Solar Energy Project Development Issues: Preliminary Considerations

Stephen J. Humes, Holland & Knight LLP. **The author acknowledges with appreciation the contributions of Tiana McLean, an associate in Holland & Knight's New York City office, who assisted in the research and revisions to this article.**

A discussion of some of the issues that solar developers and their counsel should consider when developing a solar energy project including with respect to land acquisition, solar resource analysis, permitting, transmission and interconnection. Although drafted from the perspective of project developers, this Note also includes information that lenders, their counsel and other project participants may also find useful.

Developing a utility-scale solar energy project is complex and involves many different parties including developers, landowners, utilities, grid operators, government agencies and financing parties. A utility-scale project (also known as a grid-scale project) refers to a project that is intended to deliver electricity to the power grid as opposed to the site where the property is located or to a local community. Utility-scale solar projects require extensive due diligence and analysis of many issues. The first of these issues is preliminarily identifying a site that has sufficient solar resources and other characteristics to make the installation of a project on that site economically feasible. Other issues that must be analyzed include:

- The land rights needed to build the solar farm or install the solar photovoltaic (PV) project.
- The amount of energy that a project built on the selected site can produce.
- The environmental regulations to which the project is subject.
- The local, state and federal permits required to construct and operate the project and to sell the electricity produced.
- The government incentives available to promote and encourage investments in solar projects.
- How the project will be connected to the grid and the electricity generated sold.

This Note provides a summary discussion of these issues. For a general introduction to solar energy, see *Practice Note, Understanding Renewable Energy: Solar (http://us.practicallaw.com/2-519-8033)*. Although not built for the purposes of selling electricity to a utility or other wholesaler, this Note also discusses residential and other installations that are built to provide electricity to the site where the project is located.

ACQUISITION OF PROPERTY RIGHTS

To develop a solar farm or a utility-scale project, a solar project developer must secure sufficient property rights to build, operate and maintain the project. There are various possible real estate entitlements that can be acquired to support a solar project, ranging from an outright purchase of the land at one extreme to a license at the other end. To minimize their land acquisition costs, some project developers use an option agreement for a ground lease or a purchase to be memorialized in formal documentation after all other permits and approvals are secured. While a full analysis of land rights issues are beyond the scope of this Note, there are a few issues that developers and their counsel should consider.

Easements

Some project developers seek an easement to convey the property interest needed. An easement is a possessory interest in real property that provides the holder with the right to use another party's real property for a specific purpose. Legal title to the real property encumbered by the easement is retained by the original owner for all other purposes. Easements are usually used for rooftop and smaller-scale solar PV projects.

Leases

A lease is probably the most common device used to convey the necessary real property rights to a solar developer. These agreements provide broad rights and are normally used for concentrated solar power (CSP) projects and ground-mounted PV systems. Depending on the size of the project, a ground lease may be used. For more information on the different types of solar energy projects, see *Practice note, Understanding Renewable*

Energy: Solar: Types of Solar Projects (http://us.practicallaw.com/2-519-8033).

When negotiating these agreements, solar developers and their counsel should make sure they obtain:

- Unrestricted access to and from the property.
- Exclusive right to use the property to construct, operate and maintain the solar project.
- Generous lease renewal and extension rights.

The scope of the rights a solar developer may receive depends on:

- The identity of the lessor. A solar developer may be able to negotiate broader rights from private landowners than they can from the Bureau of Land Management (BLM), the agency within the Department of the Interior that manages federally owned land or land held by the government in trust for Native American groups (see *Federal Managed Land*).
- The topography of the land. Solar farms require exclusive use of large amounts of land that provide unobstructed access to sunlight (see *Practice Note, Understanding Renewable Energy: Solar: Intensive Use of Land* and *Site Topography Requirements (http://us.practicallaw.com/2-519-8033)*). To make the negotiations easier and to minimize the amount the solar developer may have to pay, solar developers may need to seek property with minimal alternative use.

Energy Services Agreement

Another possible contracting strategy for acquiring property rights is to combine the real estate acquisition agreement with a power purchase agreement (PPA) in a contract sometimes called an energy services agreement. Under this agreement, the property owner:

- Conveys to the solar developer the requisite real estate entitlement rights to develop the project.
- Agrees to buy the power produced by the project.

This approach has its proponents but it is rarely used because a breach of the PPA by the property owner may lead to the termination of the agreement. In turn, this may result in the developer losing its right to lease the property and operate the solar project. If an energy services agreement is used, the developer, to the extent commercially and practically feasible, should negotiate the right to continue occupying the leased premises and operate the solar PV facility even if the power sale provisions are no longer effective.

If a separate lease and PPA with the property owner are used, project developers and their counsel should carefully consider whether the lease survives the termination of the PPA. Project documents are frequently drafted so that the lease terminates on termination of the PPA. However, similar to the combined lease and PPA, the project developer may wish to retain the lease rights to continue to operate the solar facility to sell the electricity it produces to a third party even if the PPA with the property owner terminates for any reason (other than breach by the developer). If the PPA terminates, the lease should be kept in effect to, among other things, give the developer a mechanism to mitigate its damages if the property owner improperly terminated the PPA. The developer can enter into a PPA or a tariff sale transaction with a local electric utility to sell its electricity wholesale. However, certain regulatory issues are triggered if an on-site host ceases to buy power from the solar PV project but the project continues to operate. Depending on the identity of the offsite buyer of the power, the project developer may become a wholesale seller or a retail seller subject to regulations that were not an issue before. For example:

- If it becomes a wholesale seller, the project developer may need authorization from the Federal Energy Regulatory Commission (FERC) to engage in wholesale sales of electricity under the Federal Power Act (FPA) in the form of a power marketer authorization.
- If a retail sale is taking place, the project developer may need a license from the state public utility commission to engage in retail sales of power.

The best option under this situation may be to declare the project a qualifying facility (QF) under the Public Utilities Regulatory Policy Act (PURPA) and to sell the power to the local electric utility, which may simplify the regulatory issues and analysis (see *Federal and State Energy Regulatory Issues*).

Fee Simple Estate

Another alternative to easements and leases is to obtain fee title to the property required. This is the greatest possible interest in real property because the owner's rights are unconditional, unlimited and perpetual. Owning the property outright, however, is often expensive and imposes several obligations on the owner that a solar developer may not want.

Federal Managed Land

Solar project owners must often enter into leases with the BLM for the property needed because of:

- The amount of land that may be required to build a CSP power plant or a solar PV farm.
- The land characteristics that are most conducive to solar project developments.

The BLM manages more than 250 million acres of land of which over 20 million acres (located primarily in Arizona, California, Colorado, Nevada, New Mexico and Utah) have been identified as having significant solar potential. The BLM approved its first solar project in 2011 and as of July 2012, has approved ten additional projects capable of producing more than 4,500 MW of electricity which is sufficient to power over 1.3 million homes (see *BLM Solar Projects Fact Sheet*). The BLM has also approved rights-of-way for transmission lines to enable the construction of six additional projects with another 1,475 MW of installed solar generation capacity.

Federally granted land rights differ from purely private arrangements in several ways. In many cases, the rights of way and leases are not exclusive. More materially from the perspective of the project's lenders, the BLM does not generally execute estoppel certificates that give project lenders certain rights (including exercising the developer's rights under the lease) if the project's developer defaults under the lease. In addition, in every federal land transaction, the solar developer will have to satisfy environmental review requirements (see *Federal Environmental Review*).

SOLAR RESOURCE ANALYSIS

One of the key issues a project developer must determine at the outset of every project is the amount of sunlight that a proposed site receives on a daily, weekly, monthly and yearly basis and the location of the sun during those times. This is called "insolation" and understanding it allows the project developer to determine:

- The size of the project that can be built on the proposed site.
- The amount of energy the project can produce.
- The technology and facilities that are required.

In the early stages, the project developer typically retains engineering or technical consultants to assist in modeling and analyzing the available solar resources. The National Renewable Energy Laboratory's website has published modeling and analysis resources, including *National Renewable Energy Laboratory: Photovoltaic Solar Resource Map of the United States* and *Concentrating Solar Resource Map of the United States*.

ENVIRONMENTAL REVIEW

It is essential that the developer and its counsel conduct a thorough environmental due diligence review in the early stages of the project before finalizing the lease (or other real estate entitlement) and certainly before permitting or site work begins. Environmental review of the project site before commencing construction is important to:

- Ensure the parties' rights and responsibilities are properly documented.
- Ensure that all relevant risks are properly identified and allocated.
- Evaluate areas of potential environmental concern (for example, subsurface contamination) or sensitive environmental receptors (including wetlands, endangered species habitat and historic resources). In either case, the findings of the environmental review should lead the project development team and appropriate legal and technical advisers to consider whether remediation, mitigation or avoidance strategies are needed.
- Satisfy prudent lending or equity investor requirements. Except in the case of residential or small commercial solar PV projects, lenders and investors typically insist that environmental due diligence be undertaken to ensure areas of potential environmental concern are understood and delineated before building the project.
- Ensure there is a baseline against which to evaluate any future environmental issues. Typically, a ground lease or other real estate entitlement document imposes on the project developer, as lessee, the duty of indemnifying the lessor for environmental issues caused by the project or occurring during the lease term. A baseline environmental assessment may identify preexisting conditions or areas of concern that arose before the solar lease term began. As a result, the lessee may require in the lease that the lessor indemnify the lessee for preexisting environmental conditions.

The failure to undertake basic environmental due diligence could lead to project delays or unexpected surprises later in the project development process. For example, some states, such as New Jersey and Connecticut, have statutes imposing environmental remediation responsibility on parties to real estate transactions, including leases. As a result, it is possible that a party to a lease for a solar project could become responsible at the end of the lease term for environmental conditions on the site even if the lessee did not cause or contribute to the environmental issue. For more information on these issues, see *Practice Note, Environmental Law: Overview: Environmental Liability in Transactions* and *Environmental Diligence (http://us.practicallaw.com/2-500-4092).*

In addition, because of recent US Supreme Court decisions and subsequent regulatory developments at the Environmental Protection Agency, environmental lawyers generally agree that environmental due diligence should meet the test of having conducted an "all appropriate inquiry." This legal standard is intended to protect the party acquiring a real property interest in the site from later treatment as an "owner/operator" responsible for the preexisting environmental conditions, within the meaning of certain environmental statutes, including but not limited to the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as the federal Superfund law.

Counsel with knowledge of the specific state environmental laws should be consulted to ensure that the necessary environmental due diligence is conducted properly.

Federal Environmental Review

A project to be located on federal land typically requires a review under the National Environmental Policy Act (NEPA). A NEPA review assesses the environmental impact of the project on natural, cultural or historic resources and wildlife. Generally these projects require a Phase I environmental site assessment (ESA) along with a NEPA screen (sometimes referred to as a NEPA checklist) to determine the project's impact on these resources.

Depending on the outcome of this review, an Environmental Impact Statement (EIS) may also be required. Generally the EIS covers the same scope of information as an ESA, except in more depth. An EIS review can be complicated, lengthy and expensive. Depending on the project, it may take more than three years to complete and cost millions of dollars.

The Phase I ESA should be compliant with the standards most recently published by ASTM International (formerly known as the American Society for Testing and Materials). In 2005, ASTM published an update to its Phase I ESA standard (see *ASTM E1527 - 05 Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process*).

NEPA Review of CSP projects

CSP projects typically require NEPA review because they are often located on land that is owned by either the federal government or Native American communities (see *Federal Managed Land*). NEPA reviews for these large scale CSP projects are typically complex and require extensive stakeholder collaboration through a full EIS process that usually includes scoping of alternative undertakings.

NEPA Review of PV projects

Solar PV projects can require a NEPA EIS review if the project is:

- Substantial in size (25 to 100 acres).
- Located near sensitive environmental receptors such as wetlands or watercourses.

However, most solar PV projects are smaller in scale and land use approvals typically involve local zoning boards and electrical and building officials.

State Environmental Review

The scope of the environmental review conducted at the state level depends on the project and the laws of the applicable state. Some states conduct this review simultaneously with the permitting process. Developers' counsel should discuss with local counsel the relevant requirements and the timing for completing this review.

PERMITTING REVIEW

Permitting of solar projects is usually governed by the laws of the local and state jurisdictions where the project is located, unless the facility will be located on land owned or managed by the federal government. The permitting requirements of solar projects are generally not that challenging, unless the project will be located on environmentally sensitive land. For example, if wetlands, watercourses or coastal resources are on or near the site, the permitting requirements may be more extensive and stringent. A smaller project that is proposed to be built on or near a wetland can expect more permitting difficulty, including a more thorough and detailed level of environmental review, than a larger project proposed to be built on a rooftop or a canopy over a parking structure. Project developers building on farmland may also find that the land has acquired some protected farmland status which, depending on state law, may or may not be compatible with a solar farm use.

However, some land use permitting can still be expected. The land use permits that are required depends on the local jurisdictional requirements and the design features of the project, including whether the project is installed on a rooftop or on the ground. Solar projects generally require:

- Approval from a local land use board or zoning authority.
- A building permit.
- An electrical permit.

Although, the permitting of solar projects is generally not complex, the process can be time consuming and expensive. This is because of the number of agencies that are typically involved (at the federal and state levels) and the documents that must be furnished in support of the permit applications. As a result, the permitting process can delay the deployment of solar projects. Several initiatives have been implemented to improve the permitting process for solar projects, but it is still an issue that project developers should consider when developing their project plans (see *Practice Note, Understanding Renewable Energy: Solar: Streamlining Permitting and Environmental Review (http://us.practicallaw.com/2-519-8033)*).

Federal Permitting

Solar projects proposed for land that is owned or managed by the federal government may require permits from the BLM or the Department of Agriculture's Forest Service. These permits and rights of way are typically awarded after the completion of any NEPA review (see *Federal Environmental Review*).

State Permitting

The permits required and the process for obtaining permits varies depending on the state. Some states have a single agency or siting authority that manages the permitting process for all solar projects and other large utility infrastructure within the state. By contrast, in other states, the developers may have to obtain permits from different state and local agencies. These varied permitting systems can be detrimental to solar project deployment. Once a developer has identified the location for its project, its counsel and project technical consultants should review the applicable laws to determine the agency that has siting and permitting authority over the project. Understanding the permitting process is crucial because it can have a material impact on a project's development schedule and cost.

Some states have enacted zoning preference laws that declare solar to be a "beneficial use" within the meaning of their zoning laws, which has the practical effect of shifting the burden of proof and establishing the presumption in a zoning process that the zoning permit should be approved for the solar project. These laws vary by state and should be examined carefully by counsel advising the project locally.

INTERCONNECTION ANALYSIS

Interconnection is the fundamental access point for a solar project to deliver energy to the grid, either by direct sales to the local electric utility or indirect sales in the form of net metered transactions with a host. If the project is intended for net metering, interconnection is critical to ensure the electricity is delivered to the grid when the host uses less energy than the solar PV facility produces. This is done indirectly in cases where the host uses all of the output of the solar PV facility. In this case, the interconnected project "delivers" electricity to the grid in the form of displacement by offsetting what would otherwise need to be supplied by the utility to the host if the solar PV project was not installed. For more information on net metered transactions, see *Practice Note, Understanding Renewable Energy: Solar: Grid Connected versus Distributed Generation* and *Net Metering (http://us.practicallaw.com/2-519-8033)*).

Interconnection agreements are typically pre-approved for the utility by the state public utility commission and usually are not open to negotiation, except that project-specific information can be added to the agreement identifying:

- The project's location.
- The project's general design characteristics.
- Interconnection points and electrical engineering details.
- The project owner and the purchaser of the electricity.

Electric utilities may have different types of interconnection agreements depending on:

- The project's size.
- The process for applying for interconnection.
- The project's impact on the utility's system.

The project developer must pay the costs required for the utility to accept an interconnection and for any facilities and upgrades that may be required. The fee for interconnecting can vary significantly from low for small commercial or residential to substantial for larger scale projects. These system upgrade costs are non-negotiable. However, for upgrades to the network transmission system, the project developer receives a credit against future transmission service.

Any improvements or additions to the transmission and distribution systems are the property of the utility, not the project developer, and become part of its system. This is because the utility typically owns all the facilities from the meter located on the customer's property back to the point of interconnection.

SYSTEM RELIABILITY ISSUES

For a variety of reasons, local electric utilities bear substantial reliability obligations, not the least of which are imposed by federal law, FERC regulations and FERC-approved mandates and regulations of the North American Electric Reliability Corporation.

The fundamental issue electric utilities are concerned with during an evaluation of a potential solar facility is the impact it will have on the electric system or grid reliability. Solar project developers who are applying to the electric utility for interconnection must:

- Support the system impact study process.
- Agree to pay for the system upgrades necessary to allow for the safe interconnection of the project to the grid.

While project engineers and the developer's representatives can and should attend scoping meetings with the local electric utility representatives and, for big projects, with the regional transmission operators (RTO) or independent system operators (ISO), the requirements for interconnection will be prescribed for the project. As a result, the project developer typically has no opportunity to challenge or negotiate the specified system upgrades identified as conditions precedent to the interconnection.

For wholesale sales of electricity, RTOs and/or ISOs typically require new generators to:

- Apply for a place in the "queue" or line of planned generation in development.
- Pay for a transmission study or system impact study to evaluate how the new generator will likely impact the rest of system.
- If system upgrades are needed to accommodate the new generator's interconnection, pay for all upgrades needed to support the system's reliability after the new generator's interconnection is energized.

Local electric utilities also undertake state-specific system impact reviews for distribution-level interconnections. Just like the RTO or ISO on the regional or interstate level, local electric utilities similarly evaluate from a reliability perspective whether, in the utility's judgment:

- The local or intrastate system can accept the interconnection.
- Upgrades are required to accept the interconnecting solar projects.

While these reviews will likely be pro forma and simplified exercises for smaller scale residential or small commercial solar PV projects, project developers should anticipate substantial lead time and cost for interconnections proposed for larger scale solar PV or CSP projects.

FEDERAL INCENTIVES

Many federal incentives are available to renewable energy projects generally and solar projects in particular.

Investment Tax Credit

In the final months of the Bush administration, Congress gave the renewables industry generally and the solar industry in particular, a boost with the enactment of the Energy Improvement and Extension Act of 2008 (EIEA) (as part of the bill informally known as TARP). Since October 3, 2008, the EIEA has provided nearly $17 billion in various tax credits to promote clean power generation technologies, alternative fuels, renewable energy and energy efficiency.

The solar industry emerged as one of the clear winners in the legislation as it extended for eight years through December 31, 2016 the 30% investment tax credit (ITC) for qualifying solar energy systems. The credit is still available after 2016, but it is reduced to 10%. Tax owners of qualifying solar energy systems can receive a credit equal to 30% of the capital expenditures for solar facilities, which reduces significantly the cost of constructing a solar project. The EIEA also eliminated the previously applicable $2,000 cap on residential solar installations. The ITC is realized in the year the project is placed into service and vests ratably over a five-year period.

Section 1705 Loan Guarantee Program

This temporary loan program was established under Section 1705 of the Energy Policy Act of 1992 and is administered by the DOE. Of the nearly $34.7 billion that has been awarded under this program, about $23.7 billion has been awarded to 16 solar projects (see *DOE: Loan Programs Office: Our Projects*). As discussed above, this program has been the subject of significant controversy and criticism following the high profile bankruptcy of Solyndra LLC in 2011 (see *Practice Note, Understanding Renewable Energy: Solar: Solyndra Bankruptcy and Political Backlash (http://us.practicallaw.com/2-519-8033)*). Although the program expired in 2011, in May 2011, the Department of Energy (DOE) sent letters to more than three dozen project sponsors who could not meet the Section 1705 program deadline, informing them that they could apply for a guarantee under Section 1703 of the EPAct 1992, which has about $34 billion in lending capacity.

Following the bankruptcy filings of a few other grant recipients (Abound Solar, which received $400 million in guarantees, and Beacon Power Corporation, which received $43 million in guarantees), a pending bill in the US House of Representatives calls for the DOE to cease issuing guarantees under all loan guarantee programs and for more oversight of the DOE's administration of these programs (see *HR 6213: No More Solyndras Act*). Although it is unlikely that this bill will be passed, it and other similar initiatives among some members of Congress continue to demonstrate the hostility to and political polarization of support for renewable energy incentives in Washington, DC, which continues to cause uncertainty for the renewable energy industry.

US Treasury Cash Grants

Shortly after entering office and representing his first legislative initiative, President Obama signed the American Recovery and Reinvestment Act of 2009 (ARRA), further expanding the federal incentives for renewables. Most prominently for the solar industry was ARRA Section 1603, which created a Treasury grant program that gave renewable project developers the option to obtain a 30% cash grant in lieu of the ITC. Payment under this program is made within 60 days of the project achieving commercial operation and submitting appropriate documentation. To be eligible to receive this credit, a solar project must have already applied and been in the system for review and approval by now. No new projects are eligible for this program at this time.

Bonus Depreciation

In addition to the Treasury grant program that is only available for projects that met the now-expired deadlines, Congress has authorized bonus depreciation of 50% for capital costs incurred after January 1, 2012. This is a "bonus" because the developer is also eligible to claim a depreciation of 50% using the usual Modified Accelerated Cost Recovery depreciation deduction rules over the applicable period. Renewable energy tax policy changes frequently and, therefore, a tax adviser should be consulted when relying on the availability of any renewable energy tax incentives.

STATE INCENTIVES

Many states in the US have been promoting investments in renewable energy, energy efficiency and conservation for many years. But recent concerns about the risks of climate change have added enhanced urgency in the various states to use policies such as arenewable portfolio standard (RPS) or public utility incentives to achieve the following major public policy objectives:

- Reduce greenhouse gas emissions.
- Increase renewable energy production.
- Reduce consumption of energy.

States have come to recognize that it is extremely difficult for Congress to enact a national energy strategy or nationwide RPS program and have elected to set their own policies. To date, 29 states have enacted state specific RPS (see *Database of State Incentives for Renewables & Efficiency: Renewable Portfolio Standards Map*).

Although several states provide renewable energy incentives, New Jersey and California lead by a wide margin.

Renewable Portfolio Standards and Renewable Energy Credits

One key element that provides support for solar development is an RPS program. Under these programs, load-serving entities (typically, utilities and competitive suppliers) must purchase a percentage of their electricity from clean energy sources (including wind, solar and geothermal) or make a penalty payment, an alternative compliance payment (ACP), into a state clean energy fund. Some states have a separate percentage of electricity that must be obtained from solar energy sources (referred to as the solar carve-out).

In an effort to simplify clean energy transactions in the wholesale market, owners of renewable energy projects are allowed to "disaggregate" or sell separately the renewable energy "attributes" of their project outputs from the actual electricity delivered to hosts or into the power grid by selling RECs or solar renewable energy credits (SRECs), in the case of solar, separately in the market. For each megawatt hour (MWh) of electricity produced, a qualifying project earns one REC or SREC, as the case may be. If a load-serving entity cannot acquire enough RECs or SRECs, in states with a solar carve-out, they must pay an ACP or solar ACP (SACP), as the case may be.

Once the state determines the ACP or SACP, that amount becomes the ceiling price for RECs or SRECs and the trading market for these credits can flourish under typical supply-demand market forces below the ACP or the SACP, as applicable. The value of the ACP or SACP sets the ceiling price for what RECs or

SRECs can possibly rise to in the market because a compliance entity would make the ACP or SACP payment rather than pay for RECs or SRECs if its costs increase above a certain price.

New Jersey

New Jersey is the leading state in the northeast in implementing market-based solar incentives that have attracted large investments, but other states are adopting similar approaches. In the last few years, New Jersey's governors have signed legislation that:

- Exempts renewable energy systems from real property taxes in the state.
- Sets zoning preferences.
- Limits the ability of municipal zoning authorities to regulate solar.

The state also enacted a solar bill that steadily increases the quantity of solar energy that must be procured over at least the next decade to satisfy the state's RPS. Under its RPS program, New Jersey has established a goal of obtaining more than 20% of its energy from renewable energy by the year 2020. Also, under New Jersey's Global Warming Response Act, the state's electric utilities are authorized to invest directly in renewable energy projects and recover their investment costs in utility rates which is viewed as a key component to achieve its RPS goal.

In addition, New Jersey's public utility commission, the Board of Public Utilities, issued orders authorizing and directing the electric utilities to implement solar programs that support the growing market. One utility was authorized to start a solar loan program that covers 60% of the project cost and allows repayment of the loans in the form of assignment of SRECs, instead of in cash. Other utilities were required to procure contracts for the long-term delivery of SRECs at a specified price. Unlike feed-in tariff programs common in Europe, the SREC programs developed in states like New Jersey create market mechanisms that support private investments in renewables without direct cash grants from the government or utilities.

The results of New Jersey's market-support incentives speak for themselves. Through September 2012, New Jersey has more than 18,000 residential and commercial solar projects installed with a capacity to produce about 900 MW of solar energy, second only to California. Another 740 MW of solar projects are in development in New Jersey. However, this rise in the supply of installed solar capacity in New Jersey has led to saturation in the market, with SREC values dropping.

California

On March 29, 2011, the California legislature reaffirmed that state's ambitious commitment to support renewables with the enactment of Senate Bill X1-2, expressing the policy intent that the amount of electricity generated per year from renewable energy resources in California be increased to 20% per year by 2013 and 33% by the end of 2020, the second most ambitious state standard in the US, second only to Hawaii's 40% standard.

Massachusetts

In August 2012, the Governor of Massachusetts signed the 2012 Energy Act which among other solar-friendly provisions increased Massachusetts' cap on solar net metering (see *Bill S. 2395, An Act relative to competitively priced electricity in the Commonwealth*). Massachusetts has an auction process for SRECs that offers project developers a minimum price of $300 per SREC sold through the auction, less a $15 per SREC administrative fee. A project developer, therefore, has reasonable near-term assurance that there is a floor in the market of $285 per SREC (although SRECs are currently trading in the $500 MWh range). This assumption, however, only held while the market was constrained with less than the 400 MW authorized by the solar program. The new legislation doubles the amount of consumer generation that will qualify for the retail pricing incentive because it raises the cap on privately and publicly owned net metering installations to 3% each, or 6%. This legislation provides more assurances to the market and should increase solar energy development and market growth.

Connecticut

Connecticut enacted legislation in 2011 that promotes "zero emission" technologies (ZRECs) and "low emission" technologies (LRECs) by establishing a market for ZRECs and LRECs to satisfy the state's RPS. As a result, Connecticut's electric utilities are conducting procurement auctions to buy long-term contracts for the sale of ZRECs and LRECs, with solar PV facilities qualifying for ZRECs. Connecticut's ZREC and LREC approach reflects a state policy to eschew "picking winners and losers" in the renewable sector. Connecticut is instead striving to be agnostic to solar versus other technologies and seeks to let the renewable energy industry decide what technologies make sense for Connecticut. Other states, like New Jersey and Massachusetts, have policies that clearly favor and contain carve outs for solar, which critics describe as these states picking winners and losers.

FEDERAL AND STATE ENERGY REGULATORY ISSUES

Under the FPA, FERC has regulatory jurisdiction over wholesale sales of power. Sellers of wholesale power must obtain FERC authorization, the power marketer authorization, and file with it its tariffs. In addition, state regulations may also apply. Whether FERC jurisdiction and regulation applies and the extent of state regulation depends on several factors, including:

- The size of the project.
- Whether the project is connected to the grid.
- The entity to which the power produced will be sold.

Generally, solar projects are subject to FERC's regulatory supervision unless they can qualify as an:

- Exempt wholesale generator (EWG). Created under the EPAct 1992, an EWG is a category of power producer that is exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935, and following its repeal, thePublic Utility Holding Company Act of 2005. EWGs are independent power producers (IPP) that generate electricity for sale in wholesale power markets at market-based rates. An IPP may qualify as an EWG, and thereby become exempted from certain regulation if the IPP is exclusively in the business of owning and/or operating an electric generation facility for the sale of electricity to wholesale customers. This exemption is available to an IPP regardless of the size of the facility or the fuel used to generate the electricity.

- Qualifying facility (QF). This refers to the status conferred on a generation facility owned and operated by an individual or corporation, but that is not primarily engaged in the generation or sale of electric power. QFs are either renewable power production (such as biomass, geothermal, hydroelectricity and solar) or co-generation facilities that qualify under Section 201 of PURPA. Under PURPA, a small power producer may obtain QF status and be eligible for exemption from the FPA's authorization, tariff and other provisions, except that small producers that are larger than 1 MW must file a Form 556 registration with FERC declaring and self-certifying to QF status. Smaller projects can qualify for QF status without satisfying the filing requirements.

A solar facility may be subject to the extensive regulation of the state where it is located depending on the entity to which it sells its electricity. Retail sales are governed by state law and wholesale sales are governed by federal law. Depending on the nature of its sales, the solar facility may qualify as a public utility under state law, which then makes it subject to extensive regulations regarding tariffs and terms of sale. Because of the shared jurisdiction of FERC and state public utility commissions over electric energy law and regulation, there are specific federal regulatory issues that arise from the sale of power from a solar system to the grid or utility through a state metered arrangement.

When Does a Net Metering Arrangement Trigger FERC Regulation?

Certain states such as New Jersey embrace net metering. However, because these arrangements involve the sale of excess generation to utilities, they may trigger federal laws and regulations governing wholesale sales of electricity. For example, the New Jersey solar program's net metering allows for up to one year of averaging if the solar host uses more energy on average over the year from the solar project than the solar project supplies to the grid. It is an open legal question as to whether this yearly averaging constitutes a wholesale sale of electricity subject to FERC jurisdiction.

As FERC explained in its *Sun Edison LLC* decision, where there is no net sale over a billing period, FERC does not assert FPA jurisdiction when the end-use customer connected to a net metered solar PV facility receives a credit against its retail power purchases from the selling utility (*129 FERC ¶ 61, 146 (Nov. 29, 2009)*). While FERC has suggested that net metering over a month may be allowed if that is consistent with the customer's billing period, it has not yet ruled on the propriety of longer-term net metering situations, such as those lasting one year. There is uncertainty, therefore, on whether FERC would approve of programs such as New Jersey's that allow for up to one year of net metering.

The particularly vexing issue in a net metering situation is whether the wholesale "seller" for FPA purposes would be deemed by FERC to be the developer (or the owner and/or operator of the net metered solar PV facility) or the host. This is because it is the host, not the developer, that:

- Has the interconnection agreement with the local electric utility.
- Will be entitled to payments from the electric utility if the solar project results in net sales of power to the electric utility because the host's electric consumption dropped.

Wholesale Price

Another issue to consider is price at which the solar facility sells the excess power to the local electric utility. Under PURPA, electric utilities have an obligation to buy power from wholesale IPPs such as QFs at avoided cost rates. This rate was intended in 1978 to be the cost a utility avoided by not having to manufacture the electricity that was purchased from the QF. Currently, however, after many states mandated that electric utilities "deregulate" by selling off their power plants to competitive wholesale power companies, the avoided cost calculation has now been replaced with the wholesale market price of power obtained through the RTOs and/or ISOs.

Given the avoided cost language in PURPA, the question is whether feed-in tariffs, like the one California uses to incentivize solar procurements with above-market power prices, can pass muster under PURPA. The electric utilities have challenged these tariffs in court and the courts have tried to strike a balance that respects the federal limitations while allowing some flexible interpretations of what is meant by avoided costs. This area of law remains in flux that will not likely be resolved unless Congress passes a national renewable energy law that provides more clarity on how to reconcile the federal and state energy programs.

A related development emerged with the Energy Policy Act of 2005 (EPAct 2005), which empowered FERC to relieve certain electric utilities of the PURPA avoided cost purchase obligation if FERC determined that the electric utility is operating in a "competitive" wholesale marketplace. Some utilities have petitioned FERC for these determinations and, in some cases, FERC has been granting limited relief from the avoided cost obligation.

For example, in New Jersey, one of the electric utilities successfully petitioned FERC to discontinue the obligation to buy power from QFs at avoided costs, but FERC limited this relief to projects with a capacity of 20 MW or greater. As a result, solar PV projects that are under 20 MW in New Jersey will continue to have the ability to compel the interconnecting local electric utility to engage in mandatory purchases of wholesale power from the QF under the PURPA avoided cost requirement, but projects over 20 MW would have to sell surplus power into the Pennsylvania

12-12

New Jersey Maryland Interconnection (PJM), the regional electric transmission system's ISO.

POWER PURCHASE AGREEMENTS

The PPA is one of the main contracts of any energy project. This agreement is especially important if the project is project financed because most lenders will not extend financing unless there is a firm PPA in place that can provide a predictable income stream to service the debt. The terms and scope of the PPA depend on several factors, including:

- Whether it is being used to document the sale of power to a utility or other third party or as part of a distributed generation project.
- Whether the sale of electricity is coupled with the sale of RECs.
- The nature of the power plant. PPAs for solar and other renewable energy-sourced power plants raise several issues that are not present in other PPAs.

While a detailed analysis of PPA issues are beyond the scope of this Note, this section discusses some preliminary issues that developers and their counsel should consider.

Distributed Generation

There are generally two different business models that are used in distributed generation transactions:

- Customer as host.
- A third party PPA.

Customer as host

Under this structure, a property owner buys the solar PV equipment that is appropriate for its location and enters into a contract with a third party to install the system. The property owner is responsible for ownership, operation and maintenance of the project. The project owner is the "tax owner" of the solar project and can therefore claim any incentives for which the project may be eligible including the ITC and any accelerated depreciation benefits. In this situation, the primary contract needed is an engineering, procurement and construction (EPC) contract.

This approach may be used:

- In states that do not allow the third-party PPA model or that do not allow net metering.
- Where a property owner is willing to accept the cost and inconvenience of owning, operating and maintaining a solar installation in exchange for the ability to claim its full benefits (including electricity at cost and tax and renewable energy benefits).

In this case, there is no PPA because the owner uses the power produced by its solar installation.

Third-party PPA model

Under this structure, which is the preferred approach, the owner of a property (whether residential or commercial) enters into a contract with a third-party energy provider under which it gives the energy provider the right to design, install, own, operate and maintain a solar installation or project on the property. In exchange, the owner agrees to purchase the energy generated by the project for a specified period.

This model:

- Enables a property owner to receive a reliable and long-term supply of electricity without having to invest significant capital in a new energy plant.
- Allows the host to avoid the costs associated with the operation and maintenance of the project.
- Provides a property owner with a predictable and in some cases less expensive source of electricity. The purchase price for the electricity in these contracts is in many cases lower than what the property owner would have to pay to a utility, but still priced high enough to allow the solar developer to make a reasonable profit.

Depending on the transaction, this PPA may be a separate agreement from the property lease or combined with it in one agreement, although the latter is not preferred (see *Energy Services Agreement*).

If the business customer is a non-commercial entity such as a government, hospital, school, college or other charitable organization, the PPA model also allows the third party or its lenders to access ITCs that would be otherwise unavailable. These non-taxpayers do not have the tax attributes that would enable them to take advantage of the ITC and they need a third party to unlock the value of the credit that can be monetized and passed back to the non-profit in the form of lower energy costs.

A third-party PPA may be structured as a:

- **Take or pay**. Under this arrangement, the host site is unconditionally obligated to pay the amounts specified in the PPA whether or not the solar project actually produces or delivers any output to the host site, although in some cases, the payment may be reduced if there is no output if output is reduced materially. Take or pay PPAs are not common, however, in distributed generation transactions. The host site typically expects to receive and to be obligated to pay for power it actually receives. In addition, one of the main purposes of having a solar project on-site is to reduce the amount of electricity that must be purchased from the utility or other third-party provider. Host sites do not want to be in the position of paying the project developer and a utility or other third party for electricity it needs.
- **Take and pay**. Under this arrangement, which is less burdensome for the host, the host is obligated to take and pay for all output actually delivered by seller, but does not have to pay for any output not actually produced or delivered. This approach is more common in PPA transactions.

Utility- or Grid-scale Projects PPAs

In a grid-scale PPA, the seller of the electricity is the owner of a ground-mounted PV installation or CSP project who typically sells the electricity generated by the project to a utility or into the wholesale power markets. A utility-scale PPA, however, raises many issues that are beyond the scope of this Note, including:

- Permitting.
- Interconnection and transmission.
- Pricing.
- Commencement of service.

Similar to distributed generation facilities, a utility PPA may be structured as a take or pay or a take and pay contract. Take-or-pay contracts are typically used in a power facility financing to protect lenders or bondholders because they provide a guaranteed revenue stream to the project developer that lenders can rely on to support repayment of any loans they make. However, the take or pay structure has fallen out of favor in the aftermath of litigation in the early 1980s in which courts voided take or pay contracts that many utilities had signed to support the building of their nuclear power plants.

The typical PPA structure in the solar industry currently is take and pay. Solar project developers are unlikely to find buyers in current markets willing to undertake commitments to make fixed payments, whether the seller delivers any units of power or not. If the construction of the solar facility will be project financed, the developer typically looks for a creditworthy offtaker, possibly with obligations backed by guarantees, to attract lenders and equity investors.

For the links to the documents referenced in this note, please visit our online version at http://us.practicallaw.com/7-522-8476.

For more information on renewable energy, search for the following resources on our website.

Practice Notes:

- Renewable Energy: Overview (US) (http://uslf.practicallaw.com/4-518-1338)
- Understanding Renewable Energy: Wind (http://us.practicallaw.com/6-504-0856)
- Understanding Hydraulic Fracturing: Issues, Challenges and Regulatory Regime (http://uslf.practicallaw.com/8-518-4410)
- Understanding Renewable Energy: Solar (http://us.practicallaw.com/2-519-8033)
- Wind Energy Project Development Issues: Preliminary Considerations (http://us.practicallaw.com/9-521-9174)