SunShot

U.S. Department of Energy

SunShot Vision Study

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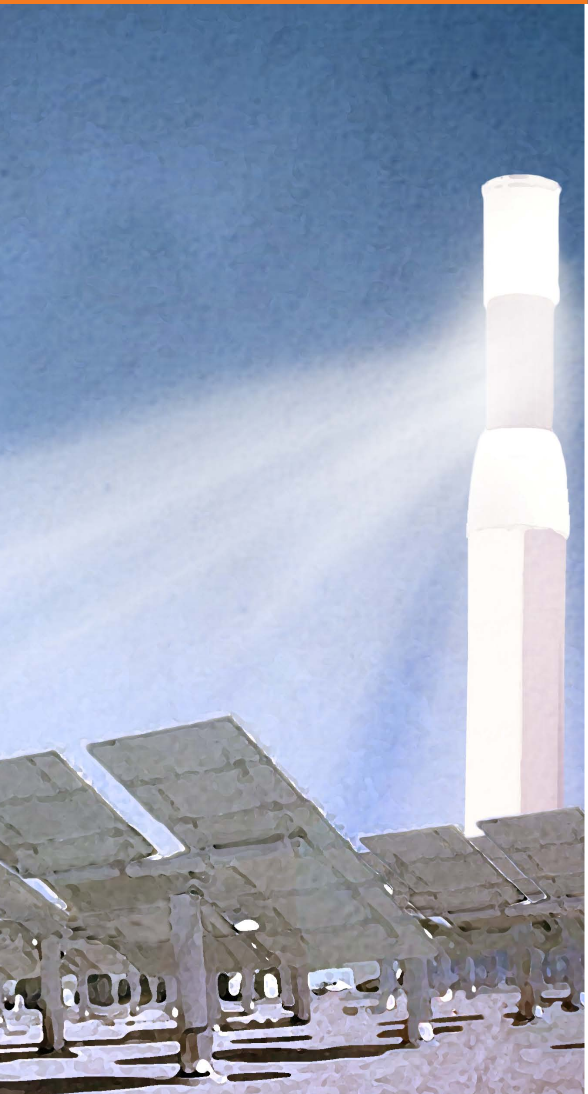
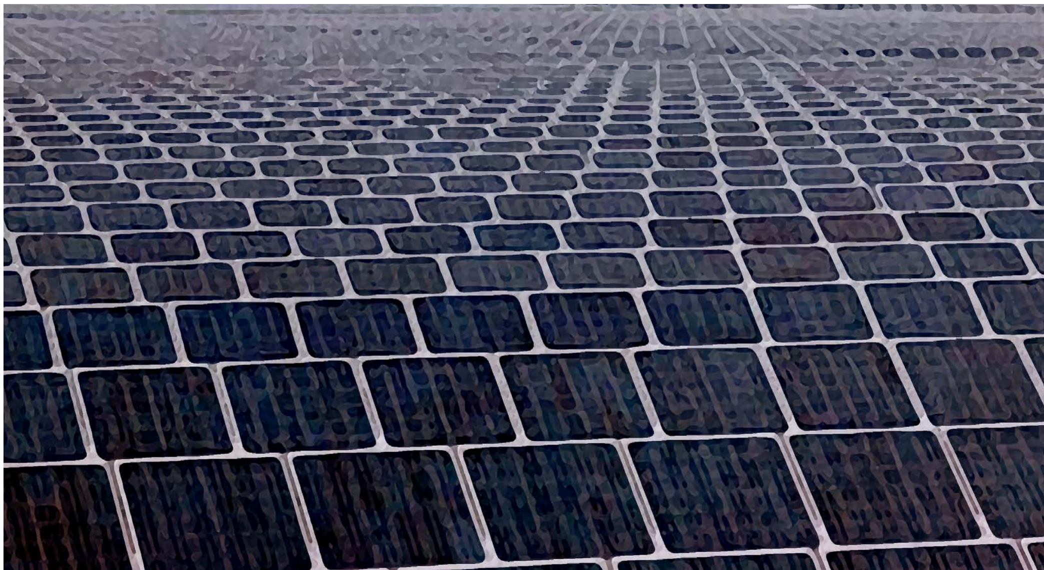




4. Photovoltaics: Technologies, Cost, and Performance

4.1 INTRODUCTION

Photovoltaic (PV) technologies currently supply only a small fraction of U.S. energy needs, largely because PV-generated electricity historically has cost more than electricity from conventional sources. Achieving the SunShot Initiative's PV cost-reduction targets—reducing the price of PV systems by about 75% by 2020—is projected to make PV competitive with conventional sources on a levelized cost of energy (LCOE) basis. Achieving this electricity price parity is projected to result in large-scale U.S. deployment of PV technologies, which would meet 11% of contiguous U.S. electricity demand in 2030 and 19% in 2050 (see Chapter 3 for detailed analysis of the SunShot scenario).

Over the past several decades, PV manufacturing costs and sales prices have dropped dramatically while experience accumulated by solar manufacturers and developers, utilities, and regulatory bodies has shortened the time and expense required to install a fully operating PV system. These gains have come partly through research, development, and demonstration (RD&D) and partly through market stimulation. Best-in-class installed PV prices in late 2010 were about $3/watt (W)[41] for utility-scale systems, with an average of about $3.80/W (Goodrich et al. 2010), and prices continue to decline following the global trend of continuous price and performance improvements.

Bringing PV prices down even further and more rapidly, to the SunShot levels, will require a combination of evolutionary and revolutionary technological improvements, in conjunction with, and in support of, substantial market and manufacturing scale-up. Concerted RD&D efforts are needed to create breakthrough technologies and processes that drastically reduce PV module, power electronics, and balance-of-systems (BOS) costs. This will also include a close collaboration with the private sector to ensure that new PV technologies are deployed commercially and installed in a cost-effective manner.

This chapter evaluates the current price and performance of PV technologies. Price projections representing incremental/evolutionary technological improvements are compared with the SunShot price projections. This analysis indicates that achieving the SunShot price-reduction targets will require going beyond evolutionary changes

[41] Note: all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC), unless specified.

to PV technologies; revolutionary steps forward are needed to achieve the SunShot targets.

The availability of key PV materials and the required scale-up of PV manufacturing capacity are also evaluated. Increased production and improved utilization of PV materials should enable the PV growth projected under the SunShot scenario. Rapid PV manufacturing capacity scale-up is possible and should not constrain SunShot levels of PV growth.

4.2 Today's PV Technology

Current PV technology is the result of decades of performance and price improvements. This section describes the components that make up a PV system, the types of PV module technologies, and the history and current status of PV prices and performance.

4.2.1 Components of a PV System

For the purpose of characterizing costs, PV systems can be classified into three subsystems: PV modules, power electronics, and BOS.

PV modules are made up of interconnected PV cells that convert sunlight directly into electricity. PV cells are fabricated from semiconductor materials that enable photons from sunlight to "knock" electrons out of a molecular lattice, leaving a freed electron and "hole" pair that diffuse in an electric field to separate contacts, generating direct-current (DC) electricity. This "photoelectric effect" has most commonly been generated with materials such as crystalline silicon (c-Si) and a range of thin-film semiconductors, which are described in the next subsection (Luque and Hegedus 2003).

The great majority of electrical applications require alternating-current (AC) electricity. For these applications, power electronics are required to convert and condition the DC electricity generated by the PV module into AC electricity suitable for customer use or transmission; most importantly, an inverter converts DC to AC, and a transformer steps the electricity up to the appropriate voltage. BOS comprises the remaining components and procedures required to produce a complete PV system, including mounting and wiring hardware, land, installation, and permitting fees.

4.2.2 PV Module Technologies

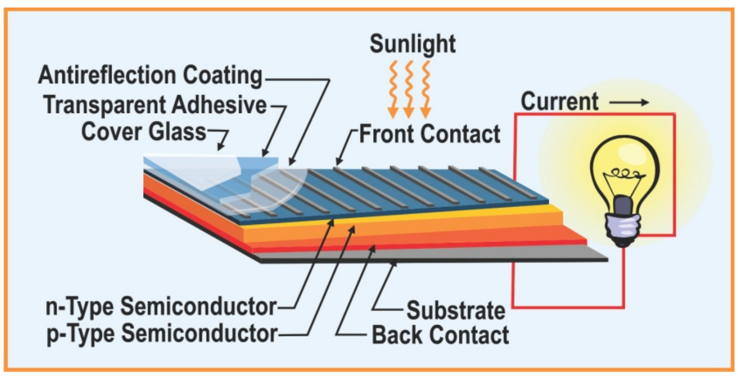
Several c-Si and thin-film PV technologies have been demonstrated commercially on a large scale. In addition, several emerging PV technologies may be technically and economically competitive in the future. This subsection briefly describes these types of PV module technologies. Efficiency is one important characteristic described in this subsection. The efficiency of a solar cell or module is the percentage of the sun's energy striking the cell or module that is converted into electricity.

Crystalline Silicon

Crystalline silicon technologies constitute about 85% of the current PV market (Mints 2011). This technology has a long history of reliable performance; c-Si modules have demonstrated operational lifetimes of more than 25 years (Jordan and Kurtz 2011).

There are two general types of crystalline, or wafer-based, silicon PV: monocrystalline and multicrystalline. Monocrystalline semiconductor wafers are cut from single-crystal silicon ingots. Multicrystalline semiconductor wafers are cut from directionally solidified blocks or grown in thin sheets. Monocrystalline ingots are more difficult, energy intensive, and expensive to grow than simple blocks of multicrystalline silicon. However, monocrystalline silicon produces higher-efficiency cells. For both types, the silicon is processed to create an internal electric field, and positive and negative electrical connections are added to wafers to form a cell (Figure 4-1). Standard cell processes are used to complete the circuit for both mono- and multicrystalline cells, and multiple cells are linked and encapsulated to form modules.

Figure 4-1. Basic Components of a c-Si PV Cell



Source: NREL

The rated DC efficiencies of standard c-Si PV modules are about 14%–16%. A number of new or non-standard cell architectures—such as back-contact cells—are growing in importance because they offer the potential for significantly higher efficiency. Non-standard cell architectures tend to use high-quality monocrystalline wafers and more sophisticated processing to achieve module efficiencies of about 17%–21%.

Thin Film

Thin-film PV cells consist of a semiconductor layer a few microns (µm) thick, which is about 100 times thinner than current c-Si cells. Most thin films are direct bandgap semiconductors, which means they are able to absorb the energy contained in sunlight with a much thinner layer than indirect bandgap semiconductors such as traditional c-Si PV. The most common thin-film semiconductor materials are cadmium telluride (CdTe), amorphous silicon (a-Si), and alloys of copper indium gallium diselenide (CIGS). The semiconductor layer is typically deposited on a substrate or superstrate inside a vacuum chamber. A number of companies are pursuing lower-cost, non-vacuum approaches for manufacturing thin-film technologies. Glass is a common substrate/superstrate, but thin films can also be deposited on flexible substrates/superstrates such as metal, which allows for the potential for flexible lightweight solar modules. Thin films are very sensitive to water vapor and thus have traditionally been encapsulated behind glass to maintain performance. Eliminating the need for glass through the use of "ultra barrier" flexible glass replacement materials is an important next step in thin film development.

Thin-film modules have lower DC efficiencies than c-Si modules: about 9%–12% for CdTe, 6%–9% for a-Si, and 8%–14% for CIGS. CdTe-based PV has experienced significantly higher market growth during the last decade than the other thin-film PV technologies primarily due to the success of First Solar, which utilizes CdTe technology.

Concentrating PV

Concentrating photovoltaics (CPV) technologies use mirrors or lenses to concentrate sunlight 2–1,200 times onto high-efficiency silicon or multijunction (MJ) PV cells. CPV uses concentrating optics made out of inexpensive materials such as glass, steel, and plastic to focus sunlight onto a relatively small semiconductor area. This approach offers several significant benefits. First, it minimizes the amount of active semiconductor material (the material that converts sunlight into electricity) needed to produce a given amount of electricity. On an area basis, the active semiconductor material is the most complex and expensive component of many PV modules; this is particularly true for MJ cells. MJ cells are capable of much higher efficiencies than single junction silicon or thin-film cells. This is because each junction of a MJ cell is designed to collect a different part of the solar spectrum: MJ cells are typically a stack of three different cells on top of one another. This higher efficiency comes at an increase in manufacturing cost, and thus MJ devices are too expensive to use in terrestrial applications without concentration. The downside to CPV, especially for higher concentration levels, is that, in order to maintain the concentration of sunlight on the cell, the module must accurately track the sun throughout the day. Tracking results in a more complex and expensive installation. Recent improvements to MJ PV cells have produced cell efficiencies of 43.5% in the laboratory. Use of CPV systems for utility-scale electricity generation has been growing.

Emerging PV Options

A number of other PV technologies—frequently referred to as third-generation PV—are being developed. Dye-sensitized solar cells use dye molecules absorbed onto a nanostructured substrate and immersed in a liquid or gel electrolyte to absorb solar radiation and have demonstrated laboratory efficiencies as high as 11.1%. Organic PV (OPV) solar cells, based on polymers or small molecules with semiconductor properties, have demonstrated laboratory cell efficiencies above 8%; organic modules have the potential for low-cost manufacturing using existing printing and lamination technologies (Shaheen et al. 2005). Quantum dots—nanospheres with physical properties similar to both bulk semiconductors and discrete molecules—have the potential to achieve higher efficiencies through multiple exciton generation, but they have not yet been used to produce efficient PV cells.

There are significant challenges to the commercialization of solution-processed organic solar cells, dye-sensitized cells with certain electrolytes, and quantum dots due to the stability of the materials against oxygen and water ingress. This limits the lifetime of these devices to anywhere from a few hundred hours to 2 years. This issue is being addressed through efforts to develop improved, yet cost-effective, encapsulants. In addition, organic and dye-sensitized solar cells use dyes that have been shown to degrade when put in direct sunlight for long periods of time, a significant issue to have in a solar cell. Further research and development (R&D) is needed to improve the viability of these materials.

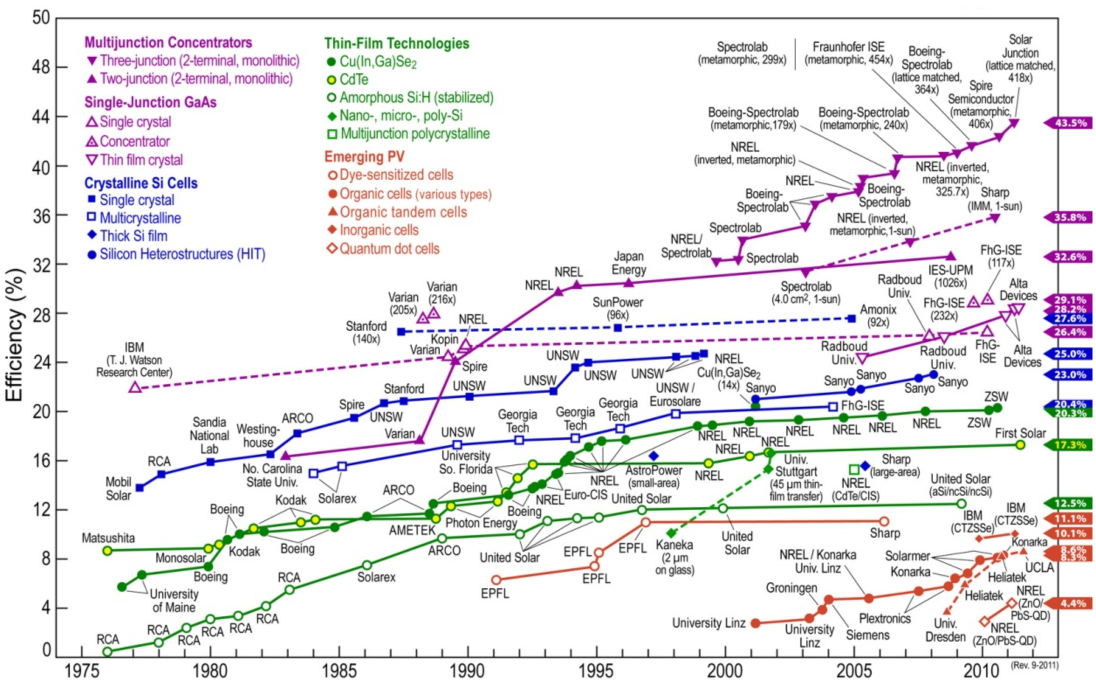
4.2.3 PV Performance and Price

The performance of PV technologies has improved substantially, while PV manufacturing costs have declined during the past several decades due to a combination of technological innovation, improved manufacturing processes, and growing PV markets. All of these factors have contributed to a downward trend in PV prices.

PV Efficiency

Figure 4-2 shows the increase in laboratory best-cell efficiencies by PV technology over the past few decades. These are laboratory prototype cells, developed through successful R&D. A number of challenges—such as simplifying or modifying cell properties to improve manufacturability and economics—must be overcome before laboratory cell innovations lead to improvements in commercial products. Some cell

Figure 4-2. Laboratory Best-Cell Efficiencies for Various PV Technologies



Source: NREL (2011)

efficiency improvements are simply too expensive to implement at the commercial scale. Further challenges are encountered as small cells are linked together (e.g., c-Si or flexible thin film on metal substrate) or made in much larger areas (e.g., thin films) and then encapsulated to form commercial modules. Commercial module efficiencies typically track best-cell efficiency improvements, with a time and performance lag.

PV Module Prices

Photovoltaic modules have followed a well-documented historical trend of price decline. Since 1976, global module prices declined about 20% on average for every doubling of cumulative global production, resulting in a price decline of roughly 95%—from about \$60/W to about \$2/W—between 1976 and 2010 (Figure 4-3).

Historic PV module prices stem from a long-term trend of continued technology and manufacturing improvements, along with shorter-term trends driven by supply and demand dynamics. As the industry has matured over the long term, factories have increased in scale and efficiency. During 1980–2001, cost reductions related to increasing plant size, often called economies of scale, had the single greatest impact of any factor on PV module prices (Nemet 2006). As the annual production capacity of manufacturers grew from hundreds of kilowatts (kW) to hundreds of megawatts (MW), economies of scale were realized in purchasing raw materials and equipment. Companies also adopted leaner process control techniques found in more mature, analogous sectors such as semiconductors.

As an example of shorter-term price variations, PV module prices rose from 2005–2008, reflecting both a supply-constrained market and high polysilicon feedstock prices. The resulting high market prices led to a global expansion of polysilicon feedstock supplies, which increased PV manufacturing capacity. These market forces brought module prices back to the long-term trend line by 2010 (Figure 4-3).

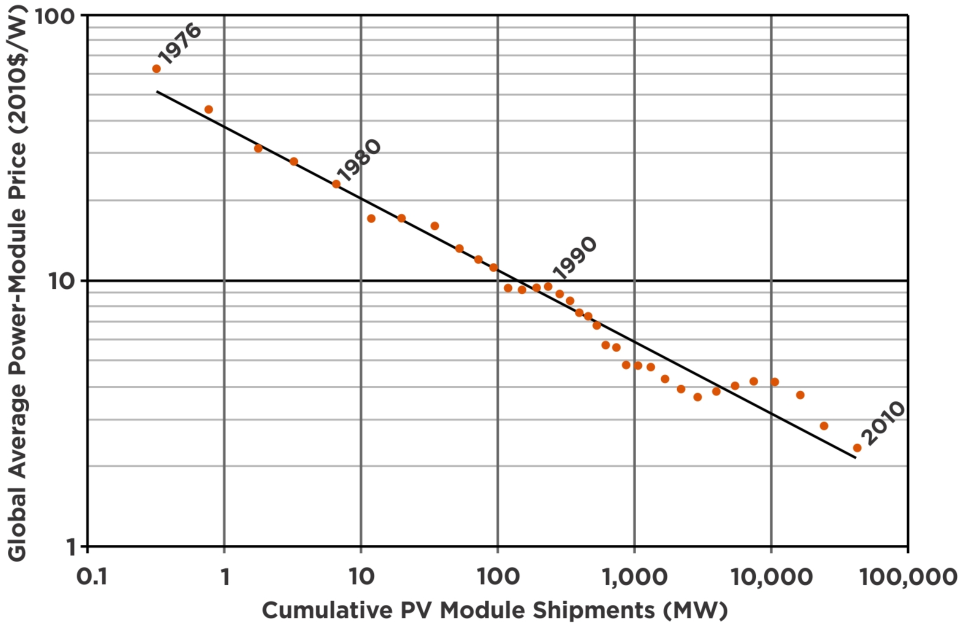
Module production costs vary by technology and manufacturer. For example, cost leaders for mono- and multicrystalline silicon modules have cited costs as low as \$1.10/W (Trina Solar 2010), but this manufacturing cost is not representative of all manufacturing processes, products, and financial assumptions. Typical module prices in 2010 ranged from about \$1.5–\$2/W (Mints 2011).

PV modules achieved significant price and performance improvements in 2011, relative to the benchmarked 2010 numbers in Figure 4-3. PV module prices trended toward \$1.5/W for several technologies in the first half of 2011 (First Solar 2011a, UBS 2011). Also, both thin-film and c-Si PV technologies achieved modest efficiency gains (First Solar 2011a, SunPower 2011).

PV System Prices

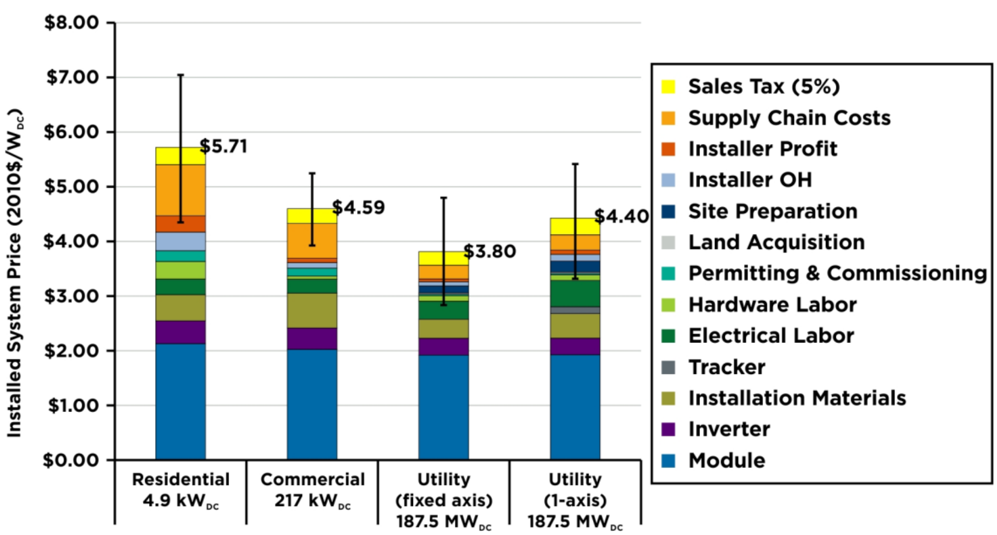
Installed PV system prices include the price of the module and power electronics and the BOS costs. Figure 4-4 shows benchmarked installed PV system prices in 2010, assuming typical monocrystalline silicon PV module prices and efficiencies for each of the key PV market segments: residential, commercial, and utility-scale installations. Residential systems have the highest installed system prices, at roughly \$6/W in 2010. This is because of their small size (typically 3–5 kW), fragmented

Figure 4-3. Decline in Factory-Gate PV Module Prices with Increasing Cumulative Module Shipments



Sources: Mints (2011), Mints (2006), Strategies Unlimited (2003)

Figure 4-4. Benchmarked 2010 Installed PV System Prices with Uncertainty Ranges for Multiple Sectors and System Configurations with Three Standard Deviation Confidence Intervals Based on Monte Carlo Analysis[42]



Source: Goodrich et al. (2012)

[42] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on cadmium telluride were also considered.

distribution channels, and high customer acquisition and installation costs. Residential PV modules typically pass through multiple distributors between the factory gate and local installers, each of which adds a price markup.

Commercial systems, such as those on the flat roofs of big-box retail stores, can be tens of kilowatts to multiple megawatts in size. Even though they are much larger than residential systems, they are not typically large enough to attain all economies of scale in purchasing components and installation labor. As shown in Figure 4-4, the installed price of a commercial system in 2010 was roughly $5/W, about 20% lower than for a residential system. While commercial systems typically cost more than utility-scale systems, a growing number of commercial systems are being developed by third-party installers using power purchase agreements (PPAs). These third-party installers are frequently able to achieve significant economies of scale in component purchasing and can finance, permit, and build commercial projects more quickly than larger utility projects.

Utility-scale PV systems typically have the lowest installed price: roughly $4/W in 2010. These systems are large enough to realize significant economies of scale in component purchasing and installation labor, significantly reducing installed system prices. Many module manufacturers act as the engineering, procurement, and construction (EPC) firm for large-scale utility installations, achieving an improvement in supply chain costs over traditional third-party installers.

4.2.4 LEVELIZED COST OF ENERGY

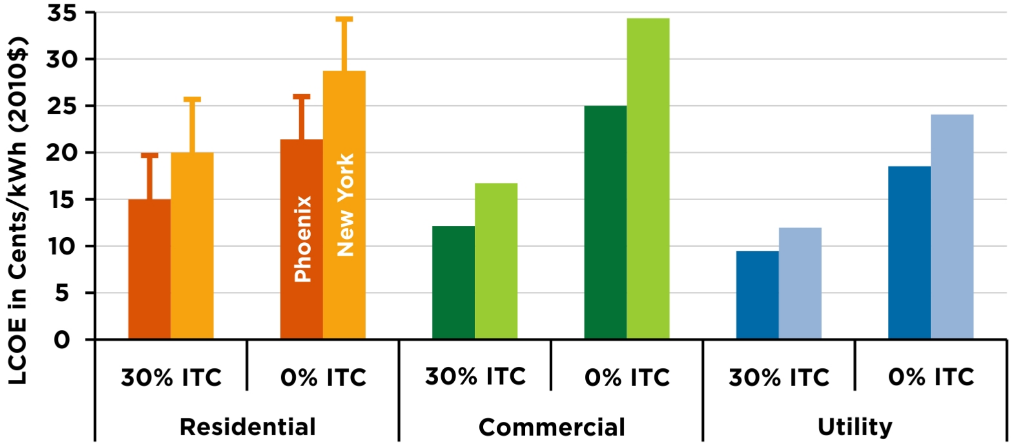
LCOE is the ratio of an electricity-generation system's costs—installed cost plus lifetime operation and maintenance (O&M) costs—to the electricity generated by the system over its operational lifetime, given in units of cents/kilowatt-hour (kWh). The calculation of LCOE is highly sensitive to installed system cost, O&M costs, local solar resource and climate, PV panel orientation, financing terms, system lifetime, taxation, and policy. Thus, PV LCOE estimates vary widely depending on the assumptions made when assigning values to these variables.

Figure 4-5 shows the LCOE for residential, commercial, and utility-scale (1-axis tracking) PV systems as benchmarked above, i.e., priced at roughly $6/W, $5/W, and $4/W, respectively. Because local solar resource is such an important factor, LCOE is calculated in two locations: Phoenix and New York City. Figure 4-5 shows the LCOEs both with and without the 30% federal investment tax credit (ITC). With the ITC, LCOE ranges from $0.15–$0.20/kWh for residential systems, $0.12–$0.17/kWh for commercial systems, and $0.9–$0.12/kWh for utility systems. Without the ITC, LCOE ranges from $0.22–$0.28/kWh for residential systems, $0.25–$0.34/kWh for commercial systems, and $0.18–$0.24/kWh for utility-scale systems.

The LCOEs in Figure 4-5 were calculated using monocrystalline silicon PV performance characteristics[43] and the standard financing assumptions provided in Table 8-1 in Chapter 8. Residential systems are assumed to be fixed tilt and south facing, commercial systems are assumed to be a mix of flat mount and fixed tilt, and

[43] Several PV performance characteristics, such as the temperature sensitivity of cell efficiency, vary across technologies. These differences lead to annual output changes that can affect annualized LCOEs.

Figure 4-5. LCOE for PV Systems in Phoenix (left bars) and New York City (right bars) in 2010, with and without the Federal Investment Tax Credit



Note: For residential systems, mortgage financing is shown on the main bars, and cash purchase is represented by the high error bars.

utility systems are assumed to use 1-axis tracking. Residential and commercial systems are assumed to be owned by the site host, and utility systems are assumed to be owned by an independent power producer (IPP) or investor-owned utility (IOU) that pays taxes on electricity revenues. Even though the installed price of commercial systems is lower than the price of residential systems, the LCOEs are comparable due to multiple factors including higher cost of capital for commercial systems, different performance characteristics, and different tax impacts. Table 4-1 lists other important assumptions used in the LCOE calculations.

4.3 Overview of Strategies for Reducing PV System Prices

The SunShot targets require that the following installed PV system price reductions be achieved by 2020, relative to benchmarked 2010 installed system prices:

- Residential system prices reduced from $6/W to $1.50/W
- Commercial system prices reduced from $5/W to $1.25/W
- Utility-scale system prices reduced from $4/W to $1.00/W.

Figure 4-6 shows the SunShot targets broken out by subsystem prices. The per-watt price of a PV system is directly proportional to the total installed system price and inversely proportional to the system efficiency:

$$\frac{\$}{\text{W}} \propto \frac{\text{Total installed system price (\$)}}{\text{System efficiency (\%)}}$$

Table 4-1. Assumptions for LCOE Calculations

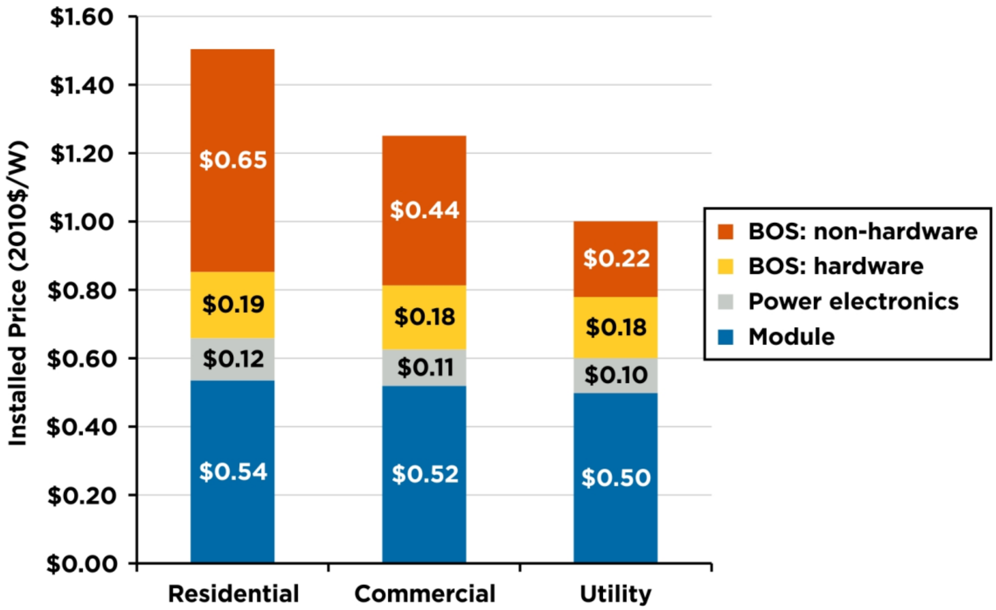
PV Performance and O&M Costs (2010$)	Residential		Commercial		Utility	
	2010 Actual	SunShot Proj.	2010 Actual	SunShot Proj.	2010 Actual	SunShot Proj.
System Lifetime (Years)	30	30	30	30	30	30
Annual Degradation (%)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Inverter Replacement Price ($/W, at time of replacement)	$0.25	$0.12	$0.20	$0.11	$0.17	$0.10
Inverter Replacement Labor[a] ($/inverter, at time of replacement)	$600	$600	$3,000	$3,000	$1,000	$1,000
Inverter Lifetime (Years)	10	20	15	20	15	20
O&M Expenses ($/kW-yr)	$32.8	$10.0	$23.5[d]	$7.5	19.93[e]	$6.5
Pre-Inverter Derate[b] (%)	90.0%	93.0%	90.5%	93.5%	90.5%	93.5%
Inverter Efficiency[c] (%)	94.0%	97.0%	95.0%	98.0%	96.0%	98.0%
System Size (kW-DC)	5.0	7.5	200	300	20,000	30,000

[a] Residential and commercial values for inverter replacement labor costs are based on a 2009 estimate from Standard Solar. Estimates of residential and commercial values for inverter replacement labor costs are also provided by Standard Solar. The utility value is discounted from commercial inverter replacement labor costs due to ground, rather than rooftop, location.
[b] Includes losses in wiring, soiling, connections, and system mismatch.
[c] 2010 inverter efficiencies for residential, commercial, and utility systems are based on data from the California Energy Commission, available at www.gosolarcalifornia.org/equipment/inverters.php.
[d] Based on LBNL (Lawrence Berkeley National Laboratory) (2009). Internal survey of commercial rooftop O&M costs.
[e] Based on average O&M costs at Arizona Public Service's 1-axis tracking PV installations, available at www.resourcesaver.org/ewebeditpro/items/O63F5452.pdf.

Thus, the per-watt PV system price can be reduced by reducing the total installed system price or increasing system efficiency. The total installed system price can be reduced by reducing the price of one or more of the three PV subsystems: PV modules, power electronics, and BOS. System efficiency can be increased by increasing the sunlight-to-electricity efficiency of the PV modules and/or increasing the electrical efficiency of the integrated PV system (including power electronics and wiring losses).

Total installed system price and efficiency are interrelated. For example, high-efficiency PV modules might cost more than lower-efficiency PV modules on a per-watt basis. However, their higher efficiency might reduce non-module costs, e.g., per-watt power electronics and BOS prices could be lower because the amount of

Figure 4-6. Estimated Subsystem Prices Needed to Achieve 2020 SunShot Targets



equipment, labor, and land required per watt of installed capacity is lower with higher-efficiency modules. It is important to consider these tradeoffs and to understand that there are a number of potential PV system pathways (e.g., low-cost, low-efficiency modules versus higher-cost, high-efficiency modules) for reducing total installed PV system prices. The following sections explore the methods for reducing total installed system price and increasing system efficiency via improvements to PV modules, power electronics, and BOS.

4.4 Reducing PV Module Prices

As Figure 4-4 shows, benchmark 2010 PV module prices were about $2.00/W. As Figure 4-6 shows, the SunShot targets for PV module prices are $0.50/W for utility systems, $0.52/W for commercial systems, and $0.54/W for residential systems. Module prices can be reduced by reducing module material, manufacturing, and shipping costs and by increasing module efficiency. This section explores these approaches.

4.4.1 Reducing PV Module Material, Manufacturing, and Shipping Costs

Substantial PV system price reductions have been achieved over the past several decades via reductions in material, manufacturing, and shipping costs. These approaches are discussed below, including historical improvements and potential pathways to the improvements needed to achieve the SunShot targets.

Reducing Material Costs

There are a number of ways to reduce material costs in support of the SunShot targets. The active semiconductor material is a complex and expensive component of most PV modules, accounting for about 60% of c-Si module cost and 8%–22% of CdTe and CIGS module cost (Goodrich et al. 2011a, Woodhouse et al. 2011). The cost of polysilicon for c-Si modules could be reduced by making thinner wafers, minimizing polysilicon losses during the wafering process, improving polysilicon scrap recycling capabilities and costs, and introducing low-cost polysilicon feedstock-purification methods. Replacing c-Si with thin-film and CPV technologies is potentially another way to reduce semiconductor material costs. However, although CPV and thin films use less semiconductor material per watt than c-Si, the materials used can be rare and expensive. Using these materials more efficiently or identifying substitutes that are less expensive, earth-abundant, and non-toxic or recyclable could reduce semiconductor material costs in these technologies.

It will also be important to ensure that the supply of PV feedstock materials remains sufficient to meet demand, since supply constraints can significantly increase feedstock prices. For example, when demand for polysilicon outpaced supply in 2007 and 2008, polysilicon contract prices increased from about $50–$60/kilogram (kg) up to $150/kg, and spot market prices peaked above $500/kg (Mehta 2010).

The front and back cell contacts are another important cost component in c-Si PV modules. PV manufacturers strive to design cells that balance the cost of these materials with their effect on module performance.

Module-encapsulation materials—such as front and back glass, adhesives to bind the layers and the cells, edge seals, and frames—can add considerable cost to PV modules (Mehta and Bradford 2009) and dominate the material costs of many thin-film modules. Cost reductions may be possible via depositing semiconductor material on substrates that are lighter and cheaper than glass and replacing traditional framing material and encapsulation glass with flexible ultra barrier encapsulation material. Again, manufacturers must balance the benefits of using less-expensive materials against resulting effects on module performance and reliability. Other materials to be considered are those used in edge seals, mounting hardware, cell interconnections, bus bars, and junction boxes.

Manufacturers may also be able to reduce materials costs by becoming more vertically integrated. In particular, vertical integration can help manufacturers reduce exposure to volatile market prices and improve the efficiency of handling materials.

Improving Manufacturing Processes

PV manufacturing process improvements stem from mass-production efficiency and labor-reduction strategies analogous to those of any manufacturing operation. In addition, improved manufacturing processes can minimize the cell-to-module losses that occur during the transition from laboratory-scale PV technologies to mass-produced commercial products.

Manufacturing equipment costs, which are frequently characterized in dollars per watt of annual manufacturing capacity, can be estimated from capital expenditure (CapEx) investments, which should not be confused with the per-watt module and system costs. New PV manufacturing facilities are being developed at costs from $1–$2/W (First Solar 2011b, Goodrich et al. 2011a, Woodhouse et al. 2011). Because equipment is depreciated over time (e.g., 7 years), the contribution of CapEx costs to module cost is about one-seventh of the per-watt CapEx costs. For example, a $1.4/W CapEx would add approximately $0.2/W to module costs. There are also additional costs related to the cost of capital for the manufacturer and equipment maintenance costs.

Several factors affect manufacturing cost structure, including speed, yield, labor, and energy prices. Increasing manufacturing speed results in higher throughput and lower capital costs per watt, but often comes as a result of a tradeoff in other categories, such as yield, cell efficiency, and materials costs. Speed can be enhanced by measures such as increasing deposition rates, increasing the width of an in-line reaction chamber, and building large furnaces that can process many substrates at once.

Increasing yield—the proportion of manufactured product that meets commercial specifications—is another way to increase throughput and reduce cost per watt. Crystalline silicon production lines typically operate at yields of at least 93%. However, yields can vary widely depending on the quality of the incoming material, such as wafers, and the desired minimum product quality, such as cell efficiency. Having a wide variation in cell efficiencies would create unacceptable module-stringing losses later. As polysilicon prices have dropped, the use of recycled silicon in casting operations has diminished, increasing the overall quality of materials on the market. The point in the manufacturing process at which defective parts are identified is also critical. Bad parts that are not identified until the end of a process increase costs more than those identified at the beginning or middle of the manufacturing process.

Reducing labor and energy-use requirements also reduces manufacturing costs. Labor costs frequently depend on the maturity of the manufacturing approach and local labor rates. Labor costs are expected to decline as PV matures and manufacturing plants become larger and more automated. Energy use can be reduced by implementing several strategies, including faster processing techniques, lower-temperature processes, and replacing vacuum with non-vacuum processes where possible. Past improvements of this sort have lowered the PV energy payback periods—the length of time the system must operate to match the energy used to make it—to 1–3 years, which has important policy implications. See the discussion of greenhouse gas (GHG) emissions in Chapter 7.

To reach the SunShot price targets, new technologies likely will need to be developed and brought quickly to commercial maturity. Moving technological innovations from the laboratory to commercial production quickly and efficiently will be critical. Potential manufacturing strategies for achieving the SunShot targets include increasing manufacturing throughput, using roll-to-roll thin-film module manufacturing, using high-frequency plasma deposition for thin films, and using atmospheric-pressure liquid washing. Another strategy is to reduce the cost of fabrication equipment and facilities to achieve a CapEx of $0.7/W of annual manufacturing capacity, or lower.

Reducing Module Shipping Costs

The PV industry relies on a global supply chain. As the industry matures, the economies-of-scale advantages captured by large suppliers likely will increase the average distance that a PV product travels from manufacturer to installer. Sea-transport (container) rates are currently at historic lows, and the cost of shipping modules by sea is about \$0.05–\$0.06/W (Goodrich et al. 2011a), adding 5%–10% to module costs. As module costs decrease, shipping costs for some types of module manufacturing could become a more significant factor and may lead to disaggregated manufacturing models, with separate cell manufacturing and module assembly facilities, for example.

Many PV components—including polysilicon, wafers, and cells—can be shipped cheaply due to their low weight and volume and high value. In fact, cells can often be shipped by air to module manufacturing facilities. The glass content of both thin-film and c-Si modules adds the most to shipping costs, because glass is dense and tends to fill a shipping container based on weight rather than volume. Lower-efficiency modules have more glass per watt—and thus cost more to ship—per unit of power.

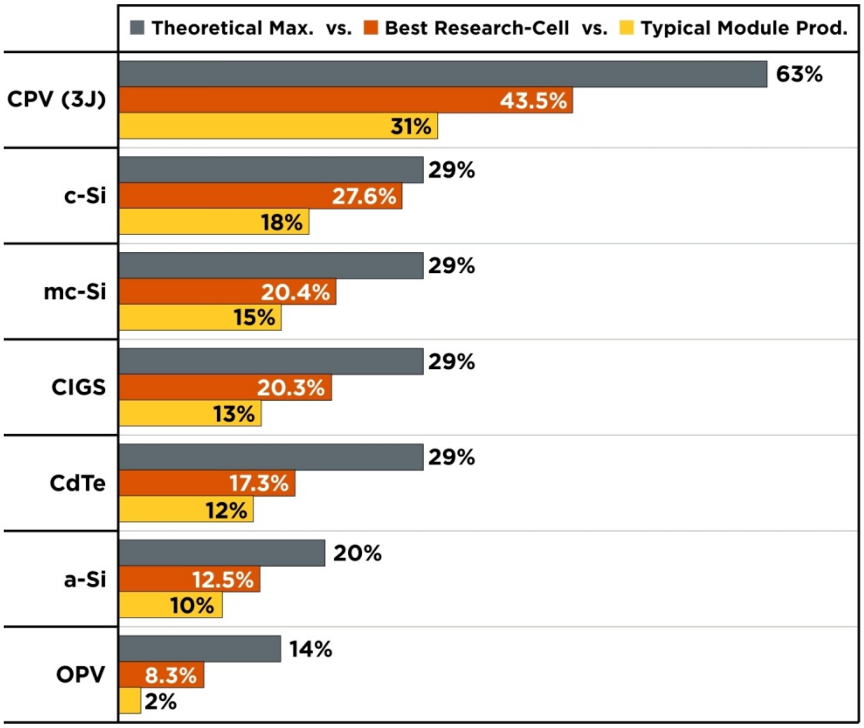
Crystalline silicon module manufacturers frequently have a disaggregated supply chain, where wafers, cells, and modules are manufactured by different companies in different locations. Thin-film manufacturers typically have an aggregated supply chain that is inherent to their device design, where there are no intermediate products. This can be an advantage for reducing c-Si shipping costs: wafer and cell manufacturing can be located in low-cost regions, and module-manufacturing facilities can be sited near end-use markets. This reduces the need to ship glass and encapsulation materials over long distances.

4.4.2 Increasing PV Module Efficiency

Increasing module efficiency is the other major strategy for reducing per-watt module price. Consistent improvements in PV cell efficiency have been realized for virtually every PV technology (Figure 4-2), and module efficiency has followed this trend, albeit with a time and performance lag. This trend is projected to continue, owing to R&D improvements that produce higher best-cell efficiencies and manufacturing technology improvements that advance commercial modules toward best-cell efficiencies. As single-junction PV technologies approach the theoretical (Shockley-Queisser) efficiency limit for their respective semiconductor materials, the extent to which further cost reduction may be attributable to efficiency gains will be reduced, and more substantial cost reductions will need to be realized via other avenues. Nevertheless, as shown in Figure 4-7, there is still significant room for efficiency improvements for many PV technologies.

Module efficiencies greater than 25% (with much of this efficiency maintained for a 30-year module lifetime) may be required to achieve the SunShot PV system price-reduction targets. Multi-year, even multi-decade, R&D programs—such as the U.S. Department of Energy (DOE) Thin Film PV Partnership, which drove several of the improvements shown in Figure 4-2—have improved the industry's understanding of PV technologies and helped develop this knowledge into commercial products. Additional R&D efforts will be required to increase laboratory PV efficiency and to

Figure 4-7. Closing the Gap: Production, Laboratory, andTheoretical (Maximum) PV Module Efficiencies



Source: NREL

transition high-efficiency laboratory technologies to large-scale commercial production.

R&D must support the many stages leading to commercialization: proof of concept, prototype development, product and process development, demonstration-system deployment, and commercialization/scale-up. A substantial base of scientific knowledge exists for c-Si PV technologies, largely owing to integrated circuit R&D, but such a base is still being developed for other leading PV technologies. This current advantage for c-Si PV is true for materials, interfaces, processes for making and altering PV devices, advanced PV device layers, device scale-up from square inches to square meters, and process scale-up to square miles of annual output at high yield. Additional challenges include maintaining or improving device efficiency, device stability, and process stability. Several key R&D issues are discussed below.

Interfaces

Many of the most critical issues of PV device performance and reliability occur at interfaces such as the device junction, back contact, front contact, and between various additional layers that modify device behavior, such as light and carrier reflectors. Examples of critical interface challenges include the following:

- Recombination of free carriers within the junction region of high-efficiency PV devices

- Poor, non-ohmic contacting and instability to high-work-function, resistive p-type material such as CdTe
- The physics, chemistry, and stability of grain boundaries in multicrystalline semiconductors
- The adherence and lifetime of semiconductor/encapsulant and thermal interface materials
- The numerous interfaces resulting from the use of different materials that respond to different parts of the spectrum in multijunction cells.

There is a need for increasing the fundamental knowledge around the interfaces of a PV device. Although most work to date has been empirical, there is an opportunity to use more sophisticated R&D tools and expertise to better understand the optical, electrical, mechanical, and chemical properties of these interfaces.

Performance of Large-Area PV

Sophisticated computational models, tools, and analysis could assist in the correlation of processing parameters with fundamental device physics to accelerate research and commercial product development. One opportunity for existing silicon- and thin-film-based modules is the further exploration of material parameter space for optimizing electronic and optical properties. Another is the development and employment of *in situ* process controls and in-line metrology and diagnostics for improved manufacturing yield.

Degradation Science

An improved understanding of degradation mechanisms in devices and protective materials would allow for further improvements that can increase module lifetimes and further reduce PV LCOE. It is important to increase understanding in the following areas:

- Photochemical degradation
- Dielectric breakdown
- Leakage current in the presence of water and oxygen
- Impurity diffusion processes in semiconductors and through interfaces, especially in large-area devices (which have inevitable compositional variations in all dimensions).

Well-designed stress tests are needed to define and test degradation mechanisms, as are parallel accelerated lifetime models that correlate these new tests with actual outdoor performance through many decades. Also, better qualification tests would standardize PV performance metrics and drive reliability improvements.

The above list is not all inclusive, and there are several technology-specific R&D challenges. For example, thermal management of CPV devices will be important for optimizing performance and durability under the high-operating temperatures common with concentrating solar devices.

Long-Term, High-Potential R&D

R&D funding for universities, companies, and national laboratories to explore non-traditional, high-potential PV technologies promotes innovation and the development and expansion of future PV technology. This R&D funding also expands the pool of scientists and engineers with PV expertise, of which there is a critical shortage.

The PV research community is exploring a portfolio of promising new materials in the category of abundant, non-toxic, easily processed inorganic semiconductors for direct-bandgap thin-film cells. Wadia et al. (2009) highlighted these novel R&D efforts. Subsequent to this study, there has been renewed interest among the basic science community in exploring underdeveloped materials for PV such as metal oxides and metal sulfides for new PV absorbers. Such long-term efforts build on lessons learned from developing the existing, successful direct-bandgap inorganic thin films and could open up new avenues for low cost while avoiding issues of toxic materials and material availability.

Beyond new materials, there are new PV device concepts that could reduce costs. Examples include organic, nanostructured, and dye-sensitized cells, which are in early stages of commercial development (see Section 4.2.2). They offer the potential for lower module costs through use of less-expensive materials and simpler processing. However, there have been challenges in attaining high efficiency and long-term reliability with the materials that have been used to date.

4.5 Reducing Power Electronics Costs

Power electronics include inverters, which convert DC electricity produced by the PV module into AC electricity used by the grid, and transformers, which step the electricity up to the appropriate voltage. These are often combined into a single integrated device and referred to as the inverter.

As Figure 4-4 shows, benchmark 2010 inverter prices were about $0.20/W–$0.30/W for utility systems and about $0.40/W for residential and commercial systems. As Figure 4-6 shows, the SunShot targets for power electronics prices are $0.10/W for utility systems, $0.11/W for commercial systems, and 0.12/W for residential systems. Power electronics prices can be reduced via exploiting economies of scale, developing advanced components, improving reliability, and enabling smart grid integration. Specific power electronics strategies that may be needed to achieve the SunShot targets include the following:

- Solving fundamental power electronics problems at the component level that can be leveraged by advances across multiple industries.
- Reducing the cost of advanced components (e.g., silicon carbide and gallium nitride), which will reduce the size and cost of the magnetic materials (and other components) traditionally used in power electronic inverters and converters.
- Addressing reliability failures due to the thermal cycling of materials with different coefficients of thermal expansion.

- Developing technologies that allow high penetrations of solar technologies onto the grid (e.g., reactive power, energy storage, and advanced functionalities).
- Developing PV system technologies that reduce overall BOS costs (e.g., high-voltage systems).
- Developing technologies that harvest more energy from the sun (e.g., maximum power point tracking and micro-inverters).
- Integrating micro-inverters into modules, reducing installation effort and achieving further cost reductions through mass production.

4.6 Reducing Balance-of-Systems Costs

BOS comprises the non-module, non-power electronics components and procedures required to produce a complete PV system. "Hard" BOS elements include support structures (including trackers), mounting hardware, wiring, monitoring equipment, shipping, and land. "Soft" BOS elements include system design and engineering, customer and site acquisition, installation, permitting, interconnection and inspection, financing, contracting, market-regulatory barriers, and operation and maintenance.

As Figure 4-4 shows, benchmark 2010 BOS prices were about $2.00/W for utility systems, about $2.40/W for commercial systems, and about $3.00/W for residential systems. As Figure 4-6 shows, the SunShot targets for BOS prices are $0.40/W for utility systems, $0.62/W for commercial systems, and $0.84/W for residential systems. BOS prices can vary substantially based on the size and type of PV system, its location, and profit margins. Specific BOS strategies that may be needed to achieve the SunShot targets include the following:

- Hard BOS
  - Improve supply chains for BOS components
  - Develop high-voltage systems
  - Develop racking systems that enhance energy production or require less robust engineering
  - Integrate racking and mounting components in modules
  - Develop innovative materials (e.g., steel or aluminum alloys designed specifically for solar industry applications) for applications such as lightweight, modular mounting frames
  - Create standard packaged system designs
  - Develop building-integrated PV (BIPV) to replace traditional roofing and building facade materials.
- Soft BOS
  - Identify strategies for streamlining permitting and interconnection processes and disseminate best practices to a broad set of jurisdictions
  - Develop improved software design tools and databases
  - Address a wide range of policy and regulatory barriers, as well as utility business and operational challenges
  - Streamline installation practices through improved workforce development and training, including both installers and code officials

- Expand access to a range of business models and financing approaches
- Develop best practices for considering solar access and PV installations in height restrictions, subdivision regulations, new construction guidelines, and aesthetic and design requirements
- Reduce supply chain margins (profit and overhead charged by suppliers, manufacturers, distributors, and retailers); this is likely to occur as the PV industry becomes more mature.

4.7 SunShot versus Evolutionary-Roadmap PV System Price Projections

Before the SunShot Initiative was launched, modeling was performed to project the effect of aggressive—but incremental/evolutionary—PV system improvements to today's dominant PV technologies: c-Si and CdTe. This section compares the PV price projections from this evolutionary roadmap with the more aggressive SunShot price targets.

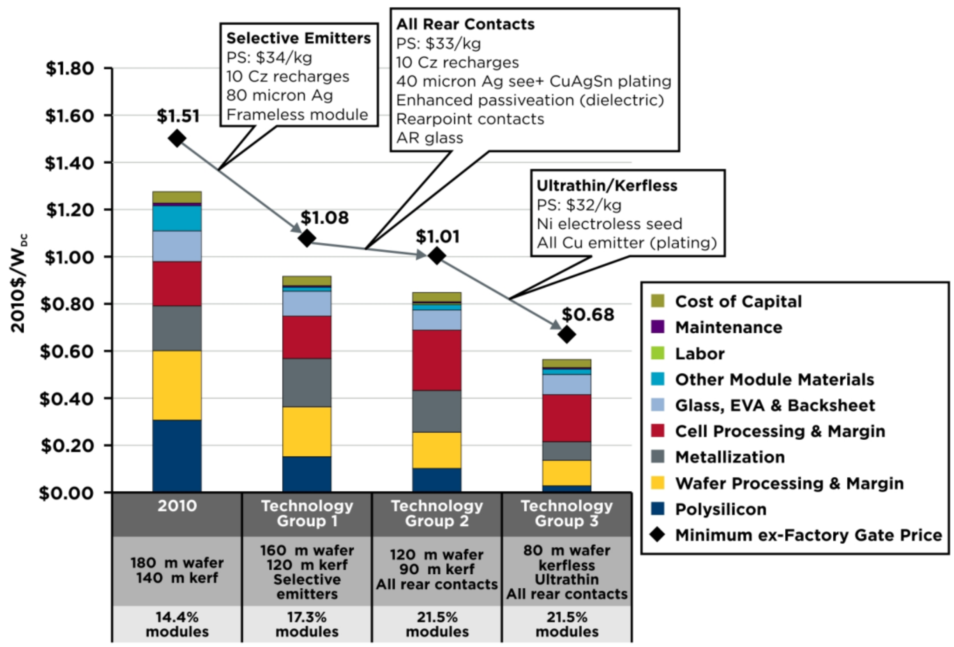
To develop the evolutionary roadmap, NREL created detailed models, in collaboration with industry stakeholders, to quantify residential and commercial distributed (residential and commercial rooftop) and utility-scale (ground-mounted) PV installation prices. Because the results of these models were validated against industry input for current installation prices, the models could be used to estimate future installed system prices. Forecast system prices considered a range of assumptions, including a range of inverter (0%–66%), installation materials (0%–50%), and installation labor (0%–50%) cost or content reductions. Further, in the case of residential and commercial rooftop installations, it was assumed that, over time, competition and industry growth would reduce installer overhead and margins for all sectors to ranges typical of a mature electrical contractor service business (i.e., 16% for residential and 10% for commercial).

Projected PV module price reductions were a primary part of the evolutionary roadmap modeling effort. Figure 4-8 shows a modeled pathway to c-Si module cost reductions. The modeling showed that evolutionary improvements could lead to industry median c-Si modules with an ex-factory gate price of about $1.01/W by 2020 ("Technology Group 2" in Figure 4-8) (Goodrich et al. 2011a). Importantly, it was estimated that this price could be achieved along with a substantial increase in median production module efficiency, to 21.5%—equivalent to a production cell efficiency of approximately 24%. Increasing module efficiency reduces many system costs.

Figure 4-9 shows the system-level results of the evolutionary roadmap modeling. The projected PV system prices are based on forecasted lower cost limits and upper efficiency limits for c-Si and CdTe modules, as well as the range of non-module cost improvements discussed above. The 2010 benchmarks and SunShot PV system price targets are also plotted on Figure 4-9 for comparison.[44]

[44] The official SunShot price targets are $1.5/W for residential systems, $1.25/W for commercial systems, and $1/W for utility-scale fixed-mount systems. Tracking PV systems could have slightly higher costs and still reach comparable LCOEs. As discussed in Chapter 3, $1/W tracking PV systems were modeled for the SunShot scenario, but this is not to imply that 1-axis tracking systems will dominate all markets; the types of mounting/tracking technologies deployed likely will vary regionally.

Figure 4-8. Evolutionary Module Manufacturing Cost Reduction Opportunities
C-Si PV



PS: polysilicon
Ag: silver
Cz: Czochralski
Cu: copper
Sn: tin
AR: anti-reflection
EVA: ethylene vinyl acetate

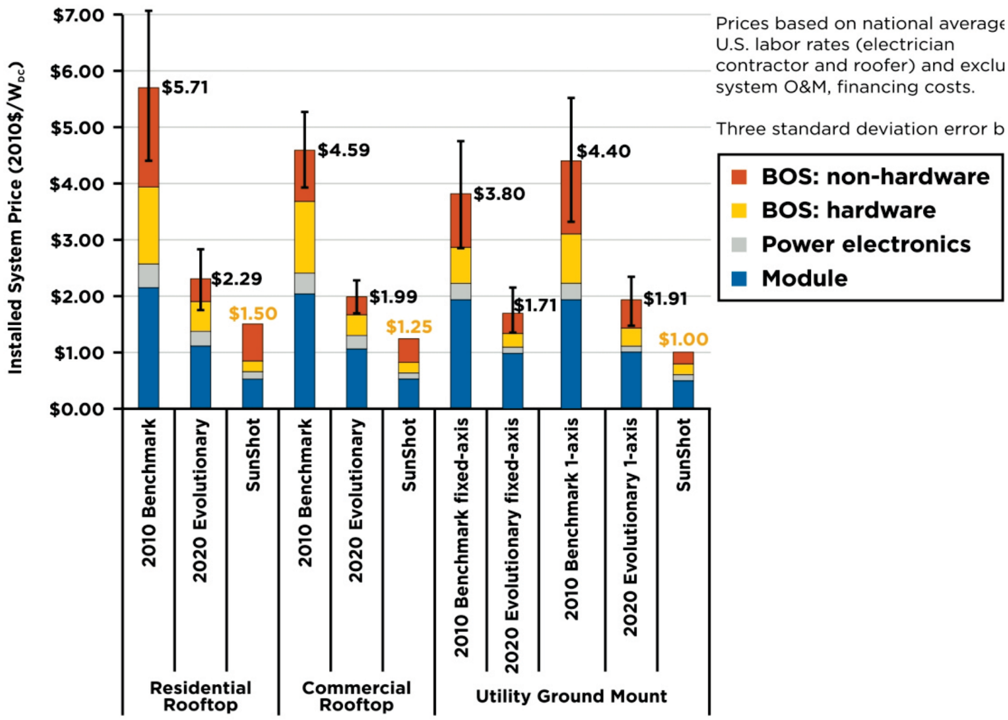
Source: Goodrich et al. (2011a)

Under the evolutionary roadmap assumptions, the installed price of utility-scale PV systems could reach about $1.70–$1.90/W by 2020.[45] Although CdTe has a steeper module price-reduction trajectory and lower estimated module average selling-price limit, CdTe systems have higher non-module costs relative to c-Si owing to lower module efficiency and smaller module size. Residential and commercial installed system prices are projected to reach about $2.30/W and $2.00/W, respectively, by 2020. All of these projected prices are well above the SunShot targets. Even assuming a more optimistic evolutionary module price reduction ($0.68/W, "Technology Group 3" in Figure 4-8), the evolutionary system prices would still be well above the SunShot targets.

The key insight gained through this analysis is that evolutionary change is not likely to be sufficient to reach the SunShot price-reduction targets via today's dominant technologies (single-junction c-Si and CdTe). Instead, reducing the installed price of PV systems by roughly 75% likely will require significant technological improvements, such as, through the acceleration of innovative technologies into the

[45] See Appendix C for several sensitivity analyses which explore deployment projections based on different cost assumptions for solar and other technologies.

Figure 4-9. Installed PV System Prices: 2010 Benchmark, Projected 2020 Evolutionary, and 2020 SunShot Target[46]



Source: Goodrich et al. (2012)

marketplace and the pursuit of more radical change by developing new, R&D-driven PV technologies.

For example, multi-junction device architectures theoretically could achieve much higher efficiencies than single-junction c-Si and CdTe; however, to be viable in the marketplace, they would need to do so at a competitive cost structure. Alternative module configurations, such as flexible encapsulation of thin films, could also offer pathways to the SunShot price-reduction targets. Such pathways are important to consider because they leverage the experience of researchers and manufacturers gained over each technology's long history. The actual technological pathways to revolutionary PV improvement are not known today—continued R&D and sustained focus on meeting the price-reduction targets will be necessary to identify and realize these pathways.

[46] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on CdTe were also considered.

4.8 SunShot LCOE Projections

Figure 4-10 shows the LCOEs resulting from achieving the SunShot installed PV system prices. These LCOEs are calculated using assumptions about O&M expenses, inverter efficiencies, and derate factors (due to losses in wiring, diodes, or shading) as provided in Table 4-1. Moreover, Figure 4-10 represents LCOEs with no ITC and no state, utility, or local incentives. The financing assumptions are the same as those listed in Table 8-1 in Chapter 8. Finally, three locations—Phoenix, Kansas City, and New York City—and a number of system orientations are used to represent a range of PV LCOEs.

Figure 4-10. SunShot PV LCOEs by Year and Market Segment[47,48]

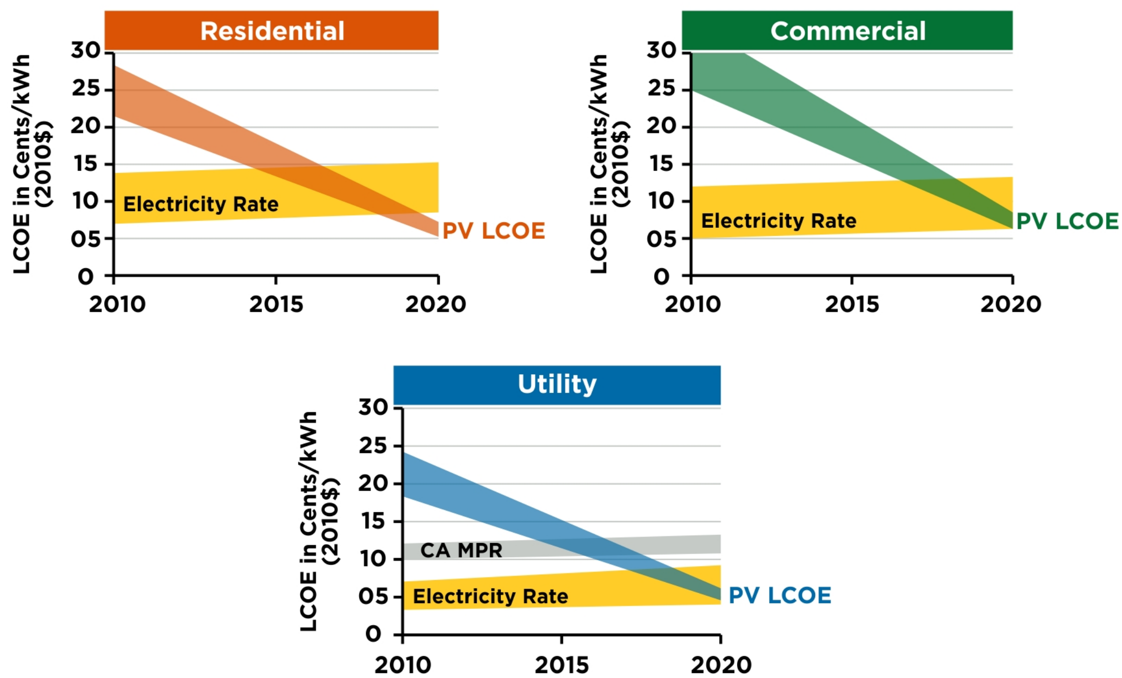


Figure 4-10 shows that, assuming the SunShot targets are met by 2020, residential PV is projected to be increasingly competitive with residential electricity rates, commercial PV is projected to be increasingly competitive with commercial electricity rates, and utility-scale PV is projected to be increasingly competitive with wholesale electricity rates. Utility-scale PV LCOEs become competitive with California's Market Price Referent (MPR), which is used as a benchmark to assess the value of renewable generation in California (CPUC 2011), by 2015 at higher

[47] Note that commercial systems assume site-host ownership, in contrast to utility systems, which are owned by IPPs or IOUs and pay taxes on electricity revenue. However, the apparent tax advantage of site ownership is reduced by the fact that for-profit commercial entities may deduct electricity expenses from their taxable income. Thus, the LCOE of a site-owned commercial system must be compared to the after-tax commercial electricity rate.

[48] The electricity-rate range represents one standard deviation below and above the mean U.S. electricity prices for the respective market segment, including residential, commercial, and utility. The California Market Price Referent (MPR) is in real terms and includes adjustments by utility for the time of delivery profile of solar.

costs than those targeted in the SunShot scenario. This illustrates that, while achieving SunShot price targets will allow PV to compete broadly with conventional generation in several U.S. markets, PV will become competitive in some markets more quickly and at higher prices.

4.9 MATERIALS AND MANUFACTURING RESOURCES

The SunShot scenario reaches 302 gigawatts (GW) of cumulative PV capacity by 2030 and 632 GW by 2050. To achieve this, annual U.S. PV installations will stabilize at about 25–30 GW per year (see Chapter 3). Satisfying these high levels of demand will increase the PV industry's raw materials requirements significantly and require rapid expansion of manufacturing capacity. Essential raw materials include polysilicon feedstocks for c-Si PV technologies and relatively rare elements for several thin-film and CPV technologies. This section evaluates the materials and manufacturing challenges to meeting SunShot PV demand.

4.9.1 RAW MATERIALS REQUIREMENTS

Raw material availability can become a concern when there is a supply/demand mismatch or a material shortage. These two conditions are discussed below.

Supply/Demand Mismatch

A supply/demand mismatch is a temporary market imbalance resulting in a shortage of available material due to a lack of exploration, extraction, or refining efforts—even when the basic accessibility of the underlying material is presumably not a problem. An example of this type of mismatch in the PV sector is the recent shortage of polysilicon feedstock, which occurred because demand for polysilicon-based modules rose more rapidly than polysilicon production capacity.

Although the polysilicon shortage has dissipated over the past few years, it is useful to examine its causes. The delay between perceiving the opportunity and increasing polysilicon production resulted from the time and expense required to build, start up, and qualify a new polysilicon plant. From initiating plant construction to beginning qualified production, it takes 2–3 years and costs hundreds of millions of dollars. This constraint on response time was further exacerbated by the lack of vertical integration within the industry as cell manufacturers had to wait for producers to respond to the market signals of increased demand. Lower capital-cost processes such as the use of thinner silicon wafers and less-refined, solar-grade silicon could help mitigate this type of imbalance in the future (provided that the most successful cell architectures will still not require the higher-quality material and that the yield losses from thinner wafers are still acceptable).

Such a temporary supply/demand mismatch is familiar to other industries and is likely to remain a part of the PV landscape as it evolves. Better planning can help to minimize these types of disruptions but cannot eliminate them completely in the future.

Material Shortage

A more serious challenge is a fundamental shortage of raw material availability. For example, a shortage can occur when not enough material is being mined, when material cannot be economically mined at prices the PV industry can support, or when competing uses can afford higher prices for the material. Prices can rise significantly long before supply is truly exhausted, which incentivizes the exploration and development of new supply and helps balance demand for each technology.

There are five main ways that material constraints can be mitigated:

- Increase ore extraction and refining—both the amount and material extraction efficiency
- Increase PV efficiency
- Reduce the thickness of semiconductor layers in PV devices
- Improve process utilization and in-process recycling
- Recycle semiconductor materials at the end of module life.

Crystalline silicon feedstocks are virtually unlimited. However, silver, which is currently used for contacts, has some limitation. If different contact materials are used, such as nickel-copper (which is currently under development), the c-Si supply is virtually unconstrained. The glass, steel, and aluminum used as encapsulation and support structures are not subject to rigid supply constraints, but their costs will be tied to changing commodity prices.

Material shortages are a concern for several semiconductor materials used in some thin-film, concentrating, and emerging PV technologies: tellurium in CdTe; indium, selenium, and gallium used in CIGS; indium, germanium, and gallium used in some III-V multijunction cells; and ruthenium, sometimes used in dye-sensitized PV cells. Conductive materials may also be a concern in the longer term, including molybdenum used for CIGS PV contacts. Of these, the primary concerns are the tellurium supply for CdTe and the indium supply for CIGS; thus, this discussion focuses on these two materials.

In its *Critical Materials Strategy*, DOE (2010) estimated current (2010) and projected (2015) supplies of several materials, including tellurium and indium. It estimates 2010 tellurium production at 500 metric tons (MT)/yr and projects it to rise to 1,220 MT/yr in 2015 based on assumptions about increased production from copper anode slimes. It also estimates that global tellurium production could increase four-fold by 2020 due to increased production from copper anode slimes, assuming copper refiners do not move away from electrolytic processing (to promote larger tellurium supplies, the PV industry could incentivize an increased use of electrolytic copper refining). Copper production historically has grown by about 3% per year (ICSG 2006) and is, with planned new capacity additions, projected to grow around 4.5% per year from 2011–2014 (Edelstein 2011). According to Ojebuoboh (2008), the efficiency of tellurium extraction from copper could increase substantially, although the impact on tellurium prices is unknown. Mining of tellurium ores and recovery of tellurium from gold concentrates are additional potential tellurium sources (DOE 2010, Green 2009). The cost of alternative tellurium sources and extraction techniques is not well known. However, the cost of recovering any element is inversely proportional to its concentration (Green 2009). Therefore, tellurium costs are likely to increase if the industry shifts to these new sources.

Indium is a relatively rare coproduct of zinc refining. Nearly all of the indium supply is used in thin-film coatings, such as in the production of indium tin oxide for flat-panel liquid-crystal displays, which could present a challenge to the PV industry because other uses could potentially accommodate a higher indium price. The *Critical Materials Strategy* estimates the 2010 indium supply at 1,345 MT/year (yr) (480 MT virgin and 865 MT reclaimed) (DOE 2010). It estimates 2015 indium supplies could increase to 1,612 MT/yr based on increased recovery from additional zinc production and recycling.

CPV modules frequently use indium and gallium but do not face the same resource limitations as flat-plate PV technologies. Optical concentration reduces the amount of semiconductor material required by a factor nearly equivalent to the concentration ratio.

Table 4-2 summarizes how reduced material requirements and increased tellurium and indium availability could increase potential PV production capacity for CdTe and CIGS PV technologies.[49] Under the SunShot scenario, annual U.S. PV installations could reach 27 GW/yr by 2030. If global PV penetration roughly follows SunShot-like trajectories, global PV demand could reach well over 100 GW/yr by 2030. Table 4-2 shows that, at current material requirements and availability, the ability of tellurium- and indium-dependent PV technologies alone to meet projected U.S. and global demand would be limited. However, with reduced materials requirements, even current tellurium and indium availability could enable these technologies to play a substantial role in satisfying projected demand, and the projected increase in tellurium and indium availability is substantial even in the 2015 time frame. Availability could increase even further by the time annual U.S. SunShot demand is in the 20–30 GW/yr range and global demand is on the order of 100 GW/yr. Of course, competing uses of these materials will reduce the amounts available for PV. See DOE (2010) for long-term tellurium and indium demand scenarios and additional discussion about materials availability.

4.9.2 Manufacturing Scale-Up

The PV industry is currently expanding its manufacturing capacity to meet growing demand. This has been helped, in large part, by new market entrants bringing manufacturing and supply chain management experience from other successful industries, including computers, semiconductors, and liquid crystal displays. The expansion has also been aided by improved manufacturing throughput, based on technology improvements and efficiency gains. The annual production capacity of PV manufacturing lines has typically increased by an order of magnitude over the last decade, from tens to hundreds of megawatts per year.

[49] Because of the success of cadmium telluride (CdTe) in the marketplace, the amount of CdTe production potential has been examined by a number of investigators (Green 2006, Green 2009, Feltrin and Freundlich 2007, Ojebuoboh 2008, Fthenakis 2009).

Table 4-2. Potential Annual PV Capacity Supply Based on Current and Potential PV Material Requirements and Material Availability

Material	PV Type	Material Requirement (MT/GW)[a]	Material Availability (MT/yr)[b]	Potential PV Capacity (GW/yr)
Current (2010) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	60–90	500	**6–8**
Indium	CIGS	52	1,345	**26**
Reduced (Future) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	19	500	**26**
Indium	CIGS	5	1,345	**270**
Reduced (Future) Material Requirements and Increased (2015) Material Availability				
Tellurium	CdTe	19	1,220	**64**
Indium	CIGS	5	1,612	**320**

[a] The reduced material requirement estimates listed here are not projected to a specific year, e.g., not to 2015. Rather, they represent estimates of practical minimum limits on tellurium and indium requirements for CdTe and CIGS PV technologies. Accelerated R&D may reduce the time required to reach these levels.

Current CdTe production module efficiencies have been demonstrated to be as high as 11.7% (First Solar 2011a), with CdTe layers that are 2–3 µm thick (Green 2011). Process materials use is about 90% for current CdTe module production techniques (with in-process recycling), which implies tellurium requirements of about 7–10 grams (g)/m^2 and, correspondingly, 60–90 MT/GW of tellurium. According to Woodhouse et al. (2011), if R&D-driven improvements could increase CdTe efficiency to 18% and decrease layer thickness to about 1 µm—roughly the amount of semiconductor thickness needed to efficiently fully absorb the solar spectrum (without significant drops in photocurrent)—tellurium requirements could drop to 19 MT/GW.

The CIGS indium requirements are from Goodrich et al. (2011b). The 2010 CIGS (coevaporation technique) indium requirement of 52 MT/GW is based on current estimates of material yield losses, 10% module efficiency, and a 1.5-µm absorber. The reduced CIGS indium requirement of 5 MT/GW includes estimated material yield losses, 20.8% module efficiency, a 1.0-µm absorber, and a high gallium-to-indium ratio.

[b] Current/2010 and increased/2015 material availability are from DOE (2010); although this report does not project longer-term tellurium and indium availability, availability may be higher beyond 2015. The large projected increase in tellurium availability between 2010 and 2015 is based, in part, on assumptions about greatly increasing the rate of tellurium recovery from copper refining; the added cost of this increased recovery rate is unknown, thus it is unknown whether the process will prove economically viable.

The need to scale up PV manufacturing capacity will not limit PV deployment under the SunShot scenario. For example, global PV manufacturing capacity has grown from 1.4 GW/yr in 2004 to 22.5 GW/yr by the end of 2010 (Mints 2011). Given that U.S. PV manufacturing capacity at the end of 2010 was 1.4 GW/yr, expanding U.S. PV production to 27 GW/yr over the next 20 years under the SunShot scenario is very realistic. The capital equipment and land costs required to build a 1-GW/yr PV manufacturing facility has been estimated at $1–$3 billion for c-Si (Mehta and Bradford 2009), and has been reported to be as low as $0.64/W for CdTe (First Solar 2010). Thus, the cost of building new PV manufacturing capacity should not limit SunShot-scale deployment.

That said, supply chain planning and clear market signals are needed to enable the required scale-up. For an “emerging” technology such as PV, strong and consistent government policy support can help to create initial demand. Prospective PV investors and manufacturers must see a clear market-growth pathway before committing the substantial resources needed to scale up production capacity and output.

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