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Thin Film Photovoltaics

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Thin Film Photovoltaics

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The Idea of Low-Cost PV

The motivation to develop thin film technologies dates back to the inception of photovoltaics. It is an idea based on achieving truly low-cost photovoltaics appropriate for mass production and energy significant markets. The key to the idea is the use of pennies worth of active materials. Since sunlight carries relatively little energy in comparison with combustion-based energy sources, photovoltaic (PV) modules must be cheap to produce energy that can be competitive. Thin films are presumed to be the answer to that low-cost requirement. But how cheap do they have to be? The following is an oversimplified analysis that allows some insight into this question.

If a PV module converts about 10% of incident sunlight into electricity, it will produce about 100 W/m^2. (Actually, to produce that much electricity under *operating* conditions, with all temperature-dependent and other electronic losses, requires a module that is well over 10% efficient—more on this later.) In one year, with average sunlight in the United States of about 1800 kWh/m^2-yr for a fixed, flat-plate system in, for example, Kansas City, such a PV module would produce 180 kWh/m^2-yr. Over a 30-year lifetime, it would produce about 5000 kWh/m^2. How much cash flow would it generate? If we assumed a revenue of 6 cents/kWh in the first year and an inflation rate of 3%, revenue would grow to 14.6 cents/kWh in the 30th year. Average revenue would be 10.3 cents/kWh, so total revenue would be about \$515/m^2.

If the same PV system cost \$500/m^2, it just barely pays for itself over its 30-year lifetime: The total reduction in electricity bills is \$515. The capital cost of the system will have to be smaller than \$500/m^2 to make it a worthwhile investment. To estimate how low the capital cost needs to be requires a way to compare the PV investment to other potential investments the consumer could make.

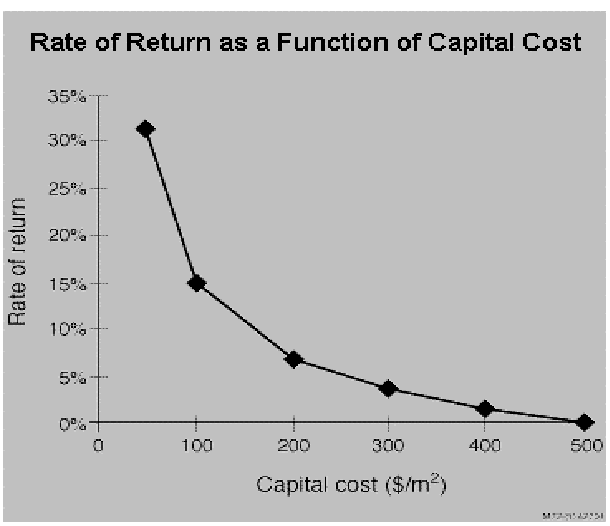

Figure 1. If an investor were to buy a 10% (operating efficiency) PV system for various prices, the internal rate of return on that investment would be attractive (about 10% annually) at about \$150/m^2.

The concept of internal rate of return (IRR) provides the most straightforward way of making this comparison. Roughly speaking, the IRR can be defined as follows:[2] Suppose the consumer has money in a money market fund. He withdraws from this account the money needed to install the PV system. He deposits the amount of his energy savings back into the account as they accrue. The IRR is the interest rate on the money market account that leaves the consumer indifferent. That is, he will have the same amount of money after 30 years if he buys the PV system as he would have had if he had simply left all the money in the money market fund. Obviously, the higher the equivalent interest rate, the better since that indicates how much of a return he'd get if he left the money in the account. It can be compared to "going rates" for such accounts to decide if a PV investment would be worthwhile.

Figure 1 shows how the rate of return changes as the capital cost is reduced from \$500/m^2 to \$50/m^2. (Note that at 10% system efficiency, these are equivalent to \$5/W and \$0.5/W, respectively, at operating conditions.) The consumer pays no tax on the reduction in his energy bill. So the rate of return on the PV investment should be compared to *after tax* yields on other investments.[3] One yardstick for after-tax return is the yield on municipal bonds. A 30-year, high-quality, tax-free bond currently pays about 5% per year. To achieve this return at 10% system efficiency, the capital cost of the PV system would need to be $260/m^2$, or about $2.60 per operating watt. At a system price of about $150/m^2$, or $1.5/W, the rate of return is about 10%—a very attractive return, especially in after-tax dollars.

Although this helps establish an ambitious long-term goal for thin-film PV (about $1.5/W for systems, at operating conditions, or about $1.2/$W_p$ in terms of module efficiencies under standard measurements), it does not characterize well the interim situation. Fortunately, PV has been found useful by numerous consumers who value PV electricity at greater than 6 cents/kWh. In fact, today's world PV market of about 150 MW/year is sold at prices closer to 7 times the goal—$8/$W_p$. Annual sales of systems are about $1.2 billion. Thus, although the ambitious long-term goal of PV is to be competitive in familiar markets such as for U.S. utilities, a series of interim markets of increasing magnitude will allow PV to evolve toward the long-term goal while generating considerable revenue and profits. Indeed, even in the United States, daytime electricity is more valuable than the average (because it meets higher daytime demands), implying that 6 cents/kWh may be a conservative figure for revenue. Any discussion of the $1.2 W_p goal/market must include these factors.

Let us return to the long-term goal to obtain a good perspective concerning the kind of progress needed. Today's PV modules are sold at a price of about $3.5-$5/W_p. They are almost all wafer-based crystalline silicon. Module efficiencies are about 10%-13%. The price is then about $400/m^2$. (Converting $/$W_p$ to $/m^2$ is simple: multiply the $/$W_p$ by W_p/m^2 to get $/$W_p$. W_p/m^2 is simply the module efficiency times 1000 W/m^2. So for 11% modules at $4/$W_p$, the conversion is $4/$W_p$ x 1000 W/m^2 x 11% = $440/m^2$.) If there is a 30% margin in this sale price, it would imply *a manufacturing cost of about $300/m^2$ for today's PV*. Similarly, the cost of the rest of the PV system is also large. The lowest-price PV systems are being installed for about $6/$W_p$. Perhaps balance-of-systems (BOS) prices are about $2-$3/W_p, or about $250/m^2$. Despite its usefulness for other markets, PV would never reach 6 cents/kWh if BOS prices were to remain high. Fortunately, there are a number of reasons why BOS prices should fall significantly: today's systems are "one-of-a-kind" and incur very large one-time-only costs associated with design and installation; large-scale, in-plant production of arrays should be possible for future large-scale systems; and none of the designs (mechanical or electronic) have yet been well optimized for PV. We must make an assumption that BOS costs will drop substantially to even discuss systems (modules and BOS) that can be competitive at about $150/m^2$ initial investment.

PV will be sold for quite some time into higher-value markets. Some of those markets (e.g., rural electrification) are about as large as the potential markets in developed countries. It is important to include this in planning by restating the PV goals to include these large, developing-country markets. Developing countries cannot easily find electricity at 6 cents/kWh, especially for dispersed uses. If one accepts a goal of 12 cents/kWh (plus inflation) for these markets, then a set of goals can be given, as in Table 1.

Table 1. Goals to Achieve >10% Annual Return (Level of Initial Investment)

	Today	**@12 cents/kWh**	**@6 cents/kWh**
Thin-film modules	400 $/m^2$ (wafer Si)	150 $/m^2$	75 $/m^2$
BOS (including "$/kW" costs)	250 $/m^2$	150 $/m^2$	75 $/m^2$

Assumes: 6 or 12 cents/kWh revenue plus 3% inflation; 10% system efficiency (ac); average US sunlight; 30-year life

Note that the technical goals include more than price. In addition to the fact that thin-film modules must be priced at about $75/m^2$, they must produce electricity at an efficiency implying an ac system efficiency of 10%, and they must lose less than 1% of their output annually for 30 years. The apparently low system efficiency goal (10%) is misleading. Normal loss mechanisms (operating temperature losses, wiring, module packing factor, dc-to-ac conversion, dust) reduce module performance by about 20%-30%. A 10% system efficiency and a 30% operational loss implies a module of 14% efficiency under standard measurement conditions. Tradition has pegged the module goal for thin films at 15%, which is as close as this kind of analysis can imply. Note also that some thin films may be less efficient but also less expensive, thus meeting the goals with different combinations of these key parameters. Indeed, various analyses (see below) suggest thin films can be made for under \$50/m^2, leaving some room for improving beyond the Table 1 goals.

Having established reasonable long-term *cost, performance and reliability* goals for thin films, the question becomes: Can thin films meet these goals?

The Performance Goal

Perhaps the easiest goal to quantify is the performance goal. Figure 2 shows the world-record efficiencies of one-of-a-kind laboratory cells made from copper indium diselenide (CIS) and its alloys, from cadmium telluride (CdTe), and thick film Si. Not shown are amorphous silicon cell efficiencies, which lag behind (about 12% maximum for stabilized cell efficiencies), and other innovative thin films like dye-sensitized cells and very thin film crystalline silicon (about 10%). The one-of-a-kind cell results of Figure 2 are by no means equivalent to achieving the same efficiencies in commercial products, but they are an important indicator of such a potential. But what is the relationship between small-area laboratory cells and large-sized modules?

In June 1988, ARCO Solar Inc. (Camarillo, CA; now Siemens Solar Industries) fabricated a one-of-a-kind CIS submodule (1-ft^2) measured at the National Renewable Energy Laboratory (NREL) at 11.1% efficiency. At the same time, the world-record CIS cell efficiency was 12.5%. In 1994, United Solar Systems Corporation (Troy, MI) fabricated a 10.2%-efficient amorphous silicon submodule (1-ft^2) at a time when the record cell efficiency was only 11% for this material. The ratios of these efficiencies (cell/submodule) are 0.89 an 0.92, respectively. Using a ratio of 0.9, implies that it would require a cell of 16.6% efficiency to fabricate a 15% submodule. This efficiency (16.6%) has been achieved by CIS-based cells and has nearly been achieved by CdTe cells.

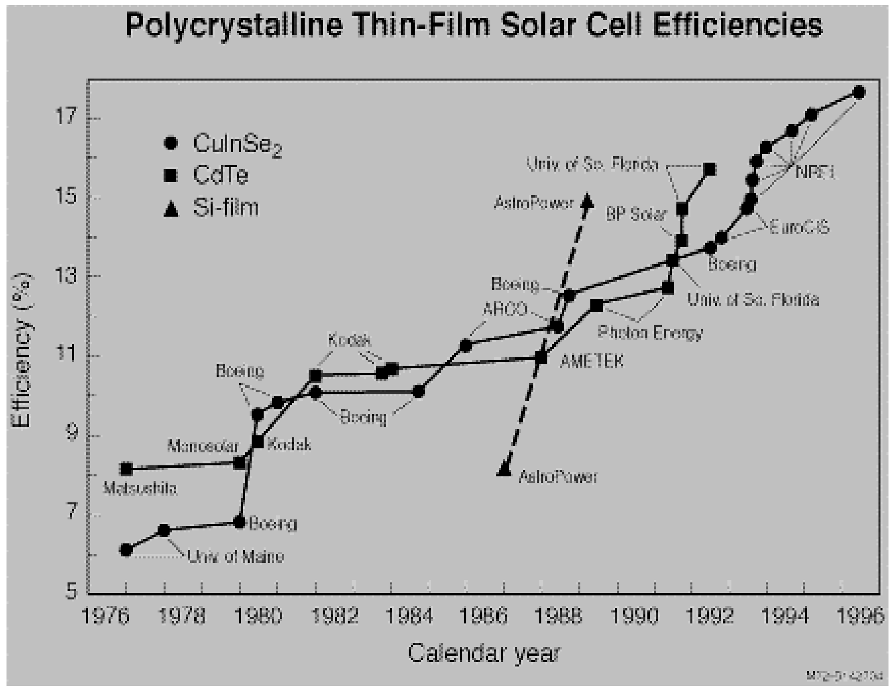

Figure 2. The best on-of-a-kind laboratory cell efficiencies for thin films now approach the best efficiencies produced by classic polycrystalline silicon. These achievements, once thought impossible, are the basis for expecting thin films to reach the performance goals needed for truly low cost.

The use of 0.9 somewhat misses the point, however. Commercial modules will always be less efficient than one-of-a-kind submodules. They are larger (implying some uniformity-related loss) and must be made in large quantities (i.e., they are "average," not best). Some of these differences will be minimized as thin-film manufacturing technologies mature. To be careful, let us assume a further 10% gap between best modules and commercial modules. This suggests that laboratory cells of almost 19% would be needed to make 15% commercial modules. Cells of 17.7% efficiency (like those CIS cells already made) would imply modules of about 14.3% efficiency. This is in the range needed to make the goal. Table 2 shows today's best one-of-a-kind thin-film modules. In many cases, the effort to scale up to product sizes (4-10 ft^2) has been the recent focus, rather than efficiency champions at smaller, more tractable sizes (e.g., 1 ft^2). For this reason, module efficiencies trail best-cell efficiencies substantially. Companies recognize that an 8%-10%-efficient thin film will allow them to successfully compete in today's PV market, and that is their immediate motivation.

Table 2. Best Large-Area Thin-Film Modules

Company	Material	Area (cm^2)	Efficiency (%)	Power (W)
United Solar	a-Si Triple	9276	7.6	70.8
Solar Cells Inc.	CdTe	6728	9.1	61.3
Solarex	a-Si Dual Junction	7,417	7.6	56
APS	a-Si/a-Si	11,522	4.6	53.0
Siemens Solar	CIS	3,664	11.1	40.6
BP Solar	CdTe	4,540	8.4	38.2
United Solar	a-Si Triple	4519	7.9	35.7
Golden Photon	CdTe	3,366	9.2	31
ECD	a-Si/a-Si/a-SiGe	3,906	7.8	30.6

Given the past history of achievements in thin-film cell efficiency, it seems that performance—*if it can be transferred from lab cells to product-sized modules*—will not be a "show stopper" for one or more thin-film technologies.

The Reliability Goal

Outdoor performance must be dependable and of a duration approaching 30 years to rationalize the cost goals. PV has not been around much more than 30 years, but observation of PV systems suggests that the modules—almost all made using wafer-based silicon cells—are the most durable part of the system. Documented failure rates of only one per 10,000 per year are an important achievement by the wafer-silicon PV technology.

In contrast, thin films have a checkered outdoor track record to-date. The first thin films, made of copper sulfide, suffered from an electrochemical instability that led to degraded performance. Copper sulfide never became a significant thin film. The second commercial thin film—amorphous silicon (a-Si)—suffers from a serious degradation associated with (of all things) exposure to light. Called the Staebler-Wronski Effect, it results in about a 15%-40% degradation, unless checked by design modifications such as thinner intrinsic layers and the use of multijunctions. This degradation is what keeps a-Si efficiencies below those of other thin films. Combined with some start-up problems with encapsulation and quality control, the poor outdoor performance of a-Si products has—until recently—defined the bad reputation of thin films.

Fortunately, many of these problems are behind us. Numerous minor problems (designing encapsulation, controlling the quality of the modules themselves) have been overcome as a-Si has matured. In addition, a major breakthrough came when it was observed *that a-Si devices degrade to a reduced level and then do not degrade further*. The absolute amount of degradation is somewhat dependent on the outdoor temperatures [1], being worse at lower operating temperatures. Advanced PV Systems (APS) built and installed a 400-kW a-Si system at an installation in California called Photovoltaics for Utility-Scale Applications (PVUSA). This $\$5/W_p$ system (perhaps the world's cheapest) has shown the typical behavior of a-Si modules: initial degradation, followed by stabilization and mild oscillation around the stabilization point. This behavior, called "stabilized efficiency" has taken the place of previous usages: now, all efficiencies quoted concerning a-Si are at lower, stabilized efficiencies, not at the unintentionally misleading initial efficiencies. NREL has independently performed similar testing of numerous a-Si modules and found the same phenomenon: an initial drop of about 25% followed by stabilization.

The other, newer thin films have problems as well. Like a-Si, they will no doubt suffer some start-up problems (encapsulation, quality control). However, they do not have the Staebler-Wronski Effect to worry about, because they do not share the same "amorphous, hydrogenated" semiconductor nature as amorphous silicon they are small-grained crystalline materials, more similar to crystalline silicon in that sense. In fact, initial outdoor tests of CIS-based and CdTe modules has been quite encouraging. NREL's data shows that some thin film modules have been made that appear to be stable over a period of 6 months to 10 years [30]. This is a proof-of-concept that stability is possible. However, it is not the final word. To achieve true commercial stability, modules will have to be made with complete reproducibility so that such one-of-a-kind stability results become the norm for every module. Similarly, any hidden, longer-term issues—such as diffusion of impurities, the action of humidity, or other subtle degradations—will still require attention. One cannot be absolutely sure that new thin films have no catastrophic degradation mechanism lurking in the n+1 (<30) year. Only time will remove this natural concern.

The Price Goal

"Price" is a slippery item for a number of reasons:

(1) True manufacturing costs depend critically on yields and on step-by-step details such as materials utilization;
(2) Process complexities often show up only after the learning experiences of pilot and early, full-scale production;
(3) Innovations are continuously occurring, making last-year's bottleneck, next year's opportunity;
(4) Sales price is "what the market will bear" and is not fully reflective of costs; overhead varies by size of production and by markets; taxes and business strategies to reduce costs are impossible to fully characterize;
(5) Companies hold most or all such details confidential.

Because of this, it has been traditional to develop production cost models and to view any such models skeptically. A compilation of PV production cost projections [2-13, 29] shows general agreement on the following:

- Thin films can be quite inexpensive. Costs (with overhead and profit) in the range of $40-$80/m^2 are reasonable long-term expectations.
- Materials costs are small: about $5-$10/m^2 for the active semiconductors and about another $10/m^2 for the glass and encapsulation.
- Other important costs (energy input, equipment depreciation, labor) are less than $10/m^2 each, with additional costs for overhead and profit. For example, an original investment of $50 million for equipment for a 100-MW plant, amortized over 5 years, is close to $10/m^2-yr. Using a 7-year amortization, it is about $7/m^2. This is the second largest cost behind materials.
- All costs depend critically on achieving high production yield (>90% final product) and reasonable (over 50%) materials utilization in the materials-intensive steps (e.g., absorber layer deposition).

Production yield is the most sensitive issue. If yields fall below 50%, economics are impossible (costs double). Somewhere in the 70%-80% range, yields move toward acceptability, but mature production plants should be in the 90% range to be able to approach the lower end (under $50/m^2) of the cost goals.

Materials utilization will also become important as the technologies mature. Analyses of mature industries of various kinds suggest that the ultimate cost-limit is associated with materials costs. In a 2-micron-thick layer of $CuInSe_2$, there are about 4 g/m^2 of indium (by far the most expensive element). At a cost of about $300/kg ($0.3/g), this is about $1.2/m^2 at 100% utilization. At a more realistic 70% utilization, this would be an acceptable $1.71/m^2. At 33% utilization, it would be up to $3.6/m^2. At 10% use, it would be an undesirable $12/m^2. This example shows that there is some leeway in semiconductor costs and utilization, but such costs could become a problem if the most expensive material is used poorly. Indeed, as some of the key materials (e.g., In, Te) are needed for larger production volumes, their costs may rise, tightening the allowable losses during production. In-plant recycling of these materials is a likely scenario for mature production.

If yields are high and materials use is fair to good, thin films can be inexpensive. These issues reside in the manufacturing area and can only be fully proven when large scale manufacturing matures.

The Thin-Film Technologies: Issues and Opportunities

To understand the developmental issues of thin films, it is important to examine each individually. Each has a unique set of advantages and shortcomings in terms of their potential to reach the needed performance, reliability, and cost goals.

Amorphous Silicon

Amorphous silicon was viewed as the "only" thin film in the 1980s. By the end of that decade, and early in the 1990s, it was written off by many observers (and some investors). However, amorphous silicon technology has made good progress developing a very sophisticated solution—multijunction cells/modules—to most of its problems. Now it appears that commercial, multijunction a-Si modules could be in the 7%-9% efficiency range in the near term, and two companies (Solarex-Enron and United Solar) have built multi-MW facilities. This is a reminder of the well-known fact that all PV technologies go through difficult periods, and some (with enough investment) emerge with realistic chances of success.

However, there remain a number of serious problems with amorphous silicon technology. Today's best cell efficiencies (stable) are about 12%. This is almost 50% lower than copper indium-gallium selenide (CIGS). But the difference is somewhat overstated by this bald comparison. Why? Outdoors, CIGS loses about 20% of its output (due to operating temperature), while a-Si loses about 5%. Yet the problem of low efficiency (modules well under 10% efficiency) could keep a-Si from ever dropping below $\$0.5/W_p$ manufacturing cost. In the $\$0.5$-$\$1.5/W_p$ range, a-Si could have a major impact on the PV marketplace. But its future will be limited if it cannot overcome the 10%-efficiency "barrier" in power modules.

Today's multi-band gap, multijunction designs are driven by the need to make thin layers to minimize the Staebler-Wronski Effect. Thus, key research efforts are focused on the component cells and their optimization. Recently, cell efficiencies have improved substantially, mostly through the success of United Solar, which has improved from 10% to over 12% in the last three years. Module efficiencies have also improved, and much effort has been expended on bringing amorphous silicon into multi-MW production.

A second problem with amorphous silicon is manufacturing cost associated with initial capital investment and with germane use in multijunctions [29]. Capital costs in the range of \$3/Wp of annual capacity amortized over 7 years cost over \$0.4/Wp ($\$35/m^2$), which is unacceptably high. Two proposed solutions to this problem are higher rates and batch processing of multiple modules simultaneously. Good progress has been made in rates that are 3-10 times higher than those being used in production [14-17]. A small company, EPV, has demonstrated lower-performance same-band-gap multijunction modules using a batch process that produces 48 modules in the same reactor. If performance can be maintained (and eventually improved) using these lower cost approaches, it will substantially help amorphous silicon progress to low cost. The second problem, germane use, is also serious, since germane in gas form costs about \$4000/kg. With poor usage of about 5%-25% for existing amorphous silicon processes (for a-Si:Ge middle and bottom cells), this can cost more than $\$10/m^2$ by itself. Improving Ge use is another area of focus.

Cadmium Telluride

The thin-film technology next closest to commercialization is based on cadmium telluride. Two U.S.-based multi-MW manufacturing plants (BP Solar and Solar Cells Inc.) are being built. CdTe cell efficiencies are high (almost 16% in the laboratory), but commercial module efficiencies are likely to be in the 7%-9% range in the first plants due to a lag in getting leading-edge lab results incorporated in initial manufacturing.

It is generally believed that CdTe is the *easiest* of the thin films to fabricate. More than a dozen methods have been used to make 10% cells. This allows the potential manufacturers to choose their least-cost method. The currently favored methods are high-rate sublimation (Solar Cells Inc.), screen printing/sintering (Matsushita), and electrodeposition (BP Solar). Their rapid rates and/or low capital costs are a substantial advantage for CdTe.

A subtle problem is that CdTe *modules* are much less efficient than CdTe *cells*. The main issue is the use of a thin n-CdS layer to form the junction with p-CdTe. This CdS layer must be thin enough to allow high energy light (above the 2.45-eV CdS band gap) to reach the junction. Yet, the CdS must be of adequate quality and coverage to make a good, high-voltage junction. Achieving these conflicting goals has been difficult in cells, but the best cells are made this way. It has yet to be done in modules. The ability to achieve high current and high voltage with thin CdS is the main research problem in CdTe technology.

Two other issues are also of concern: stability and cadmium. With respect to stability, many CdTe cells and modules have been made with excellent stability. But under extreme stresses (not replicated outdoors) cells degrade. What are the mechanisms of degradation—copper diffusion to the junction, oxidation at the contact, or humidity-driven corrosion at the contact? How long will the devices that work remain stable? As of now, it appears that these stress-driven mechanisms will not limit CdTe reliability outdoors to the 30 year goal.

Cadmium issues are another area of concern. Very little cadmium is used in CdTe modules—but enough to be of interest to health officials and policy makers [17-28]. It is as yet unknown whether commercial CdTe modules will be classified as hazardous waste, because some modules (BP Solar) have been reported to pass the appropriate U.S. Environmental Protection Agency tests (the TCLP) whereas others do not. Fluorescent lights (containing mercury) and computer screens (containing lead) are common examples of items that do not pass this test. In-plant waste-handling strategies at PV plants have been excellent, with suppliers such as ASARCO agreeing to take back (for re-smelting) any in-plant wastes. Engineering and management strategies to minimize worker hazards have been excellent as well. Sophisticated engineering controls have been put in place, and biomonitoring has been under way for years with no significant observed increases in worker exposure. Tests have been carried out to examine the toxicity of CdTe devices by ingestion (National Institutes of Health), and these have shown that the material is quite indigestible (and thus, does not normally enter the body by this route). Work is also under way to examine cost-effective means of assuring future product recycling of these modules. Two companies have succeeded in developing the technology for stripping and recycling CdTe films. In summary, although a concern exists about cadmium in CdTe modules, it is viewed as manageable. Considering the advantages of PV in offsetting other sources of energy, the cadmium issue should be put in the same perspective as similar issues, e.g., mercury in fluorescent lights (where the environmental balance is considered favorable). Due to the nature of "thin film" CdTe modules, the use of cadmium in PV is always likely to remain a small fraction (under 10%) of the world's existing use of cadmium—even if CdTe modules are one day able to provide a significant fraction (more than 10%) of the world's electricity.

CdTe technology (1) suffers from the possibility that near-term commercialization will encounter classic start-up issues (although such issues have not yet emerged); (2) has a stability problem under severe stresses, although stability is perfect outdoors; and (3) must raise the efficiency of modules toward those attained by the best cells, which will require solution of processing challenges associated with using thin CdS in manufacturing. If these problems can be solved over the next 10 years, CdTe technology has a very good chance to achieve the long-term cost, performance, and stability goals. Viewed from this standpoint, it could be regarded as the leading thin film.

Copper Indium Diselenide (and Related Alloys)

Copper indium diselenide cells have reached nearly 18% efficiency under standard test conditions. This means that the best CIS cell is approaching the *best* efficiency of a polycrystalline *silicon* cell. This is a strong proof-of-concept that thin films can perform well. However, CIS cells have major hurdles to overcome to be successful in the marketplace.

In 1988, the then ARCO Solar made a best-ever 11% CIS square-foot module. Ten years later, this is still the most efficient thin film of its size, and CIS is still not commercially available. CIS manufacture ran into a set of start-up problems at ARCO Solar (now Siemens Solar Industries, SSI) that put it in jeopardy. They ranged from poor adhesion between the CIS and the bottom contact (molybdenum) to irreproducible deposition of the CIS. High yields at high efficiency could not be achieved. Commercialization was postponed while SSI went back to basics.

SSI has now addressed the important CIS issues and has resolved most manufacturing problems. SSI reports that they have improved yields and raised efficiencies significantly. In the meantime, NREL learned how to make the best CIS cells in the world, reaching 17.7% efficiency in 1996. We did so by including gallium and graded layers in our cells, achieving both improved morphology (larger grains) and better electronic properties. The NREL work built on previous groundbreaking work at Boeing (now discontinued) and by EuroCIS, the European consortium of universities.

Today, CIS and its alloys with gallium and sulfur, have regained importance, because Siemens Solar Industries recently began commercial production of CIS modules. The modules have been tested at NREL, and they are the first thin films over the 10% efficiency barrier. The long, difficult history of CIS is another example of how unexpected challenges occur and can be overcome.

Outdoor reliability has never been an issue with CIS. NREL data on CIS modules and a 1-kW system (SSI) have been exceptionally good, with no degradation by any modules, some outdoors for a decade.

Good stability and proven efficiency make CIS a strong thin film. Commercialization is still problematic because SSI is only now dealing with the challenges of true commercial production. Longer-term, the technology is as promising as any.

Film Silicon and Dye-Sensitized Cells

Several groups have tried to combine the strong performance of crystalline silicon devices with the attractive economic advantages of thin-film manufacture—large-area processing. In fact, as the thickness of silicon is reduced, its material costs approach those of thin films. Except for the very high temperature of silicon processing, most attributes of the thin films can be achieved, if the crystalline silicon devices can perform as well as hoped, and if they can be interconnected monolithically like thin films. One U.S. company, AstroPower, has taken this approach quite successfully. Today, AstroPower has a thick film Si product, and they are developing thinner products down to 100 microns.

Very thin crystalline silicon cells have not reached high performance levels above 10%. Some of the physical aspects of silicon processing (the required diffusion lengths, the high temperatures, sensitivity to impurities, light trapping) cause problems in making thin silicon cells on inexpensive (impure) substrates. There is significant work in Japan on some of these problems, both at Mitsubishi and Sanyo. But deposition rate and performance are serious issues for this approach and the future of large-area very thin (under 10 micron) silicon films designed to meet <\$1/W_p goals remains uncertain.

The Swiss scientist Michael Graetzel is known for an electrochemical device sometimes called the Graetzel cell, which is possibly the most elegantly simple PV device made. It is also one of the few really unique and promising technologies to emerge as a viable PV competitor over the last decade. Using titanium dioxide (like that used for paint) and a long-lasting dye, a thin-film cell is made that has been reported to have reasonable (near 11%) efficiency. Initial commercialization has been begun by an Australian company (Sustainable Technologies Australia Limited). However, like other PV electrochemical devices, the new TiO_2 cells must overcome outdoor stability issues such as module design and sealing. Making higher efficiencies, achieving stability and demonstrating low cost in actual manufacturing are barriers that are familiar to all thin films; they remain challenges for the Graetzel cell.

Back to the Future

The future of thin films looks strong. Despite serious obstacles, amorphous silicon has established itself as a viable competitor for wafer-based crystalline silicon devices. Once established in the marketplace, amorphous silicon is likely to make good progress and could even come to dominate the world PV market. Meanwhile, the next generation of thin films, CIS and CdTe, shows stronger technical performance (laboratory efficiency and stability) and similar or lower potential cost. The goals for truly inexpensive PV are ambitious (15% modules, 30-year life, price under \$75/m^2, or about \$0.5/W_p), but thin films seem capable of reaching and even exceeding these goals. The future is likely to be as checkered as the past, with technologies experiencing the harsh realities of early production and companies forced to endure losses that extend well past expectation. Other technical plateaus will be suffered, but most issues will be overcome. The technical basis for thin films is solid, and the accomplishments up to now have been in line with the technical foundation and are likely to continue. Thin-film goals should be met, and thus low-price photovoltaics will become real. The key will be the resources and endurance needed to overcome the technological challenges.

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Footnotes

1. This ignores operating and maintenance costs, which are, however, expected to be almost nil. It also lumps costs such as inverters, which are usually stated as \$/kW, into the "\$/m^2" category. This is okay for specific systems where the cost can be parameterized as "\$/m^2" after the fact.
2. More formally, internal rate of return is defined (and calculated) as the discount rate which makes the present value of the stream of net cash flows involved in this investment equal to zero.
3. If the PV installation were built by a firm, say an independent power producer, several tax considerations would complicate the analysis. Somewhat surprisingly, the net effect of these tax considerations does not significantly change the after-tax IRR from what is shown in Figure 1.