4. Photovoltaics: Technologies, Cost, and Performance

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4. Photovoltaics: Technologies, Cost, and Performance

4.1 Introduction

The Solar Vision evaluates the technical and economic implications of meeting 10% and 20% of U.S. electricity demand using solar technologies by 2030, about half with photovoltaics (PV) and half with concentrating solar power (CSP). PV markets would have to see very strong growth in the U.S., from just over 1 gigawatt (GW) of installed capacity in 2010 to several hundred GW by 2030. Although this represents significant market growth, both the magnitude and pace are feasible based on recent global growth trends and will not be constrained by the availability of materials, land, or manufacturing scale-up.

Achieving steady PV cost and performance improvements is essential to rapid PV market growth. PV technologies have been demonstrated commercially since the early 1970s and have undergone continual R&D-driven cost and performance improvements. All PV technologies have benefitted from significant cell efficiencies improvements and cost reductions, particularly during the past decade. Mature PV technologies—such as crystalline silicon, cadmium telluride (CdTe), and amorphous silicon (a-Si)—have been manufactured and deployed at the GW scale. These technologies have clear pathways to achieving significant cost reductions, with evolutionary technology improvements and more efficient manufacturing methods, reduced supply chain inefficiencies, and benefitting from economies of scale as markets continue to grow and mature. Several emerging PV technologies—including copper indium (gallium) diselenide (CIS or CIGS) and concentrating PV (CPV)—have seen an accelerating pace of capital investment which is moving these technologies toward full-scale production.

In the United States, federal and state government incentives have made PV an attractive investment in markets ranging from residential and commercial rooftops, to distributed and central wholesale markets. These incentives have accelerated PV cost and performance improvements, and stimulated private investment supporting PV R&D and manufacturing scale-up. As PV costs continue to decline, unsubsidized PV electricity will be able to compete directly with retail electricity rates in rooftop markets and wholesale electricity rates in utility markets, especially in regions with a good solar resource and high electricity rates like California. In addition to becoming cost competitive, distributed utility-scale (also referred to as wholesale distributed generation) PV can be sited near load centers, thus reducing grid congestion and the need for costly transmission and distribution infrastructure.

This chapter evaluates the current cost, performance, and potential of several PV technologies. A detailed, bottom-up engineering analysis identifies opportunities for continued PV cost reductions, and these are compared with historical trends and industry roadmaps. Key challenges to achieving Vision PV penetration targets are evaluated including manufacturing scale-up, and the supply and cost of feedstock materials. This analysis makes clear that continued cost reductions and research and development (R&D) investment will be essential to reaching Vision growth targets, but no technology breakthroughs will be required. The market growth outlined in Vision scenarios could be reached using today's demonstrated PV technology, and the successful development and demonstration of emerging PV technologies would enable reaching Vision targets at lower cost.

4

4.2 TODAY'S PV TECHNOLOGY

Today's PV technology is the result of decades of performance and price improvements. This section describes the history of these improvements and the current status of PV technology.

4.2.1 PARTS OF A PV SYSTEM

PV systems are typically classified into two subsystems for the purposes of understanding technologies and costs: PV modules and balance of systems (BOS)[1]. PV modules are fabricated from several interconnected PV cells, which convert sunlight directly into electricity. PV cells are fabricated from semiconductor materials that enable photons 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 and thin films with semiconductor-like properties (e.g. amorphous silicon, CdTe, and CIGS). For additional detail on the physics of PV cells, there are several good references such as *Luque & Hegedus* (2003).

The DC electricity generated by the PV module is frequently converted to alternating current (AC) electricity using an inverter, and stepped-up to the proper voltage for customer use or export to the grid using a transformer. The components associated with this delivery process, such as inverters, transformers, electrical protection devices, wiring, and monitoring equipment, are all a part of the BOS. In addition, the BOS also includes structural components for installing PV modules, which include fixed mounting frames and sun-tracking systems.

4.2.2 PV MODULE TECHNOLOGIES

Several crystalline silicon and thin film PV technologies have been demonstrated commercially on a large scale. Concentrating PV (CPV) has yet to reach the same level of market penetration but offers potential cost and performance advantages. Additionally, several emerging PV technologies may be technically and economically competitive in the future.

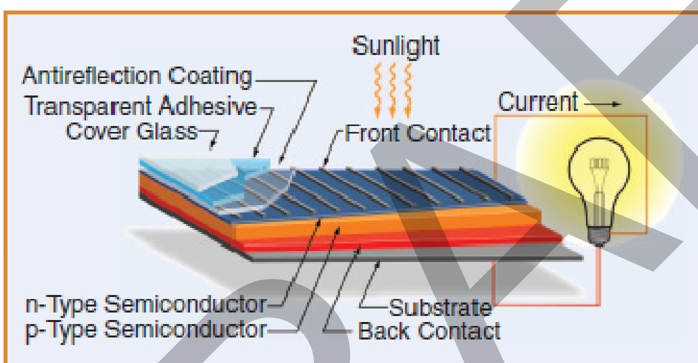
[1] BOS is sometimes limited to mounting and wiring hardware and does not include the inverter, labor or permitting fees. Here and elsewhere in the Vision study, BOS refers to the inverter, mounting and wiring hardware, installation, and permitting fees.

Crystalline Silicon

Crystalline silicon technologies constitute about 85% of the current PV market. This type of module has demonstrated operational lifetimes of more than 25 years.

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 PV wafers are cut from directionally solidified blocks or grown in thin sheets. 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 cells, (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 Silicon PV Cell (NREL)



Although standard cell architectures dominate the market today, non-standard architectures are growing in importance because they offer the potential for significantly higher efficiency. The rated DC efficiencies of standard crystalline silicon PV modules are approximately 13%–15%. Non-standard cell architectures tend to use high-quality monocrystalline wafers and more sophisticated processing to achieve module efficiencies of approximately 17% to 19%.

Thin Film

Thin film PV cells consist of a semiconducting layer—most commonly CdTe, a-Si, or alloys of CIGS—a few microns thick, which is about 100 times thinner than crystalline silicon cells. This layer is typically deposited on a low-cost substrate inside a vacuum chamber. A number of firms are pursuing lower cost non-vacuum approaches for manufacturing thin film technologies. Glass is a common substrate, but thin films can also be deposited on flexible substrates such as metal or plastics, which can be incorporated into building materials. Thin film modules have lower peak DC efficiencies than crystalline silicon modules: approximately 9%–11% efficiency for CdTe, 8%–12% efficiency for CIGS, and 6-8% efficiency for a-Si. Among the thin films, CdTe has experienced significantly higher market growth over the last decade than the other thin film technologies.

Concentrating PV

CPV technologies use mirrors or lenses to concentrate sunlight 2–1,500 times onto a high-efficiency silicon or multijunction[2] PV cell. The use of inexpensive materials such as glass and steel to focus sunlight reduces the amount of semiconductor material required for a given unit of output. Recent improvements in the efficiency of multijunction PV cells (over 40%) offer the potential for very high power density. There is renewed interest, and investment, in CPV for utility-scale applications.

Noncommercial PV Options

A number of other PV materials—frequently referred to as third-generation PV—are being developed. Dye-sensitized solar cells use dye molecules in an electrolyte solution to absorb solar radiation and have demonstrated efficiencies up to 12%. Organic solar cells, based on plastics with semiconductor properties, have demonstrated laboratory efficiencies up to about 8%; organic modules have the potential for low-cost manufacturing using existing printing and lamination technologies (Shaheen et al. 2005). Challenges to commercialization of organic and dye-sensitized cells include the absorber layer's degradation rate and heightened moisture barrier requirements. Quantum dots—nanospheres with physical properties similar to both semiconductors and molecules—absorb solar radiation at multiple frequencies but have not yet been used to produce efficient PV cells. Each of these technologies could be a source of low-cost PV cells in the future. However, the Vision study only evaluates cost and performance improvements for commercially proven technologies.

4.2.3 PV Performance and Price

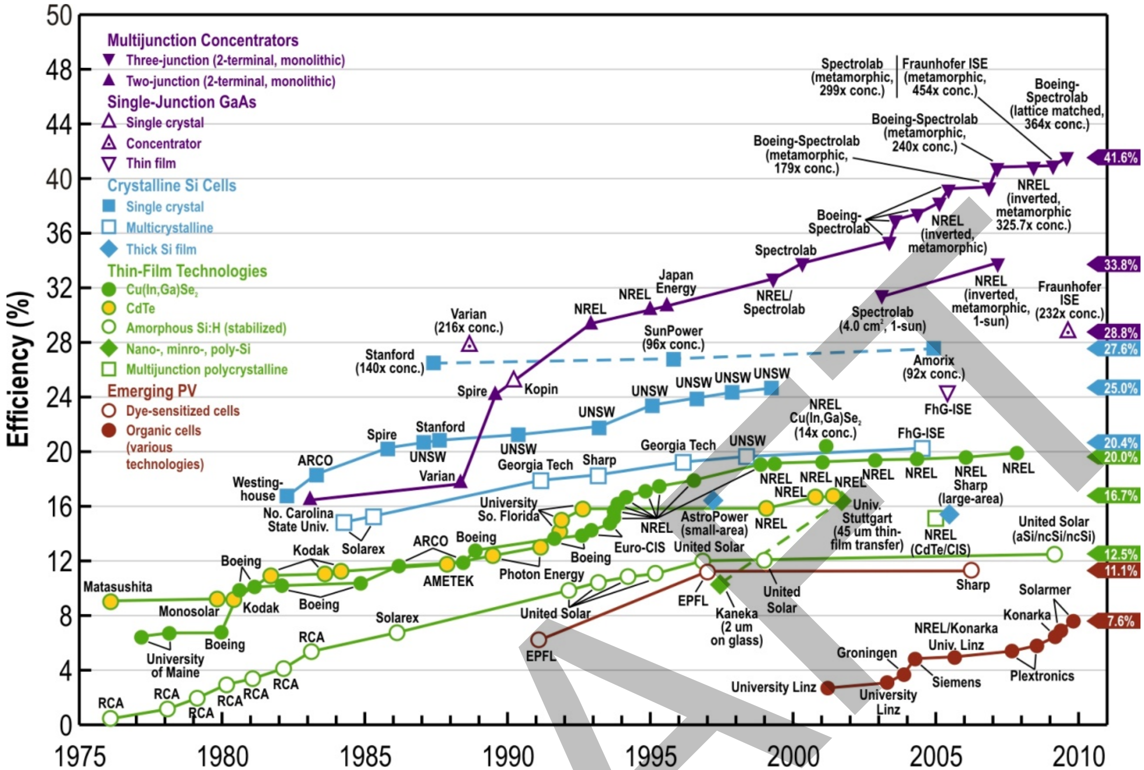
The performance of PV technologies has improved substantially over the past several decades, based on technical innovation, improved PV manufacturing processes, and growing PV markets. All of these factors have contributed to a downward trend in PV prices.

PV Performance

PV performance has improved steadily over the past four decades. Figure 4-2 shows the increase in best-cell efficiencies by PV technology. 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 cells lead to commercial products. Some cell efficiency improvements are simply too expensive to implement at the commercial scale. Further challenges are encountered as small cells are linked together (crystalline silicon) or made in much larger areas (thin films) then encapsulated to form commercial modules. Commercial module efficiencies typically track best-cell efficiency improvements, with a time and performance lag (Table 4-1).

[2] Multijunction cells consist of different semiconductor layers stacked on top of each other, each with unique energy "bandgaps" that absorb different parts of the solar spectrum. This allows multijunction cells to convert more of the sun's energy into electricity and thus attain higher DC efficiencies than conventional cells.

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



Source: Kazmerski (2009)

Table 4-1. Estimated Module Parameters, 2010, Used in Analysis (Figure 6)

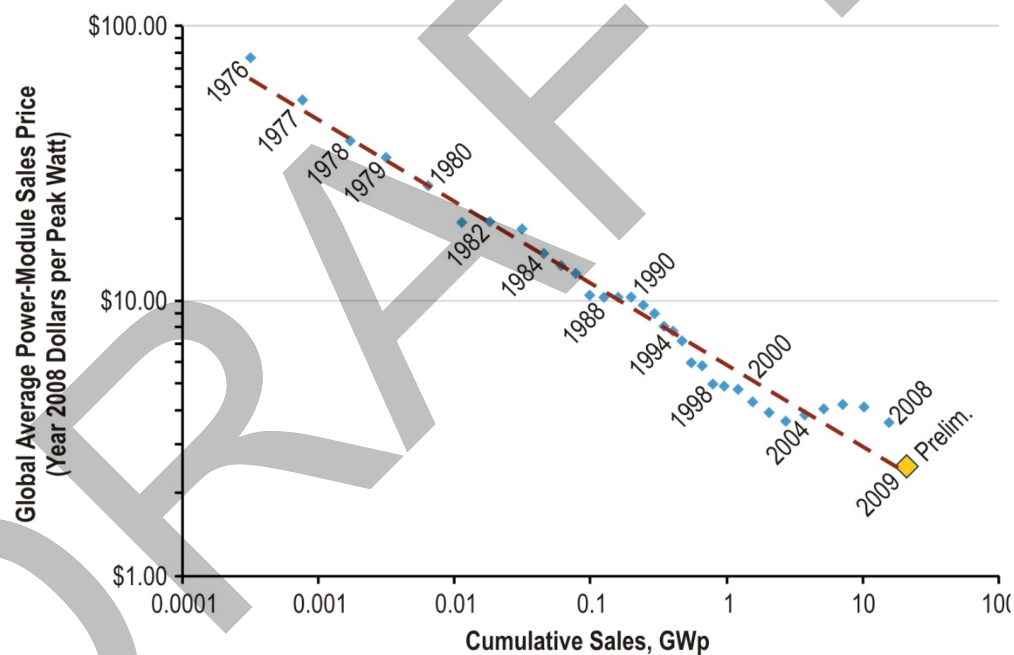
Technology	Best-Cell Efficiency	Commercial Module Efficiency	Production Module *Cost* ($/W)[3]
Monocrystalline silicon[4]	25%	14%	$1.35
Multicrystalline silicon	20%	14%	$1.28
CdTe	16.7%	11%	$0.90
a-Si[5]	12.5%	7%	$1.50
CIGS	20.4%	11%	$1.75
Low-concentration CPV with 20%-efficient silicon cells	—	15%	$2.20
High-concentration CPV with 38%-efficient III-V multijunction cells	—	29%	$1.75

[3] For each technology, there is a distribution of costs reflecting company-specific product, technology, and manufacturing assumptions.
[4] The cost and 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 now commercially available.
[5] a-Si modules range from single to triple junction, including microcrystalline layers.

PV Module Prices

PV module prices are strongly influenced by the most available PV technology (i.e. crystalline silicon), and prices oscillate when supply and demand are mismatched (Figure 4-3). The most available PV technologies to date have been monocrystalline and multicrystalline silicon, although CdTe market share is growing rapidly (Grama and Bradford 2008). PV prices from 2005–2008 reflect a supply-constrained market, in which the price of polysilicon feedstocks for crystalline silicon PV, and margins, stayed high. Since 2009, polysilicon supply has increased without an equivalent increase in demand, reducing polysilicon prices dramatically. As a result, crystalline silicon PV manufacturing costs and end-use prices declined considerably in 2009, returning to the long-term trend line.

Figure 4-3. Decrease in PV Module Prices with Cumulative Manufactured Capacity



Sources: Adapted from Mints (2009) and Mints (2010)

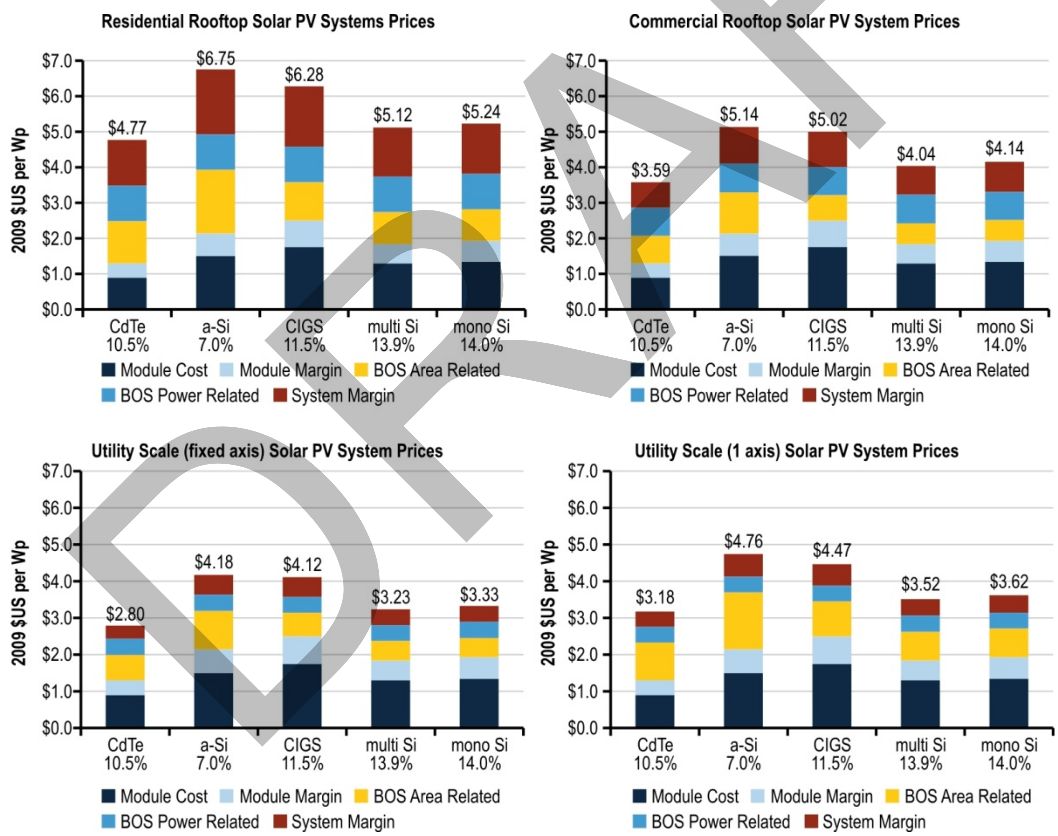
PV System Prices

To better understand PV cost and performance, and how much these can improve over time, a bottom-up engineering analysis of PV systems was conducted as part of the Vision study. The cost of each process in the production of crystalline silicon PV systems was analyzed based on conversations with vendors and manufacturers. This analysis, along with cost data reported by a range of manufacturers for each of the other technologies, was used to evaluate the drivers behind today's PV system costs as well as the potential for future cost reductions.

Efficiency is one of the factors that contributes to PV system cost. Table 4-1 shows representative production-module efficiencies by technology—from a survey of product datasheets (von Roedern 2010)—along with corresponding best-cell efficiencies. Table 4-1 also shows representative module manufacturing costs, which vary by manufacturer and technology. Cost leaders for each technology, such as Trina Solar, have reported lower costs ($1.24/Wp for mixed mono- and multicrystalline silicon) that are not necessarily reflective of all manufacturers' processes, products, and financial assumptions (Trina Solar 2009).

Figure 4-4 summarizes the results of the bottom-up engineering analysis, estimating "best" PV system prices (in 2010) for the residential, commercial, and utility markets for several technologies. These prices represent estimated manufacturing costs plus a reasonable margin at each stage of the supply chain based on detailed discussions with numerous module and component suppliers. Component and system prices vary by market segment owing to these margin assumptions, which reflect the various channels to market. BOS assumptions were similarly developed through conversations with suppliers and installers. BOS costs are separated into area-related and power-related components to reflect the decrease in BOS costs with increasing module efficiency.

Figure 4-4. Best-PV-System Prices (Using Representative PV-Module Prices) for Residential, Commercial, and Utility-Scale Markets for Several Technologies



Most distribution, siting, and regulatory inefficiencies in the marketplace are not included in the estimates. These inefficiencies vary by region. In some regions (e.g., Germany), they are small, and actual market prices approximate the estimate of "best" system prices. In other regions (e.g., the United States), they are large and thus create a significant gap between average prices in the market and these best-price estimates.

Residential systems have the highest prices because of their small size (2–4 kW), fragmented distribution channels, and high marketing and installation costs. Residential PV modules typically pass through multiple distributors between the factory gate and local installers. Installers then add their own markups and associated costs.

Commercial systems, such as those on the flat roofs of big-box retail stores, are larger than residential systems (up to 2 MW). However, they are not typically large enough to attain all economies of scale in purchasing components and installation labor. The prices of commercial systems are about 20% lower than the prices of residential systems, but they are higher than the prices of utility-scale systems.

Utility-scale systems have the lowest per-watt price. These systems are large enough to realize significant economies of scale in component purchasing and installation labor, significantly reducing system margins. CdTe appears to have the lowest price for all applications. However, the best PV system prices do not represent prices typically seen in the marketplace, because system prices are set by crystalline silicon PV. Multicrystalline and monocrystalline silicon PV systems are only slightly more expensive than those shown in Figure 4-4, now that polysilicon feedstock prices have dropped. CIGS and a-Si have the highest 'best cost' estimates. CIGS is a relatively immature technology, and higher-volume manufacturing could result in decreasing CIGS prices. This is merely a snapshot of today's competitive landscape, as the relative 'best cost' of all PV technologies could change significantly as R&D advances are adapted into commercial products (e.g. the recent emergence of CdTe).

4.2.4 Levelized Cost of Energy

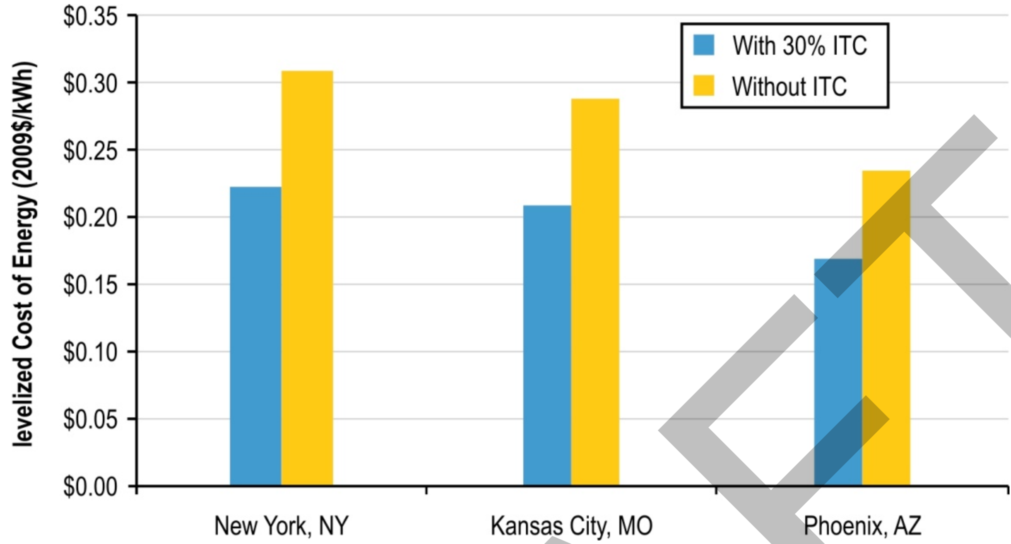
Levelized cost of energy (LCOE) is the ratio of an electricity-generation system's costs—installed cost plus lifetime operation and maintenance (O&M) costs—to the electricity generated by the system over its operational lifetime, given in units of cents/kWh. The calculation of LCOE is highly sensitive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

Figure 4-5 shows the LCOE for past residential PV systems priced at $7/W in three U.S. cities; this price is 40% higher than the approximately $5/W residential systems shown in Figure 4-4, representing the inefficiencies in the U.S. market that reduce the availability of best-price systems. The LCOE ranges are about $0.17–$0.22/kWh with the 30% federal ITC and $0.24–$0.31/kWh without the ITC. These estimates are based on the following assumptions: 80% of the system is financed via a 30-year mortgage at a 6% interest rate; the customer has an effective tax rate of 33% and a discount rate of 5.4%;[6] the customer incurs $380/kW for inverter replacement and related labor costs in year 10; annual O&M expenses are $36/kW-yr; the system output degradation rate is 1.0%/year; and no state or local incentives are included.

The LCOE for commercial and utility-scale PV systems is generally much lower than for residential PV systems located in the same regions, mainly because

[6] The discount rate is in nominal terms and equal to the customer's after-tax weighted average cost of capital (WACC), computed from the cost of debt of 6.0% and cost of equity of 10.8% (based on long-term historical returns of the S&P 500).

Figure 4-5. LCOE for $7/W Residential PV Systems in several U.S. cities in 2009, with and without the Federal Investment Tax Credit



Source: DOE (2010)

commercial and utility-scale PV systems have significantly lower installed prices per watt. O&M costs per watt also tend to decrease as PV system size increases owing to more advantageous economies of scale and other factors. The output of large systems can be enhanced by using tracking systems, and larger, optimized, better-maintained PV systems can produce electricity more efficiently and consistently. In addition, the largest systems are likely to be disproportionately built in regions with the best solar resource (e.g., Arizona).

4.3 PV COST AND PERFORMANCE PROJECTIONS

The price of PV modules has decreased 20-fold since the 1970s, and significant future cost reductions are projected. Although a number of factors will drive these cost reductions, five areas are key: increasing PV system efficiency, reducing module costs, reducing BOS costs, reducing supply chain margins, and improving market efficiencies. No technological breakthroughs are required to achieve substantial cost reductions, and the Vision analysis considers only commercially proven PV technologies. The potential of emerging technologies (see Section 4.2.2) is less quantifiable but still substantial.[7]

4.3.1 INCREASING PV SYSTEM EFFICIENCY

Consistent improvements in efficiency have been realized for virtually every PV technology (Figure 4-2). This trend is projected to continue owing to R&D improvements that produce higher best-cell efficiencies, manufacturing technology

[7] Once new technologies become market leaders, they can rapidly gain market share. For example, First Solar, Inc. (www.firstsolar.com) launched commercial CdTe PV cells in 2002, and within 7 years it had become the world's largest PV manufacturer. Although the potential of emerging technologies is not considered in this study, it should not be underestimated.

improvements that advance commercial modules towards best-cell efficiencies, and system improvements such as converting DC electricity into AC electricity more efficiently. These efficiency improvements will drive down PV module and system costs.

Continued efforts are required to achieve the necessary efficiency improvements. Increasing PV-system efficiency is technically challenging and rewards sophisticated observations, ideas, and experiments. Multi-year (even multi-decade) R&D programs such as the DOE PV Program, which drove the improvements shown in Figure 4-2, are often required to improve the industry's understanding of a technology and then transfer this knowledge to commercial production.

4.3.2 Reducing Module Costs

The PV market is dominated by crystalline silicon modules, with the market share of CdTe modules growing rapidly. Cost reduction potentials are unique to each technology, but reducing material costs and improving manufacturing processes are key strategies for all technologies.

Reducing Material Costs

Active semiconductor material (the material that converts sunlight into electricity) is the most complex and expensive component of a PV module. Polysilicon semiconductor material, the feedstock used to grow crystalline silicon PV, was a large component of early module costs, and remains a major component of today's module costs. However, polysilicon feedstock costs have been reduced via several methods:

1. Making thinner wafers (reducing the industry average from 300 to as low as 140 microns)
2. Minimizing polysilicon losses during the wafering process
3. Improving polysilicon scrap recycling capabilities and costs
4. Introducing low-cost polysilicon feedstock purification methods to reduce energy and capital-equipment costs
5. Developing new PV technologies that require minimal or no polysilicon and minimizing the use of all semiconductor materials, e.g., by reducing the semiconductor thickness in thin films or using CPV technologies to reduce the required semiconductor area

Costs for thin film active semiconductor material vary from a few dollars per square meter to tens of dollars per square meter (which can be almost as much crystalline silicon semiconductor material, on a per-watt basis). The wide range of costs among different thin film technologies results from the use of small amounts of non-abundant materials and the inefficient use of expensive, highly processed sources (e.g., sputtering targets or certain gases).

After the active semiconductor material, the front and back cell contacts are the next most-expensive materials in 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 and adhesive to bind the layers and the cells—add considerable cost to PV modules. Again, manufacturers must balance the benefits of using less-expensive materials against resulting effects on module performance; modules with better reliability and longer lifetimes have lower lifetime costs. Other materials to be considered are those used in edge seals, frames, mounting hardware, cell interconnections, and bus bars. A junction box with external wires costs several dollars per module.

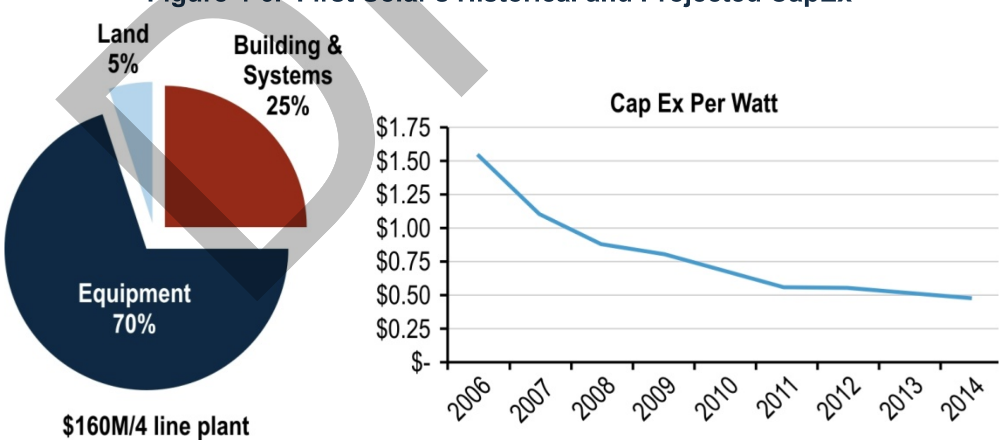
Another way manufacturers can reduce material costs is to become more vertically integrated. Even partial in-house supply of materials that have volatile prices will help a manufacturer have access to the best-available market pricing.

Improving Manufacturing Processes

Manufacturing costs are a major component of module costs. Manufacturing equipment costs are measured in dollars per watt of annual factory output, known as the "CapEx" (which should not be confused with per-watt module and system costs). Because equipment is depreciated over time (e.g., 7 years), its contribution to module cost is about one seventh of this cost per annual watt of module output, after adjustments are made to account for the cost of capital. There are also equipment maintenance costs.

Several factors affect manufacturing costs, including speed, yield, labor, and energy. Increasing manufacturing speed results in higher throughput and lower costs per watt. For example, First Solar makes its CdTe layer in approximately 1 minute, giving it one of the lowest CapEx levels (less than $1 per watt) among fully vertically integrated module manufacturers (Figure 4-6). Some manufacturers have a CapEx as high as $3 per watt. Speed can be increased 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.

Figure 4-6. First Solar's Historical and Projected CapEx



Source: First Solar (2009)

Increasing yield—the proportion of manufactured product that meets commercial specifications—is another way to increase throughput and reduce costs 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 (e.g., wafers) and the desired minimum product quality (e.g., cell efficiency). A wide range of acceptable cell efficiencies may contribute to module stringing losses later. As virgin 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.

Reducing labor and energy use requirements also reduces manufacturing costs. Labor costs depend on the maturity of the manufacturing approach and the local labor rates. It is almost certain that labor costs will 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, using lower temperature processes, and replacing vacuum with non-vacuum processes where possible. Past improvements of this sort have lowered the PV energy payback periods to 1–3 years, which has important policy implications (see the discussion of GHG emissions in Chapter 8).

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 approximately \$0.05–\$0.06/W (Goodrich 2010), adding 5-10% to module costs.

Many PV components—including polysilicon, wafers, and even cells—can be shipped cheaply. The glass content of both thin film and crystalline silicon 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 weight—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 commonly manufactured by different companies in different locations. Thin film manufacturers typically have an aggregated supply chain. This is an advantage for reducing crystalline silicon shipping costs, because module manufacturing facilities can be sited near end-use markets, eliminating the need for ocean transport and associated costs. Crystalline wafers and cells are significantly less heavy, since they lack encapsulating materials, and can be shipped for significantly less cost.

Cost Projections

Figure 4-7 and Figure 4-8 illustrate cost-reduction potential for typical multicrystalline and monocrystalline silicon PV modules. Component costs were calculated using a detailed PV-manufacturing cost model intended to simulate “typical” silicon PV module production costs (Goodrich and Hsu 2010), and do not include incentives. Actual costs will vary by company and situation (depreciation schedule, taxes, labor rates, etc.). The 2010 module costs represent manufacturing processes currently in use. Cost reductions result primarily from increased efficiency and reduced polysilicon use (thinner wafers, greater yields) and prices.

Figure 4-7. Projected Multicrystalline Silicon PV Wholesale Module Prices (in 2009 U.S. Dollars)

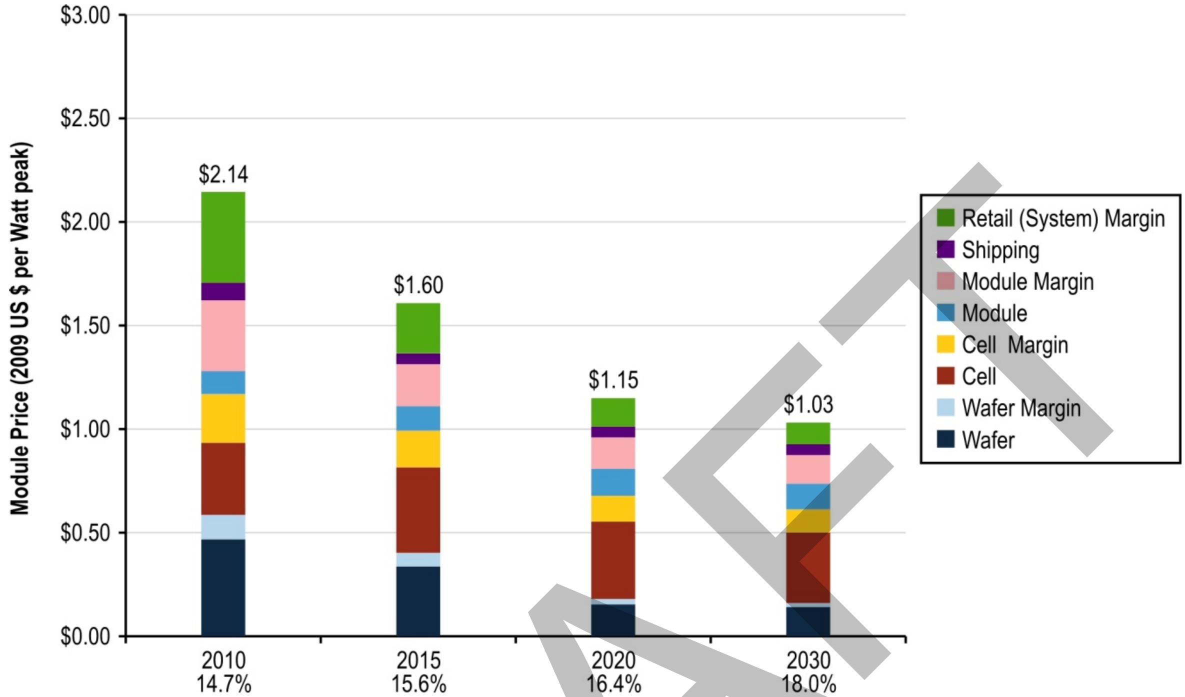
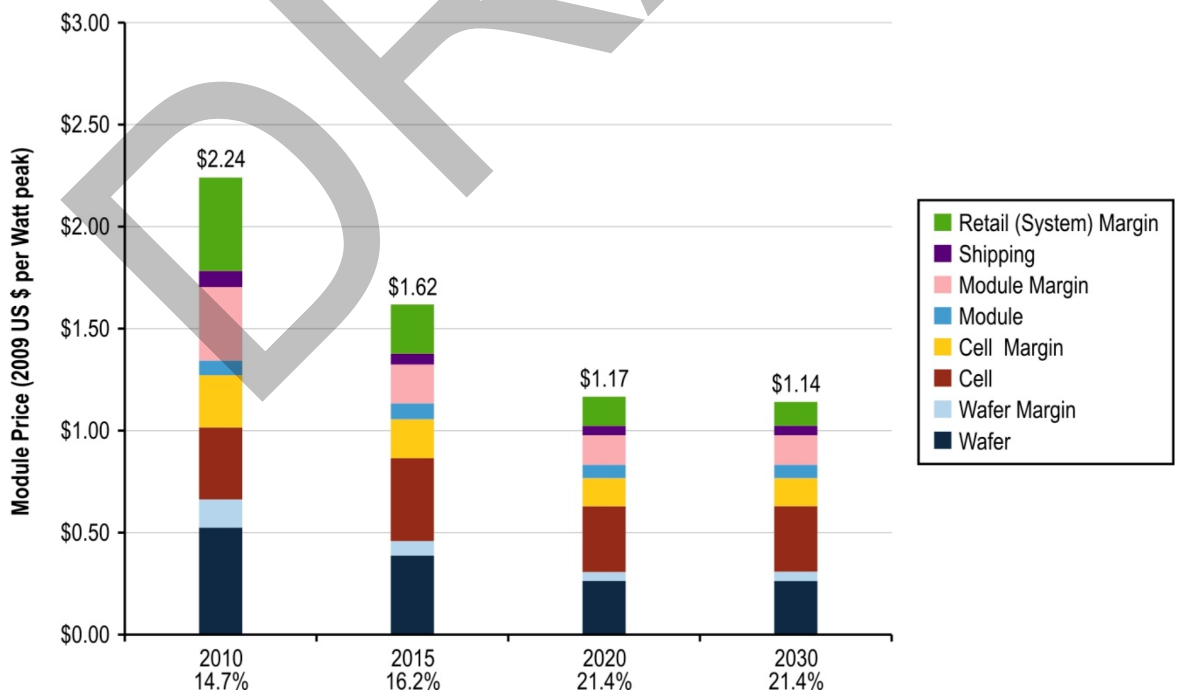


Figure 4-8. Projected Monocrystalline Silicon Wholesale PV Module Prices (in 2009 U.S. Dollars)



Product efficiency gains are projected to be achieved through multiple pathways. For example, using higher-quality feedstocks, reducing shadowing losses due to front-side cell contacts, and implementing advanced cell architectures. By 2015, most monocrystalline and multicrystalline modules are projected to be made using a selective-emitter technology and fine (~40 micron wide) front contacts. By 2020, monocrystalline modules are projected to use back contacts.[8]

Another large component of the cost reductions is decreasing profit margins at each step of the supply chain, resulting from increased competition. Minimum sustainable profit margins have been forecast using detailed manufacturing cost and pro forma financial models. Similar cost-reduction potentials are likely for thin film technologies, although the actual rate of cost reduction and efficiency enhancement will vary by technology.

4.3.3 Reducing Balance of Systems Costs

BOS includes inverters, transformers, support structures (including trackers), mounting hardware, electrical protection devices, wiring, monitoring equipment, shipping, land, installation labor, permitting, and fees. BOS costs frequently add $1-$4/W, depending on the size and type of PV system, its location, and margins. In many PV applications, BOS costs are higher than module costs, and it is becoming increasingly important to reduce these costs in tandem with reducing module costs.

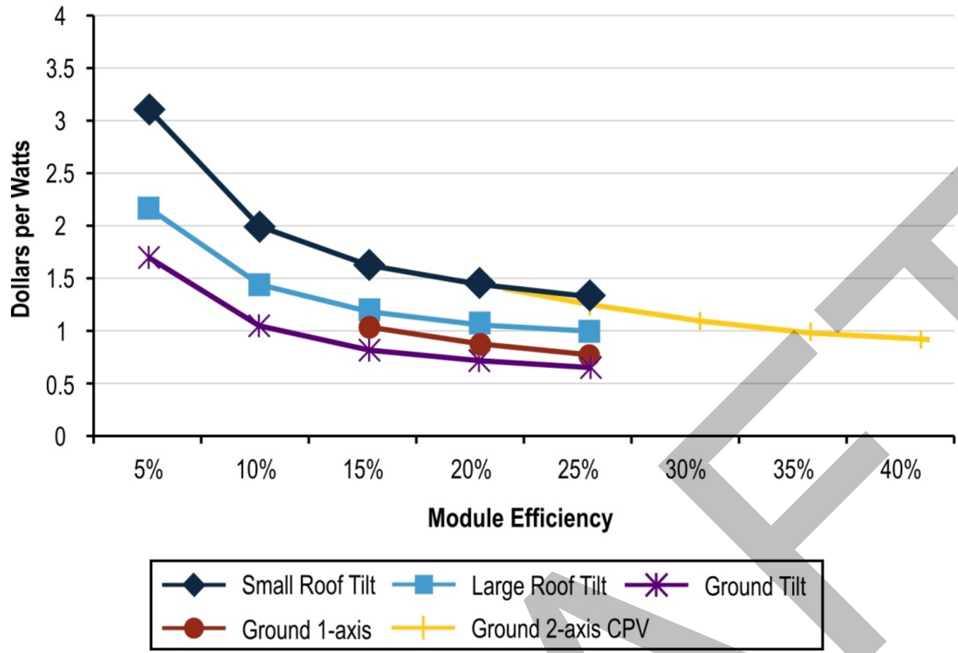
Major improvements in BOS cost are likely to come from reducing the cost of installation, likely by simplifying designs to reduce installation time and effort and streamlining distribution and installation margins as the industry grows. Additional BOS cost reductions are likely to come from increasing inverter efficiency and durability, improving module matching to reduce electrical-mismatch losses, and reducing support structure and tracking costs.

Figure 4-9 shows the efficiency-dependence of BOS costs (2010 US$) using a detailed cost model developed for the Vision study. These costs do not include system integrator margins. Increasing system efficiency lowers the area-dependent component of BOS costs (installation labor, support and tracking structures, wiring, and land costs) since fewer modules are required to reach a given system capacity. In this way, BOS costs are reduced even when the cost of structural and tracking components, and labor remain fixed.

Utility-scale, ground-mounted systems can be configured in various ways, each with a different effect on BOS costs. It is possible to gain approximately 25% more annual output from a module using a one-axis tracking array. Tracking also increases PV output in the mornings and afternoons, the latter being especially valuable in regions with strong afternoon cooling loads. This additional PV output incurs the cost of the tracking system, and tracking is economic if its benefits outweigh its costs. Today, tracking systems are frequently used with crystalline silicon PV in utility-scale installations. Thin film PV utility-scale installations do not as yet use tracking systems, but as their efficiencies increase, they may evolve in that direction.

[8] Multicrystalline modules are not projected to implement all back contacts owing to material performance and lifetime limitations.

Figure 4-9. Balance of System Costs (Before Installer Profit) for Several PV Multiple Applications and a Range of Module Efficiencies



CPV is an emerging approach to utility-scale systems, especially in arid regions that receive high levels of the direct-beam insolation CPV needs. The types of tracking used in CPV systems influences BOS costs considerably: both equipment costs and electricity production increase with increasing tracking-system sophistication (i.e., from no tracking to 1-axis tracking to 2-axis tracking). Thus, tracking costs are a tradeoff between equipment costs and the additional electricity generation enabled. CPV systems with low concentration ratios (2–10 "suns") can use no tracking or can use 1- or 2-axis tracking. CPV systems with higher concentration use 2-axis tracking.

4.3.4 Reducing Supply Chain Margins

The final PV price paid by a consumer can include significant margins—representing both profit and overhead—charged by suppliers, manufacturers, distributors, and the retailer/installer (Figure 4-4, Figure 4-7, and Figure 4-8). These margins are far higher than those charged by manufacturers and suppliers of mature electricity-generation technologies. A number of factors can cause high PV margins, particularly for smaller systems.

Installers of large utility-scale or commercial rooftop systems frequently negotiate module costs directly with manufacturers and the prices they receive do not include distribution and retail margins. Also, the margin charged by large-system installers is frequently lower (on a per-kW basis) than that charged by smaller-system installers. Residential-system installers typically procure modules and mounting hardware from distributors, paying an additional margin before charging a typically higher per-kW installation margin. This can nearly double the cost of higher-cost residential systems compared with lower-cost utility and commercial systems.

PV margins—and the cost differential between large and small systems—likely will decrease as the markets grow and mature, competition streamlines the supply chain, and personnel requirements per unit of capacity decrease. In addition, installer margins likely will decrease as PV systems become simpler to install and more competition is created by growth in the number of installers. Similarly, the absolute magnitude of margins falls as the cost of PV components falls; this has had a major effect in the past few years as module costs have fallen by a factor of three.

4.3.5 Streamlining Regulatory Processes

Several regulatory requirements increase the cost of developing PV resources—including costs related to site acquisition, surveys, environmental studies, permitting, and government fees. These vary by region, but tend to become standardized and streamlined, reducing costs, as PV markets grow and mature. This has been the case in market-leading countries such as Germany and Japan.

4.3.6 Total System Costs and Delivered Cost of Energy

Aggregating all of the component costs, including the cost of modules, BOS (inverter, tracker, other materials, installation labor, permitting and regulatory compliance, and installer overhead) yields the total system cost. Viewed from the perspective of the final system owner, these component costs are inclusive of their respective margins and are thus referred to as prices. Table 4-2 shows current and projected installed costs for systems using multicrystalline silicon modules. Multicrystalline prices are shown as 'representative' of the PV market because they account for nearly 50% market share and have intermediate efficiencies (DOE 2010). In addition to including component cost margins, Table 4-2 shows average system prices, as opposed to the 'best cost' systems presented in Figure 4-7.

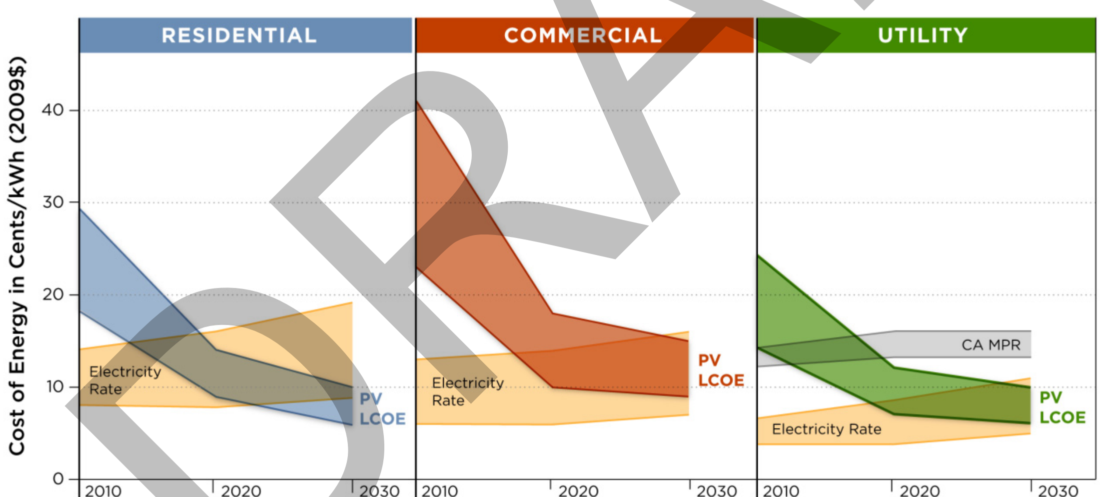
Figure 4-10 converts the total installed system costs in Table 4-2 to the delivered, or levelized cost of energy (LCOE), as discussed in Section 4.2.3. These are calculated using assumptions about O&M expenses, inverter efficiencies, and derate factors from DOE (2010). Moreover, Figure 4-10 represents LCOEs with no investment tax credit (ITC) for residential systems and only the permanent 10% ITC and 5-year MACRS for commercial and utility systems (since the 30% residential and non-residential ITCs are scheduled to expire after 2016). No state, utility or local incentives are factored into the LCOE. Lastly, we use a number of locations (Phoenix, Kansas City and New York), system orientations and financing conditions to represent a range of PV LCOEs (DOE 2010).

As illustrated in Figure 4-10, residential PV (without the ITC) is broadly competitive with retail electricity rates by 2020, and cheaper than most retail electricity rates by 2030. Commercial PV (with the 10% ITC) is competitive with the higher range of commercial retail electricity rates by 2020 and broadly competitive by 2030. Utility-scale PV (with the 10% ITC) is below the California Market Price Referent (based on the levelized cost of a new combined cycle natural gas turbine facility) by 2020 and broadly competitive with wholesale electricity rates by 2030.

Table 4-2. Installed Costs for Systems with Multicrystalline Modules by Year and Market Segment[9,10]

PV System Component Prices (2009 US$/Wp)	Residential			Commercial			Utility		
	2010	2020	2030	2010	2020	2030	2010	2020	2030
Multicrystalline-Si Module	2.14	1.15	1.03	1.92	1.08	0.98	1.70	1.01	0.92
Inverter	0.51	0.25	0.16	0.40	0.15	0.13	0.36	0.17	0.15
1-axis Tracker	---	---	---	---	---	---	0.48	0.22	0.20
Other Materials	0.51	0.25	0.16	0.73	0.28	0.24	0.31	0.14	0.13
Installation Labor	0.66	0.32	0.20	0.67	0.26	0.22	0.20	0.09	0.08
Permitting & System Design	0.53	0.26	0.16	0.33	0.13	0.11	0.21	0.10	0.09
Installer Overhead & Other	1.60	0.78	0.49	1.05	0.40	0.34	0.80	0.37	0.33
Installed System Cost	**$5.95**	**$3.00**	**$2.20**	**$5.10**	**$2.30**	**$2.00**	**$4.06**	**$2.10**	**$1.90**

Figure 4-10. PV LCOEs by Year and Market Segment[11,12]



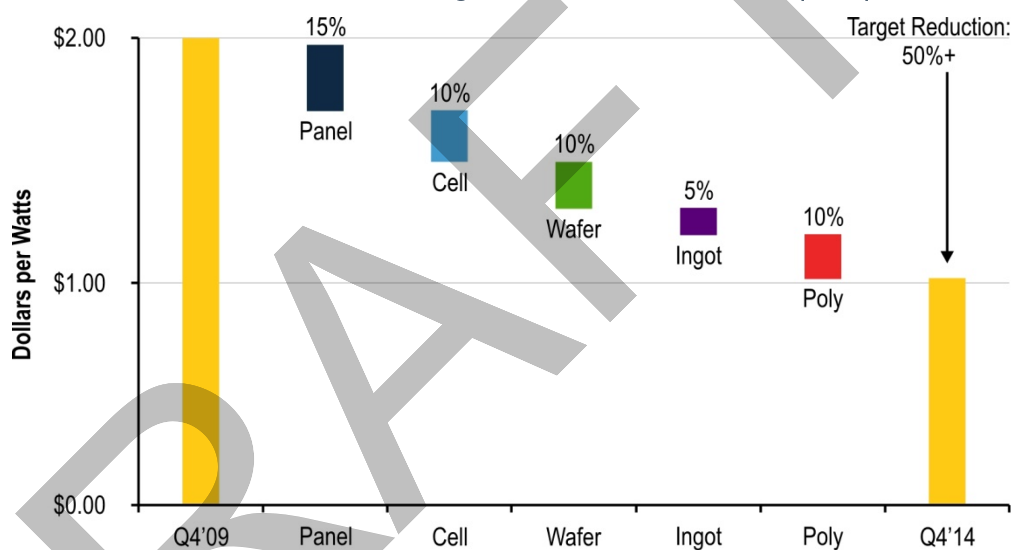
[9] Module costs are from Figure 11, with the assumptions that residential customers would pay the entire module margin, commercial customers would pay half of the module margin, and utility customers would not pay any module margin.
[10] Non-module costs for 2010 are from DOE (2010). Projections assume that all non-module costs decline in equal proportion.
[11] Note that commercial systems assume third-party ownership, and thus the LCOE includes the taxes paid on electricity generated. The same is true for utility systems, but not for residential systems.
[12] The electricity rate range represents one standard deviation below and above the mean U.S. electricity prices for the respective market segment (residential, utility, wholesale). The CA MPR includes adjustments by utility for the time of delivery profile of solar.

4.3.7 INDUSTRY ROADMAPS

The roadmaps of two leading U.S. PV companies offer another perspective on the near-term potential for manufacturing cost reductions. In 2009, SunPower and First Solar published technical roadmaps for module manufacturing cost reductions through 2014. First Solar also produced a roadmap for reducing BOS costs.

SunPower's roadmap is shown in Figure 4-11. SunPower projects that it can reduce its monocrystalline silicon module manufacturing costs from roughly \$2/W in the fourth quarter of 2009 to \$1/W in 2014.

Figure 4-11. SunPower's Roadmap for Decreasing Monocrystalline Silicon Module Manufacturing Costs from \$2/W to \$1/W (2009)



First Solar projects reducing its CdTe module manufacturing costs from \$0.93/W during the first quarter in 2009 to \$0.52–\$0.63/W in 2014 (Figure 4-12). Potential cost-reduction strategies include increased module efficiency, increased line throughput, more production in low-cost locations, increased plant scale, and continued R&D investment.

Large PV module manufacturers are working to decrease BOS costs as well, which will ultimately lead to a system cost reduction for all technologies. For example, First Solar is targeting a 30%–35% cost reduction over the next 5 years, primarily by increasing inverter and wiring efficiency and reducing the cost of installation, mounting hardware, engineering, and project management (Figure 4-13).

Combining the mid-range of First Solar's projected module (\$0.57/W) and BOS (\$0.95/W) cost with a 30% module margin and a 13% system integrator margin yields a total installed price for a large, nontracking system of a little more than \$2/W in 2014. Since SunPower does not publish BOS cost projections, we use our BOS model to obtain a 2014 monocrystalline system price of approximately \$2.9/W (assumptions are summarized in Table 4-3). The resulting 2014 roadmap-based costs are more aggressive than the cost estimates in Table 4-2, suggesting that even if

Figure 4-12. First Solar's Roadmap for Decreasing CdTe Module Costs to $0.52–$0.63/W (2009)

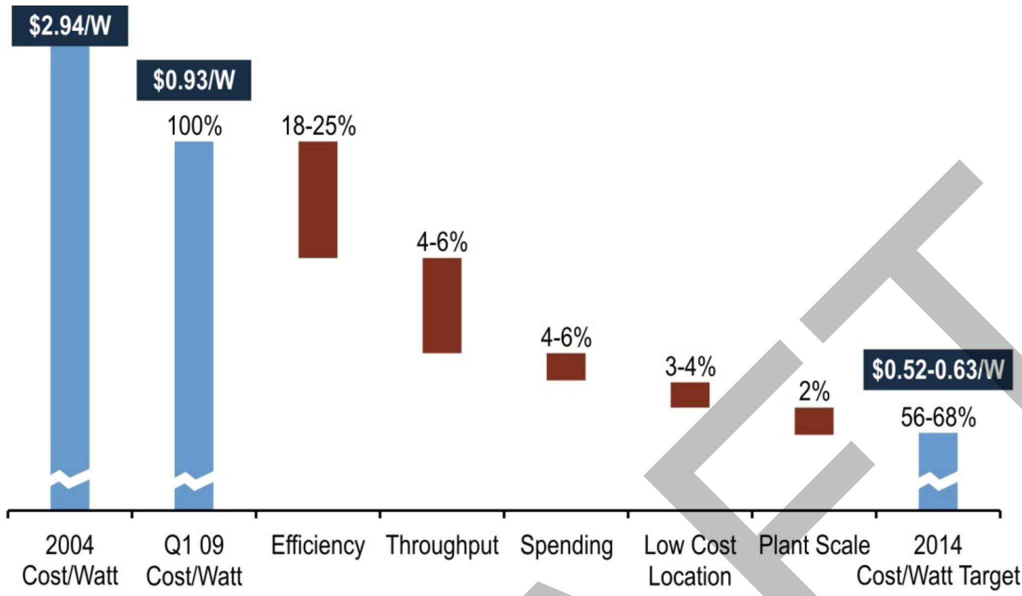
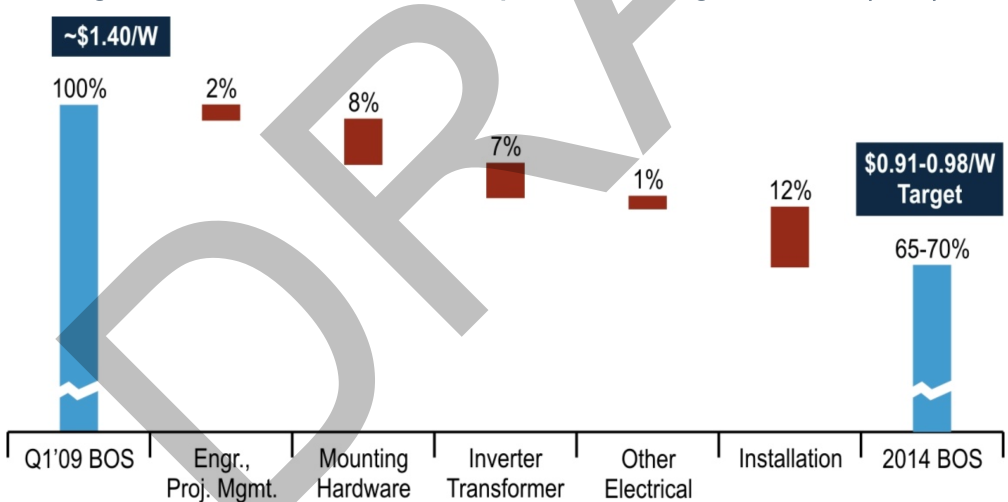


Figure 4-13. First Solar's Roadmap for Decreasing BOS Costs (2009)



these companies fall short of their targets, they are still on track to reaching PV LCOEs in line with those shown in Figure 4-10.

4.3.8 RESEARCH AND DEVELOPMENT

The potential for PV to achieve the Vision goals assumes no additional material- or system-level breakthroughs. However, continued R&D is assumed and is essential to produce the necessary improvements in performance, cost, reliability, and manufacturing scale.

Table 4-3. Corporate Roadmaps to 2014

	CdTe (First Solar, Nontracking)	Monocrystalline Silicon (SunPower, 1-Axis Tracking)
Module Efficiency (estimated)	13%	22%
Module Cost ($/W)	$0.57	$1
Module Margin, 30% ($/W)	$0.25	$0.43
BOS Cost ($/W)	$0.95	$1.06 (w/tracker)
Integrator Margin, 13% ($/W)	$0.26	$0.37
Total System Price, 2014 ($/W)	**$2.03**	**$2.86**

The Foundation

A robust near-term PV R&D plan is needed to support the many stages leading to commercialization: prototype development, product and process development, measurement and characterization, technology evaluation, and demonstration-system deployment. A substantial base of scientific knowledge exists for crystalline silicon PV technologies, largely owing to computer chip R&D, but such a base is still being built for other leading PV technologies. This is true for all aspects of PV: 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. Challenges include maintaining or improving device efficiency, device stability, and process stability.

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 (e.g., light and carrier reflectors) that modify device behavior. Examples of critical interface behavior 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 fundamental insights about the interfaces of a PV cell and packaging. 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 inline diagnostics for improved manufacturing yield.

Degradation Science

An improved understanding of degradation mechanisms in devices and protective materials would increase module lifetimes and further lower PV's LCOE. It is important to increase understanding of 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 potential degradation mechanisms, as are parallel accelerated lifetime models that correlate these new tests with actual outdoor performance over many decades.

Long-Term, High-Potential R&D

Funding for universities, companies, and national laboratories for R&D on non-traditional, high-potential PV technologies promotes innovation and the development and expansion of future PV options. These pre-commercial programs also expand the pool of scientists and engineers with PV expertise.

The PV research community is exploring a portfolio of promising new materials, primarily 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 to explore underdeveloped materials for PV (e.g., 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 materials availability.

Beyond new materials, there are new PV device concepts that could improve power conversion efficiency and reduce costs. Of these, the most developed are organic, nanoparticle, and dye-sensitized cells, which are in early stages of commercial development (see Section 4.2.2). They offer the potential for lower costs through use of less-expensive materials and simpler processing. However, there are challenges in attaining high efficiency and long-term reliability.

4.4 MATERIALS AND MANUFACTURING RESOURCES

The 20% Vision goal assumes that U.S. PV installations will reach about 220 GW in 2030, requiring the PV industry to achieve rapid, large-scale expansion of its raw material supply and manufacturing capacity. If the rest of the world were to follow this same growth trajectory, about 1,100 GW might be installed worldwide, with the actual output in 2030 being about 115 GW/year. This section discusses these expansion challenges.

4.4.1 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 extraction, refining, or source-formation capacity, despite a basic accessibility of the underlying material. 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 during the past couple of 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 and start up a new polysilicon plant. From initiating plant construction to beginning production 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 in the industry, since cell manufactures had to wait for producers to respond to the market signals of increased demand. Lower capital cost processes (e.g., the use of thinner silicon wafers and use of less-refined, solar-grade silicon) will help mitigate this type of imbalance in the future.

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

Material Shortage

A more serious challenge is a fundamental shortage of material supply. For example, a shortage can occur when not enough material is being mined, or could be mined economically, or when competing uses can afford much higher prices for the material and thus lock up all available supply. Long before the supply is truly inaccessible, prices can rise to uncompetitive levels, which frequently stimulate new sources of supply, balancing demand at a sustainable level.

Material shortages are a concern for the semiconductor materials in some PV technologies: tellurium used in CdTe; indium, selenium, and gallium used in CIGS and some III-V multijunction cells; germanium frequently used in a-Si; and ruthenium sometimes used in dye-sensitized PV cells. Conductive materials may also be a concern in the longer term, including copper used in all PV wiring, silver used for crystalline silicon PV contacts, and molybdenum used for CIGS PV contacts. Of these, the primary concerns are tellurium for CdTe and indium for CIGS.

About 1,500 MT/yr of tellurium are available from extracted copper, but only about 500 MT/yr are refined owing to a lack of demand. The amount of tellurium available will increase with increasing copper extraction, the demand for which has recently grown by 1%–3% per year. Also, the amount of tellurium recovered from copper mining will increase as tellurium demand increases. Tellurium's major use is as an alloy additive in steel and copper, neither of which is expected to increase significantly with PV demand. About one fifth of the tellurium supply is used in CdTe PV production.

Indium is a relatively rare byproduct of zinc refining. Nearly all of the indium supply is used in thin film coatings, such as those on flat panel liquid crystal displays. Additionally, the use of indium for indium-tin-oxide (a transparent conductive oxide) could limit a-Si; however, using a different conductive oxide such as zinc oxide (ZnO) would alleviate this materials constraint. Germanium used in a-Si bottom cells is an issue but easily replaced by using un-alloyed microcrystalline silicon instead. CPV modules also frequently use rare indium and gallium materials but do not face the same limitations as other technologies. Optical concentration reduces the active semiconductor area required (and thus the rare materials required) by a factor equivalent to the concentration ratio. Also, rare materials are more affordable on a per watt basis which may lead to displacing competing applications or incentivize increased extraction of material resources.

Although crystalline silicon feedstock materials are virtually unlimited, the silver used for contacts has some limitations. However, if a different material is used for contacts, the supply is virtually unlimited. 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.

There are four main ways to ease material constraints:

- Increase efficiency (less material per delivered watt)
- Reduce material use through thinner layers for PV devices
- Improve process utilization and in-process recycling
- Increase ore extraction and refining

Because CdTe and CIGS have basic limits without improvements, these are critical strategies for these technologies. The best CdTe module efficiencies are about 11%, layers are about 3 microns thick, and there are 10 g/m^2 of tellurium in a 3-micron CdTe layer. Combined with 90% process material use (with in-process recycling), this implies that 100 MT of tellurium are needed per GW. If CdTe module efficiency increased to 15% and layer thickness decreased to a little less than 2/3 of a micron (about what is needed to absorb the solar spectrum), tellurium requirements would drop to 13 MT per GW. Copper extraction is increasing 1%–3% per year, which implies that tellurium availability in 2030 could increase to about 1,800–2,700 MT/yr. At 13 MT/GW, this implies possible production of 140-200 GW/yr in 2030.

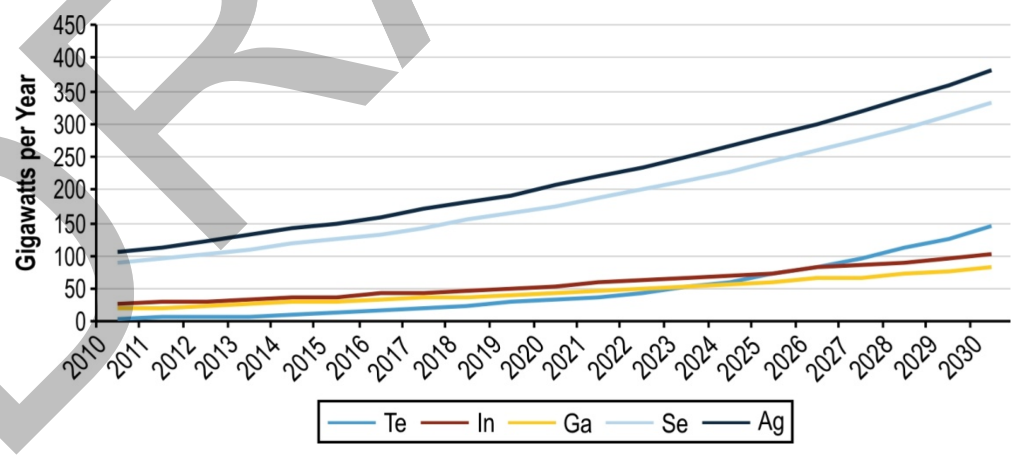
Table 4-4 shows how material use can be reduced with improved efficiency and reduced thicknesses for each material.

Table 4-4. Possible Materials Needed in 2030 per GW of Newly Installed Systems if Material-Reduction Strategies are Successful

Material	PV Type	MT/GW (2010)	MT/GW (2030)
Tellurium (Te)	CdTe	100	13
Indium (In)	CIGS, multijunction	30	9.4
Gallium (Ga)	CIGS, multijunction	8	2.3
Molybdenum (Mo)	CIGS	100	30
Selenium (Se)	CIGS, multijunction	30	16
Silver (Ag)	crystalline Silicon	200	70

Figure 4-14 shows the annual module production limits for several materials calculated using the materials use assumptions in Table 4-4, and a 1% annual growth in extractions. The Vision scenarios could lead to 115 GW/yr of PV demand globally by 2030, and most of these materials appear capable of approximating that amount.

Figure 4-14. Key PV Material Availability Forecast



4.4.2 MANUFACTURING SCALE-UP

The PV industry is expanding its manufacturing capacity, helped by new market entrants bringing capital as well as technology, manufacturing, and supply chain management experience, often from other successful industries (e.g., computer semiconductor, liquid crystal display, and specialized material industries). Annual production capacity of PV manufacturing lines has increased from tens to hundreds of MW over the past decade.

The challenge of scaling-up manufacturing capacity will not limit PV deployment. Global PV manufacturing capacity could be on track to grow from 3.2 GW/year in 2007 to 23.7 GW/year by 2012, based on existing and planned investment (Mehta and Bradford 2009). Peak annual PV deployment reaches 23 GW/year by 2030 in the 20% Vision scenario. The scale up of global PV manufacturing to achieve Vision trends in the U.S., and similar growth targets globally, are not out of line with recent manufacturing growth trends. The capital required to build a 1-GW/year PV manufacturing facility has been estimated at $1–$3 billion (2009 U.S. dollars) (Mehta and Bradford 2009), although recent progress (e.g., First Solar) is pushing this number below $1/W. Neither the cost of building new PV manufacturing capacity nor the rate of growth required to reach Vision PV deployment levels are out of line with current trends.

That said, supply chain planning and clear market signals are needed to enable the required scale-up. For an "emerging" technology such as PV, which initially will have above-market prices, strong and consistent government policy support is needed to create initial demand. PV 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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