LEX HELIUS: THE LAW OF SOLAR ENERGY
—Financing a Solar Project—

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I. Today's Uncertain Environment. The worldwide credit crunch and economic downturn have had a significant impact on the ability to obtain financing for many solar development projects in the United States. Among the consequences of these global economic events has been a decrease in the pool of financial institutions and intermediaries interested in purchasing pass-through tax credits, such as the federal investment tax credit for solar projects (also referred to in this chapter as the federal "Energy Credit"), and other tax benefits available from solar projects, such as accelerated depreciation. This has made it very difficult for many otherwise viable projects to obtain tax equity financing. Potentially countering this trend, at least in part, is the reduction in the cost per installed watt of panel based solar photovoltaic ("PV") projects. To the extent these cost reductions remain in existence, it potentially causes a dramatic change in the financial evaluation of solar PV projects. If the cost reduction trends also emerge in concentrated solar technologies that may have a technology advantage for some utility-scale solar developments, the positive aspects of this trend will expand.

The impact on financing of percentage of cost based incentives, such as the federal investment tax credit and accelerated depreciation (*i.e.,* 30% of cost is the same regardless of whether it is a higher cost or a lower cost) should remain relatively unchanged. (See Chapter 8 for more specific details on federal and state tax incentives.) However, power sales revenues go up as a percentage of the cost of the project as the overall cost comes down. Although, as mentioned above, it is presently uncertain how low solar costs may go and for how long these reductions may remain in effect, revenue based fee changes should now have a greater place in determining a project's economic viability. A higher relative level of revenue to cost may make debt financing a more attractive option than it has been for solar projects. In addition, solar energy is very well placed for many utilities' time-of-day pricing mechanisms, where electricity delivered during the peak hours of the day during the peak seasons automatically receives a higher purchase price. In addition, some states are experimenting with specific programs to provide at least some level of feed-in tariff pricing support for a defined capacity of project development. The feed-in tariff rates typically being approved are significantly higher than standard market rates and substantially higher than avoided cost pricing, although as noted the capacity qualifying for these experimental programs tends to be relatively limited.

Consequently, writing this in early fall 2009, we are in a period of uncertainty and temporary measures with respect to the financing of solar projects. Measures such as the option to elect a cash grant in lieu of the federal investment tax credit assist liquidity, but this program expires December 31, 2010 (except for certain carryovers available if the required percentage of expenditures are incurred prior to December 31, 2010). On the other hand, the availability of the cash grant option may or may not make it more difficult to monetize the value of accelerated depreciation. It all depends upon whether a market for such depreciation benefits develops. Reduced cost per installed watt moves the solar market closer to the goal of "grid parity." However, although the overall amount of capital required to finance a solar project has gone down, these more cost effective projects are still in competition with many other potential investments in a market where a broad cross-section of industries are having difficulty finding necessary capital.

We will discuss many of the financing approaches that have been used in the past in recognition that the capital markets may return to more historical norms. In addition, we will mention some of the approaches that are being considered to respond to current conditions. However, on an overall basis, obtaining financing for solar development is likely to remain challenging in the short run and a work in process with a significant degree of uncertainty as to how financing options will look and work over the middle and longer term.

II. Some Things Remain the Same. A power purchase agreement for the output of a distributed generation solar PV or utility-scale project regardless of technology is a necessary component of each transaction and will be an important consideration for any source of financing. However, the revenue generation potential of

a solar facility is not the only consideration to make a project financeable. Thus a "bad" power purchase agreement may make it impossible to obtain financing.

As mentioned above, historically the relatively less important role of project revenues highlighted the fact that solar installations were primarily tax-advantaged investments, just as low-income housing, historical preservation credits, new market tax credits, and other tax subsidies have made other types of tax-advantaged projects popular focuses of development and industries dedicated to those specific types of projects over the past 25 years. The federal investment tax credit for solar projects and accelerated depreciation have been very significant drivers for the financing of distributed generation solar PV projects where the creditworthiness of the power purchaser might not be as strong as that of a utility buying the output of a utility-scale project. (See Chapter 8). Equally significant, however, is the availability of Renewable Energy Certificates, referred to as "RECs" or "green tags" (see Chapter 9), and state-level subsidies, state tax credits, and other forms of incentives available to support solar PV projects.

III. The Role of Federal Tax Benefits in the Financing of Solar Projects. There is no question that historically many solar projects would not have been built if there were not substantial federal tax benefits available. This is likely to remain the situation unless and until it is proven that the installed cost per watt of solar projects will remain at or below "grid parity" and power sales revenues alone will be able to support the financing of these projects. Absent these tax incentives, the intrinsic cost structure of these projects and the generally constrained prices at which output can be sold probably still do not make them economically viable sources of generation on a standalone basis under existing market conditions. Tax benefits are likely to remain a principal driving force behind solar development for some time. Consequently, it is helpful to look at just how difficult it is to do the federal tax analysis of a solar facility. The answer is, as to some tax issues, not very, and as to other tax considerations, fairly difficult. (See Chapter 8 for a fuller discussion of the technical aspects of these federal and state tax incentives.)

Most financing sources have three basic questions relating to the tax benefits and other economic aspects of the transaction. First, how much? Second, how certain? Third, when? These questions reflect the financing sources' primary concerns in deciding whether to invest. One primary concern is being able to put on a spreadsheet the expected economic return from the project based on a combination of tax benefits, power sales revenues, and other revenues (such as from the sale of RECs), state tax credits, or special program payments (such as from the California Solar Initiative ("CSI")). A second primary concern is the risk analysis of the project, in particular, how certain it is that the benefits reflected on the spreadsheet will actually be realized. A third primary concern is when the expected benefits will become available. In part, this reflects the various midyear and other conventions under the Internal Revenue Code, which provide that the amount of certain specific tax benefits at the end of the tax year depends on when during the tax year those benefits became vested, such as half-year conventions regarding depreciation deductions. However, the timing question takes on added significance when there are questions about when and if a key tax component of the transaction, such as the federal Energy Credit, is set to expire in the near future. Then the financing source may become concerned about whether the project can be physically completed before the end of the current authority, and what economic risk mitigation must be built into the terms of the financing to protect the financing source if the project does not reach the "magic date" before the credit expires. In terms of federal tax issues, the magic date is the "placed in service" date, which may or may not be the same as the "commercial operation date" or "final completion date," which are critical dates in the power purchase agreement and the installation agreement.

IV. How Much and How Certain? The discussion in Chapter 8 sets out the components of a solar project that will qualify for federal tax credits. Most states with a state tax credit program utilize these same federal

qualifying costs. There is not much question regarding the certainty of receiving these tax credits if a competent analysis of qualifying costs has been done before claiming them, or applying for them in the case of the cash in lieu of credits program and most state programs using a cost based methodology.

V. Timing. The analysis of when during a tax year the federal tax benefits will become available is difficult because it must take into account factors that tend to be beyond the control of the developer or the financing source. There are many questions complicating this determination. Will the panel manufacturer be able to meet the requested delivery schedule? Is there sufficient time to reasonably expect that the installation will be placed in service before a significant deadline passes (such as the expiration of the current cash in lieu of credits program, whether that expiration date is likely to be extended, and if it is, when the law extending it will be passed and go into effect)? Will the installer run into adverse weather conditions, a labor dispute, an inability to get the required materials because it was waiting for a better price to increase its margin, or any of the other well-known construction risks?

Consequently, although the financing source will find it necessary to make an estimate of when tax benefits will become available, the developer can expect a constant stream of requests for updates and status reports as the financing source attempts to stay on top of its risk position. This is one of the reasons many tax investors will refuse to provide construction financing. They are only interested in the tax benefits when there is a very high probability they will actually be available on or before a date certain. These financing sources do not want to bear construction risk or have these risks impact their anticipated return on the transaction.

VI. The Role of Project Revenues in Financing a Solar Project. As noted briefly above, historically project revenues were not a primary driver of the economics of a solar installation. However, they were important because they provided the gap filler between (1) the financing source's return from tax benefits and other revenue sources, such as RECs, and (2) the investor's desired overall return on the project. Another way of saying this is that the tax benefits, subsidies, and other revenues were not sufficient to provide a return that was acceptable to financing sources. Project revenues were the only means of bridging that gap because they were the only source of funds that were not subject to defined legal restrictions as to either the method of calculation or the overall eligible amount of funding. Whether project revenues would be sufficient to fulfill that role has always been difficult to project because the price at which any specific buyer for a project's output was willing to buy was dependent on a wide variety of factors completely separate and independent from the actual costs of the project.

In particular circumstances, project revenues are now likely to play a more primary role in the economics of a project. The availability of certain utility tariff changes such as time-of-day pricing and experimental feed-in tariff programs should be looked at closely in assessing the long-term economics of a project. The generation characteristics of solar fit well with many common classifications of "On-Peak" delivery, allowing a significant multiplier to the price of the electricity delivered to a utility. If the usage at a particular residential or commercial site allows excess generation during these "On-Peak" hours, a net-metered distributed generation solar PV site could realize these additional benefits for the facility owner. For utility-scale installations and "qualified facilities" selling to utilities, an emerging trend of state public utility commissions allowing differential "avoided cost" calculation methodologies for renewable energy resources means that the price for electricity under an "avoided cost" tariff may be higher than would otherwise be available. This could be particularly true for areas of the country where an aggregated "avoided cost" price takes into account significant amounts of electricity generated by very low-cost sources such as hydroelectric. In addition, the need for large quantities of RECs to meet compliance standards under a specific state's renewable portfolio standards that have carve-outs for specific generation sources such as solar should also be expected to have a positive impact on the price of electricity being purchased by a utility from a solar or other renewable generation source.

For facilities that are not going to be negotiating with regulated public utilities, particularly distributed generation solar PV, the first touchstone for attempting to predict the range in which output from a specific solar PV facility can be sold is still likely to be the current market rate for electricity in that location. The second touchstone should continue to be the local utility's recent record on rate increases. The third touchstone is even more likely to be whether there are time-of-day, "solar-friendly," or other tariff adjustments the local utility has made or has publicly announced it intends to make in the near future that raise the consumers' perception of what grid delivered electricity is likely to cost them in the future. It is very clear from these touchstones that a major driver in determining the sale price of output from a specific solar PV facility will continue to be its competition, the cost of electricity delivered by the local utility.

Many believe that in light of global warming concerns and other environmental factors, the cost of solar power should not be dependent on any competitive price from a local "dinosaur" utility. In our experience, the actual purchaser of solar PV output still rarely feels this way. Although the decision to acquire a distributed generation solar PV installation may take into consideration environmental benefits, it also has a substantial economic component. Purchasers have been willing to pay some premium for solar power, but not a disproportionate premium to the cost of buying power from the local utility. We have seen no evidence that this has changed or is changing dramatically, although the general sense that the cost per installed watt is decreasing significantly does seem to be having some impact. In addition, there are certain unknowns regarding the performance, maintenance, and longevity of any specific installation that continue to weigh into the calculation of whether it is "worth it" to have a solar installation on-site or whether to take the easy route, which is to just flip the switch and take delivery from the local utility. One thing that must be conceded is that, in America, our local utilities continue to be very good at maintaining a ready flow of electricity, available at the customer's demand.

Therefore, the financing source's three questions—how much, how certain, and when—cannot be fully settled until there is a negotiated and signed power purchase agreement. This is a major reason why, before seriously considering an investment in the project, most financing sources will want to see the terms of the power purchase agreement and will want to know that the power purchaser is creditworthy and has agreed to the price structure over the term of the power purchase agreement and to damages due upon a breach.

VII. The Role of Other Revenues in the Financing of a Solar Project. After federal tax benefits, and now potentially revenues, another primary driver of solar economics is the other sources of cash or economic benefits available to the project. As previously mentioned, historically solar projects needed to be heavily subsidized to be economically viable. The cost per watt of a solar PV project, in particular, has been significantly higher than that of other renewable generation sources. In part, this was because of the higher costs of the basic components, primarily solar panels, and, in part, it was a consequence of the relatively limited output capacity of the current solar panels. Major changes have occurred in the availability of solar panels and panel components, such as polysilicon, and significant efficiency increases may be coming. So the equation has changed in some parts and has not changed in other parts. Consequently, on an overall basis, the need for subsidies to make solar generation projects economically viable remains high and the importance of "other revenue sources" remains high.

These "other revenue sources" take a variety of forms and are determined on a state-by-state basis. Some states, such as Oregon, Hawaii, North Carolina, and New Mexico, have chosen to offer a state income tax credit based on the cost of qualifying renewable equipment. There have been efforts in some of these states to make these tax credits "refundable" in cash, much like the cash in lieu of credits federal program. Some have been successful, some have not. (See Chapter 8 for additional information about state-level subsidy programs.) Other states, such as California, chose to implement a direct payment subsidy system (the CSI). Again, how the program is structured makes all the difference in how useful it will be in practice. The CSI program provides a decreasing

level of direct cash subsidy as commitments for solar projects are made and applications for CSI payments are submitted to the state. Sufficient applications have been submitted to drive the subsidy level far down from its initial level. However, the CSI program also has offsetting benefits regarding items such as the ability to designate a party other than the owner of the facility as the recipient of the subsidy payments.

Other revenue sources include the wide variety of grants and subsidized loans that are being made available for renewable resource generation projects by states, federal agencies, and local-level environmental organizations. Using Oregon as an example, the local-level Energy Trust of Oregon makes grants for the initial development efforts related to renewable projects. The typical grant is not sufficient to pay for a major portion of the project but does make it possible to get through some of the planning, design, and initial power purchase agreement phases necessary to put together a package that potential investors will take seriously. However, these subsidized sources of financing have consequences for the federal tax analysis of the project.

An additional source of other revenue is the sale of RECs, which are discussed in Chapter 9.

At the end of the day, the financing source is going to again ask the three questions as to the other revenue or economic benefit sources for the project. The financing source may be willing to be flexible on when signed commitments from these sources become available, but the deadline will certainly be before closing and usually before the execution of a firm commitment to fund the project.

VIII. The Interaction of Federal Tax Benefits, Project Revenues, and Other Revenue Sources in Financing a Solar Project. In today's environment, the final conclusion of whether or not a specific project is financeable continues to depend on the firmness and level of each of the three factors discussed above. Neither the federal tax benefits alone, the project revenues alone, nor the other revenue or economic benefit sources alone are sufficient to make the project economically viable, and consequently financeable. Even though the reduction in cost per installed watt of some solar PV projects, particularly if combined with the ability to locate a project in an area where power sales revenue enhancements can be realized, should provide the economic viability for solar projects with some additional margin, there is no room for any one of these three factors to be significantly depressed if a project is going to receive financing. A very low power price to accommodate the purchaser may still push the project below the acceptable economic return threshold. In states using a tax credit state-level subsidy mechanism, the failure to have adopted recent changes in federal law may result in a significant decrease in available state tax benefits if governmentally provided grants and loans are received, even though these no longer cause a reduction in the federal Energy Credit. An inability to receive sufficient revenues from the sale of RECs or an inability to realize any monetary benefit from accelerated depreciation when the cash in lieu of credits program is utilized may do so as well.

These three factors exist independent of each other, but must be viewed in combination to determine whether the project is economically viable. Each must meet the financing source's scrutiny on its own, and then must also meet that test in the aggregate with all of the three factors considered together. Although a continuing reduction in the cost per watt of solar energy is highly likely to have significant effects on this analysis, it is still somewhat too early to determine exactly what these impacts will be and how general or localized they will prove to be. A problem in one area of the project's economic performance is still unlikely to overcome performance above historical expectations in other areas. These remain difficult projects to make "pencil out" to an acceptable return level for financing sources.

IX. So, Whom Should You Be Approaching for Financing? The availability of financing for distributed generation solar PV projects took a dramatic downturn in the late summer and early fall of 2008. This downturn

was caused by a number of well-known factors coming together in a very short period of time and was not limited to the solar PV industry alone. It is unclear how these changes in the financial market will affect utility-scale projects. These adverse factors appear to remain in play, and we are hearing that many commercial building distributed generation solar PV projects continue to have problems obtaining financing, although some significant projects are getting done. Given the longer lead time required to bring utility-scale solar projects through predevelopment, there is not enough data currently available to determine whether utility-scale projects are also going to have the same degree of difficulty obtaining financing. There are a fairly large number of publicly announced power purchase agreements for projects of 100 MW and above, so it should be relatively easy to track whether these projects are moving smoothly through the predevelopment and development process in the coming year. However, from the information that has been shared at seminars or disseminated in public releases, certain factors that were important for obtaining financing in early 2008 appear to still be important.

Among the factors with continuing importance, size of the project appears to be toward the top of the list. The process of putting together a commercial or utility-scale solar project of any size continues to be extremely time-consuming. They are complex, sometimes overly complex, transactions where even small facts can change the qualification for the tax benefits needed for economic viability. Some legislative changes intended to make this easier have been enacted at the federal level, but not all states that follow the federal tax model have adopted corresponding legislation removing these issues at the state level. Substantial upfront time is required for projects that are subject to regulatory and environmental compliance processes, which includes any projects that intend to sell output to regulated utilities or are located on significantly sized sensitive ecological areas. In addition, potential financing sources will want to do substantial due diligence on a project they are considering funding, which requires a substantial commitment of time and internal resources. All of these considerations combine to make many potential financing sources believe that it is more cost-effective to consider financing one large project rather than a number of smaller projects.

"Big" projects, probably on a scale of several megawatts or greater, should continue to have relatively better access to large investment banks and private equity capital sources of financing than do developers of commercial scale rooftop distributed generation solar PV projects. The economic value of the federal tax credits generated by very large projects makes them attractive to funds that provide high-income-generating entities with tax credits and losses to apply against their other taxable income. However, the general economic picture can influence the appetite of these financing sources for any particular tax year, sometimes in unforeseen ways.

Based on the limited information publicly available, "middle-level" projects may continue to face a difficult financing environment for some period of time. They do not have the scale to attract large investors on a stand-alone basis but (unless installed costs per watt continue to decline) are too expensive to be financed solely through subsidized sources. Banks are increasingly becoming interested in looking at renewable energy generation, including solar, as new business opportunities. However, federal banking regulatory issues may operate to discourage some banks from taking an investment equity position in the project entity. In other words, banks are concerned that they cannot become the tax investor without crossing the lines governing their banking operations. Many banks do have subsidiaries and related entities that can make investments not subject to the "basic" banking regulations. The ability to make these investments usually requires that some distinct facts apply, such as the project being in a recognized economically disadvantaged area. In addition, some banks may be interested in purchasing the federal Energy Credits but not the accelerated depreciation generated by a project. The Energy Credit reduces taxes dollar for dollar. The accelerated depreciation reduces earnings, something many banks currently want to avoid given the current impact on banks of commercial real estate and subprime mortgage problems in the economy. Private equity firms and smaller investment banks may have some

increasing interest in projects of this size, but if potential returns are thinner than potential returns of other investments opportunities that may arise if the economy recovers, these financing sources may remain on the sidelines to a greater or lesser extent.

We speculated a year ago that "smaller" projects, and some midsize projects, would be likely to go one of three ways. They would have access to financing through some local source of capital established specifically to encourage the development of solar generating resources in their geographic area; they could approach one of the number of funds being established that would do the entire project on a turn-key basis, including equity financing; or they would access some form of owner financing. A fourth option has arisen during the past year: a larger company doing a number of smaller projects with a line of credit or similar rolling credit facility made available based on the strength of the company rather than on a project-by-project basis. For those companies that have been able to meet their lenders' requirements for this type of line, this has been a successful approach to financing a series of smaller installations.

Although the local capital source avenue may be active in some parts of the country, as a general rule we are not aware that this approach has turned out to be a consistent or significant source of financing for smaller commercial projects. The larger fund approach has also not demonstrated a strong market presence outside of the vertically integrated situation where the funds' financing is being used for projects that are sponsored or being developed by affiliated members of the same business group. This approach continues to use a trade-off for the power purchaser, requiring acceptance of a one-size-fits-all and take-it-or-leave-it approach to avoid the large commitment of upfront time, effort, and cost typical for putting together any solar project—regardless of size. Depending on the power purchaser's and building or site owner's (the "host") interests, it may or may not be a good trade-off. The owner financing approach will usually involve an established business with an owner or executives who have personal ties to high-net-worth individuals in the community. This group will put together a private investment vehicle geared to take advantage of the tax and other economic benefits available from the project. (In the context of technology venture capital, this is usually referred to as "angel investor" financing.) This approach has been used with some success but is necessarily of limited availability. A variation of this approach has also been coming up from time to time: installer financing. We have seen this most often when a solar installer has affiliated companies that can take advantage of the tax benefits generated by a specific project. However, again this is an opportunity of limited availability since considering its use depends upon very specific facts and circumstances.

One factor likely to influence whether local banks become more active in this market is whether tax advisors become comfortable with the IRS's recent pronouncement in Revenue Procedure 2007-65 and the changes contained in Announcement 2009-65. These authorities created a specific safe harbor defining when the IRS will recognize the validity of a "flip" transaction structure involving wind projects (although there continues to be debate in the tax community as to whether the safe harbor established goes beyond wind transactions to solar and other renewable transactions). Flip structures are frequently used for two primary purposes. First, they allow the easier withdrawal of tax equity investors after their investment goals have been realized and the tax benefits available from a particular project have been exhausted. Second, they provide the developer the opportunity to realize a return from the stream of power sales revenues later in the term of the power purchase agreement. A number of variations are being discussed that involve changes in the interest percentage allocations of members (or limited partners) in the project-owning entity during its existence. In general, all of these variations are intended to obtain the objectives described above. One of the changes contained in Announcement 2009-65 is the allowance of a back-end purchase option in the power purchaser that is defined at the start of the transaction. This change will allow a much higher degree of certainty regarding the economics of the exercise of a purchase

option and will allow the economics of the transactions to be modeled with a much higher degree of clarity. This added clarity may make financial institutions more comfortable with the economics of a solar project over its life and especially in terms of what happens if a purchase option is exercised relatively early in the life of the power purchase agreement.

X. What Terms Can I Expect to See in the Financing Documents? In addition to the standard terms typical in any financing, there are certain provisions that have been more or less unique to solar financing. These relate to occurrences during the Energy Credit recapture period, the allocation of risk upon the occurrence of certain events, and how the price for any purchase option is calculated.

The federal Energy Credit has a recapture period of five years after the facility is placed in service. Many documents in solar transactions will draw a bright line at the fifth anniversary after the placed-in-service date, providing that certain terms apply before the fifth anniversary date and other terms apply after the fifth anniversary date. However, if only a partial year of accelerated depreciation is available in the first year, the full federal tax benefits are not used up until about the 5.5-year mark. Consequently, many documents now provide that the benchmark for the shift in terms is the sixth anniversary of the placed-in-service date. This can become more complicated if the project has been placed-in-service in component pieces capable of independent operation, but the result is that the benchmark date will be measured from the placed in service date of the final piece. Other consequences of the potential for projects to be placed in service in parts smaller than the full intended installation are discussed in Chapter 3.

Allocation-of-risk provisions in solar transactions are different because the potential events that can cause an economic loss for the project owner are fairly unique in the universe of tax-advantaged investments, and because of the complicated role that the interaction of tax credits, project revenues, and other sources plays in the economic viability of the project. For example, federal Energy Credits vest upon the project's being placed in service. So long as the project exists and has not been abandoned or been used for other than its intended purpose of generating electricity, there is no recapture. In many situations this can be true even if the facility is not actually generating electricity for some period of time. Project revenues and other sources of revenues or economic benefit, however, typically are measured by the actual output of the facility. If it is not producing electricity or there is a reduction in the production of electricity, there is a reduction in the available amount of these economically important items. Because all three items are important for the investor to recover its return, a negative impact on any of the three has a negative impact on the entire project's viability.

Numerous events can occur that may negatively impact project revenues or other sources of revenue or economic benefit. For example, suppose the building owner needs to repair the roof area where the solar installation is located. It is likely that the installation will have to be moved aside or even removed from the roof for some period of time. During that period there will be no output, so there will be no power sales or RECs generated to fulfill any REC sales contracts. In addition, there is the actual cost of moving or removing the facility from the rooftop. Someone will bear these real costs; the purpose of the risk allocation provisions is to define who that is. Similarly, if the purchaser simply decides to stop buying the output of the facility, the economic loss is not just the lost revenue from the sale of electricity. The loss calculation must also take into account any other revenue sources that depend on the facility actually generating and delivering electricity.

In some states where net-metering regulations allow the pass-through of "excess" generated output to the local utility, there may be a means of mitigating these risks without allocating them between the project owner and the power purchaser or the host. To determine whether this is even a viable alternative, though, requires a careful examination of the net-metering rules applicable to the specific local utility that owns the grid meter for the

project. Some states allow or require the local utility to buy the excess output from the facility at market rates or avoided cost (which is less than market rate). Some states may allow the local utility to decide whether it wants to allow that "sale" rather than making it mandatory; some states may provide that any excess generation from the solar facility simply creates a credit for the purchaser ("making the meter run backward") but does not allow that credit to be monetized. In those states, the local utility does not have to pay anything for the excess electricity delivered to it through the meter. At the end of the year there is a true-up, and if the purchaser has a credit on its side of the ledger, that credit goes away and the meter is effectively reset to zero for the new year. The investor has a very legitimate interest in how this will play out because it has a direct impact on the investor's risk profile.

In the absence of any net metering "out," the documents are likely to provide that after the operation of the facility is disrupted due to causes within the control or responsibility of the purchaser or the host for some negotiated period of time (for example, seven days each calendar year), either the purchaser or the host becomes responsible for paying the project owner the full economic cost of lost revenues. This includes the lost revenues from electricity sales, as well as any lost revenues or subsidies from local tax credits, REC sales, etc. In addition, some REC sales contracts have a provision requiring the project owner to reimburse the REC purchaser for the failure to deliver a certain level of RECs during each year of the contract. If the disruption of generation would trigger this cost to the project owner, it is likely that the project owner will want to pass that cost through to the purchaser or the host.

There are also risks present in rooftop distributed generation solar PV projects arising directly from the fact they are located on top of buildings, and risks exist for ground-mounted solar installations where the ground is condemned, partitioned, subdivided, etc. Suppose the building roof has not been well maintained and can no longer bear the weight of the solar installation. Local law may require that it be removed. The project owner will want the host to pay the related costs, including lost revenues, lost REC sales, costs of removing the installation, etc. A similar potential problem arises if the building is sold and a new owner does not want to have the solar installation on its roof, or tenants change and the new tenant does not want to agree to the same power purchase agreement terms as the former tenant. Each of these possibilities needs to be considered, and some means of removing the risk or mitigating the potential damages to be incurred by the project owner should be built into the documents.

XI. Dealing with Purchase Option Pricing. One unique aspect of solar generation installations is that many project power purchasers want to own the installation themselves at some point. This has been a common feature of distributed generation solar PV power purchase agreements for some time, particularly where the site host is also the power purchaser. More recently, many utility scale power purchase agreements appear to be including these purchase rights on behalf of the power purchaser. They have read the public news stating that solar installations appear to have a useful life based upon the track record of earlier solar PV installations. It appears that the power purchasers view these installations as a hedge against dramatic increases in the market rate of power and wish to acquire the installations at what they believe will be a more affordable cost after the tax benefits have been exhausted.

For those purchasers and hosts who are strongly committed to one day owning the installation on their property, the timing and price of their purchase option is an important consideration in being willing to enter into the transaction. The publication of Announcement 2009-65, mentioned above, may prove very useful in resolving one of the problems that have arisen in many power purchase agreements with respect to the purchase option. Under the guidelines set out in Revenue Procedure 2007-65, the purchase option could not be less than the fair market value of the installation at the time the purchase option is exercised. This lingering uncertainty as to what the fair market value would be in the future caused a number of potential power purchasers to back away

from a transaction they were considering. The changes under Announcement 2009-65 now allow the purchase option price to be determined at the time the power purchase agreements is entered into, provided it is a reasonable approximation of what fair market value is expected to be at the time of exercise.

There is always disagreement and debate regarding how to determine the fair market value of an installation at any particular point in time. Whether a particular approach is more or less appropriate in a particular situation usually depends upon the facts of the specific case. For example, one approach is to (i) obtain an appraisal of the value of the equipment in a secondary market; (ii) add the discounted present value of power and REC sales that the project could expect for the remainder of the term of the power purchase agreement; and (iii) deduct the cost of removing the installation from its present location and restoring the site to the required condition. This approach may prove difficult to apply in connection with a solar installation since there is not an active secondary market for solar equipment at the present time and the discounted present value of the remaining term of a power purchase agreement is questionable when the party that is buying power under the power purchase agreement is the same party that will be buying the installation.

A second approach ignores the remaining cash flow from the project and stipulates that only the value of the equipment itself (again, with or without removal costs) is relevant in determining the fair market value of the project. This particular approach is clearly relevant when the purchase option is exercisable only at the end of the power purchase agreement term when there is no expected remaining stream of revenues; however, it is also one that can only truly be accurate at some time in the future. In the absence of an active secondary market for used solar equipment, there are not benchmarks existing today regarding what the value of the used equipment might be 10, 15, or 20 years in the future. The changes in value of used computer equipment over the years are a warning with respect to trying to accurately forecast the future value of equipment that may be subject to significant technological change and improvement over time.

A third approach provides for a valuation of the equipment and a discounting of the remaining cash flows from the project, and includes a designated "buyout price" determined at the time the power purchase agreement is entered into, which is the "greater of" the equipment and cash flow amounts plus designated buyout price <u>or</u> fair market value. This approach has the advantage of at least establishing a floor option price since the buyout price establishes the minimum potential option price even if the equipment and cash flows have no value. However, it does not solve the problem of power purchasers who are uncomfortable that the option exercise price might be much higher than they had expected.

By allowing the option price to be set up front, Announcement 2009-65 recognizes problems caused by having to wait for a period of years until the option price can be determined. What this change appears to actually do is open the door for using any reasonable method of predicting future values that will pass a reasonable and credible test. For example, one approach to pricing the remaining value of a power purchase agreements may be to determine what the cost savings on a per-watt basis is between the price under the power purchase agreements and the estimated market value of electricity during the term of the power purchase agreements following the purchase option exercise. This cost savings approach could be considered to approximate the value to the power purchaser of exercising the option. Using the historical data of utility market price increases for electricity over the past 10 years prior to execution of the power purchase agreements, weighting the more recent years more heavily, might be considered a "reasonable" approach to determine this future value. Discounting that savings stream from the end of the power purchase agreements term back to the time of exercise of the purchase option should provide some approximation of the value to the power purchaser of exercising the option. Perhaps this equates to the fair market value of the project, at least to the purchaser, as of the time the purchase option is exercised. The fact that these thoughts represent conjecture and hypothetical analysis demonstrates that much

more thought needs to be given to how to estimate fair market value under the Announcement 2009-65 approach. Determining fair market value is still not a clean and clear determination, even though it can now be done up front.

There is an equal lack of clarity in how power purchase agreements determine when the purchase option can be exercised. Revenue Procedure 2007-65 provides that the IRS does not want to see any purchase option exercisable during the first five years, equivalent to the recapture period discussed above. This portion of the safe harbor guidelines was *not* changed by Announcement 2009-65. Most participants accept this as a reasonable threshold. After the five- (or six-) year period, however, the dates are all across the board. Some power purchase agreements provide that the purchase option may be exercised any time after the threshold date. Some agreements provide that the purchase option may only be exercised after the investor has received a specific target rate of return, whenever that happens. Some agreements provide that the purchase option may only be exercised on the 10th, 15th, and 20th anniversaries of the facility's delivering output, with the 20th year equaling the end of the term of the power purchase agreement. Some agreements provide that the purchase option can only be exercised upon the expiration of the power purchase agreement. What timing is available to the party who wants to have a purchase option depends, to some extent, on how the investor views its position. If the target return for the investor requires that it realize all of the available tax benefits, all of the projected power sales, and all of the revenues or economic benefits available from other sources, then the exercise of a purchase option is going to defeat the investor's realization of its desired return unless the purchase option price includes something to "make the investor whole" on these items. If the target return can be realized without all of these items, then there will likely be more flexibility in how the purchase option price is determined. The major point here is that there is currently no single clear market standard on this issue.

XII. Summary. Determining whether a particular proposed solar installation will be financeable requires quantifying a variety of interrelated and moving parts. In this respect, the financing of solar is not particularly different from the financing of many other types of investments. What makes solar somewhat different is the nature and character of some of these parts and the current situation in which there is not much room for offsetting a problem in one area of the project with headroom in another area. Except for the situation in which a distributed generation solar PV installation will be put on a building owned by a power purchaser that is willing to basically finance the project itself and take all of the tax benefits for its own use, this is not a "do-it-yourself" type of project.