U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

2010 Solar Technologies Market Report

NOVEMBER 2011

2010 Solar Technologies Market Report

NOVEMBER 2011

Table of Contents

Figures

Tables

Acknowledgments

Primary Authors: The *2010 Solar Market Trends Report* was completed by Kristen Ardani (NREL) and Robert Margolis (NREL).

Additional contributing authors include: Galen Barbose (LBNL), John Bartlett (formerly New West Technologies), Karlynn Cory (NREL), Toby Couture, Jennifer DeCesaro (DOE SETP), Paul Denholm (NREL), Easan Drury (NREL), David Feldman (NREL), Mark Frickel (formerly Sentech, Inc.), Barry Friedman (NREL), Rachel Gelman (NREL), Adam Goldstein (formerly New West Technologies), Charles Hemmeline (formerly DOE SETP), Ted James (NREL), Michael Mendelsohn (NREL), Sean Ong (NREL), Alexander Pak (MIT), Lauren Poole, Carla Peterman (LBNL), Selya Price (formerly NREL), Paul Schwabe (NREL), Arun Soni (formerly Sentech, Inc.), Bethany Speer (NREL), Ryan Wiser (LBNL), and Jarett Zuboy.

For comprehensive editing and publication support, we are grateful to: Courtney Kendall, as well as NREL for graphics and cover design.

For the use of and support with their data, special thanks to: Paula Mints (Photovoltaic Service Program, Navigant Consulting), Larry Sherwood (Sherwood Associates), Shyam Mehta (Green Tech Media), and Justin Baca (Solar Energy Industries Association).

For support of this project, the authors thank: The U.S. DOE Solar Energy Technologies Program (SETP) and the U.S. DOE Office of Energy Efficiency and Renewable Energy (EERE). NREL's contributions to this report were funded by the Solar Energy Technologies Program, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308. The authors are solely responsible for any omissions or errors contained herein.

List of Acronyms

6N	"six nines" or 99.999999%
AC	alternating current
ARRA	American Recovery and Reinvestment and Act of 2009 (S.1, "Stimulus Bill")
a-Si	amorphous silicon
BAB	Build America Bond
BIPV	building-integrated photovoltaics
BLM	U.S. Bureau of Land Management
CAGR	compound annual growth rate
CdTe	cadmium telluride
CEC	California Energy Commission
CIGS	copper indium gallium (di)selenide
CIS	copper indium (di)selenide
CREB	Clean Renewable Energy Bond
c-Si	crystalline silicon
CSI	California Solar Initiative
CSP	concentrating solar power
DC	direct current
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables & Efficiency
EECBG	Energy Efficiency and Conservation Block Grants Program
EERE	U.S. DOE's Office of Energy Efficiency and Renewable Energy
EESA	Emergency Economic Stabilization Act of 2008 (H.R. 1424, "Bailout Bill")
EIA	U.S. DOE's Energy Information Administration
EIS	Environmental Impact Statement
EPAct	Energy Policy Act of 2005
EPBB	expected performance-based buyout
EPIA	European Photovoltaic Industry Association
FBR	fluidized bed reactor
FERC	Federal Energy Regulatory Commission
FIRST	Financing Initiative for Renewable and Solar Technology
FIT	feed-in tariff
FTE	full-time equivalent
FY	fiscal year
GW	gigawatt
GWh	gigawatt-hour
HTF	heat-transfer fluid
IEA PVPS	International Energy Agency Photovoltaic Power Systems Programme
IPP	independent power producer
IREC	Interstate Renewable Energy Council
IRS	Internal Revenue Service
ISCC	integrated solar combined cycle
ITC	investment tax credit (federal)
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy

LFR	linear Fresnel reflector
M&A	mergers and acquisitions
MACRS	Modified Accelerated Cost Recovery System (federal)
MENA	Middle East and North Africa
MG-Si	metallurgical-grade silicon
MNGSEC	Martin Next Generation Solar Energy Center
MOU	memorandum of understanding
MT	metric ton
MW	megawatt
MW_e	megawatt electric
MWh	megawatt-hour
NABCEP	North American Board of Certified Energy Practitioners
NEF	New Energy Finance
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
O*NET	Occupational Information Network
PACE	Property Assessed Clean Energy
PBI	performance-based incentive
PE	private equity
PPA	power purchase agreement
PV	photovoltaic
QCEB	Qualified Clean Energy Bond
R&D	research and development
REC	renewable energy certificate
REN21	Renewable Energy Policy Network for the 21st Century
RETI	Renewable Energy Transmission Initiative
Ribbon Si	ribbon crystalline
ROW	rest of the world
RPS	renewable portfolio standard
SE REF	Solar Energy Research and Education Foundation
SEGS	Solar Electricity Generating Stations
SEIA	Solar Energy Industries Association
SEP	State Energy Program
SETP	U.S. DOE's Solar Energy Technologies Program
SNL	Sandia National Laboratories
SOC	Standard Occupational Classification
SOCPC	SOC Policy Committee
Solar PACES	Solar Power and Chemical Energy Systems
SREC	solar renewable energy certificate
TES	thermal energy storage
UAE	United Arab Emirates
UEDS	utility external disconnect switch
UMG-Si	upgraded metallurgical-grade silicon
VC	venture capital
W	watt
W_p	(peak) watt
WGA	Western Governors' Association
WREZ	Western Renewable Energy Zones

Executive Summary

This report focuses on solar market trends through December 31, 2010; it provides an overview of the U.S. solar electricity market, including photovoltaic (PV) and concentrating solar power (CSP) technologies, identifies successes and trends within the market from both global and U.S. perspectives, and offers a general overview of the state of the solar energy market. The report is organized into five chapters. Chapter 1 provides a summary of global and U.S. installation trends. Chapter 2 presents production and shipment data, material and supply chain issues, and solar industry employment trends. Chapter 3 presents cost, price, and performance trends. Chapter 4 discusses policy and market drivers such as recently passed federal legislation, state and local policies, and developments in project financing. Chapter 5 closes the report with a discussion on private investment trends and near-term market forecasts.

Highlights of this report include:

- **Global installed PV capacity increased by 16.6 gigawatts (GW) in 2010, a 131% increase from the year before and nearly seven times the amount (2.4 GW) that was installed in 2007.** The 2010 addition brought global cumulative installed PV capacity to nearly 40 GW. Leaders in 2010 capacity additions were Germany, with 7.4 GW, and Italy, with 2.3 GW installed, followed by the Czech Republic and Japan with approximately 1.5 GW and 990 megawatts (MW) installed, respectively. Germany maintained its lead in cumulative installed capacity in 2010 with 17 GW, followed by Spain at 3.8 GW, Japan at 3.6 GW, and Italy at 3.5 GW.

- **The United States installed approximately 918 MW of PV capacity in 2010, a 84% increase over the 477 MW installed in 2009.** The 2010 addition brought U.S. cumulative installed PV capacity to 2.5 GW. California continued to dominate the U.S. market with nearly 252 MW installed in 2010, bringing cumulative installations in that state to 1.02 GW, or 47% of the U.S. market. New Jersey followed with 132 MW installed in 2010, bringing cumulative capacity to 259 MW, or 12% of the U.S. market.

- **Globally, there was approximately 1,318 MW of cumulative installed CSP capacity by the end of 2010[1] with nearly 20 GW[2] in the pipeline (GTM Research 2011).** In 2010, there were 3 CSP plants installed in the United States, totaling 78 MW, and 9 CSP facilities installed in Spain, totaling 450 MW. Outside of the United States, 814 MW of CSP was under construction by the end of 2010, with 10 GW in the U.S. pipeline.

- **Global PV cell production continues to demonstrate impressive growth, with global cell production capacity increasing at a 3-year compound annual growth rate (CAGR) of 66%.** A majority (59%) of all PV cells were produced in China and Taiwan in 2010, which also retains 62% of global cell production capacity. Europe maintained its position as the second largest cell producer, with 13% of global production. Japan held a 9% share of the market, while North America was in fourth with 5% of PV cells produced globally in 2010.

- **Thin-film PV technologies have grown faster than crystalline silicon (c-Si) over the past 5 years, with a 5-year CAGR of 94% for thin-film shipments and a 5-year CAGR of 63% for c-Si, from 2005 to 2010.** Globally, thin-film technology shipments grew by 72% in 2010 compared to 2009, despite the fact that thin films overall market share decreased from 17% in 2009 to 13% in 2010.

[1] Cumulative installed CSP capacity aggregated from NREL 2010, Protermo Solar 2010, SEIA 2011, and GTM Research 2011.
[2] As of December 31, 2010 there was a total of 19,699 MW of global CSP capacity planned or under construction.

- **Global average PV module prices continued to drop in 2010 due to increased supply competition.** As manufacturers lowered prices to compete in the global market, average module prices reached all-time lows despite robust demand and tight raw materials supplies during the second half of the year. In 2010, the average module price for a mid-range buyer dropped 16%, to $2.36/W_p$ ([peak]w) from $2.82/W_p$ in 2009.

- **Global venture capital (VC) and private equity (PE) investment in solar totaled $2.3 billion in 2010, representing a 58% CAGR from 2004 to 2010.** Some of the notable transactions completed during 2010 included BrightSource Energy's $150 million series D VC transaction, Abound Solar's $110 million series D VC transaction, and Amonix's $64 million series B VC transaction.

- **Federal legislation, including the Emergency Economic Stabilization Act of 2008 (EESA, October 2008) and the American Recovery and Reinvestment Act of 2009 (ARRA, February 2009), is providing unprecedented levels of support for the U.S. solar industry.** The EESA and ARRA provide extensions and enhancements to the federal investment tax credits (ITCs), including allowing utilities to claim the ITC, the removal of the residential cap on the ITC, a new 30% manufacturing ITC for solar and other clean energy technologies, and an option that allows grants in lieu of tax credits for taxpaying corporate entities. The $787 billion ARRA package includes funds for the U.S. Department of Energy's (DOE) Loan Guarantee Program, DOE Office of Energy Efficiency and Renewable Energy (EERE) programs, and other initiatives. In addition to federal support, state and local policies, incentives, rules and regulations, as well as financing developments, these programs continue to encourage deployment of solar energy technologies.

Notes:

- This report includes historical price information and forecasts of future prices. Past and future prices can be provided as "nominal" (actual prices paid in the year stated) or "real" (indexed to a reference year and adjusted for inflation). In some cases, the report states whether prices are nominal or real. However, some of the published analyses from which price information is derived do not report this distinction. In practice, prices are usually considered to be nominal for cases in which the distinction is not stated explicitly.

- In some tables and figures, the sum of numerical components is not equal to the total sum shown due to rounding. Also, note that calculations such as growth rates were computed before numbers were rounded and reported. Standard rounding conventions were used in this report.

- Solar water heating, space heating and cooling, and lighting technologies are not covered in this report. DOE supports these technologies through its Building Technologies Program.

Installation Trends, Photovoltaic and Concentrating Solar Power

1

This chapter presents global and U.S. trends in photovoltaic (PV) and concentrating solar power (CSP) installations. Section 1.1 summarizes global installed PV capacity, growth in PV capacity over the past decade, and market segmentation data such as interconnection status and sector of application. Section 1.2 provides the same for the U.S. market and includes a discussion of U.S. states with the largest PV markets. Section 1.3 discusses global and U.S. installed CSP capacity.

1.1 Global Installed PV Capacity

This section identifies a number of sources that estimate capacity worldwide and includes a discussion on some of the uncertainty surrounding these estimates.

1.1.1 Cumulative Installed PV Capacity Worldwide

While there are inherent limitations to measuring the cumulative nameplate capacity of all PV systems worldwide, the European Photovoltaic Industry Association (EPIA) estimated that global cumulative installed PV capacity totaled nearly 40 gigawatts (GW) by the end of 2010, as shown in Figure 1.1. The approximately 16.6 GW of additional capacity installed in 2010 constituted a 131% increase over the 7.2 GW installed in 2009, for a 71% increase in global cumulative installed PV capacity. As a region, the European Union led new installed capacity in 2010 with 13 GW of the total 16 GW installed last year. Germany led new installed capacity with 7.4 GW installed, followed by Italy, Czech Republic, Japan, United States, France, China, and Spain.

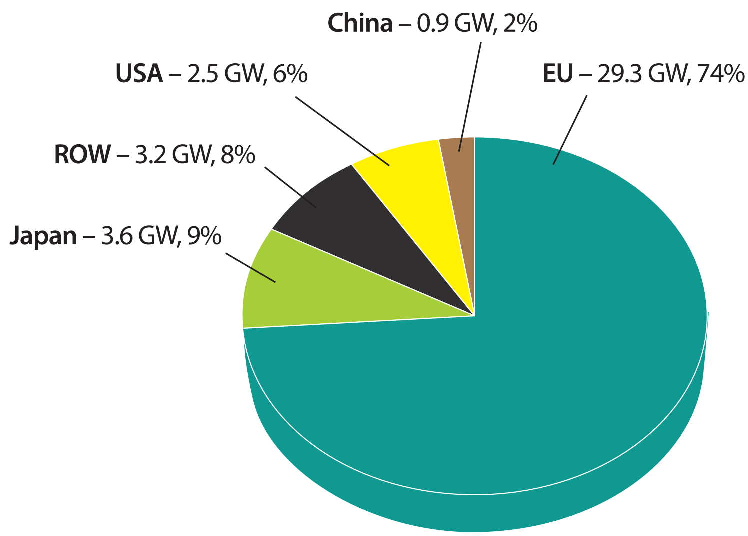


Figure 1.1 Global cumulative installed PV capacity through 2010 , with market share (%) (EPIA 2011)

Estimates of global solar capacity vary widely across data sources. Part of the variance is explained by the implementation of a broad range of metrics to determine the amount of PV deployed. For example, tracking cumulative production or shipments of PV cells and modules may lead to higher estimates for total installations, as some of these cells might not yet be installed or are warehoused in inventories around the world. However, only utilizing data from reported installations tends to underestimate the total amount of installed PV, on account of the difficulty of tracking off-grid installations, installations by companies that no longer exist, and other capacity not captured by the measure.

1.1.2 Growth in Cumulative and Annual Installed PV Capacity Worldwide

Germany- In 2010, Germany continued to dominate the world PV market with over 7.4 GW of installed capacity, which is nearly double the 3.8 GW installed in 2009, as shown in Figure 1.2. As of the end of 2010, Germany had 17 GW of cumulative installed capacity, which represents a 73% increase over 2009 cumulative installed capacity of 9.8 GW. Since 2000, Germany's market for PV has been supported by a feed-in tariff (FIT), a guaranteed payment over a 20-year contract period for PV-generated electricity supplied to Germany's grid. Germany's FIT has continued to drive consistent and sustained growth for the last several years. Germany's PV market experienced its highest annual growth year in 2004, a 290% increase from 153 megawatts (MW) in 2003 to 597 MW in 2004, coinciding with an amendment enhancing and streamlining Germany's FIT (called Erneuerbare-Energien-Gesetz [Renewable Energy Resources Act]).[3]

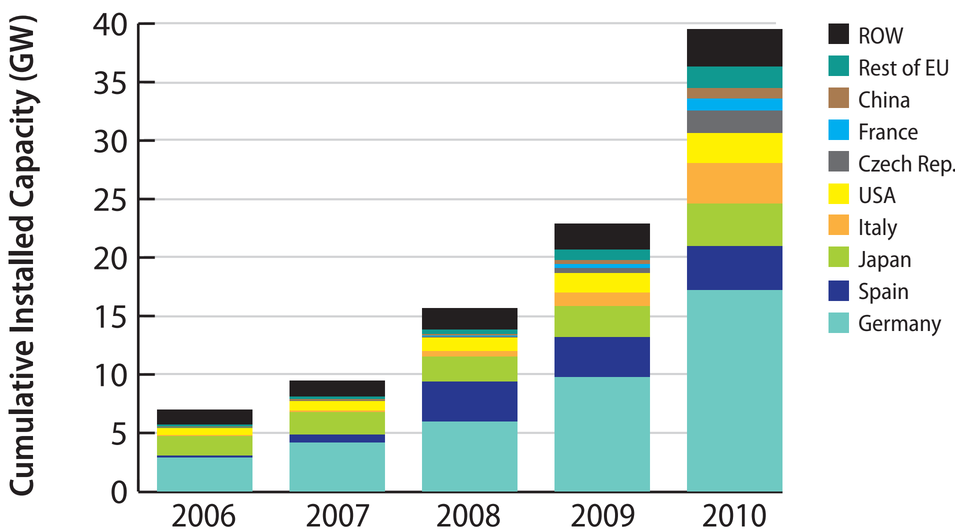


Figure 1.2 Cumulative installed PV capacity in the top eight countries (EPIA 2011)

Spain – Spain's annual installed capacity dropped from 2.7 GW installed in 2008 to 17 MW installed in 2009, for a slight rebound in 2010 with 369 MW. Despite a significant recent downturn in the Spanish PV market, Spain remains second in terms of cumulative installed capacity, with 3.8 GW installed through 2010. The dramatic decline of installations in Spain in 2009 was credited to a number of different factors. First, the Spanish government set a cap of 500 MW on the total number of megawatts that could be installed at a given FIT; however, the cap was not met in 2010. Second, applications for new installations far exceeded what was expected, and the program became oversubscribed. Third, Spain's complex administrative

[3] The revision to the Erneuerbare-Energien-Gesetz included an overall increase in the per-kilowatt-hour (kWh) payment for PV-generated electricity among other adjustments such as the setting of digression rates and the specification of payment rates according to PV-system type (building- versus ground-mounted) and size.

procedures caused severe delays in bringing systems online. Due to all of these factors, combined with the uncertainty surrounding the level and timing of a new FIT, Spanish developers simply placed many projects on hold until market conditions improved. To address these challenges, the Spanish government created a registry for solar projects in early 2009 (EPIA 2010, Wang 2009). The benefit of this registry has yet to be realized, however, due to the ongoing debate surrounding Spain's industry ministry's proposal to cut FIT levels.

Japan –By the end of 2010, Japan's cumulative installed PV capacity reached 3.6 GW, following the installation of 990 MW that same year. Japan's cumulative installed capacity at the end of 2010 represented an approximate 38% increase over the 2009 year-end cumulative installed PV capacity of 2.6 GW. This made Japan the third largest PV market in terms of global installed capacity, at the end of 2010. The reinstatement of Japan's residential incentive program, coupled with the introduction of net metering in 2009, helped drive this growth.

Italy –In 2010, Italy experienced its strongest growth in annual PV capacity additions to date, with 2.3 GW installed. This growth in annual capacity additions was bolstered by the country's favorable FIT and net metering structure, called Conto Energia [Energy Bill]. In terms of annual PV capacity additions, Italy ranked second behind Germany in 2010. In terms of cumulative installed PV capacity, Italy ranked fourth amongst leading solar markets, with 3.5 GW installed at the end of 2010.

United States – By the end of 2010, the United States' cumulative installed PV capacity reached 2.5 GW, following the installation of approximately 918 MW that same year. In 2010, the United States moved down from fourth to fifth place in terms of annual installed PV capacity, despite the 54% increase in cumulative installed PV capacity from 2009 to 2010. Market growth in the United States largely resulted from favorable policies, including the Treasury cash grant, aggressive renewable portfolio standards (RPSs), and state rebate programs.

Czech Republic – The Czech Republic's cumulative installed PV capacity increased from 1 MW in 2006 to nearly 2 GW by the end of 2010. The strong growth in the solar PV market is attributed to the country's feed-in tariff scheme. However, in 2010, the government enacted a new tax on solar PV energy production in response to the market's boom. All non-rooftop and rooftop PV systems, 30 kW or larger, installed between 2009 and 2010, will be required to pay the tax retroactively. The tax effectively reduces the net incentives available to solar developers in the Czech Republic and will likely dampen project investment going forward.

France – France represented the seventh largest PV market in the world in 2010, with 1 GW of cumulative installed PV capacity at year's end. The country's annual capacity additions of 719 MW represented an increase of 228% over 2009 additions of 219 MW. As a result of policies laid out by the Grenelle de l'Environment, a FIT encouraging building-integrated PV was passed in 2006. Since then, cumulative capacity increased by over 3,000%, growing from 0.03 GW of installed capacity by the end of 2006 to 1 GW installed by the end of 2010. Nevertheless, as is the trend with several other European countries struggling with the ongoing obligation of paying high FIT rates, France planned on lowering the amount of the FIT in order to deal with shortfalls in the government's annual budget (Hughes 2010).

China – China's solar market experienced a significant growth spurt in 2010, with 160 MW of annual installed PV capacity. The 2010 additions brought the country's cumulative installed capacity to 893 MW by year's end, a 125% increase over 2009 cumulative installed capacity. In 2006, China had a mere 80 MW of PV capacity installed. With a cumulative installed PV capacity of 893 MW by the end of 2010, China's compound annual growth rate (CAGR) has been in excess of 62% over the last 5 years. As average module prices fall and electricity demand continues to rise, the country is well positioned to become a major market.

The cumulative installed PV capacity data presented in figure 1.2 highlights the countries that have led the solar market to date; however, evaluating the measure of annual installations by country reveals emerging trends, such as Italy's rapid increase in installed capacity over the past two years. Figure 1.3 presents annual installed PV capacity from 2006–2010 for the eight leading countries.

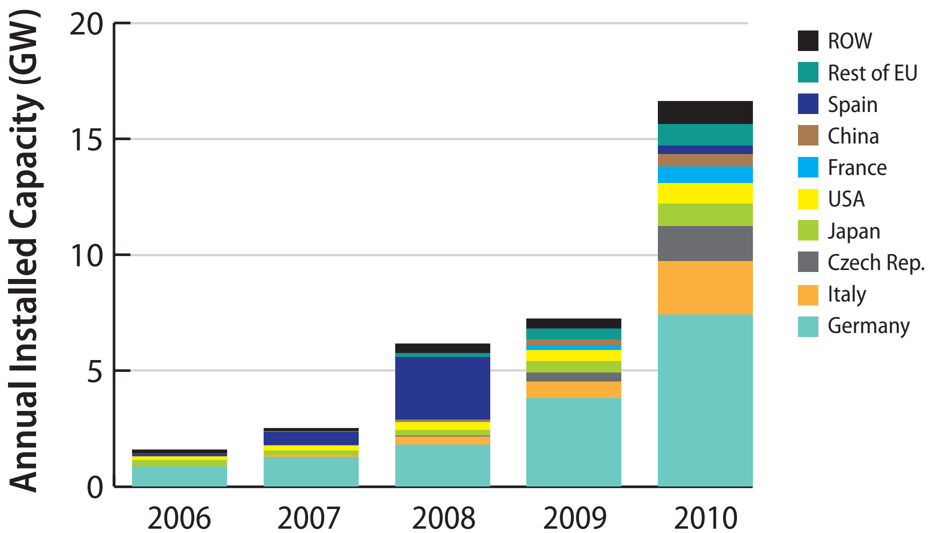


Figure 1.3 Annual installed PV capacity in the top eight countries (EPIA 2011)

1.1.3 Worldwide PV Installations by Interconnection Status and Application

Since 2005, grid-connected systems have steadily gained market share relative to off-grid systems. One reason for the shift is that government subsidies tend to promote grid-connected PV.

While grid-connected PV is more prominent, there are still a number of countries where smaller, off-grid systems comprise the majority of the local PV market. The disparity in different countries' market distribution between grid-connected and off-grid installations reflect the various types of subsidies, stages of market maturity, demand for particular applications, and other economic and cost factors. More than half of the countries listed in Figure 1.4 had a majority of grid-connected PV in 2010, including Germany, France, Switzerland, South Korea, Italy, and the United States. In contrast to the world leaders in installed PV, countries like Sweden, Turkey, Mexico, and Norway all displayed PV market compositions dominated by off-grid systems. Generally, domestic off-grid applications tend to be more common than off-grid industrial or agricultural systems.

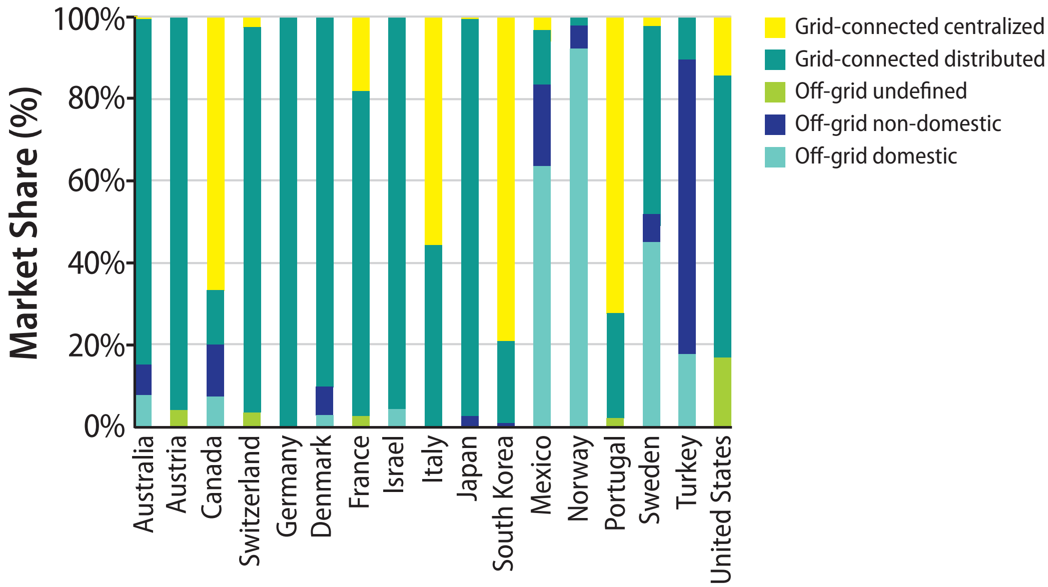


Figure 1.4 Market share of cumulative installed PV capacity, by application[4] (IEA 2011)

1.2 U.S. Installed PV Capacity

Once a world leader in total installed solar capacity, the United States has since lagged behind a number of its developed country counterparts. This section discusses total installed capacity in the United States and the historical data leading up to 2010.

1.2.1 Cumulative U.S. Installed PV Capacity

Though growth in domestic installed PV capacity has not kept pace with other developed countries, the U.S. PV market continues to grow. In 2009, the United States added 477 MW, for a total of 1.6 GW installed by the end of 2009. In 2010, the United States added 878 MW of new grid-connected PV capacity and an estimated 40 MW of off-grid capacity (SEIA/GTM 2011), representing a 92% increase over new capacity additions in 2009.

The Energy Policy Act of 2005 (EPAct) increased the federal ITC for solar energy from 10% to 30% for nonresidential installations and extended the tax credit to residential installations. Previously, no federal tax credit was available for residential installations. Initially, EPAct capped the ITC for residential solar installations at $2,000, but this cap was removed by the Emergency Economic Stabilization Act of 2008 (EESA), effective January 1, 2009. EESA extended the ITC through 2016 and removed the restriction on utilities, making utilities eligible for the credit for the first time.

In February 2009, the federal government enacted the American Recovery and Reinvestment Act (ARRA). ARRA includes a provision allowing cash grants to be awarded in lieu of an ITC for qualifying projects. Any solar project completed after February 17, 2009, may be eligible for ARRA's Section 1603 grant (Payments for Specific Energy Property in Lieu of Tax Credits).

[4] ***Off-grid domestic systems*** *are defined as PV systems installed to provide power mainly to a household or village not connected to the (main) utility grid(s).* ***Off-grid non-domestic systems*** *are defined as PV systems used for a variety of industrial and agricultural applications.* ***Grid-connected distributed systems*** *are defined as PV systems installed to provide power to a grid-connected customer or directly to the electricity grid (specifically where that part of the electricity grid is configured to supply power to a number of customers rather than to provide a bulk transport function).* ***Grid-connected centralized systems*** *refer to PV power production not associated with a particular electricity customer; the system is not located to specifically perform functions on the electricity grid other than the supply of bulk power (International Energy Agency 2011).*

Although the Section 1603 grant program was scheduled to expire at the end of 2010, the Tax Relief, Unemployment Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) provided for a 1-year extension. Without Congressional action, the Section 1603 grant program will expire at the conclusion of 2011 (see section 4.1.2. for more information). ARRA also created the Advanced Energy Manufacturing Investment Tax Credit, a competitive award of 30% in tax credits for manufacturers of renewable energy technologies. The U.S. Department of Energy (DOE) and the U.S. Department of the Treasury jointly announced the recipients of the $2.3 billion in credits in January 2010 (see section 4.1.3 for more information).

Leading states like California and New Jersey offer rebates that cover a significant portion of the up-front costs of PV systems. Other state and local policies, such as renewable portfolio standards (RPSs) and improved interconnection and net metering rules, have further promoted the growth of solar energy in recent years.

1.2.2 U.S. PV Installations by Interconnection Status

Figure 1.5 illustrates that the grid-connected market has dominated since the enactment of state and federal policies in 2004, and continues to increase in market share (61% in 2007, 70% in 2008, 76% in 2009, and 82% in 2010). Of the 2.5 approximate GW of cumulative installed PV capacity at the end of 2010, an estimated 2.1 GW were grid-connected while 440 MW were off-grid.

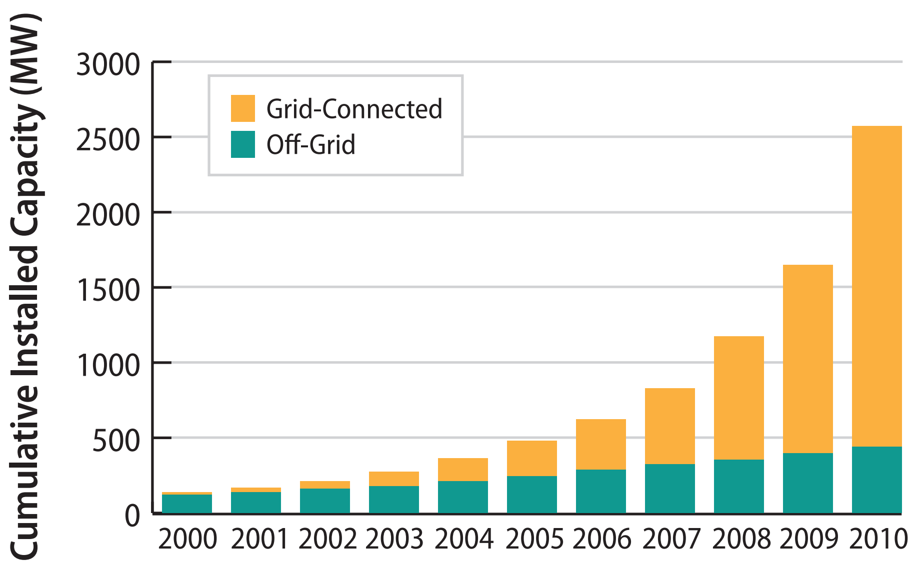


Figure 1.5 U.S. cumulative installed PV capacity, by interconnection status (Sherwood 2011)

1.2.3 U.S. PV Installations by Application and Sector

In addition to the manner in which PV systems are interconnected for their use, there are a number of different types of PV installations as well. For example, PV systems can be broken out based on whether they are integrated into their host buildings, whether they are built onto a rooftop, or mounted on the ground. Each of these systems can be further broken down based on whether they will be used in the residential, commercial, or utility market.

Historically, residential installations have dominated the market as a percentage of the total number of installations. The removal of the ITC cap for residential system owners continued to help drive the increase in the number of grid-connected residential PV systems installed from

31,817 in 2009 to 45,652 in 2010 (Sherwood 2011). While the number of residential-scale installations increased by 87% in 2009 compared to 43% in 2010, non-residential installations increased by 24% in 2009 compared to 75% in 2010. Figure 1.6 shows that although the number of non-residential and utility PV installations was increasing, the residential sector still accounted for the vast majority of annual installations in 2010.

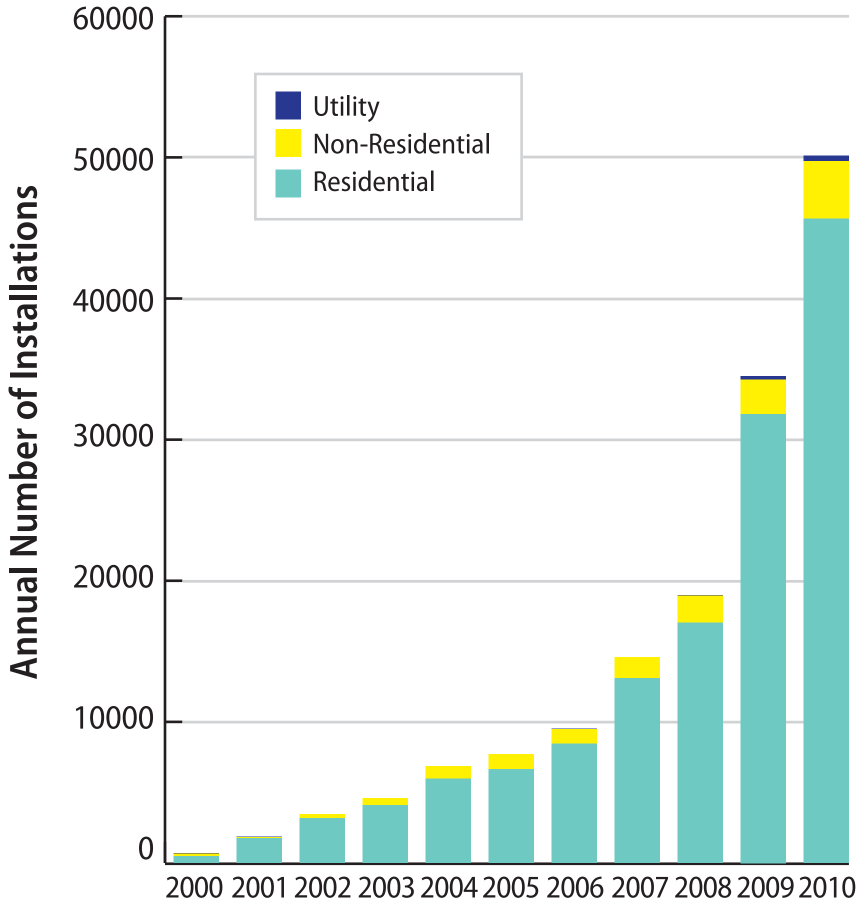


Figure 1.6 U.S. annual grid-connected PV installations, by sector (Sherwood 2011)

Of the 50,078 grid-connected PV systems installed in 2010, 91% were residential applications. Because the average size of non-residential systems is 10 times greater than that of residential systems, residential systems accounted for only 29% of the total grid-connected PV capacity installed in the United States in 2010 (Sherwood 2011). As indicated in Figure 1.7, the additional capacity from grid-connected, non-residential, and utility installations accounted for 69% of grid-connected capacity added in 2010 (Sherwood 2011).

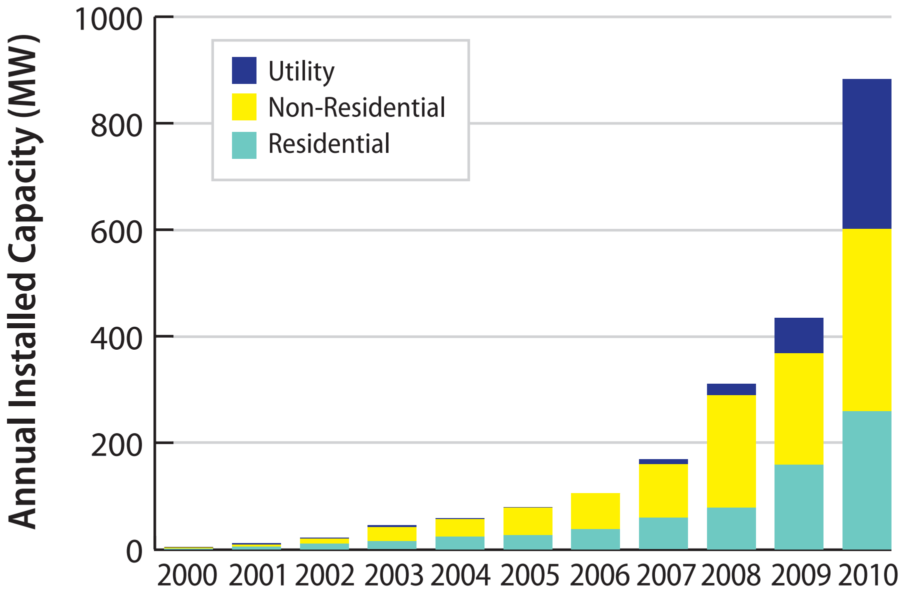


Figure 1.7 U.S. annual grid-connected PV capacity, by sector (Sherwood 2011)

The utility-scale market accelerated in 2010, growing to 31% of total grid-connected PV capacity installed that year.[5] Nine utility-scale projects came on line, in six different states. Of these nine projects, three were cadmium telluride (CdTe), two were multi crystalline silicon (c-Si), three were mono c-Si, and one was amorphous silicon (a-Si). As of mid-November 2010, 15 projects were under construction in 10 different states.

With 55-MW direct current (DC) of capacity, the Copper Mountain PV installation in Boulder City, Nevada, surpassed Florida Power and Light's 28-MW_{DC} DeSoto plant in Arcadia, Florida as the largest PV installation in the U.S. Construction on Copper Mountain began in January of 2010 and the facility came online in December of the same year. It deploys 775,000 First Solar thin-film modules.

1.2.4 States with the Largest PV Markets

The top five states in terms of cumulative installed grid-connected PV capacity, as of the end of 2010, were California (1,021 MW, 47% market share), New Jersey (259 MW, 12% market share), Colorado (121 MW, 5% market share), Arizona (109 MW, 5% market share), and Nevada (104 MW, 4% market share). Figure 1.8 depicts a breakout of the total cumulative installations of PV for the top states, with their corresponding market share in the United States.

[5] Utility-scale installations are defined as installations that feed electricity directly into the bulk power grid and are owned by the utility, third party, or building owner.

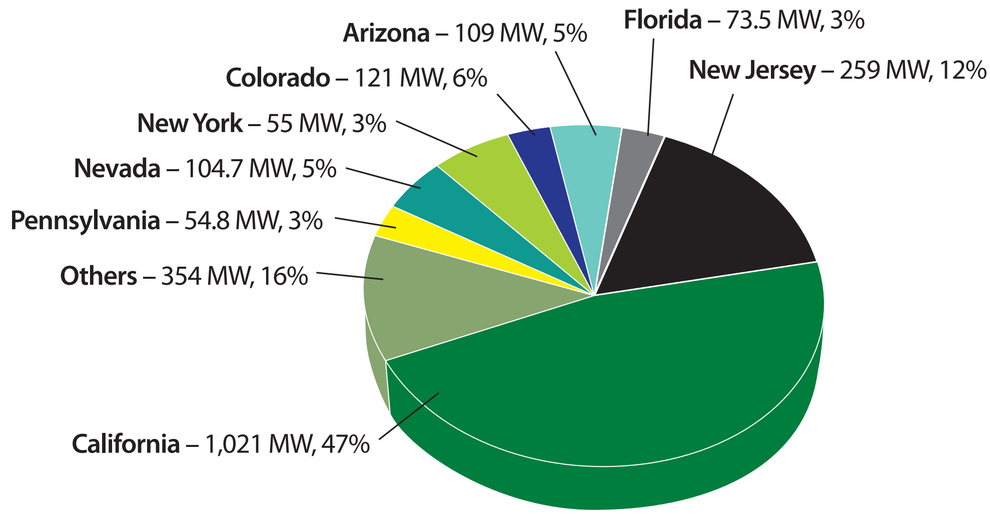


Figure 1.8 Cumulative grid-connected PV capacity, by state, with market share (%) (Sherwood 2011)

California continued to lead the U.S. market with 252 MW of new grid-connected PV capacity in 2010, up from 212 MW installed in 2009. In New Jersey, 132 MW of new capacity was installed in 2010, more than double the 57 MW installed in 2009. Nevada also made tremendous gains in 2010, adding 68 MW, for a cumulative installed capacity of 105 MW.

Both Colorado and Arizona more than doubled new PV capacity additions in 2010 over 2009. Colorado added 62 MW, compared to 23 MW installed in 2009, while Arizona added 63 MW of PV in 2010 compared to 21 MW installed in 2009. Showing considerable growth, Pennsylvania added 46 MW of capacity in 2010, compared to 5 MW installed in 2009.

1.3 Global and U.S. Installed CSP Capacity

CSP is a growing part of the overall solar power industry. This section addresses cumulative and annual gains made within the CSP industry, both in the United States and abroad.

1.3.1 Cumulative Installed CSP Worldwide

At the end of 2010, there was 1,318 MW of cumulative installed CSP capacity worldwide, with nearly 20 GW of capacity in the pipeline[6] (GTM Research 2011). In 2010, Spain was the world leader in CSP installations, with 450 MW of added capacity and 55.4% of cumulative installed capacity worldwide. Meanwhile, the United States added 78 MW of CSP capacity, for a total of 38.5% of cumulative installed CSP capacity worldwide. Iran (5.0% of market share), Israel (0.5%), Australia (0.2%), and Germany (0.1%) have all recently entered the CSP market. Table 1.1 lists installed CSP plants worldwide, including demonstrations projects, as of December 31, 2010.

[6] *As of December 31, 2010 there was a total of 19,699 MW of global CSP capacity planned and under construction.*

TABLE 1.1. GLOBAL INSTALLED CSP PLANTS					
Plant Name	**Location**	**Developer**	**Technology**	**Year Installed**	**Capacity (MW)**
United States of America					
Martin Next Generation Solar Energy Center (MNGSEC)	Florida	NextEra Energy Resources	Trough	2010	75
Maricopa Solar Project	Arizona	Tessera Solar	Dish/Engine	2010	2
Cameo Coal-Fired Hybrid Demonstration Plant	Colorado	Abengoa Solar	Trough	2010	1
Kimberlina Solar	California	AREVA	CLFR	2009	5
Sierra SunTower	California	eSolar	Tower	2009	5
Holaniku	Hawaii	Sopogy	Trough	2009	1
Nevada Solar One	Nevada	Acciona	Trough	2007	64
Saguaro	Arizona	APS	Trough	2006	1
Solar Electric Generating Stations (SEGS) (I-IX)	California	Luz	Trough	1985-1991	354
US Total					508
Spain					
Manchasol-1	Ciudad Real	ACS-Grupo Cobra	Trough	2010	50
Palma del Rio II	Cordoba	Acciona	Trough	2010	50
La Dehesa	Badajoz	Renovables SAMCA	Trough	2010	50
Majadas I	Caceres	Acciona	Trough	2010	50
La Florida	Badajoz	Renovables SAMCA	Trough	2010	50
Solnova 1	Sevilla	Abengoa Solar	Trough	2010	50
Solnova 3	Sevilla	Abengoa Solar	Trough	2010	50
Solnova 4	Sevilla	Abengoa Solar	Trough	2010	50
Extresol-2	Badajoz	ACS-Grupo Cobra	Trough	2010	50
Extresol-1	Badajoz	ACS-Grupo Cobra	Trough	2009	50
Alvarado 1 (La Risca)	Badajoz	Acciona	Trough	2009	50
Puertollano (Ibersol Ciudad Real)	Puertollano	Iberdrola Renovables	Trough	2009	50
Andasol-2	Granada	ACS-Grupo Cobra	Trough	2009	50
Puerto Errado 1 (PE1)	Calasparra	Novatec Biosol	CLFR	2009	1
Planta Solar 20 (PS20)	Sevilla	Abengoa Solar	Tower	2009	20
Andasol-1	Aldeire	ACS-Grupo Cobra	Trough	2008	50
Planta Solar 10 (PS10)	Sevilla	Abengoa Solar	Tower	2006	10
Spain Total					731
Iran					
Yazd ISCC Power Station	Yazd	TBA	Trough	2009	67
Israel					
Solar Energy Development Center (SEDC)	Negev Desert	BrightSource	Tower	2008	6
Australia					
Liddell	New South Wales	AREVA	CLFR		3

TABLE 1.1. GLOBAL INSTALLED CSP PLANTS					
Germany					
Julich Solar Tower	Kraftanlagen München	TBA	Tower	2009	2
France					
THEMIS Solar Power Tower	Pyrénées-Orientales	TBA	Tower		1
Cumulative Installed CSP Capacity (MW)					1,318

(NREL 2010, Protermo Solar 2010, SEIA 2011, GTM 2011)

1.3.2 Major non-U.S. International Markets for CSP

Besides the United States, Spain, North Africa, Australia, and the Middle East are promising markets for CSP on account of the regions' high levels of insolation and land available for solar development. The world insolation map below depicts the most ideal areas for CSP development.

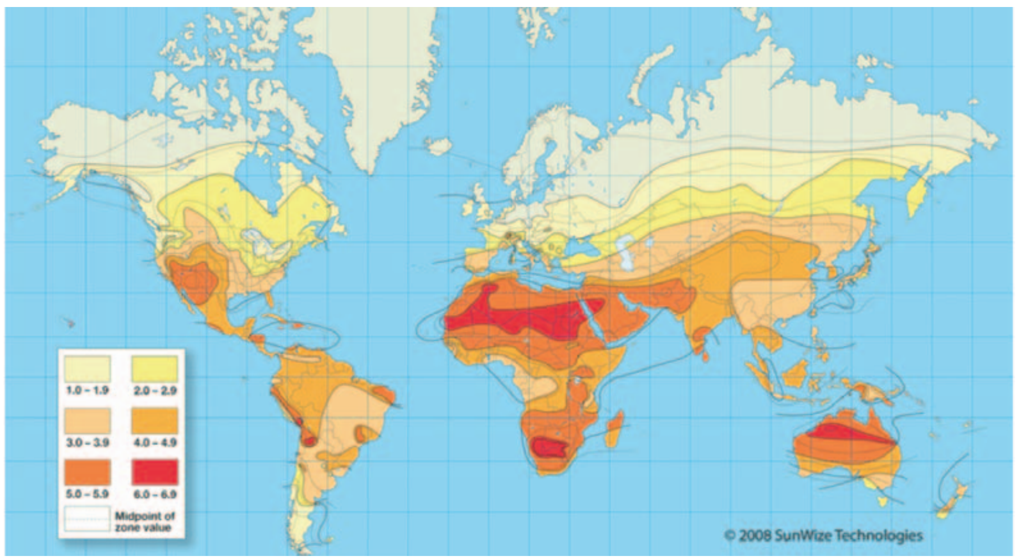


Figure 1.9 World insolation map
(SunWize Technologies, Inc. 2008)

The first commercial CSP plant in Spain, the 11-MW tower system known as PS10, was completed in 2006 (Protermo Solar 2010). With a 25% capacity factor, PS10 can generate 24 gigawatt-hours (GWh)/year, which is enough to supply about 5,500 households with electricity (Grama et al. 2008). Andasol 1, which came online in November 2008, has a maximum capacity of 50 MW and was the first trough system in Europe. Andasol 1 was also the first commercial CSP plant with an energy-storage capability designed specifically for electricity generation after sunset. This added feature enables the plant to provide electricity for approximately 7.5 hours after sunset (Solar Millennium 2009). Two additional plants, the Puertollano Plant and PS20, totaling 70 MW, came online in Spain in 2009. In 2010, Spain added 9 more CSP plants totaling 450 MW (Protermo Solar 2010). Spain had the most projects under construction in 2010 (548 MW) of any country, however, the United States had close to three times more projects in development than Spain (GTM 2011). The FIT structure in Spain has two major restrictions. First, the maximum allowable size of a plant is 50 MW. Second, there is an overall capacity ceiling of 500 MW. However, the attractive rate for solar thermal—about .27 Euro/kilowatt-hours (kWh)—successfully attracted CSP development and is poised to continue until 2032.

Just to the south of Spain, North Africa also has tremendous potential for CSP growth. Figure 1.10 reveals the favorable solar irradiation in North African countries, where the red indicates the best locations for CSP, while the blue is less favorable.

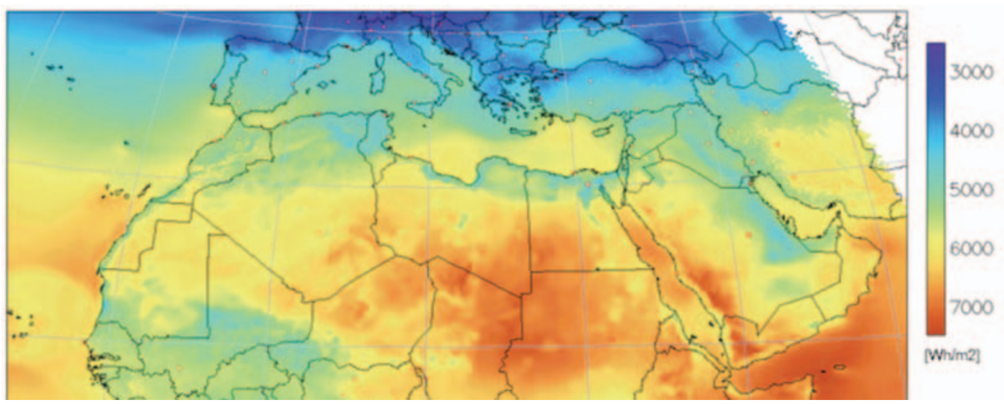


Figure 1.10 Solar resources in North African countries (CSP Today 2008)

By late 2010, Morocco was completing construction on a hybrid system with 20 MW of CSP that will be combined with a natural gas plant for a total generation of 472 MW (Agence Maghreb Arabe Presse 2010). Similar plants were under construction in Algeria and Egypt. This type of design, known as an integrated solar combined cycle (ISCC), was gaining some traction in these regions. An ISCC plant combines heat from the natural gas turbine and the solar field, achieving capacity gains without increasing emissions. Another benefit of such a system is that an additional turbine is not needed when the CSP portion is built. This speeds up the construction process while at the same time reduces capital expenditures. However, the solar thermal component usually composes a small percentage of the total generation; therefore, additional research will be required following commercial operation of the ISCC plants in North Africa in order to optimize the steam cycle in the future (CSP Today 2010). Interest in CSP had also been growing in the Middle East for reasons similar to those in Africa—high solar irradiation (as shown in Figure 1.11), available land, and growing demand for clean energy.

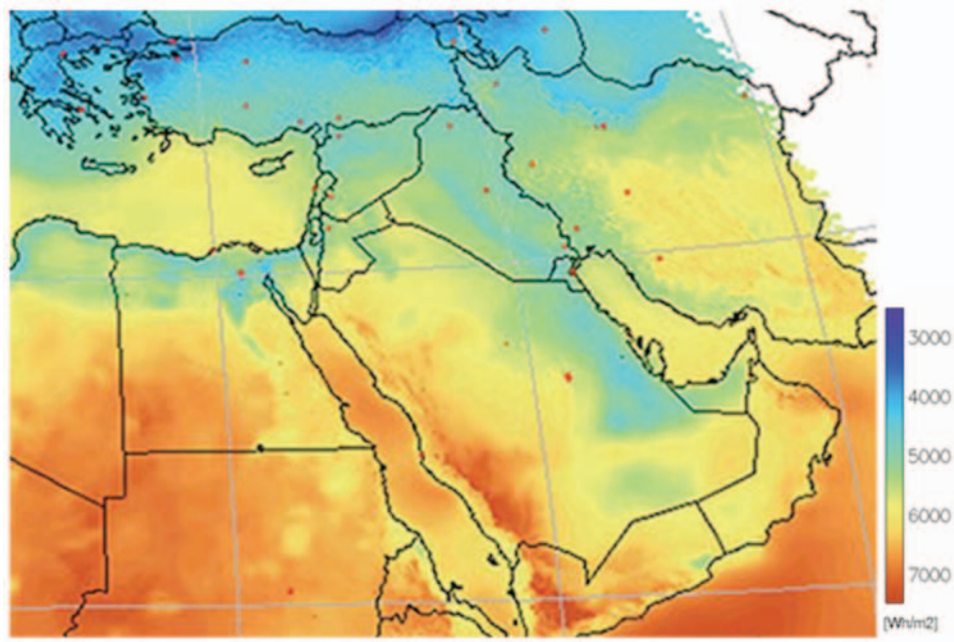


Figure 1.11 Solar resources in the Middle East (CSP Today 2008)

In December of 2009, the Clean Technology Fund approved financing of $750 million, which will mobilize an additional $4.85 billion from other sources, to accelerate deployment of CSP in the Middle East and North Africa (MENA) regions. Program resources will focus on the following five countries: Algeria, Egypt, Jordan, Morocco, and Tunisia. These funds will be used, in part, to support the transmission infrastructure in the MENA region, including a 2,000-mile transmission cable that will allow export of 100 GW of solar electricity from MENA to Europe. The research for this transmission network was being conducted by a consortium of 12 large companies in the energy, technology, and finance sectors known as the DESERTEC Industrial Initiative. The total cost for the project is estimated to be €400 billion (including the transmission lines) over the next 40 years to supply 15% of the European electricity market with solar power produced by North African CSP plants. The Clean Technology Fund supports the goals of the DESERTEC Industrial Initiative by providing industry, government, and market deployment experiences, while laying a foundation for replicable CSP projects in the region. Additionally, the Clean Technology Fund allocated resources to spur the deployment of an estimated 1 GW of new CSP generation capacity in the five eligible countries (Climate Investment Funds 2009).

Although there are no commercial CSP plants installed in China, many large-scale projects have been announced for development by 2020. However, China has not set up any incentives for the CSP sector, and power purchase agreements (PPAs) must be approved by the government on an individual basis. In early 2010, a deal was signed for the construction of 2 GW of CSP plants by 2020 between the California solar technology company, eSolar, and China power equipment manufacturer, Penglai Electric. The first project is a 92-MW hybrid biomass and CSP plant, which will deploy eSolar's power tower technology. Industry support in China is also building steadily—Chinese manufacturers are very active in the production of components for CSP projects, a new CSP research park broke ground with a scheduled completion of 2015, and the National Alliance for Solar Thermal Energy was established with the support of the Chinese government.

On the global level, 814 MW of CSP was under construction as of December 31, 2010, as summarized in Table 1.2. The majority were trough systems being built in Spain, with the United Arab Emirates (UAE), China, Algeria, Egypt, and Morocco constructing their first ever utility-scale CSP plants. Table 1.3 lists CSP plants in development in the United States, which total over 10 GW of capacity (GTM 2011).

TABLE 1.2: CSP PLANTS UNDER CONSTRUCTION AS OF DECEMBER 31, 2010, BY COUNTRY			
Plant Name	**Developer**	**Technology**	**Capacity (MW)**
Spain			
Andasol 3	Solar Millenium AG	Trough	50
Arcosol 50 (Valle 1)	Torresol Energy	Trough	50
Estresol-2	ACS-Grupo Cobra	Trough	50
Helioenergy 1	Abengoa Solar	Trough	50
Helioenergy 2	Abengoa Solar	Trough	50
Manchasol-1	ACS-Grupo Cobra	Trough	50
Palma del Rio I	Acciona	Trough	50
Palma del Rio II	Acciona	Trough	50
Termesol 50 (Valle 2)	Torresol Energy	Trough	50
Lebrija 1	Solucia Renovables	Trough	50
Puerto Errado 2 (PE2)	Novatec Biosol	CLFR	30
Gemasolar (Solar Tres)	Torresol Energy	Tower	17
Casa del Angel Termosolar	Renovalia	Dish/Engine	1
Fresdemo II	Solar Power Group	CLFR	
Spain Total			548
China			
Yulin Alternative Energy Park	Penglai Electric/eSolar	Penglai Electric/eSolar	92
Dezhou	Himin Solar	Himin Solar	3
Yanqing	Himin Solar	Himin Solar	1
China Total			96
UAE			
Shams 1	Abengoa Solar	Trough	100
Egypt			
El Kuraymat	Solar Millenium AG	Trough	20
Algeria			
ISCC Argelia	Abener Energia	Trough	20
Morocco			
ISCC Morocco	Abener Energia	Trough	20
Australia			
Cloncurry Solar Power Station	Ergon Energy	Tower	10
Global CSP Plants Under Construction (MW)			814

(GTM 2011)

1.3.3 U.S. Installed and Proposed CSP Capacity

The United States added approximately 78 MW of CSP in 2010, bringing the country's cumulative installed capacity to over 500 MW, as shown in Table 1.1 (NREL 2010, SEIA 2011, GTM 2011). The Solar Electricity Generating Stations (SEGS) in the Mojave Desert of southern

California accounted for 354 MW of this capacity. SEGS consists of nine parabolic trough plants ranging from 14 to 80 MW, located in three main locations: Daggett, Harper Lake, and Kramer Junction (see Figure 1.12). The plants were built between 1984 and 1991 and have collectively generated more than 11,000 gigawatt-hours (GWh) (BrightSource 2008).

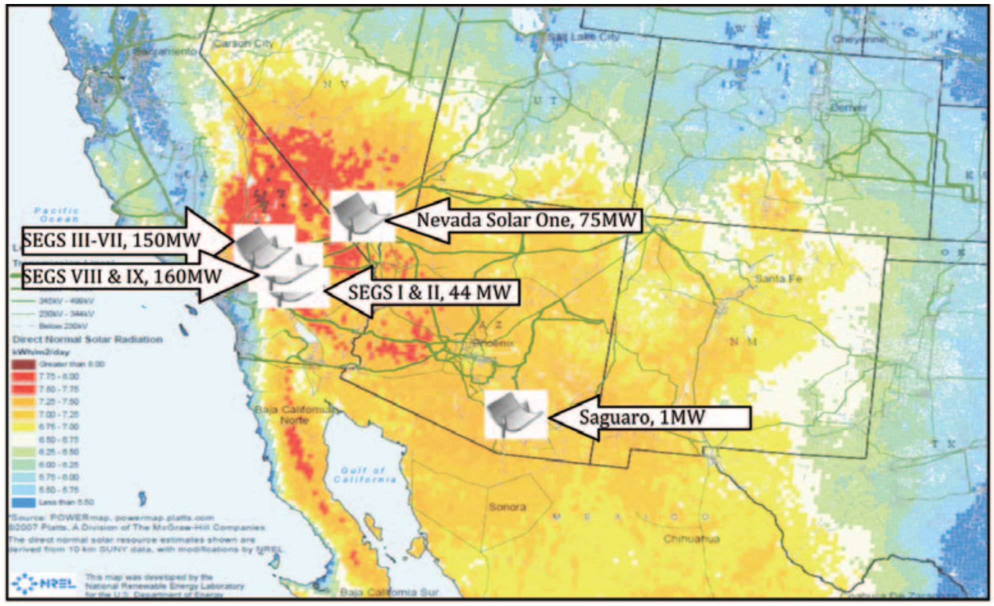


Figure 1.12. Concentrating solar power plants of the southwestern United States[7] (NREL 2010)

Following completion of the SEGS plants, Arizona Public Service brought the Saguaro 1-MW parabolic trough plant online in 2005. The system, which was installed in Red Rock, Arizona, had a capacity factor of 23%, allowing for generation of 2 GWh per year (Grama et al. 2008). The Nevada Solar One project had a maximum 75-MW generation capacity and a 64-MW nominal production capacity. The Solar One project was installed in 2007 in Boulder City, Nevada. The Solar One project had a capacity factor of 23% and generated more than 130 GWh each year (Acciona Energy 2008, Grama et al. 2008).

As shown in Table 1.1, new CSP facilities have come online in 3 of the past 4 years after 15 years of inactivity. In 2010, three new plants totaling 78 MW of new generation capacity were added, including the first dish-engine plant in the United States (Maricopa Solar Project), the first CSP facility in Florida (Martin Next Generation Solar Energy Center), and the first hybrid project with a coal plant in Colorado (Cameo) (SEIA 2011, GTM 2011).

The three new CSP plants installed in 2010 were an indication of the growing CSP market in the United States, in part due to a number of policies that are allowing for the expedited permitting of projects as well as the construction of key transmission lines that will allow generation in remote areas (see section 2.4.5 for more information on these policies). Several new projects are on track to break ground in 2011. As of December 31, 2010, over 10 GW of CSP are in active development in the United States (Table 1.3, GTM 2011).

[7] *This map has been modified to include CSP plants that came online in 2009 and 2010.*

TABLE 1.3: PROPOSED CSP PLANTS IN THE UNITED STATES AS OF DECEMBER 31, 2010			
US CSP PLANTS UNDER DEVELOPMENT			
Plant Name	**Developer**	**Technology**	**Capacity (MW)**
BrightSource SCE (Solar Partners XVI-XXI)	BrightSource	Tower	1,200
Calico Solar Project II (Solar One)	Tessera Solar	Dish/Engine	575
Mojave Solar Park	Siemens Energy (Solel Solar Systems)	Trough	553
Blythe (Phase I)	STA (Solar Millenium & Ferrostaal)	Trough	500
Blythe (Phase II)	STA (Solar Millenium & Ferrostaal)	Trough	500
Fort Irwin	Acciona	Trough	500
Palen Solar Power Project	STA (Solar Millenium & Ferrostaal)	Trough	484
Amargosa Farm Road	STA (Solar Millenium & Ferrostaal)	Trough	484
Imperial Valley Solar II (Solar Two)	Tessera Solar	Dish/Engine	409
Sonoran Solar Energy Project (fka Jojoba)	NextEra Energy Resources	Trough	375
Hualapai Valley Solar Project	Mohave Sun Power	Trough	340
Imperial Valley Solar I (Solar Two)	Tessera Solar	Dish/Engine	300
Calico Solar Project I (Solar One)	Tessera Solar	Dish/Engine	275
Abengoa Mojave Solar (AMS) Project	Abengoa Solar	Trough	250
Beacin Sikar Energy Project	NextEra Energy Resources	Trough	250
Solana Generating Station	Abengoa Solar	Trough	250
Harper Lake Solar Plant	Harper Lake LLC	Trough	250
Ridgecrest Solar Power Project	STA (Solar Millenium & Ferrostaal)	Trough	242
BrightSource PG&E 5	BrightSource	Tower	200
BrightSource PG&E 6	BrightSource	Tower	200
BrightSource PG&E 7	BrightSource	Tower	200
Coyote Springs 1 (PG&E 3)	BrightSource	Tower	200
Coyote Springs 2 (PG&E 4)	BrightSource	Tower	200
Saguache	SolarReserve	Tower	200
Rice Solar Energy (RSEP)	SolarReserve	Tower	150
San Luis Valley	Tessera Solar	Dish/Engine	145
Gaskell Sun Tower (Phase II)	NRG Energy	Tower	140
Ivanpah PG&E 2	BrightSource	Tower	133
Ivanpah SCE	BrightSource	Tower	133
Ivanpah PG&E 1	BrightSource	Tower	126
Genesis Solar Energy Project-1	NextEra Energy Resources	Trough	125
Genesis Solar Energy Project-2	NextEra Energy Resources	Trough	125
Gaskell Sun Tower (Phase I)	NRG Energy	Tower	105
Crescent Dunes Solar Energy Project	SolarReserve	Tower	100
Kingman Project (Phase I)	Albiasa Solar	Trough	100
Kingman Project (Phase II)	Albiasa Solar	Trough	100
Quartzsite Solar Energy Project	SolarReserve	Tower	100
eSolar 1	NRG Energy	Tower	84

TABLE 1.3: PROPOSED CSP PLANTS IN THE UNITED STATES AS OF DECEMBER 31, 2010			
eSolar 2	NRG Energy	Tower	66
Palmdale Hybrid Gas-Solar Plant	Inland Energy Inc.	Trough	50
Victorville 2 Hybrid Power Project	Inland Energy Inc.	Trough	50
Mt. Signal Solar	MMR Power Solutions	Trough	49
SolarCAT Pilot Plant	Southwest Solar Technologies	Dish/Engine	10
Westside Solar Project	Pacific Light & Power	Trough	10
UA Tech Park Thermal Storage Demonstration	Bell Independent Power Corp	Trough	5
US CSP Plants Under Development (MW)			10,843

(GTM 2011)

1.4 References

Acciona Energy. (2008). *www.acciona-na.com*. Accessed November 2008.

Agence Maghreb Arabe Presse. (May 12, 2010). "HM the King inaugurates integrated solar combined cycle power plant in Eastern Morocco." *http://www.map.ma/eng/sections/royal_activities/hm_the_king_inaugura6924/view*. Accessed August 18, 2010.

BrightSource Energy, Inc. (2008). *http://www.brightsourceenergy.com/bsii/history/*. Accessed November 2008.

Climate Investment Funds website. (November 10, 2009). "Clean Technology Fund: Investment Plan for Concentrated Solar Power in the Middle East and North Africa Region." *http://www.climateinvestmentfunds.org.* Accessed August 18 2010.

CSP Today. (February 11, 2010). "Integrated Solar Combined Cycle Plants: Right Place, Right Time." Industry Insight. *http://www.csptoday.com/*. Accessed August 18, 2010.

CSP Today. (October 2008). "An Overview of CSP in Europe, North Africa and the Middle East." *http://www.leonardo-energy.org/webfm_send/2761*. Accessed August 18, 2010.

European Photovoltaic Industry Association (EPIA). (May 2010). *Global Market Outlook for PV until 2014*. *http://www.epia.org/fileadmin/EPIA_docs/public/Global_Market_Outlook_for_Photovoltaics_until_2014.pdf*. Accessed August 18, 2010.

European Photovoltaic Industry Association (EPIA). (May 2011). *Global Market Outlook for PV until 2015*. *http://www.epia.org/fileadmin/EPIA_docs/public/Global_Market_Outlook_for_Photovoltaics_until_2015.pdf*. Accessed June 1, 2011.

GLG Research. (March 2011). "Feed-in tariffs, oil prices and nuclear security." *http://www.glgroup.com/News/Feed-in-tariffs-oil-prices-and-nuclear-security.-52993.html*. Accessed May 25, 2011.

Greentech Media (GTM). (January 2011). *Concentrating Solar Power 2011: Technology, Costs, and Markets*. *http://www.greentechmedia.com/research/report/concentrating-solar-power-2011-technology-costs-and-markets*. Accessed May 9, 2011.

Grama, S.; Wayman, E.; Bradford, T. (2008). *Concentrating Solar Power—Technology, Cost, and Markets*. 2008 Industry Report. Cambridge, MA: Prometheus Institute for Sustainable Development and Greentech Media.

Hughes, E. (2010). PV Tech: Czech Republic. *http://www.pv-tech.org/tariff_watch/czech_republic*. Accessed June 1, 2011.

International Energy Agency (IEA). (2011). Trends in photovoltaic applications. Survey report of selected IEA countries between 1992 and 2010. Report IEA PVPS T1-20:2011. IEA Photovoltaic Power Systems Programme (IEAPVPS). *http://www.iea-pvps.org*. Accessed September 6, 2011.

Kann, S. (June 2010). "Market in Focus: Italy." PV News. Greentech Media Volume 29, Number 6, June 2010.

Mallet, V. (August 1, 2010). "Madrid Cuts Subsidies for Solar Power Plants." Financial Times. *http://www.ft.com/cms/s/0/4c5ac4ce-9d8d-11df-a37c-00144feab49a.html*. Accessed August 18, 2010.

Mints, P. (2009). *Analysis of Worldwide Markets for Photovoltaic Products and Five-Year Application Forecast 2008/2009*. Report # NPS-Global4. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

National Renewable Energy Laboratory (NREL). (2010). "Concentrating Solar Power Projects" website. *http://www.nrel.gov/csp/solarpaces/*. Accessed August 18, 2010.

Sherwood, L. (July 2010). *U.S. Solar Market Trends 2009*. Latham, NY: Interstate Renewable Energy Council (IREC). *http://irecusa.org/irec-programs/publications-reports/*. Accessed August 18, 2010.

Sherwood, L. (July 2011). *Special data compilation*.

Protermo Solar.(2010). Monthly Bulletin December 2010. *http://www.protermosolar.com/historico.html*. Accessed June 16, 2011.

Solar Energy Industries Association (SEIA). (April 15, 2010). *U.S. Solar Industry: Year in Review 2009*. *http://seia.org/galleries/default-file/2009 Solar Industry Year in Review.pdf*. Accessed August 18, 2010.

Solar Energy Industries Association (SEIA) and Greentech Media (GTM). (2011). *U.S. Solar Market Insight: 2010 Year in Review*. *http://www.seia.org/cs/research/SolarInsight*. Accessed May 9, 2011.

Solar Millennium. (July 1, 2009). "Andasol 1 is officially inaugurated." Press Release. *http://www.solarmillennium.de/Press/Press_Releases/Andasol_1_is_officially_inaugurated,lang2,50,1660.html*. Accessed August 2009.

SunWize Technologies, Inc. (2008). SunWize World Insolation Map. *http://www.sunwize.com/info_center/solar-insolation-map.php*. Accessed May 9, 2011.

Wang, U. (February 20, 2009). "Spain Kicks Off New Solar Feed-in Tariffs." GreenTech Solar. *http://www.greentechmedia.com/articles/read/spain-kicks-off-new-solar-feed-in-tariffs-5764/*. Accessed August 18, 2010.

Industry Trends, Photovoltaic and Concentrating Solar Power

Tracking both the production and shipment of PV cells and modules provides insight into the overall market for PV, yet production and shipment data differ. While production figures include a portion of cells and modules that remain in inventory, shipments of cells and modules measure demand for PV in a given year. This chapter presents information on production and shipments separately, in order to capture underlying market dynamics.

This chapter covers global and U.S. PV and CSP industry trends. Section 2.1 summarizes global and U.S. PV cell and module production trends, including production levels, growth over the past decade, and top producers. Section 2.2 presents data on global and U.S. PV cell and module shipments and associated revenue, including shipment levels and growth, top companies in terms of shipments and revenues, shipment levels by type of PV technology, and U.S. import and export data. Section 2.3 provides information on major CSP component manufacturers and CSP component shipments. Section 2.4 discusses material and supply-chain issues for PV and CSP, including polysilicon, rare metals, and glass supply for PV; material and water constraints for CSP; and land and transmission constraints for utility-scale solar projects. Section 2.5 covers global and U.S. solar industry employment trends for both PV and CSP, including job type analysis, current and projected employment, solar PV installation requirements, and barriers and solutions to solar workforce development.

2.1 PV Production Trends

The previous chapter discussed the worldwide increase in the total number of PV installations. This chapter covers recent trends in the production of PV cells and modules worldwide, but focuses on cell production as opposed to module assembly. It is difficult to accurately track cell and module production separately, due to the fact that cell assembly into modules may result in double counting. Additionally, there is a lag-time between cell and module production because cells must be produced first.

2.1.1 Global PV Production

The annual growth rate for global PV cell production was 111% from 2009 to 2010, with global cell production reaching 23.9 GW by the end of 2010 (Mehta 2011). Global cell production capacity increased at a 3-year CAGR of 66%, and rose by 70% between 2009 and 2010 (Mehta 2011).

Figure 2.1 shows the regional distribution of all PV cell production in 2010. Nearly two thirds (59%) of all PV cells were produced in China and Taiwan. Europe maintained its position as the second largest cell producer in 2010, with 13% of global production. Japan held a 9% share of the market, while North America came in fourth with 5% of PV cells produced globally in 2010. The rest of the world (ROW) countries composed the remaining 14%. At the end of 2010, China and Taiwan had the most cell production capacity (62%). Europe followed with 12%, Japan ranked third with 8%, and North America ranked fourth with 5% of global cell production capacity (Mehta 2011). From 1997 to 2010, approximately 54.5 GW of PV cells were produced globally, and an estimated 39.5 GW were installed over the same period (Mehta 2011, EPIA 2011). The discrepancy between produced and installed figures can be attributed to broken or defective panels and those stored in warehouses as inventory for future installations.

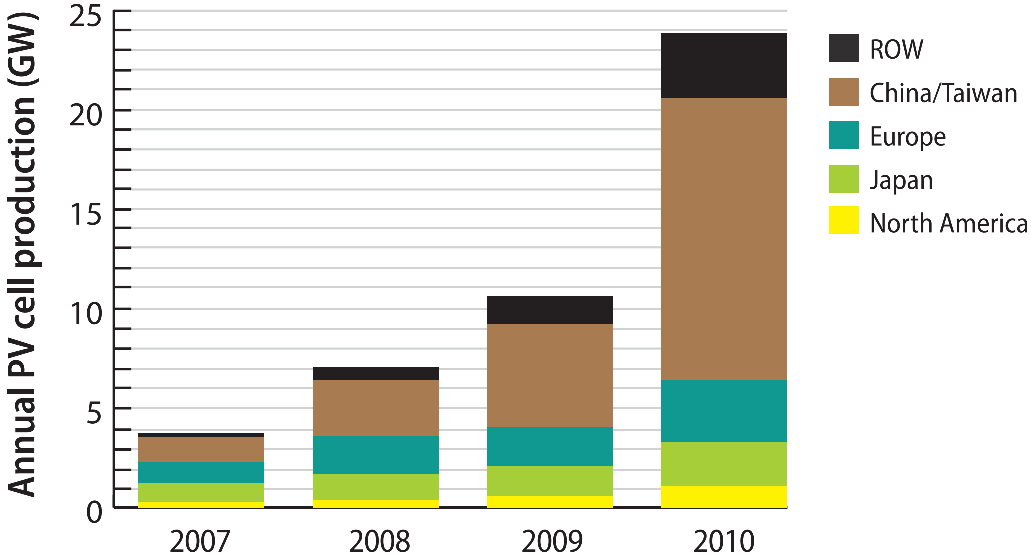


Figure 2.1. Global annual PV cell production, by region (Mehta 2011)

While previously the United States was a world leader in the production of PV, Europe and Japan achieved dominance over the market with aggressive and stable growth from 2001 to 2008. Collectively, the market share of these two regions grew to 76% in 2004, but then dropped to 53.5% in 2009, and even further to 20% in 2010. From 2009 onward, China and Taiwan outpaced all other countries in production growth.

China and Taiwan's cell production grew by over 150% in the last year and by over 1,000% since 2007 (Mehta 2011). Nearly every other country's market share has diminished relative to China and Taiwan's. In 2010, China produced 10.8 GW, nearly half of global cell production that year. Meanwhile, Taiwan's 2010 cell production surpassed all of Europe's, with 3.4 GW (Mehta 2011). The ROW countries also experienced tremendous growth, with a 118% increase in annual cell production in 2010. In 2007, the ROW countries' global production share totaled 6%, rising to 13.8% by the end of 2010. Meanwhile, North American market share remained relatively steady in recent years, producing 580 MW for just over 5% of the global market in 2009, and 1,116 MW for 4.7% market share in 2010 (Mehta 2011).

The market for solar PV production remains largely fragmented, with numerous companies competing for market share. Figure 2.2 offers some insight into the production of PV worldwide, with the top 10 global suppliers contributing 44% of total PV cell production in 2010. Figure 2.3 shows production data for these same companies from 2007 to 2010. Japan-based Sharp Corporation was the global leader in PV production between 2000 and 2006. In 2007, Germany-based Q-Cells overtook Sharp to become the world's number one producer, with 390 MW of output. Q-Cells maintained its top position in 2008, but was surpassed by First Solar, Suntech Power, and Sharp in 2009 due to a 6% reduction in output between 2008 and 2009. In 2010, Suntech Power surpassed First Solar as the leader of cell manufacturers worldwide. First Solar, the top cell producer in 2009, was the third largest at the end of 2010, with JA Solar ranking second.

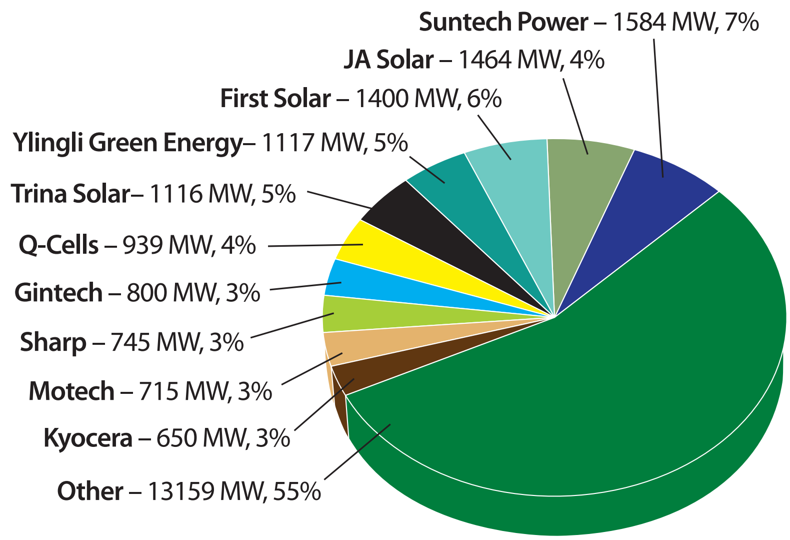


Figure 2.2 Top 10 global PV cell producers in 2010, with market share (%) (Mehta 2011)

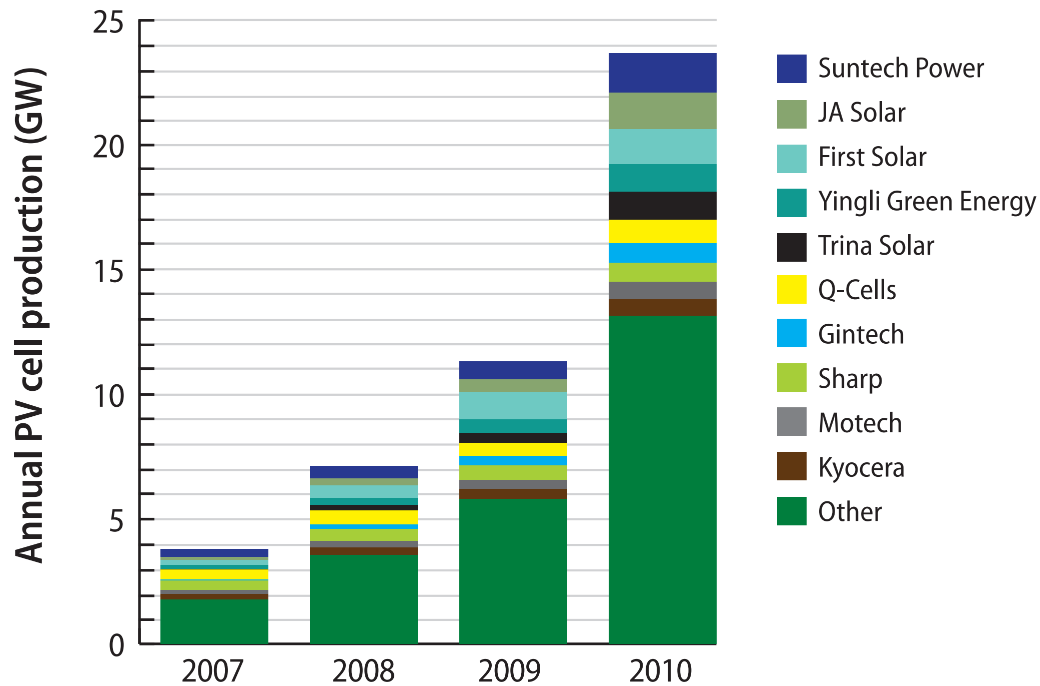


Figure 2.3. Global annual PV cell production from 2007 to 2010, by manufacturer (Mehta 2011)

Suntech Power, a China-based c-Si company, has seen impressive growth rates in recent years, with a 125% increase in cell production to 1,584 MW in 2010, up from 700 MW in 2009. Suntech also boasted a 5-year shipment CAGR of 121% at the end of 2010. These high-growth rates helped Suntech become the top manufacturer in 2010. Suntech's success can be attributed to its very competitive pricing and high-quality products (Mints 2011). The Chinese company had a manufacturing capacity of 1,800 MW by the end of 2010, with a forecast for 2,400 MW by the end of 2011 (Hering 2011).

JA Solar, another China-based company, was the second largest cell producer in 2010. With a 2010 production of 1,464 MW, JA Solar increased production by 188% from 2009 levels. The company, like many of the top Chinese producers, has seen impressive growth in recent years. JA Solar's shipment CAGR was 143% from 2007 through 2010 (Mints 2011). The Chinese company has plans to boost manufacturing capacity to 3,000 MW by the end of 2011, from a 2010 capacity of 2,100 MW (Hering 2011).

First Solar, a U.S. company, ranked third in 2010 global PV cell production and was the only firm amongst the top 10 producers that specializes in thin-film modules. First Solar became a public company at the end of 2006 and has demonstrated tremendous growth since then ranking as the top global producer in 2009. First Solar's U.S.-based facility produced the second largest domestic PV cell output in 2010, and the company remains the world's largest manufacturer of thin-film modules (Hering 2011). First Solar increased total production by 26% to 1,400 MW in 2010, up from 1,110 MW in 2009 (Mehta 2011). The majority of First Solar's manufacturing occurred in Malaysia (67%), with the remaining output split between U.S. and German facilities (Hering 2011).

2.1.2 U.S. PV Production

2010 was a strong year for U.S. PV manufacturing. U.S. PV cell production capacity reached 2,112 MW_{DC} in 2010, with cell production across all technologies increasing by 88% to reach approximately 1,100 MW_{DC} by the end of the year. Figure 2.4 illustrates a breakout of the U.S. annual PV cell production, across technologies, since 2007. Despite the dramatic rise in U.S. manufacturing, domestic gains lag behind the astronomical growth in China, Taiwan, and ROW countries.

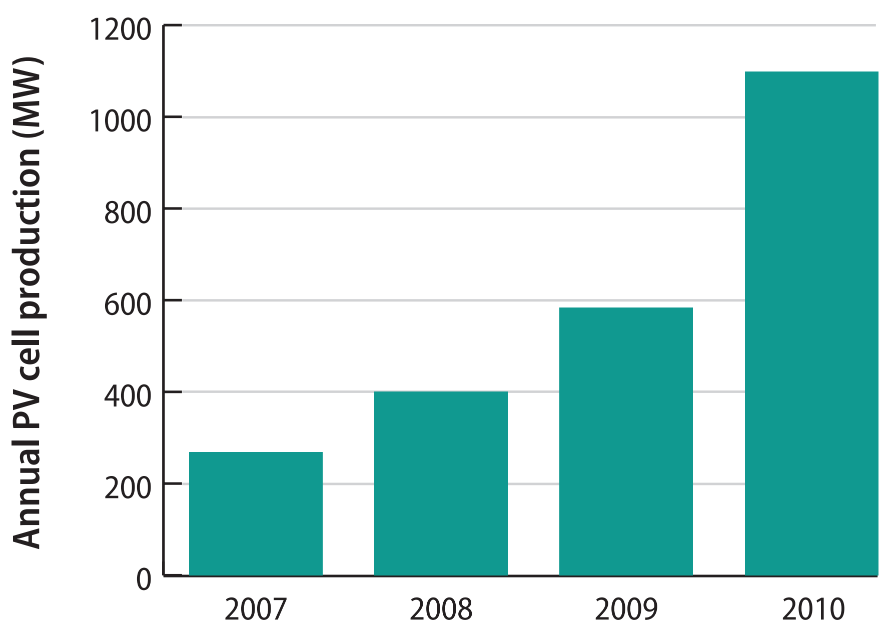


Figure 2.4 U.S. annual PV cell production, all technologies (SEIA/GTM 2011)

Thin-film PV cells and modules produce electricity via extremely thin layers of semiconductor material made of cadmium telluride (CdTe), amorphous silicon (a-Si), copper indium gallium diselenide (CIGS), copper indium diselenide (CIS), as well as other materials using emerging technologies. The United States produced 485.3 MW of thin-film cells and 468.1 MW of thin-film modules in 2010. With c-Si cell and module production totaling 614.5 MW and 799 MW-, respectively, U.S. production of c-Si continues to outpace U.S. production of thin films. Despite the dominant market share of c-Si, the United States is a leader in early-stage thin-film PV technologies over other countries, for thin films are less labor intensive than c-Si modules and require a skilled workforce to maintain high efficiencies and production yields. Moreover, the United States has a well-established specialty gas infrastructure, including trichlorosilane, a byproduct of polysilicon feedstock production. Such gases can be used as inputs for thin-film manufacturing, furthering the United States' comparative advantage in thin-film PV.

While First Solar's domestic manufacturing facility was previously the top ranked in output amongst U.S. facilities, Solar World led domestic PV cell production, with 251 MW produced in 2010. First Solar ranked second, with 222 MW, produced the same year. Suniva ranked third, with 170 MW, up from only 16 MW produced in 2009. Having completed its first 32 MW manufacturing line in November 2008, and an additional 64 MW line in 2009, Suniva increased production capacity again in July of 2010. With the increase in Suniva's production, Evergreen Solar assumed fourth position, with 158 MW produced. United Solar Ovonic (Uni-Solar) was the fifth largest producer of PV domestically, with 120 MW of production in 2010. In 2010, Solyndra more than doubled production, increasing output from 30 MW in 2009 to 67 MW in 2010. Figures 2.5 and 2.6 summarize U.S. annual PV cell production, by manufacturer.

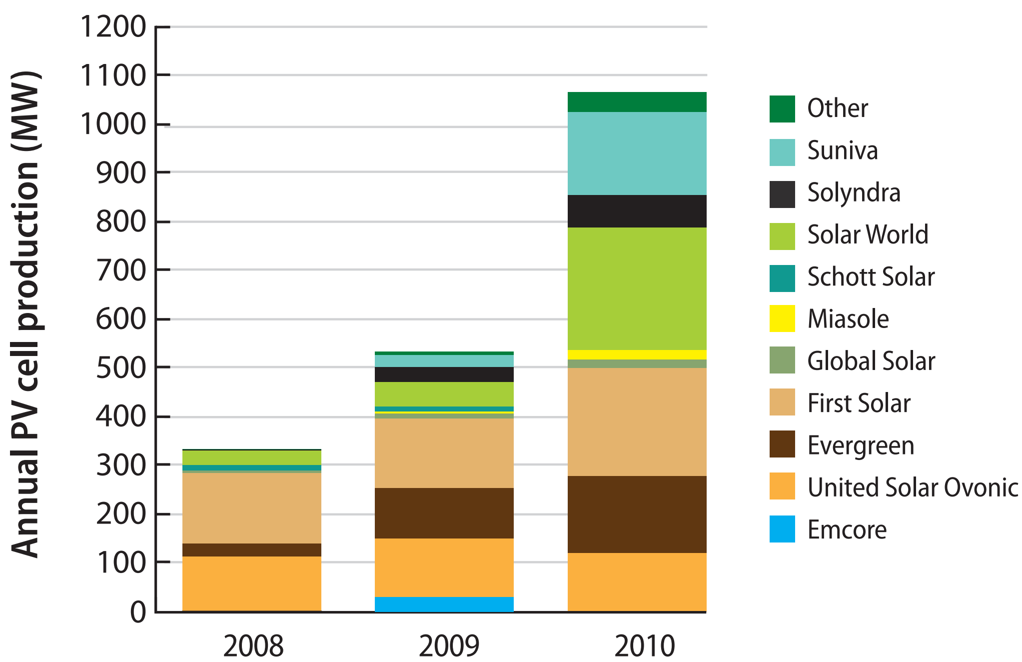


Figure 2.5 U.S. annual PV cell production, by manufacturer (SEIA/GTM 2011)

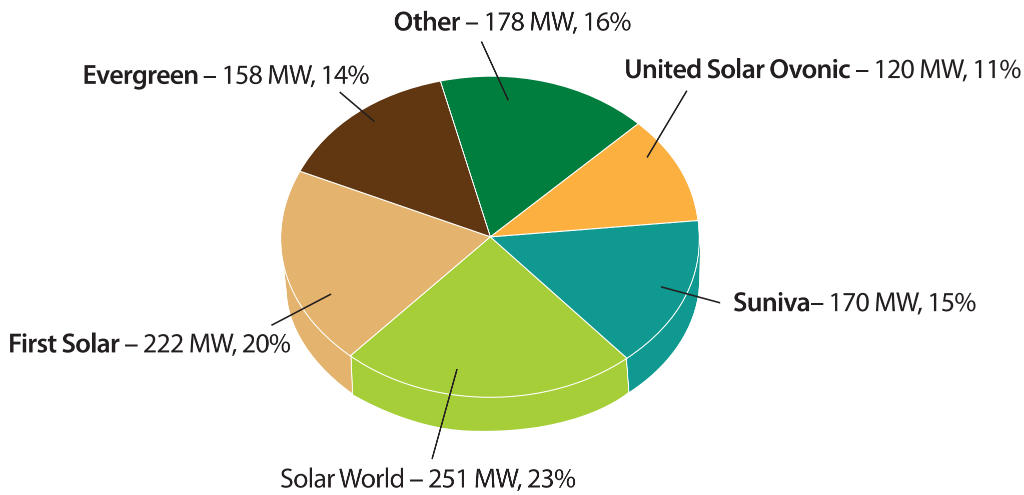


Figure 2.6 Top U.S. PV producers 2010, with market share (%) (SEIA/GTM 2011)

2.2 Global and U.S. PV Shipments and Revenue

Companies covered in this section manufacture technology as cells, cells to modules, and thin-film panels. Companies that buy cells from technology manufacturers and assemble the cells into modules are not included in this analysis to avoid potential double-counting and because they are considered part of the demand-side market participants.

2.2.1 Global PV Shipments

It is estimated that from 1976 to 2010, a total of 41 GW of PV modules were shipped globally (Mints 2011). When examining global shipments of PV cells and modules combined, the shipment sector has experienced extensive growth, with a 5-year CAGR of 65% from 2005 to 2010. Yearly growth from 2009 to 2010 was 119%, with 17.4 GW shipped in 2010 compared to only 7.9 GW shipped the year prior (Figure 2.7). In terms of global market share for total PV shipments, China and Taiwan have seen a tremendous rise in the last few years, moving from contributing 25% of the global market for PV shipments in 2007 to 54% of the market in 2010. Since 2004, no region has enjoyed more rapid growth in shipments than China and Taiwan, with an unprecedented 5-year CAGR of 156%. In 2006, China's and Taiwan's shipments surpassed those of the United States to become the third-largest contributor to global PV shipments. By the end of 2009, China and Taiwan had risen to the top position with 36 GW shipped.

As China and Taiwan continue to gain global market share, previously established market dominants, such as Europe, Japan, and the United States display relative declines. Europe's market share declined from 32% in 2007 to 15% in 2010. During this same period, Japan experienced a market share drop from 29% to 12%. U.S. market share of PV cell and module shipments also decreased from 8% to 6% between 2007 and 2010. Meanwhile, shipments from ROW countries, excluding China and Taiwan, rose from 5% in 2007 to 14% in 2010.

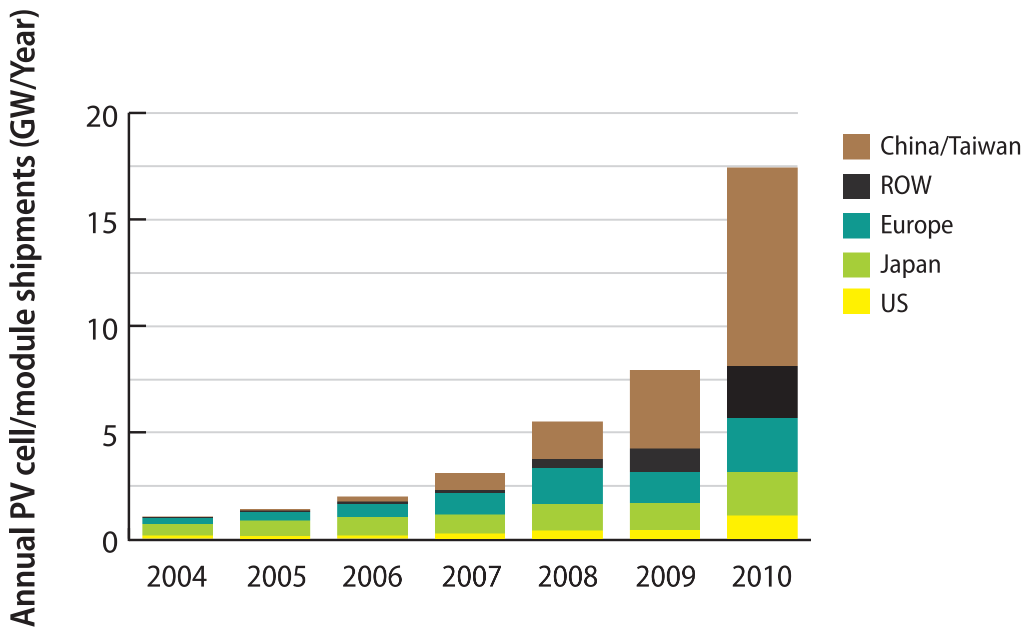


Figure 2.7 Global annual PV cell and module shipments, by region (Mints 2011)

Figure 2.8 and 2.9 show 2010 PV shipments for the top global manufacturers. In 2007, Sharp was the leading exporter of PV cells and modules. By 2008, however, both Q-Cells and Suntech overtook Sharp by shipping 550 MW and 500 MW, respectively.

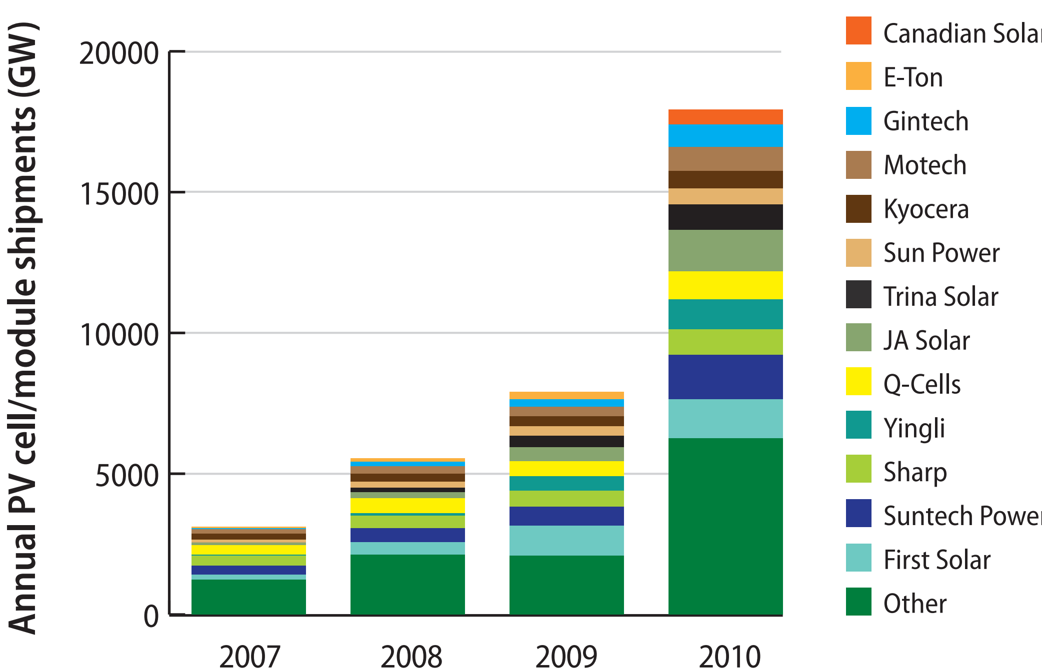


Figure 2.8 Global annual PV cell and module shipments, by manufacturer (Mints 2011)

In terms of shipments in 2010, Suntech overtook First Solar to become the largest contributor to global shipments, with 1.57 GW shipped. Behind Suntech, JA Solar shipped 1.46 GW of PV, and First Solar ranked third by shipping 1.38 GW. In 2010, Yingli ranked fourth in terms of PV shipments, increasing shipments from 525 MW in 2009 to 1.06 GW in 2010, a growth rate of 102%. For the first time, Canadian Solar ranked amongst the top 12 global companies for PV cell and module shipments, with 526 MW shipped in 2010.

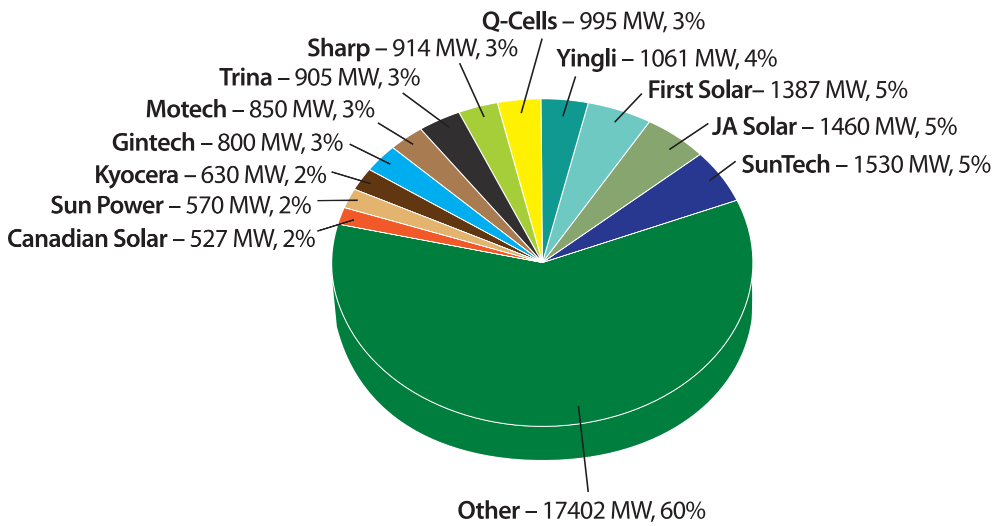


Figure 2.9 Top 12 global companies for PV cell and module shipments 2010, with market share (%) (Mints 2011)

2.2.2 Global PV Cell/Module Revenue

In 2010, global cell and module revenue increased by 85% from $16.8 billion in 2009 to $31.1 billion (Mints 2011). From 2005 to 2010, global cell and module revenues increased by a CAGR of 45%. Figure 2.10 provides revenue and associated data for the top global contributors to PV shipments. Suntech, Sharp, and First Solar were the top earners in 2010, bringing in $2.7, $2.5, and $2.18 billion in cell and module revenue, respectively.

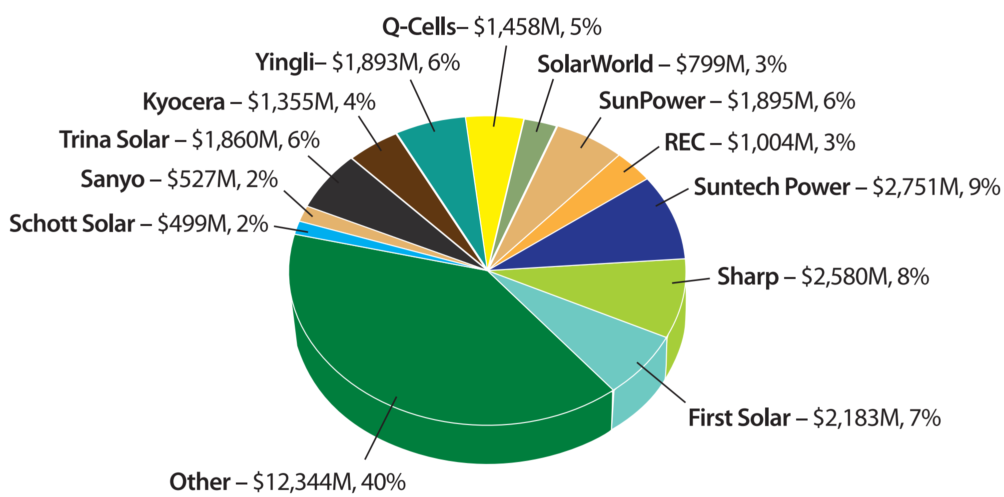


Figure 2.10 Top global companies for PV cell and module revenues 2010 (Mints 2011)

Crystalline silicon cells and modules continue to dominate the world market, but the total market share of c-Si modules has dropped from a peak of 95% in 2004 and 2005 to about 85% in 2010. As seen in Figure 2.11, polycrystalline cells represented 48% of market share worldwide in 2010, followed by monocrystalline cells at 37% and ribbon crystalline (Ribbon Si) at 2%. Today, thin-film technologies are gaining traction. Globally, thin-film technology shipments grew by 72% in 2010 compared to 2009, despite the fact that thin-film's overall market share decreased from 17% in 2009 to 13% in 2010.

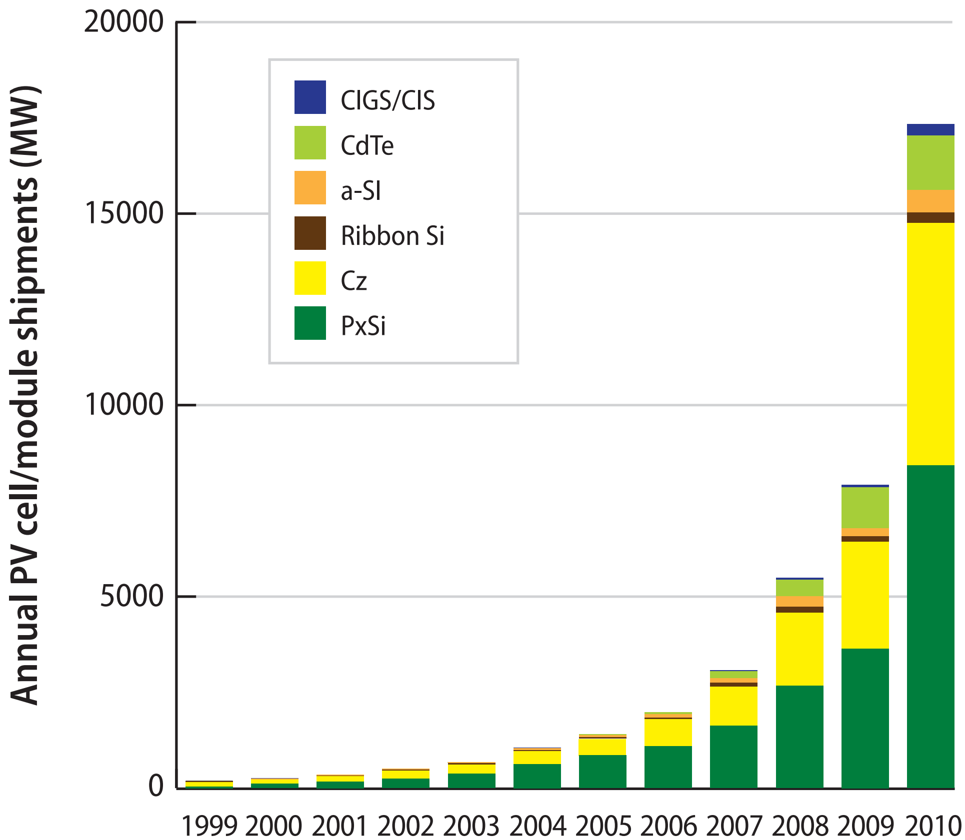


Figure 2.11 Global annual PV cell and module shipments, by PV technology (Mints 2011)

2.2.3 U.S. PV Shipments

During the past 10 years, the United States has seen steady growth in PV shipments analogous to the global PV shipment trends, with a 10-year CAGR of 30% and a 5-year CAGR of 52% through 2010. Figure 2.12 illustrates the annual growth in PV shipped from the United States. In 2004, U.S. shipments grew significantly, up 30% from 2002. From 2004 to 2006, the U.S. market stagnated slightly, averaging 140 MW shipped annually over the 3-year span. After 2006, however, U.S. shipments returned to a state of steady growth. Despite one of the worst recessions in recent history, the United States' PV shipments increased by 5% in 2009, for a total of 410 MW shipped. In 2009, the United States was the fifth-greatest contributor (by region/country) to PV shipments with a 5% global market share. In 2010, the United States' market share of global PV shipments increased to 6%, for a total of 1.1 GW shipped.

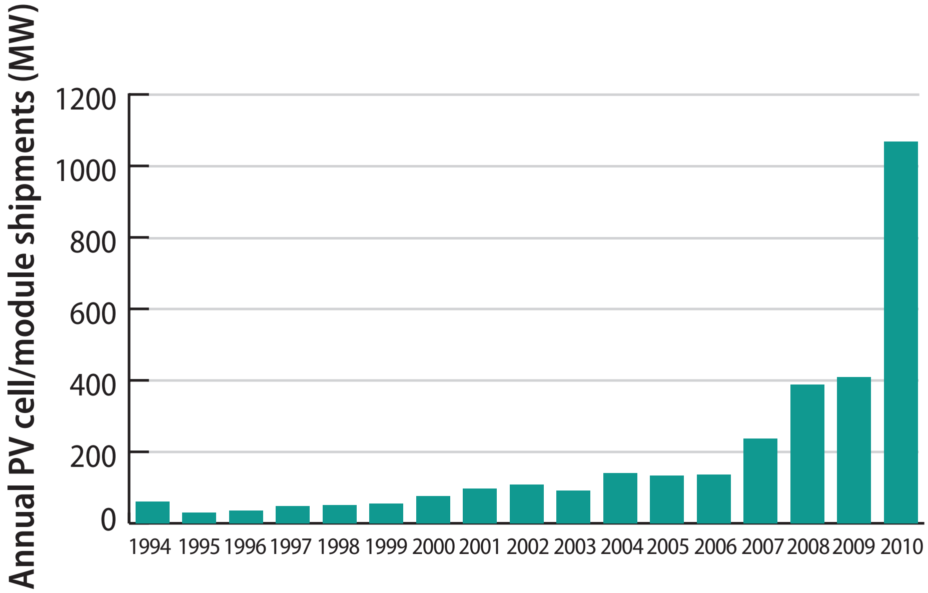


Figure 2.12 U.S. annual PV cell and module shipments, 1997-2010 (Mints 2011)

The United States more than doubled annual PV shipments in 2010 over 2009, despite the closure of three domestic manufacturing facilities—BP Solar's plant in Maryland, Spectrawatt's cell manufacturing facility in New York, and Evergreen's 160-MW plant in Massachusetts. The leading U.S. producer in 2010 was SolarWorld, shipping 254 MW for the year. The former leading U.S. and global PV manufacturer, First Solar, shipped 229 MW from its U.S.-based facility and 929 MW from its Malaysia facility in 2010. Ranking third and fourth in terms of domestic shipments was Suniva and Uni-Solar, shipping 132 MW and 120 MW, respectively. Other significant contributors to U.S. PV shipments in 2010 were Solyndra (58 MW) and Cali Solar (40 MW). Figures 2.13 and 2.14 depict U.S. annual PV cell and module shipments, by manufacturer, and the top U.S. companies in 2010.

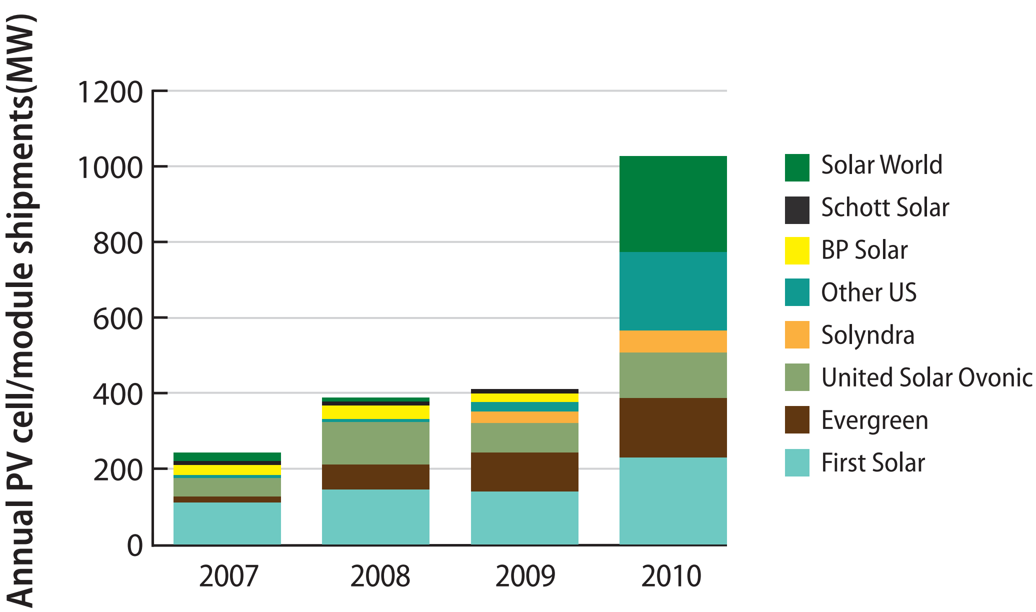


Figure 2.13 U.S. annual PV cell and module shipments, by manufacturer (Mints 2011)

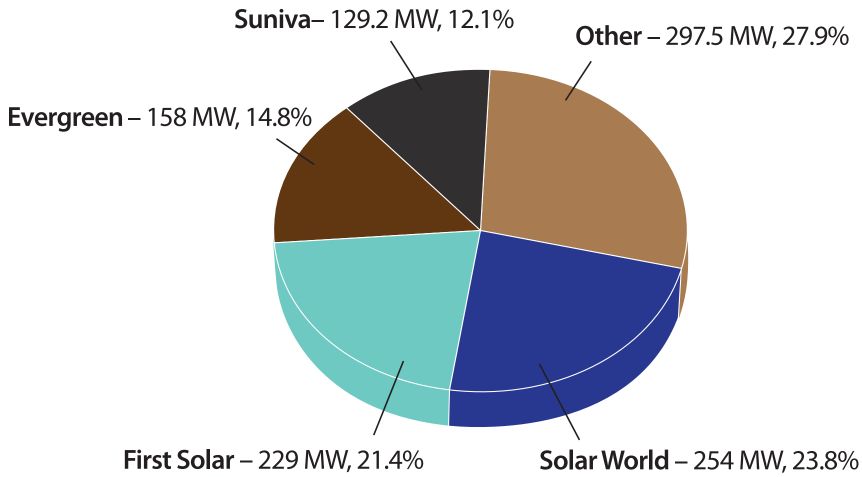


Figure 2.14 Top U.S. companies for PV cell and module shipments 2010, with market share (%) (Mints 2011)

2.2.4 U.S. PV Cell/Module Revenue

U.S. revenue from PV cells and modules reached $1,876 million in 2010, up 99% from $941 million in 2009 (Mints 2011). As shown in Figure 2.15, among U.S. companies in 2010, SolarWorld had the highest revenue at $457 million, with First Solar ranking second at $361 million. Both Solar World and First Solar have more than 20 years of PV production experience. Meanwhile, Evergreen, UniSolar, and Suniva earned $334 million, $227 million, and $219 million in revenue, respectively.

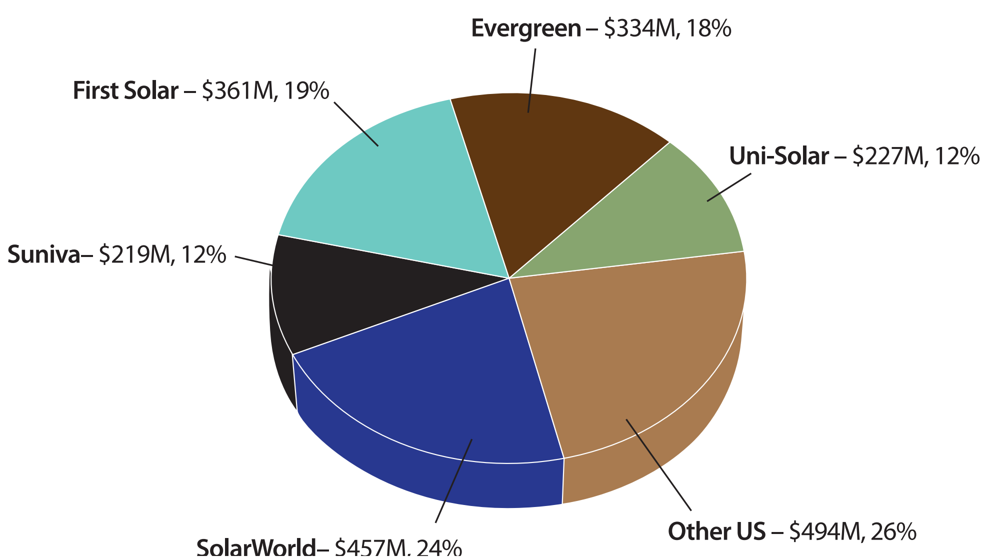


Figure 2.15 Top U.S. companies for PV cell and module revenues 2010 (Mints 2011)

2.2.5 U.S. PV Imports and Exports

Figure 2.16 presents data on U.S. PV cell and module imports and exports through 2009, including both c-Si and thin-film. Due to availability of data, 2010 is not included. From

1999 to 2004, U.S. PV cell and module exports significantly exceeded imports. This changed in 2005, when the U.S. increased imports of c-Si modules and cells, making imports and exports nearly even. In 2006 and 2007, U.S. total PV cell and module imports exceeded exports for the first time. Although U.S. thin-film exports doubled each year from 2005 to 2007, dominating U.S. exports in 2007, the demand for c-Si modules in the United States grew significantly during the same period. As a result, imports of these modules more than doubled exports in 2006, 2007, and 2008. This rapid growth in demand, beginning in 2006, was in response to the federal investment tax credit for PV systems, included in EPAct of 2005, and extended in 2008. In spite of increasing growth in demand worldwide for crystalline modules, U.S. exports of crystalline PV have remained fairly flat, with the increase in exports coming entirely from the fast-growing, thin-film industry. In 2009, the United States imported a majority of its cells and modules (82%) from Asian countries, including the Philippines (25.59%), Japan (24.85%), and China (22.68%). The remainder of imports came from Taiwan, Hong Kong, India, Germany, Spain, and Mexico.

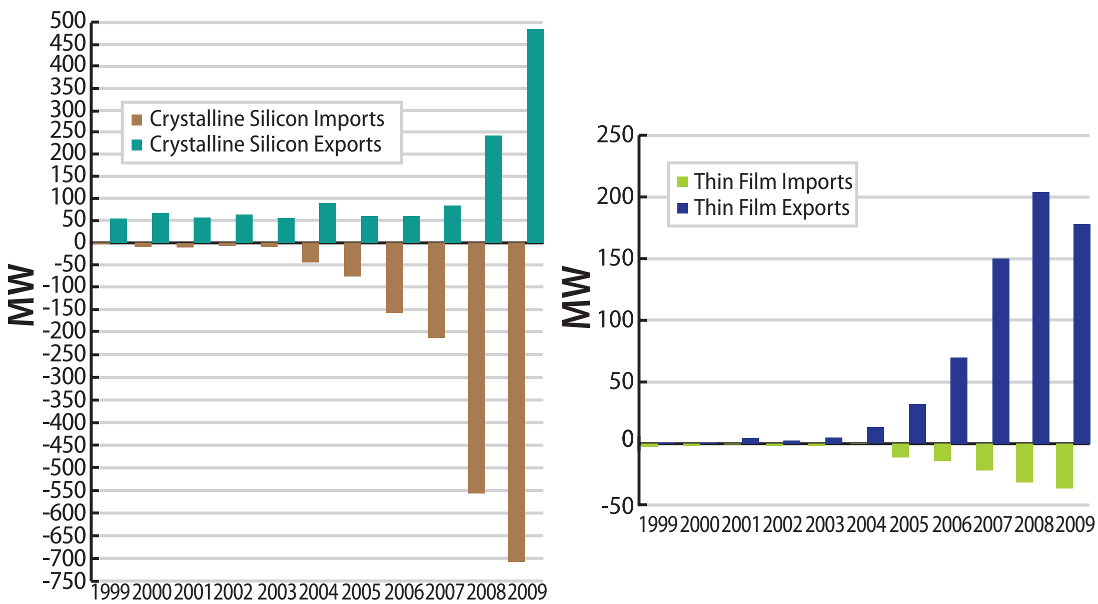


Figure 2.16 U.S. PV cell and module shipments, exports, and imports (U.S. Energy Information Administration [EIA] 2011)

In 2009, 83% of U.S. PV exports were destined for Europe and 9% went to Asia (Figure 2.17). The dominance of the European market was due primarily to significant government incentives. Germany, Italy, and France were the top importers of U.S. cells and modules in 2009, representing 45%, 16%, and 7% of U.S. exports, respectively.

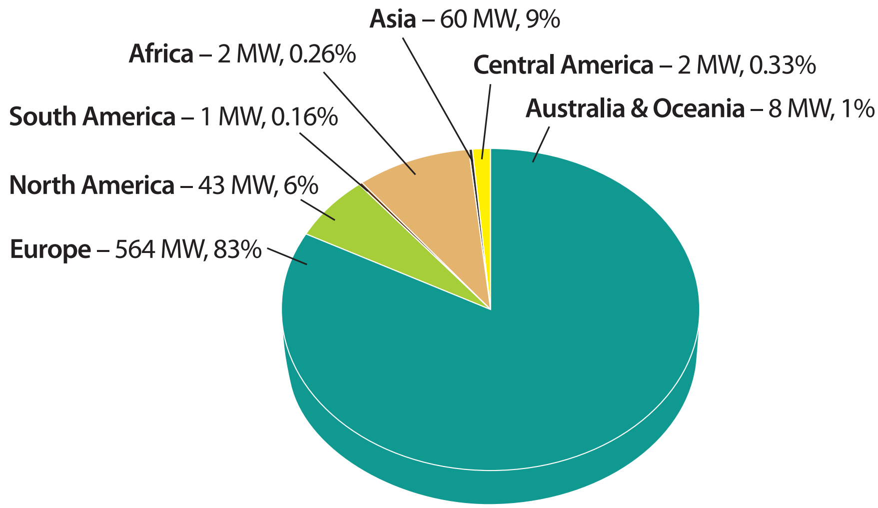


Figure 2.17 U.S. exports of PV cells and modules (MW) 2009, by destination (EIA 2011)

2.3 CSP Manufacturer and Shipment Trends

While the vast majority of the market for concentrated solar energy resides in the United States and Spain, there are important global industry trends that are worthy of consideration.

2.3.1 CSP Manufacturers

Reflectors, receivers, and turbines are the three major components in CSP technologies that are currently being installed worldwide. Table 2.1 lists the major manufacturers of each of these components.

TABLE 2.1. CSP COMPONENT MANUFACTURERS

Reflectors	Receivers/Engines	Turbines
Alanod	Areva	ABB
eSolar	Babcock & Wilcox	Alstom
Flabeg	Babcock Power	GE-Thermodyn
Guardian	Infinia	MAN Turbo
Patriot Solar Group	Pratt & Whitney	ORMAT
PPG Industries	Schott	Siemens
ReflecTech	Sener	
Rioglass	Siemens	
	Solel	
	Stiring Energy Systems	

(GTM 2011, CSP Today January 2010)

To date, glass has been the leading material for CSP reflectors. However, 2010 saw a range of polymer and alloy alternatives proving to be competitive with the traditional glass reflectors. Historically, Flabeg has been the primary manufacturer of bent glass reflectors, providing products with 95% or better reflectivity. PPG Industries and Rioglass also manufacture glass reflectors, but aim to lower capital costs of glass and increase durability. Emerging companies such as ReflecTech and 3M were offering polymer films with equal, if not better, reflectivity, are up to 60% lighter, and said to be more durable than glass. Alloy mirrors are also contending with glass reflectors. The mirrors had comparable performance and durability, while being lighter and therefore less labor-intensive to manufacture and install. Patriot Solar

Group introduced a clear, acrylic plastic surface with an aluminum or zinc backing, while Alanod-Solar was manufacturing nano-composite-coated, anodized alloy Miro-Sun mirrors. Glass manufacturers such as Rioglass suggest that polymer films suit only smaller installations with less serious durability requirements. Experts suggest that while polymer films have lasted through weathering and accelerated life-cycle tests, their real-life durability in large CSP plants will have to be proven before they can dominate the market over traditional glass technology (CSP Today January 2010, Grama et al. 2008).

For receivers, Solel was historically the dominant manufacturer. However, in late 2009, Solel was purchased by the German turbine manufacturer, Siemens. Solel continues to manufacture the same solar receivers that are installed in a number of high-profile CSP plants; only now with Siemens' financial backing and synergies in the CSP technical field (CSP Today October 2009). The only other major solar receiver manufacturer is Schott Solar Systems, a company that recently became a significant player. In 2009, Schott expanded its North American sales operations, began collaborating with NREL to develop an improved absorber coating for receivers, and consequently won the 2010 CSP "Best Applied Research and Development" award given out by CSP Today (Schott Solar 2010).

For turbines, ABB, GE-Thermodyn, and Siemens are major manufacturers, and companies such as Alstom, MAN Turbo, and ORMAT were looking to gain market share.

2.3.2 CSP Shipments

Annual U.S. shipments of CSP dish and trough collectors remained relatively constant from 2000 to 2003, as shown in table 2.2. A noticeable increase occurred in 2005, followed by a substantial increase in 2006. The significant increase in 2006 was primarily the result of a 64-MW CSP plant built in Nevada. The facility, Nevada Solar One, consists of 760 parabolic reflectors comprising nearly 219,000 individual mirrors. It was the world's largest plant built in 16 years (U.S. EIA 2010b). In 2007, shipments dropped back down to a level more in line with shipments prior to the construction of the Nevada Solar One project. However, as shown in table 2.2, 2008 dish and trough collector shipments experienced a significant increase to 388,000 ft^2. This market momentum carried forward into 2009, and by year's end, the United States annual CSP shipments had increased three-fold over 2008, to 980,000 ft^2. The marked growth in CSP shipments in 2009 propelled high-temperature collectors to make up 8% of total solar thermal collector shipments, across types. Due to availability of data, dish and trough collector shipments for 2010 are not included.

2.3.3 Material and Supply-Chain Issues

This section seeks to identify the initial source of materials and the process by which those materials are gathered or created to construct the cells, modules, and other system components used across solar systems worldwide.

2.3.3.1 Polysilicon Supply for the PV Industry

This section presents information on polysilicon manufacturing and its importance to the PV industry, the historical and 2010 market, and forecasts and trends. About 92% of PV cells produced in 2010 used c-Si semiconductor material derived from polysilicon feedstock, for a total production of 21 GW. This represents a 142% increase over 2009 (Mehta 2011). Polysilicon is silicon purified for use in making semiconductors. Solar-grade polysilicon is silicon refined to be at least 99.999999% pure (Winegarner and Johnson 2006). The polysilicon supply and demand imbalance that became widely recognized around 2005 was caused not by a lack of silicon (silicon is the second most abundant element in the earth's crust, behind oxygen) but by a lack of capacity for purifying silicon into solar-grade material.

Producing solar-grade polysilicon is a complex and capital-intensive process. Quartz is heated in the presence of a carbon source to produce liquid silicon. After being refined, the liquid silicon is allowed to solidify to become metallurgical-grade silicon (MG-Si), which has an average purity of 98.5% (Bradford 2008). MG-Si is a relatively abundant and inexpensive commodity worldwide. However, it must be processed further to achieve solar-grade purity using one of several processes. The following three processes are currently the most commonly used means to purify silicon into solar-grade material:

- Siemens process (chemical deposition)
- Fluidized bed reactor (FBR) process (resulting in granular silicon)
- Upgraded MG-Si (UMG-Si) processes.

The Siemens process is the most widely used, followed by FBR. Siemens and FBR facilities are capital-intensive, typically costing between \$80 and \$120 per kilogram (kg) per year. Moreover, they require a lead time of 18 to 36 months from planning to production (Hirshman 2010). UMG-Si processes, which enhance the purity of MG-Si, promise substantial cost and time savings over the Siemens process and FBR. However, the UMG-Si product is of lower purity and must be blended with purer polysilicon for PV applications (Bradford 2008). Maintaining polysilicon quality is critical. Even small decreases in PV efficiency resulting from using lower-quality polysilicon can offset the savings gained from using the lower-quality polysilicon (Rogol et al. 2006). A variety of other polysilicon production processes, such as vapor liquid deposition, promise potential cost and production-rate advantages if they can attain commercial performance goals (Bradford 2008).

Another source of solar-grade polysilicon is the electronics industry. However, polysilicon used in this industry must be even purer than solar-grade polysilicon. About 10%–20% of the off-specification and scrap polysilicon sold to the electronics industry eventually becomes available to the solar industry (Bradford 2008, Winegarner and Johnson 2006).

Beginning around 2004, an imbalance between polysilicon supply and demand contributed to increasing prices. For years, the PV industry had subsisted largely on leftover polysilicon from the electronics industry. However, polysilicon demand for PV surpassed the demand for electronics in 2007, and today solar is the primary driver of growth in polysilicon production (Bartlett et al. 2009). Production facilities, with high capital costs and lengthy construction times, were unable to respond immediately to the PV-driven spike in polysilicon demand. This resulted in a supply/demand imbalance and a more than doubling of the average polysilicon contract price between 2003 and 2007 (Bradford 2008, Mehta and Bradford 2009).

The increase in polysilicon prices prompted a dramatic increase in new producers, investments in new production capacity, and cutting-edge technologies (including UMG-Si). In 2008, the additional polysilicon production capacity initiated in 2005 to satisfy unmet demand began production after 24–30 months of construction (Bradford et al. 2008c). By mid-2008, the tightness in polysilicon supply began to ease, and PV cell and panel manufacturers reported that suppliers were more willing to sign long-term contracts with new partners (Bradford et al. 2008b, Bradford et al. 2008c).

The United States produced 42,561 metric tons (MT) of polysilicon in 2010, approximately 30% of global supply. The median estimate of total polysilicon produced in 2010 was 148,750 MT, of which about 81% (or 120,400 MT) was produced for the solar industry. In addition to these numbers, scrap polysilicon from the electronics industry has always supplied the solar industry with varying amounts of the material. The total 2010 production of polysilicon represented an estimated 60% increase over 2009 production.

Most of the polysilicon supply is sold under contract, with only a small proportion available on the spot market; some PV manufacturers pay the higher spot market prices because they cannot secure long-term contracts due to onerous upfront cash requirements or because additional capacity requirements cannot be met by their contracted polysilicon supply (Bradford 2008). While spot market prices for polysilcon decreased from 2008 to 2009, they rose in 2010. Spot prices topped $450/kg in early 2008, but they dropped to less than $150/kg by early 2009 (Wu and Chase 2009). By the end of 2009, spot prices were nearly the same as contract prices, at about $70/kg. By the end of 2010, spot prices had risen to $80–$90/kg (SEIA/GTM 2011). With respect to polysilicon production, analysts who released reports in 2010 projected 180,000–227,000 MT of polysilicon production by 2012, an 80% to 127% increase over 2009 (Figure 2.18).

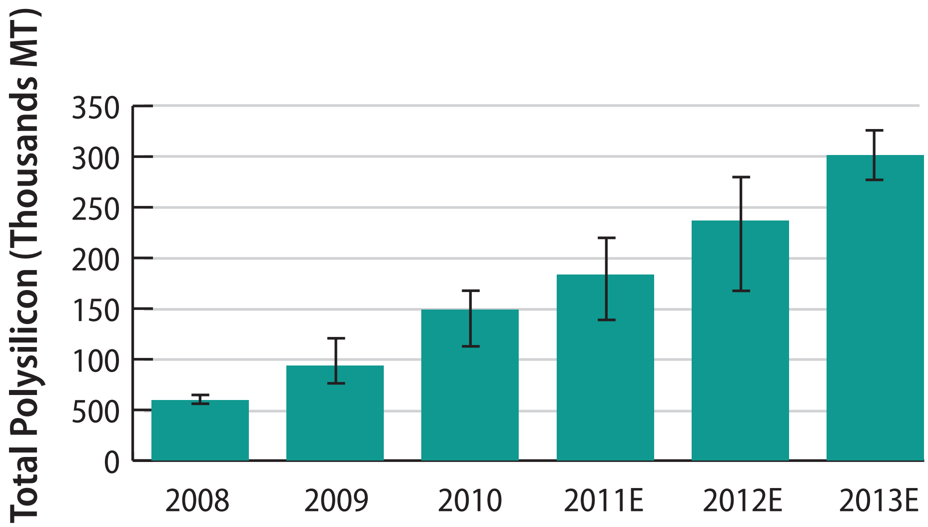


Figure 2.18 Polysilicon supply projections through 2013 (Bloomberg New Energy Finance 2011, J.P. Morgan Chase 2011, Stifel Nicolaus 2011, Simmons 2011)

The projected increase in polysilicon supply is expected to meet or exceed PV demand for the next several years. Several major trends will influence polysilicon supply and demand during this period, with the potential to increase supply or decrease demand beyond current projections:

- **Improved silicon utilization.** The PV industry has continued to improve silicon utilization (watts of PV per gram of polysilicon) by decreasing silicon wasted during manufacturing, producing thinner wafers, improving polysilicon scrap recycling capabilities and costs, introducing low-cost polysilicon feedstock purification methods, and producing cells with higher efficiency. In addition, increased use of UMG-Si can help improve silicon utilization. As discussed above, UMG-Si processes could offer substantial cost and time savings over the Siemens process and FBR. If technology is developed to enable the use of UMG-Si in blends higher than the current level of 10%, UMG-Si could become a larger source of low-cost PV feedstock.

- **Market penetration of thin-film PV.** Thin-film PV, which requires little or no polysilicon feedstock, has become a major competitor to c-Si PV.

Other factors that could affect the supply of or demand for polysilicon include larger-than-expected polysilicon production by companies based in China, technological breakthroughs (e.g., rapid penetration of concentrating PV), manufacturing disruptions (e.g., an accident in a very large polysilicon manufacturing facility), PV supply-chain disruptions (e.g., shortages of solar-grade graphite or glass), changes in PV-related government policies, and other "macro shocks" (e.g., large-scale natural disasters or epidemics) (Rogol et al. 2008).

2.3.3.2 Rare Metals Supply and Demand for PV

As discussed above, thin-film PV technologies, which use a hundred times less silicon than conventional crystalline cells (e.g., for a-Si PV) or use no silicon at all (e.g., for CdTe, CIGS, and CIS PV), were projected to garner 19%–22% of the PV market by 2012 (Mehta 2010). This large-scale production has raised concerns about the supply of rare metals that are used as semiconductor materials in some thin-film PV technologies, such as indium, gallium, and tellurium (Grama and Bradford 2008). The metals of primary concern are indium, which is used in CIGS, and tellurium, which is used in CdTe. The market supply and demand for each of these metals are described in more detail below.

The estimated worldwide indium reserve base was 16,000 MT in 2007, and annual production was 574 MT in 2010 (USGS 2011). CIGS PV requires approximately 30 MT of indium per GW (NREL 2010b). With projected production growth to 3.1 GW by 2012, CIGS PV will require approximately 90 MT of indium (15% of current annual production) by that year (Grama and Bradford 2008). Competing uses for indium include liquid crystal displays, integrated circuits, and electronic devices. The price of indium recovered in 2010, after sharp declines in 2009. The U.S. producer price for indium was \$500/kg at the end of 2009 and increased to \$570/kg in late January 2010; the price remained at that level until mid-September 2010 (USGS 2011). Indium recycling could increase significantly and alternative sources could be developed if the indium price remains elevated. Indium has substitutes, but they usually lead to losses in production efficiency or product characteristics.

CIGS PV requires approximately 8 MT of gallium per GW (NREL 2010b). Gallium prices increased during the second and third quarters of 2010. U.S. importers paid \$670/kg for gallium in 2010[8] compared to \$480/kg in 2009 (USGS 2010). Gallium can be used in some applications as a substitute for indium in alloys. In glass-coating applications, silver-zinc oxides or tin oxides can be used. The United States has no primary indium or gallium production capacity. Consequently, most reserves were located in other countries, and these rare metals must be imported into the United States.

Based on different estimates of rare metal supply, tellurium has been estimated to limit total thin-film capacity to about 100 GW for CdTe (Feltrin and Freundlich 2008). About 1,500 MT per year of tellurium are available from extracted copper, but only one-third of that is refined due to a lack of demand. In the years to come, tellurium supply derived from extracted copper is likely to increase, as demand for both copper and tellurium increases. For modules with 11% efficiency and layers about 3 microns thick, CdTe PV requires approximately 100 MT of tellurium per GW. If CdTe module efficiency increased to 15% and layer thickness decreased to about two-thirds of a micron, only 13 MT of tellurium would be needed per GW. Competing uses for tellurium include semiconductor and electronics products, although most tellurium is used as an alloy in steel and copper. About 20% of the tellurium supply is used for CdTe PV production. The tellurium required for CdTe PV has driven a general price increase in recent years; the market price increased from \$50/kg in 2004, to more than \$225/kg in August 2008, and down to \$145/kg in 2009 due to the economic downturn. With increased demand for solar cells, the price of tellurium increased to \$210/kg in 2010. Tellurium

[8] The U.S. Geological Survey (SGS) estimate based on the average values of U.S. imports for 99.9999% and 99.99999% pure gallium.

recycling could increase significantly, and alternative sources could be developed (e.g., bismuth telluride), if the tellurium price stays high. Beyond 2012, tellurium production likely will need to increase to keep pace with demand from the solar industry (Grama and Bradford 2008, USGS 2010).

2.3.3.3 Glass Supply for PV

Glass is resistant to long-term weathering, is relatively inexpensive, and has good mechanical strength, making it an ideal encapsulation material for c-Si PV as well as an encapsulation and substrate material for most thin-film PV (glass is also the key component of the mirrors necessary for CSP technologies). The demand for solar glass is expected to see strong growth in conjunction with growing PV demand. Yole Development forecasts that solar glass demand will grow from 50 million m^2 to more than 300 million m^2 in 2015. Mark Farber, former CEO and cofounder of Evergreen Solar, notes that in 2008, PV accounted for less than 1% of the glass market, but that it could account for up to 5% by 2012 (Podewils 2008).

The glass demand for PV (as well as for CSP) is primarily for high-quality, low-iron glass. This demand is met by both the rolled-glass and float-glass markets. Rolled pattern glass is a better choice for solar applications because the patterned surface can increase the efficiency of PV modules. Also, rolled glass requires up to 80% less energy to manufacture than float glass, it can use resources with 30% more iron to achieve the same transparency, and it is 30% less expensive to produce.

There was an increasing trend, particularly in China, toward vertically integrating glass production in the PV supply chain by building rolled-glass factories on site. In doing so, supply-driven price volatility and transportation costs were minimized. China's Dongguan CSG Solar Glass Co., a subsidiary of China Southern Glass Holding, built the first factory to produce glass exclusively for the solar industry (Podewils 2008).

2.3.3.4 Material and Water Constraints for CSP

CSP facilities are constructed primarily of concrete, steel, glass, aluminum, heat-transfer fluid (HTF), and molten salt. The long-term availability of these materials at stable prices is necessary for the successful completion of CSP plants. Although these materials are not subject to rigid supply limits, they are affected by changes in commodity prices (DOE 2009). Price increases in the raw materials results in an inflation of the levelized cost of energy (LCOE) that project developers can offer to utilities.

Steel is used in CSP systems for the power block, heliostat and dish structures, piping, heat exchangers, tower structures, receivers, molten salt storage tanks, and some parabolic trough structure designs (DOE 2009). Steel is a commodity that cannot be replaced in many CSP components, including piping, turbines, structures, foundations, and pumps. The cost of steel had been fluctuating over time, rising substantially beginning in 2006 and reaching a historical high in July 2008. However, the average global price of steel steadily declined through 2008 and the first half of 2009. The second half of 2009 saw moderate price increases, but prices stayed well below the July 2008 peak. Prices have continued to rise through 2010, albeit, more gradually than in 2009 (Yahoo Finance Steel 2011). For CSP projects to be economically viable, it will be important for steel prices to remain reasonable, as project developers do not have pricing power for this commodity (Bullard et al. 2008).

Aluminum is used in place of steel for some major CSP components, making it another critical commodity for CSP plants. It is used for reflectors, structural material for extrusions (especially for parabolic troughs), and non-glass mirrors that are laminated onto aluminum sheets or are coated with aluminum. Aluminum price fluctuations track those of steel; both materials had rising prices that peaked in mid-2008, coming back down until mid-2009, and slightly rising but currently at reasonable costs (Yahoo Finance Aluminum 2011).

The combination of a limited number of companies producing the main CSP system components on a commercial scale and a large construction pipeline could create a component supply bottleneck, depending on the growth of demand. This is especially true for turbines, which require a 24–30 month advance order by the project developer (Merrill Lynch 2008). Conversely, the main materials and equipment critical to the CSP industry could leverage other manufacturing industries (e.g., automotive and buildings), potentially facilitating a relatively fast production ramp-up (Andraka 2008). In addition, some companies are entering multiple levels of the value chain, thus becoming less dependent on other companies for meeting large supply requests (e.g., Solel and Abengoa are entering the reflector market). For these reasons, many believe that reflector and receiver demand will not create bottlenecks in the near future (Bullard et al. 2008, Merrill Lynch 2008).

Aside from the aforementioned solid materials, water resources are also essential to the operation of a CSP plant and may be a limiting factor to the amount of CSP deployed in arid regions. The amount of water required varies greatly depending on the type of technology a CSP power plant uses to cool the condenser. As with fossil and nuclear power plants, the most common and economical method for cooling a CSP plant is evaporative water cooling (or "wet cooling"). Alternatively, dry cooling (also called the "Heller System") reduces water consumption by over 95% as compared to wet cooling, and the impact on CSP performance is minimal (NREL 2007). Dry cooling, however, requires higher capital expenditure and is likely to decrease plant efficiency, especially under higher-temperature conditions. The loss of efficiency is greatest for systems requiring lower operating temperatures (DOE 2009).
An NREL study (2010) demonstrates that a loss of generation capacity is not always associated with dry cooling. In the reference plant used in this study, switching from wet to dry cooling raised the plant's installed cost by about 10% and LCOE by 7%, while decreasing water consumption by 93%. LCOE was not affected as much as the installed cost because the dry-cooled plant actually produced more energy due to the utilization of an oversized solar field and power block, which maintained design-point generation at high ambient temperature. At the lower ambient temperatures, that characterize most of the year, the dry-cooled plant generates more energy than the slightly smaller wet-cooled plant. Another surprising finding from this study is that the dry-cooled plant occupies less land per megawatt-hour (MWh) than the more efficient wet-cooled plant. This occurs because the additional solar field area required to maintain the net capacity of the dry-cooled plant is offset by elimination of over 60 acres of evaporation ponds (NREL 2010a). Another cooling solution is to use hybrid wet/dry cooling, which may reduce water consumption by 50%, with only a 1% drop in annual electrical energy output. Alternatively, the system may reduce water consumption by 85%, with only a 3% drop in output, depending on how the hybrid system is operated. For closed-cycle CSP heat engines, such as dish-engine generators, air cooling is sufficient (DOE 2009).

2.3.3.5 Land and Transmission Constraints for Utility-Scale Solar

Solar project developers have been attracted to numerous locations in the Southwest. However, transmission in many of these areas is lacking and substantial upgrades to the western grid will be necessary for projects to move forward. Moreover, land-use conflicts exist, as a large percentage of the area is federal land traditionally set aside for conservation and recreational purposes. To address the transmission, grid upgrade, and land-use issues, a number of major multi-agency agreements and initiatives have arisen at the national, state, and regional levels. Five such agreements and initiatives are described in this section.
The U.S. Bureau of Land Management (BLM) and DOE are collaborating on a Solar Programmatic Environmental Impact Statement (EIS). The EIS identifies the impacts of, and

develops better management strategies for, utility-scale solar development on the public lands of six states: Arizona, California, Colorado, New Mexico, Nevada, and Utah. In June 2009, the BLM provided maps that identify 24 tracts of BLM-administered land for in-depth study for solar development. A public comment period was open until mid-September 2009. The public comments were for consideration in identifying environmental issues, existing resource data, and industry interest with respect to the proposed study areas in particular; and to explain how BLM will address existing and future solar energy development applications on BLM-administered lands. In December of 2010, the draft EIS was published for public comment, with the public comment period closing in May 2011. Further details can be found at *http://solareis.anl.gov*, and solar energy study area maps are available at *http://solareis.anl.gov/eis/maps/index.cfm*.

The Western Governors' Association (WGA) and DOE launched the Western Renewable Energy Zones (WREZ) Project in May 2008. WREZ involves working groups that are identifying high-resource areas to include in energy development and environmentally sensitive lands to exclude from this development. The WGA and DOE released a joint WREZ Phase 1 report on June 15, 2009, that took the first steps toward identifying those areas in the Western Interconnection that have both the potential for large-scale development of renewable resources and low environmental impacts. Since the publication of the report, WGA turned its focus to some key next steps: determining which of the high-quality areas are of greatest interest to electric service providers, determining how their renewable resources can best be developed, and planning for a transmission network that will bring those resources to market. In December 2009, DOE announced that a combined total of $26.5 million of stimulus money would be given to the WGA and the Western Electricity Coordinating Council. The funding will be used to analyze transmission requirements under a broad range of alternative energy futures and to develop long-term, interconnection-wide transmission expansion plans. WGA and its affiliate, the Western Interstate Energy Board, are concentrating their efforts in two major areas: continuation of activities initiated under the WREZ project and the development of transmission plans that will open up high-quality renewable resource areas. More information, including the WREZ Phase I Report, is available at *http://www.westgov.org/* (WGA 2010).

In California, the Renewable Energy Transmission Initiative (RETI) is a collaboration of public and private entities whose objective is to provide information to policymakers and stakeholders on the transmission requirements to access cost-effective, environmentally sensitive renewable energy resources. Phase one of the initiative, which was completed at the start of 2009, identified and ranked zones in California and nearby states that can provide and competitively deliver renewable energy to the state. Phase two, which includes developing conceptual transmission plans and refining previous work, was released in May of 2010. Additional information is available at *www.energy.ca.gov/reti*.

In November of 2009, Secretary of the Interior Ken Salazar announced two initiatives to speed the development of renewable energy projects on public lands. First, four Renewable Energy Coordination Offices were established across the West (in California, Nevada, Wyoming, and Arizona). Second, the BLM awarded priority processing for nine solar Right-of-Way permit applications under the Fast Track Initiative. Announced in 2009, the Fast Track Initiative expedites the permit approval process for proposed solar developments that demonstrate a strong likelihood to comply with environmental regulations. While selected projects still require rigorous reviews, they are subject to shorter approval times.

A list and status update of the solar and other renewable energy projects that are being fast-tracked are available at *http://www.blm.gov/wo/st/en/prog/energy/renewable_energy/fast-track_renewable.html*.

The long approval process for the Sunrise Powerlink Transmission Project, a 1-GW, 117-mile transmission line in California, provides an example of a project that could have benefited from the type of coordination being carried out through the above agreements and initiatives. In December of 2008, the California Public Utilities Commission approved the Sunrise Powerlink Transmission Project, which would allow San Diego Gas & Electric to connect producers in the Imperial Valley to end users in the San Diego area. After beginning construction in the fall of 2010, the project is expected to be completed in 2012. The process for obtaining the permit was arduous due to initial lack of disclosure by the proponent, the environmental sensitivity of the land proposed to be developed, and the number of stakeholders involved (Herndon 2009). Many PV and CSP projects in the planning stages are dependent on construction of this line.

2.3.4 Solar Industry Employment Trends

The U.S. solar job market experienced the most rapid expansion to date in 2010, corresponding to the doubling of U.S. demand for solar PV, to approximately 878 MW installed for the year (SEIA/GTM 2011), during an otherwise difficult economy by most measures.[9] Though the pace of this growth may not extend through 2011, long-term expectations for the labor demand market remain strong. In some state and local markets, additional trained workers are needed to design, manufacture, install, and maintain solar systems. As a result, labor supply and demand within the solar industry, and the manner in which the two are tied to educational and training opportunities, is of great interest to the industry, workers, and government.

A study by the Solar Foundation in October 2010 found that the U.S. solar industry employs an estimated 93,500 direct solar workers, defined in the study as those workers who spend at least 50% of their time supporting solar-related activities (Solar Foundation 2010). This equates to more than 46,000 job-years or full-time equivalents (FTEs),[10] defined as approximately 2,000 hours of labor. These include workers in installation, utilities, wholesale trade, and manufacturing sectors. The Solar Foundation study found that over the period of August 2010 to August 2011, over half of U.S. solar employers expect to increase their staff, compared to 2% planning staffing cuts. Globally, the solar PV industry represents about 300,000 direct and indirect jobs, according to Clean Edge research (Pernick, Wilder, and Winnie 2010).

Several factors combined to generate unprecedented U.S. labor demand growth in 2010. First of these was the availability of a cash grant in lieu of tax credits for renewable energy projects, known as "§1603 Treasury grants" and established in 2009 under the American Recovery and Reinvestment Act (ARRA). Construction-related expenditures for $6.9 billion in grants for 7,957 projects average 10.5 FTEs per million dollars of investment. Of the estimated 221,500 U.S. FTEs generated through this investment during 2009 and 2010[11] (an average of 10.5 jobs per million dollars of investment), photovoltaic projects accounted for about 13 percent—approximately 29,100 FTEs in construction phase jobs. There are an additional 700 jobs related to the ongoing operation and maintenance of these installations.[12] Second, the 30% manufacturing tax credit for renewable energy manufacturing investments under Section 48 of the Internal Revenue Code helped drive utility-scale projects. Third, the rapid expansion of third-party ownership

[9] It is impossible to accurately quantify the percentage growth of labor demand for the year, since there are no comparable job counts for previous years. Previous U.S. studies quantified the number of existing jobs by applying estimated jobs per megawatt to input-output models, contrasted with jobs census studies conducted in 2010.

[10] One FTE job can result from any combination of workers working a total of 2,080 hours, such as full-time employment for one person for the duration of a year or two people for 6 months each. Because typical residential rooftop installations employ people for a few weeks or less, it's important to translate this employment to FTEs in order to make apples-to-apples comparisons.

[11] This represents the equivalent of less than 0.2 percent of total non-farm employment in 2010 (130.3 million), yet it represents more jobs than the total number of employees in the electric utility sector in the same year (170.8 thousand). See U.S. Dept. of Labor, Bureau of Labor Statistics, Summary Table B. Employment, hours, and earnings of employees on nonfarm payrolls, seasonally adjusted, ftp://ftp.bls.gov/pub/suppl/empsit.cessum.txt and Utilities, Electric Power Generation, Employment, Hours, and Earnings, http://data.bls.gov/.

[12] To derive the economic and employment impacts from the §1603 Grant Program, the program database was used for 2009 and 2010 projects and the National Renewable Energy Laboratory's Jobs and Economic Development Impact models. Grants were provided for 7,957 projects, totaling just over $6.9 billion, for 15 types of renewable technologies (see Table 1). The total cost (including federal grant and cost-share funds) for these projects was over $23.2 billion. Of these, 7,337 were photovoltaic, totaling $742 million.

business models for solar installations also drove the labor market expansion in 2010, as a function of increased consumer and business demand for solar fostered by these models. Lastly, the precipitous decline in global module costs also helped drive interest.

Another key factor driving U.S. solar employment growth in both 2009 and 2010 is the expansion of the utility-scale segment of PV demand, which increased its U.S. market share by a factor of 3.5 in the 2-year period, from 8% to 28% of the market. This increased construction labor demand in states now bringing projects into operation and staffing for announced projects. In particular, Nevada, Arizona, and New Mexico announced several utility-scale PV projects in 2010. Across these three states, an additional 310 MW of utility-scale installed capacity is expected in 2011 (Barclays Capital 2011), with more than half of this development (345 MW) announced for Arizona alone (SEIA/GTM 2010).

A recent NREL installation labor market study (Friedman et al. 2011) estimated between 32,000–38,000 FTEs currently employed in the solar installation sectors, with an estimated 5,000 to 7,000 additional expected for the study period ending in August 2011, a nearly 20% increase. Employment at the point of installation benefits local economies; employment at other parts of the value chain may not. The geographic location of the installation sector jobs varies across the United States. Table 2.2 depicts the regional distribution of U.S. solar employment. The first column shows the total number of employees working for companies that engage in solar installation, while the second column represents only those employees with a 50% or more solar focus.

TABLE 2.2 REGIONAL DISTRIBUTION OF U.S. SOLAR EMPLOYMENT, 2010.

Installer	Current Permanent Employment by Solar Employees	Current Solar Employment (at least 50% of Employees' Time)	12-Month Expected Solar Empoyment	12-Month New Solar Empoyees
Region 1: NY, VT, RI, CT, MA, NH, ME	4,932	2,282	2,821	539
Region 2: WV, PA, DE, NJ	10,356	4,888	6,269	1,381
Region 3: SC, NC, VA, DC, MD	8,664	3,995	5,116	1,121
Region 4: MS, AL, GA, TN, KY, FL	12,793	2,101	2,594	493
Region 5: MN, IA, WI, IL, IN, MI, OH	15,885	1,303	1,423	120
Region 6: NM, TX, OK, LA, AR, MO	9,769	4,309	5,219	910
Region 7: AK, AZ, NV, UT, CO, KS, NE, WY, SD, ND, MT, WA, OR, ID	22,858	7,521	9,017	1,496
Region 8: CA, HI	56,044	15,592	18,911	3,320
Other/Data provided across regions (more than one location)	6,201	1,944	2,422	478
Total	147,501	43,934	53,793	9,859

(Friedman, Jordan, and Carrese 2011)

The NREL installation labor market study also found that approximately half of U.S. solar installation employers reported "some" or "great" difficulty in meeting their labor needs for qualified entry-level candidates who have the appropriate skills and training. Considering the high sustained national unemployment in construction sectors, these findings underscore the need for solar training and up-skilling unemployed workers in those states experiencing unmet demand. However, several states with high construction unemployment have very small solar markets. During a difficult period in the housing market, many workers in these states lack the mobility to relocate to markets with higher solar installation labor demand. It is incumbent upon training programs to know their current and expected local markets and offer trainees a conduit to local solar employers and a meaningful pathway to employment.

In the NREL installation sector study, employers expressed preference for workers with foundational construction or electrical experience or skills, as well as a strong preference for on-the-job training, such as internships and apprenticeships, over coursework. At the present time, the need is particularly acute for training in codes, permitting, and inspection for both officials and installers, as well as for sales staff and those physically able to do installations, possessing background skills and capabilities required. Of the 11 occupations studied in the NREL report, PV installers (51%), electricians with specific solar skills (42%), and sales representatives and estimators (39%), are expected to grow the fastest over the 12-month study period ending in August 2011.

U.S. Department of Labor's Bureau of Labor Statistics took a significant step in 2010 towards enabling a better understanding of the U.S. solar installer labor market, by revising their Standard Occupational Classification (SOC) system of 840 occupations for the first time since 2000. Among the over 80 "green" occupations evaluated by the SOC Policy Committee (SOCPC), and for new SOC codes under the 2010 revision, only two new renewable energy occupations were selected—Solar Photovoltaic Installers (47-2231) and Wind Turbine Service Technicians (49-9081).[13] In each of the other cases, the SOCPC found that the work performed by a proposed "green" job was already covered by the description of an existing SOC occupation. The SOC system is not scheduled for another revision until 2018.[14]

The task description for the new Photovoltaic Installers is as follows: "assemble, install, or maintain solar photovoltaic (PV) systems that generate solar electricity." In conjunction with the revised SOC, the Occupational Information Network (O*NET), sponsored by the Employment and Training Administration of the United States Department of Labor, also established a new job title for Solar Photovoltaic Installers (O*NET-SOC code # 47-4099.01).[15] Within the O*NET system, the Solar PV Installer occupation is designated as both a "Green New and Emerging" occupation, as well as a "Bright Outlook" occupation, signifying rapid anticipated growth.[16] Inclusion of the new Solar PV Installer classification is a significant step in enabling federal and other agencies to better count solar installation jobs in the future. The 2010 SOC system contains 840 detailed occupations, aggregated into 461 broad occupations and is used by federal statistical agencies to classify workers and jobs into occupational categories for the purpose of collecting, calculating, analyzing, or disseminating data.

Though not the focus of this report, several studies have quantified the job creation potential of renewable energy as compared to fossil fuel technologies. A recent study by analysts at the University of California at Berkeley concluded that renewable energy technologies generate more jobs per unit of energy than fossil fuel-based technologies (Wei et al. 2009). Among the renewable energy technologies, according to the study, solar PV creates the most jobs per unit of electricity output. Solar PV was estimated to create 0.87 job-years/GWh, whereas natural gas and coal were each estimated to create 0.11 job-years/GWh.

[13] Standard Occupational Classification Policy Committee, "Responses to comments on 2010 SOC," http://www.bls.gov/soc/2010_responses/response_08-0012.htm.

[14] The SOC system classifies workers into occupational categories "for the purpose of collecting, calculating, or disseminating data." http://www.bls.gov/soc/revisions.htm.

[15] http://www.onetonline.org/link/summary/47-4099.01 and http://www.onetcenter.org/.

*[16] The O*NET system describes the PV Installer job tasks as follows: "assemble solar modules, panels, or support structures, as specified. Install active solar systems, including solar collectors, concentrators, pumps, or fans. May include measuring, cutting, assembling, and bolting structural framing and solar modules. May perform minor electrical work such as current checks."*

It is difficult to quantify precisely what the labor demand will be beyond 2011 because of uncertainty in the policies and cost reductions that drive markets, such as the §1603 Treasury grant set to expire in December 2011, and because of the variability in labor efficiency that occurs in maturing markets. There is significant variation in job number and labor intensity estimates, which results from many factors, including:

- Data collection and analysis method
- Types of jobs being considered (e.g., direct, indirect, and induced)
- Types of occupations being considered (e.g., factory worker, installer, and salesperson)
- Variation in estimates of capacity being installed (for job forecasts)
- Technologies included (e.g., PV, CSP, solar water heating)
- Types of industry subsectors included (residential new and retrofit, commercial, utility, remote, or off-grid)
- Variation in metrics or units being used
- Variation in the time periods being considered, such as the lifespan of an installation or within only a certain phase (e.g., construction, operation and maintenance [O&M])
- Whether a study is measuring gross or net job impacts (net impacts account for displacement of jobs in other industries such as coal or natural gas).

2.3.4.1 Types of Jobs in the PV and CSP Industries

The following are examples of occupations associated with the manufacture and installation of PV and CSP:

- Manufacturing positions such as factory worker, sheet metal worker, glass worker, technician (e.g., semiconductor for PV), material handler, factory supervisor, manufacturing manager, engineer (i.e., quality assurance, manufacturing, chemical process, mechanical, electrical, and optical), and material scientist
- Installation positions such as solar system installer/technician (PV), solar system designer (PV), technical sales representative and estimator (PV), architect (PV), roofing contractor (PV), general contractor, supervisor/foreman, heavy construction worker, welder, pipefitter, and engineer (i.e., mechanical, electrical, and civil)
- Administrative and support positions such as administrative assistant, purchasing agent, accountant, health and safety officer, information technology professional, and director.

Jobs in the solar industry fall into three categories: direct, indirect, or induced. Direct jobs are those within the solar industry itself (e.g., manufacturing, installation, and plant construction and maintenance); indirect jobs are those in industries that support the solar industry (e.g., jobs in the polysilicon, glass, and steel industries); and induced jobs are those that result from the economic activity stimulated by the solar industry (e.g., people buying more goods and services in a region where there is a new PV manufacturing plant or where a new PV or CSP installation is under construction). Direct jobs, in turn, include those involved in manufacturing, selling, and installing solar systems (based on production and installation in a given year), those required to operate and maintain systems (based on total cumulative capacity in a given year), and those involved in research and development (R&D).

2.3.4.2 Labor Intensity in the PV Industry, Global, and United States

Compared to the solar labor force in other countries and relative to the size of their solar demand (their "labor intensity")[17], the U.S. solar labor market is relatively large, in part because of public investment under the ARRA and in part because of inefficiencies in the market. Over time, economies of scale, increasing competition, and the resulting increases in labor productivity will modulate increased labor demand created by expanding markets. At the same time, improved labor productivity can play a significant role in helping to reduce costs and may occur through various labor-saving strategies and technologies. These include streamlining the installation process, increasing automation in manufacturing, and emphasizing solar PV in new housing and building construction.

The U.S. solar installation market is still immature and likely inefficient. As with any young market, one would expect significant improvement in labor productivity over time, scale, and industry development. The NREL labor installation employment study found that 64% of current U.S. installers employ 10 or fewer people. Many of these small start-up firms may go out of business or otherwise consolidate over time, as overall labor efficiency improves through the increasing competitive forces that take place in the development of any market. Nascent markets are inherently burdened by relatively inefficient supply and distribution chains, and the solar market may currently require extra staff time to manage state, local, and utility regulations and requirements that tend to be inconsistent or cumbersome. Lastly, human resources and extra staff time is required for any new business, especially one in a new industry, for such disparate organizational development tasks as building staff, conducting market research, business development, establishing credit, and raising capital.

2.3.4.3 Employment and Labor Intensity in the United States and Global CSP Industry

As with PV installations, the construction phase of a CSP facility, as opposed to the operation phase, results in the greatest economic impact. A report examining the economic impacts of constructing a 100-megawatt electric (MWe) CSP facility in Nevada estimated that each year of a 3-year construction period would result in slightly more than 800 direct jobs and approximately 1,600 indirect and induced jobs (Schwer and Riddel 2004).[18] This equates to 8 direct jobs/MW and 24 jobs/MW including indirect and induced jobs, simply for solar system construction. In addition, 0.45 job per MW are created directly during the O&M phase.[19] By comparison, Black and Veatch estimated more than twice that number for O&M, namely, that every megawatt of CSP constructed results in 0.94 permanent O&M jobs (Stoddard et al. 2006). It is unclear, however, whether the higher number includes indirect as well as direct jobs.

Another U.S. example of a project for which job creation was identified for CSP is the 400-MWe Ivanpah Solar Electric Generating System proposed for a site in California's Mojave Desert, a power tower plant that was estimated to take 4 years to build and that will require approximately 500 jobs averaged over the construction period, amounting to 1.25 jobs/MW during this time (CEC 2007b). The project also would require 100 full-time jobs for O&M, equivalent to 0.25 job per MW. The Ivanpah Solar Electric Generating System is a very large system and is actually a staged cluster of four separate CSP systems, which could explain the lower O&M labor intensity.

2.3.4.4 Quality Assurance and Certification for Solar PV Installation

Proper installation of solar PV systems is essential for accelerating market acceptance and maintaining consumer confidence. Regional and state incentive programs vary in their licensing and technical requirements. The largest certification body of U.S. installers is the

[17] Labor intensity is most often defined as jobs/MW (or FTEs/MW), jobs per MWh, or jobs per dollar invested.

[18] The term MWe represents megawatt electric and is used to distinguish electrical generation from thermal generation at CSP plants.

[19] Direct jobs are in FTEs. In total, 140 O&M jobs are created annually when including indirect and induced jobs.

North American Board of Certified Energy Practitioners (NABCEP). NABCEP holds PV installer exams twice a year, in March and September. As of March 2011, NABCEP had certified nearly 1,328 PV installers, a 22% increase over 2009. NABCEP also certified its first group of PV technical sales professionals in February 2011, following its release of a PV Technical Sales Certification Exam Resource Guide 4 months earlier. In addition, product-safety-certifiers Underwriters Laboratories (UL) announced a new PV installer certification program for electricians beginning in July 2010.

NABCEP and UL both also offer an entry-level achievement award for basic PV knowledge. These awards should be distinguished from installer certifications, since the learning objectives for the exam do not cover all aspects of an installer's job, but rather the basic concepts of the fundamentals of solar electric system design, operation, installation, and troubleshooting. To achieve solar PV installer certification, candidates require training plus experience as the responsible party on a set number of installations.

2.3.4.5 Solar Instructor Training Network

Funded through the DOE Solar Energy Technologies Program (SETP), the Solar Instructor Training Network entered its second year in 2010. Composed of a national administrator and eight regional training providers, the solar instructor training network is a nationwide "train-the-trainer" program established in October 2009 "to address a critical need for high-quality, local, and accessible training in solar system design, installation, sales, and inspection."[20]. The Solar Instructor Training Network responds to the needs of the employer community and coordinates its efforts with the federal and state Departments of Labor and local Workforce Investment Boards. Among its current areas of focus, the network is developing online trainings, particularly those that will aid installers and code officials in managing the permitting and inspection process. In addition, the Solar Instructor Training Network is also focused on mapping career pathways and solar occupational lattices, helping employers, workers, and government agencies address the range of skills and competencies that lead to a wide variety of interconnected solar jobs and careers. The Solar Instructor Training is helping address the training gaps required to meet solar installer employment demand.

[20] *See http://www1.eere.energy.gov/solar/instructor_training_network.html.*

2.3.5 References

Andraka, C. E. (July 2, 2008). *Statement of Charles E. Andraka, Sandia National Laboratories. Concentrating Solar Power*. United States Senate Committee on Energy and Natural Resources Field Hearing in Albuquerque, New Mexico.

Bartlett, J. E.; Goldstein, A. H. (2010). *Q2 2010 Solar Industry Update.* Report for Office of Energy Efficiency & Renewable Energy, Solar Energy Technologies Program. (Internal only).

Bartlett, J. E.; Margolis, R. M.; Jennings, C. E. (2009). *The Effects of the Financial Crisis on Photovoltaics: An Analysis of Changes in Market Forecasts from 2008 to 2009*. NREL Report no. TP-6A2-46713. Golden, CO: National Renewable Energy Laboratory.

Boas, R.; Farber, M.; Meyers, M.; Porter, C.; Rogol, M.; Song, J.; Trangucci, R. (April 2010). "PHOTON Consulting's Monthly Market Commentary." Photon International.

Böhme, D.; Dürrschmidt, W.; Van Mark, M., eds. (June 2009). *Renewable Energy Sources in Figures: National and International Development.* Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU). *http://www.erneuerbare energien.de/inhalt/5996/3860/*. Accessed November 20, 2009.

Bradford, T. (2008). Polysilicon: Supply, Demand, and Implications for the PV Industry. Prometheus Institute and Greentech Media.

Bradford, T.; Englander, D.; Lewin, A.; Maycock, P. (2008a). March 2008. "24th Annual Data Collection – Preliminary." *PV News.* Prometheus Institute and Greentech Media.

Bradford, T.; Englander, D.; Lewin, A.; Maycock, P. (2008b). April 2008. *PV News.* "Letter from the Editor." Prometheus Institute and Greentech Media.

Bradford, T.; Englander, D.; Lewin, A.; Maycock, P. (2008c). "Polysilicon Forecasts through 2012." PV News. Prometheus Institute and Greentech Media. May.

Bradford, T.; Englander, D.; Smith, F.; Maycock, P. (April 2009). "25th Annual Data Collection Results: PV Production Explodes in 2008." *PV News.* Prometheus Institute and Greentech Media.

Bradford, T.; Letendre, S.; Flynn, H.; Maycock, P. (March 2006). "22nd Annual Data Collection." PV News. Prometheus Institute and Greentech Media.

Bullard, N.; Chase. J.; d'Avack, F. (May 20, 2008). "The STEG Revolution Revisited." Research Note. London: New Energy Finance.

California Energy Commission (CEC). (2007a). August 2007. "Memorandum of Understanding Between the U.S. Department of the Interior, Bureau of Land Management California Desert District, and the California Energy Commission Staff Concerning Joint Environmental Review for Solar Thermal Power Plant Projects." http://www.energy.ca.gov/siting/solar/BLM_CEC_ MOU. PDF. Accessed November 23, 2009.

CEC. (2007b). October 12, 2007. Ivanpah Application for Certification, Executive Summary. *http://www.energy.ca.gov/sitingcases/ivanpah/documents/ applicant/AFC/Volume1/*. Accessed November 23, 2009.

CSP Today. (October 19, 2009). *Acquisitions: New Horizons for Solel Solar Systems.* Executive Viewpoint. http://social.csptoday.com/qa/acquisitions-new-horizons-solel-solar-systems. Accessed August 18, 2010.

CSP Today. (January 14, 2010). *Parabolic trough reflectors: Does glass still have the cutting edge?* Industry Insight. *http://social.csptoday.com/industry-insight/parabolic-trough-reflectors does-glass-still-have-cutting-edge*. Accessed August 18, 2010.

Dongguan CSG Solar Glass Co. website (2009). Company Profile. *http://www.csgglass.com/eng/index.asp*. Accessed August 18, 2010.

European Photovoltaic Industry Association (EPIA). (May 2010). *Global Market Outlook for PV until 2014*. *http://www.epia.org/fileadmin/EPIA_docs/public/Global_Market_Outlook_for_Photovoltaics_until_2014.pdf*. Accessed August 18, 2010.

European Photovoltaic Industry Association (EPIA). (May 2011). *Global Market Outlook for PV until 2015*. *http://www.epia.org/fileadmin/EPIA_docs/public/Global_Market_Outlook_for_Photovoltaics_until_2015.pdf*. Accessed June 1, 2011.

Feltrin, A.; Freundlich, A. (2008). "Material Considerations for Terawatt Level Deployment of Photovoltaics." Renewable Energy, 33, pp.180–185.

Federal Energy Regulatory Commission (FERC). (October 23, 2009). "Memorandum of Understanding among the U.S. Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Environmental Protection Agency, the Council on Environmental Quality, the Federal Energy Regulatory Commission, the Advisory Council on Historic Preservation, and the Department of the Interior, regarding coordination in federal agency review of electric transmission facilities on federal land." *http://www.ferc.gov/legal/maj-ord-reg/mou/mou-transmission-siting.pdf*. Accessed August 18, 2010.

Grama, S.; Bradford, T. (2008). *Thin-Film PV 2.0: Market Outlook Through 2012*. Cambridge, MA: Prometheus Institute and Greentech Media.

Grama, S.; Wayman, E.; Bradford, T. (2008). *Concentrating Solar Power—Technology, Cost, and Markets*. 2008 Industry Report. Cambridge, MA: Prometheus Institute and Greentech Media.

Greentech Media (GTM). (January 2011). Concentrating Solar Power 2011: Technology, Costs, and Markets. *http://www.gtmresearch.com/report/concentrating-solar-power-2011-technology-costs-and-markets*, Accessed May 9 2011.

Grover, S. (2007). *Energy, Economic, and Environmental Benefits of the Solar America Initiative*. Prepared for the National Renewable Energy Laboratory by ECONorthwest. NREL Report SR 640-41998.

Hering, G. (March 2011). "Year of the Tiger." Photon International. pp. 186–218.

Herndon, A. (2009). "Sunrise in the West: California's $1.9bn Renewable Energy Transmission Line." Analyst Reaction. London: New Energy Finance. January 20.

Hirshman, W. P. (March 2010). "Market Survey on Worldwide Cell Production 2009." Photon International.

J.P. Morgan Chase. (2011). Personal Communication.

Maycock, P. D. (February 2002). "World PV Cell/Module Production (1988-2001)." *PV News*. Greentech Media.

McCrone, A.; Peyvan, M.; Zindler, E. (June 17, 2009). "Net Job Creation to 2025: Spectacular in solar, but modest in wind." Research Note. London: New Energy Finance.

Mehta, S.; Bradford, T.; (2009). PV Technology, Production, and Cost, 2009 Forecast: The Anatomy of a Shakeout. Prometheus Institute and Greentech Media.

Mehta, S. (May 2011). "27th Annual Data Collection Results." PV News. Greentech Media.

Merrill Lynch. (2008). *Solar Thermal: Not Just Smoke and Mirrors.* New York, NY: Merrill Lynch.

Mints, P. (2010). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 2009/2010*. Report # NPS-Supply5. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Mints, P. (2011). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 2010/2011*. Report # NPS-Supply6. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Navigant Consulting. (2008). *Economic Impacts of Extending Federal Solar Tax Credits.* Prepared for the Solar Energy Research and Education Foundation (SEREF). *http://www.seia.org/cs/news_research_and_multimedia/research/*. Accessed February 2009.

National Renewable Energy Laboratory (NREL). (2007). *Water saving heat rejection for solar thermal power plants. http://www.nrel.gov/csp/troughnet/pdfs/2007/dersch_dry_cooling.pdf*. Accessed August 18, 2010.

National Renewable Energy Laboratory (NREL). (2010a). *Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM). http://www.nrel.gov/docs/fy10osti/47605.pdf*. Accessed August 18, 2010.

Osborne, M. (February 25, 2010). "iSuppli: PV Component Price Declines Set to Continue with Polysilicon Declining 56.3% in 2010." *http://www.pv-tech.org/news/_a/isuppli_pv_component_price_declines_set_to_continue_with_polysilicon_declin/*. Accessed August 18, 2010.

National Renewable Energy Laboratory (NREL). (2010b). *Internal analysis.*

Friedman B, Jordan, and Carrese. (2011). *Solar Installation Labor Market Analysis*. National Renewable Energy Laboratory (NREL).

Pernick, R., Wilder, C., and Winnie, T. (2010), *Clean Tech Job Trends. http://www.cleanedge.com/reports/reports-jobtrends2010.php*. Accessed June 10, 2011.

Podewils, C. (2008). "On the glass path." *Photon International*. pp.74–79. February.

Renewable Energy Policy Network for the 21st Century (REN21). (2010). *Renewables 2010: Global Status Report. http://www.ren21.net/Portals/97/documents/GSR/REN21_GSR_2010_full_revised Sept2010.pdf*. Accessed September 20, 2010.

Rogol, M.; Choi, P.; Conkling, J.; Fotopoulos, A.; Peltzman, K.; Roberts, S. (2006). *Solar Annual 2006: The Gun Has Gone Off*. Solar Verlag GmbH/Photon Consulting.

Rogol, M.; Farber, M.; Flynn, H.; Meyers, M.; Paap, S.; Porter, C.; Rogol, J.; Song, J. (2008). *Solar Annual 2008: Four Peaks*. Photon Consulting.

Schott Solar website. (2010). *News Archive. http://www.schottsolar.com/no_cache/us/news/top-news/archive/*. Accessed August 18, 2010.

Schwer, R. K.; Riddel, M. (February 2004). *The Potential Economic Impact of Constructing and Operating Solar Power Generation Facilities in Nevada*. Prepared for the National Renewable Energy Laboratory by the Center for Business and Economic Research at UNLV. NREL Report SR-550-35037.

Sharp Corporation. (June 7, 2010). "Green Front Sakai Special Feature." *http://sharp-world.com/corporate/ir/library/annual/pdf/12-17.pdf*. Accessed August 19, 2010.

Simmons. (2011). Personal Communication.

Solar Energy Industries Association and Green Tech Media (SEIA/GTM). (April 15, 2011). *U.S. Soar Industry: Year in Review 2010. http://www.seia.org/galleries/pdf/SMI-YIR-2010-ES.pdf*. Accessed May 18, 2011.

Stifel Nicolaus. (2011). Personal Communication.

Stoddard, L.; Abiecunas, J.; O'Connell, R. (April 2006). *Economic, Energy and Environmental Benefits of Concentrating Solar Power in California.* Prepared for the National Renewable Energy Laboratory by Black and Veatch. NREL Report SR-550-39291.

U.S. Department of Energy (DOE). (2009). Report to Congress. Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation. U.S. Department of Energy. *http://www.eere.energy.gov/solar/pdfs/csp_water_study.pdf*. Accessed August 18, 2010.

U.S. Department of Energy, Energy Information Administration (EIA). (2008). *Solar Photovoltaic Cell/Module Manufacturing Activities 2003-2007*. *http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solarpv.html*. Accessed May 28, 2009.

U.S. Department of Energy, Energy Information Administration (EIA). (2009). *Solar Photovoltaic Cell/Module Manufacturing Activities 2008. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solarpv.pdf*. Accessed January 12, 2010.

U.S. Department of Energy, Energy Information Administration (EIA). (2011). *Solar Photovoltaic Cell/Module Manufacturing Activities 2009*.

U.S. Department of Energy, Energy Information Administration (EIA). (2010a). *Solar Thermal and Photovoltaic Collector Manufacturing Activities 2008. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solar.html*. Accessed August 18, 2010.

U.S. Department of Energy, Energy Information Administration (EIA). (January 2010b). *Solar Thermal Manufacturing Activities 2008. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solar.pdf*. Accessed August 18, 2010.

U.S. Department of Energy, Energy Information Administration (EIA). (December 2010c). *Solar Thermal Manufacturing Activities 2009. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solar.pdf*. Accessed May 10, 2011.

U.S. Geological Survey (USGS). (2010). Mineral commodity summaries 2010: U.S. Geological Survey. http://minerals.usgs.gov/minerals/pubs/mcs/2010/mcs2010.pdf. Accessed August 18, 2010.

USGS. (2011). Mineral commodity summaries 2011: U.S. Geological Survey. http://minerals.usgs.gov/minerals/pubs/mcs/2011/mcs2011.pdf. Accessed June 3, 2011.

Wei, M; Patadia, S.; Kammen, D. (2010). "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the U.S.?" *Energy Policy*. Volume 38. pp. 919-931. *http://rael.berkeley.edu/greenjobs*. Accessed June 10, 2011.

Western Governors Association (WGA). (2010). "Western Renewable Energy Zones." *http://www.westgov.org/index.php?option=com_content&view=article&id=219&Itemid=81*. Accessed August 18, 2010.

Winegarner, R.M.; Johnson, R.O. (2006). *Polysilicon 2006*. Sage Concepts, Inc./Solar Insights LLC.

Wu, J.; Chase, J. (2009). "Silicon and Wafer Spot Price Index." Analyst Reaction. London: New Energy Finance.

Yahoo Finance Steel. (2011). *Market Vectors Steel ETF* (SLX). *http://finance.yahoo.com/q/hp?s=SLX&a=11&b=31&c=2005&d=00&e=1&f=2011&g=m*. Accessed May 10, 2011.

Yahoo Finance Aluminum. (2011). *Century Aluminum Co.* (CENX). *http://finance.yahoo.com/q/hp?s=CENX&a=02&b=29&c=1996&d=00&e=1&f=2011&g=m*. Accessed May 10, 2011.

Cost, Price, and Performance Trends

This chapter covers cost, price, and performance trends for PV and CSP. Section 3.1 discusses levelized cost of energy (LCOE). Section 3.2 covers solar resource and capacity factor for both PV and CSP. Section 3.3 provides information on efficiency trends for PV cells, modules, and systems. Section 3.4 discusses PV module reliability. Sections 3.5 and 3.6 cover PV module and installed-system cost trends. Section 3.7 discusses PV O&M trends. Section 3.8 summarizes CSP installation and O&M cost trends, and Section 3.9 presents information on the characteristics and performance of various CSP technologies.

3.1 Levelized Cost of Energy, PV and CSP

LCOE is the ratio of an electricity-generation system's amortized lifetime costs (installed cost plus lifetime O&M and replacement costs minus any incentives, adjusted for taxes) to the system's lifetime electricity generation. The calculation of LCOE is highly sensitive to installed system cost, O&M costs, location, orientation, financing, and policy. Thus, it is not surprising that estimates of LCOE vary widely across sources.

REN21 (2010) estimated that the worldwide range in LCOE for parabolic trough CSP in 2009 was \$0.14–\$0.18 per kWh, excluding government incentives. The European Photovoltaic Industry Association (EPIA) estimated that worldwide, the range of LCOE for large ground-mounted PV, in 2010, was approximately \$0.16–\$0.38 per kWh (EPIA 2011). The wide LCOE range for PV (\$0.16–\$0.38 per kWh) is due largely to the sensitivity of the solar radiation (insolation) to the location of the system. That is, even minor changes in location or orientation of the system can significantly impact the overall output of the system. The PV LCOE range in Northern Europe, which receives around 1,000 kWh/m2 of sunlight is around \$.38 per kWh; Southern Europe, which receives around 1,900 kWh/m2 of sunlight, has an LCOE of \$.20 per kWh; and the Middle-East, which receives around 2,200 kWh/m2 of sunlight, has an LCOE of \$.16 per kWh (EPIA 2011).

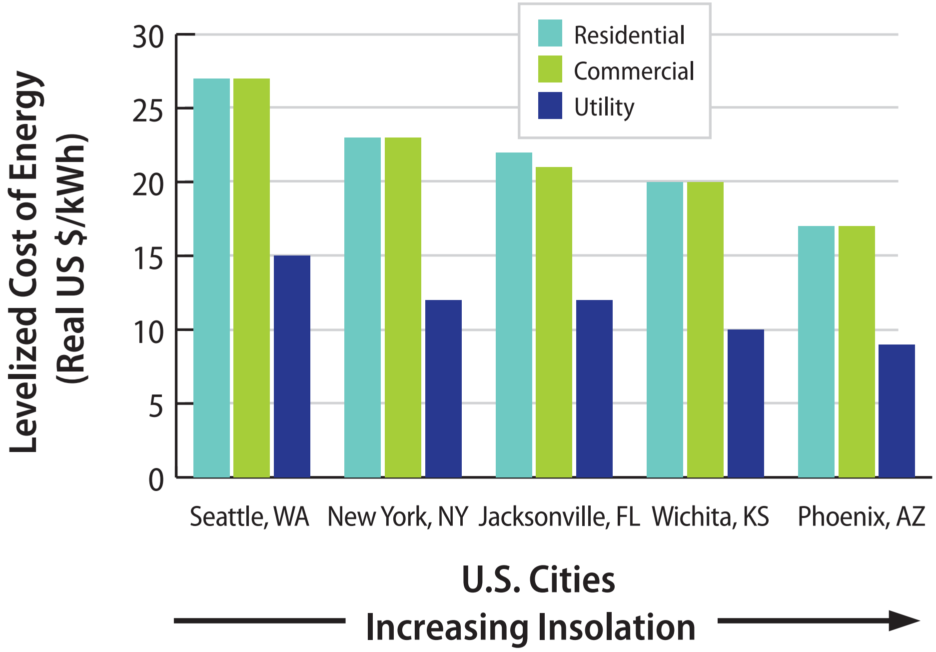


Figure 3.1 LCOE for residential, commercial, and utility-scale PV systems in several U.S. cities[21] (NREL 2011)

Figure 3.1 shows calculated LCOE for PV systems in selected U.S. cities ranging from about \$0.17/kWh to \$0.27/kWh in residential systems, \$0.17/kWh to \$0.27/kWh in commercial systems, and \$0.09/kWh to \$0.12/kWh for utility-scale systems (all when calculated with the federal ITC) based on the quality of the solar resource. It is important to note that assumptions about financing significantly impact the calculated LCOE and that the following graph shows a sampling of estimates that do not include state or local incentives.

The LCOEs of utility-scale PV systems are generally lower than those of residential and commercial PV systems located in the same region. This is partly due to the fact that installed and O&M costs per watt tend to decrease as PV system size increases, owing to more advantageous economies of scale and other factors (see Section 3.6 on PV installation cost trends and Section 3.7 on PV O&M.) In addition, larger, optimized, better-maintained PV systems can produce electricity more efficiently and consistently.

3.2 Solar Resource and Capacity Factor, PV and CSP

Of all the renewable resources, solar is by far the most abundant. With 162,000 terawatts reaching Earth from the sun, just 1 hour of sunlight could theoretically provide the entire global demand for energy for 1 year.

[21] *The LCOEs for Figure 3.1 were calculated using the NREL Solar Advisor Model (SAM) with the following assumptions:*

Residential: *Cost of \$6.42/WDC. Cost is the weighted average residential installed system cost from Q4 2010, SEIA/GTM U.S. Solar Market InsightTM Year-In Review; cash purchase; 25-degree fixed-tilt system facing due South; and discount rate of 2.9% (real dollars) based on the after-tax weighted average cost of capital. LCOE assumes a 30% federal ITC. No state, local, or utility incentives are assumed.*

Commercial: *Cost of \$5.71/WDC. Cost is the weighted average commercial installed system cost from Q4 2010, SEIA/GTM U.S. Solar Market Insight Year-In Review; 60%debt, 20-year term, and 40% equity; 10-degree fixed-tilt system facing due South; and discount rate of 4.4% (real dollars) based on the after-tax weighted average cost of capital. LCOE assumes a 30% ITC and 5-year Modified Accelerated Cost Recovery System (MACRS). No state, local, or utility incentives are assumed. Third-party/independent power producer (IPP) ownership of PV is assumed, and thus the LCOE includes the taxes paid on electricity revenue.*

Utility: *Cost assumes panels have a one-axis tracking to be \$4.05/W. The utility-installed system cost is from Q4 2010, SEIA/GTM U.S. Solar Market Insight Year-In Review; 55% debt, 15-year term, and 45% equity; and discount rate of 6.4% (real dollars) based on the after-tax weighted average cost of capital. LCOE assumes a 30% ITC and 5-year MACRS. No state, local, or utility incentives are assumed. Third-party/IPP ownership of PV is assumed, and thus the LCOE includes the taxes paid on electricity revenue.*

3.2.1 Solar Resource for PV

Photovoltaics can take advantage of direct and indirect (diffuse) insolation, whereas CSP is designed to use only direct insolation. As a result, PV modules need not directly face and track incident radiation in the same way CSP systems do. This has enabled PV systems to have broader geographical application than CSP and also helps to explain why planned and deployed CSP systems are concentrated around such a small geographic area (the American Southwest, Spain, Northern Africa, and the Middle East).

Figure 3.2 illustrates the photovoltaic solar resource in the United States, Germany, and Spain for a flat-plate PV collector tilted South at latitude. Solar resources across the United States are mostly good to excellent, with solar insolation levels ranging from about 1,000–2,500 kWh/m2/year. The southwestern United States is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the mainland United States is about 1,350–2,500 kWh/m2/year. The U.S. solar insolation level varies by about a factor of two; this is considered relatively homogeneous compared to other renewable energy resources.

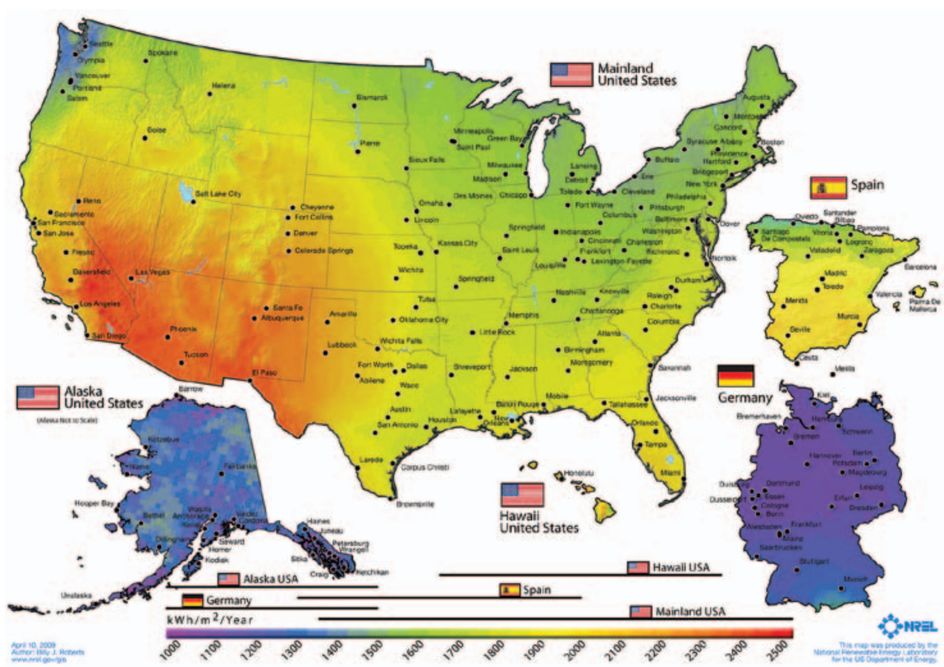


Figure 3.2. Photovoltaic solar resource for the United States, Spain, and Germany[22] (NREL 2009d)

As is evident from the map, the solar resource in the United States is much higher than in Germany, and the southwestern United States has better resource than southern Spain. Germany's solar resource has about the same range as Alaska's, at about 1,000-1,500 kWh/m2/year, but more of Germany's resource is at the lower end of that range. Spain's solar insolation ranges from about 1,300–2,000 kWh/m2/year, which is among the best solar resource in Europe.

The total land area suitable for PV is enormous and will not limit PV deployment. For example, a current estimate of the total roof area suitable for PV in the United States is

[22] *Annual average solar resource data are for a solar collector oriented toward the South at tilt = local latitude. The data for Hawaii and the 48 contiguous states are derived from a model developed at SUNY/Albany using geostationary weather satellite data for the period 1998–2005. The data for Alaska were derived by NREL in 2003 from a 40-km satellite and surface cloud cover database for the period 1985–1991. The data for Germany and Spain were acquired from the Joint Research Centre of the European Commission and capture the yearly sum of global irradiation on an optimally inclined surface for the period 1981–1990. States and countries are shown to scale, except for Alaska.*

approximately 6 billion square meters, even after eliminating 35% to 80% of roof space to account for panel shading (e.g., by trees) and suboptimal roof orientations. With current PV performance, this area has the potential for more than 600 GW of capacity, which could generate more than 20% of U.S. electricity demand. Beyond rooftops, there are many opportunities for installing PV on underutilized real estate such as parking structures, awnings, airports, freeway margins, and farmland set-asides. The land area required to supply all end-use electricity in the United States using PV is about 0.6% of the country's land area (181 m2 per person) or about 22% of the "urban area" footprint (Denholm and Margolis 2008b).

3.2.2 Solar Resource for CSP

The geographic area that is most suitable for CSP is smaller than for PV because CSP uses only direct insolation. In the United States, the best location for CSP is the Southwest. Globally, the most suitable sites for CSP plants are arid lands within 35° North and South of the equator. Figure 3.3 shows the direct-normal solar resource in the southwestern United States, which includes a detailed characterization of regional climate and local land features; red indicates the most intense solar resource, and light blue indicates the least intense. Figure 3.4 shows locations in the southwestern United States with characteristics ideal for CSP systems, including direct-normal insolation greater than 6.75 kWh/m2/day, a land slope of less than 1°, and at least 10 km^2 of contiguous land that could accommodate large systems (Mehos and Kearney 2007).

After implementing the appropriate insolation, slope, and contiguous land area filters, over 87,000 square miles are available in the seven states considered to be CSP-compatible: California, Arizona, New Mexico, Nevada, Colorado, Utah, and Texas. Table 3.1 summarizes the land area in these states that is ideally suited to CSP. This relatively small land area amounts to nearly 7,500 GW of resource potential and more than 17.5 million GWh of generating capacity, assuming a capacity factor of 27% (see Section 3.2.3). Therefore, the amount of CSP resource potential in seven southwestern states is over quadruple the annual U.S. electricity generation of about 4 million GWh.[23]

TABLE 3.1. IDEAL CSP LAND AREA AND RESOURCE POTENTIAL IN SEVEN SOUTHWESTERN STATES[23]

State	Available Area (square miles)	Resource Potential (GW)
Arizona	13,613	1,162
California	6,278	536
Colorado	6,232	532
Nevada	11,090	946
New Mexico	20,356	1,737
Texas	6,374	544
Utah	23,288	1,987
Total	87,231	7,444

(Internal NREL Analysis 2011)

[23] *EIA Net Generation by Energy Source: Total (All Sectors), rolling 12 months ending in May 2010 http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html.*

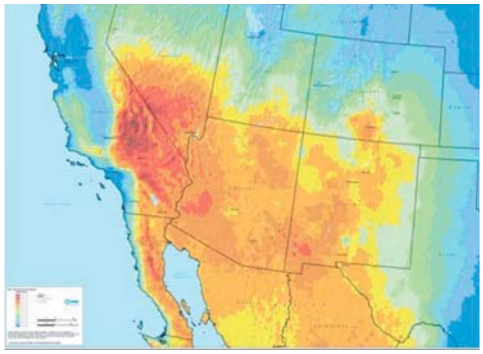


Figure 3.3. Direct-normal solar resource in the U.S. southwest (Mehos and Kearney 2007)

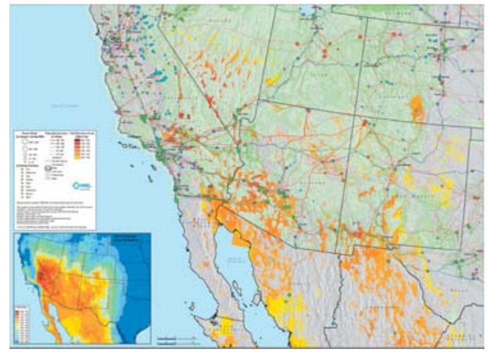


Figure 3.4. Direct-normal solar radiation in the U.S. southwest, filtered by resource, land use, and topography (Mehos and Kearney 2007)

Besides the United States, promising markets for CSP include Spain, North Africa, and the Middle East because of the regions' high levels of insolation and land available for solar development. Section 1.3.2 discusses the major non-U.S. international markets for CSP in further detail.

3.2.3 Capacity Factor, PV, and CSP

Capacity factor is the ratio of an energy-generation system's actual energy output during a given period to the energy output that would have been generated if the system ran at full capacity for the entire period. For example, if a system ran at its full capacity for an entire year, the capacity factor would be 100% during that year. Because PV and CSP generate electricity only when the sun is shining, their capacity factors are reduced because of evening, cloudy, and other low-light periods. This can be mitigated in part by locating PV and CSP systems in areas that receive high levels of annual sunlight. The capacity factor of PV and CSP systems is also reduced by any necessary downtime (e.g., for maintenance), similar to other generation technologies.

For PV, electricity generation is maximized when the modules are normal (i.e., perpendicular) to the incident sunlight. Variations in the sun's angle that are due to the season and time of day reduce the capacity factor of fixed-orientation PV systems. This can be mitigated, in part, by tilting stationary PV modules to maximize annual sunlight exposure or by incorporating one- or two-axis solar tracking systems, which rotate the modules to capture more normal sunlight exposure than is possible with stationary modules. Figure 3.5 shows the effect of insolation and use of tracking systems on PV capacity factors. Fixed tilt (at latitude) capacity factors are 14%–24% for Seattle to Phoenix, whereas one- and two-axis tracking systems result in higher ranges. Analysts sometimes use 18% or 19% for an average U.S. PV capacity factor.[24]

[24] These are direct current (DC) capacity factors, i.e., based on the DC rating of a PV system and taking into account inverter and other system losses. By definition, they are lower than an AC capacity factor, which is how fossil, nuclear, and CSP plants are rated, and thus are not directly comparable to more traditional AC capacity factors.

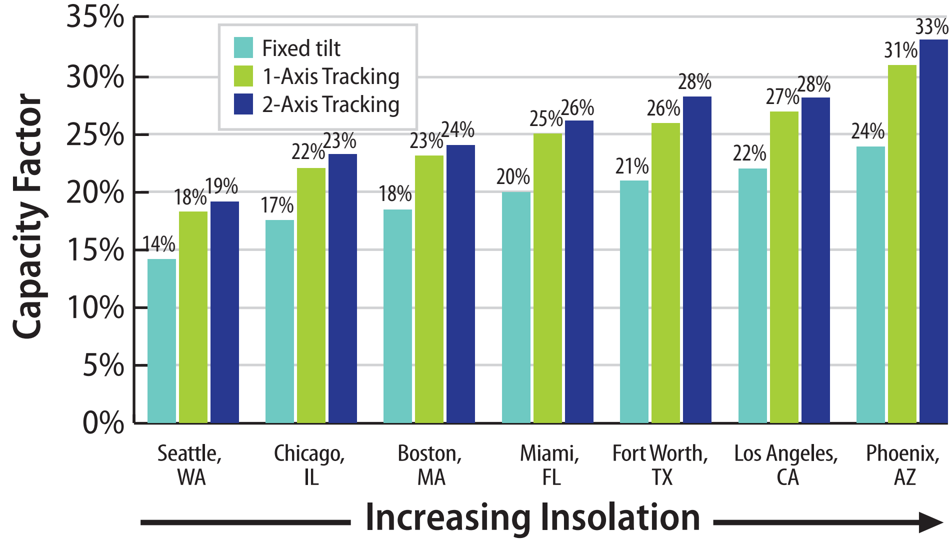


Figure 3.5 PV capacity factors, by insolation and use of tracking systems [25] (NREL 2009b)

The performance of a CSP plant is variable depending on factors such as the technology, configuration, and solar resource available in any given location. For example, capacity factors increase drastically in plants with thermal energy storage (TES) because they have more hours of operation. As of August 2010, plants without storage have capacity factors within the 20%–28% range, while plants with 6–7.5 hours of storage have a 40%–50% capacity factor. Larger amounts of storage and therefore higher capacity factors and dispatchability (the ability to increase or decrease electricity generation on demand) are possible. Capacity factors have been increasing as technologies mature and deploy and as plant operating techniques improve.

3.3 PV Cell, Module, and System Efficiency

In addition to the solar resource and capacity factor discussed above, the amount of electricity produced by PV systems depends primarily on the following factors:

- Cell type and efficiency
- Module efficiency
- System efficiency
- Module reliability.

This section discusses the efficiency of PV cells, modules, and systems. Module reliability is discussed in the next section.

3.3.1 PV Cell Type and Efficiency

Two categories of PV cells are used in most of today's commercial PV modules: c-Si and thin-film. The c-Si category, called first-generation PV, includes monocrystalline and multicrystalline PV cells, which are the most efficient of the mainstream PV technologies

[25] Capacity factors were estimated using data from NREL's PVWatts™, a performance calculator for on-grid PV systems, available at http://www.nrel.gov/rredc/pvwatts. The capacity factors shown here reflect an overall derate factor of 0.77, with the inverter and transformer component of this derate being 0.92, the defaults used in PVWatts. The array tilt is at latitude for the fixed-tilt systems, the default in PVWatts.

and accounted for about 86% of PV produced in 2010 (Mehta 2011). These cells produce electricity via c-Si semiconductor material derived from highly refined polysilicon feedstock. Monocrystalline cells, made of single silicon crystals, are more efficient than multicrystalline cells but are more expensive to manufacture.

The thin-film category, called second-generation PV, includes PV cells that produce electricity via extremely thin layers of semiconductor material made of a-Si, CIS, CIGS, or CdTe. Another PV cell technology (also second generation) is the multi-junction PV cell. Multi-junction cells use multiple layers of semiconductor material (from the group III and V elements of the periodic table of chemical elements) to absorb and convert more of the solar spectrum into electricity than is converted by single-junction cells. Combined with light-concentrating optics and sophisticated sun-tracking systems, these cells have demonstrated the highest sunlight-to-electricity conversion efficiencies of any PV technologies, in excess of 40%.

Various emerging technologies, known as third-generation PV, could become viable commercial options in the future, either by achieving very high efficiency or very low cost. Examples include dye-sensitized, organic PV cells and quantum dots, which have demonstrated relatively low efficiencies to date but offer the potential for substantial manufacturing cost reductions.

The efficiencies of all PV cell types have improved over the past several decades, as illustrated in Figure 3.6, which shows the best research-cell efficiencies from 1975 to 2010. The highest-efficiency research cell shown was achieved in 2010 in a multi-junction concentrator at 42.3% efficiency. Other research-cell efficiencies illustrated in the figure range from 15% to 25% for crystalline silicon cells, 10% to 20% for thin film, and about 5% and to 10% for the emerging PV technologies organic cells and dye-sensitized cells, respectively.

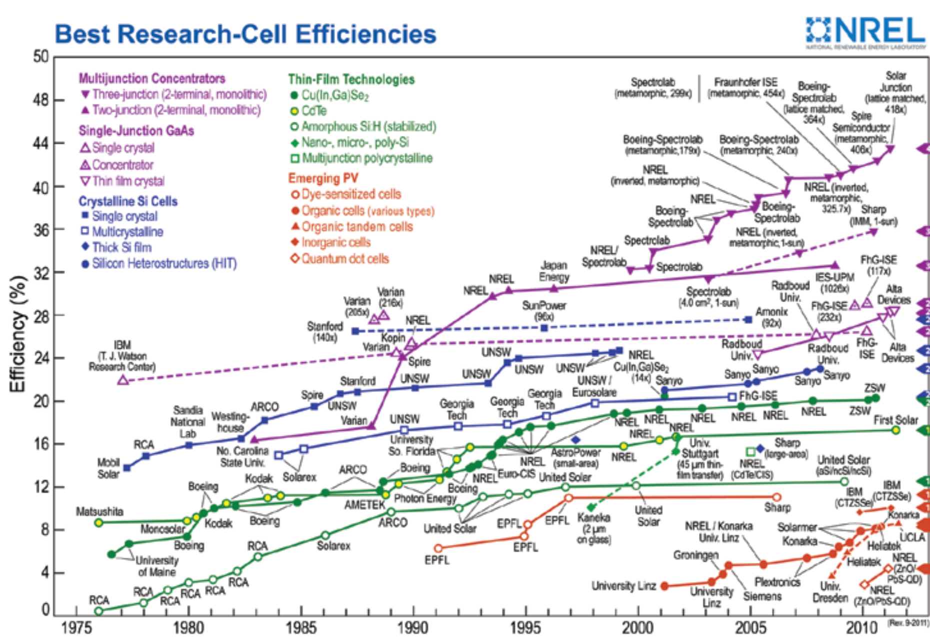


Figure 3.6. Best research-cell efficiencies 1975–2010
(NREL 2010)

3.3.2 PV Module Efficiency

The cells described in Figure 3.6 were manufactured in small quantities under ideal laboratory conditions and refined to attain the highest possible efficiencies. The efficiencies of mass-produced cells are always lower than the efficiency of the best research cell. Further, the efficiency of PV modules is lower than the efficiency of the cells from which they are made.

TABLE 3.2 2010 COMMERCIAL MODULE EFFICIENCIES	
Technology	**Commercial Module Efficiency**
Monocrystalline silicon [b]	14%
Multicrystalline silicon [b]	14%
CdTe [c]	11%
a-Si [d]	6%
CIGS [e]	11%
Low-concentration CPV with 20%-efficient silicon cells	15%
High-concentration CPV with 38%-efficient III-V multi-junction cells	29%

[b] The efficiency represents average production characteristics. Non-standard monocrystalline technologies—such as SunPower's rear-point-contact cell (19.3% efficiency) and Sanyo's HIT-cell-based module (17.1% efficiency)—are commercially available.
[c] First Solar 2010a
[d] Uni-Solar 2010. Based on a flexible laminate a-Si module.
[e] Mehta and Bradford 2009

In 2010, the typical efficiency of crystalline silicon-based PV commercial modules ranged from 14% for multicrystalline modules to 19.3% for the highest-efficiency monocrystalline modules (average monocrystalline module efficiency was 14%). For thin-film modules, typical efficiencies ranged from 7% for a-Si modules to about 11% for CIGS and CdTe modules (Table 3.2).

3.3.3 PV System Efficiency and Derate Factor

A PV system consists of multiple PV modules wired together and installed on a building or other location. The AC output of a PV system is always less than the DC rating, which is due to system losses.

For grid-connected applications, a PV system includes an inverter that transforms the DC electricity produced by the PV modules into AC electricity. The average maximum efficiency of inverters in 2009 was 96%, up from 95.5% in 2008, with the best-in-class efficiency reaching 97.5% for inverters larger than 50 kW and 96.5% for inverters under 50 kW (Bloomberg 2010). Other factors that reduce a PV system's efficiency include dirt and other materials obscuring sun-collecting surfaces, electrically mismatched modules in an array, wiring losses, and high cell temperatures. For example, NREL's PVWatts™ [26], a performance calculator for on-grid PV systems, uses an overall derate factor of 0.77[27] as a default, with the inverter component of this derate being 0.92.

3.4 PV Module Reliability

Historic data suggest that reliability is a very important factor when considering the market adoption of a new technology, especially during the early growth stages of an industry. PV is currently experiencing unprecedented growth rates. To sustain these growth rates, it is imperative that manufacturers consider the implications of product reliability.

[26] *See http://www.nrel.gov/rredc/pvwatts/version1.html*

[27] *A 0.77 derate factor is an older number applicable primarily to small residential PV systems. Ongoing data collection efforts at NREL indicate that this number is closer to 0.83 for modern PV installations.*

Today's PV modules usually include a 25-year warranty. Standard warranties guarantee that output after 25 years will be at least 80% of rated output. This is in line with real-world experience and predicted performance from damp-heat testing of modules (Wohlgemuth et al. 2006).

Manufacturers in the United States, Japan, and the European Union currently implement qualification standards and certifications that help to ensure that PV systems meet reliability specifications. There have been efforts to bring reliability standards to Chinese manufacturers as well, considering their rapid growth in the PV market. DOE has been a leader in engaging Chinese manufacturers in discussions on reliability standards and codes by organizing a series of reliability workshops and conferences in China. The global PV community realizes that if reliability standards are not quickly implemented among the fastest-growing producers, high-maintenance installations could negatively impact market adoption of PV modules both now and in the future.

3.5 PV Module Price Trends

Photovoltaic modules have experienced significant improvements and cost reductions over the last few decades. The market for PV modules has undergone unprecedented growth in recent years owing to government policy support and other financial incentives encouraging the installation of (primarily grid-connected) PV systems. Although PV module prices increased in the past several years, prices have been falling steadily over the past few decades and began falling again in 2008. This is illustrated in Figure 3.7, which presents average global PV module selling prices for all PV technologies.

Although global average prices provide an index for the PV industry overall, there are a number of factors to consider prior to coming to any firm conclusions. First, the PV industry is dynamic and rapidly changing, with advances in cost reductions for segments of the industry masked by looking at average prices. For example, some thin-film PV technologies are achieving manufacturing costs and selling prices lower than for crystalline silicon modules. Applications including large ground-mounted PV systems, for which deployment is increasing, and applications in certain countries and locations accrue cost advantages based on factors such as economies of scale and the benefits of a more mature market (some of this is captured in Section 3.6 on PV installation cost trends). Finally, historical trends may not provide an accurate picture going forward, as new developments and increasing demand continue to change the PV industry landscape.

Module prices vary considerably by technology and are influenced by variations in manufacturing cost and sunlight-to-electricity conversion efficiency, among other factors. This variation is significant because the manufacturing costs of modules is the single biggest factor in determining the sale price necessary to meet a manufacturer's required profit margin; the closer the selling price is to the manufacturing cost, the lower the profit margin. Higher conversion efficiency generally commands a price premium. This is because higher-efficiency modules require less installation area per watt of electricity production and incur lower balance-of-system costs (i.e., wiring, racking, and other system installation costs) per watt than lower-efficiency modules. The current estimated effect is a $0.10 increase in price per 1% increase in efficiency; for example, all else being equal, a 20%-efficient module would cost about $1 more per watt than a 10%-efficient module (Mehta and Bradford 2009).

Figure 3.7 shows the range of average global PV module selling prices at the factory gate (i.e., prices do not include charges such as delivery and subsequent taxes), as obtained from sample market transactions for small-quantity, mid-range, and large-quantity buyers. Small-quantity buyers are those buyers who often pay more, on a per watt basis, for smaller quantities and modules (e.g., less than 50 W).The mid-range buyer category includes buyers of modules greater than 75 W, but with annual purchases generally less than 25 MW. Large-quantity buyers purchase large standard modules (e.g., greater than 150 W) in large amounts, which allows them to have strong relationships with the manufacturers. The thin-film category includes the price of all thin-film panel types (i.e., CdTe, a-Si, CIGS, and CIS). In 2010, the average price per watt for the large-quantity category was $\$1.64/W_p$ while the average price per watt for the mid-range quantity category was $\$2.36/W_p$. The nominal prices shown in the figure are actual prices paid in the year stated (i.e., the prices are not adjusted for inflation).

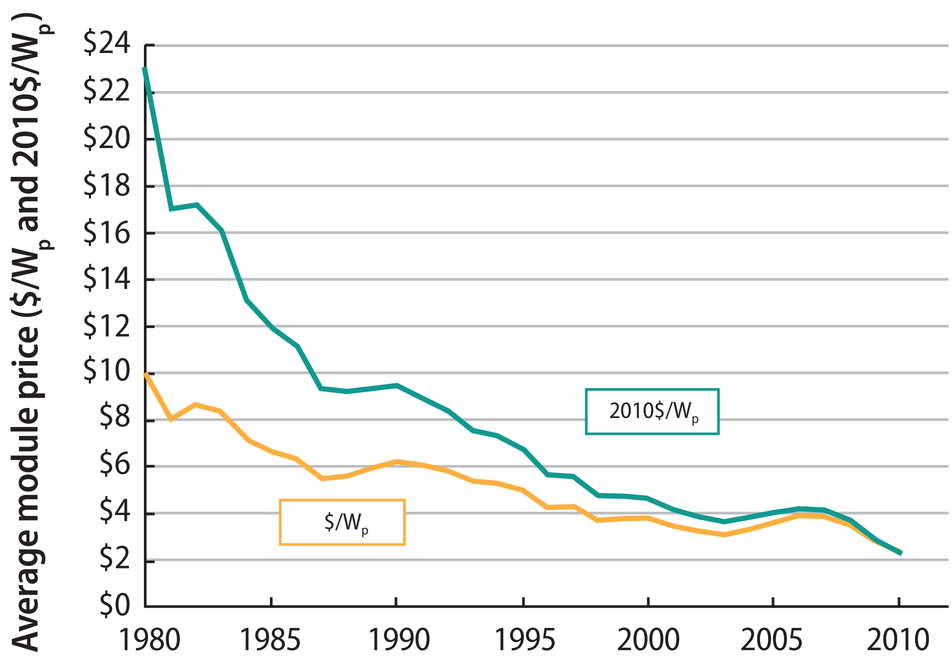


Figure 3.7 Global, average PV module prices, all PV technologies, 1984-2010 (Mints 2011)

PV module prices experienced significant drops in the mid-1980s, resulting from increases in module production and pushes for market penetration during a time of low interest in renewable energy. Between 1988 and 1990, a shortage of available silicon wafers caused PV prices to increase. For the first time in a decade, the market was limited by supply rather than demand. Prices then dropped significantly from 1991 to 1995 because of increases in manufacturing capacity and a worldwide recession that slowed PV demand. Module prices continued to fall (although at a slower rate) from 1995 to 2003, which was due to global increases in module capacities and a growing market.

Prices began to increase from 2003 to 2007 as European demand, primarily from Germany and Spain, experienced high growth rates after FITs and other government incentives were adopted. Polysilicon supply which outpaced demand also contributed to the price increases from 2004 to mid-2008. Higher prices were sustained until the third quarter of 2008, when the global recession reduced demand. As a result, polysilicon supply constraints eased, and module supply increased. The year 2009 began with high inventory levels and slow demand due to strained financial markets, then sales began to recover mid-year. Both 2009 and 2010 were years of constrained margins, as pricing competition amongst manufacturers became markedly more pronounced. With heightened demand and a less strained polysilicon supply, prices increased throughout the third quarter of 2010, only to decline by year's end due to growing supply and slowing demand.

3.6 PV Installation Cost Trends

Lawrence Berkeley National Laboratory (LBNL) has collected project-level installed system cost data for grid-connected PV installations in the United States (Barbose et al. 2011). The dataset currently includes more than 116,500 PV systems installed in 42 states between 1998 and 2010 and totals 1,685 MW, or 79% of all grid-connected PV capacity installed in the United States through 2010. This section describes trends related to the installed system cost of PV projects in the LBNL database, focusing first on cost trends for behind-the-meter PV systems and then on cost trends for utility-sector PV systems.[28] In all instances, installed costs are expressed in terms of real 2010 dollars and represent the cost to the consumer before receipt of any grant or rebate. PV capacity is expressed in terms of the rated module DC power output under standard test conditions. Note that the terminology "installed cost" in this report represents the price paid by the final system owner. This should not be confused with the term "cost" as used in other contexts to refer to the cost to a company before a product is priced for a market or end user.

It is essential to note at the outset the limitations inherent in the data presented within this section. First, the cost data are historical, focusing primarily on projects installed through the end of 2010, and therefore do not reflect the cost of projects installed more recently; nor are the data presented here representative of costs that are currently being quoted for prospective projects to be installed at a later date. For this reason and others, the results presented herein likely differ from current PV cost benchmarks. Second, this section focuses on the up-front cost to install PV systems; as such, it does not capture trends associated with PV performance or other factors that affect the levelized cost of electricity (LCOE) for PV. Third, the utility-sector PV cost data presented in this section are based on a small sample size (reflecting the small number of utility-sector systems installed through 2010), and include a number of relatively small projects and "one-off" projects with atypical project characteristics. Fourth, the data sample includes many third party-owned projects where either the system is leased to the site-host or the generation output is sold to the site-host under a power purchase agreement. The installed cost data reported for these projects are somewhat ambiguous – in some cases representing the actual cost to install the project, while in other cases representing the assessed "fair market value" of the project.[29] As shown within Barbose et al. (2011), however, the available data suggest that any bias in the installed cost data reported for third party-owned systems is not likely to have significantly skewed the overall cost trends presented here.

3.6.1 Behind-the-Meter PV

Figure 3.8 presents the average installed cost of all behind-the-meter projects in the data sample installed from 1998 to 2010. Over the entirety of this 13-year period, capacity-weighted average installed costs declined from \$11.00/W in 1998 to \$6.20/W in 2010. This

[28] For the purpose of this section, "behind-the-meter" PV refers to systems that are connected on the customer-side of the meter, typically under a net metering arrangement. Conversely, "utility-sector" PV consists of systems connected directly to the utility system, and may therefore include wholesale distributed generation projects.

[29] The cost data for behind-the-meter PV systems presented in this report derive primarily from state and utility PV incentive programs. For a subset of the third party-owned systems – namely, those systems installed by integrated third party providers that both perform the installation and finance the system for the site-host – the reported installed cost may represent the fair market value claimed when the third party provider applied for a Section 1603 Treasury Grant or federal investment tax credit.

represents a total cost reduction of $4.80/W (43%) in real 2010 dollars, or $0.40/W (4.6%) per year, on average. Roughly two-thirds of the total cost decline occurred over the 1998–2005 period, after which average costs remained relatively flat until the precipitous drop in the last year of the analysis period. From 2009 to 2010, the capacity-weighted average installed cost of behind-the-meter systems declined by $1.30/W, a 17% year-over-year reduction.

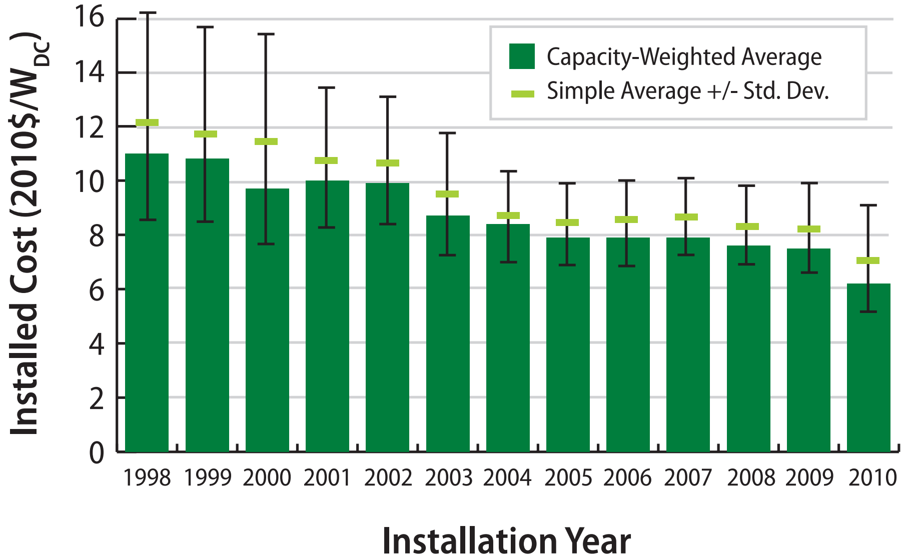


Figure 3.8 Installed cost trends over time for behind-the-meter PV (Barbose et al. 2011)

The decline in installed costs over time is attributable to a drop in both module and non-module costs. Figure 3.9 compares the total capacity-weighted average installed cost of the systems in the data sample to Navigant Consulting's Global Power Module Price Index, which represents average wholesale PV module prices in each year.[30] Over the entirety of the analysis period, the module price index fell by $2.50/W, equivalent to 52% of the decline in total average installed costs over this period. Focusing on the more recent past, Figure 3.9 shows that the module index dropped sharply in 2009, but total installed costs did not fall significantly until the following year. The total drop in module prices over the 2008–2010 period ($1.40/W) is roughly equal to the decline in the total installed cost of behind-the-meter systems in 2010 ($1.30/W), suggestive of a "lag" between movements in wholesale module prices and retail installed costs.

Figure 3.9 also presents the "implied" non-module costs paid by PV system owners—which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and installer profit. Implied non-module costs are calculated simply as the difference between the average total installed cost and the wholesale module price index in the same year; these calculated non-module costs therefore ignore the effect of any divergence between movements in the wholesale module price index and actual module costs associated with PV systems installed each year. The fact that the analytical approach used in this figure cannot distinguish between actual non-module costs as paid by PV system owners and a lag in module costs makes it challenging to draw conclusions about movements in non-module costs over short time periods (i.e., year-on-year changes).

[30] The global, average annual price of power modules published by Navigant Consulting is also presented in Section 3.5 on PV module price trends.

Over the longer-term, however, Figure 3.9 clearly shows that implied non-module costs have declined significantly over the entirety of the historical analysis period, dropping by \$2.30/W (37%), from an estimated \$6.10/W in 1998 to \$3.80/W in 2010.

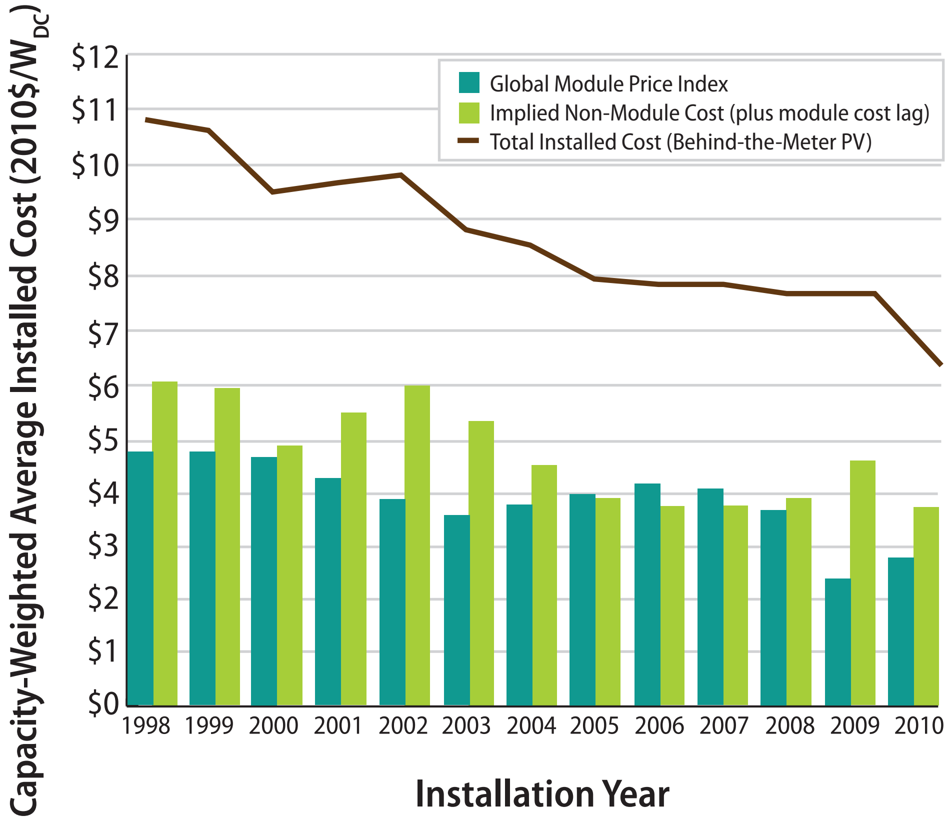


Figure 3.9 Module and non-module cost trends over time for behind-the-meter PV (Barbose et al. 2011)

Although current market studies confirmed that significant cost reductions occurred in the United States from 1998 through 2010, observation of international markets suggested that further cost reductions are possible and may accompany increased market size. Figure 3.10 compares average installed costs, excluding sales or value-added tax, in Germany, Japan, and the United States, focusing specifically on small residential systems (either 2–5 kW or 3–5 kW, depending on the country) installed in 2010. Among this class of systems, average installed costs in the United States (\$6.90/W) were considerably higher than in Germany (\$4.20/W), but were roughly comparable to average installed costs in Japan (\$6.40/W).[31] This variation across countries may be partly attributable to differences in cumulative grid-connected PV capacity in each national market, with roughly 17,000 MW installed in Germany through 2010, compared to 3,500 MW and 2,100 MW in Japan and the United States, respectively. That said, larger market size, alone, is unlikely to account for the entirety of the differences in average installed costs among countries.[32]

[31] Data for Germany and Japan are based on the most-recent respective country reports prepared for the International Energy Agency Cooperative Programme on Photovoltaic Power Systems. The German and U.S. cost data are for 2-5 kW systems, while the Japanese cost data are for 3-5 kW systems. The German cost data represents the average of reported year-end installed costs for 2009 (\$4.7/W) and 2010 (\$3.7/W), which is intended to approximate the average cost of projects installed over the course of 2010.

[32] Installed costs may differ among countries as a result of a wide variety of factors, including differences in incentive levels, module prices, interconnection standards, labor costs, procedures for receiving incentives, permitting, and interconnection approvals, foreign exchange rates, local component manufacturing, and average system size.

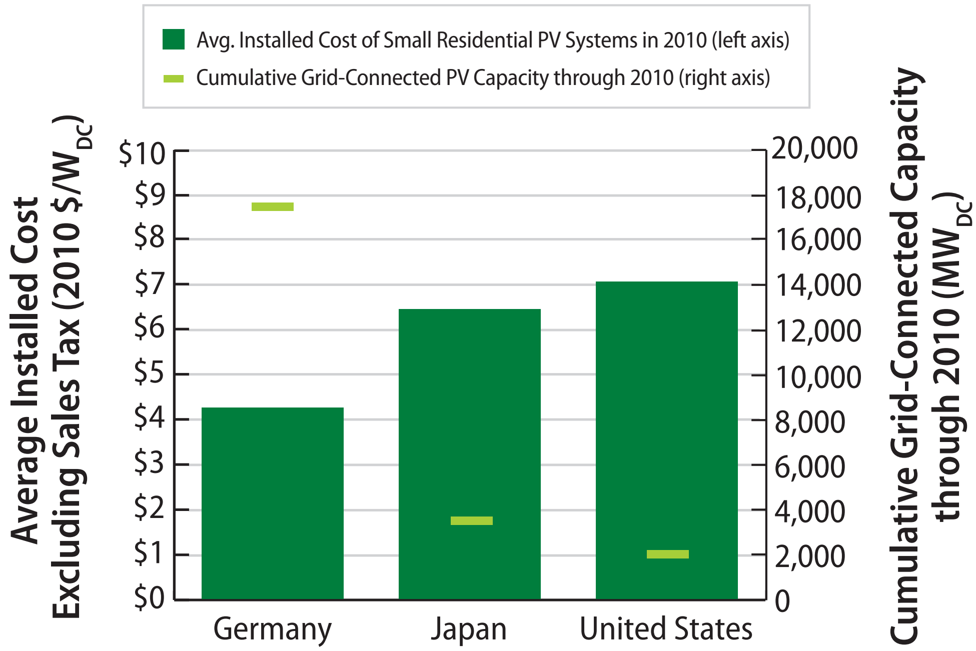
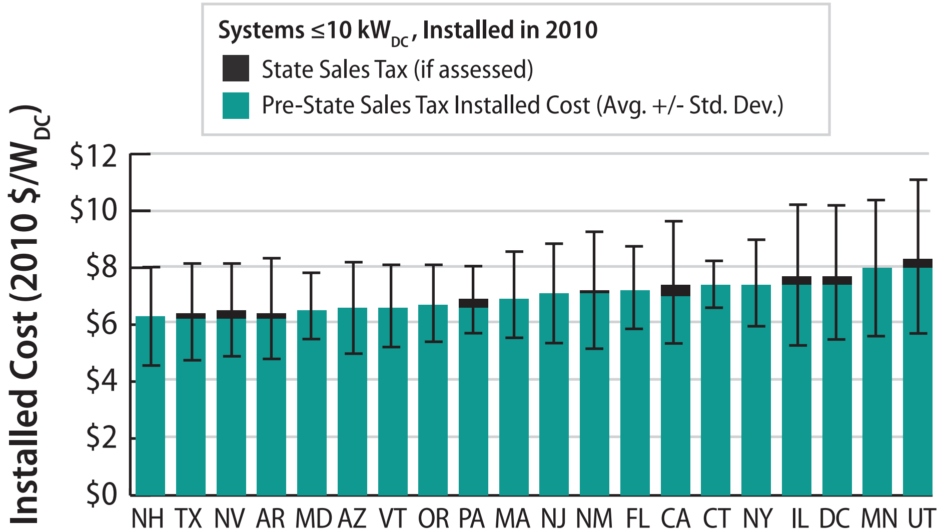


Figure 3.10 Average installed cost of 2 to 5-kW residential systems completed in 2010 (Barbose et al. 2011)

The United States is not a homogenous PV market, as evidenced by Figure 3.11, which compares the average installed cost of PV systems <10 kW completed in 2010 across 20 states. Average costs within individual states range from a low of $6.30/W in New Hampshire to a high of $8.40/W in Utah. Differences in average installed costs across states may partially be a consequence of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and hence greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. That said, the two largest PV markets in the country (California and New Jersey) are not among the low-cost states. Instead, the lowest cost states—New Hampshire, Texas, Nevada, and Arkansas—are relatively small markets, illustrating the potential influence of other state- or local factors on installed costs. For example, administrative and regulatory compliance costs (e.g., incentive applications, permitting, and interconnection) can vary substantially across states, as can installation labor costs. Average installed costs may also differ among states due to differences in the proportion of systems that are ground-mounted or that have tracking equipment, both of which will tend to increase total installed cost.

As indicated in Figure 3.11, installed costs also vary across states as a result of differing sales tax treatment; 10 of the 20 states shown in the figure exempted residential PV systems from state sales tax in 2010, and Oregon and New Hampshire have no state sales tax. Assuming that PV hardware costs represent approximately 60% of the total installed cost of residential PV systems, state sales tax exemptions effectively reduce the post-sales-tax installed cost by up to $0.40/W, depending on the specific state sales tax rate that would otherwise be levied.



Notes: State Sales Tax and Pre-State Sales Tax Installed Cost were calculated from 2010 sales tax rates in each state (local sales taxes were not considered). Sales tax was assumed to have been assessed only on hardware costs, which, in turn, were assumed to constitute 65% of the total pre-sales-tax installed cost.

Figure 3.11 Variation in installed costs among U.S. states (Barbose et al. 2011)

The decline in U.S. PV installed costs over time was partly attributable to the fact that PV systems have gotten larger, on average, and exhibit some economies of scale. As shown in Figure 3.12, an increasing portion of behind-the-meter PV capacity installed in each year has consisted of relatively large systems (though the trend is by no means steady). For example, systems in the >500 kW size range represented more than 20% of behind-the-meter PV capacity installed in 2010, compared to 0% from 1998 to 2001. The shift in the size distribution is reflected in the increasing average size of behind-the-meter systems, from 5.5 kW in 1998 to 12.8 kW in 2010. As confirmed by Figure 3.13, installed costs generally decline as system size increases. In particular, the average installed cost of behind-the-meter PV systems installed in 2010 was greatest for systems <2 kW, at $9.80/W, dropping to $5.20/W for systems >1,000 kW, a difference in average cost of approximately $4.60/W.

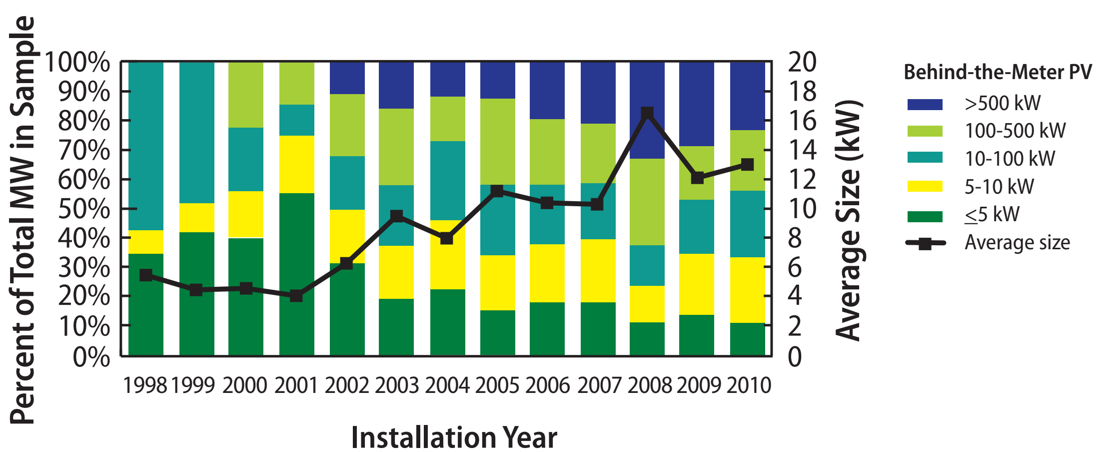


Figure 3.12 Behind-the-meter PV system size trends over time (Barbose et al. 2011)

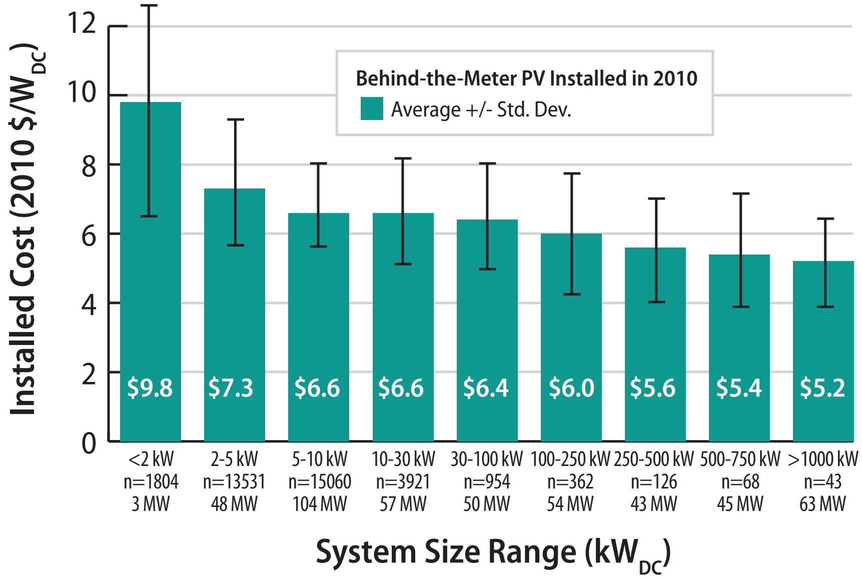
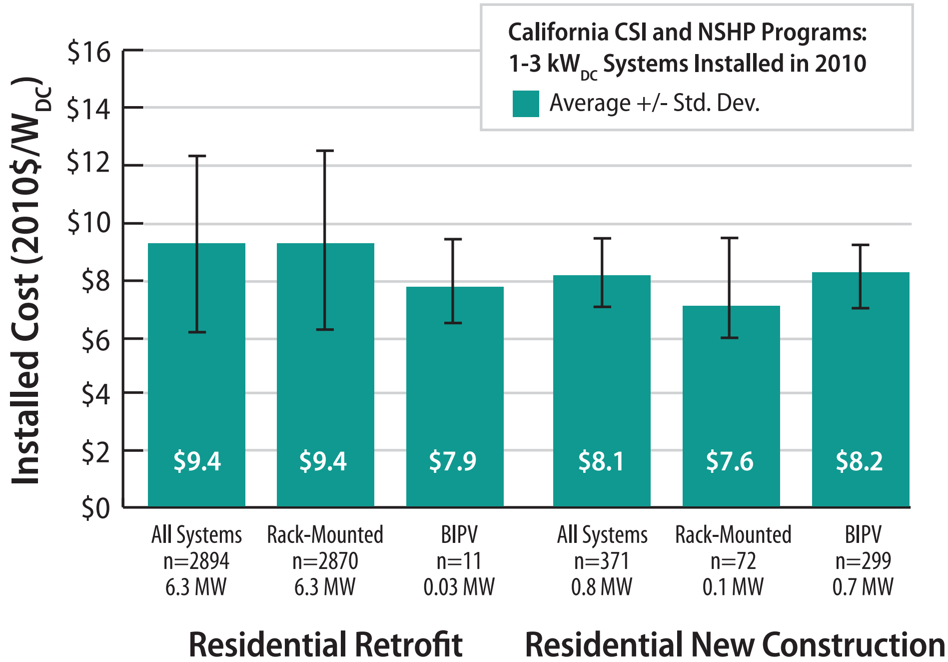


Figure 3.13 Variation in installed cost of behind-the-meter PV according to system size (Barbose et al. 2011)

In addition to variation across states and system size, installed costs also varied across key market segments and technology types. Figure 3.14 compares the average installed cost of residential retrofit and new construction systems completed in 2010, focusing on systems of 2–3 kW (the size range typical of residential new construction systems). Overall, residential new construction systems average \$0.70/W less than comparably sized residential retrofits, or \$1.50/W less if comparing only rack-mounted systems. However, a large fraction of the residential new construction market consists of building-integrated photovoltaics (BIPV), which averages \$0.60/W more than similarly sized rack-mounted systems installed in new construction, though the higher installed costs of BIPV may be partially offset by avoided roofing material costs.

Figure 3.15 compares installed costs of behind-the-meter systems using crystalline silicon versus thin-film modules, among fixed-axis, rack-mounted systems installed in 2010. Although the sample size of thin-film systems is relatively small, the data indicate that, in both the <10-kW and 10–100-kW size ranges, PV systems using thin-film modules were slightly more costly, on average, than those with crystalline technology (a difference of \$0.90/W in the <10 kW size range and \$1.10/W in the 10–100-kW range). In the >100-kW size range, however, the average installed cost of thin-film and crystalline systems were nearly identical. As shown in the following section on utility-sector PV systems, within that segment, thin-film PV systems generally had lower installed costs than crystalline systems.



Note : The number of rack-mounted systems plus BIPV systems may not sum to the total number of systems, as some systems could not be identified as either rack-mounted or BIPV.

Figure 3.14 Comparison of installed cost for residential retrofit vs. new construction (Barbose et al. 2011)

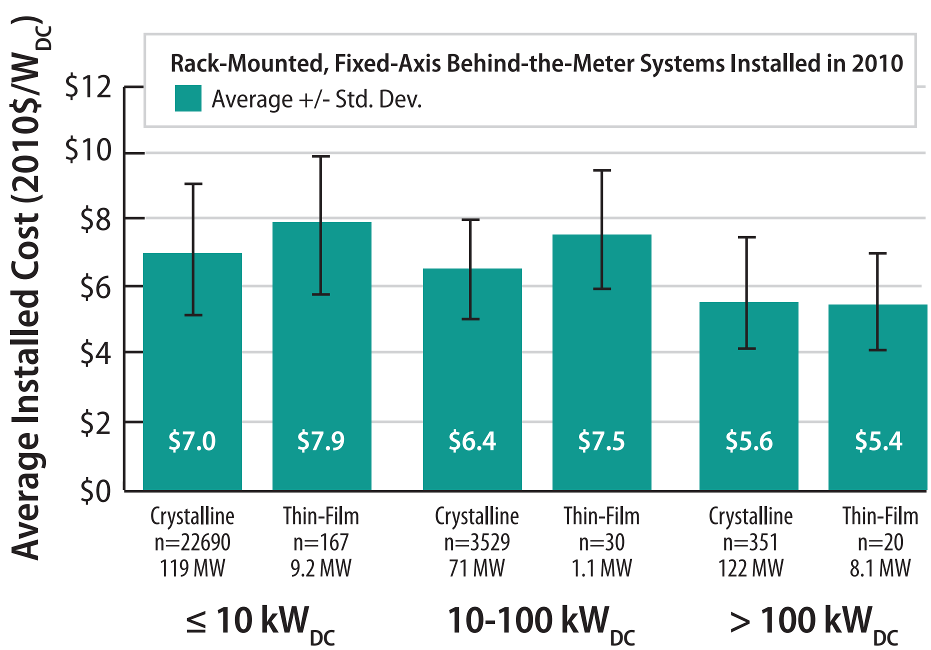


Figure 3.15 Comparison of installed cost for crystalline versus thin-film systems (Barbose et al. 2011)

3.6.2 Utility-Sector PV

This section describes trends in the installed cost of utility-sector PV systems, which, as indicated previously, is defined to include any PV system connected directly to the utility system, including wholesale distributed PV.[33] The section begins by describing the range in the installed cost of the utility-sector systems in the data sample, before then describing differences in installed costs according to project size and system configuration (crystalline fixed-tilt vs. crystalline tracking vs. thin-film fixed-tilt).

Before proceeding, it is important to note that the utility-sector installed cost data presented in this section must be interpreted with a certain degree of caution, for several reasons.

- *Small sample size with atypical utility PV projects*. The total sample of utility-sector projects is relatively small (31 projects in total, of which 20 projects were installed in 2010), and includes a number of small wholesale distributed generation projects as well as a number of larger "one-off" projects with atypical project characteristics (e.g., brownfield developments, utility pole-mounted systems, projects built to withstand hurricane winds, etc.). The cost of these small or otherwise atypical projects is expected to be higher than the cost of many of the larger utility-scale PV projects currently under development.

- *Lag in component pricing*. The installed cost of any individual utility-sector project may reflect component pricing one or even two years prior to project completion, and therefore the cost of the utility-sector projects within the data sample may not fully capture the steep decline in module or other component prices that occurred over the analysis period. For this reason and others (see Text Box 1 within the main body of the report), the results presented here likely differ from current PV cost benchmarks.

- *Reliability of data sources*. Third, the cost data obtained for utility-sector PV projects are derived from varied sources and, in some instances (e.g., trade press articles and press releases), are arguably less reliable than the cost data presented earlier for behind-the-meter PV systems.

- *Focus on installed cost rather than levelized cost*. It is worth repeating again that, by focusing on installed cost trends, this report ignores performance-related differences and other factors that influence the levelized cost of electricity (LCOE), which is a more comprehensive metric for comparing the cost of utility-sector PV systems.

As shown in Figure 3.16, the installed cost of the utility-sector PV systems in the data sample varies widely. Among the 20 projects in the data sample completed in 2010, for example, installed costs ranged from \$2.90/W to \$7.40/W. The wide range in installed costs exhibited by utility-sector projects in the data sample invariably reflects a combination of factors, including differences in project size (which range from less than 1 MW to over 34 MW) and differences in system configuration (e.g., fixed-tilt vs. tracking systems), both of which are discussed further below. The wide cost distribution of the utility-sector PV data sample is also attributable to the presence of systems with unique characteristics that increase costs. For example, among the 2010 installations in the data sample are a 10 MW tracking system built on an urban brownfield site (\$6.20/W), an 11 MW fixed-axis system built to withstand hurricane winds (\$5.60/W), and a collection of panels mounted on thousands of individual utility distribution poles totaling 14.6 MW (\$7.40/W).

[33] *The utility-sector PV data sample also includes the 14.2 MW PV system installed at Nellis Air Force Base, which is connected on the customer-side of the meter but is included within the utility-sector data sample due to its large size.*

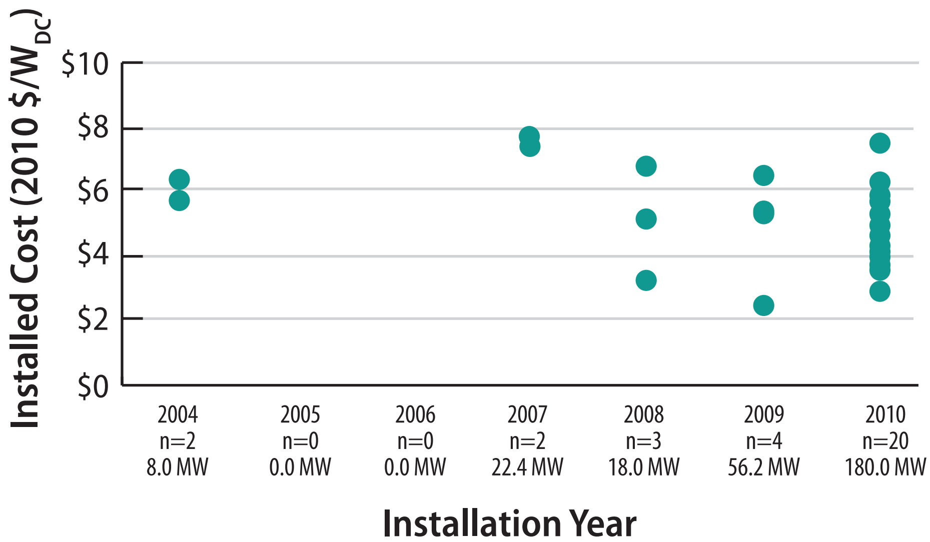


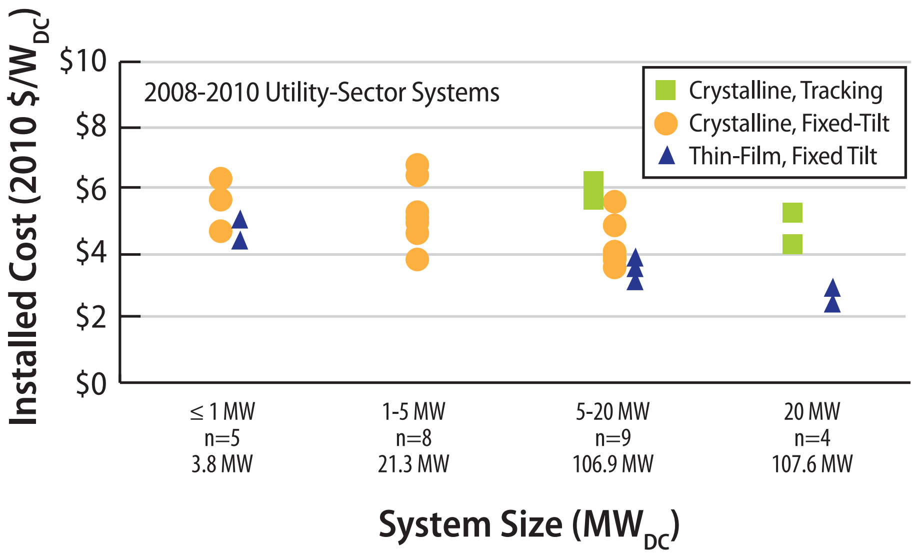
Figure 3.16. Installed Cost over Time for Utility-Sector PV (Barbose et al. 2011)

The impact of project size and system configuration on the installed cost of utility-sector PV systems is shown explicitly in Figure 3.17, which presents the installed cost of utility-sector systems completed in 2008-2010 (we include a broader range of years here in order to increase the sample size) according to project size and distinguishing between three system configurations: fixed-tilt systems with crystalline modules, fixed-tilt systems with thin-film modules, and tracking systems with crystalline modules.

The number of projects within each size range is quite small, and thus the conclusions that can be drawn from this comparison are highly provisional. Nevertheless, the figure clearly illustrates the impact of system configuration on installed cost, with thin-film systems exhibiting the lowest installed cost within each size range, and crystalline systems with tracking exhibiting the highest cost, as expected. For example, among >5 MW systems in the data sample, installed costs ranged from $2.40-$3.90/W for the five thin-film systems, compared to $3.70-$5.60/W for the five crystalline systems without tracking and $4.20-$6.20/W for the four crystalline systems with tracking. As noted previously, however, comparing only the installed cost ignores the performance benefits of high-efficiency crystalline modules and tracking equipment, which offset the higher up-front cost.

Figure 3.17 also illustrates the economies of scale for utility-sector PV, as indicated by the downward shift in the installed cost range for each system configuration type with increasing project size. For example, among fixed-tilt, crystalline systems installed over the 2008-2010 period, installed costs ranged from $3.70-$5.60/W for the five 5-20 MW systems, compared to $4.70-$6.30/W for the three <1 MW systems. Similarly, among thin-film systems, the installed cost of the two >20 MW projects completed in 2008-2010 ranged from $2.40-$2.90/W, compared to $4.40-$5.10/W for the two <1 MW projects.

Notwithstanding the aforementioned trends, Figure 3.17 also shows a high degree of "residual" variability in installed costs across projects of a given configuration and within each size range, indicating clearly that other factors (such as "atypical" project characteristics) also strongly influence the installed cost of utility-sector PV.



Notes: The figure includes a number of relatively small wholesale distributed PV projects as well as several "one-off" projects. In addition, the reported installed cost of projects completed in any given year may reflect module and other component pricing at the time of project contracting, which may have occurred one or two years prior to installation. For these reasons and others, the data may not provide an accurate depiction of the current cost of typical large-scale utility PV projects. This figure excludes the set of utility pole-mounted PV systems installed in PSE&G's service territory (totaling 14.6 MW through 2010); in Figure 3.16, those systems are counted as a single project.

Figure 3.17. Variation in Installed Cost of Utility-Sector PV According to System Size and Configuration (Barbose et al. 2011)

3.7 PV Operations and Maintenance

O&M is a significant contributor to the lifetime cost of PV systems. As such, reducing the O&M costs of system components is an important avenue to reducing lifetime PV cost. The data, however, are difficult to track because O&M costs are not as well documented as other PV system cost elements (which is due, in part, to the long-term and periodic nature of O&M).

3.7.1 PV Operation and Maintenance Not Including Inverter Replacement

During the past decade, Sandia National Laboratories (SNL) has collected O&M data for several types of PV systems in conjunction with Arizona Public Service and Tucson Electric Power (Table 3.2). Because O&M data were collected for only 5–6 years in each study, data on scheduled inverter replacement/rebuilding were not collected. Inverters are typically replaced every 7–10 years. Therefore, the information in Table 3.2 does not include O&M costs associated with scheduled inverter replacement/rebuilding. This issue is discussed in the next section.

As shown in Table 3.2, annual O&M costs as a percentage of installed system cost ranged from 0.12% for utility-scale generation to 5%–6% for off-grid residential hybrid systems. The O&M energy cost was calculated to be $0.004/kWh alternating current (AC) for utility-scale generation and $0.07/kWhAC for grid-connected residential systems. It should be noted that this is simply annual O&M cost divided by annual energy output and should not be confused with LCOE. For all the grid-connected systems, inverters were the major O&M issue. Four recent studies on O&M that provide additional context are summarized below.

A study by Moore and Post (2008) of grid-connected residential systems followed the experience of Tucson Electric Power's SunShare PV hardware buy-down program. From July 2002 to October 2007, O&M data were collected for 169 roof-mounted, fixed-tilt, crystalline silicon residential systems smaller than 5 kWDC and with a single inverter, in the Tucson area. A total of 330 maintenance events were recorded: 300 scheduled and 30 unscheduled.

The scheduled visits were credited with minimizing unscheduled maintenance problems. Many of the unscheduled visits involved replacing failed inverters that were covered under the manufacturer's warranty. The mean time between services per system was 10.1 months of operation, with maintenance costs amounting to $226 per system per year of operation.

A study by Moore et al. (2005) of grid-connected commercial systems followed the experience of PV systems installed by Arizona Public Service. From 1998 to 2003, O&M data were collected for 9 crystalline silicon systems size 90 kWDC or larger, with horizontal tracking. Most of the O&M issues were related to inverters, which required adjustments for up to 6 months after system installation, after which the inverters generally performed well. Maintenance associated with the PV modules was minimal. Maintenance associated with the tracking components was higher initially, but became a small factor over time.

A study by Moore and Post (2007) of utility-scale systems followed the experience of large PV systems installed at Tucson Electric Power's Springerville generating plant. From 2001 to 2006, O&M data were collected for twenty-six 135 KWDC crystalline silicon systems (all 26 systems were operational beginning in 2004). The systems were installed in a standardized manner with identical array field design, mounting hardware, electrical interconnection, and inverter unit. About half of the 300+ O&M visits made over the 5-year period were attributed to unscheduled visits. Many of the 156 unscheduled visits were due to unusually severe lightning storms. The mean time between unscheduled services per system was 7.7 months of operation.

A study by Canada et al. (2005) of off-grid residential hybrid systems followed the experience of a PV system lease program offered by Arizona Public Service. From 1997 to 2002, O&M data were collected for 62 standardized PV hybrid systems with nominal outputs of 2.5, 5, 7.5, or 10 kWh/day and included PV modules, a battery bank, an inverter and battery-charge controller, and a propane generator. Because of the geographic dispersion of the systems, travel costs accounted for 42% of unscheduled maintenance costs. Overall, O&M (including projected battery replacement at 6-year intervals) was calculated to constitute about half of the 25-year life-cycle cost of the PV hybrid systems, with the other half attributed to initial cost.

[32] *When measuring the cost per generation output of power plants, the industry standard is to use $/kW, rather than $/MW.*

<table>
<tr><th colspan="6">TABLE 3.3. SUMMARY OF ARIZONA PV SYSTEM O&M STUDIES, NOT INCLUDING O&M RELATED TO INVERTER REPLACEMENT/REBUILDING</th></tr>
<tr><th>System Type (Reference)</th><th>O&M Data Collection Period</th><th>Scheduled O&M</th><th>Unscheduled O&M</th><th>Annual O&M Cost as Percentage of Installed System Cost</th><th>O&M Energy Cost[42]</th></tr>
<tr><td>Grid-Connected Residential, Fixed Tilt (Moore and Post 2008)</td><td>2002–2007</td><td>Visits by category: general maintenance/ inspection (45%), pre-acceptance checks required for SunShare program (55%)</td><td>Visits by category: inverter (90%), PV array (10%)</td><td>1.47%</td><td>$0.07/</td></tr>
<tr><td>Grid-Connected Commercial, Horizontal Tracking (Moore et al. 2005)</td><td>1998–2003</td><td colspan="2">Inverters were the primary maintenance issue; most systems required inverter adjustments during initial setup for up to 6 months after installation, after which the inverters generally performed well. Minimal maintenance was associated with modules. Maintenance for tracking components started higher during early part of development effort, but decreased over time.</td><td>0.35%</td><td>Not Reported</td></tr>
<tr><td>Utility-Scale Generation, Fixed Tilt (Moore and Post 2007)</td><td>2001–2006</td><td>Mowing native vegetation, visually inspecting arrays and power-handling equipment</td><td>Costs by category: inverter (59%), data acquisition systems (14%), AC disconnects (12%), system (6%), PV (6%), module junction (3%).</td><td>0.12%</td><td>$0.004/</td></tr>
<tr><td>Off-Grid Residential Hybrid (Canada et al. 2005)</td><td>1997–2002</td><td>Quarterly generator service (oil change, filter, adjustment, and inspection), battery inspection and service, inverter inspection, overall system inspection; repairs/ replacements made when problems noted.</td><td>Costs by category: system setup, modification, and removal (41.4%); generator (27.8%); inverter (16.5%); batteries (4.7%); controls (4.2%); PV modules (2.7%); system electrical (2.6%).</td><td>5%–6%[43]</td><td>Not Reported</td></tr>
</table>

While research institutions such as SNL have collected data, the study groups are generally limited. Commercial entities are usually more protective of performance data, though they generally have larger and more diverse study groups that can provide more significant results. In order to provide industry knowledge that could further optimize solar energy systems and otherwise improve O&M, efficiency, and solar project costs, SunEdison published detailed performance data of nearly 200 commercial-scale solar energy systems (Voss et al. 2010). The systems surveyed cover a wide variety of geographic and environmental conditions, represented a wide range of system sizes (from a minimum size of 23 kW to a maximum size of 1.7 MW, and with an average system size of 259 kW) and were monitored for O&M issues over a 16-month period (January 2008–April 2009). The study collected data on solar PV system outages/reductions (rather than site visits, as the SNL research reported), as well as the production potential during that time, also called "unrealized generation," was calculated to provide an impact in kWh (rather than a monetary figure of $/kWh, which was reported in the SNL research). Major conclusions of the study include the following (Voss et al. 2010):

- Of systems studied, approximately 45% did not experience a single outage throughout the 16 months of the survey.

- Outages were categorized as high-impact events (which comprised only 10% of the outages yet accounted for 60% of the total lost production) or nuisance events (which occurred 50% of the time, but accounted for less than 10% of total lost production). Both categories provide significant areas for economic improvement but for different economic reasons: the high-impact events are costly due to a loss in production while the nuisance events drive up O&M costs due to the higher frequency of outages and therefore timely site visits.

- Similarly to the SNL research, the inverter was the cause for the most outages (over 50% of the time) as well as the most energy lost (approximately 42%). Of all inverter failures, nearly 25% of the time they were due to control board failures, which were replaced under warranty by the manufacturer (see Section 3.7.2 for more information on replacement/warranty trends). Other inverter failures were due to either unknown causes, followed less frequently by fans and software failures (which had a relatively lower impact on unrealized generation), followed by defective internal wiring (which caused a disproportionately higher loss of generation due to the complexity of the repair).

- While only 5% of the outages studied were due to failure in the AC components, they caused a disproportionately large amount of unrealized generation (approximately 38%) due to the long duration of service-time required to thoroughly address and solve the problem.

- Additional causes of outages ranging from the most frequent to least frequent include customer/utility grid issues, DC components, unknown reasons, tracker failure, weather, modules, meter/monitoring, service, and construction. Of these additional reasons, the weather had the greatest impact on generation (causing 12% energy loss), followed by service (causing approximately 4% of energy loss).

3.7.2 PV Inverter Replacement and Warranty Trends

Inverters have become a central component in the solar industry due to the ever-growing grid-connected PV market. A major component of overall PV system efficiency is determined by the ability of an inverter to convert the DC output from PV modules into AC electricity that can be sent into the grid or used in a home or business.

Although much attention is given to increasing inverter efficiencies, inverter reliability has a greater impact on lifetime PV system cost, which makes it an important factor in market adoption. In the study of Tucson Electric Power's utility-scale PV described above, replacing/rebuilding inverters every 10 years was projected to almost double annual O&M costs by adding an equivalent of 0.1% of the installed system cost. In turn, bringing the total annual O&M cost to 0.22% of installed system cost (Moore and Post 2007). Similarly, the O&M energy cost was projected to increase by \$0.003/kWhAC, resulting in a total O&M energy cost of \$0.007/kWh_{AC}. Again, this is simply annual O&M cost divided by annual energy output, not LCOE. Inverters are the component of a PV system that will need replacement at least once over the lifetime of a PV system. The warranty that a manufacturer is willing to provide is a good indication of an inverter's reliability.

As inverter reliabilities increase, manufacturers have started to offer longer warranties. Today, a majority of manufacturers are comfortable giving default 5- to 10-year warranties as opposed to 1- to 3-year warranties, as was the case in the mid-2000s. In addition, a growing number of manufacturers have begun offering customers optional extended warranties for an additional fee. This suggests that inverter companies are becoming increasingly confident in the reliability of their products. Table 3.4 offers warranty information for a sampling of some of the leading inverter suppliers in today's market.

TABLE 3.4. INVERTER WARRANTY DATA FROM SELECT INVERTER MANUFACTURERS		
		WARRANTY
Manufacturer	Standard	Extended (Total Years)
Fronius	10	20
Motech	5	10
Enphase (microinverters)	15	N/A
PV Powered (now part of Advanced Energy)	10	20
SatCon	5	20
SMA Technologies	5	20
Solarix	5	7
Xantrex	5	10

(websites of respective companies listed)

Micro-inverters are emerging as an alternative to large, central inverters. Systems employing micro-inverters utilize multiple small inverters rather than a single, centralized inverter to convert DC into AC electricity. Because micro-inverters convert the DC from each individual module rather than entire arrays of modules, inverter failure does not cripple the entire system. Enphase Energy and Petra Solar micro-inverters are commercially available. Sparq Systems, Inc. plans to produce high-durability, lightweight micro-inverters to be commercially available in North America in the third quarter of 2010 (Solar Server 2010).

3.8 CSP Installation and Operation and Maintenance Cost Trends

The average cost, after federal incentives, for a CSP plant without storage is greater than \$4,000/kW in the United States (Bullard et al. 2008). More recent analysis in early 2010 estimates the capital costs for a CSP plant to range from \$3,000/kW to \$7,500/kW, where the upper limit reflects plants that have invested in thermal energy storage (GTM 2011). For example, investment for construction and associated costs for the Nevada Solar One plant, which has a nominal 64 MW capacity and only 30 minutes of storage via its HTF, amounted to \$266 million or about \$4,100/kW. Several similar-sized trough plants with more storage have been built in Spain; however, the project costs have not been disclosed (DOE 2009). System developers strongly believe that improvements in system design and O&M will reduce this cost considerably, making it more competitive with traditional electricity sources.

Current CSP costs are based largely on the parabolic trough, which is the most mature of the various CSP technologies. Figure 3.18 shows a typical cost breakdown for components of a parabolic trough system that is sized at 100-MW capacity with 6 hours of thermal energy storage. In this reference plant, energy storage is the second most expensive portion at 17% of the total cost, while the solar field comprises approximately 30% of the total. Solar field components include the receivers, mirrors (reflectors), structural support, drivers, and foundation. Receivers and mirrors each contribute approximately 10% to the total cost. The power block (or "power plant"), which is not considered part of the solar field, normally has the highest cost of all the major components (especially in systems lacking thermal energy storage), contributing roughly 13% to the total (NREL 2010b).

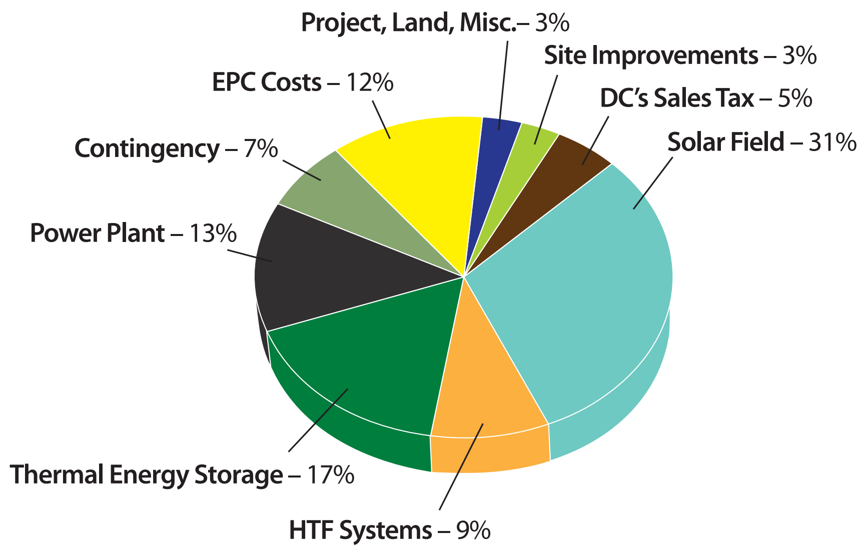


Figure 3.18 Generic parabolic trough CSP cost breakdown (NREL 2010b)

3.9 CSP Technology Characteristics and System Performance

Four types of CSP technology were under development: parabolic trough technology, power tower technology, dish-engine technology, and linear Fresnel reflector (LFR) technology. Each technology along with its defining attributes and applications is discussed below.

3.9.1 Parabolic Trough Technology

Parabolic trough technology benefits from the longest operating history of all CSP technologies, dating back to the SEGS plants in the Mojave Desert of California in 1984, and is therefore the most proven CSP technology (DOE 2009). Trough technology uses one-axis tracking, has a concentration ratio of 80 (concentration ratio is calculated by dividing reflector area by focal area), and achieves a maximum temperature of nearly 400°C. This relatively low temperature limits potential efficiency gains and is more susceptible to performance loss when dry cooling is used. Moreover, the relatively low operating temperature makes it very difficult to provide the amount of heat storage (in a cost-effective manner) that is required for around-the-clock dispatch (Grama et al. 2008, Emerging Energy Research 2007). The current design point solar-to-electric efficiency (the net efficiency in the ideal case when the sun is directly overhead) for parabolic troughs ranges from 24%–26%. This metric is useful in indicating the ideal performance of a system and is often used to compare components on similarly designed trough systems. The overall annual average conversion, which provides a better assessment of actual operation over time, is approximately 13%–15% (DOE 2009).

3.9.2 Power Tower Technology

Power towers (also called central receivers or receiver technology) use two-axis tracking, have a concentration ratio up to 1,500, and achieve a maximum temperature of about 650°C (Grama et al. 2008). The higher operating temperature of tower technology reduces the susceptibility of these systems to efficiency losses, especially when dry cooling is used (Emerging Energy Research 2007). The reflectors, called heliostats, typically comprise about 50% of plant costs. The current design-point solar-to-electric efficiency for power towers is approximately 20%, with an annual average conversion efficiency of approximately 14%–18% (DOE 2009).

3.9.3 Dish-Engine Technology

Dish-engine technology uses two-axis tracking, has a concentration ratio up to 1,500, and achieves a maximum temperature of about 700°C (Emerging Energy Research 2007). This technology set the world record for solar thermal conversion efficiency, achieving 31.4%, and has an estimated annual conversion efficiency in the lower 20th percentile. Dish-engine systems are cooled by closed-loop systems and lack a steam cycle, therefore endowing them with the lowest water usage per megawatt-hour compared to other CSP technologies. As of mid-2010, integration of centralized thermal storage was difficult; however, dish-compatible energy storage systems were being developed in ongoing research sponsored by DOE (DOE 2009). The Maricopa Solar Project became the first-ever commercial dish-engine system when it began operation in January 2010. The system is located in Arizona and generated a maximum capacity of 2 MW (NREL 2010a).

3.9.4 Linear Fresnel Reflector Technology

LFR technology uses one-axis tracking and has a concentration ratio of 80. The reduced efficiency (15%–25%) compared to troughs is expected to be offset by lower capital costs (Grama et al. 2008, Emerging Energy Research 2007). Superheated steam has been demonstrated in LFRs at about 380°C, and there are proposals for producing steam at 450°C. As of mid-2010, LFRs are in the demonstration phase of development, and the relative energy cost compared to parabolic troughs remains to be established (DOE 2009). Kimberlina Solar is the first commercial-scale LFR in the United States. It began operation in early 2009 and generates a maximum capacity of 7 MWAC. As of mid-2010, the only other operational LFR system is the Puerto Errado 1 (PE1) in Spain, which generates a maximum 1 MW and began operation in 2008 (NREL 2010a).

3.9.5 Storage

A unique and very important characteristic of trough and power tower CSP plants is their ability to dispatch electricity beyond daylight hours by utilizing thermal energy storage (TES) systems (dish-engine CSP technology currently cannot utilize TES). In TES systems, about 98% of the thermal energy placed in storage can be recovered, CSP production time may be extended up to 16 hours per day, and the capacity factor increases to more than 50%, which allows for greater dispatch capability (DOE 2009). Although capital expenditure increases when storage is added, as costs of TES decline, the LCOE is likely to decrease due to an increased capacity factor and greater utilization of the power block (DOE 2009). Moreover, storage increases the technology's marketability, as utilities can dispatch the electricity to meet non-peak demand.

TES systems often utilize molten salt as the storage medium; when power is needed, the heat is extracted from the storage system and sent to the steam cycle. The 50-MW Andasol 1 plant in Spain utilizes a molten salt mixture of 60% sodium nitrate and 40% potassium nitrate as the storage medium, enabling more than 7 hours of additional electricity production after direct-normal insolation is no longer available. Various mixtures of molten salt are being investigated to optimize the storage capacity, and research is being conducted on other mediums such as phase-change materials. Synthetic mineral oil, which has been the historical HTF used in CSP systems, is also being viewed as a potential storage medium for future systems. In the near term, most CSP systems will likely be built with low levels of storage due to time-of-delivery rate schedules that favor peak-power delivery. For example, the Nevada Solar One plant incorporates roughly half an hour of storage via its HTF inventory, but no additional investments were made in storage tanks (DOE 2009).

3.9.6 Heat-Transfer Fluid

Improvements in the HTF are necessary to bring down the levelized cost of energy for CSP. This can be accomplished by lowering the melting points and increasing the vapor pressure of these substances. For commercial parabolic trough systems, the maximum operating temperature is limited by the HTF, which is currently a synthetic mineral oil with a maximum temperature of 390°C. Dow Chemical's and Solutia's synthetic mineral oils have been used widely as the HTF in trough systems. The problem with these synthetic oils is that they break down at higher temperatures, preventing the power block from operating at higher, more efficient temperatures. Several parabolic trough companies are experimenting with alternative HTFs—most notably molten salts and direct steam generation—that would allow operation at much higher temperatures. The downside to using molten salts is that they freeze at a higher temperature than the synthetic oils, which means a drop in temperature during the night may solidify the substance. This, in turn, can damage the equipment when the salt expands and puts pressure on the receivers. Corrosion of the receivers is another potential concern when salts are introduced. Nonetheless, research is being conducted to use this substance as both an HTF and TES medium. If this can be accomplished, costly heat exchangers would not be needed, thus helping to reduce the LCOE.

3.9.7 Water Use

As stated in Section 2.3.3.4, water resources are essential to the operation of a CSP plant and may be a limiting factor in arid regions (except for dish-engine systems, which do not require water cooling). A water-cooled parabolic trough plant typically requires approximately 800 gallons per megawatt-hour. Power towers operate at a higher temperature and have lower water cooling needs, ranging from 500–750 gallons per megawatt-hour. An alternative to water cooling is dry or air cooling, which eliminates between 90% and 95% of water consumption (DOE 2009, NREL 2007). However, air cooling requires higher upfront capital costs and may result in a decrease in electricity generation, depending on location temperature. An alternative to wet cooling and dry cooling is to implement hybrid cooling, which decreases water use while minimizing the generation losses experienced with dry cooling.

3.9.8 Land Requirements

The amount of acreage needed for a CSP facility depends partly on the type of technology deployed. More importantly, though, land use is dependent on thermal storage hours and a location's solar insolation. Common practice is to state land requirements in terms of acres per megawatt. The range normally provided is 4–8 acres in a location with solar insolation similar to that found in the U.S. desert Southwest (SNL 2009). The low end of the range is possible when greater self-shading of reflectors is allowed, although this results in reduced electricity output. The high end represents the additional land needed for energy storage, with energy storage resulting in a higher capacity factor. Because of such variation, when considering land needs, it can be more useful to provide a number in terms of acres per megawatt-hour. When this is done, a comparison among CSP technology types can more easily be made. The general trend at this stage of technology development is that power towers require approximately 20% more land per megawatt-hour than troughs. The Maricopa Solar Project, the only operating commercial dish-engine facility in the world as of mid-2010, suggests a 10-acres/MW-land-use standard for the dish-engine technology (NREL

2010a). The construction of additional dish engine CSP plants in varying sizes and locations will be required to verify land requirements for this technology.

3.10 References

Barbose, G., N. Darghouth, and R. Wiser. 2011. "Tracking the Sun IV. An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010." Berkeley, CA: Lawrence Berkeley National Laboratory. Available for download at: *http://eetd.lbl.gov/ea/EMS/re-pubs.html*

Bloomberg New Energy Finance. (2010). "Research Note- PV Inverter Technology." May 20, 2010.

Bullard, N.; Chase. J.; d'Avack, F. (May 20, 2008). "The STEG Revolution Revisited." Research Note. London: New Energy Finance.

Canada, S.; Moore, L.; Post, H.; Strachan, J. (2005). "Operation and Maintenance Field Experience for Off-grid Residential Photovoltaic Systems." *Prog. Photovolt: Res.* Appl.; 13:67–74.

Denholm, P.; Margolis, R. (2008a). "Impacts of Array Configuration on Land-Use Requirements for Large-Scale Photovoltaic Deployment in the United States." NREL Conference Paper CP 670-42971. Golden, CO: National Renewable Energy Laboratory.

Denholm, P.; Margolis, R. (2008b). "Land-Use Requirements and the Per-Capita Solar Footprint for Photovoltaic Generation in the United States." *Energy Policy*; 36:3531–3543.

Emerging Energy Research, LLC. (2007). *Global Concentrated Solar Power Markets and Strategies, 2007–2020*. Cambridge, MA: Emerging Energy Research.

European Photovoltaic Industry Association (EPIA) and Greenpeace (2011). *Solar Generation 6: Solar Photovoltaic Electricity Empowering the World 2011*. *http://www.epia.org/publications/epia-publications/solar-generation-6.html*. Accessed May 31, 2011.

First Solar, (2010a). *Annual Report 2009*. Securities and Exchange Commission, p. 1.

Grama, S.; Wayman, E.; Bradford, T. (2008). *Concentrating Solar Power—Technology, Cost, and Markets.* 2008 Industry Report. Cambridge, MA: Prometheus Institute for Sustainable Development and Greentech Media.

Greentech Media (GTM). (January 2011). Concentrating Solar Power 2011: Technology, Costs, and Markets. *http://www.gtmresearch.com/report/concentrating-solar-power-2011-technology-costs-and-markets*. Accessed May 9, 2011.

Mehos, M.; Kearney, D. (2007). "Potential Carbon Emissions Reductions from Concentrating Solar Power by 2030." Kutscher, C. ed. *Tackling Climate Change in the U.S.: Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030*. NREL Report CH-550-41270. Boulder, CO: American Solar Energy Society, pp. 79–89. *www.ases.org/climatechange/*. Accessed June 2009.

Mehta, S. (May 2011). "27th Annual Data Collection Results." *PV News*. Greentech Media.

Mehta, S. (2010). "26th Annual Data Collection Results: Another Bumper Year for Manufacturing Masks Turmoil." *PV News*. Greentech Media

Mehta, S.; Bradford, T.; (2009). *PV Technology, Production, and Cost, 2009 Forecast: The Anatomy of a Shakeout*. Prometheus Institute and Greentech Media.

Mints, P. (2009). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 2008/2009.* Report # NPS-Supply4. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Mints, P. (2010). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 2009/2010*. Report # NPS-Supply5. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Mints, P. (2011). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 20010/2011*. Report # NPS-Supply6. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Moore, L.; Post, H.; Hayden, H.; Canada, S.; Narang, D. (2005). "Photovoltaic Power Plant Experience at Arizona Public Service: A 5-year Assessment." *Prog. Photovolt: Res. Appl.*; online.

Moore, L.M.; Post, H.N. (2007). "Five Years of Operating Experience at a Large, Utility-Scale Photovoltaic Generating Plant." *Prog. Photovolt: Res. Appl.*; online.

Moore, L.M.; Post, H.N. (2008). "Five Years of Residential Photovoltaic System Experience at Tucson Electric Power." *Strategic Planning for Energy and the Environment*; 28:2, pp. 58–73.

National Renewable Energy Laboratory (NREL). (2007). *Water saving heat rejection for solar thermal power plants. http://www.nrel.gov/csp/troughnet/pdfs/2007/dersch_dry_cooling.pdf*. Accessed August 18, 2010.

NREL. (2010a). "Concentrating Solar Power Projects" website. *http://www.nrel.gov/csp/solarpaces/*. Accessed August 18, 2010.

NREL. (2010b). *Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM)*. *http://www.nrel.gov/docs/fy10osti/47605.pdf*. Accessed August 19, 2010. Photon International. (2002–2008). Annual market surveys for on-grid inverters.

NREL. (2011). Internal NREL analysis.

Renewable Energy Policy Network for the 21st Century (REN21). (2010). *Renewables 2010 Global Status Report.* Paris: REN21 Secretariat. *http://www.ren21.net/Portals/97/documents/GSR/REN21_GSR_2010_full_revised Sept2010.pdf*. Accessed August 19, 2010.

Sandia National Laboratories (SNL). (September 2009). E-mail correspondence with CSP technical staff. Albuquerque, NM: Sandia National Laboratories.

SolarServer. (February 2010). "Photovoltaic Micro-Inverters: Advantages and Challenges for Rooftop PV Systems." *http://www.solarserver.com/solar-magazine/solar-interviews/solarinterviews/photovoltaic-micro-inverters-advantages-and-challenges-for-rooftop-pv-systems.html*. Accessed August 18, 2010.

U.S. Department of Energy (DOE). (2009). Report to Congress. Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation. *http://www.eere.energy.gov/solar/pdfs/csp_water_study.pdf*. Accessed October 2009.

Uni-Solar. (2010). Energy Conversion Devices Technology Roadmap Update, June 2010. *http://www.uni-solar.com/wp-content/uploads/pdf/FINAL_TR_Presentation_6_1_10.pdf*. Accessed August 2010.

Voss, S.; Golnas, T.; Hester, S.; Culpepper, M. (2010). "Service & service architecture – yield monitoring, optimization and reporting for commercial-scale solar utility installations." *Photovoltaics International*, Ed. 5. *http://www.pv-tech.org/technical_papers/_a/service_architecture_yield_monitoring_optimization_for_commercial-scale_sol/*. Accessed August 2009.

Wohlgemuth, J.H.; Cunningham, D.W.; Nguyen, A.M.; Miller, J. (2006). *Long Term Reliability of PV Modules.* Frederick, MD: BP Solar.

Policy and Other Market Drivers

This chapter covers key elements of U.S. federal, state, and local policies pertaining to solar energy technologies, as well as market-based developments that affect U.S. solar market evolution. Section 4.1 discusses federal policies, incentives, and programs including tax credits, depreciation benefits, grants, the DOE Loan Guarantee Program, Qualified Clean Energy Bonds, Build America Bonds, Clean Renewable Energy Bonds, and other federal programs and incentives. Section 4.2 discusses state and local policies and incentives, and rules and regulations including permitting, interconnection, net metering, direct cash incentive programs, renewable portfolio standards and solar set-asides, and clean energy funds. Section 4.3 provides information on major financing mechanisms and programs: third-party power purchase agreement financing, customer solar lease financing, property-assessed clean energy programs, and other emerging financing structures.

4.1 Federal Policies and Incentives for PV and CSP

Federal policies and incentives play an important role in the commercialization and adoption of solar technologies. They have enabled rapid expansion of solar markets in countries such as Germany, Spain, Italy, Japan, and the United States, among others. Legislation enacted in the United States in 2008 and early 2009 provided unprecedented levels of federal support for U.S. renewable energy projects, including solar energy projects.

The Emergency Economic and Stabilization Act of 2008 (EESA) or "bailout bill" became law on October 3, 2008. It contains tax incentives designed to encourage individuals and businesses to invest in renewable energy, including 8-year extensions of the business and residential solar ITCs.

The American Recovery and Reinvestment Act (ARRA), or "stimulus bill", or "the Recovery Act", was signed into law on February 17, 2009, with an estimated $787 billion overall in tax incentives and spending programs. Many ARRA provisions support solar energy. Some tax incentives were extended through various additional legislation passed in 2010.

This section discusses the major U.S. federal policies and incentives directed toward solar energy, with an emphasis on provisions in the EESA and ARRA. For additional information, including how to apply for the benefits of the policies, see the list of websites in Section 4.1.11.

4.1.1 Investment Tax Credit

Sections 48 (for businesses) and 25D (for residences) of the Internal Revenue Code detail the federal investment tax credit (ITC) for certain types of energy projects, including equipment that uses solar energy to generate electricity. Like other tax credits, the ITC reduces the tax burden of individuals and commercial entities that make investments in solar energy technology. On an industry level, a long-term ITC provides consistent financial support for growth such as building manufacturing plants, developing an installer workforce, and investing in large-scale solar electric plants that require extended planning and construction time.

For commercial projects, the ITC is realized in the year in which the solar project begins commercial operations, but vests linearly over a 5-year period (i.e., one-fifth of the 30% credit vests each year over a 5-year period). Thus, if the project owner sells the project before the end of the fifth year since the start of commercial operations, the unvested portion of the credit will be recaptured by the Internal Revenue Service (IRS). This period is sometimes referred to as the 5-year "clawback" period.

The EESA included several important changes to the ITC through December 31, 2016, including extensions of the commercial and residential solar ITCs, providing a credit of up to 30% of the total capital costs of a project (including equipment and labor) (SEIA 2008).[35] In addition, with the passage of the EESA, the cap on the ITC for residential PV systems (previously $2,000) was removed for property placed in service after December 31, 2008. The bill also allows individual taxpayers to use the credit to offset alternative minimum tax liability. Another change to the ITC allows regulated utilities to claim the tax credit, providing significant support for increased utility investment in solar energy projects. The ARRA enhanced the ITC further by allowing individuals and businesses to qualify for the full amount of the solar tax credit, even if projects receive subsidized energy financing. Previously, the ITC would not apply to the portion of the investment funded via subsidized financing such as below-market loans. Also, the ARRA removed the $2,000 cap on the ITC for residential solar water heating systems.

4.1.2 Renewable Energy Grants

Section 1603 of the ARRA authorizes the U.S. Department of the Treasury to issue commercial-renewable-energy-project owners cash grants in lieu of the ITC. The grants program was created in response to the lack of available financing and limited appetite for tax credits, resulting from the financial crisis and economic downturn that began in 2008.The program is designed similarly to the ITC and offers an equivalent 30%-benefit based on the eligible costs of the solar property that is placed in service.

As initiated under ARRA, the grants would have only been available for projects placed in service or under construction by 2009 or 2010. However, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 extended the program for projects under construction by December 31, 2011 (DSIRE 2011). Grants are available for qualifying property that is placed in service during 2009, 2010, or 2011, or that began construction in those years and are placed in service prior to 2017. Developers must apply for the grant before October 1, 2012, and only tax-paying corporate entities are eligible. Grant applications are processed within 60 days from the date they are received or the system is placed in service, whichever is later.

The Treasury began accepting applications for grants on July 31, 2009, and the first payments were announced on September 1. As of February 2011, the Treasury had made 6,299 grants totaling $593 million for CSP and PV, with PV representing $2 billion of projects cost. (Q4 Solar Quarterly Summary) This represents $3,200 million in project costs. The U.S. Department of the Treasury posts a list of all Section 1603 awards on their website.

Several variables determine whether a developer might opt to apply for a cash grant. These factors may include state and local incentives and mandates, project scale and required lead time for development, and the ability to monetize tax credits.

[35] Historically, through 2005, the size of the commercial solar credit was equal to 10% of the project's "tax credit basis," or the portion of system costs to which the ITC applies. The EPAct of 2005 temporarily increased the solar credit to 30% of a project's tax credit basis for projects placed in service between January 1, 2006, and January 1, 2008. In late December 2006, the Tax Relief and Healthcare Act of 2006 extended the in-service deadline to December 31, 2008, and in October 2008, the EESA extended it once again for a full 8 years, through December 31, 2016. Unless extended again or otherwise altered over the next 8 years, the Section 48 commercial solar credit will revert back to 10% for projects placed in service on January 1, 2017.

More information and a weekly updated list is available at *http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx*.

4.1.3 Manufacturing Tax Credit

The ARRA created a tax credit for new investments in advanced energy manufacturing that, similar to the ITC, is equal to 30% of the eligible investment costs. Eligible technologies include renewable energy, energy conservation, electric grids supporting intermittent sources of renewable energy, carbon capture and storage, biofuel refining or blending, and hybrid electric vehicles and components. The cap for new manufacturing investment credits of $2.3 billion was reached in January 2010. The tax credits are expected to support $7.7 billion of manufacturing capital investment. In determining which projects receive the tax credits, the U.S. Department of the Internal Revenue Service, in coordination with the U.S. Department of Energy, administered a merit-based review with specific consideration and focus placed on the following criteria: commercial viability, job creation, greenhouse gas impact, technological innovation and cost reduction, and time to completion.

Manufacturers of solar energy-related technology were awarded $1.17 billion in credits, accounting for half of the available credits. This is expected to support an estimated $3.9 billion in total investment. Of the 183 winning projects, 58 were facilities supplying the solar energy industry, accounting for nearly a third of the selected projects. This excludes projects utilizing solar heating and cooling technologies (internal DOE data). This incentive is not currently available unless further funding is received.

More information is available online: *http://energy.gov/savings/qualifying-advanced-energy-manufacturing-investment-tax-credit* .

4.1.4 MACRS and Bonus Depreciation

The past 3 years have seen important alterations to the Modified Accelerated Cost Recovery System (MACRS). MACRS, which first became available for renewable energy projects in 1986, allows investors to depreciate certain investments in solar power and other types of projects on their federal tax return using a 5-year accelerated depreciation schedule. Under this provision, also known as the 5-year straight-line depreciation, "equipment which uses solar energy to generate electricity" qualifies for 5-year, double-declining-balance depreciation. In most cases, 100% of a solar project's cost will qualify for this accelerated schedule, but the 30% ITC will reduce the project's depreciable basis by 15% (i.e., only 85% of project costs are eligible for MACRS if the ITC is taken). Assuming a 40%-combined-effective state and federal tax bracket and a 10%-nominal discount rate, on a present-value basis, this 5-year MACRS depreciation schedule provides a tax benefit equal to about 26% of system costs (Bolinger 2009).[36] Taken together, the 30% ITC and accelerated depreciation provide a combined tax benefit equal to about 56% of the installed cost of a commercial solar system (Bolinger 2009).

In addition to MACRS, the EESA and following legislation enacted first-year bonus depreciations. The EESA included a first-year bonus depreciation of 50% for solar projects installed in 2008. This bonus depreciation allowed projects to deduct up to half of the eligible costs from taxable income in the first year with the remaining 50% depreciated over the 5-year MACRS schedule. The ARRA extended the first-year 50% bonus depreciation retroactively through the 2009 tax year. The ARRA also increased the size of the write-off available (up to 100% of a $250,000 investment, a declining percentage after $250,000, and phasing out at $800,000). Under the Small Business Jobs Act enacted in September 2010, this 50% first-year bonus depreciation was again extended retroactively through the 2010 tax year.

[36] Only 12% of this benefit is attributable to the acceleration of the depreciation schedule; the remaining 14% would be realized even if the project were instead depreciated using a less-advantageous, 20-year straight-line schedule.

In December 2010, the bonus depreciation was extended and increased to 100% under the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. To be eligible for the 100% bonus depreciation, projects must be acquired and placed in service after September 8, 2010, and before January 1, 2012, (Stoel Rives 2011). The 50% bonus depreciation remains available for projects placed in service after January 1, 2012, and before January 1, 2013.

Information on MACRS can be accessed on the IRS website at: *http://www.irs.gov/publications/p946/ch04.html*.

For more information on the 100% bonus depreciation, visit: www.irs.gov/pub/irs-drop/rp-11-26.pdf. Additional information on the 50% bonus depreciation can be found at: *http://www.irs.gov/businesses/small/article/0,,id=213666,00.html.*

4.1.5 Renewable Energy Loan Guarantee Program

The DOE Loan Guarantee Program, established by Title XVII of the EPAct of 2005, was expanded by the ARRA to include a new Section 1705 Loan Guarantee Program, in addition to the existing Section 1703 program. The ARRA permitted the guarantee of about $25 billion in loans by the Section 1705 program in addition to the $51 billion authorized for Section 1703. Table 4.1 summarizes the loan guarantee programs, including differences pertaining to project eligibility and benefits.

TABLE 4.1. DOE LOAN GUARANTEE PROGRAM

Year	FY 2007	FY 2008	FY 2009 Omnibus	FY 2009 ARRA
Amount	$4.0 billion	$38.5 billion	$8.5 billion	$25 billion (estimated)
Authorization	EPACT 2005, Title XVII, Section 1703			EPACT Section 1705, added by ARRA
Uses	New or significantly improved technologies			Commercial and novel technologies
Credit Subsidy	Borrower pays			$2.5 billion appropriated
Term	Available until used			Projects must be started by September 30, 2011
Carve-outs	No carve-out stipulated by Congress	$10.0 billion for energy efficiency, renewable energy, and advanced transmission and distribution technologies $18.5 billion for advanced nuclear power facilities $2.0 billion for "front end" nuclear fuel cycle facilities $6.0 billion for coal-based power generation, industrial gasification, and carbon capture and sequestration $2.0 billion for advanced coal gasification	The FY 2009 Omnibus Budget provided an additional $8.5 billion in loan authority for energy efficiency, renewable energy, and advanced transmission and distribution projects	No carve-outs were stipulated, but three project categories were listed: Renewable energy installations and manufacturing facilities for renewable energy components Electric power transmission systems Advanced biofuel projects

(DOE 2009c)

Projects eligible for the Section 1703 program include those that "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases and employ new or significantly improved technologies as compared to commercial technologies," including energy efficiency, renewable energy, and advanced transmission and distribution as well as advanced nuclear power, advanced coal-based power, and carbon capture and sequestration technologies. No funds were originally allocated to pay for the "credit subsidy cost" of these projects. The credit subsidy cost is the estimated long-term cost of making a loan guarantee, which is directly affected by the perceived likelihood of a project defaulting on a loan as well as the amount of money able to be recovered should a default occur. The credit subsidy cost must be paid for by the applicant for any loan guarantee that does not have allocated funds for this purpose.

Section 1705 is limited to renewable energy installations and manufacturing facilities for renewable energy components, electric power transmission systems, and advanced biofuel projects and is targeted toward projects at the commercialization stage (though new or earlier-stage technologies are still eligible). The Section 1705 program requires projects to commence construction by September 30, 2011, encouraging near-term deployment. Another difference is that the Section 1705 program provides for DOE to pay the cost-of-credit subsidies and requires up-front payments equal to about 10% of a loan guarantee's value, up to a total of $2.5 billion.[37] All solar generation and manufacturing projects, including both PV and CSP, that have received loan guarantees, as of December 31, 2010, were granted under the 1705 program.

The DOE has released three solicitations for the Loan Guarantee Program in which solar projects have participated. The first solicitation was for "new or significantly improved" energy efficiency, renewable energy, and advanced transmission and distribution technologies. It combined the authorities of the Section 1703 and Section 1705 programs; projects eligible for 1703 but not 1705 may still secure a loan guarantee, but may not receive 1705 appropriations to cover the credit subsidy cost. The debt provided to projects in this solicitation is designed to come from the Federal Financing Bank at a rate of approximately Treasury + 25 basis points, 100% of which may be guaranteed (but only 80% of the project cost). The second solar related solicitation was for renewable energy generating projects using "commercial technologies," defined as technologies used by three or more commercial projects for at least 2 years. The debt provided in this solicitation must come from the applicant, a commercial lender (not a project developer), and is guaranteed up to 80% of the size of the loan. The third solar applicable solicitation was for renewable energy manufacturing projects, in which manufacturer products support the generation of electrical or thermal energy from renewable resources. The loan guarantee is also limited to a maximum of 80% of the loan.

As of December 31, 2010, the DOE Loan Guarantee Program had allocated $5.9 billion in conditional commitments of loans for 12 clean energy projects ($3.9 billion went to four solar projects). Of those, eight have closed for a total of $3.9 billion ($2.4 billion to three solar projects) (DOE 2011).

Table 4.2 summarizes the solar projects below, consisting of 690 MW_{AC} of installed capacity, and 1,340 MW_{DC} of manufacturing capacity.

[37] The FY 2009 ARRA appropriation for the credit subsidy was originally $6 billion; however, $2 billion was transferred to the Car Allowance Rebate System (also known as the "Cash for Clunkers" program). In July 2010, Congress rescinded $1.5 billion for an unrelated program, decreasing the funding available to $2.5 billion.

TABLE 4.2. CLOSED AND CONDITIONAL LOAN GUARANTEES FOR SOLAR GENERATION PROJECTS				
Project	Technology	Guaranteed Loan	Project Installed Capacity	Loan Guarantee Status
Abengoa Solar Inc.	CSP	$1,446 million	250 MW	Closed
Agua Caliente	PV	$967 million	290 MW	Conditional
BrightSource Energy, Inc.	CSP	$1,600 million	383 MW	Closed
Cogentrix of Alamosa, LLC.	CPV	$91 million	30 MW	Conditional
Fotowatio Renewable Ventures, Inc.	PV	$46 million	20 MW	Conditional
Solar Trust of America (Solar Millennium)	CSP	$2,105 million	484 MW	Conditional
Solar Reserve, LLC (Crescent Dunes)	CSP	$734 million	110 MW	Conditional
SunPower Corporation, Systems (California Valley Solar Ranch)	PV	$1,187 million	250 MW	Conditional
Total Conditional Loans	––	$5,130 million	1184 MW	––
Total Closed Loans	––	$3,046 million	633 MW	––
Total All Loans	––	$8,176 million	1817 MW	––

Source: DOE 2011

For more information on DOE Loan Guarantee Program solicitations, see *https://lpo.energy.gov/?page_id=45*.

4.1.6 Qualified Clean Energy Bonds, Clean Renewable Energy Bonds, and Build America Bonds

There have been three types of qualified tax credit bonds available to public entities to finance solar energy improvements, including Qualified Clean Energy Bonds (QCEBs), Clean Renewable Energy Bonds (CREBs), and Build America Bonds (BABs). Qualified tax credit bonds enable the borrower to finance a project at a subsidized interest rate. The bond buyer either receives a tax credit, which reduces the interest payment required of the borrower, or a direct cash payment for a portion of the interest rate to be used to cover interest payments to the bond buyers.[38] The direct subsidy is received by the borrower in the form of a refundable tax credit and does not require bond buyers to have significant tax equity in order to monetize the full value of the interest payments. Unlike tax exempt municipal bonds, the tax credit and direct pay interest payments are considered taxable income.

The intent with the first generation of tax credit bonds was to provide a 0% financing cost option for state and local governments to use towards qualifying projects. However, borrowers have provided supplementary cash payments to attract investors. The rates for qualified tax credit bonds are set daily by the U.S. Department of the Treasury. For QCEBs and new CREBs, borrowers receive a subsidy amounting to 70% of the Treasury interest rate. The borrower must pay the remaining 30% and any additional interest required to attract investors. Under BABs, the borrower receives a direct subsidy for 35% of the interest rate.

QCEBs are one form of qualified tax credit bonds and were authorized under the EESA of 2008. The bonds enable state, local, and tribal governments to finance eligible conservation measures, including solar PV projects. QCEBs were initially funded at $800 under the EESA, and the allocation was expanded to $3.2 billion under ARRA. As of July 2008, bonds are allocated to states based on population; states, in turn, are required to reallocate to large

[38] *For guidance and additional information, see IRS Notice 2010-35 issued in April 2010.*

local government of 100,000.[39] Bond buyers can take the tax credit quarterly and may roll the credit forward to the succeeding year but cannot receive a tax refund.

CREBs are another type of qualified tax credit bond that was available to state and local governments, including electric cooperatives and public power providers. However, CREBs have been fully allocated, and thus are not currently a financing option for new projects. CREBs were established by EPAct as strictly tax credit bonds provided at 100% of the borrowing cost as determined by the Treasury without a direct subsidy option. The CREB program received an initial allocation of $800 million in 2005 (round 1), which was then increased to $1.2 billion by legislation in 2006, providing a second allocation of about $400 million (round 2). The Energy Improvement and Extension Act of 2008 authorized $800 million, and the ARRA authorized an additional $1.6 billion for new CREBs, for a total allocation of $2.4 billion (round 3). In April 2009, the IRS opened a solicitation for the $2.4 billion allocation, which closed on August 4, 2009. In October 2009, $2.2 billion of CREBs applications were given issuing authority by the IRS for a period of 3 years. Round 3 CREBs funding was to be allocated as follows: one-third for qualifying projects of state, local, or tribal governments, one-third for public power providers, and one-third for electric cooperatives (DSIRE 2010a). The Hiring Incentives to Restore Employment Act enacted in March 2010 enabled new CREBs borrowers to take the direct subsidy of 70% instead of the 70% tax credit.

Established under the ARRA, BABs are another type of qualified tax credit bond that, like CREBs, is not currently a financing option for solar energy or other improvements as the program has already been fully subscribed. Borrowers issuing BABs may only receive a direct pay subsidy of 35% of the interest in the form of a tax refund. Unlike with QCEBs and new CREBs, there is not a tax credit option.

4.1.7 Energy Efficiency and Conservation Block Grant Program

The Energy Efficiency and Conservation Block Grants (EECBG) Program, authorized in the Energy Independence and Security Act of 2007, was funded for the first time by the ARRA (DOE 2009a). Through formula[40] and competitive grants, the DOE has distributed nearly all of the $3.2 billion that was allocated to the EECBG program to U.S. cities, counties, states, and territories, and Indian tribes to develop, implement, and manage energy efficiency and conservation projects and programs (DOE 2009b). Local and state governments may utilize funds for solar installations on government buildings and engage in energy strategy development, which may include solar energy technology along with energy efficiency and conservation. For more information on the DOE EECBG, see: *www.eecbg.energy.gov*.

4.1.8 Additional Resources

For additional information, including how to apply for the benefits of the policies, see the following websites:

- DOE SETP Financial Opportunities
  (www.eere.energy.gov/solar/financial_opportunities.html)

- DOE Energy Efficiency & Renewable Energy (EERE) Financial Opportunities
  (www.eere.energy.gov/financing/)

- DOE EERE Recovery Act website
  (www.eere.energy.gov/recovery/)

- U.S. Department of the Treasury, AARA
  (www.treasury.gov/recovery)

[39] *See IRS Notice 2009-29 for a list of QCEB allocations for each state and U.S. territory.*

[40] *More information on the formula methodology for EECBG can be found at: http://www.eecbg.energy.gov/downloads/EECBG_Federal_Register_Notice_04_15_09.pdf.*

- U.S. Internal Revenue Service, Energy Provisions of the American Recovery and Reinvestment Act of 2009 *(www.irs.gov/newsroom/article/0,,id=206871,00.html)*

- SEIA, Government Affairs & Advocacy *(www.seia.org/cs/government_affairs_and_advocacy)*

- Database of State Incentives for Renewables & Efficiency (DSIRE) *(www.dsireusa.org)*.

4.2 State and Local Policies, Incentives, and Rules and Regulations

As outlined in the previous section, there are a number of federal-level financial incentives available to support the increased deployment of solar energy technologies. State and local policies work in parallel with these federal-level initiatives, but go beyond financial incentives to include renewable energy mandates and other mechanisms to further stimulate adoption of solar energy technologies. State legislators and utility commissioners hold primary responsibility for setting a state's overarching energy policy and regulatory framework. How solar technologies are treated in this process will significantly affect how, or even if, a solar market develops in a state. Local governments also influence solar policies.

In areas where the local government has jurisdiction over a utility, the government can directly influence solar rebate programs and renewable generation requirements. If, on the other hand, an area is served by investor-owned utilities or cooperatives, local governments can still play an important role in solar market development by streamlining permitting processes or developing innovative financing mechanisms.

In the United States, state and local policies in support of increased solar deployment are more prevalent than federal policies and have a well-documented history of both successes and failures. As such, states and regions with stronger and longer-term policies and incentives, coupled with a favorable electricity market (e.g., higher than average electricity prices) and an adequate solar resource, have established pockets of wide-scale solar installations. Furthermore, because states tend to have greater flexibility than the federal government, state governments are often seen as hubs for innovation. As such, there is a continuous flow of new policies and approaches at the state level that is driving solar development nationwide.

4.2.1 Planning and Permitting

Community planning at the state or local level is often employed to ensure that community land and resources are used in a beneficial manner. Permits are allowances issued by governments to ensure that activities undertaken within their jurisdictions meet established guidelines. Planning and permitting are important steps in the installation of solar technologies. When executed properly, they can provide assurances that a solar project meets necessary safety, operational, environmental, and community compatibility standards, while not unduly hindering the project's completion. However, planning and permitting processes that are not well designed for solar applications can increase the cost and time requirements of a project substantially. Poorly designed permitting programs may even delay or inhibit the project from completion. Section 2.4.5 describes some of the planning and permitting issues related to utility-scale solar installations. This section focuses on planning and permitting by local and state governments for smaller-scale, distributed PV installations. Installing a grid-connected PV system requires an electrical permit in most jurisdictions and, in some cases, a building permit followed by inspection of the installation (DOE 2009f).

Overly burdensome permitting requirements and the delays associated with applying for and being granted permits can hinder the deployment of distributed PV systems. Some of the most significant challenges of the permitting process are outlined below (Pitt 2008):

- Local permitting requirements are often complex and unclear
- Inspectors and permitting authorities may lack significant experience with renewable energy systems
- Permitting requirements may vary significantly across jurisdictions
- Permitting fees may be high enough to significantly increase project costs
- Enforcement of restrictive housing covenants is not always fair and can sometimes even be illegal.

State and local governments can help streamline and simplify the permitting process. A number of U.S. cities have led the way in modifying their planning and permitting policies to encourage solar energy development (DOE 2009f). For example, San Jose, California, grants electrical permits for PV systems over the counter and requires building permits only for rooftop installations that meet certain criteria. Portland, Oregon, allows residential PV installers to submit permit applications online and trains designated permitting staff in solar installations. Madison, Wisconsin, amended city laws to comply with state statutes that make it illegal to forbid PV systems in historic districts. The Solar America Board for Codes and Standards released a model for expedited permitting process in October 2009 (Brooks 2009). Continued efforts such as these will be necessary to spur the implementation of PV systems in communities nationwide.

4.2.2 Interconnection

Interconnection standards specify the technical, legal, and procedural requirements by which customers and utilities must abide when a customer wishes to connect a PV system to the grid (or electricity distribution system). State governments can authorize or require their state public utility commissions to develop comprehensive interconnection standards. Some state interconnection standards apply to all types of utilities (investor-owned utilities, municipal utilities, and electric cooperatives); other states have chosen to specify standards only for investor-owned utilities. Although most utilities fall under the jurisdiction of state public utility commissions, cities with municipal utilities can have significant influence over interconnection standards in their territory.

The aspects of interconnection standards that are most often debated are procedural, not technical, in nature. In setting technical interconnection standards, most regulatory bodies reference compliance with the Institute of Electrical and Electronics Engineer's "1547 Standard for Interconnecting Distributed Resources with Electric Power Systems," which was adopted in 2003. The most debated procedural aspects of interconnection standards are: requirements for small inverter-based PV systems to have a utility external disconnect switch (UEDS), limitations placed on PV system size, technical screens for interconnection, and requirements for additional insurance (NNEC 2009).

States continue to demonstrate a mix of approaches to these key aspects. Many major utility companies have recognized that safety devices and features already built into all code-compliant PV systems make the UEDS redundant in small systems (less than 10 kW). In 14 states and the District of Colombia, this requirement has been eliminated for small systems; however, the systems must usually meet other guidelines (IREC 2011).[41] Several other states have left the UEDS requirement to the discretion of the utility. Interconnection standards with regard to PV system-size limitations also vary widely among states, ranging from 10 kW to no cap on system size. As of May 2011, 10 states[42] and Puerto Rico do not have a limit on the installed system size (IREC 2011). The size of the PV system and complexity of the interconnection typically dictate the rigor and extent of the technical screens required before interconnection.

States also differ in their approaches to the issue of insurance requirements. States and some utilities require owners of solar PV systems that are interconnecting to the grid to purchase additional liability insurance to mitigate the risks of potential personal injury (e.g., to utility workers) and property damage (NNEC 2009). Twenty states, Washington, D.C., and Puerto Rico require varying levels of insurance based on system size, whether the system will be net metering, and other requirements (IREC 2011).[43] Fourteen states do not require insurance for small systems, often depending that the systems meet other technical specifications, and six states have not addressed insurance requirements (IREC 2011).[44]

Figure 4.1 shows as of May 15, 2011, the 41 states plus Washington, D.C., and Puerto Rico that have adopted an interconnection policy. All of the states with robust solar markets have interconnection policies in place. Similarly, solar markets do not have the same level of vitality in any of the states without interconnection policies.

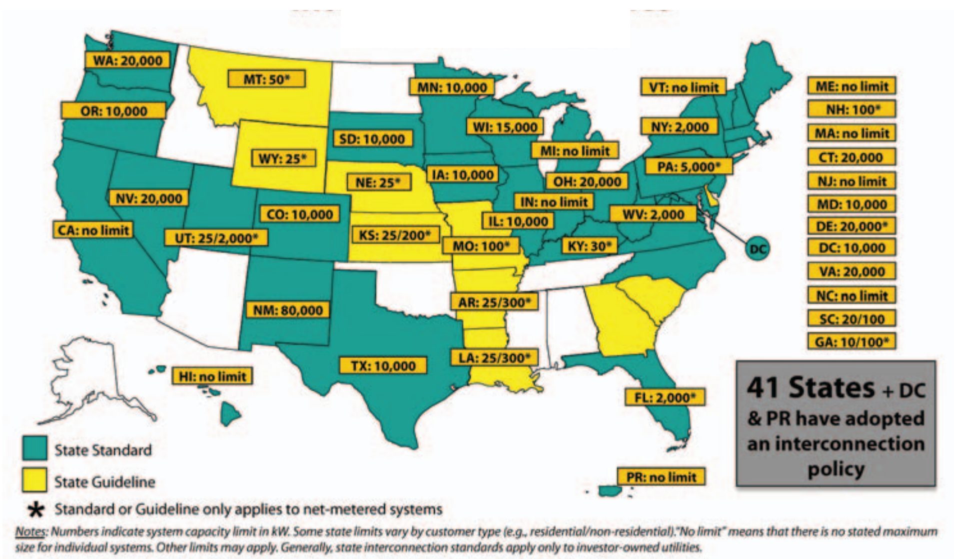


Figure 4.1 Interconnection standards, as of May 15, 2011 (DSIRE 2011)

In the absence of a national interconnection standard, state regulators often consider the four leading interconnection models when developing such policies. These models include the Federal Energy Regulatory Commission's (FERC's) Small Generator Interconnection Procedure and Small Generator Interconnection Agreement, California Rule 21, the

[41] The 14 states that have waived the utility external disconnect switch (UEDS) requirement for small systems are Alaska, Arkansas, Delaware, Florida, Louisiana, Maine, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Oregon, Utah, and West Virginia. Utilities that have waived the UEDS requirement for small systems include Pacific Gas and Electric and Sacramento Municipal Utility District in California and National Grid U.S.A. in the northeastern United States (IREC 2011).

[42] California, Hawaii, Illinois, Indiana, Maine, Massachusetts, Michigan, New Jersey, North Carolina, and Vermont do not have limits on the capacity of interconnected solar PV systems (IREC 2011).

[43] States with insurance requirements based on the size of the interconnected system are California, Colorado, Connecticut, Florida, Illinois, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nevada, New Mexico, North Carolina, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin.

[44] The 14 states that do not require insurance for small distributed include Delaware, Georgia, Kansas, Kentucky, Maine, Nebraska, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, and Washington. Arkansas, Louisiana, Montana, Texas, Utah, and Wyoming have not yet addressed the issue of insurance requirements (IREC 2011).

Mid-Atlantic Demand Resource Initiative's Model Interconnection Procedures, and the Interstate Renewable Energy Council's (IREC's) Model Interconnection Standards for Small Generator Facilities. All four procedures have comprehensive coverage of interconnection standards, including specifications for interconnecting systems up to 10 MW, pro-forma interconnection agreements, fast-track procedures for systems up to 2 MW, and a review process for interconnecting larger systems (typically greater that 10 kW). California Rule 21 was approved in December 2000 and updated based on utility tariff filings. The rule is used for the interconnection of all solar and distributed generation systems in utility service territories in California, which constitute a majority of the solar installations in the United States.

4.2.3 Net Metering

Net metering is a policy that allows PV system owners to offset electricity purchases from the utility with every kilowatt-hour of solar electricity a PV system produces. As with interconnection standards, state governments can authorize or require their state public utilities commissions to develop comprehensive net metering rules, and cities with municipal utilities can have significant influence over net metering rules in their territory.

Net metering is an important policy driver for distributed PV systems because it enables system owners to recover some of their investment through electricity bill savings (Coughlin and Cory 2009). Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar electricity is generated and exported to the electricity grid. Conversely, the meter runs forward as electricity is consumed from the grid. At the end of a billing period, a utility customer receives a bill for the net electricity, which is the amount of electricity consumed less the amount of electricity produced and exported by the customer's PV system.

Figure 4.2 illustrates the variety of net-metering system-size limitations across the United States. As of May 15, 2011, 43 states, including Washington, D.C., and Puerto Rico, have net metering policies in place. Net metering policies differ in several ways, including the eligibility of different technology types, customer classes, system sizes, the use of aggregate caps for distributed generation contribution back to the grid, the treatment of customer net-excess generation, the types of affected utilities, and the issue of renewable energy certificate (REC) ownership (IREC and NCSC 2007). Detailed state-specific information regarding net-metering availability and regulation is available through the DSIRE website at *www.dsireusa.org/*.

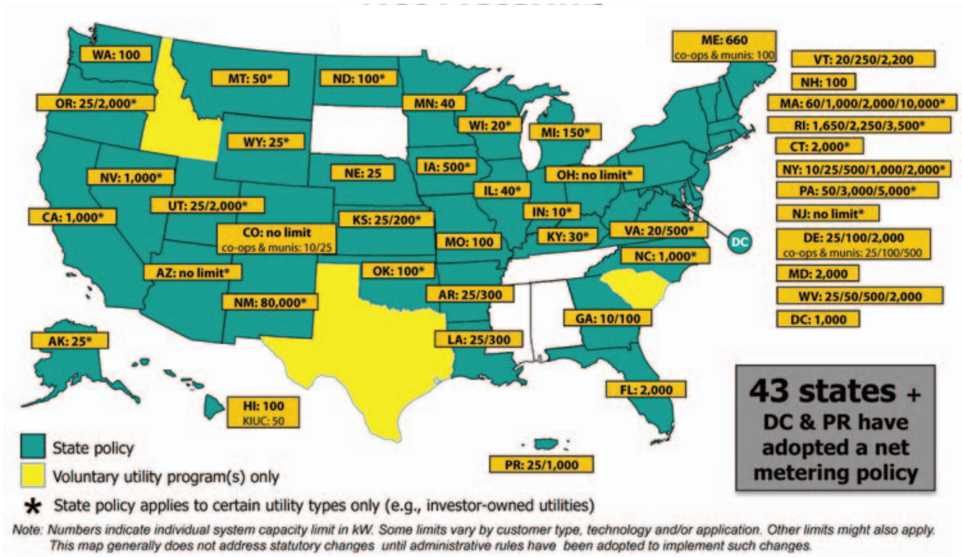


Figure 4.2 Net metering policies, as of May 15, 2011[48]
(DSIRE 2011)

4.2.4 Direct Cash Incentive Programs

Direct cash incentives give solar energy system owners cash for a qualified solar installation. Qualified solar installations vary by state and may include solar electricity producing, water heating, and space heating and cooling technologies. Direct cash incentives include rebates, grants, and production- or performance-based incentives that complement other financial incentives such as tax credits.

The manner and timing in which direct cash incentives are paid varies by location and program design. Rebate and grant amounts are often based on system size or system cost, and the funding is typically awarded at the time of installation. Performance- or production-based incentives are distributed to project owners over several years based on the amount of energy the system produces. Expected performance rebates are based on solar system capacity as well as system rating, location, tilt and orientation, and shading. Expected performance rebates may be distributed in a lump sum, but are calculated based on the expected energy output of the system. Payments based on performance or expected performance instead of capital investments are gaining favor among program administrators because they encourage optimized system design and installation. To avoid a boom-and-bust cycle that can disrupt solar energy markets, careful consideration should be given to incentive levels, program caps, and long-term funding mechanisms for direct cash incentive programs.

California, the leading U.S. state in terms of installed PV capacity, provides an example of a direct cash incentive program. In January 2006, the California Public Utilities Commission launched the California Solar Initiative (CSI), a direct cash incentive program providing more than $3 billion for solar energy projects with the objective of installing 3,000 MW of solar capacity by 2016. CSI includes a transition to performance-based incentive (PBI) and expected performance-based buyout (EPBB) (as opposed to up-front payments based only on system size), with the aim of maximizing system performance through effective system design and installation. Currently, customers may choose either the PBI or the EPBB, but not both.

[48] Numbers for each state indicate system capacity limits in kilowatts. Some state limits vary by utility, customer type (e.g., residential/nonresidential), technology, and/or system application. "No limit" means that there is no stated maximum size for individual systems. For more detail on the net metering standards for each state, see http://www.dsireusa.org/incentives/index.cfm?SearchType=Net&&EE=0&RE=1.

CSI incentive levels have been automatically be reduced over the duration of the program in 10 steps based on the aggregate capacity of solar installed in each utility service area. The California Public Utility Commission designated funding sources for the CSI program for 10 years (2006-2016). Currently, the three public utilities are in the eighth step for nearly all customer classes and are providing a PBI of $0.05/kWh or an EPBB of $0.35/W for residential and non-residential systems, and a PBI of $0.15/kWh or an EPBB of $1.10/W for non-profit/ government customers.[49] The exception is Southern California Edison, which is still in its sixth step for residential customers and is providing a PBI of $0.15/kWh or an EPBB of $1.10/W.

Figure 4.3 shows the states in which direct cash incentives are available, as of May 15, 2011.

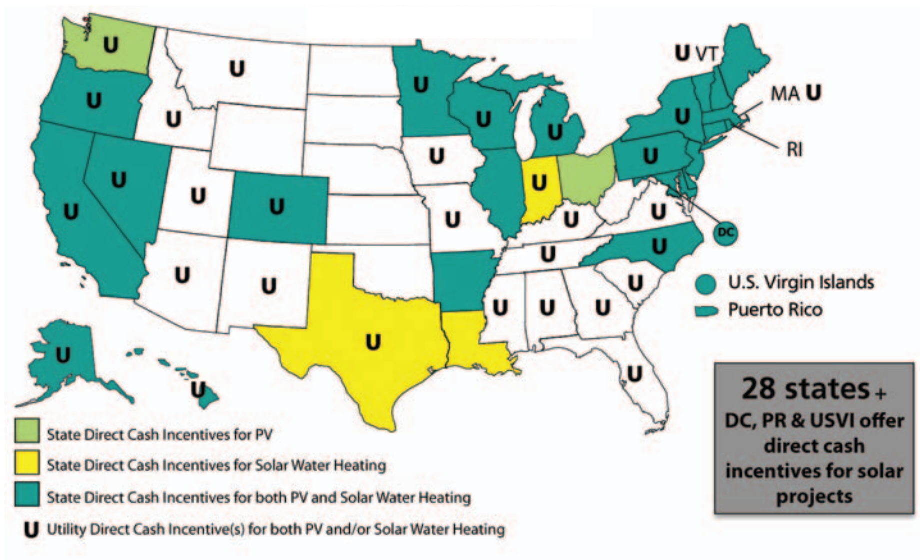


Figure 4.3 Direct cash incentives, as of May 15, 2011 (DSIRE 2011)

States and utilities usually administer direct cash incentive programs, but some local governments also offer these incentives to consumers. As of May 15, 2011, 28 states offered direct incentives for solar installations. This is a decline from August of 2010, when 32 states offered direct incentives. Direct cash incentives are often funded through a public or systems benefits fund, clean energy funds, a revolving loan fund, or the general fund. The incentives typically cover 20% to 50% of project costs and range from a few hundred to millions of dollars (DOE 2009f).

4.2.5 Renewable Portfolio Standards and Solar Set-Asides

A renewable energy portfolio standard (RPS) is a policy that requires utilities or load-serving entities to provide its customers with a certain amount of electricity generated from renewable resources. While an RPS is typically a mandate, it can also be a non-binding goal; it is almost always stated as a percentage of the total electricity provided to be reached by a predetermined future date (Bird and Lockey 2008). As indicated in Figure 4.4, 29 states plus Washington, D.C., and Puerto Rico had RPSs in place as of May 15, 2011, and an additional seven states have non-binding renewable energy production goals.

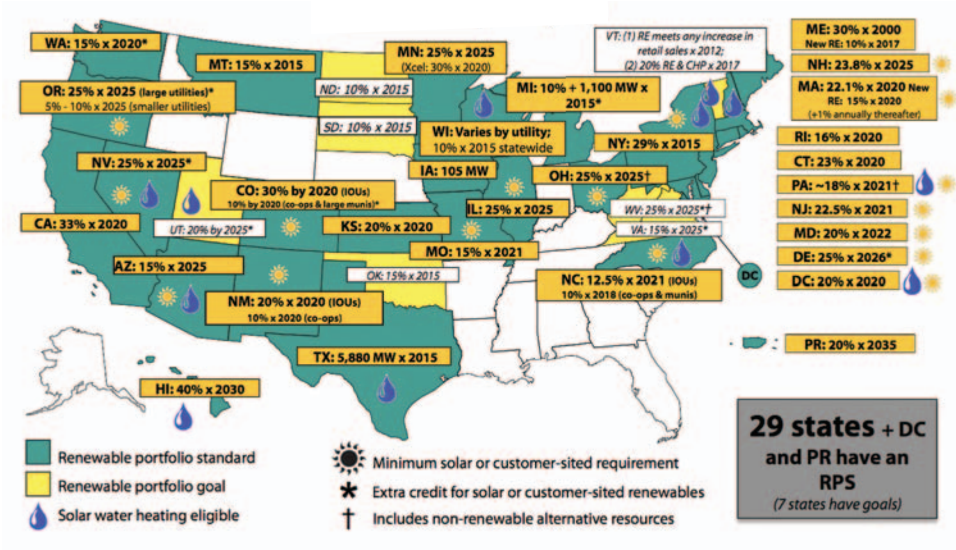


Figure 4.4 State renewable portfolio standards and goals, as of May 15, 2011 (DSIRE 2011)

In effect, two products are produced from renewable energy generation: the environmental attributes sold in the form of RECs and the actual electricity produced by the renewable generator. A REC typically represents the attributes of 1 MWh of electricity generated from renewable energy. An unbundled REC represents the environmental benefits without the actual energy, and bundled RECs include both the environmental benefits and the actual energy produced by a renewable source. Many states allow RECs to be bought unbundled from the associated electricity and used to fulfill RPS obligations (Holt and Wiser 2007).

A growing number of states are incorporating a "set-aside" or "carve-out" within the renewable portfolio standard (RPS), stipulating that a portion of the required renewable energy percentage or overall retail sales be derived from solar or distributed generation resources.[50] Figure 4.5 shows 16 states, along with Washington, D.C., that had these set-asides or carve-outs for solar electricity generation, solar water heating, and other distributed generation technologies.[51] Only four states and Washington, D.C., allow solar water heating to count toward the solar set-aside requirements.

[50] *Numbers for each state indicate system capacity limits in kilowatts. Some state limits vary by utility, customer type (e.g., residential/nonresidential), technology, and/or system application. "No limit" means that there is no stated maximum size for individual systems. For more detail on the net metering standards for each state, see http://www.dsireusa.org/incentives/index.cfm?SearchType=Net&&EE=0&RE=1.*

[51] *As of May 15, 2011.*

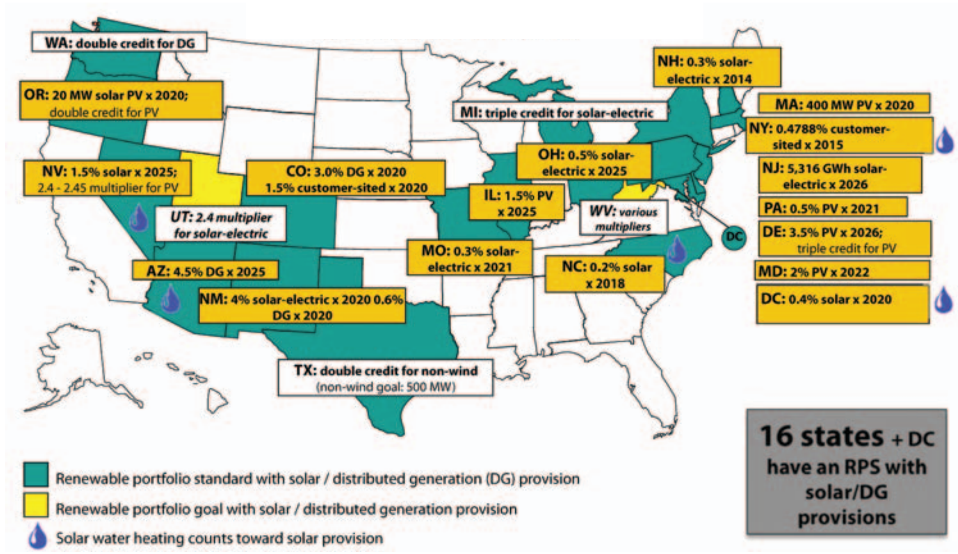


Figure 4.5 States with set-asides for solar or distributed generation, as of May 15, 2011 (DSIRE 2011)

As with the overall RPS requirements, to reach the goal of the solar set-aside, utilities or load-serving entities can either own the solar generation capacity or purchase bundled or unbundled solar RECs (SRECs) (Cory et al. 2008). One major difference between RECs and SRECs is their cost; SRECs typically generate more revenue than RECs, providing an additional financial incentive to install solar power systems. To create a value for RECs and SRECs, however, the RPS must include a penalty or alternative-compliance mechanism that has a distinctly higher penalty for those not complying with the RPS or solar set-aside (Cory and Coughlin 2009).

The continuation of New Jersey's SREC program has resulted in additional market growth in terms of installed capacity with 132 MW added in 2010 (Sherwood 2011). One SREC is issued for each megawatt-hour of electricity generated from a solar electric system. The SRECs represent all the clean-energy benefits from the solar generation and are sold or traded separately from the power, providing solar-system owners with a source of revenue to help offset the costs of installation. The New Jersey SREC Program is expected to almost entirely replace the state's rebates, which fueled solar growth in the early years of the state's solar program. The alternative-compliance payment was set at $693 in 2010. The weighted average price of SRECs traded in the 2010 compliance year was between $492 and $617 (NJ Clean Energy Program 2011).

Massachusetts has also implemented an SREC programs to support solar deployment. In Massachusetts, the alternative-compliance payment was set at $600 for the 2010-compliance year. Project owners may either sell their SRECs in the REC market or they can participate in the Massachusetts Department of Energy Resources' Solar Credit Clearinghouse as a market of last resort (Holt et al. 2010). For the 2010-compliance year, SRECs will be sold at $300, which provides a price floor for SRECs. Unsold SRECs are eligible for sale for the three subsequent compliance years (Holt et al. 2011).

4.2.6 Clean Energy Funds

In the mid- to late-1990s, many states introduced retail competition, giving rise to concerns over continued funding for energy efficiency, renewable energy, and low-income energy assistance programs. To address those concerns, system (or public) benefit funds were established and supported through an additional charge to end-users' electricity bills, either as a per-kilowatt-hour charge or a flat fee. In subsequent years, a second generation of "clean energy funds" was created and supported through a variety of methods, including RPS alternative compliance payments, general fund obligations, and oil and gas severance tax payments. The funds are dispersed in various forms, such as grants, loans, and rebates, to support investments in renewable energy, energy efficiency, and related improvements for low-income housing. Eligibility to receive support from a system benefit fund is contingent on the recipient being an electricity ratepayer (Cory et al. 2008).

As Figure 4.6 indicates, the systems benefits charges can amount to large funds in the aggregate. For example, California is expecting to raise more than $4 billion from 1998 to 2016, and New Jersey expects to raise $524 million from 2001 to 2012. Across the nation, an estimated $7.2 billion in 18 states and Washington, D.C., will have been collected by 2017 (DSIRE 2011).

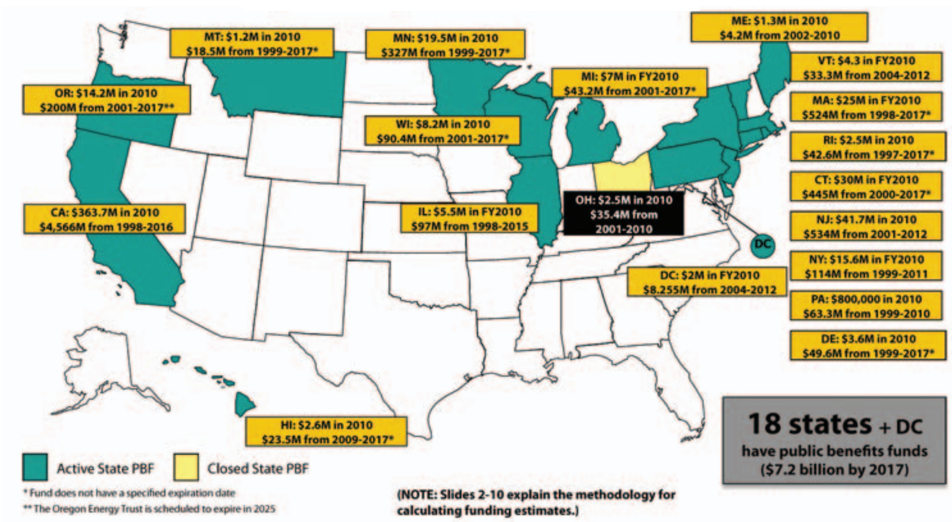


Figure 4.6 Estimated system benefit funds for renewables, as of May 15, 2011 (DSIRE 2011)

State funds have been instrumental in driving the installation of grid-connected PV systems; more than 75% of the grid-connected PV systems installed in the United States in 2007 were located in states with a clean energy fund. Moreover, the state funds have invested more than 75% of their available funding in PV projects (Clean Energy States Alliance 2009). The way in which these funds are dispersed varies from state to state. In California, for example, the system benefit fund supports the CSI, as outlined in Section 4.2.4.

4.2.7 Emerging Trends

Several policy and financing mechanisms are emerging that have the potential to incite further solar market expansion through the establishment of widespread local and utility programs. The three topics discussed in this section are FITs, property tax financing, and rate structures.

A FIT is a requirement for utilities to purchase electricity from eligible renewable systems at a guaranteed price over a fixed period. Alternatively, a FIT can consist of a fixed or variable premium above the market price. FITs increase the rate of PV deployment by providing a stable revenue stream for PV systems and by improving the rate of return on PV investments. The payment level generally is designed to ensure that the systems are able to recover costs and provide a modest profit. In addition to offering guaranteed prices, FITs typically guarantee grid access, allowing both small and large projects to connect to the grid according to uniform interconnection standards. FITs have been used extensively in Europe and are starting to be implemented in the United States (Couture and Cory 2009). FIT programs in Vermont and Gainesville, Florida, successfully helped install .25 MW and 1.75 MW[52] in 2010, respectively. FITs have faced challenges in the past, most recently from California utilities, who argued that states do not have the authority to set electricity rates; this can only be done by the Federal Energy Regulatory Commission (FERC). However, in October of 2010, FERC established guidelines allowing states to get around some of the regulatory barriers, allowing them to set rates for renewable energy projects.

Municipalities and counties across the country are launching innovative public/private financing programs that allow property owners to spread the cost of renewable energy systems over the long term. For example, Berkeley, California, and Boulder, Colorado, have passed initiatives to allow homeowners and businesses the opportunity to finance PV systems through adjustments to their property taxes, thus taking advantage of the government entities' tax-free financing capabilities to support expansion of these resources at the local level. Programs utilizing this financing approach are commonly referred to as Property Assessed Clean Energy (PACE) programs and will be discussed in more detail in Section 4.3.3, along with other innovative financing mechanisms.

As customer-sited generation and advanced metering technologies become more prevalent, there is an increased interest in developing alternative rate structures that reflect the resulting changes in electricity use. The majority of existing rate structures does not capture the actual value of time-varying increases or decreases in demand for electricity. Therefore, current rate structures are unlikely to capture the value of energy produced by customer-sited generation, including solar PV. This is because solar PV peak generation often correlates well with peak electricity demand. With the availability of more advanced metering, it is possible to create rate structures that better reflect the variances in the value of electricity as demand fluctuates throughout the day. Appropriate rate structures for PV could enable better capture of the value of excess customer-generation exported to the grid. While time-of-use rates and other emerging rate structures are still relatively uncommon, it is anticipated that they will become increasingly more prevalent and serve as a driver for solar market expansion.

4.3 Private Sector and Market-Based Developments to Facilitate Solar Deployment

Many of the financing changes made possible in 2009 through the passage of the ARRA continued to be used in 2010. For example, the ARRA greatly expanded the availability and usability of various tax credits, depreciation opportunities, loan guarantees, and other mechanisms designed to incentivize private and public investment in renewable energy and energy efficiency projects. The ARRA also expanded and extended an array of incentives made available with passage of the EESA (and other earlier laws).

In addition to the previously described support mechanisms, private sector and other solar market stakeholders, including states, counties, and municipalities, have developed mechanisms to support renewable energy financing by residents, businesses, and institutional and government consumers of energy. Three prominent financing mechanisms/

[52] *Reported in an e-mail by Gainesville Regional Utilities.*

programs for solar PV and CSP will be discussed in this section: the third-party power purchase agreement (PPA), the solar lease, and PACE programs.

4.3.1 Third-Party Power Purchase Agreement Financing

All sectors can use the third-party ownership PPA, including homeowners, businesses, utilities, and state and local governments. In a third-party ownership PPA model, one party hosts a PV system on his or her property and a solar developer purchases, installs, owns, operates, and maintains the system. In the residential sector, it is the homeowner that hosts and does not purchase or own the PV system, and instead buys the electricity produced by the PV system under a long-term PPA (see Figure 4.7). In exchange for signing the PPA, the homeowner avoids paying for the PV system up front and usually is not responsible for O&M of the system. The PPA provider receives the monthly cash flows in the form of power sales and the fully monetized federal tax benefits, including the ITC and accelerated depreciation (Coughlin and Cory 2009). SunRun and SolarCity are examples of companies providing residential (and commercial) leases and PPAs.

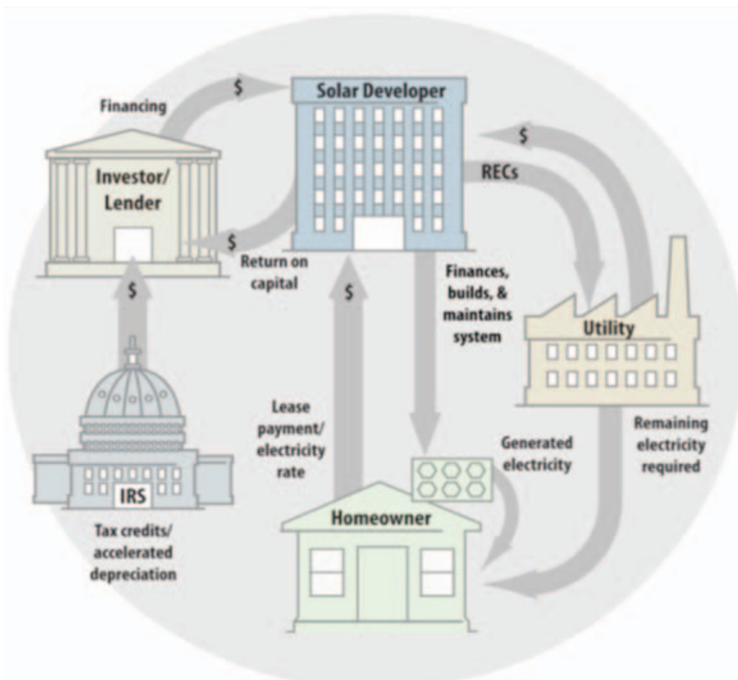


Figure 4.7 The residential power purchase agreement (NREL 2009)

The commercial PV market has witnessed a rapid proliferation of the use of the PPA-financing model of ownership. The benefits of the PPA method for financing PV deployment in the commercial sector are similar to those for customers in the residential sectors. Thus, a PPA provides the opportunity for a commercial owner to host, rather than own, a PV system. Instead of securing capital up front and being responsible for O&M, the business owner signs a long-term PPA to purchase the electricity generated by the system. The PPA is typically priced at or below the prevailing utility retail rate in the first year (with perhaps some fixed rate escalation over the life of the contract). The owner of the business avoids most, if not all, of the up-front purchase and installation costs as well as O&M responsibilities.

Utilities often rely on third parties to design, finance, manage construction of, and operate and maintain solar facilities. Development of these facilities requires the long-term procurement of the power output. Accordingly, utilities sign PPAs with the developers, allowing the developer to obtain lower-cost financing, passing on the savings through relatively lower power prices. PPAs can come in many forms and durations, but generally payments are made for both the plant capacity (maximum capable output) and energy production. PPAs typically cover a 15- to 20-year period starting with a facility's commercial operation, and on rare cases may extend as long as 25 to 30 years. However, now that utilities can use the ITC directly, their use of third-party PPAs may decline (see Section 4.3.5).

Utilities benefit from PPAs as they are designed to leverage the technical expertise and experience of the solar developer. PPAs also allocate risks of cost overruns, plant availability, and so on, to a pre-specified party, typically the plant developer. In return for accepting most development and operating risks, the developer receives price certainty and marketability of its product.

State and local governments are also responding to the challenges of funding PV development on their buildings and land by using innovative finance structures such as the third-party-ownership PPA model. As with the residential and commercial sectors, the benefits of transferring the up-front costs and O&M responsibilities to the owner/developer, maintaining steady electricity prices, and using federal tax benefits inherent to the PPA ownership model have made it an attractive option for state and local properties. In certain instances, state and local agencies have leveraged their ability to raise capital through low interest bonds, which have a lower cost of capital than most solar project developers can obtain, in order to receive more favorable PPA terms. Government entities have allowed solar project developers to borrow the funds raised by the bonds in order to build the solar projects; in return, the developers pay off the low-interest bonds and offer a lower PPA price than they would have offered with a higher cost of capital.

Note that third-party PPA financing may face regulatory or legal challenges in some states, especially where the issue of utility commission regulation of third-party owned systems has not been specifically addressed. Figure 4.8 shows as of May 15, 2011 where third-party PPAs were authorized and disallowed. At least 19 states and Puerto Rico allowed for 3rd party solar PPA's at that time.

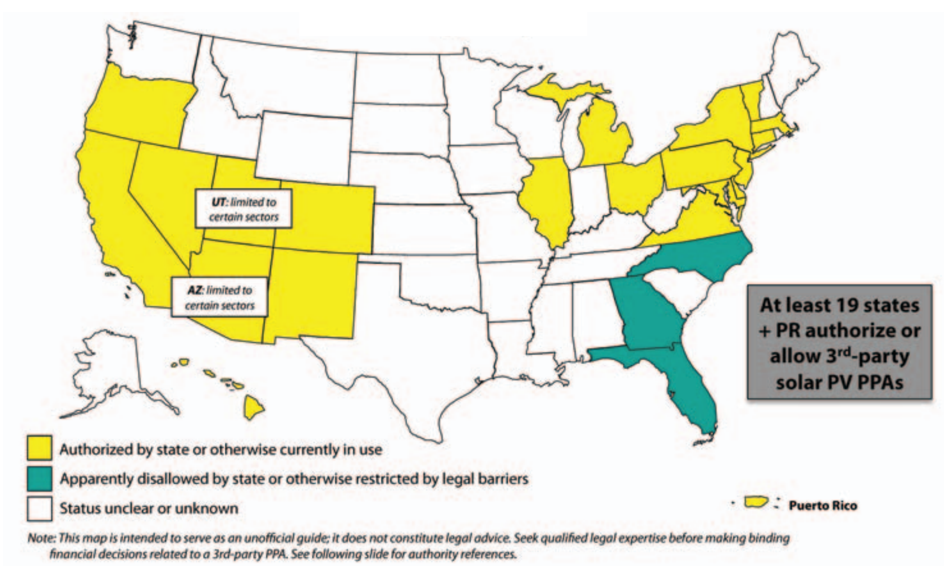


Figure 4.8 PPA policies by state, as of May 15, 2011 (DSIRE 2011)

4.3.2 Customer Solar Lease Financing

The customer solar lease is similar to the residential or commercial PPA in that a property owner hosts, but does not own, a solar PV system. It is often used in states that do not allow PPAs. To take advantage of federal tax incentives, a third-party lessor finances and owns the solar PV installation. However, distinct to a solar lease, the property owner (as lessee) pays to use the equipment instead of purchasing the generated power. Thus, the customer's lease payment remains constant even if the system's output fluctuates. If the system does not meet the customer's entire energy needs, the customer purchases additional electricity from his/her utility. Any excess electricity generated by the system can be net metered, earning the customer cents/kWh credits on the electric utility bill.

Similar to a third-party PPA, the solar lease transfers the high up-front costs to the system owner/developer, who can take advantage of valuable federal tax incentives. Some of the cost savings might be passed down to the customer in the form of lower payments. In states with complementary incentives, lease payments can be less than or equal to monthly utility savings.[53] Also, like the third-party PPA, the lease may shift maintenance responsibilities to the developer.

There are challenges associated with the solar lease. For example, the leasing company may not have as strong an incentive to maintain the system as it would under a third-party PPA contract because the customer's payments are fixed regardless of the system's output. However, some companies will monitor the system's output and will provide maintenance promptly or will include a performance guarantee that ensures a minimum of kilowatt-hours. Also, as with the third-party PPA, the solar lease may face regulatory challenges in some states. In addition, the traditional solar lease may not be available to non-taxable entities such as state and local governments because of uncertainty about renewing contracts on a year-to-year basis. However, state and local governments may be able to use a tax-exempt lease where payments to the lessor are tax exempt (Bolinger 2009).

4.3.3 Property Assessed Clean Energy Programs

In addition to private-sector financing mechanisms, local governments have also designed programs to fund energy efficiency and renewable energy development on private property, with a particular focus on funding PV installations. Several municipalities are assisting residential and commercial ownership of renewable energy systems through financing via property tax assessments. Piloted by the Berkeley Financing Initiative for Renewable and Solar Technology (FIRST) program and replicated elsewhere, the property tax assessment model finances the cost of renewable energy and energy efficiency improvements through the creation of special tax districts (Coughlin and Cory 2009). Interested property owners may opt into the program and pay for an additional line item on their property tax bill.

PACE assessments[54] transform the high up-front costs into the equivalent of a moderate monthly payment[55] and allow the property owner to transfer the assessment and capital improvement to new property owners in the event of a sale.[56] Under a PACE program, a municipality provides the financing to pay for the up-front system costs for a renewable energy system through an additional property tax assessment. The property owner repays the cost of the system, plus interest and administrative fees, through additional assessments

[54] Assessments are similar to loans in that they allow a property owner to pay off debt in installments over a long period of time. However, PACE assessments are not legally considered to be loans.

[55] Note that payments are typically made semi-annually. However, the semi-annual payment could be considered by the property owner as six moderate monthly installments.

[56] While property owners may be able to transfer the assessment to a new buyer, a buyer could require that all liens on the property (including the PACE assessment) be settled before the property is transferred.

placed on the property tax bill, which are collected over a time period that reflects the useful life of the improvements.

Funding for a PACE program has taken a number of different forms in the handful of initiatives that already have been launched. Boulder County, Colorado, is using voter-approved bond financing; Berkeley, California, is working with a private investor; Palm Desert and Sonoma County, California, used general funds to start the program. It is likely that large-scale PACE programs will eventually be financed using private capital provided through the municipal bond markets (DOE 2009f).

Residential PACE programs hit a significant roadblock in mid-2010, however, when Fannie Mae and Freddie Mac, which under-write a significant portion of home mortgages, determined that they would not purchase mortgages with PACE loans because PACE loans, like all other property tax assessments, are written as senior liens.[57] These issues are still being resolved, and while it is not yet known whether or how residential programs will move forward, PACE assessments is still a viable option in the commercial space. As of March 2011, there were four commercial PACE programs in operation, which had approved $9.69 MM in funding for 71 projects, many of which were PV. There were also nine commercial programs in formal planning stages, and at least seven in preliminary planning stages (LBNL 2011).

4.3.4 Alternative Financing Structures: Partnership Flips and Leases

PPAs, solar leases, and SRECs are used between a customer and a developer to help finance solar project development. There are also several other financing mechanisms that are used between a project developer and a separate tax investor. These financing alternatives are designed to facilitate full and efficient use of federal and state tax benefits by transferring tax subsidies to tax-burdened investors. Examples of these financing structures include partnership flips and leases.

In a partnership flip, ownership of a solar project is shared between a developer and a tax equity investor, who contributes project investment capital in exchange for federal and state tax benefits and some revenue. Once the tax equity investor reaches a specified rate of return, the project's economic returns are redistributed, or "flipped," between the developer and tax equity investor, with the developer typically receiving the majority of electricity sales revenue (Martin 2009).

Solar developers and investors have also financed solar projects with various forms of equipment leases such as a sale-leaseback and an inverted pass-through. In a sale-leaseback, a developer sells a solar system and the accompanying tax benefits to a tax equity investor, who in turn leases back the use and possession of the solar property to the same developer (Martin 2009). In an inverted pass-through lease, the roles of the developer and tax equity investor are effectively reversed (inverted). The developer makes an election to pass through the ITC to the tax equity investor along with revenue from the system's electricity sales. The developer receives fixed lease payments from the tax equity investor, as well as the tax benefit of accelerated depreciation (Jones and Lowman 2009).

4.3.5 Increasing Utility Ownership of Solar Projects

Recent federal legislation has also greatly increased the incentive for utilities to directly

[57] On July 6, 2010, the Federal Housing Finance Agency (FHFA), which regulates Fannie Mae, Freddie Mac, and the 12 Federal Home Loan Banks, issued a statement determining that PACE loans "present significant safety and soundness concerns" and called for a halt in PACE programs for these concerns to be addressed. FHFA determined that, "the size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives" (FHFA, 2010). Because Fannie Mae and Freddie Mac do not consider PACE loans to conform with traditional taxing initiatives, they are not interested in purchasing mortgages on homes with PACE liens. Certain PACE programs are attempting to solve the problem by setting up programs as second tier liens.

own solar projects themselves and not require a separate tax investor. In particular, the EESA contained three provisions that promote direct utility ownership of solar projects. First, the 8-year investment tax credit extension provides long-term certainty regarding the availability of the credit. Second, utilities are permitted to take the ITC directly, which was previously unavailable. Third, the investment tax credit can also be applied to a renewable energy system owner's alternative minimum tax—formerly a significant barrier to entry (Schwabe et al. 2009).

The ARRA also provided an extension of the 50% bonus depreciation in year one in addition to MACRS, the 5-year accelerated depreciation (which was later increased to 100% bonus depreciation with The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, for property acquired after Sept. 8, 2010, and before Jan. 1, 2012, and placed in service before Jan. 1, 2012).

However, there are two key challenges to utility ownership. First, utility regulators might not consider rate-basing of solar projects as prudent and may not approve the full value of the investment. Many utilities will not move forward without preauthorization from their regulators for owning solar assets above their utility's current avoided cost.

Second, the economics of utility ownership are challenged by a regulatory measure that limits utilities' ability to pass on the full advantage of a solar project's tax benefits to their rate bases. In particular, the IRS currently requires that the benefit of the ITC to ratepayers be amortized over the life of the facility—a process called "normalization"—thereby deferring the up-front tax benefit and diluting the incentive intended under the federal tax code. Utilities cannot take the ITC without normalizing the tax benefit. Due to this normalization issue, many utilities have not purchased solar assets. Instead, they have allowed independent power producers to monetize the ITC and pass along the benefit through lower-priced electricity.

4.4 References

Bird, L; Lockey, E. (2008). *Interaction of Compliance and Voluntary Renewable Energy Markets.* National Renewable Energy Laboratory. NREL Report No. TP-670-42096.

Bloomberg Businessweek. (2010). *Build America Bond Sales Total $100.1 Billion after 2009 Debut*. *http://www.businessweek.com/news/2010-05-12/build-america-bond-sales-total-100-1-billion-after-2009-debut.html*. Accessed August 18, 2010.

Bolinger, M. (2009). *Financing Non-Residential Photovoltaic Projects: Options and Implications*. LBNL Report No. LBNL-1410E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Brooks, B. (2009). Expedited Permit Process for PV Systems. *A Standardized Process for the Review of Small-Scale PV Systems*. Solar America Board for Codes and Standards Report. http://www.solarabcs.org/permitting/. Accessed November 2009.

Clean Energy States Alliance. (2009). State Clean Energy Fund Support for Renewable Energy Projects. *Key Findings from the CESA National Database*. www.cleanenergystates.org/. Accessed October 20, 2009.

Cory, K.; Coggeshall, C.; Coughlin, J.; Kreycik, C. (2009). *Solar Photovoltaic Financing: Deployment by Federal Government Agencies*. NREL/TP-6A2-46397. Golden, CO: National Renewable Energy Laboratory.

Cory, K.; Coughlin, J.; Coggeshall, C. (2008). *Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments*. NREL/TP-670-43115. Golden, CO: National Renewable Energy Laboratory.

Coughlin, J.; Cory, K. (2009). *Solar Photovoltaic Financing: Residential Sector Deployment*. NREL/TP-6A2-44853. Golden, CO: National Renewable Energy Laboratory.

Couture, T.; Cory, K. (2009). *State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the United States*. NREL/TP-6A2-45551. Golden, CO: National Renewable Energy Laboratory.

Database of State Incentives for Renewables & Efficiency (DSIRE). (2011). "U.S. Department of Treasury - Renewable Energy Grants" website. *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US53F&State=federal%25C2%25A4tpageid=1&ee=1&re=1*. Accessed May 24, 2011.

DSIRE. (2011). Summary Maps. *www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1*. Accessed June 2, 2011.

DSIRE. (2010a). Summary Maps. *www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1*. Accessed June 10, and August 18, 2010.

DSIRE. (2010b). Solar Policy Guide. *http://www.dsireusa.org/solar/solarpolicyguide/?id=22*. Accessed August 18, 2010.

Holt, E.; Sumner, J.; Bird, L. (Forthcoming). The Role of Renewable Energy Certificates in Developing New Renewable Energy Projects. Golden, CO: National Renewable Energy Laboratory.

Holt, E.; Wiser, R. H. (2007). *The Treatment of Renewable Energy Certificates, Emissions Allowances, and Green Power Programs in State Renewables Portfolio Standards*. Report No.LBNL-62574. Berkeley, CA: Lawrence Berkeley National Laboratory.

Interstate Renewable Energy Council (IREC); North Carolina Solar Center (NCSC). (2007). *Connecting to the Grid, A Guide to Distributed Generation Interconnection Issues*. 5th Edition. *www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Guide.pdf*. Accessed March 16, 2009.

IREC. (2011). "State-by-State Interconnection Table." *http://irecusa.org/irec-programs/connecting-to-the-grid/interconnection/*. Accessed May 24, 2010.

Jones, L.; Lowman, D. (2009). "Treasury Grant Program." Webinar. Hunton and Williams, LLP. *http://www.hunton.com/media/webinars/recordings/20090714/20090714.html?utm_source=MagnetMail&utm_medium=email&utm_term=gmarrs@hunton.com&utm_content=Treasury Grant Program WebConference Recording Available&utm_campaign=martech_0499_treasury_grant_prgrm_followup_7.15.09*. Accessed September 22, 2009.

Lawrence Berkeley National Laboratory (LBNL). (2011). Renewable Funding, Clinton Climate Initiative. *Policy Brief: Property Assessed Clean Energy (PACE) Financing: Update on Commercial Programs*. March 23, 2011.

Martin, K. (2009). *Utility Solar Tax Manual: A Utility Guide to the Federal Investment Tax Credit*. Solar Electric Power Association.

Network for New Energy Choices (NNEC). (2009). *Freeing the Grid: 2009 Edition*. New York, NY: Network for New Energy Choices. *http://www.newenergychoices.org/uploads/FreeingTheGrid2009.pdf*. Accessed January 18, 2010.

New Jersey (NJ) Clean Energy Program website. (date?). *http://www.njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing*. Accessed June 3, 2011.

National Renewable Energy Laboratory (NREL). (2009). "The residential power purchase agreement." Golden, CO: National Renewable Energy Laboratory (internal only).

Pitt, D. (2008). Taking the Red Tape Out of Green Power: How to Overcome Permitting Obstacles to Small-Scale Distributed Renewable Energy. Network for New Energy Choices. *www.newenergychoices.org/uploads/redTape-rep.pdf*. Accessed November 30, 2009.

Prometheus Institute. (2009). "Renewable Energy Industry Note." *http://www.prometheus.org/system/files/Solar+for+Federal+Buildings.pdf*. Accessed December 31, 2009.

Schwabe, P.; Cory, K.; Newcomb, J. (2009). *Renewable Energy Project Financing: Impacts of the Financial Crisis and Federal Legislation*. NREL Report No. TP-6A2-44930. Golden, CO: National Renewable Energy Laboratory.

Solar Energy Industries Association (SEIA). (2011). "Grants in Lieu of Tax Credits for Renewable Energy as of 5/5/11." *http://www.seia.org/galleries/pdf/TGP_Awards.pdf*. Accessed June 2, 2011.

SEIA. (2008). "The Solar Investment Tax Credit Frequently Asked Questions." *http://seia.org/galleries/pdf/ITC_Frequently_Asked_Questions_10_9_08.pdf*. Accessed November 2008.

SEIA. (2010). "Fact Sheet on the DOE Loan Guarantee Program." *http://www.seia.org/galleries/FactSheets/Factsheet_DOE_LGP.pdf*.

Sherwood. (2011). *Special data compilation.*

Solar Electric Power Association (SEPA). (2009). *Utility Solar Tax Manual.* Report #02-09. *http://www.solarelectricpower.org/resources/reports.aspx*. Accessed January 20, 2010.

SoloPower. (2011). "SoloPower Announces New Solar Panel Manufacturing Facility in Oregon." *http://www.solopower.com/solopower-announces-new-solar-panel-manufacturing-facility-in-oregon.html*. Accessed June 2, 2011.

Solyndra. (2011). "Solyndra Loan Guarantee Update." *http://www.solyndra.com/about-us/doe-loan-guarantee/*. Accessed June 2, 2011.

Stoel Rives LLP. (2011). "Tax Law Alert: IRS Issues Favorable Guidance Regarding Bonus Depreciation." *http://www.stoel.com/showalert.aspx?Show=7817*. Accessed June 2, 2011.

U.S. Department of Energy (DOE). (2011). "Energy Efficiency and Conservation Block Grant Program." *http://www1.eere.energy.gov/wip/eecbg.html*. Accessed June 2, 2011.

DOE. (2011). "Loan Guarantee Program" website. *https://lpo.energy.gov/?page_id=45*. Accessed June 2, 2011.

DOE. (2009a). "Energy Efficiency and Conservation Block Grant" website. U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. *http://www.eecbg.energy.gov*. Accessed August 18, 2010.

DOE. (2009b). *Energy Efficiency and Conservation Block Grant Program Fact Sheet*. U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. *www.eecbg.energy.gov/downloads/WIP_EECBG_Fact_Sheet_FINAL_Web.pdf*. Accessed September 2009.

DOE (2009c). "DOE Loan Guarantee Program." U.S. Department of Energy Solar Technologies Program and Loan Guarantee Program (internal only).

DOE. (2009d). "Obama Administration Offers $535 Million Loan Guarantee to Solyndra, Inc." Press Release. U.S. Department of Energy Loan Guarantee Program. *www.lgprogram.energy.gov/press/032009.pdf*. Accessed September 2009.

DOE. (2009e). State Energy Program Fact Sheet. U.S. Department of Energy State Energy Program. *http://apps.eere.energy.gov/state_energy_program/pdfs/sep_factsheet.pdf*. Accessed September 2009.

DOE. (2009f). Solar Powering Your Community: A Guide for Local Governments. U.S. Department of Energy Solar Energy Technologies Program. *www.solaramericacities.energy.gov/resources*. Accessed August 18, 2010.

DOE. (2010a). DOE Loan Guarantee Program. Press Release. "Department of Energy and Beacon Power Finalize $43 Million Loan Guarantee for Innovative Energy Storage Project in New York State". August 9, 2010. *http://www.lgprogram.energy.gov/press/080910.pdf*.

DOE. (2010b). DOE Loan Guarantee Program. Press Release. "Department of Energy Extends Renewable Energy Loan Guarantee Solicitation." August 5, 2010. *http://www.lgprogram.energy.gov/press/080510.pdf*.

U.S. Department of the Treasury, Internal Revenue Service (IRS). (2006). "Clean Renewable Energy Bond Volume Cap Allocation Information." *http://www.irs.gov/newsroom/article/0,,id=164423,00.html*. Accessed January 20, 2010.

U.S. Department of the Treasury, IRS. (2007). "2007 Disclosure of Allocations." *http://www.irs.gov/pub/irs-tege/creb_2007_disclosure.pdf*. Accessed January 20, 2010.

U.S. Department of the Treasury, IRS. (2009). "New Clean Renewable Energy Bonds - 2009 Allocations." *http://www.irs.gov/pub/irs-tege/ncrebs_2009_allocations_v1.1.pdf*. Accessed January 20, 2010.

Investments and Future Outlook

This chapter provides information on trends in solar energy investment (Section 5.1), a summary of DOE investment in solar energy and its role in the solar industry (Section 5.2), and a review of near-term forecasts for PV and CSP (Section 5.3).

5.1 Solar Energy Investment

This section discusses private investment in solar energy including venture capital, private equity, government-supported debt, non-government supported debt, public equity, and mergers and acquisitions (M&A). Investment in solar energy grew rapidly overall from 2004 to 2010, with a slight decline in 2009. From 2004 to 2010, global investment in solar energy increased by more than a factor of 85. Moreover, the growth in investment has been widespread, occurring across sources, technologies, and regions. Each of the three major sources of new investment examined here—venture capital, private equity, debt (government supported and non-government supported), and public equity—grew at a CAGR of more than 110% from 2004 to 2010. In addition, funding to solar companies increased dramatically for different technologies, including crystalline silicon PV, thin-film PV, and concentrating PV in each of the four main regions (Europe, China, U.S., and Other).

Figure 5.1 shows the tremendous rise of global investment in solar energy from 2004 to 2010. Investments in the years prior to 2004 set the stage for rapid expansion of the global solar industry in 2004, as generous incentive programs in Germany and Japan brought solar energy into the mainstream in both countries. Total investment in 2005 of $2.7 billion marked a 362% increase over the $575 million invested in 2004. This was followed by increases of 168% to $7.1 billion in 2006, 229% to $23.4 billion in 2007, 4% to $24.3 billion in 2008, falling 4% to $23.2 billion in 2009, and then increasing 112% to $49.2 billion in 2010. Investments staggered a bit in 2008 and 2009 as a result of the broadening impact of the recession that took root toward the end of 2008. It should also be noted that the annual growth rate between 2009 and 2010, excluding government supported debt, was 5%, rising from an adjusted $22.6 billion in 2009 to $23.8 billion in 2010.

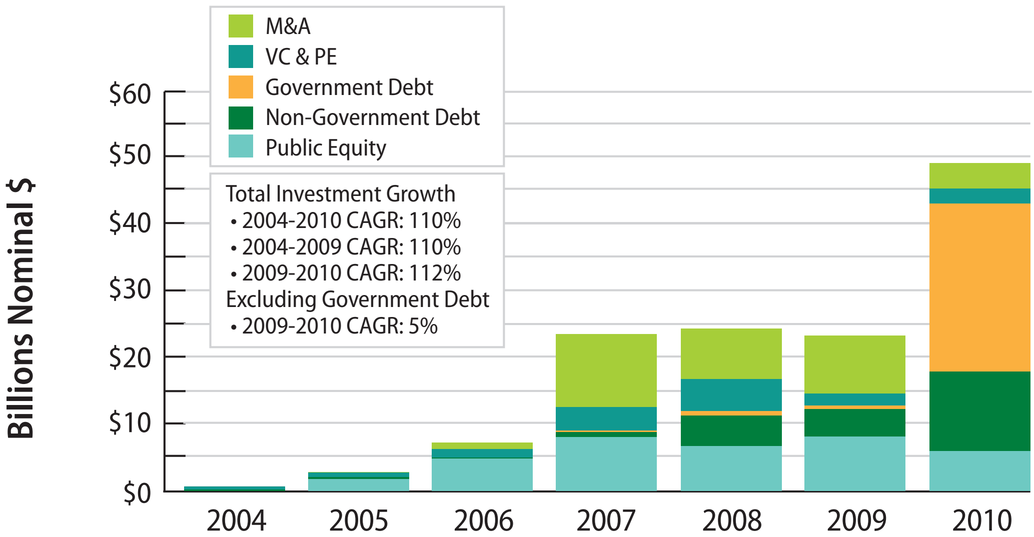


Figure 5.1 Global capital investment in solar energy[58]
(Bloomberg New Energy Finance 2011)

The role of debt (government-supported and non-government-supported) in the global solar industry continues to increase as banks and other lenders become involved in financing the operation and expansion of solar companies. Debt totaled $146 million in 2005, $104 million in 2006, $966 million in 2007, $5.2 billion in 2008, $4.8 billion in 2009, and $37.2 billion in 2010. Greater debt financing was a positive trend, suggesting that perceived market and technology risks have decreased. Furthermore, increased debt financing allows industry participants to lower their cost of capital.

Public equity offerings of solar companies were extremely limited in 2004, but in 2005 $1.7 billion of new equity was raised, followed by $4.9 billion in 2006 and $7.9 billion in 2007. From 2008 to 2010 the total value of public solar-equity offerings has fluctuated from year to year, falling to $6.5 billion in 2008 as the financial crisis deepened, rising to $7.9 billion in 2009, and then once again falling to $5.7 billion in 2010. Nonetheless, these values represent a 110% CAGR between 2004 and 2010, an enormous market expansion compared to 2004 levels.

Disclosed global M&A deals raised new equity of $345 million, $48 million, $1.0 billion, $11.0 billion, and $7.6 billion, $8.9 billion, and $3.9 billion from 2004 to 2010 sequentially, representing a 50% CAGR. In 2010, some notable M&A transactions were Sharp's acquisition of Recurrent Energy for $305 million and First Solar's acquisition of NextLight Renewables for $285 million. In M&A transactions, however, equity mostly is transferred between market participants, and thus M&A generates comparatively little new investment for the solar sector.

Global venture capital (VC) and private equity (PE) investment in solar totaled $150 million, $785 million, $1.1 billion, $3.5 billion, $4.9 billion, $1.7 billion, and $2.3 billion from 2004 to 2010 sequentially, representing a 58% CAGR. Some of the notable transactions completed during 2010 include BrightSource Energy's $150 million series D VC transaction, Abound Solar's $110 million series D VC transaction, and Amonix's $64 million series B VC transaction.

[58] Data is as of 5/16/11. The figure excludes government research and development and project finance investments. Government debt is defined as finalized loans or loan guarantees offered by the China Development Bank, the Eurasian Development Bank, the European Development Bank, the Export-Import Bank of China, the Export-Import Bank of the U.S., the Federation of Malaysia, the International Finance Corporation, and the U.S. Department of Energy. The figure may vary from the prior year's version due to changes in the underlying data source.

Figure 5.2 shows the tremendous rise in government-supported debt from 2007 to 2010. In 2007, government-supported debt totaled $152 million, rising to $698 million in 2008, and subsequently declining to $579 million in 2009. However, 2010 truly marked a watershed year; the $25.4 billion of government-supported debt completed during 2010 marked a 4,280% annual increase over the prior year and a 450% CAGR between 2007 and 2010. The China Development Bank accounted for the vast majority of the value transacted in 2010 with $23.1 billion, or 91% of the total. The U.S. Department of Energy's Loan Programs Office completed (finalized in the program's parlance) two notable solar loan guarantees worth a total of $1.9 billion during 2010, a $1.5 billion guarantee with Abengoa Solar for a CSP power generation project and a $400 million guarantee with Abound Solar for two CdTe manufacturing facilities. The International Finance Corporation completed a $75 million transaction with SunPower making up the remainder of the U.S. share, and the European Investment Banks and Eurasian Investment Bank completed two transactions worth a cumulative $343 million.

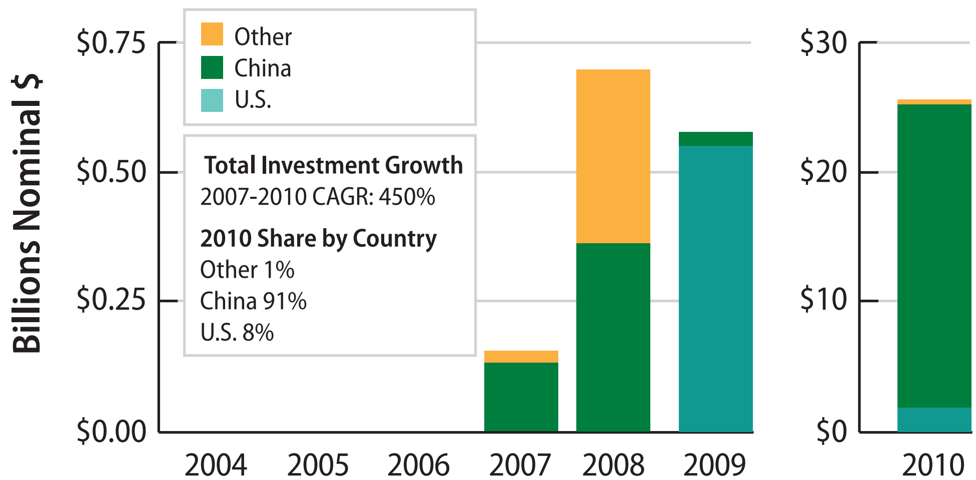


Figure 5.2 Global government debt capital investment in solar energy, by country[59] (Bloomberg New Energy Finance 2011)

Figure 5.3 shows investments in solar energy in the United States. Following a generally similar pattern similar to that of worldwide investment, from 2004 to 2010, total investment grew at a 6-year CAGR of 86%, worth $160 million, $671 million, $2.1 billion, $5.3 billion, $4.7 billion, $3.7 billion, and $6.7 billion sequentially. Debt investment (government-supported and non-government-supported) grew fastest, from $14 million in 2004 to $1.8 billion in 2010, corresponding to a 6-year CAGR of 155%. The annual growth rate, excluding government-supported debt, is also an important facet of the U.S. solar industry to note, increasing 50% from $3.2 billion in 2009 to $4.7 billion in 2010. At 50%, this annual growth rate is 10-times larger than the 5% annual growth rate seen in 2009 to 2010 for non-government-supported total global investment.

[59] Data as of 5/16/11. Government debt is defined as finalized loans or loan guarantees offered by the China Development Bank, the Eurasian Development Bank, the European Development Bank, the Export-Import Bank of China, the Export-Import Bank of the U.S., the Federation of Malaysia, the International Finance Corporation, and the U.S. Department of Energy.

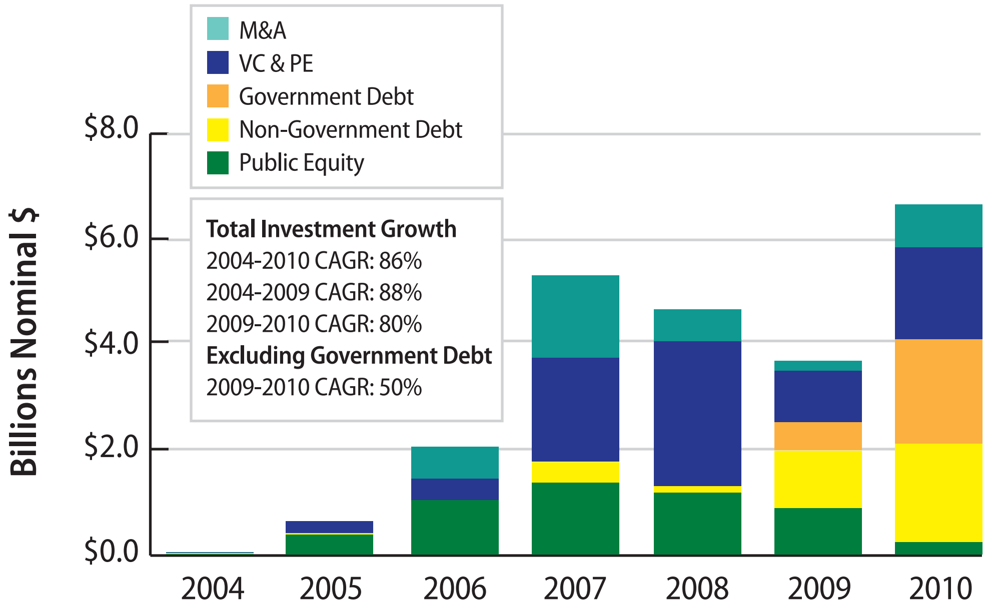


Figure 5.3 U.S. capital investment in solar energy[60]
(Bloomberg New Energy Finance 2011)

The dramatic slowing of the global investment growth rate and the negative growth rate seen in the United States during 2007 to 2009 should be considered temporary. Analysts point to a number of factors that help to explain the dramatic turnaround in investment trends, all of which center around the global recession that began toward the end of 2008:

- Declining revenues led to a sudden drop in global tax appetite. With much of the incentives in solar development coming in the form of tax credits, it is imperative that investing entities have plenty of taxable income in order to absorb the full potential of the incentives being offered. With the recession came declining revenues, and as such, investing entities did not have the necessary tax appetite to utilize the incentives offered.

- Construction of new projects worldwide came almost to a standstill. This slowdown in construction across sectors mirrors the decline in building of new PV systems.

Analysts have projected a full recovery from the decline experienced in 2009, however, it might be several years before the industry returns to the rate of growth that it had enjoyed up until the end of 2008.

Figure 5.4 shows the value of VC and PE solar investments by year, region, and technology on the left axis. The regional differences in investment in solar technologies are striking.

[60] Data as of 5/16/11. The figure excludes government R&D and project finance investments. Government debt is defined as finalized loans or loan guarantees offered by the Export-Import Bank of the U.S., the International Finance Corporation, and the U.S. Department of Energy. The figure may vary from prior year's version due to changes in the underlying data source.

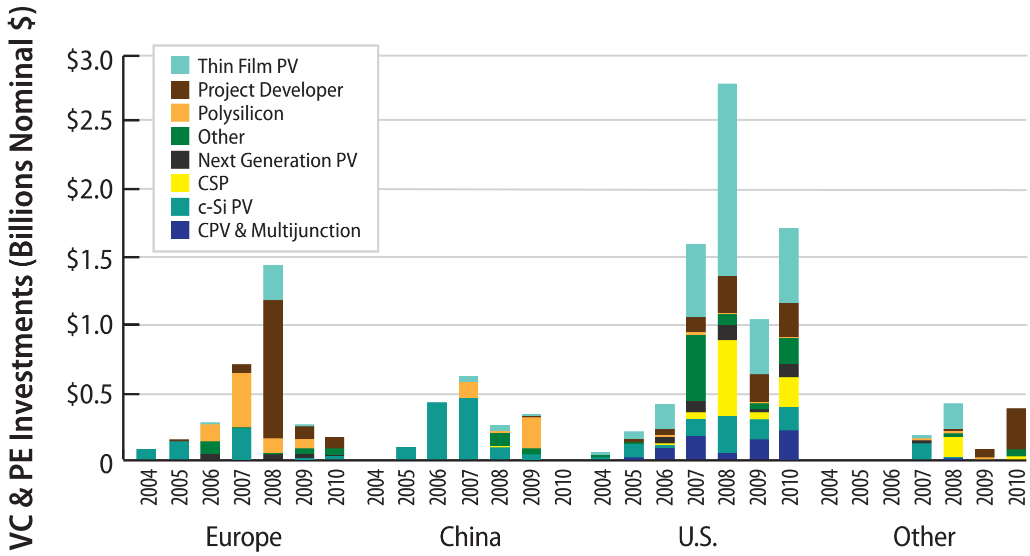


Figure 5.4 Global venture capital and private equity investments, by solar technology (Bloomberg New Energy Finance 2011)

Venture capital and private equity investments in China, almost non-existent until 2005, have remained focused mainly on the production of crystalline silicon PV with notable investments in polysilcon production during 2009. European VC and PE investments started somewhat earlier and have focused on project development, crystalline silicon PV, and polysilicon production, with some interest in thin-film technologies in recent years. In contrast, U.S. VC and PE investments have been broadly diversified, with investments in nearly all areas of the solar industry and increasing interest in concentrating PV, next-generation PV, CSP, and project development. Most importantly, all of the $546 million of global VC and PE investments in thin-film PV in 2010 went to U.S.-based companies and 84% of the $3.7 billion of global VC and PE investments between 2004 and 2010 went to U.S.-based companies as well.

In terms of regional differences in private equity versus venture capital investments, private equity investment has been predominant in Europe. A majority of PE investment in the solar industry has been to finance capacity expansions (often by means of constructing new factories), thus indicating that companies based in the European Union have been building a majority of these factories. In contrast, VC investment has been predominant in the United States. Venture capital investment is an indicator of new technologies or business models. Whereas generous subsidy programs in the European Union have spurred companies there to expand capacity rapidly, the market in the United States has not been sufficiently attractive to enable significant growth of incumbent products. Therefore, more U.S. investment has been directed to innovative technologies with longer-term prospects.

5.2 U.S. Department of Energy Investment in Solar Energy

The DOE Solar Energy Technologies Program plays a key role in accelerating development of the U.S. solar industry and advancement of solar technologies. SETP efforts are implemented through four subprograms: Photovoltaics (PV), Concentrating Solar Power (CSP), Systems Integration (SI), and Market Transformation (MT). The PV and CSP subprograms focus on reducing the levelized cost of solar energy through research and development. Systems Integration focuses on technologies, tools, and strategies to optimize the integration of solar energy into the grid. Market Transformation addresses non-R&D barriers to achieving high market penetration of solar energy technologies. SETP funding by fiscal year ([FY] i.e., FY 2010 began on October 1, 2009, and ended on September 30, 2010) is shown in Figure 5.5.

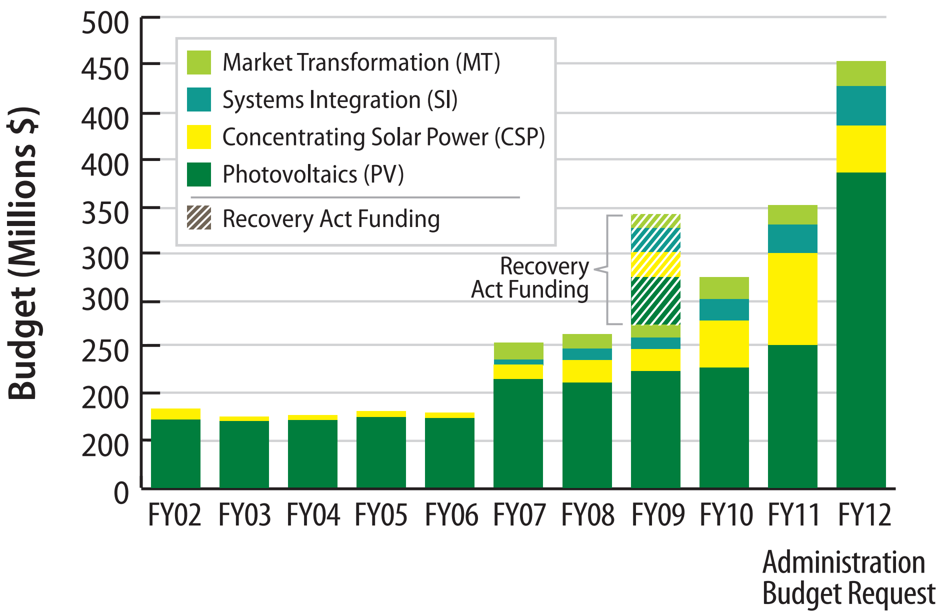


Figure 5.5 DOE SETP budget from FY 2002 to FY 2012 administration budget request[61] (DOE SETP 2011)

At $243 million (including $22 million for the Fuels from Sunlight Energy Innovation Hub), SETP's FY 2010 budget was a significant increase from the $164 million appropriated for FY 2009 and the $175 million for FY 2008. In addition, the Recovery Act appropriated nearly $118 million in additional funds to SETP. Subprogram activity funding in FY 2010 was $125.8 million to PV, $49.0 million to CSP, $23.1 million for Systems Integration, $23.5 million for Market Transformation, and $22.0 million for the Fuels from Sunlight Energy Innovation Hub (not shown in Figure 5.5). The Administration's Budget Request for SETP in FY 2011 was $302 million and $457 million for FY 2012.

The majority of SETP funding is directed at cost-shared research, development, demonstration, and deployment efforts with national laboratory, state, industry, and university partners. For current, upcoming, and past funding opportunities in all research areas, see: http://www.eere.energy.gov/solar/financial_opportunities.html.

[61] The figure excludes $22 million in FY 2010 funding for the Fuels from Sunlight Energy Innovation Hub.

The DOE SETP PV subprogram[62] invests in technologies across the development pipeline that demonstrates progress toward minimizing the effective life-cycle cost of solar energy. The PV subprogram's activities are organized into three focus areas: new devices and processes, prototype design and pilot production, and systems development and manufacturing.

The PV subprogram is currently funding activities to advance all major PV cell technologies, including wafer silicon (Si), amorphous and single-crystal, thin-film Si, high-efficiency (III-V) semiconductors, CdTe and CIGS thin films, and advanced organic and dye cells.

The CSP subprogram[63] has been ramping up R&D and deployment efforts in recent years, leveraging industry partners and the national laboratories. The subprogram's goals include increasing the use of CSP in the United States, making CSP competitive with natural gas in the intermediate power market by 2015, and developing advanced technologies that will reduce system and storage costs to enable CSP to compete in the base-load power market with up to 16 hours of storage by 2020. R&D activities focus on linear concentrator systems such as parabolic troughs and linear Fresnel reflectors, dish-engine systems such as Stirling heat engines, power towers, thermal storage systems, advanced heat-transfer fluids, advanced concepts in R&D, and CSP market transformation.

The Systems Integration subprogram[64] focuses on breaking down the regulatory, technical, and economic barriers to integrating solar energy into the electric grid by developing technologies and strategies in partnership with utilities and the solar industry. Systems Integration R&D includes solar system technology development, advanced systems integration, system testing and demonstration, renewable energy system analysis, solar resource assessment, codes and standards, and regulatory implementation.

The Market Transformation subprogram seeks to establish a national market for PV at the residential, commercial, and utility scales through improvements in business processes and market conditions. Highlights from 2010 include announcing a joint effort with the U.S. Department of the Interior to develop demonstration solar projects on public lands, strive to remove barriers to commercial development of solar technologies on public lands in the West, select a national administrator for DOE's Solar Instructor Training Network, and remove critical state regulatory barriers to solar market development.

In July 2010, DOE Secretary Steven Chu and U.S. Department of the Interior Secretary Ken Salazar signed an interagency memorandum of understanding that will enable DOE to develop innovative demonstration solar energy projects on public lands. Concurrent with the release of the memorandum, the Secretaries and Senate Majority Leader Harry Reid of Nevada announced the site of DOE's Solar Demonstration Project, which will be used to demonstrate cutting-edge solar technologies, and which provides a critical link between DOE's advanced technology development and commercialization efforts. The site is located at the Nevada National Security Site (formerly the Nevada Test Site) on lands owned by the Bureau of Land Management (BLM) and administered by DOE's National Nuclear Security Administration. These developments were followed up in December 2010 by the release of the Draft Solar Programmatic Environmental Impact Statement (EIS), the result of a 2-year comprehensive effort between DOE and the Department of the Interior to analyze the environmental impacts of utility-scale solar energy development on public lands in six western states. Following the closure of the public comment period in 2011, the final EIS will be revised and published, leading to a formal record of decision.

[62] *DOE SETP PV subprogram website: http://www.eere.energy.gov/solar/photovoltaics_program.html.*

[63] *DOE SETP CSP subprogram website: http://www.eere.energy.gov/solar/csp_program.html.*

[64] *DOE SETP Systems Integration subprogram website: http://www.eere.energy.gov/solar/systems_integration_program.html.*

DOE also selected the Interstate Renewable Energy Council (IREC) as the national administrator of its Solar Instructor Training Network in August 2010. The network promotes high-quality training in the installation, permitting, and inspection of solar technologies. Under this $4.5 M award, IREC will serve in this capacity for 5 years, and will be responsible for prioritizing the network's activities and disseminating curricula, best practices, and other products.

Finally, throughout 2010, the SETP furnished laboratory expertise to 17 public utilities commissions through its state technical assistance program. The partnerships were designed to reduce regulatory market barriers by addressing informational gaps and providing tailored technical expertise for regulators and their staffs.

5.3 Solar Market Forecasts, PV and CSP

The ongoing expansion of the solar market continued to attract the attention of numerous financial institutions and research and consulting firms seeking to provide analysis and forecasts for the PV and CSP sectors. This section analyzes these projections, both to identify the expected path of the industry and to recognize the substantial variance in market forecasts. Key trends and uncertainties for the solar market in the next several years are also discussed.

5.3.1 PV Market Forecasts

This section focuses on PV market projections made in late 2010 to early 2011.[65] The global economic crisis that became apparent in late 2008 reduced overall demand for PV and continues to hinder the availability of funds for capital investment. Because of these financial changes, some analysts revised their forecasts in early 2009 from forecasts released in mid-to-late 2008. Some of those changes have carried over as financial markets continue to remain uncertain.

Figure 5.6 illustrates the forecasted size and composition of PV production through 2013, while Figure 5.7 depicts global thin-film PV module supply forecasts. For total production, the median estimate increases from 6.0 GW in 2008 to 26.2 GW in 2013, a 5-year CAGR of 34.1%. Growth is expected to be relatively consistent through 2013 for both the c-Si and the thin-film segments, with the median estimate indicating thin films will likely maintain 88% and 82% of the PV module market. In addition to the growth of the median estimate, the range of estimates is significant. In 2013, the high estimates for c-Si and thin films are roughly twice that of the low estimates. Uncertainty in these projections is likely due to differing opinions about demand for PV, the ability to expand production sufficiently for each part of the PV supply chain, and technological and cost improvements of c-Si and thin films.

[65] *For detailed information on the effects of the economic crisis on PV forecasts, see: "The Effects of the Financial Crisis on Photovoltaics: An Analysis of Changes in Market Forecasts from 2008 to 2009." http://www.nrel.gov/docs/fy10osti/46713.pdf.*

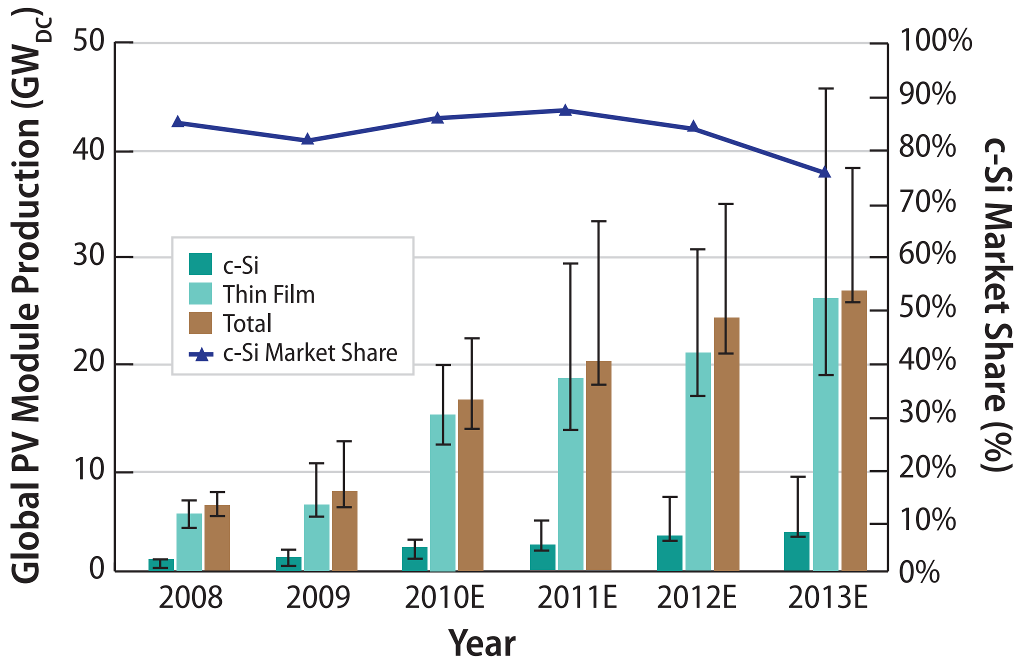


Figure 5.6 Global PV module supply forecasts[66]
(Barclays Capital (2/14/11), Greentech Media (10/26/10), Jefferies & Co. (2/2011), Lazard Capital Markets (2/11/11), Piper Jaffray (1/2011), Photon Consulting (2011), Stifel Nicolaus & Co. (1/25/11 and 2/25/11), Lux 5/27/2011)

Regarding thin-film versus c-Si production, the median projection indicates thin-film production is expected to grow at the same rate overall during the next several years, with a median forecasted 2008 to 2013 CAGR for thin-film PV and c-Si of 34%. However, c-Si is still expected to be the dominant technology for the next several years, accounting for 87% of total projected PV production in 2013. There is a reasonable level of disagreement among analysts about the future PV market share of c-Si versus thin film, demonstrated by a range of 74% to 91% for 2013 c-Si market share. To better describe the thin-film sector, Figure 5 presents the projected rise in thin-film PV module production by technology through 2010. The divergent range of supply estimates is reasonable given that thin-film PV continues to face technology and scale-up risks, in addition to overall market uncertainty for PV in general. Despite these uncertainties, median estimates for thin-film technologies imply growth, with 2008 to 2013 CAGRs of 43% for CdTe, 35% for a-Si, and 81% for CIGS production.

The a-Si market includes established producers such as Energy Conversion Devices, Sharp, Signet Solar, and Kaneka, as well as numerous new entrants. New producers had previously indicated plans to enter the market through the purchase of turnkey systems from Applied Materials or Oerlikon. However, given the capital expenditures necessary for the purchase of turnkey production lines, expansion of a-Si production from new entrants continues to be curtailed by the tight credit market. In addition, as PV module prices have fallen faster than system prices, non-module costs have increased as a proportion of total system costs. Because non-module costs-per-watt rise as module efficiency declines, a-Si (which has the lowest efficiency of any of the principal PV technologies) has become less attractive.

[66] *Not all sources provide data for each category of data in each year.*

CIGS module production started from a very low base, a median 2008 estimate of just 59 MW, but is expected to grow substantially in the near term. The median projection for 2013 is 1.1 GW, with a low estimate of about 570 MW and a high estimate of about 1.7 GW. The enormous range in estimates reflects substantial scale-up and technology risks encountered by companies such as MiaSole, Nanosolar, and Solyndra as they expand commercial production.

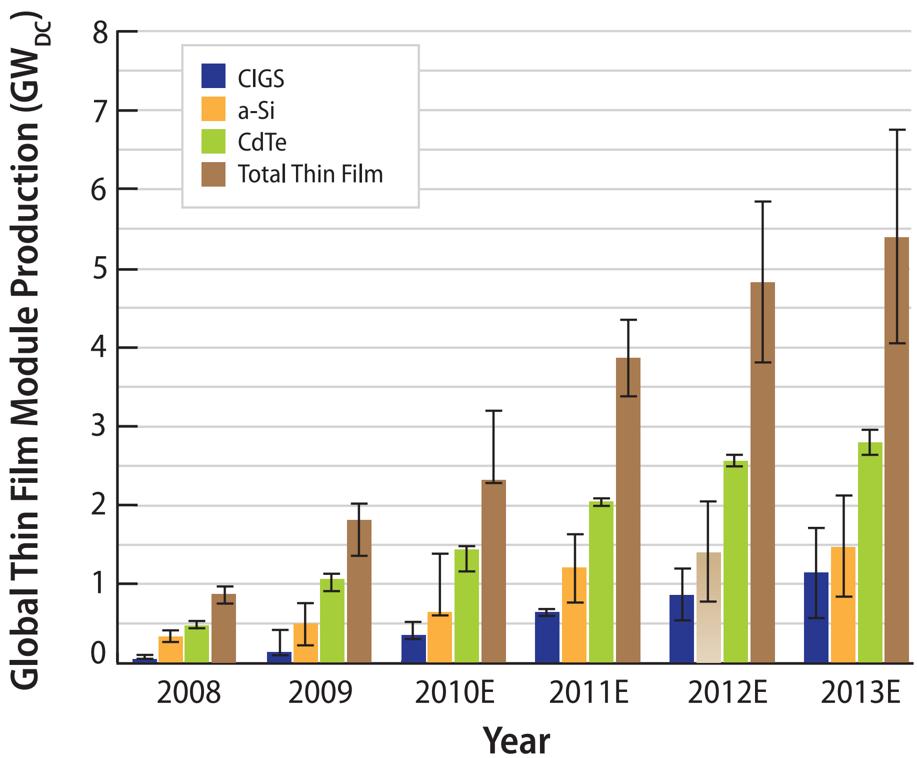


Figure 5.7 Global thin-film PV module supply forecasts[67]
(Greentech Media (10/26/10), Navigant (3/4/11), Photon Consulting (2011), Lux (2011)

Figure 5.8 shows the demand projections for solar PV modules by location. Median global demand is expected to grow from 6 GW in 2008 to 22.3 GW in 2013, a 5-year CAGR of 30%. Europe is expected to remain the largest region for solar energy through 2012, at which time the United States is presently expected to become the largest PV market in the world. The U.S. market is expected to grow at a 68% CAGR between 2008 and 2013, while Germany will grow at 1% over the same period due to the expected peak and then decline of German PV demand. As with the production projections, there is tremendous range in the demand estimates resulting from uncertainties about policy incentives, electricity prices, cost reductions of PV systems, and the price elasticity of PV demand.

[64] *Not all sources provide data for each category of data in each year.*

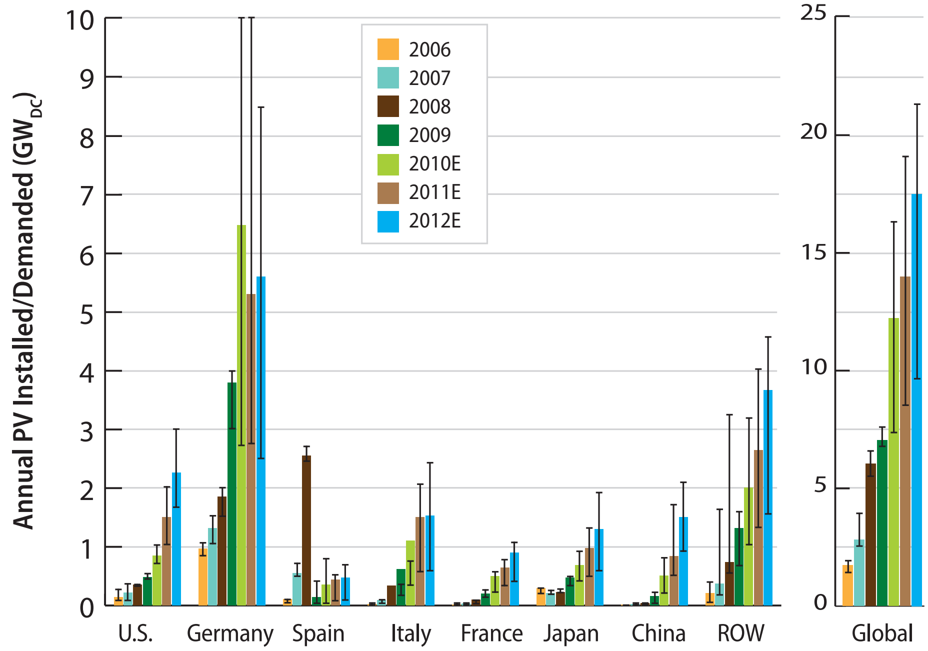


Figure 5.8 Global PV module demand forecasts[68]
(Barclays Capital (1/12/11 and 2/14/11), Citigroup Global Markets (2/14/11), Cowen & Co. (12/2/10 and 3/10/11), Goldman Sachs Group (1/23/11), Jefferies & Co. (2/2011), J.P. Morgan Securities LLC (3/9/10 and 1/11/11), Lazard Capital Markets (2/11/11), Piper Jaffray (1/2011), Stifel Nicolaus & Co. (1/13/11), UBS Securities, LLC (3/8/11), Wedbush Securities (2/8/11), Wells Fargo Securities (5/4/10 and 12/7/10)

Figure 5.9 shows forecasted global module and system prices through 2013. Module prices are expected to decrease from \$3.93/W_{DC}, to \$1.09/W_{DC} in 2013, a 5-year CAGR of −23%.

[68] Not all sources utilized provide projections for each year shown; the number of projections utilized for each year (i.e. the "n" in statistical terminology) are: 2008: 11, 2009: 12, 2010E: 12, 2011E: 12, 2012E: 10, and 2013E: 5.

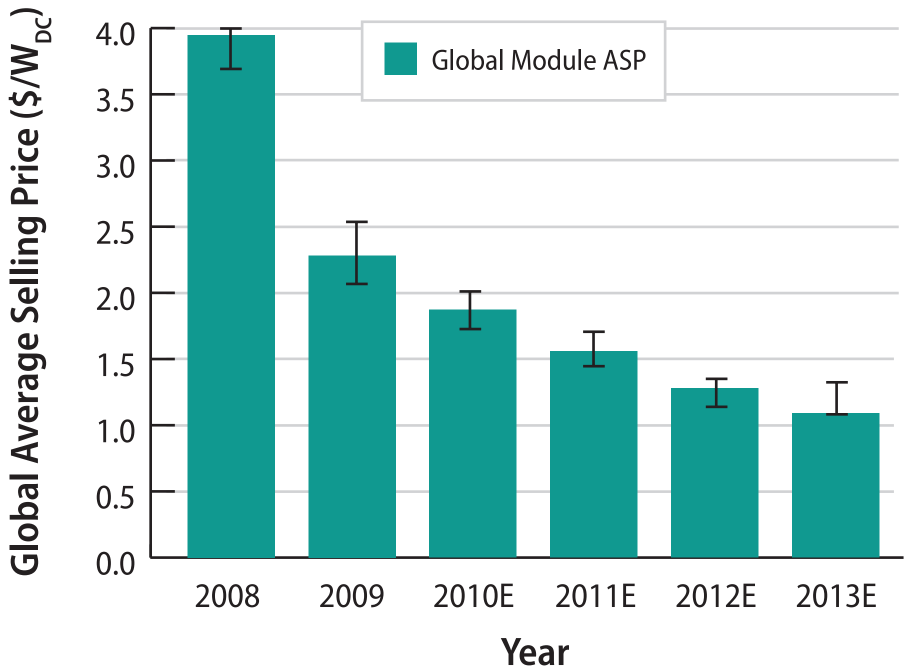


Figure 5.9 Global PV module price forecasts (Barclays Capital (11/15/10), Deutsche Bank (1/5/11), Goldman Sachs Group (1/23/11), JP Morgan (1/11/11), Lazard Capital Markets (2/11/11 and 4/13/11), Greentech Media (10/26/10), Photon Consulting (2011), UBS (3/8/2011)

5.3.2 CSP Market Forecasts

CSP differs markedly from PV with respect to history, installation size, permitting and construction duration, and technological readiness. Whereas PV has had a history of consistent annual installations, 350 MW of CSP were built in the 1980s with no subsequent installations in the United States until 2005. Installation sizes on the order of tens of megawatts and up to 4-year permitting and construction durations contribute to the difference in deployment patterns between CSP and PV. Only one CSP technology (parabolic troughs) has been demonstrated long term on a fully commercial scale, although there are a growing number of planned CSP systems that are dish engine, power tower, and linear Fresnel technologies. In 2009, three new plants totaling 12 MW of new generation capacity were added, including the first power tower in the United States (the Sierra SunTower), the first CSP facility in Hawaii (a trough system named Holaniku), and a linear Fresnel system in California (Kimberlina) (SEIA 2010). Spain also saw remarkable growth in 2009, with the installation of seven CSP facilities totaling 320 MW.

In 2010, three CSP plants came online in the United States, totaling 78 MW (GTM Research 2011), and nine CSP plants came online in Spain, totaling 450 MW (Protermo Solar 2010). Outside of the United States, 814 MW of CSP was under construction by the end of 2010, as broken down earlier in the report in Table 1.2 (NREL 2010). The number of plants under construction is dwarfed by the estimated number of planned plants. In the United States alone there was 10.8 GW of proposed CSP capacity by the end of the year (GTM Research 2011).

While different sources report planned projects differently, Tables 5.1 and 5.2 attempt to represent the amount and location of global-planned CSP installations through 2015 (GTM Research 2011). Table 5.1 lists CSP projects as planned and under construction, by country, while table 5.2 depicts the respective market share of each country. Of the estimated 19 GW in the global CSP pipeline, 57% are in the United States, 21% are in Spain, 13% are in China, about 6% are in the MENA region, and the remaining 3% are dispersed across India, Greece, South Africa, Italy, and France. It should be noted that the projects in the global pipeline are by no means guaranteed. Several major factors could prevent many of these projects from being completed, resulting in a pipeline that will likely be reshaped on a continual basis.

TABLE 5.1: GLOBAL CSP PLANNED PROJECTS AS OF JANUARY 2011, CAPACITY BY COUNTRY

Country	Capacity Under Construction (MW)	Capacity Planned (MW)	Total Planned and Under Construction (MW)
United States	0	10,843	10,843
Spain	548	3,909	4,457
China	96	2,400	2,496
Morocco	20	500	520
Australia	10	339	349
Israel	0	250	250
Sudan	0	250	250
UAE	100	0	100
Jordan	0	100	100
South Africa	0	100	100
India	0	70	70
Greece	0	50	50
Italy	0	28	28
Other	0	25	25
France	0	21	21
Eqypt	20	0	20
Algeria	20	0	20
Total MW	814	18,885	19,699

Source: GTM Research 2011

TABLE 5.2: GLOBAL CSP PLANNED PROJECTS AS OF JANUARY 2011, MARKET SHARE BY COUNTRY

Country	Market Share
United States	57%
Spain	21%
China	13%
MENA	6%
ROW	3%

Source: GTM Research 2011

5.4 References

Arcuri, T.M.; Seth, T.; Richard, R. (2011). Assessing Demand Risk. New York: Citi.

Barclays Capital. (2011). *Global Clean Technology Handbook: 2011 Sector Overview*. New York: Barclays Capital.

Blansett, C.; Lee, B. (2010, March 9). Alternative Energy Don't Try to Catch A Falling Knife; Downgrading Solar Stocks on C2H10 Oversupply Risk (FSLR and ENER to UW; ESLR to N). *North America Equity Research.*

Boas, R.; Farber, M.; Meyers, M.; Porter, C.; Rogol, M.; Song, J.; Trangucci, R. (April 2010). "PHOTON Consulting's Monthly Market Commentary." Photon International.

Bloomberg New Energy Finance. (2011). *New Energy Finance Desktop*.

Bloomberg New Energy Finance. (2011). Personal communication.

Deutsche Bank. (January 5, 2011). Solar Photovoltaic Industry 2011 Outlook - FIT cuts in key markets point to over-supply. *Industrials: Alternative Energy.*

Dubinsky, S. (2010). *Equity Research: DQ: Play On Tight Poly Market, Initiating at Outperform*. Baltimore: Wells Fargo Securities and Daqo New Energy Corp.

Dubinsky, S. (2010). *Initiating Coverage: Solar Sector.* New York: Wells Fargo Securities.

Goldman Sachs. (2011). *Global: Clean Energy: Solar.* New York: Goldman Sachs.

Greentech Media (GTM). (January 2011). *Concentrating Solar Power 2011: Technology, Costs, and Markets.* http://www.gtmresearch.com/report/concentrating-solar-power-2011-technology-costs-and-markets. Accessed May 9, 2011.

Jefferies and Company Inc. (2011). *Clean Technology Primer.* New York: Jefferies.

Limited, U.S. (2011). *UBS Investment Research: UBS Global I/O: Solar Industry.* New York: UBS Securities.

Mints, P. (2011). *Photovoltaic Manufacturer Shipments, Capacity, & Competitive Analysis 2009/2010*. Report # NPS-Supply5. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Osborne, J.; Warrier, D. (January 13, 2011). A Periodic Look at the Cleantech Industry. *Stifel Nicolaus Green Sheet.*

Protermo Solar. (2010). Operational Concentrated Solar Power Plants in Spain. http://www.protermosolar.com/boletines/23/Mapa.pdf. Accessed May 9, 2011

Shah, V.; Jake, G. (2011). Cleantech Insights V23: EU Solar Outlook—Sunny Today Cloudy Tomorrow? New York: Barclays Capital Research.

Shrestha, S. (2011). *Global Solar—4Q earnings preview, market development scenario through 2013*. New York: Lazard Capital Markets.

Solar Energy Industries Association (SEIA) and Greentech Media (GTM). (2011). *U.S. Solar Market Insight: 2010 Year in Review.* http://www.seia.org/cs/research/SolarInsight. Accessed May 9, 2011.

Stifel, N. (February 25, 2011). Progress on Pipeline and Costs Continue; 2011 More Back-End Loaded. *Clean Tech.*

Stone, R.; James, M. (2010). *Managing Solar Growth; European Limits.* Boston: Cowen and Company.

Zaman, A.; Shawn, L. (2011). *Solar Industry Growth…You Ain't Seen Nothin' Yet.* New York: Piper Jaffray.

On the cover (main photo):
At more than 8 MW of nameplate capacity, the photovoltaic (PV) power plant near Alamosa, Colorado, is one of the largest in the United States. The Alamosa plant came online in December 2007 through a partnership between SunEdison and Xcel Energy.
- *Photo from Zinn Photography and SunEdison, NREL/PIX 15563*

(Inset photo):
The Nevada Solar One concentrating solar power (CSP) plant near Boulder City, Nevada, is a 64 MW parabolic trough installation completed in June 2007 by developer Acciona Energy.
- *Photo from Acciona Energy Corporatio, NREL/PIX 15996*

U.S. DEPARTMENT OF
ENERGY
Energy Efficiency &
Renewable Energy

EERE Information Center
1-877-EERE-INFO (1-877-337-3463)
www.eere.energy.gov/informationcenter

Printed with a renewable-source ink on paper containing at least 50% wastepaper, including 10% post consumer waste.

Prepared by the National Renewable Energy Laboratory (NREL)
NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

DOE/GO-102011-3318 • November 2011