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Utility Solar Tax Manual – Version 3

A Comprehensive Guide to Federal Incentive Programs

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Contents

Note: Highlighted sections (above) have significant additions since the last update in September 2009. In addition, small parts of other sections may have minor changes, also highlighted.

Introduction

The days are long gone when anyone can be an expert in the entire U.S. tax code. The tax code has grown from a length of an article in the *New Yorker* magazine when it was first enacted in 1913 to almost 2.2 million words today with another seven million words of IRS regulations interpreting it – and that's before considering the decades of legislative history, court decisions, rulings, notices, revenue procedures and other forms of guidance that the U.S. government issues that shed additional light on the meaning. Thus, people become expert in narrower specialties.

Solar energy is an area with its own tax subsidies, peculiar issues, specialized transaction structures for converting the subsidies into capital for companies that cannot use them, and different rules for solar equipment used in a commercial versus a residential context.

Utilities have been slow in many parts of the county to embrace solar, but there are signs of change. Solar is still not economic in most parts of the United States without government support. The gap is closing quickly. Regulated utilities had been held at bay by rules that barred them from claiming a 30% investment tax credit on solar equipment used to supply electricity at rates that are set on a rate-of-return basis, but Congress lifted the ban in October 2008 effective for solar equipment placed in service after February 13, 2008. Solar energy provides less than 1% of electricity supplied in the United States today. The percentage is expected to grow, driven by rules in at least a dozen states that require a specified percentage of electricity supplied at retail to come from solar energy, by congestion on the grid and by falling prices for solar panels.

This manual is for investor-owned utilities, their unregulated affiliates, municipal utilities and electric cooperatives that are involved with solar energy.

They may be involved in solar projects directly as owners or be considering investing in or acquiring solar energy companies or projects. The involvement may be only indirect. A utility may merely have contracts to buy electricity from solar projects owned by independent generators or may be dealing with ratepayers who are installing solar equipment on their own and, in some cases, supplying electricity back to the grid through net metering.

The manual is divided into three broad sections.

The first section focuses on the potential federal tax subsidies that are available to help pay part of the cost of solar equipment and what issues come up when trying to take advantage of them. Since comparisons may be useful, the section addresses subsidies both in cases where the utility owns the equipment and where the equipment is owned by an independent generator or ratepayer.

The next section focuses on the different relationships that a utility might have to a solar project and the special tax issues that arise under each type of relationship. For example, a utility might buy electricity from a solar project under a standard power purchase agreement or a power contract structured as a "prepaid service contract" or it might own a large project with a partner as tenants in common or in a "flip" partnership.

The final section deals with other tax issues that arise frequently in solar transactions.

Potential Subsidies

The federal government pays as much as 57.5% of the capital cost of new solar energy equipment through tax subsidies. The subsidies differ depending on whether the owner is a company putting the equipment to business use or a homeowner.

They are larger for equipment put to business use.

There are two main tax subsidies at the federal level. (States may offer separate incentives.) They are the ability to deduct the cost of, or depreciate, the equipment over time and a tax credit that can be claimed in addition to the depreciation deductions.

Equipment that uses sunlight to generate electricity, or to heat, cool or produce hot water for use in a building, or to provide "solar process heat" can be depreciated over five years using the 200% declining-balance method, meaning that the deductions are front loaded. The equipment must be put to business use. It can be purchased new or used. The tax savings from the depreciation deductions over five years are worth 25.3¢ per dollar of capital cost. (This assumes the owner of the equipment pays taxes at a 35% rate and it can deduct only 85% of the cost of the equipment on account of also claiming an investment tax credit on the equipment. The calculation uses a 10% discount rate.) Solar equipment put in service in 2012 also qualifies for a 50% "depreciation bonus," meaning that half the tax basis can be deducted in 2012 and the remaining basis is recovered through regular depreciation over five years. This is worth another 2.2¢ per dollar of capital cost.

The owner can usually also claim an investment tax credit on the same equipment. However, it must purchase the equipment new (unlike the 5-year depreciation allowance, which applies to new or used equipment). The idea behind the tax credit is not only to promote heavier use of renewable energy, but also to create jobs in factories for people who build the equipment; hence the requirement that the equipment must be new. The credit is 30% of the cost of equipment put into service during the period 2006 through 2016. The credit is 10% for equipment put into service in other years. It is possible that Congress may extend the deadline to qualify for the 30% credit. However, there is also the possibility that Congress might strip a lot of incentives from the tax code as part of a major overhaul of the corporate income tax as early as 2013 or 2014. Both political parties believe the corporate income tax should be reduced. Studies by the US Treasury and the Joint Committee on Taxation in Congress suggest that stripping *all* tax incentives from the US tax code, other than accelerated depreciation, would allow the corporate income tax rate to be reduced to 31% from the current 35%. Removing accelerated depreciation would allow the rate to come down to 28%. Republicans want to reduce it to 25%. A 30% tax credit can also be claimed during the same period 2006 through 2016 on new solar lighting installed inside buildings. The lights must "illuminate the inside of a structure using fiber-optic distributed sunlight." There is no credit for solar lights in other years.

Tax credits are more valuable than deductions. A tax credit reduces the taxes that a company must pay dollar for dollar by the amount of the credit. A deduction merely reduces the taxable income the company must report, with the result that its taxes go down by its effective tax rate times the amount of the deduction.

An economic stimulus bill in February 2009 -- also known as the American Recovery and Reinvestment Act -- gave owners of solar equipment put to business use the option to receive the cash value of the investment credit by wire transfer from the US Treasury in lieu of taking the tax credit. This option only applies to new solar equipment that was placed in service in 2009, 2010 or 2011 or that was under construction by the end of 2011 and is placed in service by 2016. Projects on which grants were paid have ongoing reporting requirements and, like the investment credit, the grants remain subject to possible recapture for the first five years after equipment is first put in service, but in more limited circumstances than the investment credit. The stimulus also opened the door to possible use of various types of tax-exempt and tax credit bonds and federal loan guarantees as a way to bring down the cost of debt on solar projects. It also provided a separate "manufacturer's" credit to help pay the cost of upgrading or re-equipping existing factories -- or building new ones -- to make solar panels, inverters and other equipment used by the solar market. The windows for use of these other incentives have largely closed, but there may be an effort in Congress to extend them.

Solar energy equipment owned by homeowners is less heavily subsidized.

Depreciation cannot be claimed on equipment put to personal use. The only potential subsidy is a tax credit.

An individual can claim a tax credit for 30% of his or her spending during the year on solar equipment to supply electricity to his or her home and another 30% of spending on a solar hot water heater. Sunlight must account for at least half the energy used to run the hot water heater. The maximum credit that can be claimed for each type of spending was $2,000 a year, but Congress eliminated the cap for spending after 2008. Only spending during the period 2006 through 2016 qualifies. The credit is claimed in the year the equipment is fully installed, even though the spending may have lasted more than one year.

Utility Ownership

INVESTMENT TAX CREDIT

Amount
The investment tax credit is 30% of the "basis" that a company has in eligible property put into service during the period 2006 through 2016. See sections 48(a)(1) and 48(a)(2)(A)(i). It is 10% of the basis of eligible property put into service in other years. See section 48(a)(2)(A)(ii). (All references in this manual to a "section" without identifying the statute are to sections of the US tax code. References to "Treas. Regs. §" are to regulations issued by the Internal Revenue Service to interpret the tax code.)

A company's "basis" is what it paid to purchase or build the property. See section 1012. Sales tax and interest paid on debt to acquire assets are normally deducted immediately rather than added to the basis. See sections 163 and 164. However, an election can be made under section 266 to fold them into the basis, in which case the amounts would have to be deducted over time through depreciation, but they would enter into the calculation of the tax credit. A utility has no choice but to capitalize, or fold into the basis, interest on construction debt for any solar project that the utility is considered for tax purposes to be constructing itself and that is expected to take more than a year to construct and cost more than $1 million. See section 263A(f).

Eligible Equipment
There are two types of eligible property for the investment credit. They are:

- "equipment which uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat, excepting property used to generate energy for the purposes of heating a swimming pool," and
- "equipment which uses solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight." See section 48(a)(3)(A).

Solar lighting qualifies as eligible property only if put into service during the period 2006 through 2016. Thus, there is no investment credit at all on it after 2016. Only fiber-optic lighting systems qualify. Solar tube-type systems do not.

Credits can be claimed only on equipment as opposed to buildings. Not all structures are considered buildings for tax purposes. In general, a structure that is little more than a shell to house equipment is considered part of the equipment. However, if the structure includes office space or a control room, then it is usually considered a building.

The equipment must be new.

A company that buys a used solar installation may be able to treat it as new if it puts enough money into upgrading the equipment after the purchase. The IRS applies an "80-20 test" to determine whether equipment has been so extensively modified that it is essentially a different piece of equipment. The test is A + B, where A is the value of the used parts retained from the original equipment and B is the cost of the improvements. If B is more than 80% of the total A + B, then the equipment will be considered brand new. See, e.g., Rev. Rul. 94-31, 1994-1 C.B. 16.

Only active -- not passive -- solar systems qualify. IRS regulations define passive solar systems as ones that use "conductive, convective, or radiant energy transfer" and give as examples of such systems greenhouses, solariums, roof ponds, glazing, and mass or waster trombe walls. In systems that include both active and passive solar equipment, the credit can only be claimed on the active part. See Treas. Regs. § 1.48-9(d)(2).

The credit can only be claimed on the equipment in a solar power plant up to the transmission stage. The IRS takes the position that electricity is not yet in transmission until it passes through a step-up transformer to step it up to transmission voltage. Thus, a credit can be claimed on the step-up transformer. It can also be claimed on circuit breakers, surge arrestors and other equipment on the high-voltage side of the transformer that protect the transformer from damage, but not on a radial line to move the electricity from the transformer to the grid. See Treas. Regs. § 1.48-9(d)(3); see also Chief Counsel Advice 201122018 (May 4, 2011).

Dual-use equipment that uses other "fuels" besides sunlight (or that is related to such equipment) qualifies only if the other fuels are no more than 25% of the total energy used and then only a fraction of the cost of such equipment qualifies for the credit. An example is a solar hot water heater that also runs on gas. The fraction is the solar share of total energy used measured on a Btu basis. See Treas. Regs. §§ 1.48-9(d)(4) and (6). For example, if 20% non-solar energy is used in the year the equipment is first put into service, then the investment tax credit can be claimed on only 80% of the cost. See Treas. Regs. § 1.48-9(d)(8). A dip in the solar energy use below 80% in any of the next four years could lead to recapture of part of the tax credit claimed. See Treas. Regs. § 1.47-1(h). No additional credit can be claimed in a later year if the solar energy usage is more than 80%. See Treas. Regs. § 1.46-3(d)(4)(i).

The IRS has issued only six private letter rulings that shed light on the eligible equipment at a commercial solar project.

In one, the taxpayer represented that "almost all" of a concentrated solar power plant qualified for the credit. It represented that "[X]% of the solar collector field and its associated pipes, pumps, valves, and controls are eligible . . . and that at least [Y]% of the turbine generator, condensers, and related pipes, pumps, and controls that receive steam from the supplementary heater are eligible because their use of energy from sources other than solar energy will not exceed [Z]% of their total energy input" during the first 365 days after the project is placed in service. See Private Letter Ruling 9045046 (August 15, 1990). (The X, Y and Z were not disclosed in the ruling. The fact that the taxpayer represented how much of the equipment qualified meant that the IRS did not rule on that issue.)

Another ruling six years earlier dealt with the same type of solar plant with rows of parabolic trough collectors that focus sunlight on a heat absorption tube through which oil runs. The heat is transferred from the oil by a heat exchanger and used by a "preheater" to boil water to make steam, but the steam was then run through a gas-fired "superheater" to increase the steam pressure to the level needed to drive the steam turbine and generate electricity. The IRS ruled that all of the equipment through the heat exchanger and preheater, including oil storage tanks and pipes, qualified for the credit, but the ruling is silent about the equipment downstream from the preheater. See Private Letter Ruling 8418047 (January 27, 1984).

The third ruling involved photovoltaic equipment mounted on racks 40 to 50 feet in length and held up by steel poles planted in the ground that provided electricity to a housing development. The taxpayer asked for a ruling that "all aspects of the System located above ground," except a shed that housed an inverter, computer and power generating equipment, the foundation to which the eligible equipment is affixed, and the distribution wiring that leads from the shed to the houses qualified for the credit. The IRS said it did. See Private Letter Ruling 8520120 (February 14, 1985). (The system also involved an underground conduit from the solar panels to the shed. It is not clear whether the taxpayer proposed to claim a credit on it.)

The other three rulings addressed the line between solar equipment and a structural component of a building. A credit cannot be claimed on the latter.

In one, a knitting company installed photovoltaic cells on its roof that were cylindrical in shape, with half the cells on the underside of the cylinder facing away from the sun. Spaces between cells let sunlight pass through. The company put a reflective surface on the roof to reflect the sunlight back up to the cells on the underside of the cylinder. The IRS said the reflective surface was part of the solar equipment. See Private Letter Ruling 200947027 (August 11, 2009).

The IRS ruled that an investment credit could be claimed on a solar curtain wall, or tinted glass installed in place of a window in a building with a thin solar panel embedded in the glass to generate electricity. The IRS described the curtail wall as more a piece of machinery than a structural component of a building. The ruling is interesting because the cost of property that is put to a dual use must ordinarily be allocated between the two uses and a tax credit can be claimed only to the extent the equipment is used at least 75% of the time as a solar device and then the credit is the share of solar use above that. The IRS lawyer who worked on the ruling said he did not see any dual use of the window. It serves a "dual purpose," the ruling said, but it is not put to dual use. It is basically a solar panel that happens to have been installed on the side of a building rather than the roof. See

Private Letter Ruling 201043023 (October 23, 2009).

The IRS said in the last ruling that an investment credit could be claimed on the cost of a membrane put under solar rooftop panels that doubles as a roof, but only to the extent of the incremental cost above what a membrane that serves solely as a roof would cost. See Private Letter Ruling 201121005 (February 1, 2011).

Solar equipment owned or leased by a regulated utility did not qualify for the investment tax credit from 1980 through February 13, 2008. More precisely, credits could not be claimed on "public utility property" during that period. See section 48(a)(3). "Public utility property" is equipment used predominantly in the business of furnishing electricity for sale, but only if the rates the power company can charge are regulated on a rate-of-return basis.

Congress dropped the ban "for periods after February 13, 2008" under transition rules that mean that credits on equipment placed in service after February 13 may apply to only part of the basis in some cases where work on a project straddled that date. See section 103(e) of the Emergency Economic Stabilization Act of 2008, Public Law 110-343.

However, a utility can claim the credit only if it is not required by its regulators to share the benefit with its ratepayers more rapidly than under a normalization method of accounting. See section 50(d)(2) (which invokes old section 46(f) before the section was repealed in 1990). Under one method, called the ratable flow-through method, the benefit of the credit can be passed through to ratepayers ratably (on a level basis) over the useful life of the asset, but the utility cannot be required to reduce its rate base by the amount of the credit. Thus, it is able to earn a return on the portion of the equipment cost that was paid by the government through the investment credit. It earns a return each year on the equipment cost that is still in rate base; the cost is backed out of rate base gradually over time by claiming whatever depreciation the regulators allow for ratemaking purposes. See old section 46(f)(2). The treatment under another method, called the rate base reduction method, is essentially the opposite. The utility's rate base is reduced by the amount of the credit. However, the credit is passed through ratably to ratepayers over the depreciable life of the asset. See old section 46(f)(1).

Equipment must be used in the United States to qualify for an investment credit. See section 50(b)(1). US possessions like Puerto Rico are considered outside the United States for this purpose. However, the US tax code makes an exception for property used in possessions as long as it is owned by a US corporation or citizen. See sections 50(b)(1) and 168(g)(4). The IRS ruled privately that investment credits could be claimed on a utility-scale photovoltaic project and a wind farm in Puerto Rico. The solar project was owned by a Puerto Rican company, but the company was a "disregarded" subsidiary of a Delaware limited liability company that was a partnership for US tax purposes and all of the partners were US corporations. See Private Letter Ruling 201136018 (May 25, 2011) (solar); see also Private Letter Ruling 201136018 (May 25, 2011) (wind).

Credits cannot be claimed on equipment that is "used" by someone who is not subject to US income taxes. See sections 50(b)(3) and (4). Thus, use of the equipment by a government agency, by a foreign company (unless more than half the income earned from use of the equipment is subject to US tax), or by a school, charity or other tax-exempt organization (unless the equipment is used in a taxable side business) will rule out credits on the equipment. An example of "use" is where equipment is leased to such a person. However, a lease with a term of less than six months does not count as a "use." See section 50(b)(4)(B). Credits are calculated in the year equipment is first put into service. Equipment might not be used by an ineligible person that year, but use by such a person in any of the next four years would cause part of the tax credits claimed to be recaptured. See section 50(a).

Haircut

Using "subsidized energy financing" or tax-exempt financing to help pay the cost of solar equipment used to cause a "haircut" in the investment tax credit before 2009. Projects that are placed in service in 2009 or later, but on which work started before 2009, may still suffer a haircut to the extent subsidized energy financing or tax-exempt financing was used to pay costs that were incurred before 2009. See section 1103(c) of the American Recovery and Reinvestment Tax Act of 2000, Public Law No.

111-5; see also section 48(m) of the Internal Revenue Code as in effect before 1986.

The haircut is calculated by putting the cost of the equipment in the denominator of a fraction. (What goes into the denominator is the basis that the taxpayer has in the equipment.) The numerator is the amount of subsidized or tax-exempt financing used. The fraction is the percentage reduction in the tax credit. See section 48(a)(4).

Tax-exempt financing is borrowing through bonds issued by a state or local government at reduced interest rates. (Because the lenders do not have to pay income taxes on the interest they receive, they are able to charge less interest.) Tax-exempt financing can usually be used only for schools, roads, hospitals and other public facilities. However, the US tax code makes 15 exceptions where such financing can be used for private projects that Congress felt created some public benefit. See section 142. An example is a privately-owned sewage treatment plant or sports stadium.

"Subsidized energy financing" is "financing provided under a [f]ederal, state or local program a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." See section 48(a)(4). An example of such financing is where a state offers low-interest loans directly to help pay for renewable energy projects or where the state makes payments to a bank to buy down the interest rate on loans that the bank makes to finance such projects. A grant that the recipient must report as taxable income, loan guarantees, price guarantees and state tax credits are ordinarily not subsidized financing. Be careful about the amount. The IRS took the position in an example in regulations under the residential energy credit that used to be on the statute books from 1977 to 1990 that where a bank lent $3,000 to a homeowner to install a solar hot water heater and the bank used $500 it received under a federal energy conservation program to reduce the principal amount of the loan the homeowner had to repay to $2,500, the amount of subsidized energy financing is the full $3,000. The subsidized financing is the full financing extended under a government program and not just the cost to the government of the subsidy. See Treas. Regs. § 1.23-1(d)(3).

A number of IRS rulings give additional examples of what is and is not "subsidized energy financing."

It is subsidized energy financing for a state agency to make loans at below-market interest rates to encourage residents to buy houses from selected builders who build energy-efficient homes. The state borrows in the tax-exempt bond market to raise funds for the program and relends at the same tax-exempt borrowing rate. See Technical Advice Memorandum 8537005 (June 5, 1985).

However, it is not subsidized energy financing for a federal utility like the Bonneville Power Administration or Tennessee Valley Authority to make loans at below-market interest rates to customers of utilities to whom BPA or the TVA supplies power. By law, the federal utility must cover its full costs through its own revenues. See Rev. Rul. 81-52, 1981-1 C.B. 9.

It is not subsidized energy financing for an investor-owned utility to make rebates on electricity bills to homeowners who buy hot water heaters that use renewable energy. The money the utility uses for the program comes solely from its own revenues. It does not matter that the utility was ordered by the state public service commission to conduct the program. See Rev. Rul. 83-145, 1983- C.B. 14.

It is not subsidized energy financing for a private party to get a loan guarantee from a federal agency under a program to promote geothermal projects. The IRS said in a private letter ruling that such a loan guarantee is not subsidized energy financing even if the guarantee looks in form like a direct loan by the government to the private party. The interest rate on the loan is the same rate that a bank charges to lend with a federal guarantee. See Private Letter Ruling 8530004 (April 30, 1985); see also PLR 8432072 (May 8, 1984).

It is not subsidized energy financing for the federal government to guarantee oil companies that produce shale oil that they will get at least a minimum price for their output. See Private Letter Ruling 8428035 (April 6, 1984); see also PLR 8410092 (December 7, 1983).

Progress Expenditures
The investment credit is ordinarily claimed in full in the year that eligible property is put into service. However, a taxpayer can elect to claim

credits on construction progress payments in situations where the property is expected to take at least two years to build. See section 48(b).

The amount the taxpayer is considered to have paid toward construction in any year depends on a number of complicated rules.

The taxpayer must first determine whether a project is "self constructed" or "non-self constructed." The progress expenditure rules use a much tighter definition of self construction than the tax code uses for some other purposes, like the depreciation bonus that is available as an inducement to companies to invest in new plant and equipment. Thus, while most stick-built projects are considered self constructed for purposes of the depreciation bonus, few projects are self constructed for progress payments purposes. To be self constructed for progress payments purposes, the taxpayer must expect to spend more than half the construction expenditures on wages for the taxpayer's own employees and on materials that they will install.

This test is applied to each unit of property. A single project may consist of more than one unit. For example, each turbine, boiler and other large component at a power plant is probably considered a separate unit of property.

Spending on non-self-constructed property counts only when amounts are actually paid to a third party and, even then, one can only count the spending in a year "to the extent [it is] attributable to progress made in construction . . . ." The IRS regulations say, "Progress will generally be measured in terms of the manufacturer's incurred cost, as a fraction of the anticipated cost . . . ."

Spending on self-constructed property counts earlier in time as progress payments. The rule for self-constructed property is that spending counts when the amount "accrues," meaning when the taxpayer is legally obligated to make the payment and the amount is known. However, spending on components comes under a special rule. It cannot be counted before the components are built at the factory (in the case of components that are specially designed for a project), or when they are delivered to the site (in the case of other components that would be "economically impractical to remove" after delivery), or when they are physically attached to the project (in the case of any remaining components).

Recapture

Investment tax credits "vest" over five years at the rate of 20% a year. Therefore, if something happens to solar equipment within the next four years after equipment is put into service that would have prevented the taxpayer from claiming an investment credit had it happened at the start, then the "unvested" part of the credit will be recaptured. See section 50(a). For example, the unvested credit will be recaptured if the taxpayer sells the solar equipment or leases it for use by a government agency.

Thus, a taxpayer should take the potential tax hit into account when considering whether to sell solar equipment on which investment credits have been claimed before the recapture period has run.

The five years are measured in 12-month intervals from the date the equipment was originally placed in service.

The unvested credit will have to be reported as income in the year the recapture event occurs. The taxpayer can add back to his tax basis half the recapture income reported in the recapture year. The amount added back to basis can be deducted over time as additional depreciation if the taxpayer continues to own the project. If the recapture event is a sale of the project, then the taxpayer will have less gain to report from the sale because of the upward basis adjustment. He will also have a potential mismatch in tax rates. Recapture income is ordinary income. Gain from a sale in many cases will be capital gain. The combination of credit recapture and the upward basis adjustment have the effect of converting income from capital gain into ordinary income.

Limits on Ability to Use

Investment tax credits cannot be used to reduce a taxpayer's regular income taxes by more than 75%. See sections 38(c)(1) and (4). This limit is a limit not only on the use of investment credits, but also on most other "business credits." Thus, investment credits in combination with other business credits cannot reduce a taxpayer's tax liability in a year below the floor. Other business credits, like foreign tax credits, are used first. "Specified credits" -- which include the investment credit -- are the last in line. See section 38(c)(4)(A)(i)(II).

Until recently, investment credits also could not be used against any alternative minimum taxes. (A corporation must calculate both its regular income taxes at a 35% rate and its "alternative minimum taxes" at a 20% rate but on a broader definition of taxable income and pay essentially whichever amount is greater.) This restriction was lifted, effective for equipment placed in service in tax years starting after October 3, 2008. See section 103(b) of the Emergency Economic Stabilization Act of 2008, Public Law No. 110-343.

Carryback and Carryforward

Credits that a taxpayer cannot use because of the floor can be carried back one year and forward 20 years. See section 39. However, it appears that only 10% of the 30% solar credit can be carried back before 2006. The remaining 20% of solar credits arising in 2006 cannot be carried back. If a taxpayer ends up carrying unused energy credits forward for 20 years and is still unable to use them, the unused credit can be deducted in the year after the carryforward period ends. However, only half of it can be deducted that year. The rest is lost.

Allocation and Recapture in Partnerships

Investment tax credits must be shared among partners in the same ratio that they share in taxable income for the year in which eligible property is placed in service. See Treas. Regs. § 1.46-3(f)(2).

It does not matter whether the partnership actually has any taxable income that year. However, be careful about switching the ratio for sharing taxable income before the partnership turns "tax positive." For example, suppose there are two partners -- A and B -- who agree to allocate 99% of taxable income to B for the first three years in order to get B almost all of the energy credits and then share everything 50-50. Projections show that the partnership will have tax losses until year four. The IRS may argue on audit that the 99-1 sharing ratio for taxable income is a sham. See, e.g., Technical Advice Memorandum 8931001 (March 15, 1989)

Partners face an added risk of recapture of tax credits. In the example, B would suffer recapture of part of his credits in year four when the sharing ratio shifts. There will be recapture of a portion of B's unvested credits if B's share of taxable income drops during the next four years after the project is put in service to less than two thirds of B's ratio in the year the project is put into service. See Treas. Regs. § 1.47-6(a)(2). Thus, B's ratio could drop to 70% without any recapture, but a drop to 50% would trigger recapture of roughly half his unvested credits in year four when the flip occurs. Once B has suffered any recapture, then another flip will not cause any further recapture unless the drop is to less than one third of the share B had in taxable income in the year the project went into service.

TREASURY CASH GRANTS

Owners of new solar energy projects placed in service in 2009, 2010 or 2011 -- or that started construction in 2009, 2010 or 2011 and are completed by 2016 -- have the option to receive the value of the investment credit from the US Treasury in cash.

Grants are supposed to be paid within 60 days after a project is placed in service or, if later, 60 days after a complete application is received by the Treasury. The Treasury has no discretion whether to pay grants; if the owner qualifies, the owner is entitled to a grant. Congress provided an open-ended appropriation.

Many utilities still claim the investment credit because they may receive the benefit earlier in time. Investment credits on equipment that a utility plans to place in service during the year may be taken into account in quarterly estimated tax payments during the year. However, a utility should weigh against the timing the fact that cash grants are less likely to have to be repaid to the government if the project or an interest in the project is transferred in the future. A transfer of an interest in the project within the first five years after it is placed in service may lead to recapture of the "unvested" investment credit. It will not usually lead to recapture of a cash grant.

Amount

The grant is the same amount as the investment credit. Eligible costs for the grant are the same as for the investment credit. See "Eligible Equipment" in previous section on the ITC, p. 4 see also section 1603(b) of the American Recovery and Reinvestment Tax Act of 2009, Public Law No. 111-5.

The Treasury posted a series of benchmarks to its website in June 2011 to let the solar industry know how much it was prepared to accept as the grant basis on solar projects after solar companies complained that there was too much uncertainty surrounding how much the Treasury would pay on individual projects. The benchmarks range from $7 a watt on residential installations of less than 10 kilowatts in size to $4 a watt for systems larger than one megawatt. These benchmarks reflect solar panel prices in the first quarter 2011. Panel prices have fallen considerably since then. Companies that claim a "materially higher" tax basis can expect more questions about their applications.

Entity to Whom Grant Is Paid
The grant is paid to the legal entity that owns the project when it is put to "original use."

Many projects are owned by limited liability companies. Thus, the grant is paid to the limited liability company. It does not matter how the LLC is treated for tax purposes (as a "disregarded entity," partnership or corporation).

If the project is sold and leased back within three months after it is originally put into service, then the grant is paid to the lessor unless the lessor elects to leave the grant with the lessee. The lessor calculates the grant on its "tax basis" in the eligible equipment. That is the amount the lessor paid to purchase the equipment, even if it reflects a markup from the amount the developer-lessee paid to build the project. The grant remains with the lessee if a sale-leaseback is done more than three months after the project is originally placed in service.

A lessor can elect to pass through the investment credit to a lessee. This election is at the heart of "inverted lease" transactions where a developer leases solar equipment to a tax equity investor as lessee and elects to pass through the investment credit to the lessee. <u>See</u> discussion later under the subheading "Inverted Leases" in the section on Special Tax Structure Issues. In such cases, the lessee calculates the grant on the fair market value of the eligible equipment. The lessee must report half the grant as income on a straight-line basis over five years.

The Treasury views sale-leasebacks and inverted leases as financings rather than arm's-length sales and feels free to substitute its own judgment about the appropriate market value, notwithstanding that the lessor or lessee has an appraisal. It may ask the developer in such transactions for its actual cost of the project and then allow only a 10% to 20% mark up.

Start of Construction
A project will qualify for a cash grant if construction started in 2009, 2010 or 2011, but the project must be completed by 2016.

There are two ways to show that a project was under construction by 2011.

One is by showing that the sponsor "incurred" costs amounting to more than 5% of the basis that the owner uses to claim a Treasury cash grant. Costs are not incurred until there has been "economic performance" under section 461(h) of the tax code. Thus, it is generally not enough for an accrual-method taxpayer merely to have spent money. It must have taken delivery or title to the equipment or services. Delivery could be at the factory, but it is important in such cases to be able to prove that delivery in fact occurred. Ideally, the equipment should have been moved to a separate location or at least segregated in the factory warehouse. The sponsor should have inspected the equipment and signed a delivery certificate. If transfer taxes were triggered by delivery, they should have been paid. The sponsor should have taken risk of loss and purchased insurance. It should ideally have been responsible for further transportation of the equipment. It is hard to see how delivery could have occurred for equipment that must be returned to the manufacturer to be incorporated into a larger item.

In some cases, a sponsor could also meet the 5% test by paying for equipment in late 2011 that was delivered within 3 1/2 months of payment. <u>See</u> Treas. Regs. § 1.461-4(d)(6)(ii). The IRS national office views the 3 1/2 month rule as a "method of accounting." The Treasury adopted the same view for the cash grant program. Thus, a taxpayer who used another method in the past to determine when costs were incurred would have needed IRS permission to use it.

A sponsor could look through a binding contact with a manufacturer or construction contractor and count costs the manufacturer or contractor incurred by December 2011 to perform the contract.

The costs of land and preliminary activities that normally precede construction, like engineering and design work, exploring for sites, researching the market and legal fees to negotiate financing, do not count and must be subtracted from both the numerator and the denominator of the fraction.

The other way to show construction started is to demonstrate that "physical work o f a significant nature" began by December 2011. Such work is considered to have started once work began at the site on excavating the foundation, setting anchor bolts into the ground or pouring concrete pads for the foundation.

Physical work can also be shown to have started by looking through a binding contract with a manufacturer or construction contractor and counting work by the manufacturer or contractor to perform the contract. The contract must have been a binding contract before work started. Thus, the work to be done under the contract and the cost must have been clear. If the contract required a notice to proceed from the sponsor before work could start, then notice should have been given. The Treasury has said that it is okay if only limited notice to proceed was given in 2011; the work done under it will count. The contract can give the sponsor a right to terminate the contract at will, but the sponsor must be liable for full damages through termination. Any limit on damages cannot be less than 5% of the total contract price.

Anyone relying on the physical work test must show that the construction work after December 2011 was continuous. Banks and tax equity investors have shown a clear preference for the 5% test because there is no need to worry about whether the construction work was continuous. Care should be taken about amending any binding contract on which the sponsor is relying to count work. An insubstantial change to such a contract is not a problem. A more significant change may call into question whether the contract was really binding when originally signed.

Large solar projects may be more than one unit of property with separate start dates for construction for each unit. For example, this would be true of a solar project with multiple arrays that will be put into service on staggered dates over time. It is not true of components that are functionally interdependent in the sense that they cannot be placed in service independently of the rest of the project. A utility may elect to treat multiple units of property that are on the same site as a single unit of property for purposes of when construction of the project started and when the project is considered placed in service for purposes of the cash grant. Any such election would not affect when depreciation starts to run. A project that supplies all of its output to a utility under a single power purchase agreement should be treated as on a single site even thought it is spread over several adjoining parcels leased from separate landowners.

Care should be taken when transferring assets or a project company after 2011 on which enough costs were incurred to qualify for a cash grant while a project is still under construction. The ability to claim a cash grant on the project may be lost.

The Treasury said it will let the incurred costs carry over to the new owners in the following situations.

In cases where assets <u>are</u> transferred (rather than the project company), the costs will carry over only if the developer "acquired the property for use in that project" and owns more than 20% of the legal entity to which the equipment is transferred "immediately before or immediately after" the equipment is transferred. A developer will be viewed as owning more than 20% of a legal entity that is a partnership if it owns more than 20% of the capital <u>or</u> profits interests. A developer's capital interest is the share of the assets that the developer would be distributed if the partnership liquidated. His profits interest is his share of income and loss.

In cases where all or part of the project company is transferred, the grandfather rights carry over as long as the project company is a real project company and not just wrapping for equipment that someone stockpiled in 2011 in the hope of selling at a premium after 2011 to someone else who wants to claim a grant on a different project. The Treasury said eligibility for a grant is not affected by a change in ownership of the project company as long as two things are true. First, the new owner cannot be a "disqualified person," meaning a government or tax-exempt entity or unblocked private equity fund with any such entities as investors. Second, the project company must have "commenced development of a project as evidenced by activity such as acquiring land, obtaining permits and licenses, entering into a power purchase agreement, entering into an interconnection agreement, and contracting with an Engineering, Procurement and Construction contractor." In other words, it must be a real project company.,

A project that is considered to have been under construction in 2011 under the physical work test will remain under construction despite having been transferred to someone else while still under construction.

Recapture

The cash grants are not subject to recapture, except in three narrow circumstances.

First, recapture will occur if there is a change in use of a facility during the first five years after it is placed in service. An example is where 95% of the energy used to power a boiler at a large solar thermal project is sunlight and the other 5% is gas in the year the project is placed in service. However, the next year, the percentage of energy from gas increases to 10%.

Second, recapture will occur if the project is permanently shut down during the first five years after the in-service date. However, there will be no recapture if the project is forced to shut down by a natural disaster, unless the owner rebuilds and claims a cash grant on the new equipment.

Third, recapture will occur if the project or an interest in the project is transferred to a federal, state or local government agency or instrumentality, an entity exempted from taxes under section 501(c) of the Internal Revenue Code, an electric cooperative or Indian tribe. Such a transfer would bring into play a provision in the stimulus bill that bars cash grants to projects with such persons as investors. See section 1603(g) of the American Recovery and Reinvestment Tax Act, Public Law No. 111-5. The ban only applies if such an investor owns an interest in the project through passthrough entities like partnerships. It does not matter how small an interest such an investor owns or how far up the ownership chain.

Other sales of projects will not trigger recapture, but the buyer must agree to be jointly liable with the original owner who claimed the cash grant for the recapture liability if a recapture event occurs within the first five years after the project was originally placed in service. For example, where a project is owned originally by company A, but bank B takes the project in a foreclosure asset sale and B later resells the project to a state pension fund, the government can go after both A and B for the recapture liability. This requirement that the buyer must formally agree to exposure only comes into play where the buyer buys assets and not the project company.

Any recapture liability will reside at the project company level. The government has no claim against the owners or anyone else who received the proceeds from the cash grant, unless the project is owned by a true partnership, as opposed to a limited liability company, in which case the government would also have a claim against the general partner.

The cash grant vests ratably over five years. Any recapture would be of the "unvested" grant. Thus, for example, a sale of the project to a tax-exempt entity in year four would subject 40% of the cash grant to recapture.

Any recapture liability will not be a tax claim. That means that the government will be an unsecured creditor. The government will not ask for a lien by contract as part of the terms and conditions that companies receiving grants must sign. It will get a lien eventually as a result of any judgment against the project company for the recapture liability, but any such judgment lien will be governed by state law and be subordinate to the liens of secured lenders.

Tax-Exempt Participants

Section 1603(g) of the American Recovery and Reinvestment Tax Act bars a cash grant from being paid to any project in which any federal, state or local government agency, entity exempted from taxes under section 501(c) of the Internal Revenue Code, electric cooperative or Indian tribe owns an interest through passthrough entities. Section 1603(g) operates like a cliff. Any interest, no matter how small, is enough to deny the project a cash grant.

The staffs of the Senate and House tax-writing committees are considering a technical correction that would make it clear that investors are not considered tax-exempt entities for purposes of the ban if they pay taxes on their earnings from the projects as "unrelated business taxable income." Most do. However, state pension funds do not.

A project will qualify for a cash grant if the disqualified investors are kept on the other side of a "blocker corporation" from the project. There had been some question whether the blocker might be treated itself as a tax-exempt entity if it is owned 50% or more by tax-exempt entities. See, e.g., section 168(h)(6)(F)(iii). However, the Treasury made clear in guidance that this is not a problem. However, the blocker might still be treated as a tax-exempt entity for purposes of labeling the project partly as "tax-exempt use property" for depreciation purposes, which would have the effect of reducing the time value of the depreciation. (Also see "Asset Breakdown and Cost Recovery" in the Depreciation section.)

The blocker corporation must be in place before the owner of the project applies for the grant.

Application
The application can be found on line and must be submitted electronically. More information is available at: https:/www.treas1603.nrel.gov.

The Treasury does not want applications until projects have been placed in service for projects that go into service in 2009, 2010 or 2011. This will cut down on the time the government must spend on paperwork before files are ripe for review.

The owner may not have the final cost figures for some time after a project is completed. There is no formal process to supplement the original application. Treasury officials have suggested owners should wait until they have the final tally. However, another approach in some cases may be to treat the additional spending as a capital improvement and apply separately for a grant on it. (See the discussion below under the heading "Other Issues.")

Projects that are merely under construction in 2011 must apply in 2012, whether or not they are completed then. All applications under the program must be in by September 2012 so that the government has a sense for what it might still have to spend under the program.

The government will review 2012 applications and let the developer know that the project will qualify for a grant based on the information received so far. The developer must then complete the rest of the form within 90 days after the project goes into service.

Once an application is approved, Treasury will inform the company. The money will be wired within five days.

The applicant must submit a signed set of terms and conditions at the same time it applies for the grant.

Several other documents must be submitted with the form. The Treasury has posted a checklist to its website because so many applications have been incomplete.

The longest lead-time item is probably a cost breakdown showing how the applicant arrived at the "tax basis" on which it is calculating the cash grant. Only part of the equipment at a project may qualify for the grant. An independent accountant must certify to the cost figures and how they have been allocated. The accounting firm must give a "will" opinion that the basis has been properly calculated in cases where a grant of at least $1 million is expected.

The government has been concerned about fraud. The applicant must provide a certificate confirming that the project was put in service from a project engineer, equipment vendor or an independent third party. The Treasury has in mind the same certificate that is normally given to lenders or a tax equity investor at funding by an engineer who inspects the project on their behalves and attests that certain conditions to funding have been satisfied.

Projects that sell electricity to utilities and have interconnection agreements with the utilities must also provide proof that the project is interconnected and supplying electricity to the grid.

Anyone applying after 2011 for a project that is still under construction must submit proof that construction got underway in 2009, 2010 or 2011. The proof might be invoices marked "paid" for at least 5% of the basis the owner is expected to use to calculate its cash grant plus proof from the vendor about the percentage of construction that was completed.

The Treasury discloses in postings to its website who received grants and the amount of each grant paid.

Companies receiving grants must report annually to the Treasury for five years on how the project is doing. The reports are due 21 days after each anniversary of when the project was placed in service. The report must indicate who owns the project, the installed capacity, annual output and the number of jobs "retained."

Applicants must get a DUNS number from Dun & Bradstreet either by internet (http://fedgov.dnb.com/webform) or by calling 1-866-705-5711. The number is assigned at the end of the call. It takes roughly five minutes. Then the applicant must wait one to two days to register on the Central Contractor Registration (CCR) site (http://www.ccr.gov/startregistration.aspx). That process also is easy and requires filling out a form on line. Both registrations are free.

Other Issues

Historically, solar projects owned by regulated utilities would not qualify for cash grants unless the utility uses a normalization method of accounting. However, the National Defense Authorization Act for Fiscal Year 2012, which was signed into law by President Obama on December 31, 2011, eliminated the normalization requirement for 1603 awards.

The grant is tax-exempt income at the federal level. Grants may still be taxable at the state level in states that do not "conform" to this part of the federal rules.

Anyone who made capital improvements in 2009, 2010 or 2011 to an existing solar power plant that uses renewable energy can receive a cash grant on the improvements. However, the underlying power plant must have qualified for an investment tax credit or else the improvements must be so extensive as to turn the project into a new facility for tax purposes. The IRS uses an 80-20 test to determine whether improvements were extensive enough. They are if the amount the company spends on upgrading the plant is at least four times the value of the existing equipment retained from the old plant. Improvements after 2011 qualify for a grant only if they were under construction by December 2011.

Grant applications must be signed under penalties of perjury. Since the grants are not a tax program, if the applicant is found to have claimed too large a grant, it will be dealing with the US attorney. There may be grey areas about the scope of eligible property, placed-in-service determinations, what costs are properly capitalized into what assets, when construction is considered to have commenced and similar issues where well-meaning and reasonable people may disagree.

With a tax program, one can apply to the IRS for a private letter ruling. These usually take four to six months and are expensive.

The Treasury has tried to set up a more streamlined process. Questions can be sent by email to 1603Questions@do.treas.gov. At the end of the day, the application is no different than the tax returns companies already file and on which they take positions while attesting to the accuracy of the information on the return. However, as a practical matter, unless the treatment is clear, a company may be unable to get the opinion required from its outside accounting firm to support its application.

The IRS said in an internal legal memo that it has authority to audit cash grants received on projects. Thus, a sponsor may end up running the gauntlet twice -- once with the Treasury and again with the IRS several years later. See ILM AM2011-004 (September 27, 2011).

DEPRECIATION

Asset Breakdown and Cost Recovery

Most of the cost of a solar project should be depreciable over five years using the 200% declining-balance method, although some spending will fall into other cost recovery classes.

The same share of the project on which an investment credit can be claimed is depreciated over five years. See section 168(e)(3)(A)(i).

Any part of the project that is considered a building is depreciated over 39 years on a straight-line basis. See sections 168(b)(3) and (c). Not all structures are buildings for tax purposes. In general, a structure that is little more than a shell to house equipment is considered part of the equipment. However, if the structure includes office space or a control room, then it is usually considered a building.

Landscaping and other site improvements, like a parking lot, are depreciated over 15 years using the 150% declining-balance method. See Rev. Proc. 87-56, 1987-2 C.B. 647, as modified by Rev. Proc. 88-22, 1988-1 C.B. 785, at class 00.3; see also section 168(b)(2)(A).

Transmission equipment used to transmit at 69 kv or higher voltage is depreciated over 15 years using the 150% declining-balance method. See section 168(e)(3)(E)(vii). Other transmission and distribution equipment is depreciated over 20 years using the 150% declining-balance method. See Rev. Proc. 87-56, 1987-2 C.B. 647, as modified by Rev. Proc. 88-22, 1988-1 C.B. 785, at class 49.14.

These accelerated write offs -- accelerated because assets have been assigned shorter lives by statute than they are likely to remain in use and because the depreciation deductions tend to be front-loaded rather than mirror the pattern the equipment actually degrades over time -- are called "MACRS" depreciation for "modified accelerated cost recovery system."

Utilities usually make independent generators connecting projects to the grid reimburse for the cost of any substation upgrades, grid improvements and other equipment required for interconnection that the utility will own. Some of the costs may be classified as "network upgrades" for regulatory purposes and the utility will collect the cost from the generator but then repay it later with interest or transmission credits. Any payments a generator makes for network upgrades are treated for tax purposes as a loan. The generator has no cost recovery for them. See Rev. Proc. 2005-35, 2005-2 C.B. 76. The generator may also have to reimburse the utility for "direct intertie" costs that will not be repaid by the utility. The generator must treat any such payments as a cost of its interconnection agreement. However, cost recovery is straight line over 20 years regardless of the term of the agreement. See Notice 88-129, 1988-2 C.B. 541.

Property on Indian reservations can be depreciated more rapidly. It is moved up one depreciation class. Thus, for example, a solar project on an Indian reservation can be depreciated largely over three years rather than five years. See section 168(j)(2). The project must be privately owned rather than owned by the tribe. It cannot have been acquired from a related person. It must not be used off the reservation on a regular basis. See section 168(j)(4). A utility-scale solar facility on a reservation that sells its entire output to a utility elsewhere is considered used on the reservation, even if the output is not. The more rapid depreciation is only available for equipment put in service through 2011. See section 168(j)(8). The deadline is extended periodically by Congress.

Depreciation must be taken more slowly to the extent tax-exempt financing is used to pay part of the project cost. It is also slower for assets used predominantly outside the United States and for any assets that are considered "tax-exempt use property." In each case, the depreciation is straight line over the "class life." See section 168(g). Solar equipment that would otherwise qualify as 5-year MACRS property has a class life of 12 years. See section 168(g)(2)(c). Transmission equipment that would otherwise be depreciated over 15 years has a class life of 30 years. See section 168(g)(3)(B). Other class lives can be found in Rev. Proc. 87-56, 1987-2 C.B. 647.

Equipment will turn into "tax-exempt use property" if it is leased to a school, hospital or other government facility or agency, a foreign person who does not pay US income taxes, a nonprofit organization, Indian tribe or other tax-exempt entity. See section 168(h). Equipment that is owned in a partnership between an investor-owned utility and a tax-exempt entity will be tax-exempt use property to the extent of the high water mark of tax-exempt participation in the partnership. Thus, for example, if the tax-exempt entity is allocated 5% of partnership items initially and 80% later, then 80% of the partnership assets will be considered tax-exempt use property from inception. See section 168(h)(6).

For this reason, if a joint venture is planned with a municipal utility or government agency, it is better to have the parties own interests by undivided interests, fix the allocations for the life of the venture, have the tax-exempt entity invest through a taxable subsidiary, or find another relationship to the project for the tax-exempt entity. A subsidiary controlled by tax-exempt entities is treated itself as tax-exempt unless it makes an election under which the tax-exempt owners agree to pay taxes (as unrelated business taxable income) on dividends and interest received from subsidiary and to subject gain on the sale of the interest in the subsidiary to taxes. See section 168(i)(6)(F).

If assets are tax-exempt use property because they are leased, then depreciation must be taken over not less than 125% of the lease term. See section 168(g)(3). The lease term includes all optional renewal periods, even if the rent is reset at renewal to current market. See section 168(i)(3).

Some assets are depreciated differently when calculating income for minimum tax purposes. The United States has essentially two income tax systems. Corporations calculate their incomes under a regular corporate income tax and then under an alternative minimum tax using a broader definition of income and a lower tax rate and pay essentially whichever amount is greater. Assets are depreciated for both regular and minimum taxes over the same period, but any equipment that would have been depreciated for regular taxes using the 200% declining-balance method is depreciated for minimum taxes using the 150% declining-balance method. See section 56(a)(1). Since most solar equipment is normally depreciated over five years using the 200% declining-balance method, a company on the minimum tax suffers a loss in time value of the depreciation.

MACRS depreciation cannot be claimed on any "public utility property" unless the utility is allowed by its regulators to keep the benefit under a normalization method of accounting. See section 168(f)(2). "Public utility property" is property used in furnishing electricity at rates that are established or approved on a rate-of-return basis. See section 168(i)(10). The utility must be allowed to claim a tax expense for ratemaking purposes as if it claimed tax depreciation in the same manner as the depreciation allowance used for ratemaking. It then sets up a reserve for the deferred taxes (the difference between its actual tax expense and the tax expense using the ratemaking depreciation), and the rate base is reduced immediately by the amount of the reserve. The amount is then added back to rate base over time as the deferred taxes reverse. If the depreciation benefits are not normalized in this fashion in setting rates, then the utility will only be allowed tax depreciation equal to what it is allowed for ratemaking purposes. See section 168(i)(9).

Basis Reduction

The "basis" that a company has in solar equipment on which an investment tax credit is claimed or Treasury cash grant received must be reduced by 50% of the tax credit. See section 50(c). Thus, for example, if a 30% credit is allowed on a solar panel that cost $100X, then the owner will have a basis in the equipment of $85X. That is the amount the owner can claim in depreciation deductions. It is also the starting point for calculating gain when the solar panel is later resold.

If the investment credit or Treasury cash grant is later recaptured -- for example, because the solar equipment is sold before the investment credit or grant has fully vested -- then the basis goes back up that year by the recapture amount. Id.

However, a corporation should not make any basis adjustment for purposes of calculating its "earnings and profits." See section 312(k)(5). Earnings and profits are important because they determine how much of each distribution a corporation makes to shareholders is a taxable dividend. Distributions are dividends to the extent the company has earnings and profits. Earnings and profits are a form of net income. Thus, gross earnings are reduced by depreciation -- among other things -- to arrive at earnings and profits, but the depreciation would be depreciation on the full basis of $100X in the example, notwithstanding that an investment tax credit was claimed.

There is no basis adjustment where the owner of solar equipment leases the equipment to someone else and elects to let to the lessee claim the investment credit or Treasury cash grant. However, the lessee must report taxable income equivalent to the basis adjustment. The income is spread ratably over five years. See section 50(d)(5).

Depreciation Bonus

Some equipment placed in service during the period 2008 through 2013 qualifies for a depreciation bonus.

The bonus is 100% on new equipment put into service after September 8, 2010 through December 2011 or 2012, depending on the equipment. Equipment for which the MCRS recovery period is less than 10 years had to be in service by December 2011 to qualify for a 100% bonus. It qualifies for a 50% bonus if placed in service in 2012. Equipment with a recovery period of 10 years or more qualifies for a 100% bonus if placed in service by December 2012 and a 50% bonus if placed in service by December 2013. An example of equipment that still qualifies for a 100% bonus in 2012 and 50% bonus in 2012 is a transmission line. However, the bonus can only be claimed on costs incurred through 2012.

The bonus is a timing benefit. A 100% bonus means that entire basis can be deducted in the year the project goes into service. A 50% bonus means that half the basis can be deducted immediately. The remaining basis is deducted normally as depreciation. See section 168(k). Thus, for example, where 85% of the cost of equipment could be recovered through depreciation and the project qualifies for a 50% bonus, 42.5% of the cost can be deducted immediately.

Some careful tax lawyers have raised questions whether a Treasury cash grant can be claimed on projects on which a depreciation bonus is claimed. The Treasury cash grant program guidance says, "Costs that will be deducted for federal income tax purposes in the year in which they are paid or incurred are not includible in basis" for the cash grant. However, staff of the Joint Committee on Taxation said, after looking at the issue, that both the bonus and the grant are available on projects. Treasury confirmed this by email.

A project will not qualify for any bonus if it was too far advanced before a key date.
That date is September 9, 2010 for the 100% bonus. It is January 1, 2008 for the 50% bonus.

The IRS said that it will interpret the 100% bonus in a way that makes it easier to conclude that a project was not too far advanced before last September 9, 2010.

The rules are complicated.

Most utility-scale power plants are considered "self constructed." A power plant is self constructed, even though the developer hires a contractor to build it, as long as the construction contract was "binding" before worked started on the project and the contract is not later substantially amended during construction.

A self-constructed project was too far along if construction started before the key date. However, a developer can take the position that construction did not start until more than 10% of the project costs were incurred. Even then, the IRS said it will take a liberal approach for the 100% bonus of allowing a 100% bonus to be claimed on costs incurred for components after September 8, 2010, provided the project is completed by a deadline.

The deadline is December 2011 for equipment like solar panels that would otherwise be depreciated over five years. It is December 2012 for equipment like interties at solar projects that would otherwise be depreciated over 15 years.

A developer who wants to claim a 100% bonus on components, even though work on the larger project started too early, can do so by including a statement with his tax return for the year the project is placed in service.

Equipment that a developer "acquired" -- as opposed to self constructing -- does not qualify for a 100% bonus if it was acquired before September 9, 2010. An example might be rooftop solar panels, depending on the facts. However, the panels are not considered acquired until the costs are incurred. Costs are "incurred" only by taking delivery, with one exception. They may be incurred by making payment in cases where payment is made and delivery is reasonably expected within 3 1/2 months of payment.

The following examples show how the rules work in practice.

Suppose a solar developer signed a binding module supply agreement in 2009 to order solar panels for a project on which significant physical work commenced at the site in December 2010. The project is self constructed. The entire project qualifies for a 100% bonus provided it is completed by December 2011. If it is not completed until 2012, then it qualifies for a 50% bonus, with two exceptions. Solar arrays that go into service in 2011 qualify for a 100% bonus, and it is possible that part of the intertie qualifies for a 100% bonus even if completed in 2012.

Suppose instead that significant physical work started at the site in August 2010. The developer may still be able to take the position that construction did not start until after September 9, 2010 if no more than 10% of the costs were incurred before September 9. Each solar array may be considered a separate project, depending on the facts.

Suppose that the project was too far along before September 9, 2010: it was under construction too soon. The developer can still take a 100% bonus on the costs incurred on or after September 9. Costs are not ordinarily incurred until delivery.

A company can opt out of the bonus, but it cannot choose to take a 50% bonus on equipment that qualifies for a 100% bonus, with one exception. The IRS said it will allow such a choice for projects put into service in 2010 but not in 2011 or 2012. It is the 100% bonus or nothing for projects put into service in 2011 or 2012 if they qualify otherwise for a 100% bonus. However, elections to opt out entirely can be made selectively just for all the 5-year property put into service in 2011, for example, while keeping a 100% bonus on the rest of the project. A new election can be made each year.

Calculation Conventions

The depreciation deduction the first year when equipment is placed in service will be reduced by one of two accounting conventions and may be further reduced if the entity that owns the project has a short tax year.

Equipment is treated as having been placed in service on a hypothetical date during the year rather than the actual date it was actually put in service. Thus, for example, solar panels that should qualify in theory for a depreciation deduction the first year of 40% of cost (because that is the first-year depreciation deduction for an asset depreciated over five years using the 200% declining-balance method) will have a first-year deduction that is only a fraction of 40%.

A company must decide first whether it is required to use a mid-quarter or half-year convention. It must use the mid-quarter convention if 40% or more of its assets put into service during the year -- measured by asset bases -- went into service in the last quarter of the year. See section 168(d)(3)(A). Buildings and assets put in service and disposed of the same year are ignored. See section 168(d)(3)(B). If the mid-quarter convention applies, then assets put in service in the first quarter qualify for 7/8ths of a full-year deduction. Assets in the second quarter qualify for 5/8ths. Assets in the third quarter qualify for 3/8ths. Assets in the last quarter qualify for 1/8th. Thus, the first-year deduction for a solar panel put in service in the last quarter by a company on the mid-quarter convention is 5% of the cost of the solar panel, or 1/8 of 40%.

If the mid-quarter convention does not apply, then the half-year convention is used. See section 168(d)(1). All assets put in service at any time during the year are treated as if they were put in service on the mid-point of the year -- for example, July 1 for a calendar year taxpayer. Thus, the first-year deduction for a solar panel put in service by a taxpayer using the half-year convention is 20% of the cost of the panel, or ½ of 40%.

If two companies form a partnership or joint venture to own a solar project, then the partnership will have a "short" tax year starting when the project is placed in service. This has two consequences. First, it leads to a further reduction in the first-year depreciation allowance. The partnership must not only use one of the accounting conventions to reduce its first-year depreciation deduction, but the deduction will also be reduced further for the short year. The partnership must multiply the deduction by a fraction that is the number of months in the short year divided by 12. The second consequence is the remaining depreciation deductions must be calculated "by hand." The IRS publishes tables that taxpayers can use to calculate their MACRS depreciation. However, the tables cannot be used where the first-year deduction has been reduced by a short year. See Rev. Proc. 89-15, 1989-1 C.B. 816.

A startup company also has a short tax year.

It is common practice to form a special-purpose subsidiary to own each large power project. A special-purpose subsidiary generally does not have a short year if it is treated for tax purposes as "disregarded" or as a corporation that joins in filing a consolidated return with a parent company that was already in business. See Treas. Regs. § 1.168(d)-1(b)(5).

Carryforward and Carrbyback

A company with more depreciation or other losses than it has gross income ends up with a net operating loss. Net operating losses can be carried back two years and forward 20 years. See section 172(b)(1)(A).

MANUFACTURER CREDIT

Companies that planned by early 2014 to have built new factories or expanded or re-equipped existing facilities in the United States for manufacturing solar panels, inverters and other equipment used in renewable energy projects had until September 14, 2009 to apply for a 30% investment tax credit to help pay the cost. Only $2.3 billion in total credits were available nationwide. See section 48C(d)(1)(B).

The IRS allocated all of the credits in January 2010. Demand far exceeded the number of available credits; fewer than a third of applicants were given allocations. Efforts since then to authorize additional credits have fallen short in Congress.

It is possible that additional credits will become available because companies allocated them in the initial round in January 2010 will be unable to use them.

Any company awarded tax credits faces two deadlines. It must have had all the permits needed to start construction within one year of the award. It must have completed construction within three years of the award. The IRS has no authority to extend the three-year deadline.

Only 70% of the cost of a facility on which a manufacturer credit is claimed can be depreciated. The IRS does not consider the manufacturer credit an "energy credit" with the result that the facility will be subject to a full basis adjustment. See section 50(c).

A significant change in plans later could lead to loss of tax credits. A change is significant if it might have caused the US Department of Energy, which assisted the IRS with the awards, to assign the project a different ranking. An IRS internal memo said in 2010 that credits are not at risk if the rights to the credits are transferred to a "successor in interest" to a project, including in a sale-leaseback of the factory equipment within three months after it is first put into service, but what happens if the project changes location is more difficult. The IRS has suggested privately that a company should compare the unemployment rates in the counties where the original project was supposed to be located and where it has been moved. If the unemployment rates are comparable and the number of jobs created in the new location is the same or greater than in the old location, then the relocation should normally not be a problem. However, the decision rests ultimately with DOE. DOE has promised to give a view on proposed changes on an expedited basis.

The IRS may still challenge whether a project was entitled to the tax credits a company claimed in a later audit.

The tax credits may be recaptured if the factory or an interest in the factory is sold within the first five years after construction is completed. Only the "unvested" credits will be recaptured. The credits vest ratably over five years. Thus, if a factory is sold in year four, 40% of the tax credits claimed would have to be repaid to the government.

CLEAN RENEWABLE ENERGY BONDS

Clean renewable energy bonds are bonds that can be issued to finance renewable energy projects that are of a kind that qualified at any time in the past for production tax credits. See section 54C(d)(1). Solar projects do not qualify currently for production tax credits, but they did through 2005. See section 45(d)(4).

In theory, no interest has to be paid to the lender or bondholder. It receives federal income tax credits instead. See sections 54(a) and 54A(b)(3). The tax credits must be reported as interest income. See sections 54(g) and 54A(f).

The bonds may only be issued for projects owned by municipal utilities, government agencies, Indian tribes, electric cooperatives and US possessions. See sections 54(j)(5) and 54A(d)(1). The Joint Committee on Taxation suggested they can also be issued for projects owned by federal utilities like the Tennessee Valley Authority. See Joint Committee on Taxation, "Description of Provisions of the Energy Policy Tax Incentives Act of 2005" (JCX-44-05).

The IRS calculates the credit amount on a daily basis and publishes it on the following website: http://www.treasurydirect.gov/govt/apps/slgs/slgs_irstax.htm. For example, the credit rate for bonds issued on December 31, 2008 varied from 3.82% for bonds with a one-year term up to 5.34% for bonds maturing in 12 years. The lender or bondholder claims one fourth of the tax credit each quarter on quarterly credit allowance dates. The dates are March 15, June 15, September 15 and December 15. See sections 54(b)(4) and 54A(e)(1).

However, bonds issued after 2008 carry tax credits at only 70% of the tax credits to which earlier bonds qualified. See section 54C(b).

Anyone wanting to use the bonds must apply to the IRS for an allocation. Congress authorized $800 million in bonds originally in the Energy Policy Act in August 2005 and then authorized another $400 million in 2006. See section 54(f). It authorized another $800 million in "new" clean renewable energy bonds as part of a massive Wall Street bailout bill in October 2008 and increased the amount to $1.6 billion in the American Recovery and Reinvestment Act. See section 54C(c)(2). The new bonds carry the reduced tax credits.

The deadline to apply for the additional $1.6 billion in volume cap was August 4, 2009. Allocations were made in October 2009 to 805 projects. However, in September 2010, the IRS extended the application deadline for cooperative electric companies to November 1, 2010 due to unallocated funds following the first application round.

The first two allocations were awarded to applicants with eligible projects starting with the smallest requests and working up to the largest. See, e.g., Notice 2007-26, 2007-1 C.B. 870. The most recent volume cap of $800 million was awarded in thirds among public power providers, electric cooperatives and governmental bodies. See section 54A(c)(2). The last category included Indian tribes. See section 54A(d)(3). Congress told the agency to share the roughly $267 million set aside in the most recent round for public power providers among everyone who applies by adding up the capital costs of all the eligible projects and then dividing that number into the available bond authority of $267 million. Thus, if the $267 million was two times oversubscribed, then each public power provider received authority to issue bonds covering half the project cost. The IRS was free to use the same or a different approach with governmental bodies and electric cooperatives. See section 54C(c)(3).

Applications for the first round of allocations in 2006 were more than three times the amount the IRS had to allocate. The requests amounted to $2.6 billion for $800 million in bond authority. The IRS awarded the bond authority to 610 projects, or 86% of the 709 projects that applied for bond authority. Awards ranged from $23,000 at the low end to $31 million. Of the 610 projects receiving awards, 423 were solar facilities. See IR-2006-181 (November 20, 2006).

The IRS awarded another $400 million in bond authority in February 2008. Applicants requested almost $900 million in bond authority, or more than twice the amount available. The IRS made awards to 79% of the 395 projects that applied. The awards ranged from $15,000 to $30 million. Of the 312 projects receiving awards, 139 were solar. See IR-2008-16 (February 8 2008).

The principal amount of the bonds must be repaid in equal annual amounts over the term. See section 54(k)(5).

The IRS is supposed to announce the maximum term each month for bonds issued that month. The maximum term is the term that would leave the principal repayments with a present value of 50% of the original face amount of the bonds using as a discount rate the average rate for long-term tax-exempt bonds issued the previous month. Long term means with terms of 10 years or more. See sections 54(e) and 54A(d)(5).

All of the bond proceeds must be spent on capital expenditures for an eligible project, with the exception that up to 2% of the proceeds can be spent on the costs of issuing the bonds themselves. See sections 54C(a) and 54A(e)(4).

It is unclear whether the new CREB bonds could be used to refinance existing project debt. Such uses were permitted in the first two rounds of bond allocations, provided the debt was originally issued after August 8, 2005. The old rules permitting refinancing applied to bonds issued through 2008. See sections 54(d) and (m). The new rules are silent about refinancing.[1] See section 54A.

[1] Section 54A applies by its terms only to forestry conservation bonds, but it appears that Congress intended it to govern new CREBs since section 54 does not apply to bonds issued after 2008, and section 54C, which governs new CREBs refers in two places to section 54A. See section 54C(b) and the use of the term "available project proceeds" in section 54C(a), which is defined in section 54A and is not used in section 54.

The bond proceeds must be spent on the project within three years of when the bonds are issued.[2] See section 54A(d)(2).

Any proceeds not spent immediately must be invested so as not to earn an arbitrage profit. See sections 54(i) and 54A(d)(4).

The issuer must intend when the bonds are issued to sign a binding commitment with a third party within six months to spend at least 10% of the bond proceeds. Bonds can be used to reimburse capital spending on the projects within the past 18 months. However, the borrower must have made his intention to use the bonds for reimbursement before spending the amounts and it must have issued an "official intent to reimburse" within 60 days of the original expenditures. See sections 54(d) and 54A(d)(2).

A lender can use the tax credits against both regular and alternative minimum taxes. However, the credits are used behind other business credits. Unused credits can be carried forward. There is no apparent limit in the statute on how long they can be carried forward. See sections 54(c) and 54A(c).

In cases where the bondholder is a partnership, tax credits on bonds issued through 2008 did not reduce the capital accounts and outside bases of the partners allocated them. See section 54(k)(3). However, credits on new CREB bonds are apparently treated like a partnership distribution that reduces both capital accounts and outside bases. See section 54A(g). The tax credits can be "stripped" from the principal repayments on the bonds and sold separately. See section 54A(i). Anyone taking the credits is treated as the holder of a stripped coupon. See section 1286.

Municipal utilities and coops should have compared the long-term economics of utility ownership through CREBs versus third-party ownership that uses the ITC. They may be better off putting ownership of the project in private hands, buying the electricity from the project under a long-term contract and benefitting indirectly from the 30% investment tax credit or Treasury cash grant and five-year depreciation. The electricity prices might be set at a level that reflects the tax subsidies. The municipal utility or coop could have an option to purchase the project after a period of time. (See also "Prepaid Service Contract," p. 31)

BUILD AMERICA BONDS

Municipal utilities and other state or local government agencies can issue tax-exempt bonds to finance schools, roads, hospitals and other public facilities. See section 103. The bonds bear interest, but at reduced rates because the lenders do not have to pay income taxes on the interest payments. Tax-exempt bonds can be used to finance solar installations that a municipal utility or other state or local government entity owns and puts to public use. The state or municipality would have to be careful not to allow more than 10% "private business use" of the facilities. See section 141. Examples of private business use are where equipment is leased to a private party or used to supply electricity to a private party under a special deal on terms that are not available to members of the general public. Hiring a private party to operate the equipment could also be considered private business use unless the terms of the operating contract stay within guidelines the IRS has established for such contracts. The guidelines limit how long a term such a contract can have and limit how the private operator can be compensated.

The American Recovery and Reinvestment Tax Act gave states and municipalities the option during 2009 and 2010 to issue bonds that pay taxable interest and to receive refundable tax credits for 35% of the interest payable on the bonds. The state or municipality could turn in the tax credits to the U.S. Treasury for the cash value. Alternatively, it could let the lender or bondholder claim the tax credits. See section 54AA.

These were called "Build America Bonds."

The lender must pay taxes on the interest payments it receives. It must also report any tax credits it receives as additional interest income. See section 54AA(f). However, the bonds should bear a reduced rate of interest because

[2] Bonds issued through 2008 in the first two rounds of CREB allocations have five years to spend the proceeds. See section 54(h)(1). Although the text says proceeds from new CREBs bonds must be spent within three years, this is a conservative view. It is unclear whether Congress intended to shorten the period.

the tax credits the lender receives spare it from having to pay taxes on roughly two thirds of the interest.

A state or municipality could issue Build America Bonds to finance any public facility for which it could issue regular tax-exempt debt. See section 54AA(d). However, if it elected to keep the tax credits and to turn them into the Treasury for cash -– rather than allow them to be claimed by the bondholders – then all the available bond proceeds had to be used solely for capital expenditures. See section 54AA(g). This ruled out the use of the bonds to raise the prepayment that a municipal utility might make under a "prepaid service contract" structure, unless the municipality left the tax credits with the bondholders. (See also "Prepaid Service Contracts," p. 31)

RECOVERY ZONE BONDS

The American Recovery and Reinvestment Act authorized two other types of bonds to help finance projects in parts of the country that are suffering from significant poverty or unemployment, high rates of home foreclosures or general distress. Each state decided for itself which parts of the state fall in this category. See section 1400U-1.

Congress authorized $10 billion in "recovery zone economic development bonds." See section 1400U-1(a)(4). These are bonds for equipment that is owned by a state or municipality. The lender must pay taxes on the interest. However, the state or municipality that is the borrower receives refundable tax credits for 45% of the interest payable on the bonds. In other words, the bonds are a type of Build America Bond, but they could only be used for projects in distressed areas, and the refundable tax credits that the borrower can convert to cash are 45% of the interest payable rather than 35%.

Congress also authorized $15 billion in "recovery zone facility bonds." See section 1400U-1(a)(4). These are bonds that can be used to finance projects in the same distressed areas, but that are privately owned. The bonds could only be used to finance new equipment. Substantially the entire use of the equipment must be in the recovery zone. The lender does not have to pay any taxes on the interest. See section 1400U-3.

The IRS allocated the $25 billion in recovery zone bond authority to the states in June 2009 in proportion to their job losses in 2008. However, each state was allocated at least 0.9% of the nationwide cap for each type of recovery zone bond. Anyone who wanted to use recovery zone bonds had to apply for an allocation to the state where the project will be located.

All recovery zone economic development bonds had to be issued by December 2010. See sections 1400U-2(b) and 1400U-3(b)(1)(B).

ENERGY CONSERVATION BONDS

"Qualified energy conservation bonds" or "QECBs" are bonds that could be issued to finance many different kinds of green energy projects. See section 54D(f). The bonds were issued by state and local governments. Only $3.2 billion in such bonds were authorized nationwide. See section 54(d(d). The IRS allocated the bond authority in April 2009 among states in proportion to their populations. Thus, for example, $381 million in bonds could be issued for projects in California, $90 million for projects in New Jersey, $252 million in Texas, $51 million in Colorado and $67 million in Arizona.

The bonds were mainly for projects that are put to public use. However, up to 30% could be used to finance private projects. See section 54D(e). Eligible projects included solar generating equipment.

The lender pays tax on the interest. It receives tax credits from the federal government at 70% of the tax credits it would need to forego interest entirely. See section 54D(b). The tax credits must be reported as income. See section 54A(f).

Customer or Other Third-Party Ownership

INDEPENDENT GENERATOR

An independent generator selling electricity to a utility, or to a utility customer, qualifies for the same tax subsidies as the utility, with three exceptions.

First, since it is unregulated, it does not have to negotiate with utility regulators over how to share the benefits with its customers. Rather, any such sharing is a matter of contract negotiation with its customers directly and is reflected in the electricity prices or rents for use of solar equipment that it negotiates. There is no risk of the tax benefits being taken away because regulators impose a sharing regime that does not properly normalize the benefits in setting rates.

Second, independent generators are more likely than utilities to have short tax years that reduce the value of the first-year depreciation.

Finally, independent generators are less likely than utilities to be able to use the tax subsidies directly and, therefore, must enter into "monetization" transactions that give them less than full value for the tax subsidies. These transactions are described in the next chapter.

RATEPAYER

Commercial or Industrial

Commercial and industrial ratepayers who purchase solar equipment to generate electricity for their own use qualify for the same tax subsidies on the equipment as a utility, except that they are less likely to be able to use them due to lack of tax base.

In some states, commercial and industrial ratepayers receive rebates from the local utility as an inducement to install solar equipment. The rebates can be, and usually always are, assigned to an installer or independent solar company. If the ratepayer is the one entitled legally to the rebate in the first instance, then it must report the rebate as income even if it assigns the rebate to someone else.

A customer who assigns a rebate can deduct the amount, but the deduction is unlikely to match the income in terms of timing. The cost recovery depends on how the assignment is characterized for tax purposes. For example, a rebate assigned to a solar installer is considered part of the purchase price for the equipment. It is included in basis and must be deducted over time as depreciation. However, the customer would be able to calculate the investment tax credit on the full purchase price, including the rebate.

Residential

Homeowners qualify for a separate residential tax credit for 30% of the cost of equipment that "uses solar energy to generate electricity for use in a dwelling unit located in the United States and used as a residence by the taxpayer" as well as any hot water heater that supplies hot water to such a dwelling unit provided at least half the energy used by the hot water heater comes from the sun. See sections 25D(a) & (d).

Credits can only be claimed on spending during the period 2006 through 2016. See section 25D(g). There used to be a limit on the amount of credit that a homeowner can claim, but there is no longer.

Credits can only be claimed on hot water heaters that have been certified for performance by the nonprofit Solar Rating Certification Corporation or by a "comparable entity" endorsed by the state government in the state where the water heater will be used. See section 25D(b)(2). There is no certification requirement for generating equipment.

Credits can be used by homeowners as an offset against alternative minimum taxes. See section 25D(c)(1).

There is no carryback of residential credits that a homeowner is unable to use, but they can be carried forward. They become part of the credit amount for the taxpayer in each succeeding year until used. See section 25D(c)(2).

Utilities in some states offer rebates to homeowners as an incentive to install solar equipment. Such rebates do not normally have to be reported by homeowners as income. See section 136. (See also "Utility Rebates," p. 37)

Special Tax Structure Issues

PPA V. LEASE TO CUSTOMERS

One issue facing utilities (and other companies) that want to install solar panels on customer property while retaining ownership of the panels is what business model to use. The three main business models are:

1. "PPA"- sell the customer the solar electricity generated
2. "Lease panels" - lease the customer the panels
3. "Site access" - lease the customer's roof or ground space for an installation, but supply the electricity directly to the distribution grid, i.e. the generation has no effect on the customer's electric bill.

The tax treatment of the third business model, contracting for a right to use the customer's site, is straight forward and is covered under the "Utility Ownership" section (p. 37). However, the tax treatment of the first two deserve more discussion.

There is usually not much difference between the PPA and leasing panels models in practice. The main difference is that, with a power contract, the customer pays a charge per kilowatt hour of electricity the customer is delivered while, with a lease, the customer pays periodic rent that is unlikely to vary with the electricity delivered. Since the output from solar panels is more predictable than many other types of renewable energy facilities, this difference is unlikely to be significant in practice over a long contracting period.

Any company engaging in this business that is not a regulated utility may be driven to one model or the other by regulatory considerations. It may have to lease panels to customers in states that restrict retail sales of electricity by anyone other than the local utility.

State or local consumer protection laws may also be a factor, particularly in cases where solar panels are mounted on homes.

Tax considerations will also affect the choice of business model in some cases. The 30% investment tax credit or Treasury cash grant cannot be claimed on equipment leased to a school, government agency, nonprofit organization or other tax-exempt entity. See section 50(b). Tax depreciation on equipment leased to such entities must be stretched out by depreciating the equipment on a straight-line basis over the "class life." Solar panels that might otherwise be depreciated on an accelerated basis over five years end up being depreciated over 12 years on a straight-line basis. See section 168(g). Thus, a school, government agency, nonprofit organization or other tax-exempt entity should be sold electricity rather than leased the panels to avoid these issues.

Any lease of equipment to a regulated utility would also introduce complications. IRS regulations treat leased equipment as used in the business of the lessee. See Treas. Regs. § 1.46-3(g)(3). Thus, the equipment could turn into "public utility property" if the rates at which electricity is sold are considered sold at rates that are established on a rate-of-return basis. Public utility property is ineligible for MACRS depreciation unless the tax benefits are normalized in setting rates at which the electricity is sold.

Solar panels that a regulated utility leases to customers may still be "public utility property" for tax purposes. Id.

A "safe harbor" in section 7701(e)(3) of the US tax code requires the IRS to treat the relationship with the customer as a sale of electricity rather than a lease of the equipment, provided the parties write in the agreement that they intend it to be a "service contract" within the meaning of section 7701(e) of the Internal Revenue Code and they are careful to avoid four "foot faults" in how the contract is drafted. The four foot faults are that the customer or an affiliate cannot operate the equipment, it cannot have an option to purchase the equipment for a price other than fair market value determined at time of exercise, it cannot be required to pay for electricity it is not delivered (other than for reasons beyond the control of the electricity supplier) and it cannot share in the upside if the electricity supplier squeezes out more profit by introducing operating efficiencies or technological improvements. See section 7701(e)(4).

It is a good idea to try to fit in the safe harbor. However, there may be cases where this is not important because the contract with the customer is obviously a power contract in substance rather than a lease of the equipment. Contracts that fall outside the safe harbor are tested for whether they are leases under a general six-factor test in section 7701(e)(1). Congress drew up the six factors in 1984 in response to cases like Xerox v. Commissioner, 656 F.2d 659 (Ct. Cl. 1981), where Xerox Corporation claimed it was providing photocopying services to government employees who made their own copies at photocopying machines on government premises rather than leasing the agencies the machines. Contract evaluation is not as simple as merely adding up how many of the factors are on either side of the line. See, e.g., Private Letter Ruling 9142022 (July 19, 1991).

Care should be taken in all cases -- no matter who the customer is -- to ensure the contract does not shift tax ownership of solar equipment to the customer. The safe harbor guarantees that the IRS must respect the relationship with the customer as a sale of electricity rather than lease of the equipment, but that is only after it is established that the power company owns the equipment for tax purposes.

It is not a good idea to allow a power contract or lease of rooftop solar panels to run longer than 80% of the expected life and value of the equipment. Options to renew the contract count as part of the basic contract term if the renewal is at an electricity price or rent that has been agreed in advance. They do not count if the price or rent is reset to current market at time of renewal. Solar equipment tends to have a long life according to appraisers. The limiting factor is the speed with which the equipment loses value. The pattern will vary from one local market to the next because it is a function partly of local electricity prices.

It is important the solar equipment not be considered "limited use property" in that the power company has no option but to leave the customer at the end of the contract term. The equipment will be considered limited use property if it will be uneconomic or impractical to remove or to put to another use even if left in place at the end of the contract term. The classic example of limited use property is a chimney on someone else's building. The IRS will not accept a claim that company A owns limited use property that has been installed on the premises of company B. See Rev. Proc. 2001-28, 2001-1 C.B. 1156.

The customer should not have an option to purchase the equipment at a price that makes it a reasonable certainty the equipment will end up with the customer. Options to purchase at fair market value determined at time of exercise are not usually a problem. A customer can have one or more options to purchase at a fixed price set in advance. However, the price should be a good-faith estimate of the expected value at the time, and it should not be at a level that suggests less than 20% of the original value will remain at the end of the contract.

Many tax counsel feel uncomfortable with a continuous purchase option, even at fair market value, especially for equipment that might fluctuate in value. Such options make it more likely the customer will end up with the equipment since the customer can wait for the most opportune time to purchase when there is a dip in market value. Most tax counsel prefer to limit the customer to no more than two or, at the outside, three options to purchase. Some tax equity investors require that any early buyout option at a fixed price should be at a price that is at least 105% of the expected value on the exercise date. Care should be taken to ensure that there is nothing about the relative option prices or the larger business context in which the customer operates that will compel the customer to purchase.

Any option for the customer to purchase the equipment should not be exercisable for at least five years to ensure the investment tax credit claimed on the equipment will not be recaptured. However, if a Treasury cash grant is claimed on the equipment, a sale within five years would not trigger recapture unless the sale is to a federal, state or local government agency or instrumentality, an entity exempted from taxes under section 501(c) of the Internal Revenue Code, an electric cooperative or an Indian tribe. However, the customer would have to agree in writing to joint liability in the event the cash grant paid earlier is recaptured.

Many tax counsel are uncomfortable with a "put" where the owner of the equipment has an option to force the customer to purchase it.

It is a good idea to get a credible appraisal to put in the file. Appraisals may be too expensive to get for each solar installation in cases where solar panels are being installed on rooftops. In such cases, it may be just as useful to have a master appraisal that covers all installations in a particular market using specific brands or models of equipment. The appraisal would include a graph showing the rate at which the equipment is expected to decline in value over time.

In some states, utility customers are entitled to rebates as an inducement to install solar equipment, either from the utility, government or another entity. If the customer is entitled legally to the rebate under the local program but assigns the rebate to a power company installing solar panels, then a commercial customer must ordinarily report the rebate as income. (A residential customer ordinarily would not have to report it. See section 136.) A commercial customer would also have a deduction, but the deduction will usually not offset the income in terms of timing. The deduction turns on how the assignment is characterized. For example, it would normally be treated as prepaid rent if the solar equipment is leased to the customer. It would normally be treated as a prepayment for electricity under power contract. In either case, the amount would have to be deducted on a straight-line basis over the contract term.

The power company will also have to report the rebate as income. It may be possible to spread the income over the contract term in cases where equipment is leased to the customer by invoking rules in section 467 of the US tax code. However, this is only possible in leases where the total rent is expected to exceed $250,000. See section 467(d)(2). It may be possible to spread the income over the contract term in cases where the power company has a power contract with the customer by treating the amount as a prepayment for "goods" under a special rule for advance payments in the IRS regulations under section 451. See Treas. Regs. § 1.451-5(b) and (c).

The biggest risk in transactions with customers is "vacancy risk," or the risk that the customer will go out of business or move before a return can be realized on the equipment. The average homeowner in California, for example, moves every six to seven years. Power contracts and leases usually give the customer three options if it is planning to shut down or move. It can pay to move the equipment and continue buying electricity or leasing the equipment at its new location, it can cause the new occupant of the original premises to assume the obligations under the power contract or lease while remaining secondarily liable, or it can pay a termination value shown in a table at the back of the contract and be released from the remaining contract term.

The power contract or lease should also include a covenant against using electricity to heat a swimming pool. See section 48(a)(3)(A)(i).

PARTNERSHIP FLIP

Most independent solar developers cannot use the federal tax subsidies on solar equipment and end up bartering them to other companies that can use them in exchange for capital to cover the cost of their projects. There are several strategies for doing this. One is a partnership flip.

In a partnership flip, the developer brings an institutional investor in as a partner to own one or more projects in partnership with the developer. In the case of utility-scale projects, each project is owned by a separate limited liability company that is transparent for federal income tax purposes. If a partnership flip will be done around more than one such project, than each project is usually put in a separate "project LLC" in order to shield each project from any liabilities tied to other projects and a master partnership is created with the developer and the institutional investor as owners. (The “institutional investor” may be a utility, although it might be better to use an unregulated affiliate in order to avoid any regulatory issues.)

The economic returns, possibly other than cash, are allocated as much as 99% to the institutional investor until it reaches a target internal rate of return, after which the investor's interest usually drops to 5%.

The developer usually has an option to buy the remaining interest of the investor after the flip for fair market value determined at time of exercise.

In some transactions, cash is distributed 100% to the developer until the capital account or outside basis of the developer in the partnership hits zero, after which cash follows other partnership items. Investors usually place a time limit on how long cash can continue to be distributed disproportionately to the investor.

The partnership of the developer and investor must own each solar project before it is placed in service.

The developer usually retains day-to-day control over the project. However, a list of "major decisions" requires consent of the investor. The list is usually longer before the flip than after.

The IRS issued three private letter rulings in partnership flip transactions in late 2005. See Private Letter Ruling 200609001 (October 24, 2005), PLR 200609002 (November 2, 2005) and PLR 200620004 (November 2, 2005). (Two were identical rulings to different parties in a flip transaction involving a wind farm.) However, it soon had other ruling requests involving more aggressive forms of the structure than were addressed in the November rulings and, in May 2006, it put a hold on any further rulings.

In October 2007, the agency announced a "safe harbor" for partnership flip transactions involving wind farms. See Rev. Proc. 2007-65, 2007-45 I.R.B. 967; see also Announcement 2009-69, 2009-40 I.R.B. 475. Even though the guidelines apply solely to wind farms, the market has applied them in flip transactions involving solar and other renewable energy projects.

Most tax equity investors are careful to stay within the guidelines. The risk that the structure will not work to transfer tax benefits is borne by the institutional investor. The deal papers usually have a list of "fixed tax assumptions." The deal is assumed to work for purposes of tracking when the investor reaches its target return even though the fixed tax assumptions prove untrue.

Under the safe harbor, the investor cannot be allocated more than 99% of each material item of partnership income, loss and tax credits.

The investor must retain at least a 5% interest after the flip, but the 5% is 5% of the high water mark of the tax equity interest. Thus, if the allocations before the flip are 95-5, then the residual interest can be as low as 5% x 95% = 4.75%.

The investor must pay at least 20% of its expected purchase price to buy into the deal in cash at closing. (The safe harbor does not address portfolio deals with serial closings where one solar project after another is added to the portfolio as projects are put into service, but it would be reasonable to apply the 20% rule separately to each closing.)

No more than 25% of the purchase price can be "contingent in amount or certainty of payment."

Any option the developer has to repurchase the investor interest must be at fair market value determined when the option is exercised or at a fixed price that is not less than the expected market value on the exercise date The option cannot be exercisable before the project or projects have been in service for at least five years. The option may be exercised "at any time" after the five years. Thus, for example, in a flip partnership, the developer may have a continuous option to buy out the tax equity investor after the flip.

One of two examples in the IRS guidelines makes clear that cash can be distributed in a 100-0 ratio, notwithstanding that partnership tax items cannot be allocated more aggressively than 99-1. For example, cash may be distributed 100% to the developer until the developer gets back its capital and then as much as 100% to the tax equity investor until the flip.

It is unclear how one test to fit in the safe harbor works. The investor must "maintain" at least a 20% minimum equity investment for as long as it remains a partner, "except that the [minimum investment] can be reduced as a result of distributions of cash flow from the Project Company's operation of the [project]."

Other requirements to fit under the safe harbor are as follows:

The partnership or project company cannot enter into a contract requiring another party to purchase "the [project] or any property included in the project], excluding electricity." In other words, there cannot be a "put." It is not uncommon for projects to make forward sales of renewable energy credits. This has to have been an oversight by the IRS. (As noted, the intention was to rule out any "put" option for the partnership to shed the project. The IRS was concerned about cases where a partnership plans to liquidate as soon as the investor reaches the target return.)

The investor also cannot have a put to force someone to buy the investor's partnership interest.

No one can guarantee the investor that it will receive tax credits.

The project must bear the risk that insolation or sunlight will not be as intense as expected. The IRS said: "The Developer, the [equipment vendor], or any power purchaser may not provide a guarantee that the [renewable] resource will be available at a certain level." However, hedges and similar contracts are fine as long as they are not supplied by one of these parties.

Independent solar companies tend to finance their projects using master "financing" facilities where an institutional investor commits to purchase -- or to make ongoing capital contributions to a master partnership that has agreed to purchase -- all the solar facilities that the developer presents for purchase within a certain time period -- usually until the end of the year -- and up to a maximum dollar amount. However, the commitment only applies to facilities for which the developer can check off a list of conditions precedent.

Several issues have emerged in flip transactions involving solar facilities.

Institutional investors usually insist on at least a 2% pre-tax or cash-on-cash return from the investment. The IRS position is that production tax credits claimed on wind farms can be counted as equivalent to cash for purposes of this test. Most institutional investors appear to treat the investment credit in solar projects as equivalent to cash, but the IRS position is unclear.

Many tax counsel believe that a pre-tax return is not required at all in cases where the project is uneconomic absent the tax subsidies. The investment credit and accelerated depreciation are supposed to induce companies in invest in ways that would be uneconomic without the subsidy. It makes no sense to require a company to show it has no need of the subsidy in order to claim it. The 9th circuit court of appeals held for this reason that a lessor of solar equipment did not have to show it expected a profit in the absence of tax subsidies, but there is no similar decision in another circuit. See Sacks v. Commissioner, 66 F.2d 308 (4th Cir. 1993). The IRS has acknowledged in various private letter rulings that taxpayers did not expect a profit in the absence of tax benefits in synfuel projects and wind farms. See, e.g., Private Letter Ruling 200514003 (December 15, 2004), PLR 200617009 (January 19, 2005), PLR 200527005 (March 30, 2005), PLR 200609001 (October 24, 2005), PLR 200609002 (November 2, 2005) and PLR 200620004 (November 2, 2005).

However, most tax counsel believe the investor should expect a pre-tax return in a project that is profitable without tax subsidies and would balk at arrangements where the investor has a return that consists largely of tax benefits while the cash return is retained by the developer.

Congress codified an "economic substance doctrine" in 2010 that has been used by the IRS and the courts to deny tax benefits in transactions that serve little purpose apart from transferring tax benefits. There were differences in the form of doctrine used by the IRS and different courts. Congress chose the stricter of the two main forms of the doctrine, one that requires a showing, in any transaction "to which the economic substance doctrine is relevant," that the transaction changes the taxpayer's economic position in a meaningful way and the taxpayer has a substantial purpose for entering into the transaction apart from federal income tax benefits. See section 7701(o). Most tax counsel believe partnership flip transactions that adhere to the IRS guidelines have economic substance. The IRS said that it would continue to rely on the prior case law when applying the statutory version of the test. See Notice 2010-62, 2010-40 I.R.B. 411; see also section 7701(o)(5)(C). Therefore, transactions that were viewed as having economic substance before codification should still have such substance. The common thread in most transactions that the courts set aside in the past on grounds that they lacked economic substance is that there was no real business investment at the heart of the deal, but rather an almost singular focus on a particular tax result, often based on a narrowly technical reading of the tax laws. See, e.g., Goldstein v. Commissioner, 364 F.2d. 734 (2d Cir. 1966); ACM Partnership v. Commissioner, 157 F.3d 231 (3d Cir. 1998), aff'g 73 TCM 1997), cert. denied, 526 US 1017 (1999). The House committee report said in a footnote that Congress did not intend the doctrine to be used to deny tax benefits that are an inducement to make particular types of investments as long as the benefits are being used as intended. See H. Rep. No. 443, 111th Cong., 2d Sess. at p. 296, fn. 124 (2010). The staff of the Joint Committee on Taxation made the same point in a technical explanation issued four days before either chamber voted on the final budget reconciliation bill that codified the doctrine and included an example that referred to tax credits for solar projects. See JCX 18-10 at p. 152, fn. 344 (March 21, 2010).

"Absorption" issues are not uncommon in flip transactions. It is important to model the transaction to make sure the investor will be able to absorb the full tax benefits that the parties want to allocate it. Each partner has a capital account and an outside basis. These are two measures of what each partner put into the transaction and what it took out. If a capital account goes negative, then it is a sign that the partner took out more than his fair share of partnership returns. In most partnership agreements, any further depreciation deductions that would be allocated to a partner and drive its capital account negative shift automatically to the other partner. A partner's outside basis cannot go negative, but that's because the partner's use of any further depreciation deductions and other losses it is allocated is suspended and any additional cash the partner is distributed must be reported by the partner as capital gain. (Partners are not usually taxed on the cash they are distributed.) One common fix for absorption issues is for the institutional investor to agree to contribute additional capital when the partnership liquidates to make up any deficit in its capital account. This addresses the problem of an inadequate capital account but does not prevent depreciation deductions from being suspended once the partner runs out of outside basis. It was not uncommon before the market collapsed in late 2008 for tax equity investors to step up to a deficit restoration obligation of roughly 20% of the capital they contributed. However, by late 2011, the deficit restoration obligations to which tax equity investors were willing to agree were very small. Another way to address the problem is to add partnership-level debt. This turns a share of the depreciation into "nonrecourse depreciation" that partners can claim despite having run out of capital account. However, the tax equity investor will be allocated phantom income later to reverse the nonrecourse depreciation it was allocated. It will also want a yield premium of at least 300 basis points to protect against the risk that it might be squeezed out of the transaction due to a debt default before it reaches its target yield.

Four transactions were done in 2011 using a "fixed flip" structure where the tax equity investor has a 99% interest in partnership income and loss through year five, but 0% interest after the flip. The flip occurs at the end of year five regardless of the return the investor has reached. The tax equity investor has a right to annual preferred distributions of project cash flow equal to 2% of the capital it contributed both before and after the flip and a "put" to force the developer to buy out its remaining cash flow interest a year after the flip if the developer has not exercised a call option by then. Developers who have used the structure like the fact that it allows them to keep most of the cash flow while shedding tax benefits. The tax equity investor pays up front for an interest in the project and usually takes the structure risk. However, many tax counsel view such transactions as aggressive.

SALE-LEASEBACK

Another way for a developer who cannot use tax benefits to barter them for capital to build projects is by selling the projects to an institutional investor and leasing them back. In contrast to a partnership flip, where the investor must own the project before it is placed in service, an investor in a sale-leaseback can wait up to three months after a project is put in service to buy it. The project must be leased back to the same legal entity that placed it in service.

The developer shares indirectly in the tax subsidies in the form of reduced rent for use of the project.

Partnership flip transactions are usually evaluated in terms of the target yield the investor requires for use of its money compared to competing sources of capital or the share of project cost that will be covered by the tax equity. In a sale-leaseback, the developer focuses on the so-called NPV benefit or reduction in cost of the equipment and the implied interest rate or cost of capital through the lease compared to straight debt.

A lease provides 100% financing. In a partnership, the tax equity covers only a fraction of the project cost. Any gap must be covered with other sources of capital. However, the 100% financing in a sale-leaseback may be illusory because a shortfall between what the investor is willing to invest and the project cost is made up with debt at the lessor level. Debt could just as easily be added in a flip partnership at the partnership level or debt level to plug any gap in the capital structure. As tax equity yields have increased, lessees have also had to prepay a portion of the rent in order to enable the tax equity investor to reach its target yield. The prepaid rent is treated for tax purposes as loan by the lessee to the lessor that is worked off over the lease term as an offset against rent that would otherwise have to have been paid. The lessor deducts interest on the loan from the lessee; the lessee must report interest income.

In any transaction with third-party debt, the investor usually requires a higher yield because of the "equity squeeze" risk, or the risk that the project will default on the debt causing the lender to foreclose on the assets and the investor to fall short of its target return. It is common in partnership flip transactions for any lender at the partnership or project level to agree to forebear from foreclosing on the project after a non-payment default for an agreed number of years. It can foreclose on the developer interest and take control of the project in the meantime. In contrast, payment defaults usually carry normal remedies, including the ability to foreclose on the project without delay, but after notice to the investor and the opportunity for it to cure the default. These types of equity-squeeze mitigants are less common in leases.

A lease transfers 100% of the tax benefits. In a partnership flip, at most 99% of the tax benefits can be transferred to the investor and even that may not be possible because the investor has too little capital account and outside basis to absorb them fully.

The main downside from a lease is the developer must pay the full market value for the project at the end of the lease to retain use of the equipment.

The IRS has guidelines for determining whether a purported leasing transaction is a "true lease" for tax purposes. See Rev. Proc. 2001-29, 2001-1 C.B. 1160. (Accountants classify leases as capital leases or operating leases. These terms have no relevance for tax purposes.) The transaction must be a true lease in order for the investor or lessor to be able to claim tax benefits.

The guidelines apply to leveraged leases where the investor supplies only part of the purchase price for the equipment and borrows the rest. An investor in a leveraged lease tends to have a more tenuous claim to tax ownership of a project than in a "single investor lease" where the full project cost is funded with equity. The market has been less precise about following the IRS lease guidelines than the guidelines for partnership flip transactions where investors have been careful not to stray from the guidelines. The lease guidelines require that the lessor retain a meaningful residual interest in the project after the lease ends. Thus, the lease term should usually not run longer than 80% of the expected life and value of the equipment. The developer should not have a purchase option that makes it a reasonable certainty it will end up with the equipment. (See “PPA v. Lease to Customers” on p. 24 about other issues common to leases.)

Lease advisory firms use sophisticated software to optimize rents. Section 467 of the US tax code limits the extent to which rents can fluctuate in a lease. Rent in most leases is structured to stay within a "90-110" band, meaning the rents for a particular year can be as much as 110% or as little as 90% of the average rent for all years under the lease. The test is applied on a calendar-year basis.

There is a different risk allocation between the developer and investor in a lease versus a flip partnership. In a flip partnership, the partnership of the developer and tax equity investor is on the front line with the customers. The partnership has contracts with customers to sell them electricity. Any variation in electricity revenue is felt directly by the partnership. In a lease, the developer sells electricity to the customer and has a hell-or-high-water obligation to pay the rent under the lease.

The developer indemnifies the investor for loss of tax benefits in a lease. There is a more limited indemnity in a flip partnership. The investor must usually point to a misrepresentation made by the developer to collect an indemnity. The developer may be required to make broader representations in a lease than in a flip partnership.

If the lease is terminated early -- for example due to a casualty to the equipment -- the developer is usually required to pay a stipulated loss value or termination value in a table at the back of the lease to make the lessor and any lender whole. There are no such payments in a flip partnership.

In a lease, any sales taxes that are collected on sales of solar equipment are collected on each rent payment. In a flip partnership, they are collected on the initial sale of the equipment to the partnership. In a lease, the initial sale is considered a "sale for resale"; such sales are not subject to sales taxes. Thus, any sales taxes are deferred through a lease.

INVERTED LEASE

Interest is growing among solar developers in an inverted lease structure where the developer owns the solar project but leases it to an investor. The investor as lessee holds the power contract to sell the electricity to an offtaker. It takes in revenue from electricity sales and uses it to pay rent to the developer as lessor. The developer makes an election to allow the lessee to claim the investment tax credit or Treasury cash grant on the equipment. See section 50(d)(5). The developer keeps the tax depreciation and uses it to shelter the rents from income taxes. The investor as lessee claims the investment tax credit or Treasury cash grant and deductions for rent that may mirror the depreciation that it would have received as owner.

The main tax issue with the structure is whether the arrangement will be respected as a lease of the project to the investor. In a typical lease, the lessee pays rent for use of the leased equipment and is exposed to the risk of the market in how much revenue it will be able to earn from use of the asset.

There are two forms of the structure. In the more aggressive form, the tax equity investor is a 99.9% partner in a lessee partnership with the developer and the lessee partnership is a 49.9% partner, in turn, in the lessor. The tax equity investor makes a capital contribution to the lessee partnership of roughly 42% of the investment credit or Treasury cash grant on the project. The lessee then makes a capital contribution of the amount to the lessor in exchange for an interest in the lessor. The tax equity investor ends up with the investment credit or Treasury cash grant and 49.9% of the depreciation on the project. As many as nine bells and whistles have been proposed or added to the basic structure in some transactions, measurably increasing the tax risk. The structure is sometimes called a "sandwich" lease because the developer retains control over the project by being hired by the lessee as a contract operator and by retaining an interest in the lessee entity as the managing partner or managing member.

In the less aggressive form of the structure, the investor is the lessee. The developer is the lessor. There is no overlapping ownership. The lessee makes a rent prepayment at the start of the transaction representing value for the investment credit or Treasury cash grant and the share of customer revenue that the lessee will retain after paying rent under the inverted lease.

A lessor who elects to allow the lessee to claim the investment tax credit or Treasury cash grant does not have to reduce its depreciable basis by half the credit or grant. See current section 50(d)(5) and former section 48(d)(5)(A) as it read before 1990. However, the lessee must report half the credit or grant as income spread ratably over five years. See former section 48(d)(5)(B) as it read before 1990. The lessee calculates the credit or grant on the fair market value of the project when it is first leased. The lessee must be in place before the project is placed in service.

The structure has three attractions for developers. The main attraction is the ability to get the project back without having to pay anything at the end of the lease term. Another attraction is the ability to calculate the investment credit or Treasury cash grant on the fair market value of the project without having to pay tax on a commensurate amount of gain to step up the basis. In a sale-leaseback, the step up is taxed as gain on the sale; there is no sale in an inverted lease. Some developers may also see the ability to strip just the investment tax credit as an additional benefit or to shed the tax credit to one institutional investor who views itself as in the market for tax credits but may not be set up internally to evaluate and pay much value for depreciation deductions and cash flow while bringing in a second investor at the lessor level in a flip partnership and allocating it the depreciation and a share of cash flow.

PREPAID SERVICE CONTRACT

A prepaid service contract is a structure that a municipal utility or electric cooperative might use to enable a solar project it is developing to benefit from federal tax subsidies. The municipal utility or coop shares indirectly in the subsidies by entering into a long-term contract to buy electricity from the project at reduced prices. It may have an option during the contract term and again at the end to buy the project.

The structure may also have appeal to some investor-owned utilities.

The structure was used in 2006 by two public utility districts and two electric cooperatives for the 200-megawatt White Creek wind farm in Washington state. The public utility districts and coops did the development work on the project, but transferred the development rights to a special-purpose company just before construction started. The special-purpose company borrowed from a syndicate of banks to finance construction. Construction lenders will not lend unless there is a commitment from someone creditworthy to take out the construction debt at the end of construction. The take-out commitments came from two sources. The public utility districts and coops signed contracts to buy electricity from the project for 20 years, but to prepay for a large share of the electricity that would be delivered over the contract term at the end of construction. The prepayments covered approximately 48% of the project cost. Two institutional investors committed at the start of construction to make capital contributions to the special-purpose company at the end of construction that covered the other 52% of project cost.

The public utility districts and coops were given a significant discount off the electricity price in exchange for paying in advance. They held first liens on the project to secure performance. There was no other project-level debt.

The structure had been used to help finance at least four large wind farms by late 2011.

It is attractive to municipal utilities and coops for three reasons.

First, it is a way to come as close to ownership of a project as possible and still build in federal tax subsidies. There would not be any subsidies if a municipal utility or coop owns the project since it pays no federal income taxes. The utility or coop signs a contract to buy the output in form. However, in substance, the contract can come close to putting the municipal utility or coop in the same economic position as a lessee of the facility.

A special "safe harbor" in section 7701(e)(3) of the tax code for alternative energy facilities requires the IRS to treat the contract as a "service contract" -- meaning a contract to sell electricity -- provided the parties make clear that they intend the contract to be treated as a service contract and they are careful when drafting the contract to avoid four "foot faults." The four are that the offtaker for the electricity or an affiliate cannot operate the project, it cannot have an option to purchase the project for a price other than fair market value determined at time of exercise, it cannot be required to pay for electricity it is not delivered (other than for reasons beyond the control of the electricity supplier) and it cannot share in the upside if the electricity supplier squeezes out more profit by introducing operating efficiencies or technological improvements. <u>See</u> section 7701(e)(4). As long as these contract terms are observed, the parties are free to have other contract terms that are more commonly found in leases. For example, certain operating and maintenance costs might be passed through to the municipal utility or coop.

Second, the municipal utility or coop usually receives a discount off the electricity price in exchange for the prepayment.

Third, since a municipal utility or coop can generally borrow more cheaply than a private developer, the structure is a way to give the project access to cheaper capital.

It is important that the contract stay within the service contract safe harbor. If the contract is recharacterized as a lease, then no investment tax credit could be claimed on the project and the project would be depreciated largely over 12 years on a straight-line basis rather than over five years using the 200% declining-balance method.

The structure is attractive to a developer because it fills a gap in his capital structure. Tax equity will pay only a fraction of the capital cost of the project. The rest of the cost must be covered either through debt or true equity. The prepayment is a form of soft debt that is repaid in kind by delivering electricity. It does not have the tight default triggers that normal debt would have. For example, the project company might have up to three years to remedy any shortfall in electricity deliveries before the contract can be declared in default.

The key for the developer is the prepayment must be considered an "advance payment" for "goods" so that the prepayment can be reported as income as the prepaid electricity is delivered over time. Companies must normally report cash payments from customers as taxable income no later than when the amounts are received. However, the IRS regulations make a special exception in Treas. Regs. § 1.451-5 for advance payments for "goods." This special rule lets such payments be reported over the period the goods are delivered, provided the producer reports them the same way "for purposes of all his reports (including consolidated financial statements) to shareholders, partners, beneficiaries, other proprietors, and for credit purposes."

In the case of "inventoriable goods," a two-year clock begins to run on when the remaining advance payment must be reported as taxable income when two things are true. One is the producer has on hand in inventory or available through his normal sources of supply the remaining quantity of goods for which the customer has prepaid. The other is the producer has received a "substantial advance payment." An advance payment is "substantial" when it equals or exceeds the expected cost to supply the goods.

The IRS treats electricity as "inventoriable goods." Thus, the two-year clock has the potential to be triggered.

It is unclear whether the project company will be viewed as having available to it at inception -- or at any time in the future -- through normal sources of supply all of the electricity that was prepaid under the power contract. There is a spot market in electricity. The project company can buy at some price the full output promised over the full term of the contract. However, that cannot be what the IRS intended by this trigger.

The reason for starting a two-year clock to run is that the IRS thought it inappropriate in certain situations to tax manufacturers fully on advance payments at time of receipt, but it did not want to let manufacturers play games with timing by spreading out income when they have all the inventory needed to supply an order either sitting in the warehouse or readily accessible by picking up a phone. A power contract in a case like this calls for scheduled deliveries over a particular time period. Electricity cannot be stored. Under the IRS regulations, the two-year clock does not start to run until the producer "[h]as on hand (or available to him in each year through his normal source of supply) goods of substantially similar kind or in sufficient quantity <u>to satisfy the agreement</u> in such year."

(Emphasis added.) Treas. Regs. § 1.451-5(c)(1)(i)(c). It would not satisfy the agreement for the project company to supply the offtaker on day one with the full amount of electricity it requires over 20 years. The offtaker would bring a claim for breach of contract.

<u>Two</u> things must be true for the two-year clock to start to run. The other is that the advance payment must be "substantial." It is substantial when it equals or exceeds the expected cost to supply the electricity. The logic behind this trigger is that the United States taxes businesses on income and until the project company has received a large enough payment to lock in a profit on the electricity that has been presold, it does not yet have any income to tax.

This has a bearing on how much of the electricity price can be prepaid. The expected cost to supply the electricity includes depreciation on the solar project. The expected costs to supply electricity must be allocated among all of the output. The test whether the prepayment is substantial should be applied by comparing the prepayment only to the costs that are allocated to the prepaid electricity.

If the remaining advance payment must be reported in full as income because of the two-year clock, then the project company would be allowed to report only the <u>net</u> amount after subtracting its expected cost to supply the remaining prepaid electricity. <u>See</u> Treas. Regs. § 1.451-5(c)(1)(ii).

IRS regulations will require that the remaining advance payments be reported as income if the project company "ceases to exist" or if its liability under a power contract otherwise ends. Therefore, the unamortized portion of the prepayment would have to be reported as income if the purchase option is exercised by the offtaker before the term of the power contract ends. There is also a risk of accelerated reporting if the project company is a partnership for tax purposes and it terminates for tax purposes because of a sale of 50% of more of the profits and capital interests in the partnership.

In order to qualify as an advance payment, the power contract should require that the unamortized portion of the prepayment must be returned if the contract terminates due to fault of the project company. The contract should include a schedule showing the quantity of electricity that has been prepaid each year. Because tax deferral is allowed only for advance payments for "goods," the prepayment should only be for electricity. Any renewable energy credits, environmental allowances or other intangibles that will convey to the offtaker should be paid for as they are delivered.

The IRS is studying the tax treatment of prepaid forward contracts and may have more to say about the subject in the future. It issued a revenue ruling in January 2008 analyzing the tax treatment of a purported forward contract requiring a payment in dollars for euros to be delivered in the future. The agency said the arrangement was a euro-denominated loan in substance. See Rev. Rul. 2008-1, 2008-2 I.R.B. 248. The IRS asked in a separate notice the same day for responses to a list of questions, including whether the seller under a prepaid forward contract that is in fact a forward sale, rather than a loan, should be required to accrue income during the term of the forward contract and, if so, how the amount of income each year should be calculated.

Another issue in prepaid service contract transactions is whether partners in a partnership that owns the project can add the unamortized prepayment to their outside bases. The short answer is yes. Each partner has both a capital account and an outside basis. They are different measures of what each put into the partnership and what each took out. A partner's outside basis is basically the equity he has in the partnership plus his share of any partnership debts. Once his outside basis hits zero, the use of any further losses -- like depreciation deductions – he is allocated is suspended.

The prepayment is treated as a nonrecourse liability of the partnership. This has two consequences. Each partner can put its share of the liability in its outside basis. The other consequence is that, at some point as the prepayment is worked off by delivering electricity, the partners will have to start reporting the remaining income tied to the prepayment in the same ratio they shared in depreciation on the project (if they were not already reporting the income in that ratio). This is called a "minimum gain chargeback."

A municipal utility may issue tax-exempt bonds to raise money to make the prepayment. Another common question about the structure is whether such a use of tax-exempt bonds will affect the tax subsidies to which the project is entitled. If the project is considered to have been financed "directly or indirectly" with tax-exempt bonds, then it would have to be depreciated more slowly. See sections 168(g)(1) and (5).

In the view of many tax counsel who have studied the issue, there is no tax-exempt financing of the project. The bonds are used by the municipality to serve a public purpose of making an advance purchase of electricity to serve local residents. Such advance purchase arrangements are common among municipal gas utilities. To view the bonds as used to finance the project, one would have to view the bond offering as a conduit borrowing by the project company through the offtaker. They are not such a borrowing. If they were, then the bonds would not qualify for a tax exemption since the proceeds would have been put to an impermissible private business use.

The prepaid service contract structure may also be attractive to some investor-owned utilities. In some states, a utility may be able to treat the prepayment as a rate base investment in the solar project and earn a return on its investment (in addition to receiving the electricity). The contract would have to be structured as a capital lease for regulatory purposes. In a capital lease, the lessee records the future obligation to pay rent as a liability on its balance sheet. There have been preliminary discussions about the structure with staffs of public utility commissions in at least two states.

TENANCY IN COMMON

Concentrating solar power or solar thermal projects can reach 500 or more megawatts in capacity and $1 to $1.5 billion in cost. It was not unusual in the past to find nuclear and other large power plants owned by more than one utility as tenants in common. Such structures have been revived recently for other types of power projects as an alternative way to structure projects that are having trouble persuading a utility to sign a long-term contract to buy the output. In such cases, the developer might let one or more utilities each own separate ownership stakes and take a share of the electricity output in kind.

Each tenant in common owns an undivided interest in the entire project.

The IRS will treat any separate limited liability company or other entity through which the parties own the project as a partnership. Each participant should own an interest in the project directly rather than through a commonly-owned project company.

Each should elect under section 761 of the US tax code not to characterize the relationship as a partnership.

Each undivided interest in the project is treated as a separate asset for tax purposes and can be separately financed. See Rev. Rul. 82-61, 1982-1 C.B. 13. If a municipal utility is a participant, it can finance its share of the project in the tax-exempt bond market. However, it must be careful that the bond proceeds are not considered put to private business use because of the arrangements among the parties. For example, under IRS rules, any management contract with the developer to manage a project on behalf of all the participants could cause the proceeds to be considered to have been put to private use if the contract has a term and compensation for the manager that takes it outside one of five "safe harbors." Under one safe harbor, the contract can have a term, including renewable options, as long as 15 years provided at least 95% of the compensation paid the manager each year is in a fixed fee. There are no restrictions on operating contracts for "public utility property" if the only compensation is reimbursement of "actual and direct" expenses of the operator plus a reasonable charge for overhead. See Rev. Proc. 97-13, 1997-1 C.B. 632.

Other Issues

PLACED IN SERVICE

A solar project is considered to have been put in service when five things have occurred:

1. The equipment has been delivered and physical construction or installation on site has been completed, although contractor personnel can still be at the site in support of startup and maintenance and completion of minor tasks like painting and attending to punchlist items.

2. Pre-operational tests have demonstrated that the project can serve its intended function. (Other testing to determine whether it can operate at the design capacity and to identify and eliminate defects can occur after the project is in service.)

3. The taxpayer has taken legal title and control over the project.

4. The project is able to deliver its electricity to market. Thus, solar panels must have been "synchronized" in the sense that they are properly connected to the inverter and able to deliver electricity to the intended user or users. In the case of a utility-scale project selling to a utility, the project must have been synchronized to the utility grid.

5. The taxpayer has the licenses and permits needed to operate the project. For example, in California, the owner of rooftop solar panels that connect to the same inverter through which electricity is received from the grid is not allowed to turn on the panels until it receives a letter from the local utility confirming that the panels have been inspected for safety and are authorized for "parallel operation" with the grid. See, e.g., Rev. Rul. 76-256, 1976-2 C.B. 46 (list of five tests for a power plant to be considered in service).

The IRS takes the position that the project must also be in "daily operation." See, e.g., Private Letter Ruling 9529019 (April 24, 1995) (landfill gas facility not in service for purposes of section 29 credits until it is in "daily operation"); PLR 9627022 (April 9, 1996) (same statement); PLR 9831006 (April 23, 1998) (same statement). "Daily operation" is not defined in these rulings. However, in a technical advice memorandum in 1993, the IRS said a power plant "is considered in daily operation when it is routinely operating to supply power to the transmission grid for sale to customers." See Technical Advice Memorandum 9405006 (October 15, 1993).[3] This reflects a conservative view of the law. The real issue is whether the facility is capable of being used for its intended purpose. The fact that it is in daily operation is proof that it is. There may be other ways to demonstrate that fact. See Rev. Rul. 79-98, 1979-1 C.B. 103 (facility is placed in service when "'a state of readiness and availability for a specifically assigned function', such as 'daily operation', has been demonstrated"). (Emphasis added.)

All parts of an "integrated facility" must be installed and be in operable condition before any part is considered in service. See, e.g., Hawaiian Independent Refinery v. U.S., 697 F.2d 1063 (Fed. Cir. 1983) (refinery, tanker mooring facility, and pipelines to bring petroleum to land from tankers were all part of an integrated facility with the result that all had to be operating before facility in service). Equipment is part of an integrated facility "if it is used directly in the activity and is essential to the completeness of the activity." Treas. Regs. § 1.48-1(d)(4).

Serious mechanical problems later may prevent a system from being in service. For example, a power plant owned by Oglethorpe Power had to be shut down four months after it was first synchronized into the utility grid so that part of the plant could essentially be rebuilt. The stacks vibrated so violently that workers became nauseated if they were in the area more than about two minutes. The plant was not considered in service until it was restarted after it was rebuilt. See Oglethorpe Power Corporation v. Commissioner, 60 TCM 850 (1990); see also Consumers Power Company v. Commissioner, 89 TC 710 (1987) (pumped-storage facility built, tested, synchronized and sold 4,447 mWhs of electricity during 1972, but not in service until 1973 after accident in

[3] A technical advice memorandum is a ruling issued by the national office to settle a dispute between a taxpayer and an IRS agent stemming from an audit.

December 1972 forced one-month shut-down and resynchronization).

The bar may be higher for a taxpayer entering a new business than for a taxpayer already in that business. In the case of someone going into a new business, the courts have held that he must actually have put the equipment to use. It is not enough merely show it was capable of operating. See, e.g., Piggly Wiggly Southern, Inc. v. Commissioner, 84 TC 739 (1985) (refrigerators installed in new stores not in service until the stores opened to customers); but see Action on Decision 1988-022, 1988-2 C.B. 1 (IRS disagrees with the decision); see also Doherty v. Commissioner, 64 TCM 915 (1992) (sailboat not in service in 1986 when Northwest Airlines pilot who intended to go into the ship charter business took delivery of fully functioning boat, but in 1987 when he turned the boat over to a charter company to act as the listing agent); Simonson v. United States, 752 F.2d 341 (8th Cir. 1985) (tractor-trailer truck not in service when purchased in usable condition by individual who intended to go into the grain hauling business because he had not yet quit another job to let him go into the business); compare General Counsel Memorandum 37449 (March 6, 1978) (taxpayer already in the trade or business does not have to use equipment before it is in service, unlike taxpayers entering a new business).

A new business must usually be earning revenue before it is allowed to start depreciating equipment, especially power companies that are required to use the inventory method of accounting, which requires offsetting "costs of goods sold" like electricity against the related sales revenue in order to determine income. In Field Service Advice 2045 (1997), a newspaper company built a new facility to print its Sunday papers in color in year 1, but employees were not trained to use the new presses until a year later due to a labor dispute. The IRS national office said the presses were not in service until the newspapers had employees to use the facility. It said that treating the presses as in service earlier would "violate the very objective of depreciation as an accounting device designed to recognize the physical consumption of capital assets as a cost [of goods sold]." The depreciation claimed should match the period the presses were being used to generate income. See also Siskiyou Communication, Inc. v. Commissioner, 60 T.C.M. 475 (1990) (digital telephone switching equipment not in service after it was fully installed and capable of being used until later year when employees were trained to use it).

In William J. Walsh, 55 T.C.M. 994 (1988), a taxpayer could not start depreciating equipment that was fully installed and in operable condition for a new restaurant that the taxpayer planned to open in late 1981 because it did not actually open the restaurant for business until March 1982. The court said depreciation is not allowed on assets acquired for a business that has not begun operations. Because the restaurant did not open until 1982, "the cost of the equipment did not contribute to, and therefore should not be charged against, income for an accounting period prior to the years in which the restaurant was open for business," citing Massey Motors, Inc., a case in which the U.S. Supreme Court considered the period over which rental cars that had a longer useful life than they were actually used by an auto leasing company could be depreciated by the leasing company under the 1939 tax code. The Supreme Court described depreciation as an allowance for wear and tear to property arising out of its "actual use in the business." It said tying depreciation to the period the asset was in actual use in the business was more likely to lead to an accurate reflection of income from operations than using the full useful life. See Massey Motors, Inc. v. United States, 364 U.S. 92 (1960).

The courts have held that leasing companies put their equipment in service when the equipment is first held out for lease by prospective lessees, even though the equipment is not yet in actual use. See, e.g., Waddell v. Commissioner, 86 TC 848 (1980) (computerized electrocardiography terminals were in service when leasing company opened its doors for business, even though no doctors' had taken up the offer yet).

UTILITY REBATES, PERFORMANCE INCENTIVES, AND FEED-IN TARIFFS

Commercial and industrial customers must report utility rebates, feed-in tariffs and performance incentives in almost all cases as income. Some taxpayers have argued that rebates do not have to be reported as income by corporations because the rebates are non-shareholder contributions to capital under section 118 of the Internal Revenue Code. The IRS takes a very narrow view of what qualifies as a non-shareholder contribution to capital.

However, rebates received by homeowners ordinarily do not have to be reported as income under section 136 of the tax code. That section excludes from income "any subsidy provided (directly or indirectly) by a public utility to a customer" as an inducement to take measures "to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit." See sections 136(a) and (c)(1). Rebates to homeowners to encourage them to install solar panels are considered energy conservation measures for this purpose.

Rebates qualify for exclusion even though they are paid by a state agency or nonprofit corporation if the funds were collected from public purpose charges added to utility bills. See Private Letter Ruling 200717010 (January 19, 2007).

If the homeowner must turn over renewable credits to the utility in exchange for the rebate, then the "rebate" may be consideration for a forward sale of the RECs and have to be reported by the homeowner as income. See Private Letter Ruling 201035003 (September 3, 2010).

Solar panels and batteries that a utility planned to install in some customer residences as part of an experiment to test different approaches to energy conservation did not have to be reported by the customers as income. The customers were given the equipment to own. The utility also planned to install smart meters to help customers monitor how they are running up charges for electricity. The equipment was a subsidy covered by section 136. See Private Letter Ruling 201046013 (August 10, 2010).

A homeowner who receives a rate reduction or nonrefundable credit on the homeowner's electricity bill as a reward for taking actions to reduce energy consumption does not have income under section 61 of the tax code and does not have to move to the next question whether the benefits can be excluded from income under section 136. See Rev. Rul. 91-36, 1991-2 C.B. 17.

RENEWABLE ENERGY CREDITS (RECS)

Twenty-nine states and the District of Columbia have renewable portfolio standards that require utilities to supply a certain percentage of total electricity from renewable sources. (Another eight states have nonbinding goals.) Some states implement their programs by requiring utilities to turn in renewable energy credits at the end of each year in the amount of renewable electricity they were required to supply. In such states, utilities earn RECs by generating the electricity themselves or they can buy RECs from independent generators who used renewable energy to generate electricity.

The IRS has not addressed the tax consequences of receiving renewable energy credits from a state government. However, it has addressed the tax treatment of sulfur dioxide allowances allocated or purchased under the federal acid rain program.

A company does not have to report the allowances it receives as income. See Rev. Rul. 92-16, 1992-1 C.B. 15.

It takes a zero basis in them. Id. A company that buys allowances in the market takes as its basis the amount it paid for the allowances. The cost must be capitalized. See Rev. Proc. 92-91, 1992-2 C.B. 503 (Q&A1).

The IRS said in 1992 that the cost cannot be recovered through depreciation because the allowance has no ascertainable useful life. See Rev. Proc. 92-91 (Q&A2). This was before enactment of section 197 of the tax code. That section allows the holder of any "license, permit, or other right granted by a governmental unit" to deduct its basis over 15 years. See section 197(d)(1)(D). The IRS regulations give airport landing and takeoff slots as an example of such intangibles. See Treas. Regs. § 1.197-2(b)(8). However, the IRS said in 1992 that a power company deducts its basis in the year it uses the allowance. See Rev. Proc. 92-91 at Q&A3. Power companies are required to use an inventory method of accounting. The rule that the basis is deducted in the year the allowance is used is consistent with the view that use of the allowance is a cost of supplying electricity.

NET METERING

Some states have net metering programs that allow customers with solar panels to feed any electricity they generate beyond their needs back into the grid. The customer may or may not receive credit for any such electricity supplied. In the purest case, the meter essentially runs backwards and the customer receives a credit at the retail rate against his electricity bill.

The IRS has not addressed the tax treatment of such programs.

Utilities are required to use the inventory method of accounting. In the absence of guidance, it seems reasonable for a utility to treat the amount it credits as part of its cost of goods sold in the same year.

Commercial and industrial customers of the utility who receive credit deduct the amounts they pay for electricity as ordinary and necessary business expenses. In theory, any customer selling electricity back to the grid should report the amount it is credited as income. However, it arrives at the same place by deducting only the net amount it paid for electricity after the credit.

Homeowners should in theory also report credits as income from electricity sales. However, the treatment in individual cases turns on the details of the net metering program and is beyond the scope of this treatise. The IRS held that homeowners who take actions like installing insulation, storm windows and doors and more efficient air conditioners and are rewarded with rate reductions or nonrefundable credits by the utility do not have to report the value of the rate reductions or credits as income. See Rev. Rul. 91-36, 1991-2 C.B. 17.

Recent SEPA Research Publications

Community Solar Program Design (2012)
'Community Solar' programs are one type of utility solar business model that exemplifies the need for cross-functional coordination within the utility for both their design and operation. This Technical Brief considers the point of view of the community solar design person or team within a utility and qualitatively explores the inter-departmental strategic needs that should be addressed as a community solar program is developed.

Centralized Solar Projects Quarterly Bulletin (2012)
SEPA's quarterly solar projects bulletin provides a summary and commentary on the centralized PV and CSP projects activity in the United States through Q4 2011, including a year in review section. Thirty-one large projects (>5 MW) were completed totaling 420 MW of capacity, a 72% megawatt growth over 2010. Over 4,000 MW of new projects started construction in 2011 and will be completed between 2012-2015.

The Impact of Third-Party Business Models on the U.S. Market for Solar Water and Space Heating (2012)
The report begins with a review of solar thermal market research for both residential and commercial sectors, including loan-centered models, solar thermal ESCOS, third-party leasing, third party shared revenue projects, and third-party energy services agreements. The last section looks at one critical, remaining question: How can SWH businesses attract the upstream financing they need to scale up turnkey solutions?

Buy versus Build (2011)
This report explores a utility's two solar procurement options – ownership or contracting. The analysis considers financial, tax and regulatory implications that impact a utility's decision whether to buy (PPA) or build (own) solar generation.

Normalization of Solar Investment Tax Credits (2011)
To date, utilities have announced or are implementing over 900 MW of utility-owned projects, which is a growing and important fraction of the overall solar market over the next five years. However, the IRS code contains certain provisions, called "normalization rules," which can have adverse effects in utilities' use of the ITC and the resulting project costs. This brief describes the issue of normalization in more depth and offers case studies of utilities as they relate to normalization of solar ITCs.

Italy Fact Finding Mission (2011)
In May 2011, SEPA traveled to Italy to study the country's successes, current challenges, and future approaches surrounding the development and grid integration of distributed solar photovoltaic (PV) resources. The key takeaways from the SEPA fact finding mission are explored in this report.

SEPA/EPRI Brief - Solar Augmentation of Fossil-Fired Power Cycles (2011)
Authored by the Electric Power Research Institute (EPRI), the brief looks at the current state of research and deployment for solar augmentation with traditional fossil fuel power plants, i.e. concentrating solar power (CSP) hybrid configurations. CSP plants have thus far been largely designed and developed

Electric Utilities' Solar Employment Needs Brief (2011)
The rapid growth of solar electric markets has in-turn required electric utilities to adjust and increase their staffing capabilities to manage everything from distributed customer systems to centralized purchasing contracts to utility owned projects. SEPA's new brief, *Electric Utilities' Solar Employment Needs*, builds upon the recent analysis in the utility chapter in the U.S. Solar Jobs Census report to create a more complete and unique picture of the utility solar workforce.

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