Thin Film PV: A System Designer's Guide

Thin-Film PV: A System Designer’s Guide By Rick Holz

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This is a wonderful article, albeit, probably only for the geekiest engineering types, which "I are one".

There are concepts touched on here that really get into the subtleties and muances of solar design considerations.

To get the whole artcle which includes many tables and comparisons check out Solar Pro Magazine DEC/JAN 2011. Thin Film PV: A System Designer’s Guide The thin-film PV industry has seen extraordinary growth in the past 8 years. According to GTM Research, about 17 MW of thin-film modules were produced globally in 2002, accounting for a 3% market share. Thanks in large part to the global polysilicon shortage of the mid-2000s, not to mention the $4-per-watt crystalline silicon (c-Si) PV module prices that followed, thinfilm commercialization activities increased. “The search for alternative technologies led to a tidal wave of investment and entrepreneurial activity in thin film,” writes Shyam Mehta, senior analyst at Greentech Media, “with 46 companies entering the market between 2004 and 2008, as well as $1.8 billion in venture capital investment in the space.” Displaybank, a market research and consulting authority, reported that thin-film cell production reached 1.9 GW in 2009, for a 19.8% market share, and the company forecasts 2.8 GW of thin-film cell production for 2010.apromise,Thin-Film PVDespite these very encouraging signs for the thin-film industry, competition with traditional c-Si PV manufacturers has never been fiercer. As the polysilicon shortage passed, the global economy faltered. This led to a material and product oversupply situation, one characterized by downward price pressures. Crystalline silicon module prices have more than halved since 2007. Hennig Wicht, PhD, senior director and principal PV analyst for iSupply, expects to see an average sales price of $2 per watt for c-Si PV modules in 2010, versus an average sales price of $1.40 for thin-film PV. In some cases, c-Si PV modules (especially Asian multicrystalline products) destined for large projects are reportedly selling at prices approaching those for thin-fi lm modules. As a result of this narrowing price gap and the difficult credit market, many analysts believe that the thin-film industry is facing significant consolidation. Signs of this are evident in recent headlines, such as Applied Material’s exit from the thin-film market. Price pressures have translated into greater demands on the performance and durability of thin-film products. Tight credit markets have created an emphasis on the bankability of thin-film PV products and manufacturers. Some thin-film sectors, particularly amorphous silicon, face increasing skepticism from investors and integrators. This skepticism involves manufacturer credentials, as well as product performance and durability. In this article, I address the latter concerns, especially in terms of thin-film module deployment. I seek to answer the all-important question: What can you as system designers do to improve the performance and durability of systems that use thin-film PV modules? One valuable tool for designers in this regard is the comprehensive thin-film product specifications table on pages 48–49. Granted, thin-film technologies are quite different from the c-Si PV products that you are more familiar with. But as long as you are armed with meaningful and complete data about these modules, then you can deploy systems that meet or exceed performance expectations. What is thin-film PV? what do system designers and integrators need to know?In contrast to industry-standard monocrystalline or multicrystalline silicon cells, which are currently produced commercially with a thickness of 150 to 200 microns or more, thin-film PV technology deals with very thin layers of semiconducting materials on the order of only 2 microns thick. The semiconducting materials used in thin-film PV cells range from the ubiquitous, like silicon, to the exotic, such as tellurium or gallium. These thin material layers are typically deposited, often in multiple layers, on rigid or flexible substrates made of metal, glass or polymers.The promise of thin films, which are sometime referred to as The first a-Si cell was developed at RCA Laboratories by David Carlson and Christopher Wronski in the mid-1970s. The term amorphous refers to the random, noncrystalline structure of the atoms making up these materials. Compared to other thin-film technologies, a-Si is relatively easy and low-cost to manufacture, but it is also the least efficient of the commercialized thin films. Module efficiencies typically range between 5% and 7%.Amorphous silicon. Of the many a-Si PV module manufacturers worldwide, United Solar, a subsidiary of Energy Conversion Devices, stands out for two main reasons. First, the company’s roll-to-roll manufacturing process is unique. Three a-Si cell layers, each with a complementary spectral response, are deposited on a flexible stainless steel substrate and encapsulated within a rugged polymer. These triple-junction a-Si rolls are then cut up for use in framed UNI-SOLAR modules, as well as for a variety of building-integrated and electronicsintegrated PV products. Second, as Greentech Media’s Mehta points out in his article “The Future of Thin Film: Beyond the Hype,” going into 2010, United Solar was one of only two thinfilm manufacturers to produce in excess of 100 MW annually. The other was market leader First Solar.An increasingly common way for manufacturers to improve on a-Si efficiencies is to deposit an additional microcrystalline silicon (¼c-Si) absorber layer, resulting in a tandem-junction icromorphous a-Si/¼c-Si cell. This is still considered thin film because once both layers are deposited, the tandem-junction cell is still on the order of 2 microns thick. The a-Si/¼c-Si cell is more efficient than an a-Si cell, owing to the complementary spectral response of the microcystalline layer. Micromorphous PV products listed in the companion table are generally between 8% and 9% efficient.It was a CdTe cell, produced by esearchers at the University of South Florida, that in 1992 first broke the 15% efficiency barrier for thin-film PV. Commercial efficiencies are currently in the 9% to 11% range for these glass-on-glass modules. Only two CdTe manufacturers currently offer UL- and CEC-listed products: First Solar and Abound Solar.CIS cells include thin layers of copper, indium and selenium; CIGS cells add gallium to that mix. In the laboratory,CIGS cells produced by NREL have broken the 20% efficiency barrier. Commercial CIS/CIGS products generally have module efficiencies in the 9% to 11% range. Glass substrates are most common; however, flexible substrates are also being used for building-integrated PV (BIPV) products.

THIN -FILM Properties and Characteristics The accompanying specifications table lists the properties and characteristics of thin-film modules that are most relevant for system designers and integrators. When working with these data, however, it is important to recognize and account for the ways that specific thin films differ in their behavior from traditional c-Si PV modules. While in some cases these differences cut across cell types, in others they are unique to a technology or product.Voltage characteristics. Relatively speaking, low voltage and high current are characteristic of c-Si PV modules, whereas many thin-film modules are just the opposite, exhibiting high voltage and low current. This difference is significant when considering electrical string configurations.SolarPro published in August/September 2010, the average ratio is closer to 80%. This ratio is significant because as it decreases the voltage spread between Vmp and Voc increases, suggesting that array-to-inverter matching becomes more difficult. Other factors, of course, are at work—lower-voltage modules inherently provide more design flexibility than higher-voltage modules, for example— so string-sizing options for thin-film arrays are generally more limited than for c-Si PV

Temperature coefficients. System designers are well aware of the inverse relationship between temperature and voltage as it relates to the performance of PV materials. Lower voltages also produce less power. These effects are quantified using temperature coefficients, which are essentially measures of the voltage drop in a diode as its temperature increases. As a rule, temperature coefficients of voltage and power for thin films are quite a bit less than those for conventional c-Si PV modules. Representative temperature coefficients by cell type are illustrated in Figure 2. The lowest thin-film temperature coefficients are seen in a-Si modules, whereas CIS/CIGS products have the highest. The good news is that lower temperature coefficients generally benefit the designer and may improve system performance as well.According to Charly Bray, vice president of project engineering and operations at Sky Solar Group: “Lower temperature coefficients of voltage generally work to the benefit of the designer because this limits the operating voltage range of the system.” While the spread between Vmp and Voc is larger for thin films at STC, the lower temperature coefficients of voltage tend to moderate the spread between the maximum system voltage and the minimum operating voltage in the field. While temperature coefficients are assumed to be constants, some manufacturers have demonstrated that their products exhibit a nonlinear dependence on temperature. This may have the effect of lowering the maximum system voltage from that calculated using the published coefficients. This emphasizes the importance of working closely with product applications engineers, especially when working with a product for the first time.In terms of system performance, lower temperature coefficients suggest that thin-film products tend to outperform c-Si modules at higher temperatures. Ratios of PTC to STC, for example, are higher for thin films (93%–94%) than for c-Si (87%–90%). This is important because PV modules do not spend very much time at a single set of operating conditions, especially not at STC. In general, more energy is harvested from a PV system when cell temperatures exceed 25°C. This is one of the reasons that the annual energy yield per rated watt (kWh/kWp) for a thin-film array may exceed that for a c-Si array.Performance transients. “All PV technologies have some electronic hysteresis,” writes Ken Zweibel in a 1999 conference paper for the Electrochemical Society. The former program leader for NREL’s Thin-Film PV Partnership goes on to explain: “This means that their sunlight exposure and electronic history influence performance.” As an example, c-Si PV modules undergo an initial A small amount of hydrogen, for example, is incorporated into the a-Si cell structure. The hydrogen atoms enhance the electrical properties of the a-Si. But when these hydrogen atoms are pushed away from the silicon, a process energized by the presence of photons, defects occur in the atomic structure and the performance of the a-Si cell is gradually reduced. This is referred to as the Out of the box, amorphous and micromorphous PV modules effectively exceed their nameplate power ratings. Upon exposure to light, their effective power gradually decreases until it settles out within the power tolerance of the STC rating. This process is referred to as light soaking. The number of junctions generally determines the level of decay due to light-soaking effects. Subsequent long-term degradation in a-Si is not linear, due to the Single-junction a-Si products, for example,can experience up to 30% decay; tandemjunctionproducts, including a-Si/¼c-Sicells, might experience as much as 20%decay; and decay for triple-junction productsis usually around 10%. Typical stabilizationtimes for the Staebler-Wronski effectare 6 to 16 weeks. This is a fully reversible effect. If you coverthe a-Si module for a period of time and then uncover it, you

will see the same gradual degradation all over againStaebler-Wronski effect, after the RCA Laboratories researchers who discovered it. How this is expressed in the field is important for system designers and integrator s to understand, as it may impact inverter selection and source-circuit design.light soaking. The number of junctions generally determines the level of decay due to light-soaking effects. Single-junction a-Si products, for example, can experience up to 30% decay; tandemjunction products, including a-Si/¼c-Si cells, might experience as much as 20% decay; and decay for triple-junction products is usually around 10%. Typical stabilization times for the Staebler-Wronski effect are 6 to 16 weeks. This is a fully reversible effect. If you cover the a-Si module for a period of time and then uncover it, you will see the same gradual degradation all over again.seasonal annealing effect. At cooler times of the year, the Staebler-Wronski effect is relatively stronger and module efficiency is relatively lower as a result; warmer weather results in relatively improved efficiencies. (This relationship to temperature is counterintuitive since it is opposite of the diode power-temperature relationship.) See Figure 3 for an idealized a-Si power degradation curve. Dark soak is a performance transient that affects CdTe, and CIS/CIGS thin-film modules in particular. After modules are removed from their boxes and exposed to sunlight, their output has been observed to increase by as much as 6%. Stabilization can take up to a few weeks on large systems. According to Rommel Noufi, PhD, principal scientist and thin-film group lead at NREL: “This phenomenon is not well understood. It is due either to junctions being in a nonequilibrium state when the cells are made and packaged, or to differing electrical biases in darkness versus the presence of light.” Whatever the cause, dark soak should not complicate system design or operation.Fill factor. Apprenticeship and Training Committee, In Jim Dunlop’s textbook for the National JointPhotovoltaic Systems,the term power to the product of the open-circuit voltage and theshort-circuit current.”fill factor (FF) is defined as “the ratio of maximumFF = Pmp / (Voc x Isc)Fill factor not only describes a cell’s I-Vcurve but also its quality compared toan idealized cell.System designers are familiar withthe classic shape of the I-V curve fora c-Si PV module. While I-V curvesfor thin-film modules are similar, theyhave noticeably more rounded corners,meaning the maximum power isless pronounced. Figure 4 shows thepublished I-V curve for a UNI-SOLARtriple-junction a-Si module. The roundingof the I-V curve is more pronouncedin a-Si than in CIS/CIGS or CdTe, butit is nevertheless present for all thinfilmtechnologies.The maximum power for an idealizedPV cell is equal to the product ofits Isc and Voc, resulting in a rectangularI-V characteristic and a fill factor

of unity (FF = 1.0). According to RogerThe same cannot be said for thin-film performance transients. A small amount of hydrogen, for example, is incorporated into the a-Si cell structure. The hydrogen atoms enhance the electrical properties of the a-Si. But when these hydrogen atoms are pushed away from the silicon, a process energized by the presence of photons, defects occur in the atomic structure and the performance of the a-Si cell is gradually reduced. This is referred to as the Staebler-Wronski effect, after the RCA Laboratories researchers who discovered it. How this is expressed in the field is important for system designers and integrators to understand, as it may impact inverter selection and source-circuit design.light soaking. The number of junctions generally determines the level of decay due to light-soaking effects.seasonal annealing effect. 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It is due either to junctions being in a nonequilibrium state when the cells are made and packaged, or to differing electrical biases in darkness versus the presence of light.” Whatever the cause, dark soak should not complicate system design or operation.In Jim Dunlop’s textbook for the National Joint Apprenticeship and Training Committee, Photovoltaic Systems, the term fill factor (FF) is defined as “the ratio of maximum power to the product of the open-circuit voltage and the short-circuit current.”Fill factor not only describes a cell’s I-V curve but also its quality compared to an idealized cell.Photovoltaic Systems Engineering: “The secret to maximizing the fill factor is to maximize the ratio of photo-current to reverse current while minimizing series resistance and maximizing shunt resistance within the cell.” Series resistance, which manufacturers seek to minimize, describes the cell’s internal resistance to current, resulting from the semiconductor material itself as well as from metallic contacts and interconnections. Shunt or parallel resistance, which manufacturers seek to maximize, describes the device’s resistance to leakage current. to nonoptimal currents and voltages. FF = Pmp / (Voc x Isc) System designers are familiar with the classic shape of the I-V curve for a c-Si PV module. While I-V curves for thin-film modules are similar, they have noticeably more rounded corners, meaning the maximum power is less pronounced. Figure 4 shows the published I-V curve for a UNI-SOLAR triple-junction a-Si module. The rounding of the I-V curve is more pronounced in a-Si than in CIS/CIGS or CdTe, but it is nevertheless present for all thinfilm technologies.The maximum power for an idealized PV cell is equal to the product of its Isc and Voc, resulting in a rectangular I-V characteristic and a fill factor of unity (FF = 1.0). According to Roger Messenger and Jerry Ventre, authors of In general, thin-film modules have higher series resistance than c-Si cells do, resulting in lower fill factors and efficiencies. Shunt resistance can be affected more by module construction than PV technology. These resistances have improved (increased) in thin-film modules as module construction has improved over the years. Representative fill factors by technology are shown in Figure 5.While it is not uncommon for inverter manufacturers to tout their product’s exceptional ability to find the MPP for a thin-film array, there is no evidence that system designers need to make special accommodations for lower fill factors. The MPPT algorithms in modern inverters are both fast and highly accurate. In terms of system performance, low fill factor may actually be advantageous because it translates into lower mismatch losses.Most designers and project developers accept that c-Si modules of differing power ratings should not share the same inverter. The situation with thin-film modules is more ambiguous, however. Lower fill factors and rounded I-V curves mean that thin-film modules are relatively insensitive Some thin-film manufacturers seek to use this thin-film characteristic to their advantage. For example, a Solyndra manual states, “Panels of different power ratings do very well when wired in series and also do well when wired in parallel, but slightly less well.” This undoubtedly makes some integrators and procurement managers very happy. Thin-film cells are usually very long and narrow. While shading is always a problem for PV modules, it becomes especially problematic when one or more cells are completely shaded and unable to deliver any current at all. With long, narrow thin-film cells, the likelihood of total cell shading is diminished, provided that the designer has correctly oriented the module. The rule of thumb is to keep the long dimension of the cells perpendicular to the ground. In this manner, narrow interrow shade bands that occur early or late in the day do not shade full cells and thereby disable portions of the array. Similarly, if the module is framed, this orientation better resists the deleterious effects of dirt buildup at the frame. If present, bypass diodes help mitigate shading effects, but the best strategy is to avoid shading altogether.NREL has been studying TCO corrosion for almost 10 years. These studies have shown that the presence of a negative bias is one of several factors that encourage TCO corrosion. Other factors include heat, moisture, current leakage paths and a conductive surface, such as a metal frame, in contact with the front glass. Positive-grounded, bipolar, and floating or ungrounded PV arrays can impose the negative bias that leads to TCO corrosion.cell. Inverter Compatibility ConsiderationsWhile the design process is largely the same, there are important differences to consider when matching a thin-film array to an inverter: lower temperature coefficients, transient output effects, differing voltage characteristics and the potential for harmful ion migration internal to the module. These differences impact source-circuit design, inverter sizing and inverter selection.Source-circuit sizing. Voltage issues at the high (Voc) and low (Vmp) ends of the inverter input voltage window need to be looked at carefully when dealing with thin-film technologies. This process is not unique to thin films. According to Sky Solar Group's Bray, a professional engineer and industry veteran: "It is advisable in designing any PV system, whether thin film or crystalline, to look at the full operating range of the module in terms of temperature to make sure that the system will be staying within the maximum In part because thin films have lower temperature coefficients, system designers need to be aware that the rules of thumb they might use to predict c-Si PV performance may not apply to thin-film arrays. As an example, Table 690.7 of the multicrystalline silicon modules. Since the designers working with thin-film modules use the published temperature coefficient of Voc for maximum PV system voltage calculations, these data are included for the thin-film modules in the companion table.While the usual voltage calculations and preventative measures apply to thin-film source circuits, certain types of thin-film products introduce additional complexity. For example, just as effective power is initially higher for modules with a-Si absorber layers, open-circuit voltage can also be higher during initial illumination periods. While over-powering an inverter does not cause immediate damage, exceeding the inverter's maximum voltage rating can.How big a concern is this? As with all good engineering problems, the answer is: it depends. It depends on the cell technology, the time of year and the ambient conditions. Do your due diligence. Consult the manufacturer and its applications engineers. Double-check your numbers. If you still suspect that initially higher voltages may be an issue for your system, then it might be worth timing start-up in a warmer part of the year when steady-state Voc is not as elevated as in colder conditions. Fortunately, in most cases no additional accommodations are necessary.Bray, who has extensive experience with Sharp tandemjunction a-Si/¼c-Si modules, says: "Most of the initial degradation happens very rapidly and is experienced in the maximum power voltage and maximum power current. Out of the box, open-circuit voltage is only about 2% higher than nameplate, and short-circuit current is only about 4% higher." Further, not all arrays are designed to push the inverter's maximum voltage limit.On the bottom end of the voltage window, low fill factor is potentially a problem. However, since lower fill factors and lower temperature coefficients for thin-film products self-compensate to some degree, the issue of dropping below the inverter's MPPT window is usually not any more severe than with c-Si modules.Inverter sizing. When matching a thin-film array to an inverter, additional consideration is required if transient effects are present, such as Staebler-Wronski effect-induced initial degradation and seasonal annealing. For example, if a single-junction a-Si PV array is initially commissioned in summer, it could produce 120%–130% or more of its stabilized power rating. The most straightforward way for a designer to deal with this situation is to choose a power conditioning system that regulates its power output at exactly 100% of its continuous ac power rating. Not all inverters do this. Some manufacturers allow their inverters to be overdriven until thermal limits trigger power regulation. In my opinion, keeping the inverter operating well within its design limits is much more beneficial in the long term than capturing the potential excess energy in the first few months of operation.Note that performance transients are technology-specific. Compared with a-Si, for example, a CIGS array is relatively stable. Pacific Solar Energy, a PV construction and project management company, has designed and installed several CIGS arrays, using Solyndra modules, including a 1 MW installation for Frito-Lay's plant in Modesto, California. David Pasqualy, the company's president and CEO, says: "Because we knew we would not have a problem with transients, our big concern was finding an inverter with a wide input voltage range." While inverter MPPT range is significant, the most important consideration for designers is inverter compatibility. For instance, many thin-film manufacturers allow only solidly grounded inverters with a negative ground to be connected to their modules. This excludes the use of transformerless, bipolar or positive-ground inverters, but allows for the use of the most common North American inverter configuration. Best practice is to check the module manufacturers' published inverter compatibility list. Manufacturers may require negative-ground inverters because a thin layer of transparent conducting oxide (TCO) is applied to the front glass of many, but not all, thin-film modules. Performance degrades when this layer corrodes. Inverter selection. Module technology is relevant for optimal array-to-inverter sizing. In a SolarPro article on this topic (April/May 2010), Bill Brooks, president of Brooks Engineering, notes: "Some thin films have half the temperature coefficient of power as c-Si, so they often produce power closer to nameplate rating during hot conditions." He comments that a 10% reduction in thin-film array capacity, compared to that for a c-Si PV array, is a reasonable design response. While this is not disputed, his statement following is even more relevant: "The final answer ultimately depends upon your location." Because local weather conditions ultimately determine the best array-to-inverter sizing ratio, PV production modeling software should be one of the primary design tools used to determine the optimal array and inverter sizes. Transformerless inverters, which require ungrounded arrays, present another potential cause for concern. To ensure safety against ground faults, ungrounded arrays must have extremely high isolation resistances. High humidity and certain other operating conditions can cause the isolation resistance on some thin-film arrays to dip very low, which may create an unsafe condition with a transformerless inverter. Some thin-film manufacturers do not recommend that integrators use their modules with certain transformerless inverters for this reason.Balance of system requirementsBOS costs for a thin-film PV system are a higher portion of the total system cost compared to a c-Si PV system of the same capacity. There are many contributing factors: the larger array area requires a larger mounting system, perhaps even a larger land lease; having more modules requires more mounting hardware; and having more source circuits requires more dc wiring, fuses and combiner products. The total cost for a thinfilm PV array may therefore be greater than the total cost for a c-Si array, especially now that c-Si PV costs are approaching those for thin-film modules. However, proportionally higher BOS costs also present an opportunity. Whereas module costs are largely driven by market conditions and scientific breakthroughs, BOS costs can be reduced in some cases by simple innovations in racking and wiring.Lower thin-film module efficiencies translate directly into higher mounting costs per watt. It simply requires proportionally more structure and more labor to mount more modules. The special clips and structures that may be required for mounting frameless glass laminates may introduce extra cost as well. The fact that BOS costs are proportionally higher on thin-film arrays can act as a strong incentive to mounting system designers, encouraging creative ways to streamline material and labor costs. An example of this creativity is the Solar FlexRack, which was originally developed by Northern States Metals for use with First Solar CdTe laminates. This rack is delivered preassembled, but folded. Installation is very quick, significantly reducing labor hours. Depending on labor rates, this may result in major cost reductions. DC Mounting systems. DC Wiring. Because thin-film source circuits typically consist of two to five series-connected modules, thin-film arrays often have several times as many source circuits as c-Si arrays. The number of strings that can be wired in parallel is limited by the series fuse rating, which is sometimes referred to as the module maximum reverse current or module maximum fault current. More often than not, each string must be fused. (For guidance on this subject, see “Series String OCPD Requirements for Grid-Direct Inverter Applications,” October/November 2010, SolarPro magazine.)Many thin-film manufacturers have worked with BOS suppliers to provide low-cost BOS solutions for their products. Sharp Solar, for example, has worked with vendors like Shoals and Lumberg to provide special wiring harnesses that allow for an efficient combination of in-line fusing and parallel wiring in the field. When strings are paralleled in the array, there is no need for combiner boxes that house 50 to 100 small 2 A fuses. Instead, combiner boxes end up being configured more like those on a c-Si array, with 10 to 25 larger 10–15 A fuses. This strategy can also lead to significant cost savings.Another strategy for BOS cost savings is to raise the maximum system voltage to 1,000 Vdc. This has several benefits—including fewer strings, increased inverter efficiency and smaller wire sizes—all of which may improve thin-film system economics. In the US, this approach is used by utilities and, per the Fine Print Note to NEC article 90.2(B), by entities that are “designated or recognized bypublic service/utility commissions.” BOS cost comparison. An analysis of competitive system costing can be simplified to two very important properties: efficiency and energy yield. While efficiency is often the predominant factor in module pricing, energy yield must be considered in order to compare total system or BOS costs.”$/Wp BOS = ((Ro x $/Wp_mod1) – $/Wp_mod2) + ($/Wp_bos1 x (Ro – 1)) where Ro is equal to the relative increase in energy yield per peak watt for Module 2 compared to that for Module 1 (Ro = (kWh/kWp)_mod2 ÷ (kWh/kWp)_mod1).The following is a simplified equation comparing BOS costs between two systems with equal installed cost per unit energy:

Here is an example using this equation:Module 1: Asian multicrystalline PV; $1.60/Wp; 14% efficiency; BOS = $1.50/WpModule 2: Micromorphous silicon PV; $1.30/Wp; 8.4% efficiencyRelative energy yield: Assume that production modeling estimates for the project location—performed in SAM, PVsyst, PV*SOL or equivalent software—indicate that an a-Si/¼c-Si array will produce about 5% more annual energy per peak watt than c-Si PV (Ro = 1.05). We can now solve for the maximum difference between the BOS cost per peak watt for the a-Si/¼c-Si system if it is to be cost-competitive with the c-Si system:”$/Wp BOS = ((1.05 x $1.60) - $1.30) + ($1.50 x (1.05 – 1))= ($1.68 - $1.30) + ($1.50 x 0.05)= $0.38 + $0.08= $0.46/WpIt is fairly astonishing that the BOS for the a-Si/¼c-Si system can cost as much as $0.46 per watt more than that for the c-Si system (up to $1.96/Wp) in order for the price per energy unit ($/kWh) to be equal or better.THIN - FILM Deployment and App licationsBy and large, the domain for thin-film modules is in utility-scale, fixed-tilt, ground-mounted PV power plants. In spite of this general trend, thin films are also used in commercial and residential rooftop applications.There is also at least one precedent in the US where a thin-film array is deployed on a single-axis tracker. Since many thin-film technologies require extra BOS costs, it helps to have a repetitive building block design. This is easier to accomplish in utility-scale ground-mounted settings. Several large thin-film projects in North America are being developed and constructed by juwi solar, an engineering, procurement and construction contractor. Sven-Malte Stoerring, senior engineer at the company, states: “Our preference is to use thin film for utility-scale projects. The average juwi solar project size in the US is greater than 10 MW, while in Europe it is between 5 MW and 10 MW. We have built some plants in the range of 50 MW in Germany, but that is not typical due to space constraints.”It is a generally held belief, both in the industry and among industry analysts, that thin-film technologies cannot compete in rooftop applications due to their lower efficiencies. This may be an oversimplification.Photovoltaics World article, Paula Mints, a principal analyst for Navigant Consulting, writes: “A few years ago, it was assumed that thin films belonged in large fields, while crystalline would dominate on the rooftop. This assumption does a disservice to both technologies—but particularly to thin films, by broadcasting that they are not competitive on rooftops.” Mints believes that this is “categorically untrue,” pointing out that in the future, BIPV applications will help raise the thin-film market share.This preference is borne out elsewhere in the industry. First Solar reported earlier this year that it has a North American project pipeline of 2.2 GWac, the smallest project of which is 5 MWac. Its customers are primarily project developers and utilities. Similarly, Sharp Solar’s tandem-junction amorphous and microcrystalline silicon modules are being sold for megawatt-scale projects in North America, from California to Ontario. The 58 MWdc Avenal zero-emission solar projects in Kings County, California, for example, are slated to use Sharp thin-film products. Commercial rooftop. In a recent The evolution of flexible UNI-SOLAR PV laminates in rooftop applications perhaps best illustrates the movement in this direction. These products can be applied directly to standing-seam metal as well as to TPO and EPDM roofing membranes. Though relatively lower in efficiency, these products are lightweight, meaning they can be deployed where c-Si PV systems, whether structurally attached or ballasted, present roof loading issues. Further, because the laminates are flush with the roof, they have excellent wind-uplift ratings. There is an increasing trend toward integrating flexible PV materials directly with roofing membranes, because a true BIPV product can leverage additional labor and material cost savings that an applied product cannot. The potential for these BIPV roofing products on large rooftops is significant. Ascent Solar and SoloPower are both seeking to commercialize flexible thin-film products usi ng more efficient CIGS technology.Solyndra is another CIGS manufacturer competing in the rooftop PV market (see the Project Profile on p. 92). The Solyndra product is unique in that its CIGS cells are hermetically sealed within glass cylinders. The company refers to each cylinder as a module, and each Solyndra panel consists of 40 of these 150-cell CIGS modules. The product has a compelling value proposition for rooftop applications. It is lightweight and rated for 130 mph winds without ballasting. It requires no roof penetrations, and its low height-to base ratio may even obviate the need for roof attachments in earthquake-prone California. It stands up off the roof and is easy to assemble and disassemble, allowing for regular roof maintenance. Finally, it also shades the roof, improving building energy performance.While residential rooftops are undoubtedly the least common thin-film market, there is nevertheless movement in that direction as well. SolarCity started installing First Solar laminates in residential rooftop applications in early 2009. An internal analysis revealed that many past customers could have supported a larger array and suggested that thin-film products could deliver a lower cost per kilowatt-hour. In a SolarPro article on thin-film market share (April/May 2009), Peter Rive, chief operating officer at SolarCity, observed: “As we began installing, we wondered if the larger systems might create an aesthetic concern, but the reality was quite the opposite. Many customers loved the sleek, black, reflective glass modules, and some specifically requested them.”The vast majority of the large ground-based thinfilm systems deployed around the world use fixed-tilt mounting systems. There are various reasons for this. For one, the use of trackers exacerbates the already high BOS cost problem for thin films. Crystalline silicon modules also stand to benefit more from tracking direct normal sunlight than do thin-film modules. Further, frameless glass laminates are susceptible to cracking and the movement of trackers introduces additional stresses. Taken together, thin-film array tracking is currently of marginal interest to developers. Stoerring at juwi solar says, “Tracking does not yet play a role here in terms of megawatts, but we are looking into it at test sites in Germany and the US.”SolarPro magazine)Residential rooftops. The fact that customers may prefer the uniform dark appearance of monolithic thin-film modules is revealing. It is also interesting that thin-film modules may have benefits for system designers. As an example, high-voltage modules are actually ideal for multisurfaced roofs—where only a few modules will fit onto each roof surface—when conventional string inverters are used.Tracking. Conergy’s projects group, however, has installed 417 kW of First Solar modules on single-axis trackers alongside a 1.2 MW c-Si array at the South San Joaquin Irrigation District facility in Oakdale, California (see the Project Profile in June/July 2009, This was the first time that First Solar CdTe modules had been deployed on trackers. David Vincent, Conergy’s project development manager for the western US, reports: “Over the past fiscal year, the two systems have produced almost identical specific yield results, with the edge going to the Conergy crystalline modules by just over 1%. It is clear that the First Solar product, even on a tracker, continues to outperform the crystalline product in foggy or stormy months. However, the crystalline performance races back in months when insolation is high. Given the cost savings at the time, the First Solar tracker is proving to be a great investment for the customer. However, with the current low cost of crystalline modules, I see no real advantage to tracking thin film.”

Installation, commissioning and O&MInstalling 10 MW of thin-film PV is definitelycost for a thin-film PVsystem, this presentsan opportunity forleveraging materialsand labor efficienciesto reduce the levelized

cost of energy.While Solyndra panels shade rooftops, their cylindrical design also allows them to harvest reflected light off of the roof surface. In fact, the product’s STC-rated power is predicated on its being installed over a white membrane with a high reflectivity. While some analysts have considered this an Achilles’ heel for the product—we all know what a white membrane looks like after a year or two on a roof—an IRS private-letter ruling may reverse this thinking. Because the white membrane enhances the operation of Solyndra PV systems, installation and material costs related to these so-called “cool roof ” systems may qualify for the 30% federal investment tax credit. If so, this is a potentially significant competitive advantage, especially on new buildings or where an existingroof needs to be replaced.It is worth noting that more conventional thin-film modules are also deployed on commercial rooftops. First Solar, for example, installed a 2 MW PV system atop a large commercial facility in Fontana, California, as part of Southern California Edison’s 250 MW rooftop initiative. As efficiencies for thinfilm modules improve, the notion that space-constrained rooftops are the exclusive domain of crystalline technologies will undoubtedly become less prevalent.Installers, test engineers and service technicians who have prior experience primarily with c-Si PV projects have to make some mindset adjustments as they begin working on thin-film projects. The increased footprint of thin-film PV systems naturally makes installing and maintaining them more time-consuming and expensive. Differences in module construction, module warranty requirements and transient performance behavior create additional challenges.Installation. Installing 10 MW of thin-film PV is definitely not the same as installing 10 MW of mono- or mulitcrystalline silicon PV. Thin-film sites may be 50% larger than and have twice the number of modules as their comparably rated c-Si counterparts. Working on such large sites can have significant consequences for project planners. All of those land and labor issues that are part of any project can be magnified for large thin-film sites. Zoning and land development issues may become more contentious. Storm water facilities may grow in size and complexity. Greater traffic into and out of the site must be handled. A larger workforce must be managed. Construction managers may have to use different contractors than they use in smaller c-Si PV projects. When making the switch to thin-film projects, it is important to recognize that even if the installation is not that different from what you are doing on c-Si PV projects, the scale of the typical thin-film project will likely warrant extra consideration and require additional preparation.Material handling is one notable difference for installers. Glass laminates must be handled with care to avoid edge chips. The Sacramento Municipal Utility District (SMUD) was an early adopter of glasson-glass a-Si modules, having installed over 2 MW between 1994 and 2002. Documenting these early experiences at SMUD for the American Solar Energy Society annual conference in 2003, Donald Osborn, vice president of strategic development at Spectrum Energy, notes: “Through a modest amount of training for the handlers and installers, SMUD was able to quickly reduce a nearly 15% module failure/rejection rate down to about 1%. This special field training, while simple, is an absolute must when dealing with unframed glass laminates.” There are many details to emphasize in these trainings. To avoid stress-related cracks, glass laminates must be carefully mounted in a manner that allows for thermal expansion. Modules clamped too tightly in cold temperatures can expand and crack in warmer times. Modules clamped in hot temperatures may contract in cooler times and not leave enough clamp area on the module to properly resist wind and snow loading. Laminate modules must also be sufficiently insulated from contact with any conductive metal parts of the mounting and grounding systems in order to prevent harmful leakage currents.Some thin-film modules experience accelerated degradation if they are open- or short-circuited in the sun for long periods of time when certain temperature and irradiance conditions exist. First Solar, for example, currently recommends that its Series 2 and Series 3 modules not be operated in open- or short-circuit conditions for more than 90 days, as that may reduce energy output over the life of the modules. Conversely, a-Si or a-Si/¼c-Si modules achieve stabilization through light soaking. Project managers and installers should consider these critical light soaking times when planning module installations and subsequent commissioning of the system.Commissioning and acceptance testing. The bottom line here is, do not let the gotchas getcha. Installers and construction managers cannot rely exclusively on their experience using crystalline products. They need to consult thin-film installation instructions early and thoroughly. The overall approach to commissioning does not change very much for thin film. Commissioning still involves as-built verification, static safety checks, system start-up and establishment of the performance baseline, also known as an acceptance test. The usual assumptions made when commissioning c-Si PV systems may not hold for thin-film projects. Craig McCann, director of service operations at SunEdison, cautions: “Commissioning a multimegawatt PV system often involves taking measurements in a window of time that is not always of our choosing. Therefore, we must be able to take short-circuit current readings at irradiances less than 1,000 watts per square meter and scale the results to STC for comparison to manufacturers’ data. The relationship between short-circuit current and irradiance is linear for crystalline silicon. We must make certain this is still the case for thin-film or modify our test methodologies.”Perhaps the stickiest issue encountered during commissioning is dealing with thin-film products that require time to stabilize once they are exposed to light. In a-Si and a-Si/¼c-Si PV arrays, stable output may be 10% to 30% lower than initial test output. One of the first things the commissioning team needs to know is how close a particular array is to stabilization. Paul Wormser, senior director of engineering and product development at Sharp Solar, says: “The decay behavior is exponential, that is with each additional amount of insolation, the decay decreases until an asymptote is reached. In general, most of the decay for modules in large projects happens between the time the modules are first mounted on racks to the time the array is completed and the system is initialized. As such, for most projects the array is considered to have completed the decay prior to system commissioning.”According to Wormser, an accumulation of 1,000 kWh of solar radiation per square meter is sufficient for Sharp a-Si/¼c-Si modules to reach stable conditions, assuming a constant 50°C module temperature and a solar spectrum defined by AM 1.5. Nearly stable conditions are reached with exposure to 500 kWh of solar radiation per square meter. IEC 61646 describes a protocol for assessing when stabilized conditions have been met. Wormser explains: “Although the protocol is intended for a manufacturing environment, its approach can be applied to systems in the field. Stable output is reached when over three successive measurements, each of at least 48 hours in duration, the peak power measurements differ by no more than 2% of each other.” It may be very important for third-party engineers evaluating projects on behalf of finance entities to be able to extrapolate to an asymptotic value representing a stable output.There are some important differences in operating and maintaining thin-film systems compared to c-Si PV systems. These differences should be clearly spelled out in the product O&M manual. Plant operators should familiarize themselves with any technology- or product-specific O&M requirements found in that manual. Operations and maintenance (O&M). There are some important differences in operating and maintaining thin-film systems compared to c-Si PV systems. These differences should be clearly spelled out in the product O&M manual. Plant operators should familiarize themselves with any technology- or product-specific O&M requirements found in that manual.In terms of general thin-film plant operations, larger area arrays that may exhibit performance transients have some predictable O&M implications. It will cost more per installed watt to operate and maintain a larger physical plant. Determining when to dispatch a service technician to the site requires more skill. Expected performance targets, usually generated from production modeling software, do not account for a-Si seasonal performance variations, for instance. It takes special software or a very-well–trained eye to make those costly dispatch determinations. It is always important to keep PV modules clean. This is especially true in a thin-film array if modules are mounted such that long, narrow cells are oriented parallel to the ground. Significant power loss may occur if dirt builds up and shades entire cells. Further, this may also cause deleterious hot spots. Dirt buildup may also be a concern for thinfilm PV laminates mounted at a low tilt angle. Fortunately, if typical long, narrow thin-film cells are properly oriented—perpendicular to the ground—they are relatively shade tolerant. In addition, unframed laminates generally shed dirt better than framed c-Si modules. Further, in dry, dusty areas, thin-film arrays may actually fare better than crystalline arrays. According to Stoerring at juwi solar; “The slight, uniform dirt cover that is almost inevitable, particularly in dry regions, acts as a diffuser, and thin film copes with diffuse light relatively well.”TA KING IT TO THE BAN KSceptics are quick to point out that thin-film PV technologies have been 3 to 5 years away from dominating the market for about 20 years. While that may be the case, clearly 2009 was a watershed year. First Solar’s dominant market position indicates that even if it takes a decade or two to become an overnight success in the PV industry, thin-film technologies can live up to their promise. The First Solar experience also illustrates how difficult it can be to commercialize thin-film technologies, even after they are proven in the laboratory or on a small scale, suggesting that it will not be easy for other thin-film companies to duplicate its success. Mints at Navigant Consulting points out in her that thin-film manufacturers not only have to compete with “inexpensive and high-quality crystalline silicon technology” but also with “bankability issues” that are brought about in part by “the failure to commercialize as rapidly as promised.” In this era of multimegawatt, utility-scale PV power plants, systems are owned and operated, for varying periods of time, by institutional investors. willing financial institutions are to include certain types of systems and products in their portfolios. Often this boils down to the perceived risk that a product, technology or manufacturer represents.Bankability depends on several factors, ranging from the manufacturer’s balance sheet to a product’s documented long-term performance record in the field. Different financiers have different criteria. Raymond Hudson, principal engineer at BEW Engineering, explains: “The financiers of PV systems are weighing technology risk against a potentially lower cost of energy. It is common for sophisticated financiers to perform or commission a review of a thin-film manufacturer providing modules for a project they are considering financing. This review would cover the technical and company risks. It would then be incorporated into the stress tests the financier uses to determine whether to invest in the system or not.” Because a company’s track record is an important indicator for investors, Mints cautions thin-film manufacturers:“Don’t make promises you can’t keep to the people with the checkbooks.”Meanwhile, in “The Prospects of Amorphous Silicon PV: Down, But Hardly Out, ” Mehta of Greentech Media points out that concerns about a thin-film company’s likelihood to still exist to honor its warranty can be overcome: “Regarding bankability, the concern that a-Si companies may not be around to honor their warranties can be addressed using a simple solution: insurance for the warranty, provided by the combination of regional insurance providers and globally established reinsurers.”Product bankability is among the top concerns for system designers and project developers. As such, it should be the first or second box on your module qualification list. Without a bankable PV module, your project is not likely to make it out of the gate. If a product passes this test, however, all you really need to design thin-film PV systems with confidence is accurate and complete product performance data. Though the science behind thin-film PV technologies may at first seem daunting, designing safe and robust thin-film PV systems that meet performance expectations need not be.Micromorphous silicon. Most industry analysts group amorphous and micromorphous silicon module manufacturers together, and many companies in this field produce both types of modules. Representative manufacturers include Kaneka, Oerlikon and Sharp. Oerlikon offers complete production lines that the company claims will be capable of producing modules at a cost of $0.70 per watt or less by year end.Cadmium telluride. In spite of its large market share at present, the rise of CdTe in the thin-film ranks has not been without challenges. Early testing of CdTe cells at the National Renewable Energy Laboratory (NREL) indicated lower than advertised power output, high degradation rates and vulnerability to moisture. Furthermore, cadmium is a heavy metal waste product from zinc and copper mining that is known to be toxic, resulting in justifiable concerns about harm to the environment and to human health. First Solar has proactively addressed all of these issues and created a worldwide recycling program for its modules.light-induced degradation (LID) in the first few hours of outdoor exposure. Because this LID is rapid and specifically affects short-circuit current, system designers need not pay it any mind. The same cannot be said for thin-film performance transients.Copper indium (di)selenide and copper indium gallium (di)selenide.Though ARCO Solar fielded the first CIS modules in the mid-1980s, many researchers and analysts consider this technology to be still in its infancy. Early CIS/CIGS cells tested by NREL experienced higher degradation rates than other thin films. (See Dirk Jordan and Sarah Kuntz’s article on pages 24–28.) This may explain in part why the commercialization of CIS/CIGS has generally lagged behind that of other thinfilm technologies. This situation is rapidly changing, however, as a great deal of CIS/CIGS manufacturing capacity is now being brought online. Notable manufacturers include Dow Solar, Miasolé, Nanosolar, Solar Frontier and Solyndra.second-generation solar cells, is their potential for cost savings. Significant raw material reductions, coupled with the use of manufacturing processes well suited to mass production, should translate into material supply, energy use and environmental benefits, and ultimately lower prices. The latter is illustrated by First Solar’s average cost of $0.76 per watt in Q2 2010 for modules having an average efficiency of 11.2%. In addition, improved energy payback times for thin films are well documented.Four thin-film technologies have reached the point of commercialization on a large scale: amorphous silicon (a-Si); micromorphous silicon (a-Si/¼c-Si); cadmium telluride (CdTe); and copper indium (di)selenide (CIS) or copper indium gallium (di)selenide (CIGS). Modules from these four general technology groups are included in the companion product specifications table.second-generation solar cells, is their potential for cost savings. Significant raw material reductions, coupled with the use of manufacturing processes well suited to mass production, should translate into material supply, energy use and environmental benefits, and ultimately lower prices. The latter is illustrated by First Solar’s average cost of $0.76 per watt in Q2 2010 for modules having an average efficiency of 11.2%.In addition, improved energy payback times for thin films arewell documented.

Amorphous silicon.