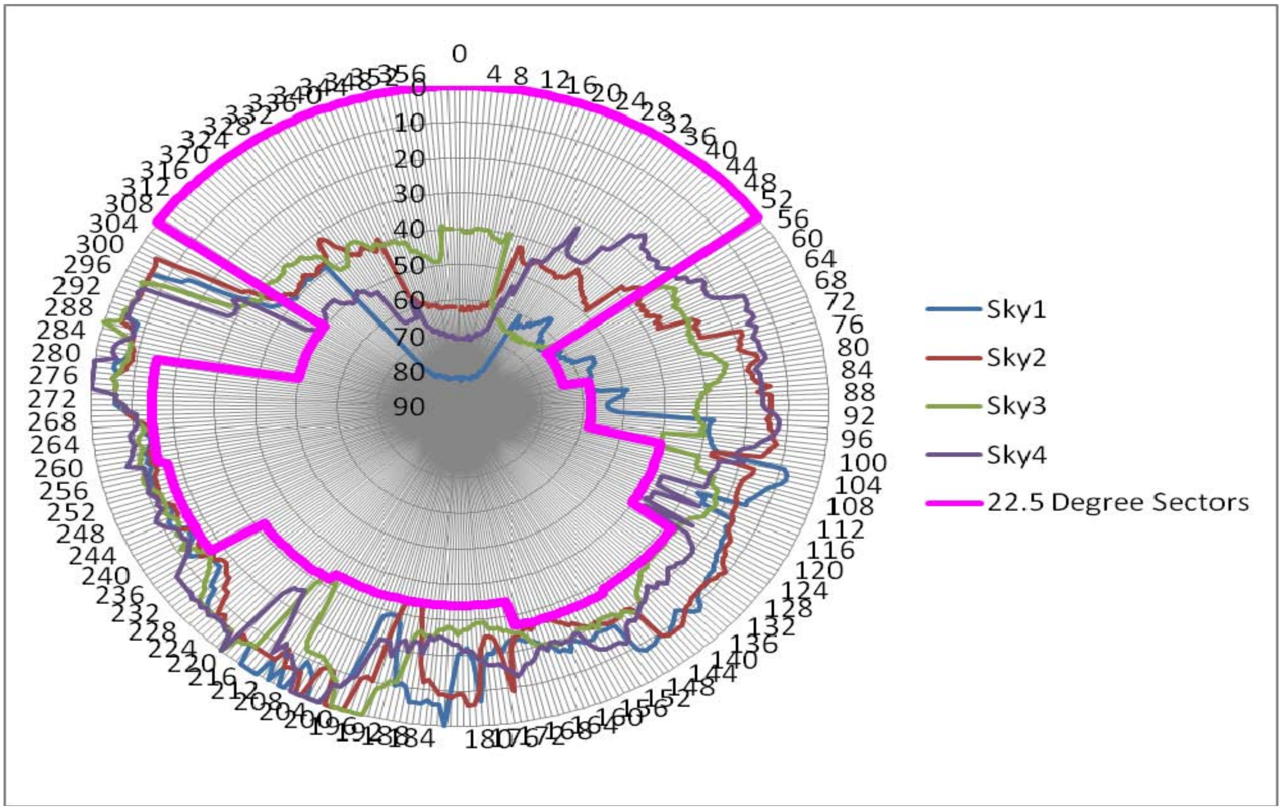


Figure7 – Example of Combining the Maximum Altitude Angle in the 11 Compass Sectors for 4 Different Points on the Array.

2. Alternatively, the maximum altitude angle measured at each of the major corners of the array may be reported for each 1 degree increment of the azimuth. This would create a set of 360 values, one for each degree of the compass orientation. These values may be electronically transferred to the calculator depending on the implementation by the program administrator.

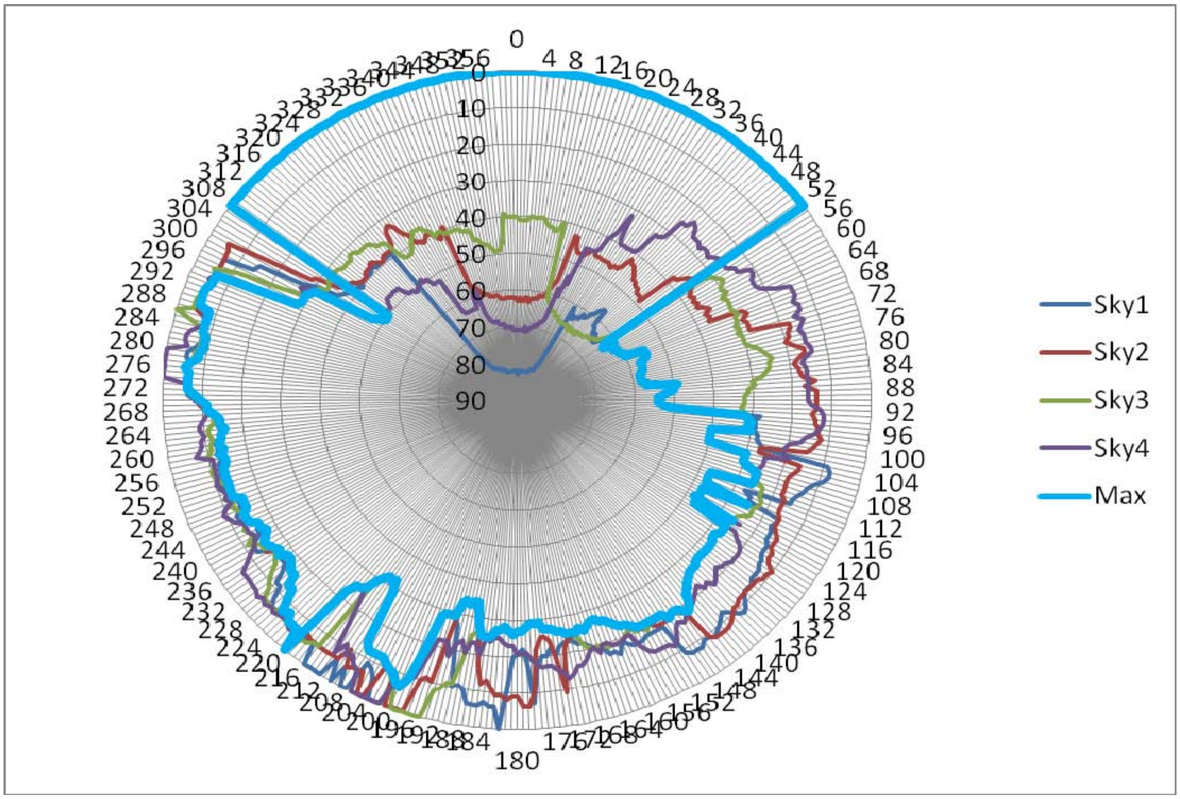


Figure 8 – Example of Combining the Altitude Angles Measured at 4 Different Points on the Array on a Per Degree Azimuth Increment

The installer shall attach the diagram shown in Figure 8 to the Installation Certificate form, along with photographic evidence of the shading shown on the tool, the location of the tool on the array, and the shading obstructions that are indicated on the tool, 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 immature trees or planned trees or expected construction of buildings or other structures on neighboring lots. To determine distances for planted immature trees a tape measure should be used. The height measurement for trees that are immature shall be based on the Mature Tree Height discussed below. Determining the distances and heights of obstructions for buildings and structures that are planned but have not yet been constructed shall be based on plans for those structures. Such shading shall be addressed separately.

The results determined by the tool in combination with the expected future shading described above 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.

Measuring Solar Availability

As an alternative to measuring heights and distances or altitude angles, program administrators may allow the use of solar availability as a method to estimate the shading impact on hourly production. The following methodology shall be followed when the solar availability is used in a calculator. Program administrators may determine the appropriate tolerance related to this methodology for field verification purposes. One reason for this tolerance is to account for the potential for user error when measurement tools are used.

Using a Solar Assessment Tool

The measurements shall be made at all the major corners of the array with no adjacent measurement being more than 40 feet apart (see example in Figure 10). The points of measurement shall be distributed evenly between two major corners if they are more than 40 feet apart such that the linear distance between any sequential points is no more than 40 feet. However, if any linear edge of the array has no obstructions that are closer than two times the height they project above the closest point on the array, then the intermediate measurements along that edge do not need to be made.

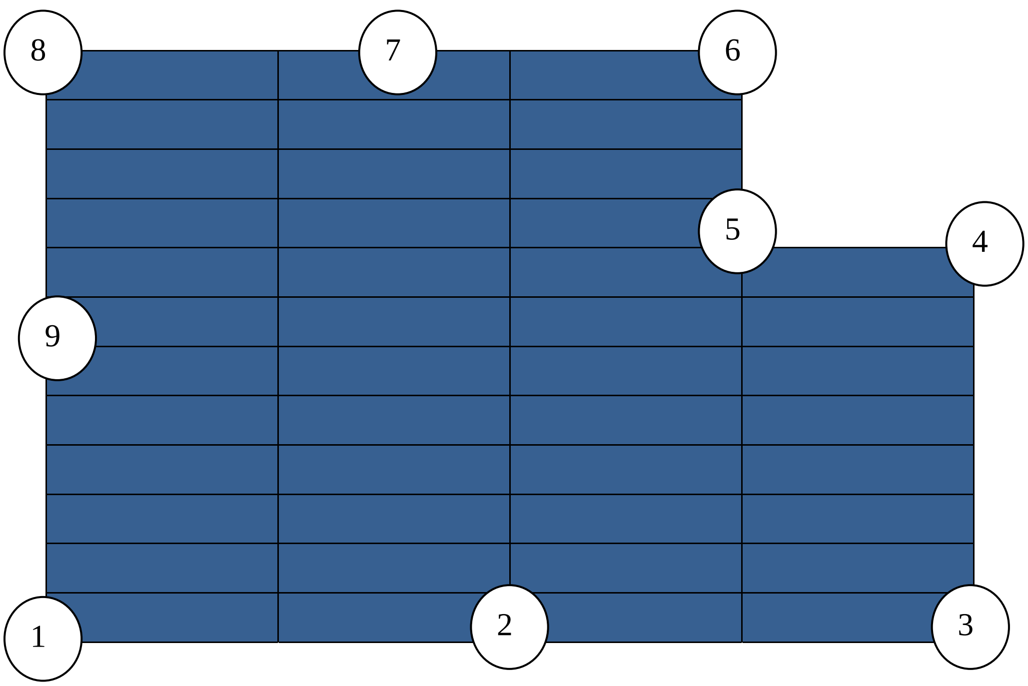


Figure 9 – Example of Points where Measurement shall be made using a Solar Assessment Tool (overall array dimensions 76 feet by 50 feet)

Monthly Shaded Production Factor Option

The Shaded Production Factor shall be reported by the tool as monthly values averaged over all the points of measurement and averaged as monthly solar availability numbers (7 am to 7 pm local standard time) except for the months of June through September where three time periods in every day of the month shall be reported. Program Administrators may weigh the Shaded Production Factor during peak periods (12 noon to 3 pm and 3 pm to 7 pm) during summer using TDV-based weighting factors determined by the Energy Commission. Each value shall be reported as a percentage of the unshaded insolation, including the application of the Shade Impact Factor, available on the array during the period given its location, azimuth and tilt. The Shaded Production Factor shall be reported in the format shown in Table 3. The Shaded Production Factor shall be determined by the solar assessment tool using the following equation. If the resultant value of the equation is negative, the Shaded Production Factor is set to zero.

Equation:

Shaded Production Factor = (1- ((1- Solar Availability/100) x Shade Impact Factor)) x 100

Where:

Solar Availability = Percent Solar Availability for the shortest time period available

Shade Impact Factor = Factor that accounts for production loss due to shading

The default Shade Impact Factor shall be 2.0. The doubling of shade loss accounts for the disproportionate impact on production due to partial shading on modules and strings. Technologies that can demonstrate effective tolerance to partial shading losses in a system shall be considered by the Energy Commission for a lesser Shade Impact Factor.

Using Shaded Production Factor Values in the PV Production Calculations for Incentive

In an incentive calculator, the monthly Shaded Production Factor values shall be applied to the estimate of unshaded production for the applicable month using the following equation.

Equation : $kWh_{shaded} = kWh_{unshaded}$ x Shaded Production Factor/100

Where:

kWh_{shaded} = the kWh produced including the effect of shading

$kWh_{unshaded}$ = the kWh produced if the array was completely unshaded

Shaded Production Factor = monthly value from solar assessment tool

Table 3 – Example of Monthly Shaded Production Factor Table

Month	
	7 am to 7 pm

1	74%		
2	83%		
3	91%		
4	94%		
5	95%		
	7 am to 12 noon	**12 noon to 3 pm**	**3pm to 7 pm**
6	89%	100%	100%
7	89%	100%	100%
8	88%	100%	98%
9	89%	100%	88%
	7 am to 7 pm		
10	88%		
11	76%		
12	67%		

Note: The Shaded Production Factor includes the Shade Impact Factor

Hourly Solar Availability Option

As an alternative to the Shaded Production Factor, the Hourly Solar Availability Option may be used. The solar availability shall be reported by the tool as hourly values averaged over all the points of measurement. Each value shall be reported as a percentage of the unshaded insolation available on the array during the hour given its location, azimuth and tilt. The hourly solar availability values shall be provided by the solar assessment tools as an electronic file with the 8760 values representing each hour of the year. The file format and security of data transfer shall be determined based on the implementation of the PV production calculator.

Using Hourly Solar Availability Values in the PV Production Calculations for Incentive

In an incentive calculator, the solar availability values shall be applied to the estimate of unshaded hourly production for the applicable hour using the following equation. If the resultant value of the equation is negative, the production for the hour is set to zero.

Equation : $$kWh_{shaded} = kWh_{unshaded} \times (1- (1- \text{Availability}/100) \times \text{Shade Impact Factor})$$

Where:

kWh_{shaded} = the kWh produced in the hour including the effect of shading

$kWh_{unshaded}$ = the kWh produced in the hour if the array was completely unshaded

Availability = Solar availability for the period including the hour

Shade Impact Factor = Factor that accounts for production loss due to shading

The default Shade Impact Factor shall be 2.0. The doubling of shade loss accounts for the disproportionate impact on production due to partial shading on modules and strings. Technologies that can demonstrate effective tolerance to partial shading losses in a system shall be considered by the Energy Commission for a lesser Shade Impact Factor.

Mature Tree Height

The expected performance calculations require the mature height to be used when accounting for the shading impact of planted immature trees and planned trees. This section provides guidelines for determining the mature height of such trees. Applicants shall identify the height category (small, medium, or large) of all planted and planned trees at the site. That information shall be documented in conjunction with the Installation Certificate and provided to the verifier for confirmation. Any existing tree with a height greater than 50 feet at the time observations are made shall be recorded with its actual height instead of the height category of its species.

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 shall be assumed to be large. The mature heights of small, medium and large trees that shall 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 4 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 [http://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 small, medium, or large.

Table 4 – 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 5 shows the horizontal distance that trees of each mature height category would need to be located from nearest point of the PV array in order to meet the condition of minimal shading.

Table 5 – 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 shall confirm that the AC power output from the PV system is consistent with that predicted by the expected performance calculations. A calculator will determine an estimate of system AC power output 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 a 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 6. The data in the table 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 AC power output for the measured field conditions from the table on the Certificate of Compliance form. The PV installer or the verifier shall then observe the AC power output displayed on the inverter and confirm that the AC power output is at least the amount shown in the table for the field measured conditions. To qualify for incentives under these Guidelines, PV systems shall have a performance meter or an inverter that has a built-in meter that measures AC power output.

The PV installer and verifier shall observe the AC power output on the inverter after waiting for a period of stable conditions during which the measured solar irradiance has stayed constant within ± 5 percent.

Table 6 – Example Table of Expected AC Power Output from 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 using an irradiance meter. When making this measurement, the PV installer or verifier shall place the irradiance meter in a plane that is parallel to the PV modules. The PV installer should position the irradiance meter on top of the PV modules or on the roof next to the PV modules. If the verifier is not able to get on the roof, he or she shall position the irradiance meter 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 irradiance meter.

Measuring Ambient Air Temperature

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

Observing AC Power Output at the Inverter

The PV installer and the verifier shall observe and record the reading as soon as possible after making the measurements of solar irradiance and ambient temperature. The inverter may cycle between multiple readings (total kWh of production, AC power output, 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

Multiple orientation arrays are those with parallel strings, each with an equal number of modules, in different orientations (azimuth and tilt) connected to the same inverter.[73] When parallel strings in different orientations are connected 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 orientation. The expected AC power output is determined separately for each orientation and the sum is used for verification purposes.

For example a qualifying 3 kW PV system has 20 modules grouped evenly into two parallel strings of 10 modules each, one facing south with an azimuth of 170 degrees and one facing west with an azimuth of 260 degrees. The verifier evaluates system performance at 11:30 AM in March with an ambient temperature of 62°F. The verifier

[73] Substantial reductions in performance will result if there are different numbers of modules in each string or if the strings with different orientations are connected in series.

measures 950 W/m^2 of solar irradiance in the plane parallel to the south array and 500 W/m^2 in a plane parallel to the west facing array.[74]
The total expected AC power output table on the Certificate of Compliance indicates that the system should be producing 1,200 W at 950 W/m^2 and 700 W at 500 W/m^2 of solar irradiance. The expected AC power output is calculated as 1,900 W by summation of each orientation's expected AC power output (1,200 W + 700 W = 1,900 W). This calculated value must be compared to the inverter display.

Installer System Inspection

These steps[75] shall be followed by the PV installer if the program administrator allows for the exemption from performing the field verification protocol. The PV installer shall complete the following steps under relatively stable solar irradiance conditions and submit a copy of a signed certificate of completing the same on every system.

These steps are only applicable for systems that have two or more strings connected in parallel to the same inverter. For all other systems the PV installer shall follow the same protocol as the field verifier.

1. Complete a visual check of the system to ensure the modules and all other system components are bolted securely, and all wiring connections have been made properly according to the system schematic, manufacturer's instructions, and applicable electrical code requirements.
2. Check the polarity of all source circuits to be correct.
3. The open circuit voltages of source circuits shall be tested and measured to be within 2 percent of each other.
4. The short circuit currents shall be tested and measured to be within 5 percent of each other.

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[74] When testing systems with multiple orientation arrays, the solar irradiance levels on all arrays must remain constant within ± 5 percent as discussed in Verification of System Performance above.
[75] The steps are based on the NABCEP *Study Guide for Photovoltaic System Installers* recommendations for Performing a System Checkout and Inspection**.**

APPENDIX 3: Senate Bill 1 (Murray, Statutes of 2006)

SENATE BILL NO. 1

CHAPTER 132

An act to add Sections 25405.5 and 25405.6 to, and to add Chapter 8.8 (commencing with Section 25780) to Division 15 of, the Public Resources Code, and to amend Section 2827 of, and to add Sections 387.5 and 2851 to, the Public Utilities Code, relating to solar electricity.

LEGISLATIVE COUNSEL'S DIGEST

SB 1, Murray Electricity: solar energy: net metering.

(1) Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission) to expand and accelerate development of alternative sources of energy, including solar resources. Existing law requires the Energy Commission to develop and adopt regulations governing solar devices, as defined, designed to encourage the development and use of solar energy and to provide maximum information to the public concerning solar devices.

This bill would require beginning January 1, 2011, a seller of production homes, as defined, to offer the option of a solar energy system, as defined, to all customers negotiating to purchase a new production home constructed on land meeting certain criteria and to disclose certain information. The bill would require the Energy Commission to develop an offset program that allows a developer or seller of production homes to forgo the offer requirement on a project by installing solar energy systems generating specified amounts of electricity on other projects. The bill would require, not later than July 1, 2007, the Energy Commission to initiate a public proceeding to study and make findings whether, and under what conditions, solar energy systems should be required on new residential and nonresidential buildings and to periodically update the study thereafter.

(2) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law required the PUC, on or before March 7, 2001, and in consultation with the Independent System Operator, to take

certain actions, including, in consultation with the Energy Commission, adopting energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods, including differential incentives for renewable or super clean distributed generation resources. Pursuant to this requirement, the PUC has developed a self-generation incentive program to encourage customers of electrical corporations to install distributed generation that operates on renewable fuel or contributes to system reliability. Existing law requires the PUC, in consultation with the Energy Commission, to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that existed on January 1, 2004, subject to certain air emissions and efficiency standards. In a PUC decision, the PUC adopted the California Solar Initiative, which modified the self-generation incentive program for distributed generation resources and provides incentives to customer-side photovoltaics and solar thermal electric projects under one megawatt.

This bill would require the PUC, in implementing the California Solar Initiative, to authorize the award of monetary incentives for up to the first megawatt of alternating current generated by an eligible solar energy system, that meets the eligibility criteria established by the Energy Commission. The bill would authorize the commission, prior to the establishment of eligibility criteria by the Energy Commission, to determine the eligibility of a solar energy system, as defined, to receive monetary incentives. The bill would require that awards of monetary incentives decline at a rate of an average of at least 7% for each year following implementation, and be zero by December 31, 2016. The bill would require the PUC, by January 1, 2008, to adopt a performance-based incentive program, as specified. The bill would require that the PUC, by January 1, 2008, and in consultation with the Energy Commission, require reasonable and cost-effective energy efficiency improvements in existing buildings as a condition of providing incentives for eligible solar energy systems. The bill would require the commission to require time-variant pricing for all ratepayers with a solar energy system. The bill would prohibit costs of the program from being recovered from certain customers and would require the commission to ensure that the total cost over the duration of the program does not exceed $3,350,800,000, consisting of 3 specified program components. The bill would authorize the PUC to award monetary incentives for solar thermal and solar water heating devices, in a total amount up to $100,800,000. The bill would prohibit the PUC from allocating more than $50,000,000 for certain research, development, and demonstration. The bill would require that by June 30, 2009, and by June 30 of every year thereafter, the PUC submit to the Legislature an assessment of the success of the California Solar Initiative program, that includes specified information.

This bill would require the Energy Commission, by January 1, 2008, and in consultation with the PUC, local publicly owned electric utilities, and interested members of the public, to establish and thereafter revise eligibility criteria for solar energy systems and to establish conditions for ratepayer funded incentives that are applicable to the California Solar Initiative. The bill would require the Energy Commission to adopt guidelines for solar energy systems receiving ratepayer funded incentives at a publicly noticed meeting. The bill would, upon establishment of eligibility criteria by the Energy Commission, prohibit ratepayer funded incentives from being made for a solar energy system that does not meet the eligibility criteria. The bill would require the Energy Commission to make certain information available to the public, to provide assistance to builders and contractors, and to conduct random audits of solar energy systems to evaluate their operational performance.

This bill would require all local publicly owned electric utilities, as defined, that sell electricity at retail, on or before January 1, 2008, to adopt, implement, and finance a solar initiative program, as prescribed, for the purpose of investing in, and encouraging the increased installation of, residential and commercial solar energy systems. The bill would require a local publicly owned electric utility to make certain program information available to its customers, to the Legislature, and to the Energy Commission on an annual basis beginning June 1, 2008. By imposing additional duties upon local publicly owned electric utilities, the bill would thereby impose a state-mandated local program.

(3) Existing law requires all electric service providers, as defined, to develop a standard contract or tariff providing for net energy metering, and to make this contract available to eligible customer generators, upon request. Existing law requires all electric service providers, upon request, to make available to eligible customer generators contracts for net energy metering on a first-come-first-served basis until the time that the total rated generating capacity used by eligible customer generators exceeds 0.5% of the electric service provider's aggregate customer peak demand.

This bill would require the PUC to order electric service providers to expand the availability of net energy metering so that it is offered on a first-come-first-served basis until the time that the total rated generating capacity used by all eligible customer-generators exceeds 2.5% of the electric service provider's aggregate customer peak demand. The bill would require the PUC, by January 1, 2010, in consultation with the Energy Commission, to submit a report to the Governor and Legislature on the costs and benefits of net energy metering, wind energy co-metering, and co-energy metering to participating customers and nonparticipating customers and with options to replace the economic costs of different forms of net metering with a mechanism that more equitably balances the interests of participating and nonparticipating customers.

(4) Existing law, the Contractors' State License Law, provides for the licensure and regulation of contractors by the Contractors' State License Board.

This bill would require the board to review and, if needed, revise its licensing classifications and examinations to ensure that contractors authorized to perform work on solar energy systems, as specified, have the requisite qualifications to perform the work.

(5) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for specified reasons.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. (a) The Legislature finds and declares that the Public Utilities Commission (PUC) adopted the California Solar Initiative in Decision 06-01-024.

(b) Nothing in this act shall be construed to codify PUC Decision 06-01-024.

SEC. 2. Section 25405.5 is added to the Public Resources Code, to read:

25405.5. (a) As used in this section, the following terms have the following meanings:

(1) "kW" means kilowatts or 1,000 watts, as measured from the alternating current side of the solar energy system inverter consistent with Section 223 of Title 15 of the United States Code.

(2) "Production home" means a single-family residence constructed as part of a development of at least 50 homes per project that is intended or offered for sale.

(3) "Solar energy system" means a solar energy device that has the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity, that produces at least one kW, and not more than five megawatts, alternating current rated peak electricity, and that meets or exceeds the eligibility criteria established pursuant to Section 25782.

(b) A seller of production homes shall offer a solar energy system option to all customers that enter into negotiations to purchase a new production home constructed on land for which an application for a tentative subdivision map has been deemed complete on or after January 1, 2011, and disclose the following:

(1) The total installed cost of the solar energy system option.

(2) The estimated cost savings associated with the solar energy system option, as determined by the commission pursuant to Chapter 8.8 (commencing with Section 25780) of Division 15.

(c) The State Energy Resources Conservation and Development Commission shall develop an offset program that allows a developer or seller of production homes to forgo the offer requirement of this section on a project, by installing solar energy systems generating specified amounts of electricity on other projects, including, but not limited to, low-income housing, multifamily, commercial, industrial, and institutional developments. The amount of electricity required to be generated from solar energy systems used as an offset pursuant to this subdivision shall be equal to the amount of electricity generated by solar energy systems installed on a similarly sized project within that climate zone, assuming 20 percent of the prospective buyers would have installed solar energy systems.

(d) The requirements of this section shall not operate as a substitute for the implementation of existing energy efficiency measures, and the requirements of this section shall not result in lower energy savings or lower energy efficiency levels than would otherwise be achieved by the full implementation of energy savings and energy efficiency standards established pursuant to Section 25402.

SEC. 3. Section 25405.6 is added to the Public Resources Code, to read:

25405.6. Not later than July 1, 2007, the commission shall initiate a public proceeding to study and make findings whether, and under what conditions, solar energy systems should be required on new residential and new nonresidential buildings, including the establishment of numerical targets. As part of the study, the commission may determine that a solar energy system should not be required for any building unless the commission determines, based upon consideration of all costs associated with the system, that the system is cost effective when amortized over the economic life of the structure. When determining the cost-effectiveness of the solar energy system, the commission shall consider the availability of governmental rebates, tax deductions, net-metering, and other quantifiable factors, if the commission can determine the availability of these financial incentives if a solar energy system is made mandatory and not elective. The commission shall periodically update the study and incorporate any revision that the commission determines is necessary, including revisions that reflect changes in the financial incentives originally considered by the commission when determining cost-effectiveness of the solar energy system. For purposes of this section, "solar energy system" means a photovoltaic solar collector or other photovoltaic solar energy device that has a primary purpose of providing for the collection and distribution of solar energy for the generation of electricity. This section is intended to be for study purposes only and does not authorize the commission to develop and adopt any requirement for solar energy systems on either residential or nonresidential buildings.

SEC. 4. Chapter 8.8 (commencing with Section 25780) is added to Division 15 of the Public Resources Code, to read:

CHAPTER 8.8. California Solar Initiative

25780. The Legislature finds and declares both of the following:

(a) It is the goal of the state 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 businesses in 10 years, and to place solar energy systems on 50 percent of new homes in 13 years.

(b) A solar initiative should be a cost-effective investment by ratepayers in peak electricity generation capacity where ratepayers recoup the cost of their investment through lower rates as a result of avoiding purchases of electricity at peak rates, with additional system reliability and pollution reduction benefits.

25781. As used in this chapter, the following terms have the following meanings:

(a) "California Solar Initiative" means the program providing ratepayer funded incentives for eligible solar energy systems adopted by the Public Utilities Commission in Decision 06-01-024.

(b) "kW" means kilowatts or 1,000 watts, as measured from the alternating current side of the solar energy system inverter consistent with Section 223 of Title 15 of the United States Code.

(c) "kWh" means kilowatthours, as measured by the number of kilowatts generated in an hour.

(d) "MW" means megawatts or 1,000,000 watts.

(e) "Solar energy system" means a solar energy device that has the primary purpose of providing for the collection and distribution of solar energy for the generation of electricity, that produces at least one kW, and not more than five MW, alternating current rated peak electricity, and that meets or exceeds the eligibility criteria established pursuant to Section 25782.

25782. (a) The commission shall, by January 1, 2008, in consultation with the Public Utilities Commission, local publicly owned electric utilities, and interested members of the public, establish eligibility criteria for solar energy systems receiving ratepayer funded incentives that include all of the following:

(1) Design, installation, and electrical output standards or incentives.

(2) The solar energy system is intended primarily to offset part or all of the consumer's own electricity demand.

(3) All components in the solar energy system are new and unused, and have not previously been placed in service in any other location or for any other application.

(4) The solar energy system has a warranty of not less than 10 years to protect against defects and undue degradation of electrical generation output.

(5) The solar energy system is located on the same premises of the end-use consumer where the consumer's own electricity demand is located.

(6) The solar energy system is connected to the electrical corporation's electrical distribution system within the state.

(7) The solar energy system has meters or other devices in place to monitor and measure the system's performance and the quantity of electricity generated by the system.

(8) The solar energy system is installed in conformance with the manufacturer's specifications and in compliance with all applicable electrical and building code standards.

(b) The commission shall establish conditions on ratepayer funded incentives that require all of the following:

(1) Appropriate siting and high quality installation of the solar energy system by developing installation guidelines that maximize the performance of the system and prevent qualified systems from being inefficiently or inappropriately installed. The conditions established by the commission shall not impact housing designs or densities presently authorized by a city, county, or city and county. The goal of this paragraph is to achieve efficient installation of solar energy systems to promote the greatest energy production per ratepayer dollar.

(2) Optimal solar energy system performance during periods of peak electricity demand.

(3) Appropriate energy efficiency improvements in the new or existing home or commercial structure where the solar energy system is installed.

(c) The commission shall set rating standards for equipment, components, and systems to assure reasonable performance and shall develop standards that provide for compliance with the minimum ratings.

(d) Upon establishment of eligibility criteria pursuant to subdivision (a), no ratepayer funded incentives shall be made for a solar energy system that does not meet the eligibility criteria.

25783. The commission shall do all the following:

(a) Publish educational materials designed to demonstrate how builders may incorporate solar energy systems during construction as well as energy efficiency measures that best complement solar energy systems.

(b) Develop and publish the estimated annual electrical generation and savings for solar energy systems. The estimates shall vary by climate zone, type of system, size, lifecycle costs, electricity prices, and other factors the commission determines to be relevant to a consumer when making a purchasing decision.

(c) Provide assistance to builders and contractors. The assistance may include technical workshops, training, educational materials, and related research.

(d) The commission shall annually conduct random audits of solar energy systems to evaluate their operational performance.

(e) The commission, in consultation with the Public Utilities Commission, shall evaluate the costs and benefits of having an increased number of operational solar energy systems as a part of the electrical system with respect to their impact upon the distribution, transmission, and supply of electricity, using the best available load profiling and distribution operations data from the Public Utilities Commission, local publicly owned electric utilities, and electrical corporations, and performance audits of installed solar energy systems.

25784. The commission shall adopt guidelines for solar energy systems receiving ratepayer funded incentives at a publicly noticed meeting offering all interested parties an opportunity to comment. Not less than 30 days' public notice shall be given of the meeting required by this section, before the commission initially adopts guidelines. Substantive changes to the guidelines shall not be adopted without at least 10 days' written notice to the public. Notwithstanding any other provision of law, any guidelines adopted pursuant to this chapter shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.

SEC. 5. Section 387.5 is added to the Public Utilities Code, to read:

387.5. (a) In order to further the state goal of encouraging the installation of 3,000 megawatts of photovoltaic solar energy in California within 10 years, the governing body of a local publicly owned electric utility, as defined in subdivision (d) of Section 9604, that sells electricity at retail, shall adopt, implement, and finance a solar initiative program, funded in accordance with subdivision (b), for the purpose of investing in, and encouraging the increased installation of, residential and commercial solar energy systems.

(b) On or before January 1, 2008, a local publicly owned electric utility shall offer monetary incentives for the installation of solar energy systems of at least two dollars and eighty cents ($2.80) per installed watt, or for the electricity produced by the solar energy system, measured in kilowatthours, as determined by the governing board of a local publicly owned electric utility, for photovoltaic solar energy systems. The incentive level shall decline each year thereafter at a rate of no less than an average of 7 percent per year.

(c) A local publicly owned electric utility shall initiate a public proceeding to fund a solar energy program to adequately support the goal of installing 3,000 megawatts of photovoltaic solar energy in California. The proceeding shall determine what additional funding, if any, is necessary to provide the incentives pursuant to subdivision (b). The public proceeding shall be completed and the comprehensive solar energy program established by January 1, 2008.

(d) The solar energy program of a local publicly owned electric utility shall be consistent with all of the following:

(1) That a solar energy system receiving monetary incentives comply with the eligibility criteria, design, installation, and electrical output standards or incentives established by the State Energy Resources Conservation and Development Commission pursuant to Section 25782 of the Public Resources Code.

(2) That solar energy systems receiving monetary incentives are intended primarily to offset part or all of the consumer's own electricity demand.

(3) That all components in the solar energy system are new and unused, and have not previously been placed in service in any other location or for any other application.

(4) That the solar energy system has a warranty of not less than 10 years to protect against defects and undue degradation of electrical generation output.

(5) That the solar energy system be located on the same premises of the end-use consumer where the consumer's own electricity demand is located.

(6) That the solar energy system be connected to the electric utility's electrical distribution system within the state.

(7) That the solar energy system has meters or other devices in place to monitor and measure the system's performance and the quantity of electricity generated by the system.

(8) That the solar energy system be installed in conformance with the manufacturer's specifications and in compliance with all applicable electrical and building code standards.

(e) A local publicly owned electric utility shall, on an annual basis beginning June 1, 2008, make available to its customers, to the Legislature, and to the State Energy Resources Conservation and Development Commission, information relating to the utility's solar initiative program established pursuant to this section, including, but not limited to, the number of photovoltaic solar watts installed, the total number of photovoltaic systems installed, the total number of applicants, the amount of incentives awarded, and the contribution toward the program goals.

(f) In establishing the program required by this section, no moneys shall be diverted from any existing programs for low-income ratepayers, or from cost-effective energy efficiency or demand response programs.

(g) The statewide expenditures for solar programs adopted, implemented, and financed by local publicly owned electric utilities shall be seven hundred eighty-four million dollars ($784,000,000). The expenditure level for each local publicly owned electric utility shall be based on that utility's percentage of the total statewide load served by all local publicly owned electric utilities. Expenditures by a local publicly owned electric utility may be less than the utility's cap amount, provided that funding is adequate to provide the incentives required by subdivisions (a) and (b).

SEC. 6. Section 2827 of the Public Utilities Code is amended to read:

2827. (a) The Legislature finds and declares that a program to provide net energy metering for eligible customer-generators is one way to encourage substantial private investment in renewable energy resources, stimulate in-state economic growth, reduce demand for electricity during peak consumption periods, help stabilize California's energy supply infrastructure, enhance the continued diversification of California's energy resource mix, and reduce interconnection and administrative costs for electricity suppliers.

(b) As used in this section, the following definitions apply:

(1) "Electric service provider" means an electrical corporation, as defined in Section 218, a local publicly owned electric utility, as defined in Section 9604, or an electrical cooperative, as defined in Section 2776, or any other entity that offers electrical service. This section shall not apply to a local publicly owned electric utility, as defined in Section 9604 of the Public Utilities Code, that serves more than 750,000 customers and that also conveys water to its customers.

(2) "Eligible customer-generator" means a residential, small commercial customer as defined in subdivision (h) of Section 331, commercial,

industrial, or agricultural customer of an electric service provider, who uses a solar or a wind turbine electrical generating facility, or a hybrid system of both, with a capacity of not more than one megawatt that is located on the customer's owned, leased, or rented premises, is interconnected and operates in parallel with the electric grid, and is intended primarily to offset part or all of the customer's own electrical requirements.

(3) "Net energy metering" means measuring the difference between the electricity supplied through the electric grid and the electricity generated by an eligible customer-generator and fed back to the electric grid over a 12-month period as described in subdivision (h). Net energy metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions. An additional meter or meters to monitor the flow of electricity in each direction may be installed with the consent of the customer-generator, at the expense of the electric service provider, and the additional metering shall be used only to provide the information necessary to accurately bill or credit the customer-generator pursuant to subdivision (h), or to collect solar or wind electric generating system performance information for research purposes. If the existing electrical meter of an eligible customer-generator is not capable of measuring the flow of electricity in two directions, the customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electricity flow in two directions. If an additional meter or meters are installed, the net energy metering calculation shall yield a result identical to that of a single meter. An eligible customer-generator who already owns an existing solar or wind turbine electrical generating facility, or a hybrid system of both, is eligible to receive net energy metering service in accordance with this section.

(4) "Wind energy co-metering" means any wind energy project greater than 50 kilowatts, but not exceeding one megawatt, where the difference between the electricity supplied through the electric grid and the electricity generated by an eligible customer-generator and fed back to the electric grid over a 12-month period is as described in subdivision (h). Wind energy co-metering shall be accomplished pursuant to Section 2827.8.

(5) "Co-energy metering" means a program that is the same in all other respects as a net energy metering program, except that the local publicly owned electric utility, as defined in Section 9604, has elected to apply a generation-to-generation energy and time-of-use credit formula as provided in subdivision (i).

(6) "Ratemaking authority" means, for an electrical corporation as defined in Section 218, or an electrical cooperative as defined in Section 2776, the commission, and for a local publicly owned electric utility as

defined in Section 9604, the local elected body responsible for regulating the rates of the local publicly owned utility.

(c) (1) Every electric service provider shall develop a standard contract or tariff providing for net energy metering, and shall make this contract available to eligible customer-generators, upon request, on a first-come-first-served basis until the time that the total rated generating capacity used by eligible customer-generators exceeds 2.5 percent of the electric service provider's aggregate customer peak demand.

(2) On an annual basis, beginning in 2003, every electric service provider shall make available to the ratemaking authority information on the total rated generating capacity used by eligible customer-generators that are customers of that provider in the provider's service area. For those electric service providers who are operating pursuant to Section 394, they shall make available to the ratemaking authority the information required by this paragraph for each eligible customer-generator that is their customer for each service area of an electric corporation, local publicly owned electric utility, or electrical cooperative, in which the customer has net energy metering. The ratemaking authority shall develop a process for making the information required by this paragraph available to energy service providers, and for using that information to determine when, pursuant to paragraph (3), a service provider is not obligated to provide net energy metering to additional customer-generators in its service area.

(3) Notwithstanding paragraph (1), an electric service provider is not obligated to provide net energy metering to additional customer-generators in its service area when the combined total peak demand of all customer-generators served by all the electric service providers in that service area furnishing net energy metering to eligible customer-generators exceeds 2.5 percent of the aggregate customer peak demand of those electric service providers.

(4) By January 1, 2010, the commission, in consultation with the State Energy Resources Conservation and Development Commission, shall submit a report to the Governor and the Legislature on the costs and benefits of net energy metering, wind energy co-metering, and co-energy metering to participating customers and nonparticipating customers and with options to replace the economic costs and benefits of net energy metering, wind energy co-metering, and co-energy metering with a mechanism that more equitably balances the interests of participating and nonparticipating customers, and that incorporates the findings of the report on economic and environmental costs and benefits of net metering required by subdivision (n).

(d) Electric service providers shall make all necessary forms and contracts for net metering service available for download from the Internet.

(e) (1) Every electric service provider shall ensure that requests for establishment of net energy metering are processed in a time period not exceeding that for similarly situated customers requesting new electric service, but not to exceed 30 working days from the date the electric service provider receives a completed application form for net metering service, including a signed interconnection agreement from an eligible customer-generator and the electric inspection clearance from the governmental authority having jurisdiction. If an electric service provider is unable to process the request within the allowable timeframe, the electric service provider shall notify both the customer-generator and the ratemaking authority of the reason for its inability to process the request and the expected completion date.

(2) Electric service providers shall ensure that requests for an interconnection agreement from an eligible customer-generator are processed in a time period not to exceed 30 working days from the date the electric service provider receives a completed application form from the eligible customer-generator for an interconnection agreement. If an electric service provider is unable to process the request within the allowable timeframe, the electric service provider shall notify the customer-generator and the ratemaking authority of the reason for its inability to process the request and the expected completion date.

(f) (1) If a customer participates in direct transactions pursuant to paragraph (1) of subdivision (b) of Section 365 with an electric supplier that does not provide distribution service for the direct transactions, the service provider that provides distribution service for an eligible customer-generator is not obligated to provide net energy metering to the customer.

(2) If a customer participates in direct transactions pursuant to paragraph (1) of subdivision (b) of Section 365 with an electric supplier, and the customer is an eligible customer-generator, the service provider that provides distribution service for the direct transactions may recover from the customer's electric service provider the incremental costs of metering and billing service related to net energy metering in an amount set by the ratemaking authority.

(g) Except for the time-variant kilowatthour pricing portion of any tariff adopted by the commission pursuant to paragraph (4) of subdivision (a) of Section 2851, each net energy metering contract or tariff shall be identical, with respect to rate structure, all retail rate components, and any monthly charges, to the contract or tariff to which the same customer would be assigned if the customer did not use an eligible solar or wind electrical generating facility, except that eligible customer-generators shall not be assessed standby charges on the electrical generating capacity or the kilowatthour production of an eligible solar or wind electrical generating facility. The charges for all retail rate components for eligible customer-generators shall be based exclusively on the customer-generator's net kilowatthour consumption over a 12-month period, without regard to the customer-generator's choice of electric service provider. Any new or additional demand charge, standby charge, customer charge, minimum monthly charge, interconnection charge, or any other charge that would increase an eligible customer-generator's costs beyond those of other customers who are not customer-generators in the rate class to which the eligible customer-generator would otherwise be assigned if the customer did not own, lease, rent, or otherwise operate an eligible solar or wind electrical generating facility are contrary to the intent of this section, and shall not form a part of net energy metering contracts or tariffs.

(h) For eligible residential and small commercial customer-generators, the net energy metering calculation shall be made by measuring the difference between the electricity supplied to the eligible customer-generator and the electricity generated by the eligible customer-generator and fed back to the electric grid over a 12-month period. The following rules shall apply to the annualized net metering calculation:

(1) The eligible residential or small commercial customer-generator shall, at the end of each 12-month period following the date of final interconnection of the eligible customer-generator's system with an electric service provider, and at each anniversary date thereafter, be billed for electricity used during that period. The electric service provider shall determine if the eligible residential or small commercial customer-generator was a net consumer or a net producer of electricity during that period.

(2) At the end of each 12-month period, where the electricity supplied during the period by the electric service provider exceeds the electricity generated by the eligible residential or small commercial customer-generator during that same period, the eligible residential or small commercial customer-generator is a net electricity consumer and the electric service provider shall be owed compensation for the eligible customer-generator's net kilowatthour consumption over that same period. The compensation owed for the eligible residential or small commercial customer-generator's consumption shall be calculated as follows:

(A) For all eligible customer-generators taking service under tariffs employing "baseline" and "over baseline" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same customer would be assigned to or be eligible for if the customer was not an eligible customer-generator. If those same customer-generators are net generators over a billing period, the net kilowatthours generated shall be valued at the same price per kilowatthour as the electric service provider would charge for the baseline quantity of electricity during that billing period, and if the number of kilowatthours generated exceeds the baseline quantity, the excess shall be valued at the same price per kilowatthour as the electric service provider would charge for electricity over the baseline quantity during that billing period.

(B) For all eligible customer-generators taking service under tariffs employing "time of use" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same customer would be assigned to or be eligible for if the customer was not an eligible customer-generator. When those same customer-generators are net generators during any discrete time of use period, the net kilowatthours produced shall be valued at the same price per kilowatthour as the electric service provider would charge for retail kilowatthour sales during that same time of use period. If the eligible customer-generator's time of use electrical meter is unable to measure the flow of electricity in two directions, paragraph (3) of subdivision (b) shall apply.

(C) For all residential and small commercial customer-generators and for each billing period, the net balance of moneys owed to the electric service provider for net consumption of electricity or credits owed to the customer-generator for net generation of electricity shall be carried forward as a monetary value until the end of each 12-month period. For all commercial, industrial, and agricultural customer-generators the net balance of moneys owed shall be paid in accordance with the electric service provider's normal billing cycle, except that if the commercial, industrial, or agricultural customer-generator is a net electricity producer over a normal billing cycle, any excess kilowatthours generated during the billing cycle shall be carried over to the following billing period as a monetary value, calculated according to the procedures set forth in this section, and appear as a credit on the customer-generator's account, until the end of the annual period when paragraph (3) shall apply.

(3) At the end of each 12-month period, where the electricity generated by the eligible customer-generator during the 12-month period exceeds the electricity supplied by the electric service provider during that same period, the eligible customer-generator is a net electricity producer and the electric service provider shall retain any excess kilowatthours generated during the prior 12-month period. The eligible customer-generator shall not be owed any compensation for those excess

kilowatthours unless the electric service provider enters into a purchase agreement with the eligible customer-generator for those excess kilowatthours.

(4) The electric service provider shall provide every eligible residential or small commercial customer-generator with net electricity consumption information with each regular bill. That information shall include the current monetary balance owed the electric service provider for net electricity consumed since the last 12-month period ended. Notwithstanding this subdivision, an electric service provider shall permit that customer to pay monthly for net energy consumed.

(5) If an eligible residential or small commercial customer-generator terminates the customer relationship with the electric service provider, the electric service provider shall reconcile the eligible customer-generator's consumption and production of electricity during any part of a 12-month period following the last reconciliation, according to the requirements set forth in this subdivision, except that those requirements shall apply only to the months since the most recent 12-month bill.

(6) If an electric service provider providing net metering to a residential or small commercial customer-generator ceases providing that electrical service to that customer during any 12-month period, and the customer-generator enters into a new net metering contract or tariff with a new electric service provider, the 12-month period, with respect to that new electric service provider, shall commence on the date on which the new electric service provider first supplies electric service to the customer-generator.

(i) Notwithstanding any other provisions of this section, the following provisions shall apply to an eligible customer-generator with a capacity of more than 10 kilowatts, but not exceeding one megawatt, that receives electrical service from a local publicly owned electric utility, as defined in Section 9604, that has elected to utilize a co-energy metering program unless the electric service provider chooses to provide service for eligible customer-generators with a capacity of more than 10 kilowatts in accordance with subdivisions (g) and (h):

(1) The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. All meters shall provide "time-of-use" measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule. If the existing meter of the eligible customer-generator is not a time-of-use meter or is not capable of measuring total flow of energy in both directions, the eligible customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions. This subdivision shall

not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a government agency or the electric service provider to reduce its costs for purchasing and installing a time-of-use meter.

(2) The consumption of electricity from the electric service provider shall result in a cost to the eligible customer-generator to be priced in accordance with the standard rate charged to the eligible customer-generator in accordance with the rate structure to which the customer would be assigned if the customer did not use an eligible solar or wind electrical generating facility. The generation of electricity provided to the electric service provider shall result in a credit to the eligible customer-generator and shall be priced in accordance with the generation component, established under the applicable structure to which the customer would be assigned if the customer did not use an eligible solar or wind electrical generating facility.

(3) All costs and credits shall be shown on the eligible customer-generator's bill for each billing period. In any months in which the eligible customer-generator has been a net consumer of electricity calculated on the basis of value determined pursuant to paragraph (2), the customer-generator shall owe to the electric service provider the balance of electricity costs and credits during that billing period. In any billing period in which the eligible customer-generator has been a net producer of electricity calculated on the basis of value determined pursuant to paragraph (2), the electric service provider shall owe to the eligible customer-generator the balance of electricity costs and credits during that billing period. Any net credit to the eligible customer-generator of electricity costs may be carried forward to subsequent billing periods, provided that an electric service provider may choose to carry the credit over as a kilowatthour credit consistent with the provisions of any applicable tariff, including any differences attributable to the time of generation of the electricity. At the end of each 12-month period, the electric service provider may reduce any net credit due to the eligible customer-generator to zero.

(j) A solar or wind turbine electrical generating system, or a hybrid system of both, used by an eligible customer-generator shall meet all applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories and, where applicable, rules of the Public Utilities Commission regarding safety and reliability. A customer-generator whose solar or wind turbine electrical generating system, or a hybrid system of both, meets those standards and rules shall not be required to install additional controls, perform or pay for additional tests, or purchase additional liability insurance.

(k) If the commission determines that there are cost or revenue obligations for an electric corporation, as defined in Section 218, that may not be recovered from customer-generators acting pursuant to this section, those obligations shall remain within the customer class from which any shortfall occurred and may not be shifted to any other customer class. Net-metering and co-metering customers shall not be exempt from the public benefits charge. In its report to the Legislature, the commission shall examine different methods to ensure that the public benefits charge remains a nonbypassable charge.

(l) A net metering customer shall reimburse the Department of Water Resources for all charges that would otherwise be imposed on the customer by the commission to recover bond-related costs pursuant to an agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, as well as the costs of the department equal to the share of the department's estimated net unavoidable power purchase contract costs attributable to the customer. The commission shall incorporate the determination into an existing proceeding before the commission, and shall ensure that the charges are nonbypassable. Until the commission has made a determination regarding the nonbypassable charges, net metering shall continue under the same rules, procedures, terms, and conditions as were applicable on December 31, 2002.

(m) In implementing the requirements of subdivisions (k) and (l), a customer-generator shall not be required to replace its existing meter except as set forth in paragraph (3) of subdivision (b), nor shall the electric service provider require additional measurement of usage beyond that which is necessary for customers in the same rate class as the eligible customer-generator.

(n) On or before January 1, 2005, the commission shall submit a report to the Governor and the Legislature that assesses the economic and environmental costs and benefits of net metering to customer-generators, ratepayers, and utilities, including any beneficial and adverse effects on public benefit programs and special purpose surcharges. The report shall be prepared by an independent party under contract with the commission.

(o) It is the intent of the Legislature that the Treasurer incorporate net energy metering and co-energy metering projects undertaken pursuant to this section as sustainable building methods or distributive energy technologies for purposes of evaluating low-income housing projects.

SEC. 7. Section 2851 is added to Chapter 9 of Part 2 of Division 1 of the Public Utilities Code, to read:

2851. (a) In implementing the California Solar Initiative, the commission shall do all of the following:

(1) The commission shall authorize the award of monetary incentives for up to the first megawatt of alternating current generated by solar energy systems that meet the eligibility criteria established by the State Energy Resources Conservation and Development Commission pursuant to Chapter 8.8 (commencing with Section 25780) of Division 15 of the Public Resources Code. The commission shall determine the eligibility of a solar energy system, as defined in Section 25781 of the Public Resources Code, to receive monetary incentives until the time the State Energy Resources Conservation and Development Commission establishes eligibility criteria pursuant to Section 25782. Monetary incentives shall not be awarded for solar energy systems that do not meet the eligibility criteria. The incentive level authorized by the commission shall decline each year following implementation of the California Solar Initiative, at a rate of no less than an average of 7 percent per year, and shall be zero as of December 31, 2016. The commission shall adopt and publish a schedule of declining incentive levels no less than 30 days in advance of the first decline in incentive levels. The commission may develop incentives based upon the output of electricity from the system, provided those incentives are consistent with the declining incentive levels of this paragraph and the incentives apply to only the first megawatt of electricity generated by the system.

(2) The commission shall adopt a performance-based incentive program so that by January 1, 2008, 100 percent of incentives for solar energy systems of 100 kilowatts or greater and at least 50 percent of incentives for solar energy systems of 30 kilowatts or greater are earned based on the actual electrical output of the solar energy systems. The commission shall encourage, and may require, performance-based incentives for solar energy systems of less than 30 kilowatts. Performance-based incentives shall decline at a rate of no less than an average of 7 percent per year. In developing the performance-based incentives, the commission may:

(A) Apply performance-based incentives only to customer classes designated by the commission.

(B) Design the performance-based incentives so that customers may receive a higher level of incentives than under incentives based on installed electrical capacity.

(C) Develop financing options that help offset the installation costs of the solar energy system, provided that this financing is ultimately repaid in full by the consumer or through the application of the performance-based rebates.

(3) By January 1, 2008, the commission, in consultation with the State Energy Resources Conservation and Development Commission, shall

require reasonable and cost-effective energy efficiency improvements in existing buildings as a condition of providing incentives for eligible solar energy systems, with appropriate exemptions or limitations to accommodate the limited financial resources of low-income residential housing.

(4) Notwithstanding subdivision (g) of Section 2827, the commission shall require time-variant pricing for all ratepayers with a solar energy system. The commission shall develop a time-variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently. In developing the time-variant tariff, the commission may exclude customers participating in the tariff from the rate cap for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, as required by Section 80110 of the Water Code. Nothing in this paragraph authorizes the commission to require time-variant pricing for ratepayers without a solar energy system.

(b) Notwithstanding subdivision (a), in implementing the California Solar Initiative, the commission may authorize the award of monetary incentives for solar thermal and solar water heating devices, in a total amount up to one hundred million eight hundred thousand dollars ($100,800,000).

(c) (1) In implementing the California Solar Initiative, the commission shall not allocate more than fifty million dollars ($50,000,000) to research, development, and demonstration that explores solar technologies and other distributed generation technologies that employ or could employ solar energy for generation or storage of electricity or to offset natural gas usage. Any program that allocates additional moneys to research, development, and demonstration shall be developed in collaboration with the Energy Commission to ensure there is no duplication of efforts, and adopted by the commission through a rulemaking or other appropriate public proceeding. Any grant awarded by the commission for research, development, and demonstration shall be approved by the full commission at a public meeting. This subdivision does not prohibit the commission from continuing to allocate moneys to research, development, and demonstration pursuant to the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000, as modified pursuant to Section 379.6.

(2) The Legislature finds and declares that a program that provides a stable source of monetary incentives for eligible solar energy systems will encourage private investment sufficient to make solar technologies cost effective.

(3) On or before June 30, 2009, and by June 30th of every year thereafter, the commission shall submit to the Legislature an assessment of the success of the California Solar Initiative program. That assessment shall include the number of residential and commercial sites that have installed solar thermal devices for which an award was made pursuant to subdivision (b) and the dollar value of the award, the number of residential and commercial sites that have installed solar energy systems, the electrical generating capacity of the installed solar energy systems, the cost of the program, total electrical system benefits, including the effect on electrical service rates, environmental benefits, how the program affects the operation and reliability of the electrical grid, how the program has affected peak demand for electricity, the progress made toward reaching the goals of the program, whether the program is on schedule to meet the program goals, and recommendations for improving the program to meet its goals. If the commission allocates additional moneys to research, development, and demonstration that explores solar technologies and other distributed generation technologies pursuant to paragraph (1), the commission shall include in the assessment submitted to the Legislature, a description of the program, a summary of each award made or project funded pursuant to the program, including the intended purposes to be achieved by the particular award or project, and the results of each award or project.

(d) (1) The commission shall not impose any charge upon the consumption of natural gas, or upon natural gas ratepayers, to fund the California Solar Initiative.

(2) Notwithstanding any other provision of law, any charge imposed to fund the program adopted and implemented pursuant to this section shall be imposed upon all customers not participating in the California Alternate Rates for Energy (CARE) or family electric rate assistance (FERA) programs as provided in paragraph (2), including those residential customers subject to the rate cap required by Section 80110 of the Water Code for existing baseline quantities or usage up to 130 percent of existing baseline quantities of electricity.

(3) The costs of the program adopted and implemented pursuant to this section may not be recovered from customers participating in the California Alternate Rates for Energy or CARE program established pursuant to Section 739.1, except to the extent that program costs are recovered out of the nonbypassable system benefits charge authorized pursuant to Section 399.8.

(e) In implementing the California Solar Initiative, the commission shall ensure that the total cost over the duration of the program does not exceed three billion three hundred fifty million eight hundred thousand dollars ($3,350,800,000). The financial components of the California Solar Initiative shall consist of the following:

(1) Programs under the supervision of the commission funded by charges collected from customers of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company. The total cost over the duration of these programs shall not exceed two billion one hundred sixty-six million eight hundred thousand dollars ($2,166,800,000) and includes moneys collected directly into a tracking account for support of the California Solar Initiative and moneys collected into other accounts that are use to further the goals of the California Solar Initiative.

(2) Programs adopted, implemented, and financed in the amount of seven hundred eighty-four million dollars ($784,000,000), by charges collected by local publicly owned electric utilities pursuant to Section 387.5. Nothing in this subdivision shall give the commission power and jurisdiction with respect to a local publicly owned electric utility or its customers.

(3) Programs for the installation of solar energy systems on new construction, administered by the State Energy Resources Conservation and Development Commission pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, and funded by nonbypassable charges in the amount of four hundred million dollars ($400,000,000), collected from customers of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company pursuant to Article 15 (commencing with Section 399).

SEC. 8. The Contractors' State License Board shall review and, if needed, revise its licensing classifications and examinations to ensure that contractors authorized to perform work on solar energy systems subject to Chapter 8.8 (commencing with Section 25780) of Division 15 of the Public Resources Code, have the requisite qualifications to perform the work.

SEC. 9. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.