Stoel Rives LLP

Fifth Edition

THE LAW OF SOLAR

A Guide to Business and Legal Issues

Compliments of

Stoel Rives LLP

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WELCOME TO

THE LAW OF SOLAR

Dear Member of the Solar Community,

The past few years have been transformational for the solar energy industry in the United States. Where previously solar energy was on the fringes of energy generation, it is now mainstream. Where previously solar energy accounted for only a tiny share of energy generation, it now generates a significant portion of the energy in many markets. Where previously solar energy was only for select regions, it is now found across the country. Where once solar energy was a political statement, it is now a sound financial decision.

The growth of the solar energy industry in America over the past several years has been phenomenal. Increased and expanded renewable portfolio standards have contributed to this growth, as has the sharply reduced price of solar modules.

As prices continue to drop, power buyers large and small have found solar energy to be an effective cost-saving measure. In more and more markets, solar energy has reached "grid parity" at the retail level, and is in the process of breaking that barrier at the wholesale level as well. Solar energy may be close to a major tipping point, which could lead to even more accelerated growth.

That is not to say that there have been no challenges. There has been resistance and counter-reactions, including proposed or enacted changes to net metering rules, solar-favorable tariff structures, and legal challenges. These efforts have left parts of the country far behind in the solar revolution, but they also create opportunities for future growth.

The sharp reduction in prices that has benefited customers and developers has been hard for manufacturers. Even as the industry as a whole has expanded, the past few years have been challenging for suppliers, and many once-familiar names are no longer present in the market. At the same time, a pricing battle is being fought with tariffs and trade sanctions, bringing our corner of the power industry to the forefront of international policy and politics.

But regardless of the larger politics and economics, we still must build projects one at a time, working within the real-world constraints and requirements. And solar energy projects, like other renewable generation projects, are subject to a plethora of real property issues, regulatory and permitting requirements, interconnection issues, power purchase negotiations, financing challenges, tax matters, and construction contracting.

Recognizing these challenges, and as part of our commitment to the growth and success of the renewable energy industry, in 2003 Stoel Rives developed its first publication in *The Law of* series. Today we are

introducing a revised and updated fifth edition of *The Law of Solar*, the newest installment in our continuing efforts to provide easily accessible information for individuals and companies interested in growing America's renewable energy resources. This guide contains insights we have gained from practical experience assisting participants in numerous solar energy projects covering a diverse range of sizes and installations, as well as our experiences serving the U.S. renewable energy industry.

We hope you find this guide useful. Please note that PDF versions of this document are available for downloading at no charge via our website, ***www.stoel.com/lawofseries***.

Let us know how well it serves your needs—any suggestions or comments on how it could be improved are most welcomed. Also, you can follow our summaries of and comments on important developments in the industry through our **Energy Law Alerts** (www.stoel.com/subscribe) and in our **Renewable + Law Blog** (www.lawofrenewableenergy.com).

Morten Lund
Partner
morten.lund@stoel.com
(858) 794-4103 (San Diego)

Chapter One
THE LAW OF SOLAR
—Solar Project Property Rights: Securing Your Place in the Sun—

Eugene A. Frassetto, Sarah Johnson Phillips

Developing and operating a successful solar energy project requires more than having the latest solar technologies. Low-maintenance, high-return projects start with securing long-term project site rights under leases or easements that ensure control of the land for all necessary uses, undisturbed access, exposure to solar rays, and flexibility for project modifications based on rapidly emerging technologies or market changes. The form and substance of solar leases and easements vary based on the type of system (photovoltaic ("PV"), concentrated photovoltaic ("CPV"), or concentrated solar power ("CSP"), for example), the type of installation (rooftop or ground-mount), the business model and practices of the developer, applicable law, and the type of landowner or host (not-for-profit, commercial, residential, or utility-scale). In light of these and other variables, this chapter focuses on a few common but key issues: establishing the scope of rights and property under a site lease, easement, or government right-of-way; addressing critical title problems; and addressing water rights, statutory solar easement requirements, and other real property matters.

I. Distinguishing Land Rights and Identifying Project Needs. Among the first steps in developing a solar project is securing rights to the land needed to construct, operate, and maintain the project. Typically, site rights are established through a lease or easement agreement. In order to maintain the deductibility of land cost for federal income tax purposes, it has usually, historically been best that the project entity not acquire fee title to the land. For large, utility-scale CSP and other large projects, however, purchasing fee title may have economic and water rights advantages or avoid limitations on the duration of leases or easements. Project counsel should be mindful of the relative advantages and disadvantages of leases and easements in various states. These issues can range from differences in tax treatment to nonrecognition of easements for possessory uses or limitations on the types of easements available in a particular state. For rooftop PV systems and small-scale ground-mounted systems, an easement agreement can offer a secure right to use areas of property or buildings that are also occupied and used by others. Large-scale PV, CPV, and CSP projects may be better served by leases that secure exclusive occupancy for the project, though easements may be sometimes used as well, with similar terms and effect. Project developers should examine their project needs in terms of unobstructed spatial requirements; exclusivity; the distribution, transmission, or use of the power generated by the project; energy storage; and resource demand (such as water, surplus power supply, and thermal energy storage). An exception to the general concerns regarding rights to land is when the project is structured as an equipment lease, generally in connection with an installation on a host entity's building(s). In this case the project owner/lessor may not have a recordable interest in the project site but will instead have access rights described in the equipment lease. This structure differs from the site lease or easement approach in several ways, which should be discussed with counsel.

A. The Solar Project Property Agreement.

1. The Purpose and Scope of the Interest. Lease agreements provide the broadest occupancy and use rights for a project site and are the most common site-control vehicle for CSP and CPV projects and ground-mounted PV systems. A solar lease agreement should provide the developer with unrestricted access to and from the property and the exclusive right to use the leased property for solar energy development. Developers generally do not share the leased property with other occupants or even the landowner because, unlike wind energy projects that allow for compatible simultaneous uses of the land, solar projects are land-intensive, dense facilities, and typically require that the developer have exclusive use of the property. While some sheep grazing may be possible and can be useful in managing vegetation among certain solar arrays that are four feet off the ground or higher, developers are generally well served to lease on an exclusive basis property that is wholly unoccupied. On the other hand, leases may be less suitable for certain rooftop PV systems or shared spaces (*e.g.,* garages and parking lots), because the developer/project entity is not the only occupant of the space, or in states where use of a lease has other adverse effects. In rooftop and shared space situations, a lease that gives the developer control of the site, and the coextensive responsibility for the site, may exceed the needs and comfort level of many developers.

Easements can be ideal agreements for rooftop and smaller-scale PV projects when the project developer and the project share a larger space with the landowner or third parties. An easement is a real property interest whereby the landowner grants to the developer a right to use the property for a specific purpose. The form of easement typically cannot be unilaterally revoked without cause by the landowner and can be pledged by the developer as security for financing. A typical rooftop shared space easement secures to the developer a right to enter and use the property and is defined by a scope of use, exclusivity (or nonexclusivity), a term, and certain responsibilities and rights of each party to the easement. A mere license or revocable permission to conduct an activity on the property is not generally considered a real property right and is unsuitable for establishing most project site rights.

Easements, while sometimes mirroring the terms and conditions of a full-blown project lease and used for stand-alone, utility-scale solar projects, also can be well suited for rooftop or shared-space installations because they ensure the developer's use of a portion of a larger piece of property or building, while limiting the developer's responsibility for areas outside of its use. Whether one uses a lease or an easement as the site-control agreement for a utility-scale project, the table of contents and terms and conditions of the agreement will be very similar. The basic site-control issues for a solar project are the same regardless of the technical form of the site-control agreement.

2. The Scope of Property Subject to a Solar Project Property Agreement. A solar developer will want to ensure that it contracts for sufficient land to access, develop, and operate its project; to protect its project facilities from dust, dirt, debris, vandalism, shading, and other outside forces; and to provide flexibility in selecting the precise location for the system and any ancillary facilities. However, unlike wind projects and some ocean and tidal projects, solar projects are land-intensive, dense developments. A typical wind project uses, on average, one acre to produce one

megawatt of energy. A wind developer might lease a 50-acre parcel and use 10 percent of it. In a typical wind project, the landowner may continue to use the remaining portion of the larger leased premises for agriculture or other uses that do not interfere with the project operations while profiting from the wind power produced on the leased land. On the other hand, solar projects can require up to five acres for every megawatt produced, and the solar facilities usually occupy (or the landowner is generally denied entry to) virtually the entire project site. Depending on the amount of additional land the landowner has and the size and location of the solar project on its land, there may not be any remaining, usable land for the landowner's own use. Consequently, the landowner may have more concern for the location and configuration of a project that uses less than all of the landowner's contiguous lands to preserve access to and use of remaining areas that may still be put to productive use by the landowner.

3. Potential Resolutions to the Scope of Land Requirements. In utility-scale solar projects, there are few alternatives to leasing or otherwise acquiring secure control of large amounts of land and retaining exclusive control over those lands for the life of the project. As mentioned above, unlike wind development projects in which the landowner retains the right to use the property not occupied by wind facilities for farming or other noninterfering uses, solar projects often entirely preclude any coexisting agricultural or other active use of the developed project area by the landowner. The landowner is likely to lose all productive use of lands leased to a solar developer. Thus the payment for the use of the project site will not be ameliorated by any offsetting additional income or benefit the landowner might otherwise obtain from joint use of the site. As a result, lands with low agricultural or mineral value are better situated for lower land rents and to potentially allow a developer a better marginal return, though in high-demand or uniquely situated properties with high-value solar characteristics, the value may be set by the solar development value of the site as its highest and best use. The savvy developer will research the value of the land and its potential uses, and be prepared to negotiate an agreement that provides an attractive income stream to the landowner in light of local market conditions while maintaining profit margin for the prospective project.

Regardless of any alternative-use value of a particular property, reaching agreement on the amount of land subject to the agreement, the payments and other terms and conditions of the agreement will involve a number of factors. Most common payment terms are tied to the number of acres of land under contract, the type(s) of improvements intended for the particular site, the amount of energy produced by the project, and what other interests or properties of the landowner may be disturbed or used in the project for access, transmission, operation and maintenance, or other facilities. In addition, a site-control agreement may give the landowner comfort that the developer will minimize the project's impact on the land and make available any unused space for other uses by the landowner. For example, an agreement may provide:

- A minimum annual rent payment based on the amount of acreage under contract. In an agricultural area, this rent may be based on the land's agricultural value or other highest and best use value, whichever is greater.

- A power sale revenue-based payment to be made if and to the extent a negotiated percentage of the payments received by the developer from energy produced and sold by the project in a particular year exceeds the minimum annual rent payment for that year.

- An agreement by the developer to consult with the landowner during the project's scoping stage regarding the location of the project and its related facilities. Sometimes, certain sensitive areas of a larger parcel are made off-limits for certain types of development in the agreement itself or carved out of the land subject to contract in the first place. Consulting with landowners can give more comfort that their concerns will at least be heard and considered in the siting process. Notwithstanding the consultation provision, the agreement will typically make clear that the developer is the final arbiter on where, whether, and when to locate project facilities within the project footprint. Again, for solar projects, the facilities generally occupy (and preclude other use of) the entire project site.

- An agreement by the developer to release lands that are not necessary for the project from the site-control agreement once the project's final scope, configuration, and location are determined. Often, such a release would not release the protective provisions relating to noninterference with the influx of solar radiation to the remaining project site and would also reserve access, utility service, and transmission or collection easements or rights serving the project site if the remaining project site did not directly abut the existing, public access and utility/interconnection/transmission routes and facilities serving the project.

- An agreement to allow exploitation of mineral, oil and gas, etc., resources of the subject property so long as such did not involve any entry onto or disturbance of the surface of the project site or of the developer's access, facilities, or operations. For instance, the agreement could allow directional drilling for oil or gas from a remote location so long as such activity did not involve explosive or concussive methods or other methods that could affect the surface use or cause or contribute to subsidence, involve any entry or activity above 500 feet below the surface, or otherwise affect the use or operation of the site or project facilities.

4. Easements: Project-Wide and Ancillary Rights. An exclusive easement will give a developer the sole right to use a portion of the landowner's larger property, much the same as a lease would. Easements are often used where the landowner's property may have other users, such as when a project is located on a roof or over a parking garage. In order to protect the developer's investment, as with any adequate site-control agreement, the easement must ensure that the landowner

and third parties will not interfere with the developer's use. Key components of a solar project easement include, among others:

A Specific Term. Easements can be perpetual in nature (for so long as the allowed use continues), whereas leases generally are established for a set period of time (though many states recognize perpetual leases where the intent to create a perpetual leasehold is clearly set out). Developers using an easement for a solar project, unless there is a reason to make the easement longer or perpetual (subject to developer's termination rights), typically include a term of 20 to 30 years, with extension rights, as they would under a lease.

A Right to Install Fixtures and System Equipment. As with a solar project lease, a solar project easement should include explicit rights to install, inspect, repair, replace, operate, improve, alter, expand, relocate, and remove all project equipment and related fixtures, which are to remain at all times the property of the developer.

A Clearly Delineated Scope. Rooftop projects and projects sharing common boundaries with unrelated facilities (for example, box stores, parking lots, and garages) may require only portions of the building or facilities for the actual project, but the developer and its installer will need access to and from the project area and the construction equipment areas, as well as utility and transmission rights. These rights should be clearly delineated in the easement agreement to protect the developer's investment and put others on notice that, even if the host facility is closed or a stairwell is off-limits to the public, the developer still has the right to access and use those areas.

As part of the scoping of a project in a shared-use situation (such as a rooftop project), developers will want to give careful consideration to the myriad uses and needs they may have throughout the entire life cycle of the project, including the periods of resource assessment, construction, operation and maintenance, and ultimate removal or decommissioning. Construction, ongoing access, and the right to move, repair, and replace equipment for the life of a project are just a few of the considerations to take into account when crafting an easement.

Every project agreement should also include access, transmission, and other rights, on- and off-site, that are needed for the development and operation of the project. Developers should work with landowners to create mutual noninterference provisions and establish access and use rights that protect the developer's project while accounting for other ongoing uses or needs of the property.

Finally, because of the more open access or close proximity of use often available to third parties, rooftop and parking structure installations have certain considerations not applicable to more isolated and secured system installations. Project site agreements should account for damage to systems from vandalism or from the landowner's invitees or others; responsibility for roof or parking lot maintenance, including any costs associated with resultant system shutdowns; and ongoing access to sunlight. See Section III.B below.

B. Alternative Land Rights: Fee Interests; Federal and State Lands. Utility-scale CSP and PV systems are uniquely suited for large swaths of flat land. With current technology, the slope of most project sites should not exceed 1 percent, though some CPV systems can be installed on rougher terrain. Relatively flat, wide-open spaces in areas with plentiful sunshine call to mind the Southwest, the plains states, and inland rural areas of California. Ownership of these lands runs the entire range of private landowners; federal, state, or local governments; or Native American tribes.

State and federal lands are under the jurisdiction of the departments of state lands and the Bureau of Land Management ("BLM"), respectively. County, city, and other state-subdivisions are governed by the applicable state statutes and local ordinances. Each state and local jurisdiction has a unique scheme for leasing or licensing the use of its public lands, as does the federal government. Many of these departments are well acquainted with granting grazing or mineral rights but can be less familiar with the installation of large-scale solar projects. Developers should explore the various forms of land-control rights available from the applicable government authority for the land at issue.

BLM regulations specify procedures for obtaining site rights, called right-of-way ("ROW") grants on BLM lands. The regulations allow resource assessment, construction, and project operations. They provide for project-specific rent (based on appraisal, with a phase-in period during project development) and terms of the grants (generally not to exceed 30 years, with an option to renew). For utility-scale solar projects, the BLM has created a separate Solar Energy Program. See http://blmsolar.anl.gov/. The purpose of the program is to support the responsible development of utility-scale solar energy projects on BLM-administered lands in the six southwestern states. Under the Solar Energy Program, the BLM has classified about 79 million acres of BLM lands that are excluded from solar energy development and also identified about 285,000 acres of BLM lands as priority areas, or Solar Energy Zones, that are suitable for utility-scale solar projects. So far, the BLM has approved 19 Solar Energy Zones across California, Nevada, Arizona, Colorado, Utah, and New Mexico and may identify new zones in the future. New applications for utility-scale solar projects are processed in accordance with the BLM's Record of Decision for the Solar Programmatic Environmental Impact Statement. Multiple applications for the same land can trigger a competitive process. The process includes BLM consideration and approval of a detailed Plan of Development for each project and full environmental review in compliance with the National Environmental Policy Act. BLM's final Record of Decision on solar ROW grants may be found at http://blmsolar.anl.gov/documents/docs/peis/Solar_PEIS_ROD.pdf.

The various available means for securing site rights on public lands should be examined, and any potential drawbacks evaluated based on time, lack of exclusivity, and costs to ensure that the project's long-term value is maintained and that the investment is protected from vandalism, potentially disruptive uses (shading), or other interference during the life of the project. Because governmental authority is often limited by, and agreements with those authorities are often subject to limitations imposed by, statute, ordinance, regulation, charter, or constitution, one must be familiar with the implementing statutory and other laws applicable to the particular arrangement. Statutes, constitutional provisions, and other applicable laws often specifically override any contrary provisions

of a written contract, so reliance solely on the text of a site-control agreement for these lands may be deceptive.

Leasing or obtaining ROWs on Native American tribal land is an attractive possibility in areas where the tribes own or control large areas of land suitable for solar development. Developers should be aware that leases and ROWs on Native American tribal land require approval by the Bureau of Indian Affairs ("BIA"). Any agreement that encumbers tribal land for a term of seven years or more triggers BIA review. Projects sited on Native American tribal land are also subject to federal environmental and other statutory review requirements. For example, projects on Native American tribal land, as with federal lands, will almost always require an environmental assessment under the National Environmental Policy Act. Thus, as part of the initial siting evaluation of a project, developers should assess sacred sites (including burial grounds, native plant harvesting areas, and ceremonial locations). Developers should consult with the tribe itself regarding unique or archaeological resources on the proposed site. Each tribe is in the best position to evaluate and determine which sites have cultural relevance to that tribe and to weigh the potential issues associated with leasing such lands for solar projects. Also, whether or not a project is to be located on tribal lands, project sites including or near potential or known cultural resource sites will also typically require consultation with the applicable tribe(s) as part of the permitting process.

When exploring potential projects on Native American tribal land, as with federal lands, developers should account for the time that likely will be involved for federal agency review and approval, plus any associated environmental and cultural resource studies. These may add significant cost and time to a project's development period and construction. As with the various state and local governments, tribes also have their own laws and rules that vary from tribe to tribe. Attorneys, local staff, and tribal contacts who are knowledgeable in tribal land leasing requirements and the intricacies of permitting and siting projects on particular tribal land are invaluable resources for navigating the statutory requirements and any review or permitting specific to the land at issue.

II. Overcoming Title Roadblocks. Securing an interest in property for a solar project requires more than just a signed solar project property agreement. If a rooftop or utility-scale project site is encumbered by existing leases, easements, mineral rights, or other interests, the project developer takes its interest in the land or site subject to those existing rights. Unless discovered and dealt with early on, third-party rights that prohibit or potentially interfere with or limit the project can result in significant delays, liabilities, losses, and costs to the developer. Accordingly, the developer should obtain and carefully analyze a search and examination of the title to the project site along with a complete, detailed survey of the site and proposed location of project facilities, and purchase a policy of title insurance to help protect its investment in the project. These principles apply equally to a new acquisition (including acquisition of the equity interests in an existing project entity, where there are additional, special title insurance concerns) or the financing of an existing or to-be-constructed solar energy facility.

A. Title Review. It is fundamental that for a complete review of title, one must obtain all documents in the public record and off-record agreements relating to the proposed project lands to

(1) determine the person(s) or entity(ies) vested with title, (2) determine whether the title is subject to liens or mortgages that create unacceptable risks to the solar project, and (3) discover all encumbrances, such as easements for utilities, road rights-of-way, mineral and timber rights, or other interests held by people or entities other than the landowner that might prevent, limit, or interfere with construction or operation of the project as planned. Beyond review of available documentation, a developer would be deemed to have notice of (and will take subject to) the rights of parties in possession of the subject property or whose rights could be ascertained from a visual inspection of the subject property. Such indicators of potential third-party rights could be a road or utility line crossing the subject property without a corresponding recorded easement (hence one aspect of the value of a complete survey), the actual physical presence of third parties on the land, or signage, vehicles, or the like on the land that indicates a third-party presence or interest. It is critical to obtain the title information as soon as possible and review it thoroughly to make certain that all interests of record and off-record are discovered, disclosed, and analyzed carefully. Insurable title to the lease and/or easement is a key factor in successfully financing, selling, or syndicating a project as well as a prudent precursor to any project development or purchase of a project or a project site control position.

B. Determining Whether to Undertake Curative Measures. Once all of the information contained in the preliminary title reports or commitments for title insurance, the survey(s), and all off-record agreements relating to the site have been reviewed, it is necessary to cull those title issues that must be corrected or cured from those that will not impair the vitality of the project and may be permitted to remain. If a leasehold or easement interest is obtained from someone claiming to own the land, when, in fact, the fee simple title of record is vested in another (or otherwise known to be vested in another, even if not of record), the title company will require correction of the title and/or the affected site control agreement before a policy can be issued. Some things are as easy as a mere name change, which can be dealt with by a recitation that the person was “formerly known as” or “who took title as” or the like. Others may require further documentation, such as the death of an owner of record before probate and disposition of the project property interest of record to the heirs or devisees. If the owner had held a survivorship estate with other co-owners, resolution may be as simple as recording a death certificate. Most often, mortgages must be addressed in some manner that will permit the lender’s interest to coexist with the project, while ensuring that the project is not subject to foreclosure by the prior mortgagee. Easements or rights-of-way can also be problematic—some must be adjusted or a side agreement entered with the easement holder to allow access to or construction and/or operation of the proposed project or related facilities or uses, whereas others may not create any risk to the project and need not be addressed. All such interests should be carefully reviewed and any potential problems dealt with before proceeding with any development on a project.

C. Curing Title Defects. After identifying potential title issues that need to be addressed, one must analyze the range of curatives to address the issue, determine the most efficient and effective means to that end, and negotiate appropriate documentation to resolve the matter. For existing mortgages, developers should work with their attorneys and the title company to evaluate whether a subordination agreement is required, which can be difficult or impossible to obtain from institutional

and other lenders, or if a nondisturbance agreement will suffice. For existing easements, the developer should evaluate whether a consent and crossing agreement is necessary, or if the easement holder will modify its easement to allow the solar project or related facilities to cross or overlap the easement area or limit the area of a blanket easement to avoid overlapping any project facilities or access.

A utility, a lender, another landowner, or some other person with a pre-existing lien or encumbrance on or an interest in the project property may not always be interested in helping to solve the developer's title problem. Nevertheless it is often necessary to secure that person's cooperation and agreement to deal with the issue in the most effective and complete way. Parties with a legal interest in a project site may hold such interest for the long term. Initiation and maintenance of good relationships with such parties may help to resolve and avoid problems throughout the life of the project.

D. Mineral Rights. Mineral rights that are not subject and junior to the developer's site control agreement present a serious challenge to developers of utility-scale projects. Projects located or sought to be located on lands with existing mineral rights holders, such as oil and gas companies, railroads or their successors, or other persons or entities, including governmental bodies, can be at risk of forced removal or destruction of the project facilities, depending on the circumstances, the applicable law, and the terms of the mineral right.

Broadly speaking, the term "mineral rights" refers to the privilege of exploring for, extracting, exploiting, processing, selling, and earning income from the removal and sale of oil, gas, and other valuable mineral resources found under the surface of the land. Note that mineral rights are rights to the applicable substances included in the right, whether at or below the surface of the land, and do not necessarily indicate that the mineral owner also owns the surface of the land. However, the mineral rights owner generally has the superior right to use as much of the surface as is reasonably necessary to extract the minerals ("surface rights"). Absent an express limitation on such right in its granting instrument, or a release, waiver, or subordination of mineral rights by the holder, or an agreement not to interfere with the solar project operations, the presence of mineral rights can be a significant obstacle to project development, financing, syndication, or sale. It is often possible, however, to insure title around mineral rights that are shown to be ancient, untraceable, or otherwise abandoned or of a nature or in a jurisdiction or location where such rights are unlikely to be (or allowed to be) exercised to the detriment of the surface use.

On occasion, the holder of mineral rights may be willing to relinquish or limit its surface rights. One option is to enter into a long-term lease under which the mineral rights owner waives surface rights in exchange for a royalty based on project revenue, similar to landowner rent. More often is some sort of surface use waiver or agreement that allows peaceful coexistence of the solar project and the mineral operations, but on different areas.

E. ALTA Energy Endorsement Series. Energy projects, including solar and other renewable energy projects, built on leasehold or easement site control agreements have certain unique attributes requiring different coverage than what has traditionally been available through a standard

American Land Title Association ("ALTA") title insurance policy in a transaction involving acquiring fee ownership of a project site. A traditional policy of title insurance on a leasehold or easement interest typically covers the real property interest insured under the policy (the leasehold rights or easement rights in the land described in the policy), but does not insure any improvements or other facilities (such as the collection system, transmission/collection lines, transformers, switchgear, etc.) installed by the tenant/easement holder and that the tenant/easement holder will or may remove from the site during or at the end of the lease term, which are deemed tenant's trade fixtures and characterized as personal property. Neither does a typical title policy take into account that such improvements are part of an integrated system in computing damages for an insured loss. In addition to the general rule regarding tenant trade fixtures, most solar project site control agreements specifically provide that the project facilities will at all times be and remain the sole separate property of the tenant and not part of the real property. ALTA policies do not insure title to nor provide for damages for the loss of personal property, and the majority of a leasehold or easement energy project's infrastructure value is in facilities that are likely considered personal property. Further, the basic ALTA title policy forms do not account for claims that arise from improvements to the land constructed after the policy date, and special endorsements to the title policies are required to address these characteristics.

F. ALTA 36 Energy-Project Endorsements. To address the unique needs presented by energy project development, ALTA created a new series of endorsements for energy projects that went into effect in 2012. The ALTA Series 36 (Energy Project) Endorsements ("Series 36 Endorsements") address certain issues that are particular to energy projects. Among other attributes, the Series 36 Endorsements: (i) expand coverage to account for loss to an integrated project where a covered claim might affect less than all of the covered property, (ii) extend coverage for losses arising from improvements constructed after the date of the title policy, (iii) consider the effect of any loss on "Severable Improvements" (which are considered part of an "Electricity Facility" but may be characterized as personal property), and (iv) include an "Additional Items of Loss" section tailored specifically for energy projects. The Series 36 Endorsements may not be available in all states; however, the title company you work with may be able to provide modified coverage under a traditional policy to account for such lack of availability. Project counsel should be well versed in the new title coverage available for energy projects and adept at working with title insurance underwriters working with renewable energy projects. Such coverage is likely a necessity for the financing, sale, syndication, and development of future projects.

III. Other Potential Property and Land Issues.

A. Water Rights for Concentrated Solar Power Projects. Water rights can be a concern regardless of the type of solar project. Every project likely has a need for water at some point in its life span. Where a project site control agreement grants or includes water rights in the project rights and the agreement or applicable law disallows waste, the developer will have to figure out a way to keep the water right in effect without forfeiture or limitation and without using the water for purposes not allowed under the applicable water right. For instance, a water right for irrigation use on a particular

area of the project site most likely cannot be used to support project activities or facilities, other than perhaps irrigation of vegetation in the prescribed area, or be applied for any purpose other than irrigation or at any other place. CSP projects have special water concerns beyond liability for waste or potential forfeiture. Water requirements for CSP projects require careful consideration and planning. When a project is located in a semidesert or desert environment, solar radiation is plentiful, but water may be scarce or severely limited. Project developers should give early and careful consideration to the water requirements for the proposed CSP project and potential sources. A few of the critical questions to ask include:

- Is there a source of water currently in place on the property—a surface source (such as a river or canal), a municipal source, or a groundwater well?
- If there is no surface source, is water available from an aquifer or a local source?
- Do the available water rights allow the water to be used at the place(s), in the quantities, at the time(s), and for the purpose(s) desired by the developer?
- Are there available alternative uses that the developer can take advantage of to ensure that the full amount of water required to be used to preserve the right can be lawfully used and applied to avoid forfeiture or other penalty?
- If water rights must be acquired, are such rights available, both legally and physically? What is the process and timing to acquire and perfect those rights?
- What water laws and restrictions will affect the ability to obtain water for the project?
- If a well or surface diversion or any storage is required to bring water to or store water for the project, what water rights or permits and easements are needed, and how much time is needed to obtain those rights?
- What are the ramifications of water use for permitting and environmental review of the project?

A clear understanding of a project's water needs, the availability of water at a project site, and the time and cost involved in obtaining water is essential to establishing a project's construction and operation timeline, budget, output, and, ultimately, feasibility.

B. Access to Sunlight: State and Local Government Laws. Approximately 40 states have passed laws or taken measures to promote the installation and use of solar energy systems. The states have two primary mechanisms for ensuring that solar projects can access sunlight to operate the system:

1. Allowing neighboring property owners to voluntarily grant solar easements that, like any other property right, must be documented and recorded in accordance with local requirements; and

2. Outlawing the imposition of prohibitions on the placement of a solar power system in a community, or outlawing the imposition of unreasonable restrictions on the placement of solar facilities such that their installation, operation, or functionality is adversely impacted.

Any grant of a property right must contain certain legal elements no matter where the property is situated. Many states require the grant of a solar easement to describe a range of items, including the dimensions (solar envelope) of the easement, the estimated amount of sunlight directed to the system, any permitted shading by vegetation and other plantings, the corresponding reduction in access to sunlight, the property benefitted and burdened by the easement, and, sometimes, the compensation to the grantor of the easement. The solar easement must also contain any state-specific requirements. A state's focus may be affected by weather, terrain, or the character of the area. Some states and/or local governing bodies can be height- or design-sensitive (California, Colorado) or locale-sensitive (Hawaii), or may focus on visibility and placement (North Carolina), orientation (Wisconsin), zoning (Rhode Island), or setback issues (Oregon). Any terms or conditions for revising or terminating the easement should be included as well. The contracting parties may include their own remedies for breach of the easement, allowing a court to order any interference with the system to stop and awarding damages for the capital cost of the system, any additional energy charges caused by the breach, and attorneys' fees and costs.

Chapter Two
THE LAW OF SOLAR
—Power Purchase Agreements: Distributed Generation Projects—

Jason A. Johns, Morten A. Lund, Jennifer H. Martin

I. Introduction. The term "distributed generation" is applied to a wide range of facilities using different technologies and varying in size. Due to the sheer variety of solar energy facilities, it can sometimes be difficult to define what is "distributed" and what is not. Perhaps the most common element of distributed generation projects is that they are located on-site. They will typically connect "behind the meter" to the site owner's building systems, aka the "site host." Connection to the grid "at the meter" is still important for the site host, though, because of the need to access electricity supply when the distributed generation facility is not generating or is not capable of meeting the full needs of the site host. Complicating the issue further is the recent expansion of virtual net metering and community solar programs, both of which share some features with on-site projects and utility-scale projects. For our purposes here, we will focus principally on on-site facilities.

For distributed generation solar photovoltaic ("PV") installations, the on-site nature of the project is typically a far larger complicating factor than the intermittent nature of its output. Unlike larger utility-scale projects, distributed generation solar PV may be located in either urban or rural areas, on rooftops or on the ground, on larger structures or on smaller structures, with clear solar access or in congested areas. In addition, the site host may or may not be the power purchaser. Consequently, there is a significant potential for strongly conflicting interests between the passive host with a limited interest in the project and the power purchaser that wants the project output, in regard to what each is willing to accept as reasonable risk allocations with the project developer.

Every distributed generation solar project requires at least two fundamental commitments from the site host and/or the offtaker. Every project needs site rights sufficient to allow the developer to build, operate, and maintain the solar installation on the site and an agreement for the purchase and sale of the power generated from the solar installation. If the power purchaser and the site host are the same, it makes little difference whether the relevant provisions are put in the site lease or the power purchase agreement ("PPA"). However, the site host can lease or sell the premises, thereby changing the identity of the host and party to the site rights agreement. Accordingly, there is no single solution for all situations. In addition, there may be situations where a license, or right to use the project site, may be preferable to an actual lease of the site. The potential for this issue is particularly present when the site host is a municipality or other type of governmental entity.

To distinguish the particular nature of distributed generation facilities and from larger utility-scale projects, we have split our discussion of PPAs into two parts. The first part discusses distributed generation solar PV PPAs and is presented in this chapter. The second part discusses solar PPAs in the context of larger utility-scale projects. To the extent that there are issues in common, the first part will

refer the reader to those sections of Chapter 3, Power Purchase Agreements: Utility-Scale Projects for discussion of those issues.

A. The Parties.

1. The Project Owner/Seller. The ownership of a distributed generation solar PV installation is a tax-advantaged investment. As a result, protecting and enhancing the available tax benefits is as important as maximizing revenues. Both are essential to a successful project, and equal consideration should be given to tax benefits and revenue protection. This may change in the not-too-distant future. The federal investment tax credit for solar is set to start phasing out in 2021, and after that the priorities may change. But for now the solar PV market largely relies on the federal investment tax credit, and our discussion below is therefore premised on the application of federal investment tax credit provisions.

To facilitate the pass-through of tax benefits and available subsidies, the project owner/seller in a distributed generation solar PV project will almost always be a limited liability company. The entity will expect to be able to pass through to its members the tax benefits, revenues from power sales, and revenues from the sale of Renewable Energy Credits ("RECs") that represent the environmental benefits and attributes of the non-carbon-based electricity generation. Depending on the particular forms of subsidy (such as state tax credits, state cash subsidy payments, or solar carve-outs in state renewable portfolio standards designating the amount of generation local utilities must derive from renewable sources by certain benchmarks), the project owner may have more or less interest in actually owning the facility after the tax credit recapture and direct subsidy period has ended (though there are other tax considerations relating to the "profit motive" test that may require the project owner/seller to maintain longer-term ownership of the installation). In other words, the project owner/seller typically has little interest in actually operating or structuring itself as a utility. Solar PV lends itself well to this lack of interest in being a "real" power generator since solar PV is generally considered to have an extremely low level of required maintenance and an extremely high level of reliability. Consequently, the project owner/seller wants to minimize risks to its expected stream of tax benefits, power sales revenues, and REC sales, particularly those that the project owner/seller considers to be within the control of the site host or power purchaser to prevent or avoid.

The project owner/seller's ability to pass through the tax benefits to third parties is fundamental to a tax equity investor being willing to provide financing to a transaction. The tax equity investor typically has an even larger desire to exit the transaction after the tax and subsidy benefits have been exhausted than a developer/owner. For this reason, many distributed generation solar PV transactions have been structured using a "flip structure" where the tax equity investor starts with typically 99 percent of the ownership interests in the pass-through project-owning entity, which "flips" to a 5 percent interest after the tax equity investor has received the return on investment that has been negotiated between the parties.

Additionally, and regardless of the specific structure utilized, the party that expects to receive the federal investment tax credit must be the "owner" of the installation on the date the installation is "placed in service" for federal income tax purposes. Consequently, all structures for distributed generation solar PV projects are premised upon the need to have the tax equity investor in ownership prior to the placed in service date. Many potential investors want to avoid any construction period risk by delaying their contributions until after the installation is completed and has proven to be functioning in accordance with its intended design specifications. Project developers should be aware of the problems that can arise if the investors are not willing to put any funds at risk prior to completion of the project.

2. The Buyer. The power purchaser typically is interested in reducing its energy costs at a specific location. This can be a single manufacturing facility, an office building, an automobile dealership, a warehouse, a school, a hospital, or a public facilities maintenance building. As the market is realizing, there is an enormous opportunity to place safe and passive solar PV installations in a wide range of locations. The main physical constraining factor is available useful space. In addition, various state regulatory hurdles often make it difficult to install the full capacity a site host could physically accommodate. See Chapter 5, Regulatory and Transmission-Related Issues. For these and other reasons, the power purchaser from a distributed generation solar PV facility will usually be a party with a long-term commitment for a large facility, who is looking for a long-term plan to fix and reduce energy costs. In essence, this power purchaser just wants to receive the power with the minimum amount of additional risk and financial obligation. In previous years, solar PV buyers were principally motivated by a desire to "go green," but with the sharply reduced cost of solar energy, today the motivation is usually financial.

3. The Site Host. If the site host and the power purchaser are not the same (or closely affiliated), the site host may become a silent partner (or at least an ever-present consideration) in the negotiation of the PPA. Although not as true for a ground-mount installation, a rooftop installation is generally in place for a long time on a structure that was probably not specifically designed to accommodate a solar PV installation. This can raise a number of issues regarding (1) the timing and need for routine rooftop repair, maintenance, and replacement (including both the costs of having to move the installation to allow repair or replacement and the lost revenues from power sales while the repair or replacement is going on); (2) the possible need for structural improvements to support the solar PV array; (3) the susceptibility of the solar PV array to high wind conditions and other climate factors where it is located; and (4) the problems of changing ownership or occupancy of the structure during the term of the PPA. The project owner must recognize that these situations pose objective risks that may disrupt the production of electricity from the installation temporarily or permanently.

These risks need to be allocated among the parties in the best position to protect against their occurrence, but always in a fashion that provides sufficient protection for the project to remain financeable. This can be particularly challenging when the site host is not also the power purchaser. Such a site host will tend to not want to bear any of these costs that may be outside its normal costs and risks of doing business, such as providing for roof repair, maintenance, and replacement. At the same

time, a power purchaser that does not own the building or structure it is occupying is likely to view these as risks that it is not normally asked to assume as a "mere tenant." The fact remains that the project owner is making a significant financial investment that will depend on all of the various economic returns from the project, tax benefits, power sales revenues, and REC sales or other subsidies to make a reasonable return on its investment. No solar PV project is so economically "rich" that allocating these risks can be overlooked. To make sense of how the power sales aspect of a PPA interacts with these "other" concerns, it is first necessary to discuss how a typical PPA deals with the actual sale of output from the solar PV installation.

B. The Power Sales Aspect of the PPA.

1. Standard Terms. Most current distributed generation solar PV PPAs simply provide that the buyer will buy all of the electricity generated by the installation at the price specified in the PPA and the electricity will be delivered at the point of interconnection with the buyer's (or site host's) electric system ("behind the meter" delivery). In other words, the obligation to pay is based on the actual receipt of output at the specified point of delivery, and payment is determined by reference to the amount of output delivered. By contrast, a "take or pay" contract specifies a certain amount of money the purchaser is obligated to pay each year (expressed as a minimum volume of energy at an agreed unit price) regardless of whether the installation actually produces output. Given the host/offtakers' expectations of substituting solar energy for utility-provided energy, and the developers' interest in guaranteeing system performance, "take or pay" contracts have not found a place in the distributed generation marketplace.

2. Pricing the PPA. The electricity to be delivered under a solar PV PPA is typically priced at a set cents-per-kWh, usually with an annual escalator. The initial price is sometimes calculated so as to provide a specified discount to the current utility retail rate, but there is now significant downward pressure on PPA prices for distributed projects as module prices have dropped. Competition among providers is now the principal driver for PPA pricing. Occasionally a PPA is priced on a variable basis as a discount from utility retail rates during the PPA term. These utility-discount variable-rate PPAs are generally disfavored by financing providers, and are much less common than in previous years.

It is unlikely these considerations will change significantly going forward. Even if regulatory actions, such as passage of a cap and trade bill by Congress, cause changes in the market rate of electricity, electricity from distributed generation solar PV installations will probably continue to be priced in reference to utility retail rates.

3. Performance guarantees are fairly unusual for distributed generation projects, but they do occur from time to time. In the case of an output guarantee there will typically be a provision stating that power output will decrease annually by a fixed percentage, usually about 0.5% per year. Regardless of calculation methodology, the project owner/developer should attempt to make certain that the threshold is set low enough that it is never triggered.

4. Net Metering Expectations. Many power purchasers enter into solar PV PPAs with the expectation that any unused output can be sold to the local utility. Net metering is one way in which the power purchaser expects that it can gain a financial benefit from any excess electricity delivered by the solar PV installation in excess of the power purchaser's immediate need. Another is the potential to sell power to the local utility. In the limited circumstances the latter option is available, the price is typically at or below wholesale levels.

The PPA itself will usually not have any provisions dealing with these situations because the typical solar PV installation is delivering behind the meter for the immediate use of the power purchaser without the requirement of any use of the local utility's grid for transmission. The project owner/developer should consider including language in the PPA specifically disclaiming any responsibility for the ability of the power purchaser to net meter or sell excess energy.

Net metering and the limited circumstances in which a power purchaser may be able to sell its excess output to the serving utility are discussed further in Chapter 5, Regulatory and Transmission-Related Issues.

II. Standard Provisions of a PPA.

A. Term of the PPA. The current standard appears to be that the PPA will have a length ("term") of 20 years, though 15 years is also common. To some extent, the term is dictated by the project owner's desire to receive, or need to receive, a certain rate of return from its investment. It is increasingly common to see PPAs with terms significantly shorter than 15 or 20 years, although shorter PPAs can be more difficult to finance. It is standard in solar PV PPAs that the project owner is responsible for paying the costs of removing the installation from the site upon the natural termination of the PPA. However, if termination occurs early due to an event of default caused by the power purchaser or a termination declared by the site host, this cost typically shifts to the purchaser.

B. Installation, Testing, and Start-Up. Most PPAs contain an obligation on the part of the project owner to cause the project to be installed, set out the conditions relating to pre-operation testing, and define when the project will be considered "placed in service" (important for tax considerations and not requiring full actual operation) or in "commercial operation" (which relates to commencement of project eligibility for power sales and usually requires that the project produce and deliver electricity at the standards set forth in the PPA). The project owner will usually satisfy its obligation to construct and install the project by entering into an installation agreement with an experienced solar installer. The installer will then undertake the obligations of testing the project, obtaining certification that the project has reached commercial operation, and completing the final punch-list items necessary to perform the installation contract. Pre-operation testing for a solar PV installation is usually quite simple: hook the system up for a set period of time (usually four hours for small projects, and longer for larger projects) and meter the output to see if it is producing within design parameters. If it does, it has passed its required pre-commercial operation testing and will be considered placed in service. For more on

installation agreements, see Chapter 4, Solar Energy System Design, Engineering, Construction, and Installation Agreements.

C. Project Operation and Maintenance ("O&M"). The solar PV PPA typically will provide that it is the project owner's responsibility to maintain the installation. Several standards are usually specified, such as conformance to prudent utility practice, prudent solar industry practice, or best practices, but they all mean essentially the same thing: the installation must be maintained so that it does not pose a danger to individuals, to the structure on which it is located, or to the grid, and so that it will produce electricity in accordance with contractual expectations. The project owner will often fulfill this obligation via a third-party O&M contract. Many installation contractors also desire to handle O&M, and may extend the term of their equipment and installation warranty (two or three years, increasing to five or 10 years) if they are awarded the O&M contract.

D. Project Purchase Options. An option for the power purchaser or site host to purchase the solar PV installation at some defined point during the term of the PPA is a common feature of solar PV PPAs. As with the pricing structure, the times at which this purchase option may be exercised vary widely.

1. Purchase Option Points During the PPA Term. It is common to have a purchase option exercisable after some or all of the sixth, tenth, or fifteenth year, or on the natural expiration of the PPA. Occasionally the purchase option is exercisable at any time after the sixth year, or any time at all. Granting a continuous purchase option presents significant issues for the project owner/seller including potential recapture issues.

2. Pricing the Purchase Option. A project owner considering granting a purchase option is faced with a combination of tax considerations and economic business considerations. The principal consideration is the requirement that the purchase price be no less than fair market value. If the purchase price is below fair market value, there is a risk that the IRS will reallocate the investment tax credit to the power purchaser instead of the project owner. There are two common methods of setting the purchase price. The most common method is to have an appraisal at the time of the option exercise, and the purchase price is set as the fair market value as determined by the appraiser. Recently, it has become increasingly common to agree to a set price in advance. This set price is determined using appraisal and accounting tools to be at least fair market value at the time of the option exercise. An additional limitation is the five-year recapture period for the federal investment tax credit, during which any exercise of a purchase option will trigger recapture of a percentage of the federal investment tax credit received by the project owner. An exercise of a purchase option during this period is therefore typically not allowed. If a purchase option is allowed during this time, the purchase price will be increased to compensate for lost or recaptured tax benefits.

E. Off-Ramps Before Construction, Events of Default, and Other Common Provisions. See Chapter 3, Power Purchase Agreements: Utility-Scale Projects for a discussion of standard event of default provisions that are generally applicable to both distributed generation solar PV PPAs and utility-

scale PPAs, other than those dealing with the creditworthiness of offtakers, guaranties, and other financial accommodations, which typically are not found in distributed generation solar PV project documentation.

III. On-Site Issues in a Distributed Generation Solar PV PPA. Several issues arise from the on-site location of distributed generation installations that are relatively unique to these types of electric generation projects. They will be encountered in any distributed generation facility regardless of technology, but the large increase in the installation of distributed generation solar PV facilities makes them an excellent template for discussing these issues.

A. Structural Integrity. Installing a solar PV system on the rooftop of an existing structure will put a significant weight load onto a structure that may not be rated for that weight. Placing a solar PV installation on a structure that cannot easily bear the weight is a clear danger to health and safety, and poses a potential threat of damage to the structure itself. A careful survey of the weight-bearing load capacity of any building on which a solar PV installation will be placed should be done before going very far into the negotiation process. Structural reinforcement may be required, and the costs of those improvements may prevent the installation from being economically viable. The only option other than making structural improvements may be downsizing the proposed installation to reduce weight. The site host, power purchaser, and project owner each have a direct and clear interest in being certain the structure on which the installation will be placed can bear the load for at least the full term of the PPA. Nonetheless, the responsibility (and risk) of structural integrity must be allocated to a party, and this can be a hotly negotiated topic.

B. Repairs and Replacement. Many roofs will require maintenance and repairs at some point or points during the term of the PPA. In addition, most roof coatings are designed with a known useful life. Exceeding the useful life of the existing roof may require the solar installation to be moved or removed from the rooftop to allow repair or replacement of the existing roof. There is a direct economic cost from both disconnecting the installation and moving it out of the way on the rooftop and disconnecting it and moving it off the rooftop while repair or replacement is conducted. That cost is the loss of power sales during the period the installation is out of service, as well as the loss of any REC sales or other subsidies that depend on the installation being in production. Project owners will often grant the power purchaser or site host some agreed period of time in which there will be no penalties incurred to accommodate ordinary repairs and maintenance. If the installation downtime will exceed this agreed-on period, many PPAs will require that the power purchaser start reimbursing the project owner for lost power sales, lost REC sales, and other lost economic benefits. If the power purchaser is not the site host, this presents a clear need to coordinate the PPA and the site lease, license, or easement to handle this risk.

C. Sale of the Structure or a Change of Tenant. Distributed generation installations also present the unique problem that ownership of the structure on which the installation is located may change during the term of the PPA, or the tenant that was previously the power purchaser may move out and a new tenant that is not interested in assuming the PPA may move in. There is no single, clear,

simple solution to this problem. The site lease, license, or easement will usually require that any purchaser of the structure assume the site lease, license, or easement (*i.e.,* it is an encumbrance that "runs with the land"). The site host may want to require a new tenant to assume the PPA as well, but if the new tenant is unwilling and has sufficient leverage with the site host, that may not happen. Consequently, even if the project owner believes it is adequately protected from these situations under the project documents, the project owner is faced with a difficult decision. There is a substantial cost attached to the project owner's enforcing its legal rights, as well as immediate lost revenues of various types if the new owner or tenant simply will not accept the delivery of electricity from the solar PV installation. This is a central issue to project success, and should be addressed carefully in the agreements.

D. Ground-Mount On-Site Issues. A ground-mount installation presents a different range of issues than a rooftop installation. Gone are the concerns about structural integrity, roof leakage, tenants, and multi-use properties. Instead, ground-mounted systems face a greater range of environmental compliance risk and regulation. These risks and obligations should be carefully allocated between the site host and the project owner. Typically, the site host will be responsible for all nonproject hazardous substances and other environmental risks, while the project owner is responsible for project-related environmental matters.

IV. Distributed Utility PPAs. Certain utilities, including the Southern California Edison Company ("SCE"), Pacific Gas and Electric Company, and San Diego Gas & Electric Company in California, have received authority to enter into PPAs with distributed generation solar installations owned by independent power producers. For example, the standard form of PPA used for the SCE program combines provisions typical to distributed general solar PPAs with some provisions typically used only in utility-scale solar PPAs, although in a more limited form than usual for a utility-scale PPA. For example, a security deposit calculated at a fixed dollar amount per kilowatt that will be held by the utility is required. If the developer fails to install any of the equipment or devices required to provide output at the designated gross power rating for the installation under the PPA by the defined starting date for power sales, the entire deposit is forfeited to the utility. If only a portion of the designated gross power rating of electricity is delivered by the defined starting date for power sales, a portion of the security deposit is forfeited. This type of security deposit is common in utility-scale PPAs but is relatively uncommon in distributed generation PPAs. Due to the character of the power purchaser as a regulated public utility, regulatory approval of the PPA is required, and the power seller is required to operate the installation in compliance with certain regulatory tariffs. Such provisions are common to utility-scale PPAs but uncommon for typical distributed generation PPAs. In addition, these hybrid PPAs are silent on the issues that typically must be dealt with between the developer/project owner and the site host discussed above. The developer/project owner must solve these on its own, and the purchaser utility has no role or interest in those issues.

V. PV System Leases. It can be seen that in the distributed generation context, a PPA is more a financing device than a commercial agreement for the sale of electricity. It allows the host/offtaker to

gain the benefits of PV generated power with little or no upfront capital expense. The PPA does this by moving ownership to a third party that has the available capital for investment and is able to take advantage of the tax benefits of PV system ownership. The host/offtaker essentially pays for the system over time. Under the PPA, the payments are based on units of electricity. In an ordinary loan, the payments of principal and interest would offer similar benefit to the host/offtaker and similar payment structure. A third financing device, offering benefits to the parties similar to those afforded by a PPA, is the system lease. As in an automobile lease, the lessee/host/offtaker contributes a relatively small upfront payment, then leases the equipment and pays the system owner rent for an agreed term. As in PPAs, there are typically early termination charges and options to purchase. IRS regulations require there to be at least 20 percent residual market value in the equipment at the conclusion of the lease term. For this reason, lease terms tend to be shorter than PPA terms.

VI. Conclusion. The project owner must carefully consider how to integrate the on-site issues presented by a distributed generation solar PV system with the basic purpose of the PPA, which is to cover the project owner's agreements with the power purchaser regarding the installation, start-up, maintenance, and sale of output from the system. Any situation in which the PPA will be with a party other than the site host will raise the question of whether these on-site-specific provisions should be in the site lease, the PPA, or a combination of the two, depending on what the project owner is able to negotiate with the site host and the power purchaser.

Simply ignoring these issues is an option for the project owner, but one that needs to be taken knowingly. While a developer/owner may elect to take these risks, most tax investors and banks will not. Failing to adequately address these issues will make third-party financing very difficult.

As to the basic core terms of the PPA, the discussion above indicates that there are many different approaches to each provision being used in the market. At this point, there is no single set of deal points that is generally accepted as the industry standard, although most experienced investors and attorneys will recognize a "bankable" PPA when they see one.

Chapter Three
THE LAW OF SOLAR
—Power Purchase Agreements: Utility-Scale Projects—

Jason Johns, Jennifer Martin

I. The Revenue Stream. When a solar project is owned by an independent power producer rather than a utility serving its own load, the agreement that provides for an assured source of revenue from the energy output and related environmental attributes of the project is central to the project's viability. In theory, the energy output of any resource—solar included—can be sold into the many local spot markets without a long-term output agreement on a "merchant" basis. In practice, however, the risk attendant to such merchant sales—where the project owner takes the prevailing market price at the point of interconnection—has proven too great to enable investors (and most developers, for that matter) to get comfortable that the project will be and remain economically viable. In part, this is due to the fact that such market prices are difficult to predict and tend, on average, to be lower than prices that would be available under a long-term power purchase agreement ("PPA"). In tight markets, the spot market can soar well above the long-term contract price, as it did in California circa 2001 or during the more recent Polar Vortex in the Northeast. Such spikes in market prices tend to not only be rare and short-lived (often lasting no more than a few hours during peak load times), but more importantly they are unpredictable, and thus cannot provide the requisite assurance that the project will produce sufficient revenues over time to maintain its economic viability.

As a result, the standard model for solar projects is to have some sort of output agreement that either provides for the long-term sale to a utility of the energy output (and associated environmental attributes) at a specified price or that provides a hedge against the price volatility inherent in the spot market. The primary vehicle used in this regard is a long-term (generally 20 years) PPA with an offtaker under which the offtaker agrees to purchase, at a specified price, all energy and related environmental attributes as and when the same are produced by the solar project. That offtaker is often a load-serving utility, but in recent years large commercial and industrial customers have been significant players in the PPA arena in order to accomplish corporate renewable energy goals and/or hedge their own power costs.

Alternatively, in the organized energy markets, it is possible to protect against market price risk by entering into an energy hedge or a contract for differences ("CFD," also known as a virtual power purchase agreement ("VPPA")) with a creditworthy counterparty. Energy hedges and CFDs have some advantages over PPAs, and they are often favored by commercial/industrial offtakers because they avoid triggering state laws that may restrict direct retail sales—one of the reasons that CFDs and VPPAs are often the type of agreement preferred by corporate offtakers. They are not contracts where the "buyer" (*i.e.,* the counterparty to the seller/solar plant owner) intends to use the energy to meet its own needs, as is the case with a utility under a PPA that is buying energy to meet its own load. As a result, in

theory, the counterparty can be located anywhere, without regard to its needs for energy in the area in which the solar plant is located. This is how energy hedges expand the universe of possible counterparties beyond just load-serving utilities.

In this chapter we will explore the basics of these output agreements, with a focus on some of the key differences between traditional PPAs and CFDs that continue to be the principal output arrangement in solar energy.

A. The Parties.

1. The Seller. With few exceptions, the seller is a special purpose entity (often called an "SPV" or the "project company") that owns and operates the solar plant that will generate energy and environmental attributes ("output"). For a variety of reasons (*e.g.,* limiting liability and having a tidy, "one-stop" security package for investors), such SPVs generally only own one asset: the solar plant in question. But the seller may also be a power marketer that is buying the output of a plant from the developer-owned SPV and reselling it to one or more purchasers. If the power marketer is reselling output, the resale PPA will usually track the relevant terms of the underlying PPA because the marketer will not want to promise more than it has the right to deliver. As a result, the marketer will often use a "back-to-back" PPA for the resale. The resulting terms will be almost the same as those in the underlying project PPA, except for price or other unique items that the marketer does not wish to pass through to the ultimate buyer.

In a tax equity financed project, the developer sells a substantial interest in the installation to an investor or utility before the installation is placed in service so that the developer can use the funds paid by the investor or the federal investment tax credits, federal accelerated depreciation, and any available state-level tax benefits to recoup all or a portion of its development costs. Because the market for tax credits remains uncertain, it appears that more developers are considering the use of debt financing as a critical component of the financing package.

2. The Buyer. The buyer is often a utility that purchases the solar project's output to serve its load. Utilities tend to be the ultimate end-user of the output simply because, under the laws of most states, only regulated utilities can sell electricity to the end-user (*e.g.*, a business, commercial, or residential user).[1]

a. But Utilities Are Not the Only Buyers. Power marketers may buy output for resale to one or more third parties. Power marketers sometimes can purchase all of a project's output (something that no other single-market player may be able to do), taking a "merchant position" and enabling the owner to finance the plant. In addition, over the past several years, commercial/industrial customers (*e.g.*, data centers) have entered into a substantial number of transactions for renewable energy. Due to legal restrictions that may prevent an end-use customer from

[1] A sale of electricity to the ultimate user of the power (such as a business, commercial, or residential user) is called a "retail sale." A sale of electricity to a party that is not the ultimate user of the power but that intends to resell it to a third party is called a "wholesale sale."

directly purchasing renewable energy, transactions with commercial/industrial customers tend to rely on a variety of structures. These structures include direct retail sales where state law allows it, pass-through deals involving the local utility, financial arrangements that do not involve a physical delivery of power (including CFDs), and true wholesale deals where the commercial/industrial customer has the capability to operate in that market. Commercial/industrial customers also often demand different contractual terms than utilities, for accounting, public relations, or other reasons. We will get into some of these differences below.

3. Credit Support Provider. The PPA will require the offtaker to purchase the output that the seller delivers. It likely will also require the seller to pay the buyer if the project is not built on schedule or fails to achieve certain performance standards. Each party will be concerned about the other's ability to satisfy these payment obligations. If one party is not creditworthy, the other may require it to provide a guaranty or post a letter of credit or other security to ensure that amounts due under the PPA will be paid. In fact, it is only the rare offtaker that does not insist that the seller provide substantial security for its obligations under the PPA.

But it should be noted that this tends to be a one-way street in utility agreements: the seller posts security in favor of the offtaker, but the utility offtaker almost never posts security in favor of the seller. Traditionally, most offtakers do tend to be acceptable credit risks (most investor-owned utilities being rated in the "BBB" category, while most municipal utilities are rated "A" or higher), and their gross revenues in comparison to their liability under the PPA are more than adequate to give assurance that meaningful recourse can be had against the offtaker should it default in its PPA obligations. That said, offtakers that are not traditional utilities pose a different set of questions for sellers to consider when negotiating credit support terms. For example, sellers may wish to revisit the offtaker credit support question if the offtaker is a subsidiary of a large corporate offtaker without assets or a community choice aggregator with no credit rating and a short operating history. In some cases, an offtaker will not agree to post credit support up-front but may be obligated to do so if its credit rating falls below a negotiated threshold, such as investment grade levels.

Sellers are usually given the option of posting security in one of three forms: cash deposited in escrow, a letter of credit from a highly rated ("A" or better) bank, or a guaranty from a creditworthy entity. Except as a temporary expedient (*e.g.,* while awaiting receipt of a letter of credit), cash is virtually never posted as security. It is simply too expensive to tie up such large amounts of cash and, in any event, an SPV that owns the solar plant generally is not cash rich (to the contrary—SPVs tend to be funded on a "just in time" basis by their parent). And because most solar plants are financed via tax equity investments where the tax equity investors will become equity owners of the SPV, sellers' parents generally do not want to take on the additional risk inherent in being the source of the cash posted as security, but would prefer to have the SPV itself provide the security (and thereby share the cost of providing the same and the risks it entails with all the owners of the SPV, including the tax equity investors).

Guaranties from a creditworthy entity—usually the parent of the developer—are used in certain instances, but for reasons similar to those noted above in connection with cash deposits, are not the most favored form of security. From a cost standpoint, one could assume that a guaranty is the least expensive choice, since it does not require forgone investment opportunities (as the posting of cash does) or an annual out-of-pocket fee (as does a letter of credit). But encumbering one's balance sheet with a multimillion-dollar guaranty does, indeed, impose a cost on the guarantor in terms of the diminished credit capacity resulting from the contingent liability represented by the guaranty. In fact, in many large companies, there is an internal charge for such use of the company's balance sheet. Furthermore, imposing the guaranty liability on the developer's parent shifts part of the project risk from the SPV to the developer's parent, and undermines the notion that all equity owners of the SPV (including tax equity investors) should share in the cost of doing business.

There is no universal standard for the amount of security that is required to be posted. In most PPAs, the security is divided into construction period security and security from and after the date the solar plant achieves commercial operation. In such cases, the construction period security is usually required in an amount equal to the per diem amount of any delay damages that may be owing if the seller does not achieve commercial operation by the target date set forth in the PPA, multiplied by the number of days between such target commercial operation date and the "drop dead" date (*i.e.,* the date the utility can terminate the PPA if commercial operation has not yet been achieved). For the post-commercial operation security, the amount is usually set somewhere between six months and 18 months of expected payments under the PPA. However, where the PPA price is a "levelized" price throughout the entire term of the PPA (*e.g.,* $27/megawatt-hour ("MWh") for 20 years, as opposed to an inflating price of, *e.g.,* $20/MWh in the first year, increasing at the rate of 2.5 percent per annum), occasionally, though not very commonly, the security amount increases over time until a certain "crossover" point is reached (usually between years 12 and 15 of a 20-year PPA). This approach is based on the theory that with a levelized price, the utility is paying more than it should in the early years and less than it should in the later years.

II. The Term. The term of the PPA has typically been around 20 years, to enable amortization of project debt and a period of return for the project sponsor. However, offtakers, particularly corporate offtakers, are increasingly requesting shorter terms, such as 15, 12, and even 10 years. Where the term is shorter, sellers will need to very carefully consider the expected financing model, especially if it is dependent upon expected returns after the end of the initial PPA term.

A. Effective Date. The PPA will be binding on the date it is signed (often called the "effective date"). This ensures that the offtaker will buy the output once the project is built and that the project owner will build the project and not sell its output to anyone other than the purchaser.

B. Commercial Operation Date. The term of the PPA usually begins on the effective date, but the length of the term is often defined by reference to a "commercial operation date." For example, the term might end on the 20th anniversary of the January 1 following the commercial operation date.

In other PPAs, the delivery term begins on the commercial operation date and extends for a specified number of years.

The commercial operation date often starts the PPA's delivery term, determines whether the project has avoided liquidated damages by achieving its "guaranteed commercial operation date," and establishes the point at which the price switches from a "test energy rate" to a "contract rate." It is therefore important to define "commercial operation date" carefully. Generally, "commercial operation date" can be defined as the date on which all or some specified portion of the project and all other portions of the project necessary to put it into operation with the interconnection facilities and the transmission system have been tested and commissioned, and are both authorized and able to operate and deliver energy to the transmission system in accordance with prudent utility practices. The parties often negotiate more specific standards for judging whether commercial operation has been achieved and occasionally require that an independent engineer be engaged to make findings that support the achievement of commercial operation.

In most cases, "commercial operation date" is defined in a manner that allows the project owner to achieve commercial operation even if it has installed fewer than all of the solar units called for by the PPA. For example, the PPA may call for an installed capacity of 50 MW, but the commercial operation date may occur when 45 MW of capacity have achieved commercial operation (*i.e.,* when the project has been "substantially completed"). Such PPAs typically require the seller to continue building the project until all of the project's installed capacity has achieved commercial operation. If the seller achieves commercial operation for substantial project completion but thereafter fails to complete the remainder of the project, it may be liable to the buyer for liquidated damages for the incomplete capacity. A developer's ability to declare commercial operation with respect to a portion of the project's expected installed capacity may also be useful to the developer in situations where partial force majeure, delayed interconnection, or an unanticipated permitting or land issue might create a problem as it relates to timing issues around the investment tax credit.

C. Termination Before the Commercial Operation Date. PPAs usually include "off-ramp" provisions that enable the offtaker to terminate the PPA if certain events occur or fail to occur. Perhaps the most common provision for early termination includes the failure of a public utility commission to approve a PPA or to allow its costs to be passed through to ratepayers. Developers should carefully consider the timing of the expected development costs it will incur to advance the project while the buyer retains an ability to terminate. In other words, a developer should not be required to incur substantial development costs, and certainly not to start construction, prior to the time in which the buyer is bound by the PPA. Accordingly, a buyer's termination right associated with commission approval should have an end date so that the developer can adjust its schedule accordingly. In the not-too-distant past, developers could also obtain early termination rights for reasons such as the failure to obtain reasonable financing. But such termination rights in favor of developers are becoming increasingly rare, as offtakers expect developers to be experienced and to take on the risks of project development. Other early termination rights that may be available are a seller's inability to obtain

interconnection on acceptable terms, particularly costs and timing, consistent with the seller's expectations and the inability or delay in obtaining permits required to build or operate the project. In cases where the buyer can invoke a termination right after the seller has exhausted its right to pay delay damages, careful attention should be paid to limiting the developer's liability and the purchaser's remedy to the delay damages already paid to the buyer or to some other clearly defined payment.

III. Purchase and Sale.

A. Delivery Point. The PPA will require the sale of energy to occur at a specified delivery point. If the energy is to be delivered at the plant in a "busbar" sale, the delivery point will usually be the high side of the transformer at the project's substation. In a busbar transaction, the buyer provides the transmission required to transmit the energy from the plant to the point where the buyer intends to use it (or to deliver it to another party in a resale transaction). The PPA may also require the seller to provide necessary and adequate transmission to take the energy away from the project's busbar or otherwise assign to the seller the curtailment risk associated with inadequate transmission away from the project. Alternatively, the PPA may also require the seller to deliver energy to a specific point some distance from the plant, in which case the seller will be responsible for securing the required transmission to the delivery point, and the buyer will be responsible for obtaining the transmission required to take the energy at the delivery point. Transmission ancillary services can be fairly costly and should be specifically allocated in the agreement. Title and risk of loss pass from seller to buyer at the delivery point. In a VPPA, energy is not actually delivered to the offtaker. Instead, energy is typically sold into the energy market with which the project is interconnected.

B. Pricing.

1. Contract Rate. Price is usually the most important part of the PPA. The price may be flat, escalate over time, or contain other features. An escalating price is often tied to a "contract year" that begins at a specified point after the commercial operation date is achieved, thus encouraging the seller to lock in the initial price and the escalation rate by achieving commercial operation as soon as possible.

2. Test Energy Rate. Because an electrically distinct array (panels behind a single inverter) can generally function independently of other arrays, the PPA may require the purchaser to buy power from the arrays as they are installed, connected to the transmission grid, and made operational, even though the project as a whole has not achieved commercial operation. To encourage the seller to achieve commercial operation as soon as possible, such energy is often sold at a test energy rate, which is lower than the contract rate that will be paid once the commercial operation date is reached. However, in Independent System Operators ("ISO")/Regional Transmission Organizations with energy markets (*e.g.,* the Midcontinent ISO), the seller may choose to sell its test energy into the market rather than to the purchaser, or alternatively the purchaser may pay the market rate for test energy.

3. Excess Rate. A PPA often requires the seller to specify how many MWhs the plant is expected to produce each year. This output estimate may form the basis of an output guarantee or a mechanical-availability guarantee. To encourage the seller to make an accurate estimate of expected output, the seller may be paid less than the contract rate for each MWh of energy in excess of, for example, 110 percent of the estimated annual output.

4. Fixed for Floating Pricing. While there are a number of different variations for how a fixed for floating price can be structured, the general concept is that the offtaker agrees to guarantee to the developer a fixed price per MWh of metered energy. A developer delivers energy from the project into the energy market, either the day-ahead or real-time market, and receives the locational marginal price ("LMP") revenue (or pays the LMP cost for negative LMP) (in either case, the floating price) to the ISO in connection with such metered energy. Over an agreed-upon time period, the parties compare the floating prices to the fixed price and a payment is made to or from the offtaker so that the end result is the developer receives no more or less than the fixed price per MWh. Variations of this structure include determining which market the seller will participate in (day-ahead or real-time) and which LMP price is used to set the floating price (the project's PNode LMP or a more liquid Hub within the energy market). If a Hub price is used, a developer must understand and mitigate the basis risk (or price differential risk) between the project's LMP and the Hub price that it is taking. In addition, the offtaker will typically want to limit its exposure to negative floating prices. This is often accomplished by setting a negative LMP floor price, below which the project is deemed to have no metered quantity, and a seller is instead paid based on the forecasted volume for such interval multiplied by an amount equal to the contract price minus the floor price.

C. Environmental Attributes. Environmental attributes are the credits, benefits, emissions reductions, environmental air-quality credits and emissions-reduction credits, offsets, and allowances resulting from the avoidance of the emission of a gas, chemical, or other substance attributable to the solar project during the term of the PPA, together with the right to report those credits. Environmental attributes are sometimes called "green tags," "green tag reporting rights," or "renewable energy credits" ("RECs"). The PPA should make it clear that production tax credits, solar energy incentives (such as those that may be provided under a state program), and any other environmental attributes necessary to generate the quantity of power being sold to the purchaser are not part of the environmental attributes and thus are not being conveyed to the purchaser.

The PPA should clearly state whether energy is being sold with or without the environmental attributes. Failure to do so can (and has) led to disputes about whether the generator or the offtaker is entitled to the ownership and use of the environmental attributes. If environmental attributes are being sold, the seller will usually warrant title to the attributes but will not universally warrant the current or future use or value of the attributes or whether and to what extent they will be recognized by law. Instead, the seller will often agree to spend up to a negotiated amount of money (either annually and/or in total) to maintain the value and use of environmental attributes. Once that financial cap is reached, the seller is under no further obligation to spend money in an effort to shield an offtaker's environmental attributes

from a change in law. As a result, the purchaser assumes some risk that the law or the market might change in a way that reduces the value of the environmental attributes.

D. Allocation of Taxes and Other Charges. The PPA should specify who pays any sales, excise, or other taxes arising from the transaction. Although most states do not tax wholesale energy sales, the parties may wish to consider allocating the tax liability that might result from future legislation.

IV. Permitting and Development.

A. Commitment to Develop. The PPA will make the project owner responsible for developing and constructing the project. The seller usually prefers a PPA that requires it to sell the project's output only if the project is actually built. A buyer tends to view such a PPA as a put and will usually insist that the seller make some commitment to develop the project. Many negotiations revolve around what the seller will or will not be required to do to develop the project, as well as the off-ramps that each party has if the project does not achieve certain stated milestones.

B. Status Reports. The buyer is typically interested in the ongoing development of the project because it needs to know when the energy will be delivered onto its system or when it will need to take a hedge position. As a result, the PPA usually requires the seller to deliver regular reports to the buyer about the status of permitting and construction.

C. Milestones and Delay Damages. The PPA often includes a schedule of certain project milestones (*e.g.,* the date by which the seller must secure project financing, the date by which equipment must be ordered, the date by which all permits and the interconnection agreement must be in place, and the commercial operation date). If the seller fails to achieve a milestone, the buyer may have a right to terminate the PPA, collect delay damages, or require the seller to post additional credit support. The seller will therefore want to limit the number of milestones and bargain for some flexibility, especially in cases when a delay in achieving an interim milestone is not likely to delay a project's completion date. Sellers would prefer PPAs that provide that the buyer's only remedy if the seller fails to meet a project milestone is to terminate the PPA without recovering damages; however, it is very rare that a PPA provides for termination without damages. Buyers are concerned that this gives the seller a right that resembles a put and strongly prefer to require the seller to suffer some consequences if project milestones are missed. Many interesting negotiations revolve around the off-ramps that the seller will have versus the damages it will pay to the buyer if it fails to build the project in accordance with the PPA. A common middle ground is for the seller to agree to pay delay damages up to an agreed-on cap (often the credit support posted by the seller during development), which defines the limits of the seller's exposure if the project is not built but gives the seller an incentive to use diligent efforts to finish the project on time.

V. Interconnection and Transmission. The PPA will require the seller to bear the cost of interconnection (including any network upgrades required by the new project) and all costs of transmitting the energy to the delivery point. If the seller is the project owner (as opposed to a

marketer), it will also be responsible for negotiating the interconnection agreement with the transmission provider. The buyer will be responsible for arranging and paying for transmission from the delivery point. (For more information on interconnection and transmission-related issues, see Chapter 5.)

VI. Performance Incentives. Although a seller would prefer to enter into an "as-delivered" PPA, which means that the seller is obligated to deliver only what the project actually produces, PPAs today will require the seller to warrant or guarantee that the project will meet certain performance standards. Such guarantees usually enable the buyer to recover all or part of its incremental cost of purchasing replacement power and environmental attributes in the market to the extent that the project fails to perform as expected. Performance guarantees enable the buyer to plan around the plant's expected output for both load and, if applicable, renewable-portfolio standard compliance, and strongly encourage the seller to maintain a reliable and productive project.

A. Output Guarantees. The PPA may include an output guarantee to the buyer. An output guarantee requires the seller to pay the buyer if the project's output over a specified period fails to meet a specified level, after taking into account output lost because of force majeure or maintenance or other agreed-on subtractors. The period may be seasonal, annual, biannual, or longer (although seasonal guarantees are unusual in today's PPA market). The PPA usually allows the owner to operate the project for one or two years before the output test is applied, enabling the owner to fix any problems at the project, and may calculate the guarantee on a two-year rolling average to minimize the impact of particularly low or high solar irradiation years. Some output guarantees, however, are calculated and compensated annually, as buyers now expect greater precision from developers.

B. Availability Guarantees. An availability guarantee requires the solar arrays in the project to be available a certain percentage of the time, after excluding hours lost to force majeure and a certain amount of scheduled maintenance. Mechanical-availability percentages usually range from 90 percent to 95 percent, but they may decline over the life of the project or even disappear altogether during the final years of the PPA term to reflect wear and tear on the panels. Mechanical-availability guarantees are quite rare in today's PPAs, particularly where the offtaker is a load-serving utility. But mechanical-availability guarantees continue to have their place in PPAs where the offtaker is a corporate or industrial user, due to accounting issues that cause these offtakers to prefer an availability guarantee over an output guarantee.

C. Liquidated Damages. If a guarantee is not met, the PPA usually provides a mechanism for determining the damages suffered by the buyer. First, the parties determine the output shortfall (stated in MWhs) relative to the amount of output that the buyer would have received had the project lived up to its guarantees. Second, the shortfall is multiplied by a price per MWh determined by reference to an agreed-on index or a fixed price (a liquidated damage for shortfalls). Because market indexes currently cover only power prices and do not include the value of environmental attributes, the PPA may include an adjustment to account for the assumed value of the environmental attributes or may use a firm price index as a proxy for the value of the energy plus the environmental attributes. The

amount of liquidated damages is usually determined once per year. The seller pays the liquidated damages to the buyer or credits the damages against amounts owed by the buyer under the PPA. The seller may in addition seek to include the right to cure any output shortfall through delivery of replacement energy and environmental attributes at its option where the seller and the buyer can mutually agree on the time and place for such replacement deliveries. In any case, the seller will likely seek to cap liquidated damages or its replacement obligation on an annual or aggregate basis.

D. Termination Rights. To protect against chronic problems at an unreliable solar plant, the PPA may allow the buyer to terminate the PPA if the output or mechanical availability of the project is below a stated minimum for a certain number of years.

VII. Curtailment and Force Majeure.

A. Curtailment. The PPA often describes circumstances in which either party has a right to curtail output. For example, the seller may have a right to curtail deliveries if the plant is affected by an emergency condition. The PPA may permit the buyer to curtail for convenience or what is often referred to as "economic curtailment," in which case the PPA usually requires the buyer to pay the purchase price for the curtailed generation. In organized markets, where the offtaker is also the scheduling coordinator for the facility and in which generation dispatch by the ISO is affected by the bid curves submitted by the scheduling coordinators, it is important that the PPA indicate that curtailment caused by the offtaker's bidding strategies are deemed to be economic, and therefore compensated, curtailments. However, buyers often negotiate the right to a certain amount of uncompensated curtailment. Facility curtailments caused by transmission congestion or conditions beyond the point of delivery are often allocated to the seller, although the topic of curtailment is frequently a difficult issue in PPA negotiations.

B. Force Majeure. If energy is curtailed at a party's discretion (above any allowed uncompensated amount) or because the party is at fault, the PPA usually requires the curtailing party to pay damages to the other. If curtailment is caused by an event beyond a party's control, the party's duty to perform under the PPA may be excused. For example, if a natural disaster disables a transformer at the facility, the seller would be excused from delivering energy, and the buyer would be excused from taking and paying for energy, until the transformer is repaired. The party responsible for maintaining the transformer would, of course, be required to use diligent efforts to make repairs.

1. Parties Often Heavily Negotiate Force Majeure Provisions. Good provisions should carefully distinguish between events that constitute "excuses" (which relieve the affected party from its duty to perform) and those that are "risks" (which are simply allocated to a party). The ability to buy energy and environmental attributes at a lower price or sell them at a higher price is not a force majeure event. Moreover, a party's inability to pay should not constitute a force majeure event under the PPA. A well-drafted force majeure clause will usually list a number of items that both parties agree are force majeure events, as well as list items that the parties agree are *not* force majeure events.

VIII. Defaults and Remedies. The PPA will usually list events that constitute defaults. These may include:

- failure by any party to pay an amount when due;
- other types of specified material defaults;
- the bankruptcy, reorganization, liquidation, or other similar proceeding of any party; or
- failure to provide or replace credit support within an agreed-on time.

The default clause should specify how long the defaulting party has to cure a default. If the default is not cured within the agreed-on period, the nondefaulting party usually has the right to terminate the agreement and pursue its remedies at law or in equity or to suspend performance of its obligations. The remedies clause may also limit remedies or place a cap on the seller's damages, although a cap on damages usually, but not always, applies to only those events of default occurring before the commercial operation date. It is worth noting, however, that where a seller's damages are capped after the commercial operation date, the offtaker typically has a right to terminate the PPA if the seller will not agree to continue paying damages, so the cap may be nominal only.

IX. Project Lenders and Equity Investors. Even if the project is expected to be financed off a developer's balance sheet, the terms of the PPA will usually take into account the possibility that the PPA will be assigned to a lender as collateral for project debt. The PPA will therefore contain provisions authorizing the seller to assign the PPA as collateral; requiring the buyer to provide consents, estoppels, or other documents needed in connection with financing; and giving the lender various protections (including additional time to cure defaults). The PPA may also include provisions to address the concerns and cure rights of future tax equity investors and should allow in the PPA or any form of consent transfers associated with exercise of remedies by lenders.

X. Buyer Options to Purchase the Project or Special Purpose Entity. Many utilities have shown a strong interest in owning solar energy projects. In PPAs, this interest often takes the form of an option to purchase the project or the entity that owns it on or after a specified date. Such options should be handled carefully. An option to purchase the project or the interests in the special purpose entity that owns the project for anything other than the project or entity's fair market value at the time of exercise has been generally disfavored by tax attorneys. Other types of options can raise a fundamental question as to whether the owner of the project is an owner for federal income tax purposes or whether the financing arrangement is something other than "ownership" (*e.g.,* a loan). Revenue Procedure 2007-65, 2007-2 C.B. 967, explicitly provides as one of the qualifying elements that there is no developer/investor/related party purchase option for less than fair market value (at exercise). Developers should ensure to carve out transfers associated with financing arrangements (tax equity investment, lender exercise of remedies) from right of first offer structured options.

A. Basic Structure of Hedge Arrangement. The essence of energy hedges and CFDs is that the parties agree upon a price (typically referred to as the "strike price") for the energy produced. If, at the time the energy is produced, the market price at the point of interconnection with the transmission grid (or at an agreed-upon pricing node on such transmission grid) exceeds the strike price, then the solar plant owner pays the hedge counterparty an amount equal to the difference between such market price and the strike price. Conversely, if the market price is lower than the strike price, the hedge counterparty pays the solar plant owner the difference between the market price and the strike price. In this way, the solar plant owner is assured that it will receive the strike price for all energy covered by the hedge, and thus have an "output arrangement" that provides some revenue certainty in a manner similar to a PPA. The hedge counterparty reaps its return by endeavoring to structure the terms of the hedge such that, in the market in which the hedge plays out, the market price for energy is likely over time to exceed the strike price, thus producing the desired profit or return.

The actual energy produced that is subject to the hedge is often sold into the local market at the prevailing nodal price. But a hedge can be structured to give the counterparty the option of picking up the energy at the interconnection point (or even perhaps at some remote point agreed upon the parties, if transmission to that point is available) so that it can resell it in bilateral sales to third parties. The motivation for such sales to third parties can be either the anticipation of a price higher than the prevailing market price or a more certain price that eliminates the risk inherent in market price volatility.

Where the energy is sold into the local market, the hedge is a pure financial transaction that is basically the same as an interest rate swap, with the strike price and market prices for the energy substituting for the "strike price" interest rate and interest rate indices used in interest rate swaps. In the event that the energy is physically delivered to the counterparty for resale, it takes on added elements similar to a PPA in certain respects. Note that where the hedge is a pure financial transaction, securing transmission to deliver the power to load is not required. But transmission considerations can still play a key role, as the location of the solar plant may be such that it is on the wrong side of a grid congestion point, thus adversely affecting the market price of the power and thereby affecting the economics (and perhaps even the availability) of the hedge.

The hedge does not always cover 100 percent of the energy anticipated to be produced by the solar plant. Rather, it is sometimes structured to be a certain percentage of the output, with the remainder being reserved to be sold on a merchant basis. The amount of production excluded from the hedge is based on a calculation by the concerned parties (the developer, financing parties, and the hedge provider) of the amount of risk the merchant piece entails and the likelihood that the merchant portion will jeopardize the project's financial viability under certain conservative operating scenarios. In a variation, rather than reserving a certain percentage of the energy, these arrangements are sometimes structured to allow the developer to withdraw all or a portion of the energy produced during certain periods of the year.

Finally, unlike a PPA where the purchasing utility typically takes the environmental attributes (*i.e.,* green tags or RECs) associated with the energy purchased and pays a single "all-in" price for both the energy and the environmental attributes, most energy hedges do not act to transfer the environmental attributes to the hedge provider. Rather, the environmental attributes are most often retained by the special purpose vehicle that owns the project and can serve as an added revenue stream (albeit one that is not given much value in the financing process due to the uncertainty as to the value of the environmental attributes over time).

However, it is possible to bundle the energy and environmental attributes under an energy hedge in the same manner as is done under PPAs. The context in which such a bundled arrangement is likely to be desirable is where a major commercial or industrial user acts as the hedge counterparty with a view to both "greening up" its own load and also providing itself with a hedge against rising energy prices in the markets in which it purchases energy to serve its own load. By entering into such a bundled hedge, the industrial or commercial counterparty gets to claim the environmental attributes and obtain whatever credit might be available to it in terms of public relations and perhaps in terms of meeting certain legal requirements relating to emissions. And by locking into a fixed strike price for an extended term, the industrial or commercial counterparty has reasonable prospects of being the net beneficiary of payments under the hedge as market prices rise over time, thus providing a hedge against similar rising prices of the electricity it purchases from third parties to serve its own load.

B. Other Terms and Conditions. Like the security a developer is required to post under a PPA, developers are also required to post substantial security to secure hedge obligations. The security most often takes the form of a letter of credit, but guarantees from a large balance sheet parent with good credit can also work. The amount of security required to be posted is determined in a manner similar to that under PPAs, based on the hedge counterparty's assessment of its exposure given the nature of the project and the market in which the hedge is settled.

Unlike a PPA where, in the ordinary course, it is the utility that is expected to pay the developer, energy hedges will routinely require the developer to make payments to the hedge provider when market prices exceed the strike price. As a consequence, the right to project cash flows as among the hedge provider, lenders, and other project participants can be more complicated than in other circumstances not involving a hedge. In general, because the hedge serves the "revenue assurance function" that a PPA serves in other contexts, the hedge provider typically has paramount rights to project cash flow. The reason is simple: if the hedge provider is not timely paid what it is owed, the hedge can be subject to termination. And termination of the hedge would be a disaster akin to the termination of a PPA.

C. Regulatory Considerations.

A unique regulatory requirement that applies to energy hedges but not to PPAs is the Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 2010 U.S.C.C.A.N. (124 Stat.) 1376 (the "Act"), which is administered by the Commodity Futures Trading Commission ("CFTC"). While the provisions of that Act are complicated, suffice it to say that energy hedges are "swaps" within the

meaning of the Act[2] and as a result it may be necessary to comply with the registration, recordkeeping, reporting, and clearing requirements of the Act.[3] In most cases, the reporting requirements will be imposed on the hedge provider, which is likely a "swap dealer" within the meaning of the Act. However, if the hedge provider is a swap dealer and the developer is a "major swap participant" (unlikely in this context, but possible), or if neither entity is a financial entity, swap dealer, or major swap participant, then the parties may agree between themselves as to which will comply with the recordkeeping and reporting requirements.

XI. Retail Sales Structures. As renewable portfolio standard demand has dipped in recent years, utility renewable procurements have, to some extent, slowed as well. However, the waning of utility demand has not, in all cases, corresponded to a lack of demand for renewable energy from customers directly. Accordingly, another option available to developers in some states is a direct sale to the end-user of energy (retail sale). This structure is particularly attractive to customers motivated by the desire to serve their loads with green power directly. The number of structures available for this type of sale varies depending on the size of the project and the jurisdiction in which the sale will take place.[4]

Generally, sales of energy directly to the end-user are regulated by state utility commissions as opposed to the regulation of wholesale power sales that is within the purview of the Federal Energy Regulatory Commission. Historically, the seller of energy to a direct end-user was regulated as a public utility under state laws, typically, by the state utility commission. Moreover, in many jurisdictions, in order to incent such public utilities to make the necessary investments to serve retail end-users, public utilities were granted an exclusive right to serve the customers within the service territory granted to such public utility (*i.e.,* the franchise). Without legislative changes to this typical legal structure, a direct sale to an end-user might have two unintended consequences to the solar energy developer: (1) the solar energy developer may find itself regulated as a public utility under state law (including a requirement to justify its rates for the sale of energy on a cost basis); and (2) it may find its sale to be in violation of the exclusive franchised service territory of the incumbent utility.

As a result, the key hurdle a developer must overcome in determining whether a retail sales model is available to it is whether the state regulations and laws would permit such a sale. The answer to the question varies a great deal from state to state.

Other approaches enabling direct sales that vary depending upon jurisdiction include an exemption for certain small projects (*i.e.,* net energy metering arrangements) from rate regulation (though safety regulation may still apply) or an exemption for a developer making sales from any renewable facility to

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[2] Although the CFTC has the authority to exempt, via regulation, certain swaps from the purview of the Act.

[3] As of March 1, 2014, energy commodity swaps are not required to be cleared under the Act.

[4] While net-metering arrangements offer one avenue for direct sales in some jurisdictions, given the size of the projects typically eligible for net-metering arrangements, these structures are not discussed in detail in this section. See Chapter 2 for more information on net-metering arrangements.

an end-user from regulation as a public utility. Yet another approach enabling direct sales is to permit sales from one affiliate to another, provided the sales are on adjacent property. The key inquiry for the prospective seller is what types of structures (and at what sizes) may be permissible under the state law.

While beyond the scope of this chapter, if the generation facility is remote from the retail load, the developer interested in direct retail sales will also have to understand the options available to it for utilizing the transmission infrastructure to deliver the energy directly to the end-user as the ability to use the transmission grid for retail wheeling is limited in many areas.

If the developer can overcome these obstacles, then the retail sales structure for direct sales to the consumer is, in many ways, much like the typical PPA, with many of the same considerations previously discussed in this chapter, including price, term, credit requirements, performance guarantees, and default terms. However, the developer may find itself grappling with some additional issues as well. For example, where the customer may still need some service from the utility, the quality of the service to the customer may impact the retail customer in ways that increase costs to such customer. The local utility may charge, for example, a standby rate to the customer for the costs to the utility of "standing by" to serve the customer in the event that the intermittent solar generation is not produced. These costs can be unexpectedly high and the developer should consider the rate impacts to the customer in various jurisdictions in developing its origination strategies. Another issue sometimes encountered in the direct end-user sales structures is addressing a desire of the customer to include a termination for convenience clause in which the customer would have a right to terminate the contract (typically with a negotiated termination payment) in connection with business interruptions, *e.g.,* corporate shutdowns.

In short, developers will be well served to understand how the regulatory landscape in target jurisdictions may offer other sales options besides direct sales to the utility.

Chapter Four
THE LAW OF SOLAR
—Solar Energy System Design, Engineering, Construction, and Installation Agreements—

Tamara L. Boeck, Brian J. Nese,
Bart W. Reed

The design and construction of facilities for the generation of electrical power from solar resources is an area that is filled with risk and opportunity. The goal of this chapter is to provide an overview of the legal issues encountered in the course of engineering and constructing utility-scale solar energy projects so as to identify key risk allocations that are commonly used in this sector to create the legal framework necessary for a successful solar energy project.

This overview is written from the perspective of a solar energy project owner/developer; however, this information may also interest design and engineering, construction, operations and maintenance, and financing entities as well. Further, the lines between owner/developer, contractor, and equipment supplier are often blurred in the solar energy industry, as contractors and/or equipment suppliers increasingly are taking on the role of developer (sometimes through joint ventures) and panel suppliers often perform the duties of the contractor. As with any complex negotiated transaction, there is significant value to be won or lost by all parties and the potential for creative legal strategies to enhance value for all parties.

I. Construction-Related Agreements. Critical to the development of any solar energy project are the various agreements a project owner must enter into for:

- Design and engineering of site improvements, adaptations, expansions or alterations of existing facilities and related infrastructure, electrical systems including interconnection facilities, and transmission and distribution systems;
- Procurement of power generation equipment, such as photovoltaic ("PV") panels, mounting racks, tracker systems, inverters, transformers, and collection systems;
- Construction management services necessary to successfully schedule, coordinate, and oversee the engineering, procurement, and construction of the power generation equipment and the balance-of-plant facilities; and
- Operation and maintenance of the completed facility.

Frequently, engineering, procurement, and construction tasks are combined within a single agreement called an Engineering, Procurement, and Construction agreement or "EPC agreement" or (if substantially all project tasks are assigned to a single entity) a "full-wrap" or "turnkey" agreement. The

historic traditional development model for risk allocation is the design-bid-build method using the EPC agreement, versus the turnkey design-build package agreement that may offer a more palatable risk allocation to owner/developers. It is also common to have separate agreements for procurement and installation of major power generation equipment supplemented by a "balance-of-plant" agreement for the construction of ancillary facilities.

As an alternative to the single-entity EPC approach, the project developer may enter into separate agreements with a key equipment supplier, such as a panel manufacturer, in order to secure favorable terms and a direct relationship with this key project player. If this structure is used, a key risk area is in matching up delivery, warranty, insurance, and project completion details from the equipment supply agreement with the terms of design, construction, and operation agreements with other contractors. It will be critical in such cases to coordinate each of these EPC agreements to make sure that they collectively produce a complete project, and that the owner/developer is aware of risk allocation and any risk gaps that will be held by the owner/developer.

Depending on the contractual structure, product or service warranties, insurance, and other matters may be addressed in the full-wrap agreement or may be addressed in individual agreements. Understanding how these issues impact and interrelate to each other is essential for creating a set of coordinated agreements.

II. Design and Engineering Services. Solar power projects require certain design and engineering expertise that is unique to this sector of the power generation industry. The designers and engineers must coordinate their services with the structural and electrical designers and engineers working on the structure to ensure proper integration and scheduling. Historically, relatively few companies designed, engineered, and manufactured solar energy generation equipment, PV or thin film panels, or solar thermal and concentrated solar units. Today there are a number of manufacturers in each of these areas.

With the growth and monetization of the industry and the maturation of incentives, new vendors are entering the market regularly. For several years, PV panel prices plummeted as manufacturing capacity increased worldwide. Currently, solar technology provides for various systems, from solar thermal hot water or concentration systems to silicon cell or PV or thin film generation panels. The needs and requirements for any particular project, however, are in part dictated by its operating parameters, which are in turn dictated by the project's purpose, energy load, and location.

For instance, the weight tolerance of a rooftop installation may be different from the weight tolerance of a ground-mount installation, and the available mounting options will be different as well. These and other factors must be considered for proper project design and risk/opportunity assessment.

III. Construction and Installation Services. Solar systems are generally assembled from predesigned components that are aggregated and installed to suit the project's needs. Nonetheless, substantial design and engineering work will typically be required to integrate the chosen system or systems into the existing environment, topography, and existing conditions at the project site, including

the necessary interconnection requirements. These design and engineering services, and related procurement and construction work, may be performed by the supplier of the solar equipment and materials under one or more agreements, but are often provided by a third-party consulting engineer contracting directly with the owner/developer or design-builder.

IV. Typical Contractual Structure for a Distributed Generation Solar Project. Given the multiple factors influencing the development of a distributed generation solar energy project, no single contractual structure applies to all projects. However, the following example of a contractual structure used for a particular distributed generation solar project illustrates, in a limited way, how a project owner, its design-builder or general contractor and prime architect, and a solar equipment supplier might address certain common concerns. Many of the concepts discussed below also apply to utility-scale solar projects.

In this example, a project owner wants to install a PV system on its building to provide a portion of its electrical needs. The owner wants to have the same entity design, install, test, and commission the system, as well as construct the electrical interconnection facilities and ensure a minimum yearly electrical output. The owner also wants to make sure it can enforce any warranties provided by third-party subcontractors and suppliers of materials and equipment, and wants liquidated damages for any delays that might affect its business and undermine the owner's expectation regarding the project's ability to claim tax credits and incentives for the system under state and federal regulations.

The project owner and the solar contractor may enter into a solar installation agreement whereby the contractor agrees to design, install, test, and commission a PV electric generating system, including necessary interconnection facilities, on the owner's property.

Under the agreement, the owner has the right to review all subcontracts for equipment, design, and installation services entered into by the contractor, and any such subcontracts are required to contain certain provisions for the benefit of the owner. The agreement also provides for delay liquidated damages, whether or not tax credits or incentives are lost due to the delay. Finally, due to the electrical integration element of such a project, the agreement provides that final completion (whereby final payment is due to the contractor) is conditioned on approval of the project by the local utility and receipt of all appropriate electrical inspection certificates.

The slate of issues that the parties address in the installation agreement includes the scope of work, inspections and testing, liens, change orders, consequential damages, indemnification, measures of completion, liquidated damages, rebates and subsidies, system and work warranty obligations, coordination of activities, permitting reports, title and risk of loss, energy guarantees, and limitations of liability.

A. Scope of Work. In the example above, the parties placed great emphasis on the description of the scope of work set forth in the installation agreement. In general, except in true turnkey projects based solely on performance specifications, the parties' scope-of-work provisions should describe, in detail, the actual design, engineering, and construction obligations of the contracting

parties, as well as their coordination with other service providers on the project. The scope of work should incorporate the system's performance and design specifications by reference to either an attached annex or a specific set of separately prepared plans and specifications. Generally, whatever is not provided for in the contractor's scope of work is the project owner's responsibility to complete or to contract with third parties to complete. A solar energy system contractor's scope of work typically includes the design and engineering of the system, including its principal parts and components, as well as certain obligations relating to commissioning and performance testing of the major components of the system, and related warranty work. The contractor's scope of work may include providing operations and maintenance services for a set number of years after completion of the system. These services are often the subject of a separate agreement. As with other aspects of such an agreement, the scope-of-work provisions will probably be heavily negotiated. Care must be taken to coordinate the scope of services being provided by the contractor with the scope and timing of services being provided by third parties on the project to minimize conflicts or gaps.

B. Measures of Completion and Start-up Obligations. The scope-of-work provisions of the relevant agreements typically determine who will be responsible for facility start-up and commissioning and when and how such activities will be accomplished. Given a solar system supplier's in-depth knowledge of its products, the supplier (or its design subcontractor) will, at a minimum, supervise system start-up and may also be engaged to commission and optimize the products and systems it supplies. However, this work can also be undertaken by the project owner/developer (with assistance from the supplier) or by a third party contracting directly with the project owner/developer. In any case, the relevant agreements must address the stages of completion, such as actual delivery of the equipment to the project site, followed by installation, start-up, and testing. Once these progress milestones are established, completion is generally evidenced by certifications of, for example, "mechanical completion," "substantial completion" (or "commercial operations"), and "final completion." Each such certification is considered an incremental measure that the project must satisfy in order to progress to the next measure. As with other supply- and construction-related agreements, progress payments by the project owner/developer to the supplier/contractor (as set forth in the relevant agreement) will be based, in part, on the milestones described above. For instance, the owner/developer typically pays a certain amount toward the agreed-on contract price when the order for major equipment is submitted and then makes additional payments upon (1) the delivery of the major equipment to the project site, (2) the installation of the equipment, (3) successful testing of the control and monitoring system, and (assuming the foregoing stages are executed properly) (4) the final sign-off by the parties on the project. The payment schedule can also be based on monthly applications for payment based on expenses and labor incurred in the foregoing period, with a percentage holdback or retention amount (for possible repairs, claims, or liens) to be released at the time of final sign-off. Alternatively, the parties can negotiate milestones that suit the project or their desire or ability to manage certain specific risks.

C. Warranty Obligations and Performance Guarantees. Warranty obligations and performance guarantees are likely to be an issue of substantial negotiation between parties to solar

energy system supply and balance-of-plant agreements. The nature and scope of such warranties will, however, depend on what services, materials, and equipment the party is contracted to provide. An equipment supplier's warranties generally include such things as a general parts warranty (the definition of a defect can be important when determining what is included or excluded as a defective or nonconforming part or component in a solar energy system or related facility), a power output warranty (which guarantees the solar equipment's power performance), and related matters. For a contractor providing only installation services and materials, the warranties are generally limited in scope relative to those of an equipment supplier, but would still include warranties relating to parts and materials used in installation and any engineering services provided. If both equipment and installation services are provided by the same contractor, or through subcontractors, it is important to ensure that the owner/developer has the right to assert direct claims under warranties provided by third parties. It is also important to specify with a contracting party minimum terms that must be negotiated into third-party agreements.

The issues that contracting parties consider in respect of warranties include (1) the period or term of a particular warranty and whether the term can be extended (it is common for a supplier to offer certain extended warranty services for an agreed-on price), (2) the definition of a defect and a serial defect (important in projects in which solar energy equipment uses identical parts and components; serial defects are those that appear in multiple components), (3) limitations on warranty arising from acts of third parties such as operation and maintenance contractors or the system operator, and (4) the remedial measures a contractor must take to repair or cure any defect. Additionally, a project owner/developer may require that any third-party or subcontractor warranties that the supplier or contractor obtains in respect of any parts or components used in the system are "passed through" or assigned to the project owner/developer.

The issues that the parties consider relating to performance guarantees include (1) what the appropriate measurements of performance are both for project components and for fully assembled systems; (2) when performance testing is to be done, under what external conditions, and by whom; (3) the consequences if performance testing is not successful (possibilities include allowing the relevant contractor to make repairs and charging damages measured by the degree to which the test was not successful); and (4) the extent to which the owner/developer has a right to the benefit of the supplier's improvements in technology.

D. Limitation of Liability. Like other contractors and vendors, solar project suppliers and contractors will seek to limit their liability to a project owner/developer. A common request is for a waiver of consequential, indirect, incidental, and special damages. Such clauses should be negotiated carefully because what qualifies as a "consequential" as opposed to a "direct" damage may be unclear. A project owner/developer's waiver of consequential damages may present potentially substantial loss exposure to the extent that the project owner/developer fails to achieve certain incentives (*e.g.,* tax credits) or performance objectives as a result of the contractor's failure to perform under the contract. The project owner/developer may attempt to mitigate such exposure through liquidated damages for

delay and performance shortfalls. A contractor may also seek to limit its liability for late performance to liquidated damages of a certain value, usually an agreed-on percentage of the contract price, and may seek to establish an aggregate liability limit. The project owner/developer should consider bargaining for exclusions to such contractor liability limitations. For instance, it could negotiate that the limitation of liability provision would not apply to the contractor's obligation to indemnify the owner for third-party claims, or that it would not limit the owner's damages for an inability to satisfy its power purchase agreement or to obtain certain time-sensitive benefits or credits, such as a tax credit, due to events in the contractor's control or a risk assumed by the contractor. These are highly sensitive areas for the parties and typically subject to substantial negotiation.

E. Solar Tax Credits. The economics of a solar energy system and the overall project budget often depend on obtaining certain benefits provided under state and federal law for renewable energy projects, including the federal solar investment tax credit ("ITC"). The loss of the ITC, or of similar state and federal benefits, can be very serious because the benefit, once lost, may never again apply to the project (unlike damages for failure to achieve an operational status for purposes of net metering, which may be limited to the actual period of delay), and thus could have long-term economic consequences. ITC-related damages are usually the subject of much negotiation between the supplier or contractor and the owner/developer. Insurance coverage may be available for certain delay-related risks, including failure to qualify for the ITC.

V. Other Issues.

A. Project Financing. A solar project owner/developer often requires some form of substantial debt or equity financing to pay for the design, engineering, procurement, construction, and initial operations of the project. Financial institutions and potential investors will demand the opportunity to review and comment on a project's design and EPC agreements (as well as related operations and maintenance and warranty agreements, if separate) before committing funds. Of special interest to prospective lenders and investors are the provisions in the agreements that provide the lender or investor with the ability to take over the project if the project owner/developer (the borrower) defaults, and the provisions that specify the extent and nature of any damages available to a project owner/developer from a contractor for late completion or failure of the project to generate expected amounts of power. Also, financial institutions will want to comment on the payment plans and security, warranty, and inspection provisions set forth in the project agreements.

Due to such involvement, and to avoid issues arising from any potential inconsistencies, the project owner/developer should be prepared to present a consistent and cogent set of project agreements to lenders and investors, and to listen to their suggestions for such agreements. Further, the owner/developer should be prepared for the possibility that lenders and investors may want to make substantial changes in the negotiated agreements. For instance, lenders will often be interested in the project's financial and operational viability (as may be reflected in a feasibility study), and much of that interest will necessarily focus on the project owner/developer's rights under the relevant agreements. In particular, lenders will be interested in the extent, limitation, and operation of any contractor

warranties, contractor indemnities, insurance policies, progress or performance-test milestones and payments, and performance and payment guarantees. Lenders will also want to know whether the various agreements are entered into on an "arm's-length" basis, meaning (among other things) that the terms and conditions of such agreements are based on typical commercial terms and standards. It is important to include typical financing cooperation provisions in the project construction agreements, including allowing the agreements to be amended as reasonably requested by lenders and investors. Contractors are likely to seek to limit this right by, among other things, including a limitation that such revisions cannot meaningfully increase the contractor's obligations or increase its costs to construct the project.

B. Performance and Payment Guarantees. A project owner/developer should cause the various contractors to procure, for the benefit of the owner/developer, performance and payment bonds (or other guarantees) to secure the obligations of the various contractors (whether engineers, contractors, or other parties) to complete their work on time and in accordance with the requirements of their various agreements, and to protect against liens and claims from unpaid contractors and subcontractors. Typical guarantees are described below.

- *Performance Bond.* A performance bond is usually issued by a bank, insurer or bonding company, and is selected or approved by the project owner/developer, and states an agreed-on "penal sum," often the full value of the project. This sum is payable upon the owner/developer's demand in the event that the contractor fails to perform its contractual obligations in a proper and timely manner. For instance, when the contractor defaults or cannot complete the project, the owner/developer may call on this bond to pay another contractor to complete the project. The owner/developer will want to reserve its other rights against a defaulting contractor in the event that the performance bond does not fully cover the owner/developer's costs of completing the project or costs associated with damages the owner/developer may owe to a third party as a result of any default by the owner/developer. While terms of the bond are often presented by the surety as "standard," they are still somewhat negotiable to ensure that the owner/developer is protected sufficiently. The bond obligations should be coordinated with the obligations of the EPC or turnkey agreement (i) to ensure that the project owner/developer's compliance with the notice and default obligations under the EPC agreement will satisfy the requirements under the bond and (ii) to avoid unintended conflicts or preclusion of the project owner/developer's ability to recover under the bond.

- *Payment Bond.* A payment bond is intended to ensure that if the contractor fails to pay its subcontractors and suppliers following receipt of payment from the owner/developer, then such subcontractors and suppliers will be paid, often without the necessity of filing liens or other security interests against the project

owner/developer's property. If a lien claim is asserted, it may be "bonded-over" so that it attaches to the payment bond or other security instead of the property. Lenders, upon their review of the agreements, may demand or require payment bonds or other guarantees (including subordination agreements where not prohibited by state law) to enhance their security interests in the project. Methods of substituting bonds for lien claims vary from state to state, so careful attention to the laws of the project state is important.

The project owner/developer or the lenders may require other security from contractors, such as parent guarantees, standby letters of credit, and other forms of assurance. The contractors will seek ample opportunity to cure any default or delay, and will try to limit the project owner/developer's ability to call on performance or payment bonds or other security without clear proof of a failure of performance by the contractor. In turn, contractors may demand some form of reciprocal security issued by the owner/developer or its parent company, including parent guarantees, payment guarantees, and the like, particularly if the owner/developer's only substantial asset is the project itself.

C. Lien Release Issues. When the project owner/developer makes periodic payments to contractors (and thus also to subcontractors and suppliers), the owner/developer should obtain lien and claim releases to the fullest extent permitted by applicable law. Many states require the use of specific statutory forms of lien releases on a conditional or unconditional basis for interim and final payments. A lien release will help protect the owner/developer from liens being filed on the project by lower tier subcontractors and suppliers that have such rights if they have not been paid, and avoiding the possibility of the project owner/developer paying twice for the same work or materials. Additionally, such liens are undesirable because, once filed, they can delay or interfere with the project's financing or sale. They also generate litigation, in which a successful lien claimant in a lien foreclosure action is often entitled to recover its attorneys' fees, costs and interest in addition to the contractual amount due. Worse still, if a lien claimant is successful in prosecuting its lien claim to foreclosure, such a lien could be used to force the sale of the project, or part of it, which would further interfere with the project owner/developer's plans for the sale or refinancing of the project. Many financing agreements will also consider a lien to be a breach of the agreement.

D. Insurance and Indemnity Issues. A project owner/developer should obtain appropriate indemnities and insurance coverage from the various parties with which it contracts, should require those parties to obtain similar protections from their subcontractors and material suppliers for the benefit of the owner/developer, and should verify compliance with such requirements. Relevant indemnities include a general indemnity for personal injury, death, and property damage claims, contractor and subcontractor lien indemnities, an indemnity for taxes (other than those payable to the owner/developer), an indemnity for violation of applicable laws, and an indemnity for intellectual property infringement claims. Appropriate insurance policies include commercial general liability, workers' compensation and employer's liability, automobile, errors and omissions (for design and engineering services), and builder's all-risk (property insurance for the project improvements). Such

policies should name the owner/developer and its financing parties as additional insureds and contain appropriate waivers of subrogation. Appropriate policy limits will vary with respect to the nature of the work being performed and the scope of the project. It is advisable for an owner/developer to consult with an insurance or risk management specialist to ensure that appropriate types and levels of coverage are obtained.

VI. Current Developments. In recent years, solar energy has grown exponentially from a start-up based niche market to what is now recognized as a sector that is "here to stay" within the entrenched electrical power generation market. Although solar energy is still viewed as more expensive to produce than other forms of energy, the cost of solar energy is dropping at a faster rate than that of any other form of energy. Creativity abounds in solar energy technologies and installations, and this creativity certainly extends to the structures and terms of the legal relationships among the entities that must come together for the design, supply of equipment, construction, and service of solar energy systems at utility scale. Stoel Rives has been at the forefront of many of the groundbreaking PV projects at utility and commercial scale, and we look forward to providing leadership in providing innovative and appropriate legal solutions to build this important sector of the renewable energy industry through successful projects for all concerned.

Chapter Five
THE LAW OF SOLAR
—Regulatory and Transmission-Related Issues—

Seth D. Hilton, Jason Johns,
Jennifer H. Martin, Jennifer Mersing

Long before a solar developer begins generating the first kilowatt of power, the developer must decide on a regulatory structure for the project, negotiate and execute net-metering or transmission and interconnection agreements, and purchase necessary transmission and ancillary services or distribution-level services. Solar projects come in many different forms, and business models range from installations for the installer's own electric needs and sales directly to third-party retail customers to large, utility-scale solar developments dozens or hundreds of megawatts ("MW") in size. Whether and to what extent the developer will be subject to regulation for the development of the project and the sale of the electricity generated by the project will depend on the business model, the size of the project, and the use to which the purchaser puts the energy (*i.e.,* direct consumption or resale). This chapter presents a general discussion of these issues on the federal level and discusses the general procedures that may apply at the state level. Of course, specific state-level regulation will vary from state to state. Before embarking on a particular course of action, it is highly recommended that a developer seek the opinion of qualified counsel, especially considering that many of the laws and regulations relating to these topics may be affected by recent legislation and ongoing rulemaking proceedings.

I. Federal Regulatory Structure Issues: PUHCA, EWGs, QFs, and Market-Based Rate Authority. The Energy Policy Act of 2005 repealed in part the Public Utility Holding Company Act of 1935 ("PUHCA 1935") and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), thereby opening the door to certain utility acquisitions and mergers that had been prohibited since 1935.

PUHCA 2005 also ended the Securities and Exchange Commission's extensive regulation of nonexempt electric utility companies, including solar developers. However, PUHCA 2005 (1) granted state regulators and the Federal Energy Regulatory Commission ("FERC") broad access to books and records of such companies and (2) provided for FERC review of the allocation of costs for nonpower goods or services between regulated and unregulated affiliates of such companies.

Solar project companies can obtain exemptions from these requirements. The two most common exemptions are for the project owner to obtain status as either an exempt wholesale generator ("EWG") or a qualifying facility ("QF"). Each of these categories is summarized below.

A. Exempt Wholesale Generator Status. In an effort to stimulate wholesale electric competition, Congress enacted the Energy Policy Act of 1992, which created an exemption from regulation under PUHCA 1935 for companies that were "holding companies" solely with respect to EWGs. That exemption continues with respect to PUHCA 2005. EWG status is determined by FERC, and

the EWG status begins once the independent power producer self-certifies such status with FERC. EWG status is available to any generator of electricity, regardless of size or fuel source, so long as such entity is exclusively in the business of owning and/or operating electric generation facilities (including certain incidental activities) for the sale of energy to wholesale customers.

Independent power producers should be aware of several issues associated with EWG status. First, the "exclusively own and/or operate" requirement mentioned above typically requires the creation of a special-purpose entity to own the solar power generation facility and to sell its electrical output. Second, EWGs are restricted to wholesale sales and therefore cannot take advantage of retail sale opportunities in jurisdictions that have approved retail direct access, or that would permit the solar developer to sell directly to retail consumers without becoming regulated public utilities, as discussed below. Finally, EWGs are restricted in their ability to enter into certain types of transactions (such as leases) with affiliated regulated utilities.

Rates for power sales by EWGs are subject to FERC regulation under Section 205 of the Federal Power Act. As a result, an EWG must apply for, and FERC must grant, market-based rate authority, *i.e.,* power-marketing rights, before an EWG can sell any wholesale power (including the generation of test energy). FERC generally grants market-based rate authority, provided that the applicant and its affiliates (if any) demonstrate a lack of horizontal market power (electric generation) and vertical market power (transmission and other barriers to market entry) in the relevant power markets, and have satisfied restrictions on affiliate abuses contained in FERC regulations. The criteria that FERC considers in granting market-based rate authority are subject to change, and instructive precedent is scattered throughout FERC's many rulings on the subject. Once FERC grants market-based rate authority to an entity, the entity will have ongoing filing requirements at FERC (including filing quarterly reports on power sales and contracts).

B. Qualifying Facility Status. During the energy crisis of the 1970s, Congress passed the Public Utility Regulatory Policies Act of 1978 ("PURPA") to encourage the development of cogeneration and small (up to 80 MW) renewable energy projects, which are referred to as QFs. Before the passage of the Energy Policy Act of 2005, PURPA was important to renewable power developers for several reasons, one of which was the exemption for QFs producing up to 30 MW from most of the provisions of the Federal Power Act, PUHCA and from certain types of state utility regulations. The Energy Policy Act of 2005 (and FERC's interpretation thereof) has narrowed the exemptions from the Federal Power Act to a smaller class of QFs, making such exemptions less common than in the past. On the other hand, the Energy Policy Act of 2005 also eliminated PURPA's requirement that restricted utility ownership of QFs, generating new interest from utilities in owning QF facilities—increasing the value of both new and existing QF projects.

The Energy Policy Act of 2005 also narrowed the advantages that renewable power generation QFs previously had over EWGs (although many renewable projects over 30 MW are certified as both QFs and as EWGs). First, as mentioned above, many QFs no longer enjoy broad exemptions from the requirements of the Federal Power Act. Significantly, only certain QFs continue to enjoy an exemption

from the need to obtain market-based rate authority from FERC in order to sell wholesale power at market rates. Specifically, sales of energy and capacity made (1) by QFs 20 MW and smaller, (2) pursuant to a contract executed on or before March 17, 2006, or (3) pursuant to a state regulatory authority's implementation of PURPA remain exempt from the market-based rate authority requirement. Second, the Energy Policy Act of 2005 weakened the "must buy" obligation that allows QFs to require retail public utilities to purchase QF output at the utility's "avoided costs," *i.e.,* the costs the utility would have incurred but for the QF energy purchased. A utility may petition FERC for an exemption from PURPA's mandatory purchase requirement if it can demonstrate that QFs in its service territory would have nondiscriminatory access to competitive wholesale markets for energy and capacity that meet certain standards. Many utilities have already obtained this exemption, primarily in the areas with organized energy markets. Most of these exemptions have affected QFs that are larger than 20 MW; however, in a limited number of cases, QFs that are 20 MW and smaller have been affected, too. The loss of this "must buy" requirement can be significant because state-established "avoided cost" rates have often exceeded prevailing wholesale market prices, and such published rates have been an effective negotiating tool for gaining favorable pricing under non-QF renewable energy sale agreements. One clear advantage of QFs over EWGs is that PURPA does not restrict the ability of QFs to make retail sales to the extent such sales are allowed under state law. Another distinction between QFs and EWGs is that QFs, when selling their energy under PURPA, are interconnected under state regulators' interconnection rules, which may or may not be advantageous for a particular project.

To obtain QF status, solar developers were traditionally required to file a self-certification of QF status or apply for FERC certification. However, in 2010, developers became exempt from making any filing with FERC to obtain QF status with respect to a facility that is 1 MW or smaller. The size of the QF is based on the net power production capacity of all affiliated same-fuel source facilities within one mile. Larger facilities remain subject to the traditional methods of certification.

C. Other Ongoing Regulatory Requirements. Whether a solar developer is an EWG and/or a QF, and/or has market-based rate authority, the solar developer may also be subject to other filing and reporting obligations at FERC. For example, for those entities with market-based rate authority, FERC's prior approval may be required before the developer disposes of FERC-jurisdictional facilities. This prior approval requirement generally applies to the direct or even indirect disposition of such assets, including the sale of project membership interests to investors, a foreclosure by debt providers, or an upstream change in corporate control. Likewise, FERC may require updates to the market-based rate authority, EWG certification, and/or QF certification in connection with changes in the material facts on which FERC relied in granting such status. Finally, FERC notice or approval may be required when certain directors or officers hold similar positions in related affiliates. The foregoing list is not exhaustive and is intended to highlight only some of the various FERC notification and filing requirements related to jurisdictional solar developers.

II. State Regulatory Structure Issues: Regulation as a "Public Utility." An important issue of state regulatory concern for solar developers looking to make retail sales to third parties is whether

such sales will result in the generation owner being regulated as a "public utility." This has become particularly important in recent years as large commercial and industrial customers have become more interested in structuring their own energy portfolio. (Note: If the sale is a wholesale sale (*i.e.,* a sale for resale), the sale will be governed by federal law.) Parties selling electricity to end-use customers are often heavily regulated as public utilities under state law, including regulation of rates and terms of sale for electricity. Typically, a solar project owner will want to ensure that it is not regulated as a state-jurisdictional public utility if it sells power directly to end-use customers. Whether a solar generation owner is regulated as a public utility will vary from state to state, and potentially relevant factors include the number and type of customers supplied and the location of those customers relative to the location of the generation. In California, for example, generally an entity that sells electricity to end-use customers is a public utility regulated by the California Public Utilities Commission ("CPUC"). In some circumstances, however, a solar generation owner can sell power to not more than two other corporations or persons for use on the real property where the electricity is generated, or on property immediately adjacent thereto, without being regulated as a public utility.[1]

III. Transmission and Interconnection Issues. To gain access to markets for project output, solar project developers that are not interconnecting pursuant to a state's net-metering rules or pursuant to a state-jurisdictional distribution tariff discussed below must negotiate agreements to interconnect with the transmission system of the local transmission provider. In addition, a developer will need to obtain any necessary transmission service to deliver project output to the purchasers of that output, and such services can become quite costly. Most lenders and many investors will require evidence of executed generation interconnection and/or transmission service agreements as a condition of financing or project purchase. Most transmission providers are subject to FERC jurisdiction, and therefore transmission service agreements and generation interconnection agreements are generally subject to regulation by FERC. However, some utilities are not subject to FERC oversight, and an interconnection with those utilities may raise unique issues, which should be considered when selecting a project site.

A. Generation Interconnection Agreements. A generation interconnection agreement is a contract between the generation owner and the transmission owner that owns the transmission facilities with which the project will be connected (and in certain instances, the Regional Transmission Organization ("RTO")/Independent System Operator ("ISO") that operates the transmission facilities will be a third signatory to the agreement). FERC's Order No. 2003 established standard interconnection procedures, including a standard interconnection agreement for generators larger than 20 MW ("large generators"). Similarly, FERC Order No. 2006 established standard interconnection procedures, including a standard interconnection agreement for generators with a capacity of 20 MW or less ("small generators"). Certain RTOs, such as the Midwest Independent System Operator, the California Independent System Operator, and the Southwest Power Pool, have since reformed their interconnection procedures and agreements in response to substantial backlogs and delays in the existing queues. As a result, interconnection processes that were once largely uniform across the nation

[1] Certain additional restrictions also apply to this exemption; whether the exemption applies depends on the particular situation.

now vary widely across regions, requiring developers to obtain region-specific knowledge or suffer the consequences. Generally, queue reform has implemented a "first-ready, first-to-advance" methodology, requiring larger study deposits that may be nonrefundable and stricter adherence to progress milestones, and allowing fewer opportunities for developers to delay the process or modify their proposed generating facilities. Queue reform has had a dramatic impact on the interconnection process, and changes continue to occur as transmission providers further refine their processes.

Generally, the two main purposes of interconnection agreements are (1) to identify and allocate the costs of any new facilities or facility upgrades that need to be constructed and (2) to set forth the technical and operational parameters governing the physical interconnection.

1. Interconnection Facilities and Cost Allocation. In general, before the execution of an interconnection agreement, the transmission provider will commission a series of interconnection studies, at the interconnection customer's expense, to determine what new interconnection and transmission facilities need to be constructed to accommodate the new generation facility and the cost of such construction. Like many renewable energy projects, if it is located in a remote place without much existing transmission infrastructure, substantial new facilities and facility upgrades may be required.

Under FERC Order Nos. 2003 and 2006, the costs of interconnection facilities and distribution upgrades are paid for by the interconnection customer. Network upgrades (*i.e.,* upgrades to the transmission system at or beyond the point of interconnection) are treated differently, however, and transmission credits or another form of reimbursement may be available to the interconnection customer. For example, if the transmission provider is a nonindependent entity, such as a vertically integrated utility, the interconnection customer will often pay the upfront cost of any required upgrades, but the transmission provider will reimburse the interconnection customer by providing transmission credits or cash reimbursement. However, in certain transmission systems, such as those controlled by the Midcontinent Independent System Operator or the PJM Interconnection, the interconnection customer will not be entitled to all or even a portion of this reimbursement. In these and other regional transmission systems, cost allocation and refund methodologies are often in flux.

Determining the point of interconnection for purposes of distinguishing between interconnection facilities and network facilities is an area of potential dispute between the parties. Transmission providers have an incentive to design interconnections in a manner that places the majority of the new facilities on the customer's side of the interconnection, thereby depriving the customer of a reimbursement against the costs of such facilities. Consistent with FERC precedent, only those facilities that are necessary to reach the point of interconnection are properly classified as interconnection facilities. In addition, for most interconnections of small generators, extensive network upgrades are unusual unless a project will be located near a congested portion of the transmission system. In some cases, the costs of interconnection can make a project uneconomical.

2. Technical and Operational Issues. Interconnection agreements address such technical and operational issues as reactive power factors, responsibility for electrical disturbances, metering and testing of equipment, exchange of operating data, and curtailment events. In some cases transmission providers attempt to impose technical requirements or control area services that go beyond those that FERC has typically approved. Solar developers should therefore pay close attention to the technical requirements and control area charges proposed in the interconnection agreement. In addition, the generator interconnection agreement may require compliance with applicable National Electrical Code ("NEC"), Institute of Electrical and Electronic Engineers ("IEEE"), and Underwriters Laboratories ("UL") standards or other state or local electrical code standards to ensure proper installation and use of certified equipment. Even if the generator interconnection agreement is silent on NEC, IEEE, and UL standards, such standards may apply through state or local law and rules and should be considered before hiring contractors and beginning engineering.

B. State Interconnection Agreements and Net Metering. Generally speaking, distribution-level interconnection is governed by state utility commission rules; however, if the distribution facilities to which the project would be interconnected are subject to a FERC-jurisdictional open access transmission tariff ("OATT"), and if the interconnection is for purposes of making wholesale sales (or even having the option of making wholesale sales), FERC's generator interconnection procedures would likely apply. Such dual-use facilities (*i.e.,* facilities that provide delivery to both end-users and wholesale purchasers) are regulated by both state and federal governments within their respective jurisdictions. In addition, if interconnection is with an entity that is not subject to state or FERC jurisdiction (such as an electric cooperative or public utility district), then the developer may face additional issues and negotiations that are beyond the scope of this summary.

If interconnection is governed by state utility commission rules, simplified procedures may apply for interconnection below a certain size threshold, including standardized form agreements specifically designed for interconnecting solar distributed generation. Standardized agreements have the benefit of lowering transaction costs, although the ability to negotiate terms and conditions in the agreement is significantly reduced if not prohibited. Interconnection procedures and agreements can in many cases be obtained by contacting the local utility. Generally, the state-level interconnection agreement will cover technical and operational issues, as well as the point of interconnection and responsibilities of the customer and utility.

Solar generation interconnecting at the distribution level may also be able to take advantage of net-metering rules. Net metering is an arrangement with a customer's utility whereby the customer uses its own installed generation to offset its energy usage and may receive credit for limited excess generation. Generally, a customer ends up with a lower utility bill for two reasons: (1) the net-metering arrangement allows the customer to offset its own electricity usage on an instantaneous basis with the solar power produced by its own solar generation system, thereby reducing the amount of power the customer must buy from the utility, and (2) the customer can deliver generation in excess of that currently used by the owner back to the utility and receive a credit from the utility for such generation.

Whether the customer can roll forward or receive a cash payment for any credits for excess generation varies from state to state. Essentially, a net-metering arrangement allows the generation owner's meter to "run backward" when excess generation is supplied to the utility, offsetting the bill from the utility. However, FERC may assert jurisdiction over a net-metering facility if the facility makes net sales of energy (*i.e.,* the facility produces more energy than can be consumed) to a utility over the netting period established by the applicable program (often one year).

Several restrictions usually apply to the net-metering arrangement. Generally, state law and public utility commission rules will set forth the process by which an entity becomes a net-metering customer. State law generally sets forth the criteria for the type of customer (*i.e.,* residential, commercial, or, in some states, limited commercial or industrial customers) and the size of the distributed generation project eligible for the state's net-metering program, plus safety requirements and other program restrictions and requirements. Finally, state law and public utility commission regulation may restrict the ability of a third party to own the renewable energy system used by a customer in that customer's local utility's net-metering program. In addition to eligibility restrictions, potential net-metering customers should look out for other potential issues in net-metering arrangements, such as high liability insurance coverage requirements, indemnification provisions, and other forms of customer charges associated with net metering. These charges may include interconnection charges, demand charges that the utility may assess to cover the costs of being on "standby" to provide power to the customer if the customer's generation does not produce energy when expected, charges for use of the transmission system when excess power is delivered, and equipment charges for specialized metering or safety equipment.

C. Transmission Service Agreements. Interconnection service or an interconnection by itself does not confer any delivery rights from the generating facility to any points of delivery beyond the interconnection point. Therefore, unless the project owner is able to sell the output of the project at the point of interconnection with the transmission grid, the project owner will be required to obtain transmission service from one or more transmission providers to wheel project output to the purchaser.

FERC-jurisdictional transmission providers are required by FERC to offer transmission service on an open, nondiscriminatory basis pursuant to a transmission tariff that will govern the terms by which such service is provided. Upon receiving a request for service, the transmission provider will evaluate available transmission on its system and determine whether additional transmission facilities need to be constructed to accommodate the requested service. In major parts of the United States, the transmission provider is an RTO or ISO rather than the actual owner of the applicable transmission facilities. Acquiring transmission service from non-FERC jurisdictional transmission providers raises additional questions that depend on the nature of the entity, the scope of its transmission facilities, and other issues beyond the scope of this chapter.

Under FERC's general transmission pricing policy, generators pay the greater of the incremental costs or embedded costs associated with requested transmission service. Incremental costs refer to the additional system costs (*e.g.,* construction of new facilities and upgrades) resulting from the requested

service. Embedded costs reflect an allocation of system costs to the various users, generally based on service capacity (MW). A solar power project that is located far from adequate transmission infrastructure may require substantial system upgrades that will cause the transmission customer to pay an incremental cost that exceeds its pro rata share of the system costs. For these and other reasons, a developer may want to consider making a sale to a third party at the point of interconnection, rather than becoming a transmission customer of the transmission provider with which the project interconnects.

These transmission pricing rules may be different if the transmission provider is an RTO/ISO. The rules of the existing and proposed RTOs/ISOs may in fact be much more favorable to solar power generation than is FERC's general transmission pricing. For example, an RTO/ISO may recover the fixed costs of the applicable transmission system from end-users, with a generator facing only transmission congestion charges. The RTO/ISO also may eliminate rate "pancaking," which is the imposition of multiple transmission charges for use of more than one utility's transmission facilities.

IV. Ancillary Services: Imbalance Charges, and Firming and Shaping Products. Project owners will be required under the transmission provider's tariff to provide or purchase transmission ancillary services, which are products designed to ensure the reliability of the transmission system. These charges apply most often to project developers who obtain transmission service away from their project's point of interconnection. Of these products, generation imbalance service often poses the most difficult issues for renewable energy power operators with variable resources. Generation imbalance service is a product that allows a generator to deliver an amount of energy that differs from the amount it had prescheduled for delivery. Although solar energy is expected to be more predictable than wind energy, certain types of solar technology have more variability, which must be considered in terms of imbalance requirements and penalties.

Most transmission providers had historically priced generation imbalance service based on the cost or value of the generation, plus a premium. For example, a transmission provider may have charged generators 110 percent of the cost of providing replacement energy in hours when the actual output of a generator was less than scheduled output, and compensated generators 90 percent of the value of energy produced in excess of the amount scheduled. In addition to this basic charge, penalties attached if the difference between scheduled and actual generation exceeded a specified threshold. Such charges were intended to promote accurate scheduling and to prevent system reliability concerns associated with large imbalances; however, these penalty-type imbalance charges punished variable resource generators for variations in output over which the generators lacked control.

Acknowledging that existing energy imbalance charges under Schedule 4 of the OATT and the generator imbalance charges described in FERC Order No. 2003 were discriminatory to variable energy generators, FERC established in Order No. 890 a tiered structure for imbalance charges, with imbalance charges increasing as the imbalances themselves grow larger. Order No. 890 also provided at least two benefits to variable resources. First, the rules provided for monthly netting of imbalance charges within the first tier. Second, variable resources were excused from exposure to the most expensive deviation

charges. Although these rules can provide significant benefits to solar power resources, it is important to understand that transmission providers may be permitted to adopt different provisions applicable to variable resources within their respective control areas.

In addition, it is becoming common for transmission providers to revise their protocols for integrating variable resources into the grid and to impose generator regulation charges or other within-hour balancing charges on variable resources.

V. Greater Access to the Transmission Grid. FERC's Order No. 890 was designed, in part, as an effort to improve transparency of transmission service and reduce transmission barriers for new market entrants. These amendments have resulted in increased and improved access to the transmission grid for renewable energy developers.

A major obstacle to making more transmission capacity available was that under previous practice, long-term requests for service from a new generator may be denied based on the unavailability of transmission in only a few hours of a year, even though that same capacity is nonetheless available for the large majority of hours of the year. To address these concerns, FERC created two options: conditional firm service and modified redispatch service. These two services provide options for variable resources to gain faster access to the transmission system, as such resources may avoid having to delay going in service until the completion of transmission upgrades.

Conditional firm service addresses the "all or nothing" problem transmission customers had faced, and it is a partial solution to the lack of available firm transmission capacity. Under this service, a conditional firm customer enters a long-term contract for the capacity that is available on a transmission path. The customer has firm service except for time periods designated in the contract and has priority over non-firm service customers for the hours in which available transfer capacity ("ATC") is not available. Similarly, some transmission providers have transformed the conditional service concept to offer conditional or limited interconnection service as well, which service may subject the project to increased curtailment but will allow a project to become operational before the construction of substantial upgrades.

Modified redispatch service, which adjusts the output of various generators to allow transactions that otherwise would be blocked by congestion on certain transmission paths, is routinely used by integrated utilities (those with transmission and generation) to serve native load and network customers, and to make off-system sales. Order No. 890 required transmission providers to offer and study the use of redispatch service to create additional long-term firm capacity on a transmission system. Customers would agree to pay the costs of redispatch service during the periods when firm ATC is not available. Conditional firm service and modified redispatch service can provide a useful bridge service until new transmission capacity becomes available, although the services may not be sufficient to satisfy the demands of performing a power purchase agreement or obtaining third-party financing.

VI. Reliability Standards. Many solar power generation owners and operators are subject to mandatory reliability standards that include ongoing, audited obligations and potential sanctions for

compliance failures. The North American Electric Reliability Corporation ("NERC") is certified by FERC as the continent-wide Electric Reliability Organization ("ERO") responsible for proposing and enforcing mandatory reliability standards. As the ERO, NERC is responsible for monitoring and improving the reliability and security of the bulk electric system, and, to do so, NERC has the authority to propose and enforce mandatory reliability standards and assess fines upwards of $1 million per day per violation for noncompliance, although penalties rarely reach that level when assessed. In addition, NERC has delegated to designated regional entities the authority to monitor and enforce the reliability standards, and the regional entities may in turn enforce region-specific reliability standards.

The reliability standards apply to certain users, owners, and operators of the bulk electric system, and the regional entities are tasked with maintaining a Compliance Registry, which lists organizations against which the reliability standards are enforceable. If an organization fails to register on the Compliance Registry, then the regional entity may register the entity itself. The Compliance Registry lists organizations by function, and compliance is analyzed by reference to function-specific reliability standards.

As is most relevant to solar developers, NERC requires that certain Generator Owners and Generator Operators register with the Compliance Registry. A Generator Owner is, broadly defined, as an organization that owns generating units, and a Generator Operator is defined as an organization that operates generating units and supplies energy. There are thresholds that may dictate whether a Generator Owner or Generator Operator must register or even meets the initial requirement of being a user, owner, or operator of the bulk electric system. Though initially exempted from registration, QFs can also be required to register with the appropriate regional entity and to comply with the reliability standards. Furthermore, solar developers should also understand that sharing a generator interconnection line with other projects (whether affiliated or not) may also lead to NERC registration. If the combined size of projects sharing a gen-tie exceeds 75 MVA and the point of interconnection is at 100 kV or higher, then NERC registration is likely.

Given the breadth of the reliability standards and the punitive sanctions attached, industry participants must take the appropriate steps to determine whether they should register with the applicable regional entity, to understand each function, and to implement a comprehensive program that will track and ensure compliance.

VII. California Regulatory Developments. In California, a dynamic regulatory environment with several active state agencies—including the CPUC, which regulates investor-owned utilities, and the California Energy Commission ("CEC"), which is California's primary energy policy and planning agency and is responsible for siting thermal generation, including concentrated solar power ("CSP")—has resulted in numerous ongoing efforts to increase opportunities for solar generation, both photovoltaic and CSP.

Among the recent developments in California is passage of Senate Bill 350 in October 2015, which increases California's Renewable Portfolio Standard ("RPS") to 50 percent by 2030. The RPS applies to

all retail sellers of electricity, including investor-owned utilities, publicly owned utilities and community choice aggregators. Both the CPUC (in Rulemaking 15-02-020) and the CEC are in the midst of efforts to implement the new legislation. California's RPS program contains a number of restrictions concerning how utilities may count renewable resources located outside a California balancing authority area toward their RPS obligations. Those restrictions vary depending on how the energy is delivered to California as well, and therefore are an important consideration for any project developments outside of California that intend to sell their output to California utilities.

The CPUC also has the Renewable Market Adjusting Tariff ("ReMAT"), a feed-in tariff for small renewable generators less than 3 MW. The ReMAT program allows renewable projects less than 3 MW to sign standard contracts, with a standard price, that must be accepted by the utilities until an overall megawatt cap is reached.

VIII. Summary. Solar developers range in size and business model greatly, and the regulatory and transmission-related issues are highly dependent on the unique circumstances presented by each particular project. Solar developers should be mindful of the various state and federal regulatory requirements, as well as the opportunities presented by the regulatory oversight in these areas.

Stoel Rives LLP

Chapter Six
THE LAW OF SOLAR
—Permitting and Land Use—

Timothy L. McMahan, Allison C. Smith

It is not enough to have the sun and the land to construct a solar energy facility. One also needs the permits to use the land for energy generation. Even in a regulatory environment that is favorable to renewable energy projects, every element of the facility must have the proper approvals to be legally constructed and operated. Failure to obtain the correct permits can be costly in terms of construction delays related to stop work orders; forgone revenues, tax credits, and commencement of accelerated depreciation; and, in today's regulatory climate, quite possibly penalties for failure to meet renewable portfolio standards. Further, it is important to identify and evaluate the required approvals prior to committing to a particular property.

I. Facility Permitting Rules. Energy facility permitting is usually a state or local jurisdiction function, unless the facility is constructed on federal land or involves other federal action.

A. State Energy Facility Siting. Many states have agencies, administrative boards, or councils that have jurisdiction over the approval or denial of the siting of energy facilities. In states with centralized siting councils, such as Oregon, Ohio, and Massachusetts, the council renders a decision to approve or deny an application to site a major energy facility. In Minnesota and several other Midwestern states, the state public utilities commission oversees siting of major energy facilities, but states may vary on whether the state certificate or site permit preempts the need to also obtain local permits (*e.g.,* in North Dakota a certificate of site compatibility does not preempt local ordinances). In California, most such decisions are made by the local planning agency, usually at the county or city level. In Washington, siting council jurisdiction for renewable energy facilities is voluntary only; a developer may opt in to state siting council jurisdiction, with the final decision made by the governor upon recommendation by the siting council.

States differ greatly on whether the state or a local agency will assert jurisdiction over energy facilities. Many states, such as Oregon and California, require energy facilities that will occupy a defined acreage area or generate a defined amount of power and/or utilize certain technologies to undergo siting by the state agency while allowing facilities generating amounts under the threshold to be sited by the local jurisdiction in which the facility is proposed. In Minnesota, a project may fall under the state's siting authority under certain conditions by aggregating several smaller distributed solar projects. Other states, such as Washington, have full authority to site any size energy facility, but do so only at the election of the applicant. Some states, such as Texas, provide for no such state jurisdiction.

Once a solar developer has determined whether state or local siting authority (or in certain cases both) has jurisdiction over solar facilities, it can move forward. The developer should check the state's jurisdictional requirements carefully to determine whether the solar development will be subject to the

state siting process and, if so, whether there are exemptions from or waivers for state siting process requirements.

B. Local Energy Facility Siting. In states in which there is no centralized siting authority or the authority lacks jurisdiction over solar facilities, the siting decisions are made by local jurisdictions, most often cities, towns, or county governing bodies. Commercial solar facilities that are not located on a rooftop often require vast tracts of land for both operations and environmental mitigation purposes. They may also require significant amounts of water. For these reasons, as well as the cost of land and aesthetics, non-rooftop solar facilities are typically located outside of urban areas. In Midwestern states where significant greenfield solar development is more recent, local siting authorities have had mixed success effectively balancing solar development with existing agricultural preservation rules.

Rooftop facilities have become a growing part of the market as a result of ease of permitting and advantageous power pricing. For example, the California Solar Rights Act (Civil Code section 714), enacted in 1978, bars restrictions by homeowners associations on the installation of solar energy systems, but originally did not specifically apply to cities, counties, municipalities, and other public entities. The Act was amended in September 2003 to prohibit a public entity from receiving state grant funding or loans for solar energy programs if the entity prohibits or places unreasonable restrictions on the installation of solar energy systems. Generally speaking, rooftop solar facilities can be installed after obtaining a building permit, significantly simplifying the permitting process.

C. Federal Energy Facility Siting. Solar facilities proposed for construction on federal land fall within the jurisdiction of the agency charged with the land's management, most often the U.S. Department of the Interior's Bureau of Land Management ("BLM") or the U.S. Department of Agriculture's Forest Service. Federal land management policies encourage the development of solar energy on public lands. BLM issues right-of-way authorizations for solar installations, and the Forest Service issues special use permits. As part of President Obama's all-of-the-above energy strategy to expand domestic energy production, on October 12, 2012, Secretary of the Interior Ken Salazar finalized a program for spurring development of solar energy on public lands in six western states. The Programmatic Environmental Impact Statement ("PEIS") for solar energy development provides a blueprint for utility-scale solar energy permitting in Arizona, California, Colorado, Nevada, New Mexico, and Utah by establishing Solar Energy Zones ("SEZs") with access to existing or planned transmission, incentives for development within those zones, and a process through which to consider additional zones and solar projects. It is unknown how these programs will be implemented in the post-Obama era.

The solar PEIS establishes an initial set of 17 SEZs, totaling about 285,000 acres of public lands, that will serve as priority areas for commercial-scale solar development, with the potential for additional zones through ongoing and future regional planning processes. If fully built out, projects in the designated areas could produce as much as 23,700 megawatts of solar energy, enough to power approximately seven million American homes. The program also keeps the door open, on a case-by-case basis, for the possibility of carefully sited solar projects outside SEZs on about 19 million acres in "variance" areas.

The program also includes a framework for regional mitigation plans, and to protect key natural and cultural resources, the program excludes a little under 79 million acres that would be inappropriate for solar development based on currently available information.

D. Choosing a Siting Process. To the extent a developer of a large, utility-scale solar photovoltaic ("PV") facility has a choice of permitting agencies, there are several other factors to be weighed in choosing a siting path. The more extensive resources that are available to a state agency can result in expert review of a proposal. However, these venues are typically costly to an applicant. Local agencies often lack the financial resources to hire various experts, particularly in an emergent field such as commercial solar energy generation. The local jurisdiction may handle this lack of staff expertise by requiring that the developer fund or reimburse the local agency's costs expended in reviewing a project. A comparison should be made to determine the difference between state and local application fees and processing and review costs.

Another critical factor involves the political nature of energy facility siting decisions. Although solar facilities generally have less immediate visual impact than nuclear cooling towers, smokestacks, or wind turbines, any energy facility can evoke strong sentiments in a community. Siting of a contentious project, when conducted by a state agency, tends to be more objective and less politicized than a town hall-style local forum. When making the decision about which path to choose, the developer should consider the local political climate, and assess any broadly held attitudes and concerns that could signal an unpredictable, politicized process. Additional concerns will be who will be staffing the permit review, who will be making the decision, and what remedies are available under each permitting regime if a negative permit result is obtained.

II. Environmental and Land Use Considerations. Depending on the forum in which an application for a solar facility is processed, a variety of environmental and land use rules will be applied to evaluate the proposal.

A. Federal Environmental and Land Use Review. Approval of a facility on federal land through the issuance of a right-of-way, special use permit, or lease, as well as other federal agency approval actions such as Army Corps permits or endangered species take authority, necessarily involves application of environmental review under the National Environmental Policy Act ("NEPA"). The scope of a NEPA review is broadly designed to assess the environmental impacts of a proposed development and the potential significance of those impacts. This includes assessment of project development impacts to both the built (*e.g.,* roads) and the natural (soil, wildlife, and ground and surface water) elements of the environment. Predictably, the more significant the potential for adverse environmental impacts, the more closely the project will be scrutinized. It follows that the higher the level of review, the longer the process will take. Projects that are categorically exempted from NEPA by federal regulations can result in near-immediate review. However, nonexempt actions must go through an environmental assessment, usually a four- to six-month process, to determine whether the solar project will cause no significant impact (*i.e.,* a finding of no significant impact or "FONSI") or will likely cause significant environmental impact, which triggers the preparation of a full-blown Environmental Impact

Statement ("EIS"). Preparation of an EIS is a lengthy process that involves considerable and multiple public and agency review opportunities, and is rarely completed in under a year. Although NEPA itself is only a procedural and evaluative tool without substantive standards or requirements that must be imposed on a project, the resulting analysis of impacts, alternatives, and potential mitigation serves as the basis for imposition of conditions on projects.

Under section 106 of the National Historic Preservation Act ("NHPA"), each federal agency must take into account the effect of its actions on any property listed on or eligible for listing on the National Register of Historic Places and must consult with the state historic preservation officer and interested parties, including Indian tribes in appropriate cases both on and outside Indian reservations, on measures to avoid, minimize, and mitigate any adverse impacts of its action on such properties. An additional level of protection is afforded by NHPA section 110 to National Historic Landmarks. Advisory Council on Historic Preservation procedures for NHPA section 106 compliance are found at 36 C.F.R. part 800. The NHPA requires each federal agency to ensure that its procedures for section 106 compliance are consistent with the Advisory Council's regulations. Properties of traditional religious and cultural importance to Indian tribes and Native Hawaiian organizations, including wide swaths of public and private land outside Indian reservations in some cases, may be determined to be eligible for inclusion on the National Register and therefore the basis of federal agency consultations with Indian tribes. Like NEPA, the NHPA is a procedural statute that requires agencies to consider effects of actions on historic properties, but these considerations can lead to mitigation measures adopted by agencies as conditions on projects.

B. State and Local Environmental and Land Use Review. Each state and local agency puts its own stamp on environmental and land use review. State and local agencies typically conduct environmental reviews during the permit issuance process, whether the project calls for a siting permit issued by a state or a local permit (typically a conditional use permit).

Some jurisdictions may conduct a comprehensive environmental review of project impacts contemporaneously with the review of the permit itself for land use and regulatory consistency based on a state level environmental policy act. The process in such states is patterned after the federal NEPA framework and is commenced through a separate application for environmental review of the proposed project. The environmental review is conducted as an overlay to the permit review. Because environmental review regulations contain public notice and participation requirements, compliance with those requirements can add considerable time to the review process, sometimes up to a year. The same procedural review is applied by local jurisdictions when reviewing a permit. The developer should consult agency staff and, if necessary, legal counsel early in the process to ascertain the responsibilities of the developer as the review progresses. There are also timelines that accompany review processes. Clarification should be obtained to determine whether timelines set a maximum processing period or a minimum period before the agency may act but not a maximum time limit for rendering a decision.

In California, developers (and, increasingly, public agencies) see the California Environmental Quality Act ("CEQA") as a statute abused by labor unions, business competitors, and other project opponents to

achieve goals that may not be entirely related to environmental protection. Many CEQA lawsuits are filed each year, and they can take two years or more to resolve through the appellate courts. CEQA litigation can significantly slow projects or even stop them from going forward. Additionally, state and federal funding, as well as meeting guaranteed commercial operational deadlines in power purchase agreements, can be jeopardized due to such delays.

Some solar resource-rich states, such as Nevada and New Mexico, do not conduct contemporaneous environmental review processes at all.

Even if environmental review is not a separate process, some states and local jurisdictions will consider environmental issues as part of the permit application itself. Oregon, for example, has adopted criteria, applicable statewide, that address environmental issues. Solar facility developers in Oregon will encounter a host of statewide land use goals with substantive prohibitions built into them. These land use goals apply to both the state's Energy Facility Siting Council and every political subdivision. Such goals are stringently applied. Although there are processes to seek exceptions, those requests are reviewed narrowly and are judiciously granted, depending on the potential impacts to protected resources. Oregon has a rich history of publishing appellate decisions of land use appeals, and legal counsel should be able to assist in determining whether the criteria for a land use goal exception have been interpreted previously, which can provide guidance for difficult siting decisions.

In addition to environmental review, applications to develop solar facilities will undergo permit review to determine whether a solar facility is in compliance with the jurisdiction's approved land use laws. The first phase of such review is nearly always to assess whether the use is allowed outright or conditionally at the proposed location. Most often, this is accomplished by reviewing the zoning code to ascertain whether the solar facility is an outright, predetermined compatible use with other uses in the zone, or is a conditional use. If the use is conditionally allowed, the environmental assessment undertaken either as part of the permit review or separately through a NEPA-like process generally provides a host of conditions that can be imposed on the facility that render it more compatible with its zone.

Some states, such as California, have lands that are covered by an agricultural protection statute that may be associated with tax incentives and the like. The Williamson Act in California allows landowners to restrict their land to agricultural and compatible uses in exchange for lower property taxes. As solar development has increased on California's agricultural lands, the rules governing solar development on Williamson Act lands have evolved. Currently, nearly every local jurisdiction in California requires that a Williamson Act contract be canceled to accommodate solar development. The cancellation process can be controversial and requires the local jurisdiction to make specific findings, but the California courts have confirmed that cancellation of a Williamson Act contract in favor of solar development is permissible under certain factual circumstances. When pursuing solar development on Williamson Act land, it is important to understand the cancellation requirements and ensure the project can meet those requirements. Similar concerns are abundant, but are only more recently being tested, in Midwestern

states where prime farmland or agricultural preservation rules must be navigated in order to allow a solar facility to be constructed on certain agricultural land.

An emerging conflict between agricultural land uses and habitat is rapidly materializing in solar PV facility siting. This is particularly true for large utility-scale solar facilities proposed on highly productive farmlands, especially those that are irrigated and have the capability to produce high-value crops. The flip side is pressure to develop areas with potentially important habitat value, including wintering range areas for deer and elk, and areas with substantial water resources. These agricultural and habitat values often emerge in project opposition choosing to use such land attributes as a proxy for perceived aesthetic impacts, as well as generalized anxiety over alterations to local landscapes.

Additional land use laws that may apply to a solar project include surface and ground water quality and quantity protection, as well as shoreline regulations. The genesis for many of the state-administered laws is the federal Clean Water Act, although states such as Washington and California have also enacted shoreline protection laws that superimpose more review and additional permits before a solar facility may be permitted.

For most local permitting decisions, the body empowered to approve a project is a board of county commissioners or a legal equivalent or, less commonly, planning agency administrators.

C. Streamlining the Process. Some jurisdictions are beginning to recognize the value of consolidating the permitting processes for several renewable technologies. For example, a county in Washington has conducted an area-wide EIS for wind energy facilities to create an overlay zone in certain areas for wind development. While the environmental impacts for wind energy development were being assessed, the ramifications of solar energy facility development were considered. As a result, both technologies have been established as permitted uses in certain zones. A solar facility proponent should meet early with the local planning authority to review the compendium of land use laws and determine which permits will be required, as the opportunity to reduce permitting costs is significant.

Energy generators and developers are also taking steps to reduce the time and cost of solar facility permitting by co-locating several renewable energy generation facilities on a single site. An example of this is found at the Wild Horse Wind Power Project in Washington. The wind energy facility owner is a utility subject to the state's renewable portfolio standards. The facility occupies over 6,000 acres on which are placed only 121 turbines. Because wind turbines occupy a vertical plane and solar panels a horizontal plane, there is room for the two technologies to compatibly occupy the same acreage. Both share transmission facilities, reducing capital facility costs. The environmental impacts for both the solar and wind facilities were constrained to the same site, resulting in a more expeditious and less onerous environmental review process.

Many ground and rooftop solar projects are now being planned for urban areas, which raise unique issues with respect to permitting and due diligence. Individual jurisdictions may have permitting or sometimes building code ordinances for such units. Further, such facilities may be located above

brownfields or other contaminated sites that require additional due diligence to understand past environmental issues and how those issues may impact the project.

Chapter Seven
THE LAW OF SOLAR
—Project Finance for Solar Projects—
Alexandra L. Mertens, Joseph E. Nussbaum

I. Introduction. The practice of solar project financing has emerged from several independent and overlapping strains of transactional practice, including traditional project finance secured lending, tax equity partnership and lease structures, development financing from early-stage investors, joint ventures, and the frequent acquiring and flipping of projects that goes on among a wide variety of solar industry participants. Though, at its core, solar project finance historically shares much with wind project finance as well as traditional energy finance, the unique issues associated with solar projects result in a highly specialized practice. For instance, the comparatively low technical risk of constructing and operating a properly sited solar facility, the reliance on large volumes of mass-produced component parts available in a global market, and the opportunities for developing distributed generation projects on residential rooftops and in community solar gardens set solar projects apart from other electricity-generating projects.

Developers, independent power producers, solar panel manufacturers, engineering, procurement, and construction ("EPC") contractors, utility companies, financial investors and, more recently, commercial and industrial end-users all participate in the financing of solar projects in different manners and at different times. Though certain common structures dominate throughout the market, it is no exaggeration to say that no two deals are the same. It is also not uncommon for projects to change hands two or three times during development before the sponsor seeks full-scale financing for a project, or for the same project to seek financing on more than one occasion. All solar industry participants are well advised to remain on the lookout for issues that may impact a project's ability to obtain financing, regardless of where in the pipeline or life cycle the project is.

Financing can be viewed as the epicenter of all aspects of project development. In order to survive the close scrutiny that lenders and investors require to approve a financing, all aspects of the project must be aligned, such that the end result will be, in all likelihood, a fully functioning, revenue-generating, and legally permitted project returning sufficient value to the investors. Accordingly, transacting on a solar project finance deal is not merely a negotiation of financial structuring but rather necessarily involves an analysis of real property rights, construction and development contracts, equipment warranties, power purchase and interconnection agreements, cash management, environmental permitting, energy regulatory matters, and, of course, tax analysis. This chapter begins with a brief discussion of the basic tenets of project finance; compares the alternative investment structures of debt financing, tax equity financing, and cash equity financing; and finally touches on the interplay between deal participants when those structures are used in combination.

II. Project Finance Basics.

A. Risk Shifting. The golden rule of project finance is one of risk mitigation: the deal structure must allocate risks that could affect the project's cash flow or assets to a creditworthy party with the ability to mitigate that risk. Much of the tension in negotiating a solar project financing will derive from each participant's efforts to shift various risks to others while retaining the particular benefits that the participant seeks from the transaction. The project sponsor seeks to shift technology risks to the equipment manufacturer and construction contractor while preserving for itself as much of the cash flow and appreciation in project value as possible. The lender will seek to shift risk to the project owner by taking paramount positions in the project revenues and assets, and to third parties such as the equipment manufacturer and construction contractor by getting the benefit of the warranties and contractual obligations of these participants, all to enhance the prospect of the loan being repaid on schedule. The tax equity investor will aim to push all project-specific risks on the sponsor through broad representations and warranties, backed up by parent guaranties and sweeps of distributable cash.

The risks at issue in a project financing can be classified in many ways, but broadly speaking the major categories of risk include the following: (a) *construction risk* – the likelihood that the project will reach commercial operation without running overbudget or behind schedule or encountering insurmountable construction issues; (b) *technology risk* – whether the technology incorporated into the project will perform as functioned and whether it has been tested and proven; (c) *counterparty risk* – will each project participant remain creditworthy, solvent, and capable of performing its particular contractual obligations when required of it, such as the EPC contractor's capacity to pay its subcontractors, procure equipment when required, or make good on a warranty claim; (d) *revenue risk* – a specific type of counterparty risk focusing on the certainty of payments received under the power purchase agreement ("PPA") from the offtaker or, in distributed generation or portfolio deals, the offtakers; (e) *operational risk* – can the project be operated to achieve the level of performance and power output that was forecast in the project's engineering and design plans, and what other factors (such as weather) can degrade this performance; and (f) *regulatory risk* – the risk of governmental action interfering with the project, including denial of discretionary permitting approvals, changes in state programs authorizing a solar program, and changes in tax law applicable to the project.

Risk shifting may be accomplished by various legal undertakings: grants of liens on the project assets, revenues, and key project agreements; warranties and contractual requirements for the equipment and the work performed in making it operational; requirements for various types of insurance products to cover certain adverse events; and guaranties of each participant's obligations from creditworthy entities. Project financing focuses on the negotiation and documentation of these risk-shifting devices and ordinarily results in documentation of substantial length and complexity.

B. SPVs, Portfolios, and Recourse. In most instances, all assets for a particular project are housed in a single special purpose vehicle ("SPV") that is a separate legal entity from the ultimate upstream owner of the project. This means that legal title to any project real estate interests (whether

outright ownership, leasehold interests, or otherwise) should be in the name of the SPV, and the SPV (and not any upstream entity) should execute all project contracts. The SPV is commonly referred to as the project company. Putting all assets into an SPV is a simple step but has significant implications for the ability to sell, buy, and finance a project. In a sale, purchasing the equity interests of the SPV is almost always simpler than assigning title to each asset individually. In a secured financing, a lender will want the SPV's parent company to pledge the equity interests in the SPV as collateral, in addition to or in lieu of the pledge of project assets, to provide a simpler route to foreclosure in the case of a default. In a portfolio financing, multiple different projects can be financed together by transferring ownership of multiple project SPVs to the same holdco, and investors can view each SPV's equity interests as a separate cash flow stream. If the portfolio financing involves a tax equity investment, the structure will often require that SPV ownership be transferred to the tax equity partnership just prior to a project being placed in service.

Portfolio financing in essence allows an investor to diversify its risk among multiple different projects through a single point of investment. In this scenario, the effect of one project's default on another project becomes a prominent question. Where the effect of a financing agreement default by one SPV also creates a default for a second "sister" SPV, the projects are said to cross-default. If the default by a project is self-contained and does not permit the investor to take enhanced action against other projects in the portfolio, there is no cross-default.

In addition to facilitating transactional flexibility, the use of SPVs also permits another central distinction to be made in project financing, that of "recourse" versus "non-recourse." If the financing provider has a claim against the balance sheet of the project sponsor/owner to support repayment of the debt, the debt is said to be "recourse" to the sponsor. However, when the financing provider has recourse not to the sponsor's assets generally but only to the assets comprising the project in question, the debt is said to be "non-recourse" or "limited recourse." (To be clear, the term is always meant as "recourse" or "non-recourse" *as to the sponsor*. Even "non-recourse" claims would still have recourse to the project and SPV.) The financing provider's remedies in non-recourse financing are fundamentally limited to the value of the project itself, and, in a worst case scenario, the sponsor could have the full value of the project taken from it through foreclosure, sale of the project, diversion of the project cash flow stream, equity dilution, or other remedies. While project financing generally means non-recourse financing, many deals will include specifically negotiated sponsor guaranties, other parent credit support, or equity contribution obligations that blur the margins of the non-recourse structure.

C. Milestone Terminology. The risks placed upon, and the benefits available to, investors in solar project financings will vary depending upon the specific stage of a project's development at the time of the financing. The exact timing of an investor's funding often hinges on a project's achievement of certain development milestones, with the financing documents incorporating concepts defined in other project contracts, the U.S. tax code and Treasury regulations, or other sources. It is thus useful to define a few key development-related concepts and acronyms before proceeding:

- "***Notice to Proceed***" or "***NTP***" refers to the formal directive given to the EPC contractor to commence full-scale construction and purchasing work. The issuance of NTP generally requires making a large mobilization payment to the EPC contractor and requires a large sum to be funded by a financing provider.

- "***Mechanical Completion***," "***Substantial Completion***," and "***Final Completion***" are terms frequently used to describe the key staged completion milestones under an EPC contract. Mechanical Completion generally means the facility is constructed and capable of being operated, subject to being physically interconnected into the grid and satisfaction of performance testing. Substantial Completion means the facility is fully built and performance tested, with only minor punch list items left to be completed. Final Completion signifies completion of the punch list and the end of the EPC scope. These three terms are not universal, and some EPC contracts use other nomenclature or have more milestones (but generally not fewer).

- "***Commercial Operation Date***" or "***COD***" is the term generally used in a project's PPA to signify construction completion, facility operation, and interconnectedness into the grid. An offtaker's obligation to purchase power under the PPA generally begins no later than COD.

- "***Placed in Service***" is the U.S. tax code concept defining when a project is placed in a condition or state of readiness and availability for a specifically designed function. The equity ownership as of (or within a certain time frame following) the Placed in Service date is a crucial concept for tax equity financing relying on the U.S. Investment Tax Credit ("ITC"), and thus the Placed in Service date is used as a guidepost for the timing of tax equity investments.

III. Debt Financing.

A. Overview. Though the prevalence of debt financing has perhaps been overshadowed in the solar industry by its cousin tax equity (more on that below), most solar projects are financed at some point in their life cycle with some manner of debt. Debt is, at its core, a contractual obligation by a borrower to repay a sum of borrowed money that will, in most instances, receive preference vis-à-vis the borrower's other creditors. In comparing the spectrum of financing options, debt tends to be a "safer bet" than any sort of equity financing, representing the prospect of limited risk (payment priority and, often, assets pledged as collateral securing repayment) for limited rewards (an interest rate and possibly other lender fees, but no further upside).

For solar projects, it is useful to classify debt primarily in relation to the project's life cycle. Roughly speaking, there are three categories of debt for solar projects, each discussed in more detail immediately below: (i) development-stage debt for the pre-construction period, (ii) construction debt to finance the

period of active EPC work, and (iii) permanent debt for the post-construction period when a project is operational and development work is complete.

B. Development Loans. Development loans can involve a variety of structures to finance early-stage project development work, including upfront interconnection deposits, PPA deposits, solar resource studies, permitting, and site control costs. As the value of the project assets remains somewhat prospective at this early stage, development lenders may forgo a full collateral pledge of project assets, opting to rely solely on a pledge of project company membership interests, or may require security interests in deposits and material assets. There is no established market for a typical development-stage loan, and terms vary widely among what are fundamentally bespoke deals. Many entities act as development financiers in order to claim a seat at the project table, for instance, entities interested in buying or funding the project if early-stage development proceeds to full construction, contractors looking to secure the project's EPC work, or module manufacturers looking to ensure their product is used in the project. Development loans can also be a bridge to future funding, providing a quick, relatively low-cost transaction with minimal documentation, a very short tenor, little borrower flexibility without lender consent, and a high interest rate, and often involving a promise to grant the lender a right of first refusal to the next round of larger financing.

Though we speak here of development loans as debt instruments, many early-stage investments involve collateral security and operational covenants securing a future payment (and are thus debt-like in their protections) without the payment obligation actually constituting indebtedness on the obligor's balance sheet. One such variant appears commonly in early-stage membership interest purchase agreements ("MIPAs"), where project sellers may retain a lien on the equity interests or assets of a project sold to secure full repayment of the MIPA purchase price, which may provide for staggered payments to the seller upon NTP or other development milestones. Though the payment obligation secured (the purchase price) may not technically be indebtedness, the creation of the lien on the SPV equity interests or project assets makes this structure function similar to secured indebtedness.

C. Construction Loans. A project's capital needs are highest during construction, when all equipment and component parts must be purchased and contractors and subcontractors are engaged in on-site physical work and must be paid on schedule. There are long-term implications of a construction process running overbudget or behind schedule. Payment streams must be managed, aligning invoices for required uses of cash with sources of cash from equity or debt funding or liquidated damages claims from tardy counterparties. As such, construction loans tend to be the most procedurally complex loan transactions, involving the most detailed covenants outlining what a project may or may not do and imposing the highest hurdles to accessing funds.

Tax equity investors will generally not take construction risk with their funds. Thus, the task of financing construction falls to lenders and sponsors together. In order to ensure proper alignment of sponsor's incentives, and to avoid extending loans beyond the project's expected collateral value, construction lenders will generally require a certain minimum sponsor equity contribution requirement as a condition to any construction loans being released, often expressed as a percentage of expected project

costs. Further, construction debt commitments will be sized to avoid a project exceeding a certain debt-to-equity ratio. If construction costs exceed budgeted contingency amounts, projects will fall back on any cost overrun guaranties or available contractual liquidated damages, but ultimately if no other sources of cash are available, it will be up to the sponsor to provide financing or risk losing the project to the secured lender.

Hallmarks of construction loans include the following:

- Very tight and detailed covenants, restricting all project activities other than development in accordance with the permitted construction contracts, prohibiting amendments to project contracts or project design plans without lender consent, restricting transactions between the project company and its affiliates, and requiring detailed progress reporting to the lenders and an independent engineer.

- A construction cash-flow waterfall governing all project cash, which requires all available cash flows to be applied to pay budgeted project costs and then, typically, required debt service, lender expenses, and any mandatory prepayments. Since solar projects generally generate no revenue from power sales during construction (other than perhaps following Mechanical Completion once COD has been achieved or payments for test power, if applicable), available cash flows generally include only construction loan proceeds, any equity contributions or proceeds from equity issuances, any liquidated damages payments from counterparties, and any insurance proceeds received. Construction debt documents typically restrict all cash distributions to equity holders.

- Construction loan collateral packages are generally straightforward: all project assets. This entails a pledge of equity interests in the applicable borrower-side entity or entities, as well as the project company granting a security interest in all its real property interests (whether a leasehold interest, fee ownership, or other access or easement rights), all project contracts (including construction and development contracts, PPA/offtake arrangements, and asset management and operation and maintenance contracts), all permits, and all cash.

  In addition to taking assignments of the contracts from the project owner, the lender will also require that each counterparty to a material contract consent in writing to the assignment in a manner in which the counterparty acknowledges the lender's rights, agrees to give the lender notice of any default by the project owner, and agrees to grant the lender certain cure rights. Consents may also include a so-called bankruptcy replacement clause whereby the counterparty agrees to enter into a replacement agreement with the lender in the event the project owner is the subject of a bankruptcy proceeding. Finally, when payments are or may be owing by the counterparty to the project owner under the contract (for example, the PPA), the consent also makes provisions for those payments to go directly into an account controlled by the lender.

To ensure the ability to benefit from a tax equity commitment, construction loan collateral packages may also include pledges of upstream equity interests or interests in the tax equity transaction documents containing the tax equity commitment.

- Staggered construction loan fundings. Rather than extend the full amount of the construction loan commitment up-front, lenders generally disburse loans for budgeted project costs or amounts that are immediately applied to invoiced project costs then due. As standard contract payment terms require payment within 30 days of invoicing, projects typically borrow on construction loans once or twice a month during construction. Lenders typically also require lien waivers from contractors, subcontractors, and major equipment suppliers as a condition to each construction loan used to pay such counterparty.

- A breach or default under any tax equity document will typically prevent the borrower from accessing any further construction loans. As the tax equity investment often serves as a source of repayment for a portion of the construction debt, lenders are wary of any event that could jeopardize the tax equity investment.

For typical solar project finance deals involving debt and tax equity, the construction loan is sized to be repaid from some combination of the permanent term loan and the tax equity investment. Where a cash equity investor provides financing to repay a construction loan as well (or instead), this investment will also be taken into consideration to size the construction loan. Thus, construction loans may often be earmarked by tranches to refer to the expected source of repayment (for instance ITC bridge loans as the bridge to a tax equity commitment). These tranches may have different features, including different interest rates or disbursement requirements.

D. Permanent Loans. Following achievement of COD and completion of construction of a solar facility, a sponsor will typically trade its restrictive and expensive construction debt for permanent financing, allowing recoupment of invested capital. When a project incurs permanent debt financing, the result is a comparatively gentler set of loan terms than during construction. Though covenants, collateral security, and defaults remain tight to ensure that project ownership and operation protects the facility and maximizes the revenue stream, the lender takes a somewhat more passive role in supervising operations than construction.

To call debt "permanent" is of course somewhat of a misnomer, as even permanent debt comes due on a maturity date. But as the term is used somewhat synonymously with "long-term debt" and is a category of "permanent financing," we use the term here. The permanence aspect of long-term project financing is that project revenues will cover debt service to significantly (or fully) pay down the loan before the maturity date, thus slotting permanent debt in the category of permanent financing solutions that operating companies typically rely on.

Permanent loans are generally single-draw term debt, with one funding on the date when the construction loan "term converts" or "terms out." When coupled with tax equity or cash equity, the term conversion will occur simultaneously with investor funding, and the closings will be cross-conditioned.

1. Cash Flow Waterfall and Distributions. A key aspect of permanent project debt is the cash flow waterfall, through which project revenues are used to pay project expenses and investor returns in a pre-determined priority. Many variations exist, but in general lenders permit cash flow to be applied as follows, on monthly or quarterly dates: *first*, to pay project operating expenses; *second*, to pay lender expenses not constituting debt service; *third*, to pay debt service (interest and scheduled principal payments); *fourth*, to fund any required cash reserves for the project, including reserves for debt service, maintenance expenses, and capital expenses; and *fifth*, to make distributions to the equity owners. To the extent the sponsor performs asset management or similar services through a contractual arrangement with the project, these costs will generally be paid at the priority *first* as operating expenses. Any other equity return comes solely from the last priority.

Permanent project loan agreements will also typically restrict distributions to only those time periods for which the project can demonstrate compliance with a specified financial covenant. Typically, the limiter is a Debt Service Coverage Ratio ("DSCR") test, which requires that cash flow over a certain period (such as cash flow available for debt service for the trailing four quarters) exceeds required debt service during that period by a certain ratio, *e.g.,* at least 1.25:1.00. If a distributions covenant is subject to a DSCR test and the project is not producing sufficient cash flow to clear the ratio at the time the waterfall is run, available cash will be trapped in the depositary accounts, and the borrower will not be able to distribute the cash to sponsors. If this occurs on a number of successive testing dates, the funds in the depositary accounts may be required to prepay the loan.

2. Back Leverage Debt. We noted previously that tax equity investors do not like to take construction risk. This statement can be expanded to say, more broadly, that tax equity investors do not like to take sponsor risk. When placed in an upper tier of the capital structure above project-level secured debt financing, tax equity investors and sponsors share much of the same perspective as project sponsors on two key risks: (a) upon an event of default under the loan agreements, a secured lender could foreclose on the project assets or an equity pledge and sever the ownership chain between the upstairs owners and the project and (b) loan agreements impose distribution restrictions that can cut off cash flow streams. While tax equity investors can bear these risks during a brief overlap period in respect of construction loans (subject to extracting certain terms from lenders via interparty agreements, as more fully described below), tax equity often views these two risks as nonstarters in permanent loans. Equity foreclosure by lenders can lead to recapture of the ITC allocated to the investor, and a structural subordination of tax equity's cash flow threatens the certainty of its preferred returns. Therefore, tax equity investors are often unwilling to sit behind secured debt in the capital structure.

In response to the unique challenges of matching the demands of secured permanent debt and tax equity investments, many renewable energy project finance deals use a back leverage debt structure. Back leverage simply moves the debt from the project level up to a holding company level, above the tax

equity investor level, such that the sole collateral securing the debt is the sponsor-side equity interests and the associated cash held by the holding company borrower. As a result of the high quality of the solar asset and the relatively low operating risk, the value of the sponsor-side cash flow streams in an operational solar facility can be significant enough to fully secure permanent debt for the project, even without project-level collateral.

The back leverage structure also offers an enhanced opportunity for a lender to diversify its risk among multiple solar projects, capturing the cash flow streams at an upper-tier holding company that indirectly owns sponsor equity positions in a portfolio of projects. The back leverage portfolio structure necessarily pairs well with a portfolio tax equity structure, which in combination provides a valuable tool for large-scale financings. This financing structure has been used to great effect by independent power producers to facilitate growth, effectively reducing the cost of transacting on a single project through large portfolios.

IV. Tax Equity Financing.

Tax equity financing is a structure of project finance unique to renewable energy project finance, owing its existence to the U.S. tax code, subject to the whim of federal politics and tax policy. As discussed more thoroughly in Chapter 8, the ITC permits an equity owner of a qualifying asset, including a solar power facility, to claim a tax credit equal to a percentage of the value of the asset's eligible basis. An owner may also be able to claim accelerated or bonus depreciation with respect to the asset's value. In combination, these benefits can offer a sizeable reduction to the federal tax liability of a solar project owner, allowing the owner to offset its taxable income from other unrelated sources but based on the value of the solar project.

Often solar project developers, sponsors, and owners do not themselves have taxable income sufficient enough to take advantage of the benefits from the ITC. Rather, a relatively small group of financial institutions and corporations with significant federal tax burdens have emerged to invest in projects as equity owners. The work of structuring transactions to permit these tax liability-laden investors to match up with qualifying solar projects and claim the benefit of the ITC is the central function and challenge of solar tax equity financing.

To achieve the goal of maximizing the ITC tax benefits, tax equity investors seek to accomplish several competing and sometimes conflicting goals. Federal tax law requires that investors put their dollars at risk in the project and share the benefits and burdens of ownership as an equity owner prior to the time the project is Placed in Service in order to claim the ITC. However, tax equity investors would prefer a position as purely financing providers, investing in the project only when offered a comparatively secure position resembling that of a lender. Tax equity investors are loath to take on risks alongside the sponsor, instead requiring certainty as to a project's viability and construction completion before investing and demanding structural priority of repayment and other fallback protections uncharacteristic of normal equity positions. Tax equity investors initially leave management of the project squarely in the hands of the sponsor, policing the management through covenants and

representations and warranties. On the spectrum of equity to debt, tax equity must sit squarely on the equity side of the line, but it wants to sit only barely over the line.

One key way in which tax equity structures achieve this balancing act is through sponsor guaranties. The tax equity investor looks first to the project itself and the cash flow stream coming from the project to provide the required economic return. But management of the project is left to the sponsor and, unable to rely on any collateral security position in any project assets, the tax equity investor is exposed to potential risks of the sponsor's mismanagement of the project, such as breach of a project contract or other event leading to diminution in a project's value. To counteract this risk, tax equity investors generally require that a creditworthy sponsor parent entity guarantee the sponsor-side project management obligations owed to the tax equity investors, protecting the tax equity investors from damages resulting from sponsor-side breach of covenant, misrepresentation, environmental liability, certain ITC recapture events, and, depending on the transaction, post-funding change in tax law.

Tax equity structures rely largely on the ability to bifurcate cash and tax benefits available from the project. In the partnership flip and inverted lease structures, the tax items of a partnership are allocated separately from the partner's respective cash flows and management rights. In a sale-leaseback, the ITC is passed through to the tax equity investor, while the sponsor retains cash from the project less periodic rent payments.

A. Partnership Flip. In a partnership flip transaction, the tax equity investor will invest in a holding company, an entity taxed as a partnership and jointly owned with the sponsor, which holding company will own the project or multiple projects in the portfolio. The projects will either be contributed to the holding company by the sponsor or the holding company will purchase the projects from a sponsor affiliate for their fair market value at Mechanical Completion. The tax equity investor will be entitled to allocations of substantially all of the tax attributes, including the ITC, from the partnership, and specified cash distributions from the partnership until the "flip date," when the investor achieves an agreed-upon after-tax return or a specified period of time has passed, depending on the requirements of the investor. Once the "flip date" occurs, the allocations of tax attributes and cash will change, and the sponsor will be entitled to the bulk of the remaining tax attributes and cash from the project thereafter. Also at the flip date, the sponsor will be entitled to exercise an option to purchase the tax equity investor's interests in the partnership for fair market value. Certain tax equity investors may require a withdrawal option, allowing the investor to determine whether to exit the partnership if the purchase option is not exercised by the sponsor.

B. Sale Leaseback. In a sale-leaseback transaction, the sponsor sells the project to a tax equity investor, within 90 days following the Placed in Service date, for fair market value. The tax equity investor then leases the project back from the investor for prepaid rent and periodic rental payments, which rental payments may be subject to a sponsor-level payment guaranty. The investor will be entitled to 100 percent of the tax benefits from the project while the sponsor will retain the right to use and operate the project and receive the revenue from its operation for a period of years, subject to paying a fixed rent payment. On one or more occasions during the term of the facility lease, the sponsor

will have an option to repurchase the project from the tax equity investor for the fair market value of the facility.

C. Other Leases. In a lease pass-through transaction, the project company is often structured as a partnership, owned 49 percent by a tenant entity and 51 percent by the sponsor. The tenant is owned 99 percent by the tax equity investor and 1 percent by the sponsor. The project company leases the project to the tenant prior to the date the project is Placed in Service. The project company then elects to have the ITC, based on the appraised fair market value of the project, passed through to the tenant. The tenant partnership is structured as a partnership flip, where tax allocations and cash distributions will "flip" after a fixed period of time.

V. Cash Equity Financing.

The final element of solar project finance discussed here is cash equity financing. The cash equity position shares the sponsor position and serves as permanent financing that can be used as an alternative or in addition to back leverage debt. From the perspective of the tax equity investor and lenders, a cash equity investor appears the same as a sponsor, and the tax equity investor will generally require guaranties from both the sponsor and the cash equity investor. However, this position is generally held by a pure financial investor that either does not have the desire or the necessary means to manage the ongoing operation of the project. The sponsor with the management role will be responsible for indemnifying the cash equity investor if a breach by the manager results in losses to the tax equity investor that are subject to guaranty payments or a cash flow sweep. The cash equity investor may acquire all or substantially all of the sponsor interests in a project, while reserving the management role and a portion of the sponsor financial position for the original sponsor.

Cash equity deals are custom designed deals, specifically negotiated with the particular cash equity investor, and thus significant variation exists between transactions. However, since the relationship between an active sponsor manager and a passive financing investor in cash equity deals mirrors the similar relationship at the core of tax equity deals, cash equity investments often resemble tax equity transactions (minus the structured allocation of tax benefits). Cash equity fundings are often cross-conditioned on the tax equity investment, and cash equity investor consent rights may overlap with the rights held by tax equity investors.

VI. Interparty Issues.

A. Construction Period. Because in several tax equity structures the tax equity investor must be an owner of the project before it is Placed in Service, the tax equity investor must take limited construction risk and invest in the project several weeks prior to repayment of the construction loan. Generally the tax equity will invest between 5 percent and 20 percent of its expected total investment before the project is Placed in Service, with the balance funded once the project achieves COD. This creates tension between the tax equity investor, who wants to be assured its investment is adequately protected, and the construction lenders, who require unfettered (or substantially unfettered) access to their collateral prior to repayment of the construction loan. Tax equity investors and lenders have

individual requirements to address this risk, but increasingly tax equity investors will permit the lenders to return the initial tax equity investment in a project prior to exercising remedies with respect to the project collateral. Certain tax equity investors will require this repayment option to be structured as an option to repurchase all of the tax equity investor's interest at fair market value, rather than an "unwind" of the transaction, to minimize any tax structuring risk. Tax equity investors may also require a time period to cure any defaults of the project company under the construction loan documents to allow the transaction to proceed as intended.

B. Operational Period. Many tax equity investors will require that before any cash can be distributed to the sponsor, the tax equity investor should be fully compensated for any indemnity claim (or cash otherwise available to the sponsor should be escrowed until any disputed claims are resolved and then paid to the tax equity investor or distributed to the sponsor). If the maximum amount of this sweep is uncapped, this will impair the sponsor's ability to raise back leverage debt. Sponsors should undertake to limit the cash sweeps to a 50 percent maximum to allow debt service to be available to the lenders. Also, similar to the construction period, the permanent lenders will require an unrestricted ability to foreclose on their collateral, which, during the operational period, is the sponsor's interest in the tax equity partnership or partnerships. Again, the permanent lenders will require unfettered (or substantially unfettered) access to their collateral. Accordingly, the transfer provisions in the tax equity partnership agreement need to be negotiated to permit a lender foreclosure and transfer to a subsequent owner that meets certain criteria acceptable to the tax equity investor and lenders.

Chapter Eight
THE LAW OF SOLAR
—Tax Issues—
(updated March 2018)

Gregory F. Jenner, Kevin T. Pearson,
Adam D. Schurle

The tax system often is used to provide incentives for particular types of investments the government wants to encourage. These incentives raise tax planning issues that go well beyond those involved in general structural, choice-of-entity, and other financing considerations, and create the potential for significant economic benefit. The available incentives also have been subject to frequent changes as federal and state energy policies have evolved. The following discussion is only a general summary and is current as of the date hereof. Please contact one of the attorneys listed above for answers to your specific legal questions and to check on any changes that may have occurred since the date of this publication.

I. Federal Income Tax Issues.

A. The Investment Tax Credit. The owner of a qualified solar facility may claim the investment tax credit ("ITC"). The ITC is a one-time credit against income tax that is based on the amount invested in a facility (rather than on the amount of electricity produced and sold). The amount of the ITC for a qualified solar facility depends on the year in which construction begins. If construction begins any time before 2020, the ITC equals 30 percent of the tax basis (generally the cost) of the qualifying property. If construction begins in 2020, the ITC equals 26 percent of eligible costs, and if construction begins in 2021, the ITC equals 22 percent of eligible costs. If construction on an eligible solar facility begins after December 31, 2021, the ITC equals 10 percent of eligible costs. The ITC is reduced if certain projects do not meet a placed-in-service deadline. If construction of a solar facility begins before 2022 but the facility is not placed in service before 2024, the ITC is reduced to 10 percent.

1. Requirements for Claiming the ITC. The ITC applies only to "energy property," which is defined for purposes of a solar facility to include only property that meets the following requirements:

a. Solar Equipment. The property must be equipment that 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. In addition, equipment that uses solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight may qualify for the ITC. Property used to generate energy for the purpose of heating a swimming pool does not qualify for the ITC.

b. First Use or Construction by Taxpayer. If the property is acquired by purchase, the original use of the property must commence with the taxpayer claiming the credit.

Otherwise, the property must be constructed, reconstructed, or erected by the taxpayer claiming the credit.

c. **Depreciable or Amortizable.** The property must be eligible for depreciation or amortization deductions for federal income tax purposes. This requires that the property be used in a trade or business.

d. **Performance and Quality Standards.** The property must meet any applicable performance and quality standards prescribed by the Secretary of the Treasury. To date, the Secretary has not prescribed any such standards.

2. **Beginning of Construction.** As described above, the amount of the ITC for a solar facility depends in part on when construction of the facility begins. The Internal Revenue Service has issued detailed guidance regarding the beginning-of-construction requirement that must be carefully considered, taking into account the specific facts involved. Although this guidance relates to wind facilities and the Internal Revenue Service has yet to issue guidance directly applicable to solar facilities, the guidance is useful for analyzing when construction begins on solar facilities. Generally speaking, construction is considered to begin when either (i) physical work of a significant nature begins or (ii) 5 percent of the cost of the facility is incurred. In either case, the owner also must engage in continuous construction or continue to make continuous efforts thereafter, although a safe harbor may be available depending on when the facility is placed in service.

3. **Progress Expenditure Rules.** In certain circumstances involving qualified energy property with a normal construction period of more than two years, a taxpayer may be entitled to claim the ITC with respect to progress expenditures incurred in tax years before the property is placed in service.

4. **Basis Reduction.** The tax basis of property with respect to which the ITC is claimed is reduced for all tax purposes (including depreciation and calculating gain from a sale) by one-half of the amount of the credit. Thus, the tax basis of the qualifying components of a solar facility with respect to which the ITC is claimed generally will be 85 percent of the cost of those components.

5. **Recapture of the Credit.** The ITC is subject to recapture if, within five years after a facility is placed in service, the taxpayer sells or otherwise disposes of the energy property or stops using it in a manner that qualifies for the credit. The amount of recapture depends on when during the five-year period the property is disposed of or ceases to be used in a qualifying manner.

6. **No Cutback for Government Financing.** Under prior law, the ITC for a solar project generally was reduced with respect to facilities that were financed in whole or in part with the proceeds of tax-exempt bonds, subsidized energy financing, or other forms of government-supported financing. This restriction generally was removed for property placed in service after December 31, 2008 (and for self-constructed property, to the extent of the basis attributable to the period after December 31, 2008).

7. Nonrefundable Credit. The ITC is a nonrefundable credit. If a taxpayer entitled to the ITC does not have sufficient income tax liability to use the entire credit for a particular year, the taxpayer is not entitled to a refund of federal income tax on account of the credit. Any unused portion of the credit generally may be carried first back one tax year and then forward 20 tax years from the year the credit arose.

8. Sunset Date. There is no sunset date for the 10 percent ITC for solar facilities on which construction begins after December 31, 2021.

B. U.S. Treasury Department Grants. The American Recovery and Reinvestment Act of 2009 allowed the owner of a qualified solar facility that was eligible for the ITC to elect to receive a grant from the U.S. Treasury Department in lieu of claiming the ITC with respect to the facility. The grant generally was designed to function in the same manner as the ITC for which the owner of a qualified project otherwise would have been eligible. To qualify for a grant, a solar project must (i) have met the qualification requirements for the ITC and (ii) have been placed in service during 2009, 2010, or 2011 or, if construction began in 2009, 2010, or 2011, have been placed in service before 2017. Like the ITC, the amount of the grant generally was 30 percent of the tax basis (generally the cost) of the qualifying property.

C. Depreciation. In addition to tax credits or grant payments, solar facilities also can generate significant tax losses that can be valuable to owners with other sources of taxable income that can be offset by the losses.

1. MACRS Depreciation. Qualifying components of a solar facility are eligible for greatly accelerated depreciation deductions under the Modified Accelerated Cost Recovery System (MACRS), typically over a five-year period based on the double declining balance method of depreciation.

2. Bonus Depreciation. An owner of otherwise qualifying property that is placed in service after September 27, 2017 and before January 1, 2023 generally is entitled to deduct 100 percent of the adjusted basis of the property in that year. An owner of qualifying property acquired after September 27, 2017, is entitled to 80 percent bonus depreciation for property placed in service in 2023, 60 percent bonus depreciation for property placed in service in 2024, 40 percent bonus depreciation for property placed in service in 2025, and 20 percent bonus depreciation for property placed in service in 2026. Bonus depreciation provisions expire for property placed in service beginning January 1, 2027. To qualify for bonus depreciation, property generally must have a recovery period of 20 years or less. Thus, property that otherwise would qualify for five-year MACRS depreciation, for example, generally will qualify for bonus depreciation.

D. Monetizing Federal Income Tax Benefits; Ownership Structuring Issues. A taxpayer that has little or no need for tax credits or losses (*e.g.,* because it has little or no tax liability) may nevertheless be able to obtain the benefit of various tax incentives by entering into an arrangement with an investor that can use credits, losses, or both. For example, in a partnership flip transaction, a taxpayer

enters into a partnership with an investor that is willing to contribute cash to help finance a solar facility. The partnership then operates the facility and, within certain limits, the tax credits and losses can be allocated to the partner that can use them. As an alternative, in a sale-leaseback transaction, a taxpayer develops a facility, places it in service, sells it to an investor, and then leases it back from the investor. These and other potential techniques for "monetizing" tax credits and losses (including inverted leases and prepaid power purchase agreements) involve risk and require careful tax planning. These considerations should be taken into account in the very early stages of a project, including when choosing the type of entity that will own a facility and the various financing alternatives available. Analysis of the economic benefits of the various incentives requires, among other considerations, careful financial modeling of the projected costs and output of each specific project and of the full array of potential tax and financing implications. This should include careful consideration of any limitations that may apply to a particular owner's ability to claim the available tax benefits, such as alternative minimum tax liability, at-risk limitations, and passive activity limitations.

II. State and Local Tax Issues. In addition to federal income tax issues, construction and operation of solar facilities also raise numerous state and local tax issues that should be carefully examined. Following is a general description of the types of issues that may arise, with selected examples. Developers and investors should be careful to obtain very current information about state tax in general, and state tax incentives in particular. States are generally narrowing their incentives for renewable energy projects, either by interpreting existing law narrowly or by legislative change, sometimes with retroactive effect.

A. Net Income Tax States. The vast majority of states impose a net income tax. States generally base their income tax system on the federal system, and many states have adopted relatively uniform rules governing division of the tax base and computation of taxable income. Despite these similarities, however, each state's tax system is different and must be separately analyzed.

1. Nexus, Business Structure, and Apportionment. Siting a solar project in a state generally will create "nexus" with the state and generally will allow the state to tax the income of the company that owns or operates the project. Less substantial activities, such as consulting, may create nexus with a state as well.

One of the most important decisions affecting state taxation is the type of legal entity used when starting a new project. Choices may include corporations (including S corporations and C corporations), LLCs, and limited partnerships. The decision can affect:

- Whether tax is imposed directly on the project company or on its owners; and
- Whether taxable income (or loss) is determined on a stand-alone basis or whether state tax will be measured by combining or consolidating the income of affiliates, including the parent company.

States generally measure the taxable income of a company by apportioning a percentage of overall taxable income to the state. The percentage is determined by a formula that relies primarily on gross receipts attributable to the state divided by gross receipts everywhere. An increasing number of states, including California, Oregon, and Minnesota, generally rely exclusively on gross receipts ("single-factor apportionment"), but additional factors such as property or payroll in the state may apply in some circumstances and are the norm in some states, including Idaho and Montana. For purposes of attributing sales of electricity among different states, some states follow the traditional approach of sourcing the sale based on where the greatest proportion of income-producing activity related to the sale occurs. Other states may use different sourcing rules. For example, for Oregon apportionment purposes, sales of electricity by public utilities are sourced to the state where delivery occurs, as indicated by the parties' documented agreement, while sales by nonutilities are sourced to the state of ultimate destination regardless of the place of delivery.

The choice-of-entity and apportionment rules can sometimes produce surprising results: if the company or group as a whole has taxable income, the company may owe tax to a state even if the activities in that state are not profitable on a stand-alone basis.

2. Income Tax Incentives. Some income tax states offer incentives to promote the development of solar energy and other alternative energy projects. It is important to understand the nature of each incentive, as there is considerable variation among the states. Also, as noted above, some state incentives may reduce the amount of the federal incentives available for the project.

a. Hawaii and Montana offer income tax credits for certain alternative energy systems, including solar systems. Hawaii provides a tax credit for the lesser of 35 percent of the cost of a solar system or $500,000 where the system is installed on commercial property for commercial use. The credit applies to the tax year in which the system is placed in service and it may be carried forward until exhausted. Montana provides an alternative energy credit for investments of $5,000 or more in property that generates energy by means of an alternative renewable energy source, which includes solar energy. The credit is equal to 35 percent of eligible costs. It is claimed in the year in which the equipment is placed in service, but may be carried forward for seven years thereafter. The credit may only be taken against taxes due as a result of Montana taxable or net income produced by (a) certain manufacturing plants located in Montana, (b) energy sales to new or expanded business facilities, or (c) the alternative energy generating equipment itself.

b. Oregon formerly offered a similar investment-based credit, known as the Business Energy Tax Credit ("BETC"), for development of solar and other renewable energy generation projects. While legacy projects will continue to benefit from the BETC for several years to come, the program has been severely curtailed for new generation projects.

B. Sales and Use Taxes. Nearly all states impose a sales tax. In most states, the tax is imposed only on sales of tangible personal property. Some states also impose use tax on sales of certain

kinds of services. In addition, some states impose a transfer tax on the sale (and sometimes the lease) of real property.

1. **Purchase or Use of Equipment.** Most states' sales and use taxes will apply to the purchase or use of equipment within those states.

2. **Generally No Sales or Use Tax on Sales of Power.** Most states that impose sales and use taxes do not impose those taxes on sales or use of electricity.

3. **Sales Tax Incentives.** A number of states, including Washington, Minnesota, and Colorado, have adopted an exemption from sales tax for machinery and equipment used in solar facilities. As noted above, some of these exemptions have recently been narrowed, and states are increasingly assigning sunset dates to tax credits and other incentives, in order to force periodic legislative review of their programs. For example, several years ago the legislatures in Nevada and Idaho allowed sales tax exemptions for solar equipment to expire.

C. **Property Tax.** Virtually all states impose property tax that is assessed annually and is measured, in some fashion, by the value of real property. Most states also tax tangible personal property that is used for business purposes. Intangible property is taxable in some states if the owner is centrally assessed, as discussed below.

1. **"Central" or "State" Assessment Likely.** In many western states, such as Oregon, a company that produces electricity is "centrally assessed" for property tax purposes. Central assessment means that the taxable value of the property is determined by the state revenue authority rather than by the county assessor's office. In Washington, central or local assessment depends in part on whether the company's property crosses county lines. In California, the facility's output is a factor in determining whether central assessment applies.

2. **Valuation.** States generally accept the three traditional valuation methods for valuing electricity generation property (the cost approach, income approach, and comparable sales approach). However, if the property is centrally assessed, the state taxing authority may also be authorized to determine value by combining the property with other facilities owned or used by the same company. In that case, the taxing authority may aggregate property within and without the state, determine the value of the entire "unit," and allocate some portion of the unit value to the taxing state by means of a formula. Determining the correct value of a particular project is a matter of frequent controversy. Industry efforts to obtain special valuation rules that take into account the unique aspects of solar power have been successful in some states, such as Colorado.

3. **Property Tax Reporting.** States typically require owners of centrally assessed property to file annual returns reporting the value of their property. It is good practice to consult a valuation expert before filing the first return with respect to the property, in order to accurately communicate on the return items that could result in tax savings in future years.

4. Rollback Penalties in Farm and Timber Use Areas. Many states impose property tax penalties when land that is used for farming or timber is dedicated to a different use. In addition to those penalties, property taxes may increase prospectively after the change of use. This issue typically arises when land leases are negotiated. It is best to address this issue as part of financial modeling.

5. Property Tax Incentives. As part of due diligence in constructing or acquiring a solar facility, it is worthwhile to inquire whether any property tax incentives are available. Property tax incentives can be particularly advantageous because property tax liability typically applies throughout the life of the project. In contrast to income tax, property tax is often highest in the early years before the project is profitable. Nevada and Montana, for example, offer property tax exemptions for certain renewable energy facilities, including solar energy facilities. The Nevada and Montana exemptions may be full or partial exemptions, depending on the characteristics of the applicable solar facility. California offers a property tax exclusion for certain newly constructed solar energy facilities. The California exclusion does not apply to facilities owned by centrally assessed companies or for which there has been a change in ownership for property tax purposes. Oregon's exemption statute was expanded in 2007 to allow exemption for a greater range of projects when the electricity is used on-site, but this exemption is scheduled to sunset for tax years beginning after July 1, 2023. Also in Oregon, it may be possible to obtain a temporary property tax exemption under the state Enterprise Zone Program or the Strategic Investment Program. The Enterprise Zone Program typically offers an exemption for three to five years, but in rural areas the exemption period may be as long as 15 years. To qualify, state law requires that the company increase its permanent, full-time employment within the zone by at least 10 percent. (Note that one employee may satisfy the minimum hiring requirement if the company has not previously operated within the zone.) Other requirements, such as minimum capital investment size, may apply. The Strategic Investment Program statutes offer a partial exemption for 15 years, with a fee payable to the county and other potential conditions. Negotiations for benefits under both the Enterprise Zone and Strategic Investment Programs generally occur at the county level, sometimes with participation of cities.

6. Taxes in Lieu of Property Tax. States may impose taxes in lieu of property tax. Minnesota, for example, imposes a solar energy production tax in lieu of personal property tax on solar facilities. The owner of a solar facility must report the annual production (in kWh) of the facility to the Minnesota Department of Revenue by January 15 of the calendar year following production. The Department of Revenue determines the production tax due and notifies the owner and county or counties where the facility is located. The owner of the facility must then remit the tax to the appropriate county or counties. The tax rate is $1.20 per MWh of energy produced. In Oregon, the governing body of a county (and any city) and the owner or lessee of a solar project may enter into an agreement that exempts the solar project from property taxes and allows the payment of a fee in lieu of property taxes imposed on the solar project. Similar to Minnesota, Idaho now imposes a tax of 3.5 percent on gross solar energy earnings, which are defined as the gross receipts of a solar energy generator from the distribution, delivery, and sale of electrical energy generated, manufactured, or produced by means of

solar energy within Idaho to a customer for direct use or resale. Annual reporting requirements also are imposed, as well as authorization of liens for unpaid taxes. The new solar energy tax is imposed in conjunction with a property tax exemption for real estate, fixtures, and personal property of a solar energy electricity producer held or used in connection with generating, transmitting, distributing, delivering, or measuring electricity produced by means of solar energy.

D. Excise Taxes. When considering operation of a solar facility, state and local excise taxes also should be taken into account.

1. Washington Public Utility Tax. The state of Washington and a number of municipalities within Washington impose a public utility tax ("PUT") on the privilege of engaging in certain utility businesses within the state and those localities. The state PUT is imposed at a rate of 3.8734 percent of gross income derived from certain enumerated public service businesses, including the "light and power business." The "light and power business" is defined for purposes of the state PUT as "the business of operating a plant or system for the generation, production or distribution of electrical energy for hire or sale and/or the wheeling of electricity for others." The state PUT is intended to apply only to revenues derived from the retail sale of electricity to consumers. Accordingly, deductions in computing gross revenues may be allowed for revenues derived from the sale of electricity for resale, among other deductions. The Washington business and occupation tax may also apply, depending on the specific activities that the business conducts. Cities and towns also may impose a local PUT or a local business and occupation tax, or in some circumstances both. Local rates can be substantial.

2. Other State and Local Excise Taxes. Other states and localities may impose other kinds of excise taxes. For example, some California cities impose gross receipts taxes for the privilege of doing business in the locality. California imposes a fee based on gross receipts for the privilege of doing business as an LLC. Similarly, Nevada imposes a commerce tax for the privilege of engaging in business in Nevada. The commerce tax is based on the Nevada gross revenue of the business, and different tax rates apply to different categories of business. All potentially applicable taxes, including state and local excise taxes, should be carefully analyzed in determining the costs and benefits of operating a solar facility.

Chapter Nine
THE LAW OF SOLAR
—Community Solar—

Sara E. Bergan, Andrew P. Moratzka,
Sarah Johnson Phillips, David T. Quinby

I. Introduction. For all of the success of the rooftop solar industry, there is a fundamental limitation in its current business model: it depends on the customer having a suitable location for the installation of the solar system. Generally, this means a roof on a building the customer owns (so it has the right to install the system), that is oriented to get plenty of sunlight, and that has suitable structural support.

Unfortunately, about 50 percent of American households and businesses do not have a roof that meets these requirements. For instance, they may rent their home, lease their office space, or have a roof that is shaded by trees or buildings. In addition, even customers who do have a suitable roof sometimes want to avoid installing solar panels on-site for any number of reasons, including aesthetics, economics, and a desire to avoid maintenance. Finding a way to serve these customers would create a substantial benefit for consumers, the solar industry, and the environment.

Over the past few years, "community solar" or "shared solar" has emerged as a solution to this problem. In essence it is a form of virtual net-metering where multiple utility customers participate in a common larger solar project located somewhere off-site. Generally this involves a three-party arrangement whereby the customers enter an agreement with the project developer (though it could also be the utility) that commits them to pay a certain amount up-front or monthly in exchange for a portion of the electricity that is generated by the solar project. Because the solar project is located off-site, it cannot deliver the energy directly to the customer but instead interconnects to the utility distribution grid and delivers power to the local utility. The utility "pays" for the delivered electricity by crediting the participating customers on their utility bills. Through this arrangement, utility customers can benefit from the economies of scale of a larger project, the solar industry can access a significant new market that might not otherwise be available, and the utility maintains its traditional role and relationship with its customers.

According to *U.S. Community Solar Outlook 2017* by GTM Research, nearly three gigawatts of new community solar capacity is currently under development across 29 states, and in the next few years, community solar is expected to hit 500 megawatts ("MW") of new installed capacity annually. While these estimates bode well for the future of community solar, as with any new market, there are challenges that will need to be overcome before the full potential of community solar can be realized. In this chapter, we analyze the key legal and regulatory challenges facing the community solar industry and provide guidance on how project developers can navigate these challenges in a way that maximizes the potential for developing successful community solar projects.

II. Key Features of Community Solar Programs. While some of the earliest community solar programs began as voluntary innovations by local cooperatives or utilities, more recently lawmakers and utility regulators have created new programs to establish the rules under which community solar projects can be developed. These rules vary widely from state to state (and even utility to utility), and tend to evolve over time as various stakeholders, regulators, and utilities work through implementation issues. It is critical to pay very close attention to the particular details of a given state's program, as early experience is showing that untested programs with complex rules tend to result in hidden costs and other uncertainties.

In this section, we provide a list of key program features to consider when evaluating a given state's community solar program. These are: (1) overall program capacity caps; (2) individual project capacity caps; (3) customer pricing; (4) subscriber requirements; and (5) geographic restrictions. By understanding these program features, developers can make informed decisions about where to direct their development efforts.

A. Program Capacity Caps. A key feature of any community solar program is the amount of capacity available under the program. In a few states, there is no overall limit on the amount of community solar project capacity that can be developed in the state. In other states, the program places a cap on total program capacity. Where these caps exist, they generally range from under 10 MW in the smaller capped states to hundreds of megawatts in the larger capped states. The larger the cap, the more opportunity exists for new project development.

B. Individual Project Capacity Caps. In addition to overall program capacity caps, most states place a cap on the capacity of each project. These caps can range from about 1 MW to about 20 MW. Some of the early community solar states, such as Minnesota, initially allowed multiple community solar gardens to be co-located to share in distribution infrastructure and to make the projects more financeable. There, regulators later limited co-location to 5 MW and more recently to 1 MW. Other states do not dictate a project capacity cap. However, projects in states like these likely face inherent limitations in the ability to interconnect to the distribution grid, which can preclude projects much over 20 MW.

C. Customer Pricing. Another key feature of any community solar program is the value of the bill credit the customer is entitled to receive. The amount of the bill credit has a direct bearing on the pricing that a developer can expect to receive in the agreement with its customer (sometimes called a "customer-developer agreement" or "subscription agreement"). If the subscription agreement requires payment in an amount below the value of the bill credit, the customer will realize savings. In contrast, if the agreement requires payment in excess of the bill credit, the customer will be paying a premium.

Community solar programs tend to be creatures of state law and state regulators set the various rates for the programs. Not unlike net-metering, many of the rates paid to customers through bill credits are related to existing retail rates. Customers in some states receive a full retail rate credit for all subscribed

energy used in a given year. In Minnesota, customers that subscribed to projects begun in the first couple years of the program were entitled to compensation at the retail rate for the applicable class of customer. Minnesota, however, more recently shifted to require a single value of solar rate be used to compensate all participating customers. Other states are following Minnesota's lead in developing a resource value of solar for their community solar program. In theory, these tariffs add up all the costs and benefits of distributed solar such that the price paid has no positive or negative impact on nonparticipating customers of the utility.

In some states, the utility pays the developer directly for any electricity above the amount for which customers have subscribed. This so-called "unsubscribed" energy is often paid at a traditional avoided cost price. This lower rate tends to create an incentive for developers to maintain customer subscription levels as high as possible.

D. Subscriber Requirements. Most programs have established certain minimums and maximums associated with customer participation. For example, in many states, projects are required to have a certain minimum number of participants so that they further the policy vision of shared solar. However, customer participation levels can vary over time as customers re-locate their homes or businesses, thereby losing eligibility for participation in projects that are subject to geographic restrictions (discussed below). Developers should be aware that some states effectively penalize projects when the level of customer participation drops below the minimum level (*e.g.,* through receipt of payments at avoided cost levels for any unsubscribed energy). In addition, many states set a maximum participation level for a given customer. Currently, many states set the maximum level of customer participation at 120 percent of the customer's load, but this can range as high as 200 percent.

States also frequently try to encourage participation by certain classes of customers. For instance, some states seek to encourage participation by residential customers by requiring some portion of the project's subscriptions to be from residential customers or by capping the capacity available to any single customer (which has the effect of limiting the participation of commercial and industrial customers). Additionally, some states seek to encourage participation by low- and moderate-income customers by requiring a certain portion of the project to be allocated to low- and moderate-income participants. Similarly, some states seek to further the cause of environmental justice by providing incentives for projects that are built in economically or environmentally disadvantaged areas (*e.g.,* through setting aside special procurement mandates or giving these projects preference in the interconnection queue).

E. Geographic Restrictions. Although one of the defining characteristics of community solar is the fact that the project and the customer can be in two different places, many states require some geographic proximity between the project and the customer. In many states, the program requires the project and the customer to be located in the same utility service territory. Sometimes, states include tighter restrictions, such as requiring the project and customer to be located in the same or a contiguous county. A variation of this requirement exists in some states, which require a showing of community interest from potential customers within a certain proximity to the project (*e.g.,* the same city or county)

through submission of nonbinding expressions of interest during the procurement process, while allowing actual subscribers to be located anywhere in the applicable utility service territory. Although geographic restrictions are common, they are not universal. Some states place no geographic restrictions on the location of the project, so long as the facility is in-state.

III. Considerations for Developing a Successful Community Solar Project.

A. The Subscription Agreement. In many typical solar projects, the developer enters a power purchase agreement ("PPA") with the utility or a lease or PPA with the owner of the home or building as the offtaker. In a community solar program, there typically is a three-way structure whereby the owner of the solar array enters into an agreement with the utility to provide the energy (and likely the associated renewable energy certificates or "RECs") directly to the utility, and a separate agreement whereby a customer of the utility subscribes with the owner of the solar garden to acquire a right to receive bill credits from the utility. The utility then provides its customer with credits against the customer's monthly bill based on the energy produced by the solar array. The agreements with utilities typically are form contracts established by the tariff governing the program, so are not subject to negotiation. The subscription agreement between the owner of the solar array and the utility customer, however, is typically open to negotiation (though practically speaking, residential subscription agreements are likely to be handled as form agreements as well).

Key issues for the parties to negotiate in subscription agreements include, among other matters, the term of the agreement, termination rights and termination payments, assignability, payment obligations (matching up production by the solar array owner and application of bill credits by the utility to the subscriber's bill), and, potentially, production guarantees.

1. Term, Termination, and Termination Payments. Typically the owner of the system wants to grant very limited termination and assignment rights by the subscriber and for the term to run as long as, or nearly as long as, the owner's agreement with the utility. The subscription agreements serve as the revenue stream for the project and such provisions will be reviewed closely by financing parties. In the event of termination, the owner will seek some version of a make-whole termination payment. The difficulty is agreeing on reasonable liquidated damages when the ability of owners to find replacement subscribers (particularly with significant subscriptions) is relatively untested given the newness of these programs. There may also be consumer or subscriber protections for the parties to navigate as they relate to the termination and termination payment provisions. For residential subscriptions, termination risk is typically at least partially addressed via having ready plans for replacing lost subscribers (*e.g.,* through maintaining subscriber waiting lists).

2. Assignability. As for assignment, the owner of the solar array (and its financing parties) are most concerned about the creditworthiness of the counterparty. Typically the owner of the solar array (and its financing parties) approve a subscriber based on its creditworthiness, and usually would not want the subscriber to be able to assign the subscription agreement to a less creditworthy subscriber. Thus, the assignment rights are typically limited and require approval of the owner of the

array. With respect to commercial and industrial subscribers, this issue is fairly straightforward and fairly customary provisions are negotiated. In the case of residential customers, limitations on assignability are more challenging. Residential customers are likely going to be reviewed and approved on the basis of their FICO scores. The issue that becomes more challenging in the context of residential customers is that they may move their place of residence during the term of their subscription agreement. In some states, subscribers are allowed to maintain their subscription to a project as long as they do not move outside of the applicable geographic area (*e.g.,* the utility service territory). However, if a customer leaves the applicable territory, they may be forced to withdraw from participation. Providing flexibility for customers while maintaining the integrity of the overall portfolio creditworthiness is the meaningful challenge. To address these challenges, some project developers may choose to contract with a separate company to handle subscriber management.

3. Payments. With respect to payment obligations of the subscriber, an issue can arise with matching up production by the solar array owner with the actual application of the bill credits to the subscriber's electric bill. While the solar array owner's production most likely is based on a calendar month basis, the application of the bill credit to a subscriber's electric bill is likely to be delayed and many electric customer's billing cycle, while monthly, may not be on a calendar month basis (*e.g.,* they may be billed on a month from the 15th of one month to the 15th of the following month). Typically the solar array owner seeks to have the subscription agreement provide for payment based on production, with an annual true up to review production with the ultimate application of bill credits to the subscriber's electric bills. In some cases, however, subscribers may seek payment only of bill credits as received.

B. Interconnection. As discussed above, many community solar programs require the project to be located within a certain distance of the customer. This leads many community solar projects to be interconnected to the local distribution grid. However, developers sometimes have very little access to information on substation capacity and load conditions on the local distribution grid. In some of the early state programs, this led to a ballooning of interconnection applications as developers sought more information on distribution system capacity through the application process, knowing that applications would be dropped if interconnection costs were found to be too high or local substation capacity saturated. Certain states have dealt with this challenge by seeking to encourage siting of projects within prioritized zones that are designed to provide the greatest locational distribution grid benefits.

The general lack of information on distribution system interconnection can lead to problems when interconnection rules impose deadlines by which a project must complete interconnection, reach commercial operation, or meet some other milestone. This is particularly true in states that have seen gigawatts of applications with significant lines or queues behind certain substations. In many cases, projects lower in the queue do not have a clear picture of interconnection costs and timing until earlier projects in the queue have either been interconnected or have relinquished their position in the queue.

As this suggests, developers should look for interconnection processes that are well designed and ultimately deliver relatively certain cost and timing estimates to interconnect the projects. Ultimately, the more coordination and transparency that exists around interconnection and project siting decisions, the more efficient the process is likely to be for all parties involved.

C. Site Control and Permitting. In general, community solar projects have the same type of site control requirements and challenges as similarly sized and sited projects. However, the nature of certain community solar programs has created some unique challenges. For example, as described above, many community solar programs include geographic restrictions that require the solar array to be located within a certain distance of the customer. These types of restrictions have resulted in sometimes intense competition for suitable land meeting all of the applicable program requirements and rapid development of multiple projects in close proximity in jurisdictions not accustomed to siting or hosting energy generation projects. The consequence in some cases has been permitting delays and even moratoria in some jurisdictions as local government officials grapple with how to establish appropriate rules for siting solar projects.

D. Securities Law Compliance. Because of the variability of many community solar programs and the potential for customers to participate in a variety of ways, an issue has arisen as to whether offering a subscription to a community solar project may constitute the offering of a "security" under applicable securities laws.

Both federal and state securities laws contain broad definitions of the term "security." Those definitions typically list instruments that have historically been considered securities (stocks, bonds, debentures, etc.), but also includes "catch-all" phrases intended to cover a broader range of instruments in addition to those historically considered securities. Under applicable federal law, regardless of the label on the certificate or instrument representing the investment, a contractual arrangement can be considered a security if it is an "investment contract." That term is included in the Securities Act of 1933, as amended, but was more clearly defined by the United States Supreme Court in the seminal case of *SEC v. Howey Co.*, 328 U.S. 293 (1946). In that case, the Court indicated that a financial relationship could be considered an investment contract—and therefore a security—if it reflected (1) an investment of money, (2) in a common enterprise, (3) with an expectation of profit, and (4) from the efforts of others.

As a result, a community solar project owner will need to carefully examine the various contractual rights and obligations reflected in its form of subscription agreement to determine if it reflects the characteristics identified by the Supreme Court in *Howey* (and the analogous state cases in the state where the project is located). If it does, the project would be involved in the offer and sale of securities, which triggers various regulatory compliance obligations, including significant information disclosures. Conversely, if one or more of the key characteristics is not present, it is likely that the subscription agreement would not be considered a security. This determination can only be made after a detailed analysis of the particular terms of a subscription agreement. To cover the risk and potential liability arising out of securities law noncompliance, some states require developers to obtain a legal opinion

from a law firm indicating whether or not the applicable community solar project involves the offer or sale of securities under applicable state and federal securities laws.

Even if shared or community solar subscriptions are determined to be securities, subscription sales could be in compliance with applicable securities laws if the entity is entitled to claim an exemption from registration under both federal and applicable state securities laws. The availability of any such exemption would be determined by the particular facts and circumstances and the offer and sale of securities by that issuer.

Two exemptions from registration are most commonly available to community solar developers. First, the federal securities laws contain an exemption from federal registration for an offering that is conducted entirely in one state by an issuer organized or formed in that state. However, this exemption only provides an exemption under federal law; it would be necessary for a community solar entity to identify and claim an appropriate state exemption as well. Second, both federal and state securities laws provide exemptions for certain offerings limited to a very small number of subscribers and for offerings of securities to "accredited investors." Accredited investors are parties who meet certain financial criteria and are therefore presumed to have the sophistication (or access to advisors) necessary to analyze an investment opportunity. Individuals are typically accredited if they have a net worth in excess of $1 million, exclusive of the individual's primary residence and any debt associated with that primary residence. Entities typically qualify as accredited investors if they have total assets in excess of $5 million. As a result, if shared solar subscriptions are deemed to be securities, parties could maintain securities compliance by offering subscriptions only to those individuals or entities that have accredited investor status (such subscription agreements may also contain subscriber representations and warranties to this effect).

E. Consumer Protection. In addition to securities law compliance, community solar developers and marketers will need to ensure compliance with state and federal consumer protection laws. States vary widely in the scope of their consumer protection laws and the extent to which such laws have been expressly extended to the sale of renewable energy or solar energy systems. For developers engaging in sales of residential subscriptions, careful analysis of the applicable consumer protection laws is critical. To the extent the subscriptions are being marketed door to door, for example, it is likely there are state laws restricting home solicitations or that require a cooling-off period. To the extent developers are marketing the benefits of the subscription agreement, they need to be cautious to avoid any pitfalls with fraud, deceptive trade, or false statement laws. In addition, many state community solar programs include specific subscriber protections. Compliance with consumer protection laws is a matter of both substantive observance of the rules and careful recordkeeping in order to demonstrate compliance to regulators and financing parties.

IV. Conclusion. The promise of community solar is an exciting one: opening up access to solar for all. It could significantly expand the market for solar by giving energy customers (big and small) access to solar projects that are located off-site and benefit from economies of scale. As a result, community solar projects are under development in dozens of states, and there are rosy projections for the market

segment's growth in the coming years. While the prospects for community solar look promising, the market is still in its infancy, the rules of the road in various states are continuing to be developed, and market participants are still working out their preferred approach. Critical to the success of any foray into the shared solar market is working with partners who have experience with community solar programs, and who know how to navigate the complexities of the community solar development process.

Chapter Ten
THE LAW OF SOLAR
—Monetizing the "Green" in Green Power: Renewable Energy Certificates—

Sara E. Bergan

I. Introduction. Renewable energy generation creates at least two distinct commodities that may be sold together or separately. These two commodities are electricity and environmental attributes. The environmental attributes include the emissions benefits associated with the use of renewable energy (*e.g.,* avoidance of greenhouse gas or other emissions) and the source of renewable energy (*e.g.,* solar or wind resources). Because there are two commodities, it is possible to sell the electricity with the environmental attributes or to sell the two commodities separately from each other. Given the ability to unbundle the environmental attributes from the electricity, the buyer of the environmental attributes may be different from the buyer of the electricity.

A renewable energy certificate or "REC" is a marketable unit representing the rights to the environmental attributes of renewable power generation. A REC typically represents the environmental attributes from 1 megawatt hour ("MWh") of electricity from a renewable energy source (though some states do allow aggregation of smaller units), and includes the reporting rights to the greenness of that MWh of electricity. In the case of electricity from solar generation, the corresponding certificate may be referred to as a solar renewable energy certificate or "SREC."

This chapter discusses the different types of markets where a solar power developer might sell its RECs, examines criteria that may affect the eligibility of your facility to sell its RECs, and explains how the tracking of RECs can lead to maximizing the value from your REC sales.

II. How RECs Help Finance Your Renewable Energy Project. Financing is usually the biggest challenge facing independent developers of solar energy projects. A profitable solar energy project typically relies on multiple sources of revenue. Electricity sales are obviously the most important, but state and federal incentives, including tax benefits, are important revenue streams as well. In addition to the revenues from electricity sales and the various governmental incentives, RECs can be a significant stream of revenue for a solar energy project, substantially aiding its financing prospects. Investors tend to require long-term certainty to give maximum credit to the cash flows for a project. Because REC markets can be volatile, investors and lenders prefer to finance a contracted cash flow. Therefore lenders or investors may not rely on revenue projections from REC sales absent a long-term REC sale agreement. Some states are also employing various tools to try to create more long-term stability in the REC markets, such as setting floor prices for RECs to enable lenders and financing parties to gain more certainty in modeling long-term REC revenues.

III. Types of Markets for RECs. REC prices are largely determined by market forces. In general, there are two markets for RECs: compliance markets and voluntary markets.

A. Compliance (or Mandatory) Markets. During the first decade of the 21st century, a majority of states passed laws requiring certain utilities to include a minimum amount of renewable energy in the portfolio of generating resources serving the utility's load. These laws are generally referred to as renewable portfolio standards ("RPS") or renewable energy standards. They require utilities to add renewable generation to their system incrementally until reaching a standard of anywhere from 10 to 100 percent of retail sales from renewable energy. Many of these initial benchmarks have been reached and will likely continue to be satisfied for the foreseeable future by utilities retiring RECs from existing renewable generation. In response, many states have recently moved to significantly raise their state standard, which has the effect of expanding the compliance market for RECs.

In compliance markets, buyers tend to care only about whether the source of renewable generation meets the state RPS requirements. As such, it is critical to understand how these policies work to either limit or add value to your particular RECs or SRECs. In addition, utilities making long-term purchases of RECs may impose credit requirements on sellers in the form of a letter of credit, a corporate guaranty, or other arrangement, as utilities tend to buy RECs only from sources that will satisfy their RPS needs for the long term.

1. REC Eligibility. Each state RPS program determines whether RECs are tradable and defines what constitutes a REC that will satisfy its own particular standards. Some states specify that the generation source must be located within the state or a particular region or that the electricity generated be delivered to the state or a nearby region to meet the state standard. Some states require their utilities to purchase the electricity and REC together, or limit the amount of the RPS that can be met by purchasing RECs alone (*e.g.,* California). States often also designate an allowable life span or shelf life for RECs to meet state standards. These often range from three to five years (but can be longer) and at the end of the designated period expire for the purposes of meeting the state RPS. And of course states determine what energy generation resources are eligible to meet the state standards, a determination that is widely varied among states. Additionally, solar facilities may be required under state law to be certified in order to sell qualifying solar RECs and such certification may include meeting additional requirements for solar like a capacity cap. Markets for RECs are changing all the time, and while tracking your RECs through a regional tracking system should gather and verify the data necessary to demonstrate compliance for various state policies, the risk of noncompliance is ultimately in the hands of the REC holder (the tracking systems do not verify eligibility). Thus it is critical to track the current RPS policies and eligibility of resources in various states where the parties intend the RECs to be used for compliance.

2. Solar Carve-Outs or Set-Asides. In an attempt to pull more solar energy into their markets than would otherwise happen under a traditional RPS where lower-cost renewable energy (*e.g.,* wind energy) will likely be utilized first to meet the requirements, many states have legislated unique standards, carve-outs, or additional incentives for solar energy. A solar carve-out or set-aside is a requirement that a certain percentage of the electricity acquired by utilities subject to a state RPS be

generated by a solar energy resource. Sometimes this is laid out in a graduated class or tier system whereby utilities are required to get a certain percentage of their electricity from each class or tier over time and where solar may occupy one class by itself or be classified with other similarly situated technologies. In other cases, there is simply a stated percentage of electricity (most common) or percentage of the total RPS that is required from eligible solar technologies, and the percentage too may increase over time. In certain cases the state legislature may have added a separate solar standard years later on top of the traditional RPS. Other states have chosen to set a capacity (MW) or production (MWh) target for solar energy that may or may not be directly carved out of the state RPS.

3. Multipliers or Factors. Many states also allow solar energy RECs or generation to be multiplied by some factor (*e.g.,* two or three) such that a utility could use less solar energy to comply with the state RPS. These measures, if put to use, effectively lower the total state renewable energy requirement and may also include a cap or sunset date to curb this effect. Multipliers may be used in lieu of or in addition to a carve-out.

Other states create priorities within solar generation by assigning different solar REC factors for different types of installations (*e.g.,* 1 for community shared solar projects vs. 0.8 for generation on brownfields). And the multipliers or factors themselves may be for any number of things potentially affecting a solar energy facility and may be mutually exclusive or additive. For example, states may include a multiplier for the type of technology (*e.g.,* solar), scale of technology (*e.g.,* under x number of MW or distributed generation), type of system (*e.g.,* ground or building mounted), time of generation (*e.g.,* peak hours), location (*e.g.,* in state or in-service territory), type of entity (*e.g.,* community based), or development characteristics (*e.g.,* use of in-state manufactured content or labor).

4. Regulating Value. States have employed a variety of legislative and regulatory efforts to stabilize the long-term market prices for solar RECs. Some states, for example, set solar alternative compliance payments ("ACPs") that aim to create a ceiling on solar REC prices on the theory that a utility would simply opt for the lower priced ACP in order to meet its requirements if solar REC prices became too high. Thus when there is a shortage of solar REC supply, the ACP could virtually set the market price for the solar RECs. In the case of New Jersey, the legislature set forth a 15-year schedule of ACPs to encourage more certainty in the market.

Efforts to stabilize solar REC prices under the opposite conditions—where there is an oversupply—include various methods of encouraging long-term contracts and establishing an effective price floor. Massachusetts, for example, addresses oversupply through its Massachusetts Solar Credit Clearinghouse Auction program, which aims to auction off any available solar RECs that are not being sold on the open market through a series of fixed-price auctions. If the available credits are not cleared by the bids at the fixed price during the first auction, another auction is held at the same fixed price but where the shelf life of the REC is extended, thereby adding value to the REC. If the shelf-life extension remains insufficient to clear the volume, the state increases the utilities' obligations for the next year in proportion to the volume of available SRECs. These actions all aim to create a market floor price and create a more stable financeable product.

The factors mentioned above also work to control the effective value of the environmental attributes associated with solar generation. In Massachusetts, for example, once a 1,600 MW program cap has been reached, the solar REC factor values will switch from a range of 0.7-1 to 0.5-0.7, resulting in the need to generate more MWh to achieve the same revenue from REC sales.

B. Voluntary Markets. Although the compliance market is a critical driver of REC sales today, the concept of RECs or green tags was originally developed for voluntary actions where individuals or companies aspired to meet certain renewable or sustainability goals. In these markets, sales are driven by customer demand. Voluntary buyers may be motivated by a desire to "do the right thing," or to enhance or affirm their corporate identity, corporate climate or sustainability goals, or general environmental awareness. Buyers include marketers, brokers, businesses, nonprofit organizations, and individuals. More recently, voluntary corporate procurement of renewable energy has been increasing dramatically as large energy users seek to meet internal goals or hedge against volatile energy market pricing. The Midwest Renewable Energy Tracking System (M-RETS), for example, has tracked voluntary market retirements for nearly a decade and shows 2017 on pace to be by far the largest year of voluntary REC retirements in its system. The following sections provide an overview of the different ways electricity customers participate in the voluntary markets for "green" electricity.

1. Green Pricing. Early examples of voluntary REC markets include utility "green pricing programs," which started with a small number of utility programs in the early 1990s and now number in the several hundred. In these cases utility customers generally sign up to pay a premium on their utility bill for renewable energy and the utility then procures and retires RECs in proportion to the amount of green power purchased by the customers involved in the program. Some of the top programs (*e.g.,* Portland General Electric) have well over 100,000 participants in their green pricing programs and the top 10 sell well over 5 million MWh of green electricity each year. While these programs have historically purchased primarily wind energy generation, solar procurement under the programs is on the rise and some utilities are offering the customers an option to procure from solar specifically. The RECs associated with these programs may be sold bundled with the electricity or separately as unbundled RECs.

2. Green Tariffs. In recent years, to accommodate the increasing desire for green power, the need for competitive and stable electricity prices, and customer goals to procure the associated RECs, utilities in some states have launched "green tariff" programs. Specifically, a "green tariff" is a price structure or rate offered by the utility and approved by the state's public utility commission that may provide for up to 100 percent of eligible customer electricity needs to be sourced from renewable resources. These green tariff programs vary widely depending on level of customer participation or price structure. Some are aimed at smaller customers and are known as "subscriber" utility programs. In such instances, the utility maintains full control over the procurement and pricing terms of a renewable energy project and the customer "subscribes" to the utility program for a portion of the project. Other "green tariff" programs primarily involving larger customers give the customer

direct control in the negotiation of the renewable power purchase agreement ("PPA"). In such instances, the customer, the utility and the solar developer enter into a "sleeved" agreement. The associated green tariff then replaces the customer's standard electricity rate with the cost of the renewable energy under the PPA and a rider added to the standard electricity rates (accounting for the total of the cost of renewable energy plus credit for the avoided cost (*i.e.,* fossil-fuel power replaced through the renewable energy project)). Lastly, in a market-based green tariff, the customer signs a PPA for the energy and RECs from a dedicated renewable energy facility and the utility sells the resulting output into its wholesale market (*e.g.,* Southwest Power Pool or Midcontinent Independent System Operator) and credits the wholesale market price to the customer. In all of the above green tariff variations, the utility and customer have unbundled the cost of service rate and substituted for the cost of service for the renewable resource. The various iterations of green tariffs are still relatively new and the ability of such arrangements to facilitate renewable transactions, at least in part, depends on the value proposition to the customer and whether it will yield savings.

3. Corporate Purchases. Alternatively, certain corporate purchasers enter into "synthetic" or virtual PPA transactions, which provide the ability to contract directly with the renewable energy generator for the sale of electricity and/or RECs without the actual delivery of the physical power. These arrangements are often used by customers with intensive energy use, who are interested in a long-term hedge given the volatility of the energy market or who are subject to corporate sustainability goals. Essentially, in these transactions, the buyer and the seller engage in a hedge or a swap, whereby the parties sell into the wholesale marketplace but agree on a "strike" price at a known hub or trading point. The buyer will pay the seller if the market price is below the strike price, and the seller will pay the buyer if the market price is above the strike price. The RECs may be built into the deal or treated separately. Synthetic PPAs can provide the buyer with long-term price security for both power and RECs, and if the strike price is financially attractive for the seller, it allows the seller to finance the project for the term of the agreement with the certainty that it will be paid no less than the strike price for the power produced. Determining whether and how to best structure such a deal is highly dependent on the particulars of a state's energy regulatory system.

4. Community Choice Aggregation. Some states allow communities to aggregate their loads and procure green power in larger quantities through an alternative electricity supplier. For example, in California, community choice aggregation ("CCA") programs have been established by individual jurisdictions (such as a city) or by two or more jurisdictions pursuant to a joint powers authority agreement. CCAs typically provide different product offerings that allow customers to choose how much of their energy will be derived from renewable energy resources. To serve these customers, CCAs enter PPAs with energy suppliers. Most commonly, these agreements call for the delivery of both the electricity and RECs generated by the applicable project. However, during the first few years of a CCA, the program may purchase unbundled RECs to meet its renewable energy supply requirements until contracted renewable energy projects come online. While CCAs provide for procurement of electricity and RECs, the existing utility will typically continue to provide energy delivery over its distribution system, as well as performing other services (*e.g.,* monthly billing).

5. Community or Shared Solar. Increasingly, electricity customers also have the option to subscribe to a shared solar project, which is currently a small but growing market. Please refer to Chapter 9 for more detail on community solar in general. For the purposes of this chapter, we note that the treatment of the environmental attributes associated with shared solar programs can vary widely and can have dramatic effects on the project's financing. In Colorado where the utility issues a request for proposals for community solar, the winning bids recently employed negative REC pricing to the surprise of many. By contrast in Minnesota, regulators initially set an effective fixed REC price of $20/MWh for all RECs transferred from community solar generating assets to the utility by raising the bill credit rate paid to subscribers in those situations by $0.02/kWh. More recently, Minnesota regulators shifted to a value of solar rate structure that, by definition, does not separately account for the environmental attributes but instead folds them into the value of solar calculation and assumes the RECs transfer to the utility alongside the electricity.

IV. Tracking RECs. Many states that have RPS legislation allowing RECs to count toward the requirements also require the RECs to be retired through a specific tracking system, such as M-RETS, Western Renewable Energy Generation Information System, New England Power Pool Generation Information System, or PJM Interconnection's Generation Attribute Tracking System. There are at least 10 regional REC tracking systems in the United States and many more now around the world. These electronic systems track each REC from "birth" to retirement. Each unit of generation is assigned a unique ID that includes its attributes, such as the date the energy was generated, the facility location, the date the facility went online, the type of renewable facility, the emissions profile, and all transactions associated with that unique ID. Operating procedures for these tracking systems generally require that the RECs remain whole and that all generation from a particular unit be reported in one tracking system to avoid double counting. A utility, or other entity, can then elect to retire that unique certificate to show compliance with a state requirement.

Initially these tracking systems were somewhat isolated and did not allow for trading into or out of another system. While a state like Michigan continues to maintain a state-specific REC tracking system (MIREC), it is also integrated with the broader M-RETS to facilitate trading across many more states in the Midwest. Today the various tracking systems are continuing to become increasingly integrated with one another.

Even so, the trading in or out of certain systems comes down to compliance with particular state policies. Some states are relatively open with respect to where the RECs can be sourced and others limit the RECs that can be retired for compliance purposes to a single state, neighboring states, or a regional tracking system. The geographic limitations imposed in state policy have deterred market liquidity for RECs and have also been subject to various legal challenges asserting that favoring in-state products above out-of-state products runs counter to constitutional provisions aimed at limiting state protectionism. Some states have changed their policies in favor of a more open approach, but legislators also like to make sure the benefits of legislation accrue locally. Thus, it is important for a developer to carefully track the eligibility of its RECs to be sold into prospective compliance markets.

V. Conclusion. RECs, and solar RECs in particular, can be a valuable revenue stream for a solar developer. Selling an intangible attribute into a growing and evolving market for cash is a great way to enhance the viability of a project. Solar RECs can be particularly valuable where they can qualify utilities to satisfy a state's RPS standards and those with specific carve-outs, multipliers, or separate standards for solar energy. Additionally, the voluntary market for RECs is seeing dramatic growth. A project's success can be highly dependent on a detailed understanding of the ability of a solar generation resource to meet certain state standard requirements or corporate sustainability goals, the value eligibility brings to the project, the mechanics of tracking and trading the RECs, and the appropriate contract terms to facilitate the transfer of rights to the attributes in exchange for an important project revenue stream over time.

Chapter Eleven
THE LAW OF SOLAR
—Tribal Laws and Land Issues—

Gary R. Barnum

Many Indian tribes own extensive blocks of land with significant solar resources. Tribal land provides solar developers (which can include the tribe or a business entity controlled by the tribe) with an opportunity to work with a single landowner to enter into a Solar Property Project Agreement securing all site control and related easements necessary to conduct a solar resource assessment and other studies and to construct, own, operate, and maintain a solar energy project.

Indian reservations are unique jurisdictional enclaves in which federal and tribal laws apply. Federal and tribal laws govern leases, easements, and other agreements for use of tribal land within Indian reservations. In addition, as governments, Indian tribes exercise significant regulatory control over use of tribal land and Indian reservation land generally. Federal laws of general application, such as federal environmental, energy, and tax laws, and some state laws also apply to solar energy project developers on tribal land. This chapter provides a brief overview of issues affecting solar energy project development on tribal land.

I. Solar Property Project Agreements on Tribal Land. Land ownership, which varies from reservation to reservation, may include a matrix of land owned by the United States in trust for tribes ("tribal land") and individual Indians and land owned in fee by tribes, individual Indians, and non-Indians. This section focuses on tribal land, although there may be separate consent and tribal law issues relating to land owned in fee by a tribe as well. Even with tribal consent, tribal land can be sold, leased, encumbered by an easement, or used as security for financing only as authorized by federal Indian law and applicable tribal law.

Under 25 U.S.C. Section 415(a), an Indian tribe, as lessor, can lease tribal land for a term not to exceed 25 years; with the consent of both parties, the lease may include provisions authorizing renewal for one additional term not to exceed an additional 25 years. Specific tribes listed in section 415(a) can also lease tribal land for up to 99 years. All leases authorized by section 415(a) must be approved by the Bureau of Indian Affairs ("BIA"). For leases authorized by section 415(a), the BIA issued new regulations with major revisions effective January 4, 2017. 25 C.F.R. pt. 162. New Subpart E includes provisions specific to solar resource leases. Through an amendment to section 415(h), enacted by Congress in 2012, all Indian tribes may lease tribal land for up to 75 years without BIA approval, once the BIA approves tribal leasing regulations. Several tribes already have adopted such regulations, with BIA approval, and more are expected to do so. Leases authorized by section 415 are for surface use and do not authorize exploration, development, or extraction of mineral resources.

Key federal environmental laws the BIA must comply with before approving leases of tribal land and taking other action include the National Environmental Policy Act ("NEPA"), the National Historic

Preservation Act ("NHPA"), and the Endangered Species Act ("ESA"). Under NEPA, the BIA must prepare an environmental impact statement before approving a lease of tribal land or taking other action, unless a categorical exclusion applies (where the BIA's action is of a type that will not have significant environmental impact, individually or cumulatively) or the BIA concludes after preparing an environmental assessment that its action will not have a significant impact on the environment. Under section 106 of the NHPA, the BIA must take into account impacts its actions may have on any property listed or eligible for listing on the National Register of Historic Places, including properties of traditional religious and cultural importance to an Indian tribe, and must consult with tribes and other interested parties in the development and evaluation of measures to avoid, minimize, and mitigate any adverse impacts of its action on the characteristics that make such properties eligible for listing on the National Register. Section 7 of the ESA requires the BIA to consult with either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service, and in some cases both, if its action may affect species or designated critical habitat of species listed as threatened or endangered under the ESA. Federal laws of general application, such as the Clean Water Act and Clean Air Act, generally apply on tribal land. Compliance with these and other federal environmental laws can delay project development and result in measures to avoid, minimize, and mitigate project impacts.

Tribal government corporations operating under charters issued by the Secretary of the Interior under 25 U.S.C. Section 5124 can lease tribal land for 25-year-maximum terms without BIA approval. Leases authorized by section 5124 cannot include an option extending the 25-year base term.

For purposes of protecting project solar resources from being disturbed by development on other tribal land, it may be appropriate to combine a lease of tribal land with an "encumbrance" on other tribal land under 25 U.S.C. Section 81. A section 81 encumbrance of tribal land for seven years or more must be approved by the Indian tribe and the BIA.

A lease may address access that a solar project developer needs to leased premises by roads or other infrastructure. Roads or other access methods within the leased premises do not require a separate right-of-way grant under 25 C.F.R. part 169. To the extent a solar project developer needs a right-of-way over nontribal trust land owned by individual Indians or tribal lands of an adjoining Indian reservation, the BIA may grant rights-of-way across tribal and individual Indian trust land with the owner's consent. Before issuing a right-of-way, however, the BIA must comply with federal laws governing federal agency actions affecting the environment. In response to a 1997 U.S. Supreme Court case limiting tribal jurisdiction within a BIA-issued right-of-way, some tribes refuse to consent to BIA-issued rights-of-way. These tribes have preferred to approve rights-of-way in the form of "linear leases" under section 415, discussed above. Generally, tribes exercise greater regulatory control over activities conducted on tribal land under a lease.

The Energy Policy Act of 2005 directed the Secretary of the Interior to issue regulations for Tribal Energy Resource Agreements ("TERAs"). Final regulations governing TERAs were issued March 10, 2008. 25 C.F.R. pt. 224. Once an Indian tribe and the BIA enter a TERA covering solar energy development, the tribe can enter into solar energy leases and other business agreements and issue right-of-way easements

for projects on tribal land for 30 years, renewable for another 30 years by the tribe, all without further BIA approval. However, the BIA must conduct NEPA analysis before approving a TERA. For this and other reasons, TERAs have not proven to be very useful in developing energy resource projects on Indian land.

II. Key Considerations.

A. Taxation and Regulatory Authority. In addition to being landowners, Indian tribes are governments that may exercise significant tax and regulatory authority over activities on tribal and other reservation land. A tribe does not waive its governmental regulatory authority by entering into contracts for development of tribal land and resources. A developer should carefully review tribal laws and regulations to determine their effect on a solar energy project. When appropriate, a developer can request that a tribe adopt new tribal laws or amend existing tribal laws to facilitate financing and other aspects of a solar energy project on tribal land.

Nontribal project developers may be subject to applicable state and tribal taxes. Regulations adopted by the BIA applicable only to leases issued under 25 U.S.C. Section 415 indicate that state and local taxes do not apply to leasehold interests of lessees of tribal land. Prior to the issuance of these regulations, various federal court cases came to different conclusions, and it is too early to determine what practical effect the BIA's new regulations will have. Careful review should be conducted to determine whether a Solar Property Project Agreement or other agreements can be designed to avoid or minimize the risk of double taxation. In some cases, Indian tribes are willing to abate tribal taxes to the extent necessary to avoid or minimize the economic impact of double state-tribal taxation.

Federal law affords accelerated depreciation for certain investments on tribal land. Some states grant credits against state taxes or abate state leasehold taxes and certain other state taxes for projects on tribal land.

Although federal and tribal laws play a dominant role in energy development on tribal land, state laws may also impact these projects. For example, if access to a state highway is needed, that must be obtained in the manner provided under state law. Nontribal developers and their nontribal employees, contractors, and suppliers may be subject to a variety of state laws.

B. Water Rights. Certain solar technologies involve significant use of water. For many purposes, tribal water rights are appurtenant to tribal land. Except for acts of Congress approving certain Indian water right settlements authorizing leases of tribal water rights apart from tribal land, the most common way to secure a right to use tribal water is through a lease of tribal land to which the tribal water right is appurtenant. Depending on local hydrology, political considerations, and other factors, including necessary transmission lines and rights-of-way, water rights secured under state law may be available for use by a solar project on tribal land.

C. Cultural Resources. In addition to BIA compliance with NHPA section 106 in approving leases of or issuing rights-of-way on tribal land, the Native American Graves Protection and Repatriation

Act and other federal laws establish procedures and permitting requirements that must be followed if human remains, funerary objects, sacred objects, or archaeological resources are intentionally or inadvertently encountered before or during project development on tribal land (and federal land). Many Indian tribes have tribal laws that deal with these matters on tribal land.

D. Dispute Resolution. As governments, Indian tribes have sovereign immunity. This means an Indian tribe cannot be sued in any court without the express consent of Congress or the tribe itself by appropriate tribal government action. Most tribes are willing to waive tribal sovereign immunity on a limited basis to promote significant tribal economic development projects. A tribal sovereign immunity waiver must be approved by a tribe in accordance with applicable requirements of tribal law, and any action or proceeding brought under such a waiver likewise must comply with applicable requirements of tribal law, including any requirements for notice to specified tribal officers before commencement of an action or proceeding.

A dispute resolution clause in an agreement with an Indian tribe typically includes a provision designating the court or courts authorized to exercise jurisdiction over a dispute with the tribe. These clauses should be carefully reviewed, as federal and state courts often will not have jurisdiction over a dispute with an Indian tribe, despite a forum selection clause. Developers are often reluctant to agree to have such disputes heard in a tribe's tribal court.

To address this dilemma, many Indian tribes will agree to a dispute resolution clause designating binding arbitration as the exclusive means of resolving disputes. Although a binding arbitration clause leaves questions regarding which court can enforce the promise to arbitrate and enforce, modify, or vacate an arbitration award, well-drafted agreements to resolve disputes by binding arbitration and well-drafted sovereign immunity waivers resolve some of the most challenging dispute resolution issues in tribal Solar Property Project Agreements.

Chapter Twelve
THE LAW OF SOLAR
—Foreign Corrupt Practices Act—
Kennon Scott

Accessing the global marketplace brings many advantages to a solar energy company including access to markets, clients, and projects; more capital sources; a wider range of companies with which to collaborate; increased manufacturing efficiencies; a greater number of vendors; and more investment opportunities. Operating in the global marketplace, however, requires the management of a solar energy company to be aware of the many regulations applicable to companies that have cross-border operations and to implement company programs and policies to ensure compliance with such regulations. Regulations potentially applicable to a solar energy company with cross-border operations include, among others, anti-corruption laws such as the Foreign Corrupt Practices Act (the "FCPA"), the UK Bribery Act, and the Organisation on Economic Cooperative Development Convention, anti-money laundering laws, U.S. trade and investment sanctions, anti-boycott laws, anti-terrorism controls, export controls, and foreign direct investment controls under the Exxon-Florio Provisions.

This chapter will focus on the FCPA.[1] The FCPA is one of the most important U.S. statutes applicable to U.S. companies with operations outside the United States and to non-U.S. companies with connections to the United States.

The notoriety of the FCPA in the energy industry is largely attributable to Siemens AG, a German conglomerate, and three of its subsidiaries (collectively, "Siemens") pleading guilty in a U.S. federal court to FCPA violations in December 2008. U.S. authorities alleged, among other FCPA violations, that starting in 2001, Siemens' Power Generation ("PG") and Power Transmission and Distribution ("PTD") divisions paid at least $356.9 million in bribes to foreign officials in multiple countries. As part of its settlement with the U.S. Department of Justice (the "DOJ") and the U.S. Securities and Exchange Commission (the "SEC"), Siemens agreed to pay $800 million—a $450 million criminal penalty and to disgorge $350 million in wrongful profits. On the same day, Siemens announced an agreement with German prosecutors to pay a €395 million ($569 million) fine for violating Germany's anti-corruption laws, adding to the €201 million ($285 million) that a Munich court sentenced Siemens to pay in October 2007. Since Siemens, the SEC and DOJ have reached large settlements with other energy industry companies accused of violating the FCPA, including Total S.A. ($398 million in 2013) and Snamprogetti Netherlands B.V. ($365 million in 2010).

The FCPA creates risks for energy sector companies because (among other reasons) they often conduct business in emerging markets perceived to have high corruption (and where remote monitoring can be more difficult), and their contact with foreign government officials, directly or indirectly, is often

[1] 15 U.S.C. § 78dd-1, *et seq.*

unavoidable due to their involvement in bid and tender processes, customs issues, and licensing and permitting.

I. Overview of the FCPA. The FCPA prohibits companies (both publicly traded and private) and individuals from paying or promising to pay foreign officials, directly or indirectly, anything of value with the corrupt intent of obtaining or retaining business; it also mandates internal accounting controls and recordkeeping practices for publicly traded companies, aimed at preventing and detecting illegal bribes.

After an overview of the potential penalties for FCPA violations, this chapter will provide a broad overview of the FCPA's two prongs: (1) the anti-bribery provisions, and (2) the books and records provisions. Thereafter, because this chapter is intended for a global audience, the jurisdictional scope of the FCPA will be described. The emergence of vicarious liability and successor liability as major enforcement trends will then be addressed, as well as a discussion of the emergence of private rights of action. With the attention that the Siemens enforcement action brought globally to the FCPA, a brief description of that enforcement action and the lessons offered by it will be addressed. A punch list of FCPA compliance action items is found at the end of this chapter.

A. Who Enforces the FCPA and What Are the Penalties? The DOJ and SEC share responsibility for enforcing the FCPA. While the DOJ handles all criminal actions and all civil actions against nonissuers, the SEC handles only civil actions against "issuers."[2]

FCPA enforcement actions can result in hefty fines and even prison time. Under the FCPA's anti-bribery provisions, entities face criminal fines of up to $2 million per violation and civil penalties of up to $16,000 per violation. Individuals face criminal fines of up to $250,000 or imprisonment of not more than five years, or both, per violation, and civil penalties of up to $16,000 per violation. As for the accounting and recordkeeping provisions, entities face criminal fines of up to $25 million and individuals face up to 20 years in prison and criminal fines up to $5 million, or both. Additionally, under the alternative "profit disgorgement" penalty provisions, a criminal fine can be significantly higher—up to twice the gross gain the defendant sought to obtain. Civil penalties for accounting and recordkeeping violations are the greater of (a) the gross amount of the gain to the defendant, or (b) a specified dollar limitation—which is based on the egregiousness of the conduct and ranges from $75,000 to $725,000 for an entity, and from $7,500 to $150,000 for an individual, per violation.

In recent years, the number of DOJ and SEC enforcement actions under the FCPA has dramatically increased. Last year was a record-breaking enforcement year—27 companies paid approximately $2.48 billion to resolve FCPA cases. For comparison, before 2016, the most active enforcement year was 2010, with 23 companies paying $1.8 billion. While the change in presidential administrations in early

[2] "Issuer" is defined *infra* at 5.

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2017 creates some uncertainty as to the future of FCPA enforcement, the DOJ has indicated that it remains committed to vigorously investigating and prosecuting FCPA violations.

To encourage cooperation, on March 10, 2017 the DOJ announced that it was extending an FCPA enforcement pilot program it started last year.[3] The pilot program provides for "mitigation credit" that takes into consideration three factors: (1) voluntary disclosure, (2) full cooperation, and (3) remediation. In cases in which criminal prosecution is otherwise warranted but all three factors have been met, "mitigation credit" can include "up to a 50% reduction off the bottom end of the Sentencing Guidelines fine range" and the avoidance of a third party-compliance monitor.[4] Moreover, in appropriate cases, where the three factors have been fully satisfied, the DOJ "will consider a declination of prosecution."[5]

B. The Two Prongs of the FCPA. The FCPA contains two sets of provisions geared toward battling bribery abroad. First, the FCPA's anti-bribery provisions prohibit companies (both private and public) and individuals from paying or promising to pay foreign officials anything of value with the corrupt intent of obtaining or retaining business. Second, the FCPA's accounting and recordkeeping provisions mandate various internal accounting controls and recordkeeping practices aimed at preventing and detecting illegal bribery of foreign officials.

1. Anti-Bribery Prohibitions. The broad scope and sweeping language of the FCPA's anti-bribery provisions render compliance challenging for public and private international solar energy companies. Again, the FCPA's anti-bribery provisions prohibit companies and individuals from paying or promising to pay foreign officials anything of value with the corrupt intent of obtaining or retaining business. "Anything of value" includes not only money, but also such perks as bottles of wine, tickets to sporting events, and internships for family members. Moreover, the phrase "obtaining or retaining business" encompasses everything from securing contracts, to winning tax breaks, to bypassing regulatory requirements.

The term "foreign official" is especially slippery, including not only actual government members, but also government instrumentalities, public international organizations *(e.g.,* the United Nations), political parties, political party officials, candidates for political office, and even royal family members. In countries such as China, where government instrumentalities known as state-owned enterprises ("SOEs") dominate the business arena, an array of potential business partners may arguably constitute "foreign officials." For example, in June 2008, the DOJ and SEC brought enforcement actions against AGA

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[3] DOJ, Acting Assistant Attorney General Kenneth A. Blanco Speaks at the American Bar Association National Institute on White Collar Crime (Mar. 10, 2017), https://www.justice.gov/opa/speech/acting-assistant-attorney-general-kenneth-blanco-speaks-american-bar-association-national.

[4] DOJ, The Fraud Section's Foreign Corrupt Practices Act Enforcement Plan and Guidance (Apr. 5, 2016), https://www.justice.gov/criminal-fraud/file/838416/download.

[5] *Id.*

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Medical Corporation ("AGA"), a Minnesota-based medical products manufacturer, for authorizing its Chinese distributor to pay $460,000 in "commissions" to Chinese doctors. These doctors in turn directed their hospitals to order AGA's products. Given that these hospitals are SOEs, the doctors constitute "foreign officials" under the FCPA, thus rendering AGA's payments illegal bribes and resulting in a $2 million penalty.

The DOJ has stated that as a "practical matter, an entity is unlikely to qualify as an instrumentality [of a foreign government] if a government does not own or control a majority of its shares."[6] Nevertheless, the DOJ will bring FCPA charges when the foreign government only owns a minority interest in the relevant entity, if circumstances warrant it. For example, in 2010, the DOJ brought charges against Alcatel Lucent France, a subsidiary of a French issuer, for paying bribes to employees of a Malaysian telecommunications company that was only 43 percent owned by the Malaysian government.

In recent years, several companies have unsuccessfully challenged the breadth of the DOJ's definition of what constitutes an "instrumentality" of a foreign government. In the leading case addressing this issue, the U.S. Court of Appeals for the Eleventh Circuit affirmed the conviction of two individuals who had bribed officials of a Haitian telecommunications company.[7] Though the telecommunications provider was the sole provider of landline phone service in Haiti, was 97 percent owned by the National Bank of Haiti, and the Haitian president appointed all of the company's board members, it was not a government entity by law.[8] The defendants argued that the company was not an "instrumentality" of the Haitian government because it did not perform traditional, core government functions.[9] The Eleventh Circuit rejected this argument, applying a fact-based, multi-factor analysis.

First, the Eleventh Circuit defined "instrumentality" as "an entity controlled by the government of a foreign country that performs a function the controlling government treats as its own."[10] It then went on to list relevant factors that courts could apply to determine what constitutes "control" and a "function the government treats as its own."[11] To determine whether a government "controls" an entity, the Eleventh Circuit suggested that courts may consider: (1) the foreign government's formal designation of the entity; (2) whether the government holds a majority interest; (3) whether the government can hire and fire the entity's principals; (4) the extent to which the entity's profits go directly to the

[6] DOJ & SEC, *FCPA: A Resource Guide to the U.S. Foreign Corrupt Practices Act* 21 (Nov. 14, 2012), https://www.sec.gov/spotlight/fcpa/fcpa-resource-guide.pdf.

[7] *United States v. Esquenazi*, 752 F.3d 912 (11th Cir. 2014).

[8] *Id.* at 928-29.

[9] *Id.* at 924.

[10] *Id.* at 925.

[11] *Id.* at 925-27.

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government; and (5) the extent to which the government funds the entity.[12] To determine whether the entity performs a "function the government treats as its own," courts are to consider whether (1) the entity has a monopoly of the function at issue; (2) the government subsidizes the costs associated with the entity providing services; (3) the entity provides services to the public at large; and (4) the public and the government perceived the entity to be performing a government function.[13]

The lesson to be drawn from the framework created by the Eleventh Circuit is that a company must conduct a fact-intensive inquiry to determine whether it is dealing with an employee or official of an instrumentality of a foreign government.

2. Accounting and Recordkeeping Provisions. Publicly traded international solar energy companies must also contend with the FCPA's accounting and recordkeeping provisions. These provisions demand corporate recordkeeping at a "level of detail and degree of assurance" sufficient to "satisfy prudent officials in the conduct of their own affairs."[14]

Specifically, under the FCPA's accounting provisions, companies (whether U.S. or non-U.S.) that are registered with the SEC and/or are listed on a U.S. stock exchange ("issuers") must establish and maintain an internal accounting controls system that provides reasonable assurance of (1) managerial oversight of all company assets and transactions, (2) compliance with generally accepted accounting principles or other criteria applicable to financial statements, and (3) periodic comparisons between the company's recorded and actual assets.[15]

Separately, the FCPA's recordkeeping provisions require issuers to make and keep books, records, and accounts that, in reasonable detail, accurately and fairly reflect transactions involving an issuer's assets.[16] In short, if an issuer bribes a foreign official to obtain or retain business, it must record this bribe in its books as a "bribe." Recording a bribe as a "discretionary payment," "performance bonus," "commission," or anything similarly deceptive constitutes an FCPA violation.

C. Jurisdictional Scope. The FCPA casts a sweeping jurisdictional net. Most U.S. criminal statutes employ the territorial principle of jurisdiction, requiring the existence of some nexus between the prohibited conduct and the territory of the United States. In contrast, the FCPA employs not only the territorial principle, but also the nationality principle, which does not require any sort of U.S. territorial connection to invoke jurisdiction. Accordingly, if a non-U.S. company bribes non-

[12] *Id.* at 925.

[13] *Id.* at 926.

[14] 15 U.S.C. § 78m(b)(7).

[15] 15 U.S.C. § 78m(b)(2)(B).

[16] 15 U.S.C. § 78m(b)(2)(A).

U.S. officials without implicating the territory of the United States in any way, the company still might face a DOJ or SEC enforcement action under the FCPA.

In general, the FCPA covers three categories of entities and individuals: (1) "issuers," (2) "domestic concerns," and (3) "any person other than an issuer or domestic concern." The anti-bribery provisions pertain to entities and individuals falling within any of these three categories, while the accounting and recordkeeping provisions apply only to issuers.

- *Issuers.* Issuers are entities required under the U.S. Securities Exchange Act to register under Section 12 or to file reports under Section 15(d). In other words, publicly held companies with securities or American Depository Receipts listed on a U.S. securities exchange (*e.g.,* New York Stock Exchange ("NYSE") or NASDAQ) are subject to the FCPA. The nationality principle subjects issuers to potential civil and criminal liability under the FCPA, regardless of whether they ever carry out a prohibited act within U.S. territory.[17]

- *Domestic Concerns.* The term "domestic concern" includes any individual who is a U.S. citizen, national, or resident. It also encompasses any business entity (public or private) with its principal place of business in the United States or that is organized under the laws of a U.S. state, territory, possession, or commonwealth. Pursuant to the nationality principle, domestic concerns that bribe foreign officials may face civil and criminal penalties under the FCPA, even if the bribery transpired completely outside of U.S. territory.[18]

- *Any Person Other Than an Issuer or Domestic Concern.* Under the more traditional territorial principle, an individual or entity faces FCPA exposure if it uses the mails or any means or instrumentalities of interstate commerce, while within U.S. territory, to carry out an act prohibited under the FCPA.[19] In other words, if such a connection to U.S. territory exists, the individual or entity need not be an issuer or a domestic concern for the FCPA to apply. This jurisdictional hook thus applies to any foreign individual or entity that causes a prohibited act to be done within U.S. territory by any person acting as the individual's or entity's agent.

Officers, directors, employees, and agents of entities that fall within one of the three categories above also face FCPA exposure. It does not matter whether the officers, directors, employees, and agents qualify as domestic concerns or issuers or utilize an instrumentality of interstate commerce in their own

[17] 15 U.S.C. §§ 78m, 78dd-1.

[18] 15 U.S.C. § 78dd-2.

[19] 15 U.S.C. § 78dd-3.

rights; mere association with the covered entity suffices for purposes of imposing FCPA civil and criminal penalties.

The FCPA's unprecedented extraterritorial reach has garnered criticism inside the United States and abroad. Regardless, the DOJ and SEC have demonstrated a willingness to bring FCPA enforcement actions against companies and individuals possessing little if any connection to the United States. For example, in December 2016, the SEC and DOJ settled enforcement actions against Teva Pharmaceuticals Industries Ltd. and its Russian subsidiary ("Teva Russia"). The bulk of the allegations focused on Teva Russia and its relationship with a company owned, controlled, and managed by a Russian government official with influence over the purchase of pharmaceutical products by the Russian government. However, Teva Russia is a foreign company and a nonissuer. Therefore, to establish jurisdiction, the government alleged, among other things, that the alleged conduct took place within the U.S. because Teva Russia sent emails through U.S.-based servers.

The DOJ's and SEC's expansive interpretation of the FCPA's jurisdictional provisions likely stems in part from the reality that many other countries are failing to enforce their own anti-bribery laws. Rather than allow U.S. companies to suffer an unfair disadvantage in the international business arena, the DOJ has suggested that extraterritorial enforcement of the FCPA is intended to "create a level playing field in the global marketplace."[20]

II. Vicarious and Successor Liability Under the FCPA. Under the FCPA, the management of a company does not have to intend, encourage, or have actual, literal knowledge of FCPA violations for the company and its management to be liable for FCPA violations. Knowledge is established under the FCPA if a person is aware of a high probability of the existence of the prohibited activity.[21] The legislative purpose of this standard is to prevent companies from adopting a "head-in-the-sand" approach to the activities of their foreign agents and partners.[22] From this "knowledge" requirement flows an ocean of potential liability.

A. Third-Party Agents. Solar energy companies operating outside the United States often rely on nonemployee agents who are locally embedded and have local knowledge to assist them. Such agents are commonly responsible for networking and making introductions to individuals, companies, and agencies in a local market; recruiting talent; providing local know-how and "show-how"; making sales; managing marketing initiatives and public relations; overseeing leasing operations and facilities management; conducting procurement and supply; handling freight forwarding and customs management; and many other actions. Additionally, a non-U.S. joint venture partner often acts as a representative or an agent in a foreign country for a U.S. joint venture partner. To succeed in completing

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[20] DOJ, Acting Principal Deputy Assistant Attorney General Trevor N. McFadden Speaks at Anti-Corruption, Export Controls & Sanctions 10th Compliance Summit (Apr. 18, 2016), https://www.justice.gov/opa/speech/acting-principal-deputy-assistant-attorney-general-trevor-n-mcfadden-speaks-anti.

[21] 15 U.S.C. § 78dd-1.

[22] *See* H.R. Rep. No. 100-576, at 920 (1988), *reprinted in* 1988 U.S.C.C.A.N. 1547, 1953.

their services to a U.S. company, agents potentially may make payments to foreign officials in violation of the FCPA.

The FCPA prohibits corrupt payments through intermediaries. Obviously, a company will violate the FCPA if it encourages or authorizes corrupt payments by its agents (including joint venture partners). Of more relevant concern to compliance-conscious solar energy companies is the fact that a company will be liable for violations of the FCPA by its agents if such company is deemed to have demonstrated conscious disregard or deliberate ignorance that such payments were being made by its agents or joint venture partners.[23]

Solar energy companies should also recognize the risks of hiring a foreign official as an agent. Paying a government official who is an agent with the intent to obtain or retain business would clearly be a violation of the FCPA. There are limited circumstances in which a government official might be retained as an agent (for example, to assist in locating and reserving conference and hotel space for a trade exhibition), but solar energy companies should consult counsel to vet carefully and to structure such arrangements. Many individuals deemed "foreign officials" might not be intuitively considered so by companies. For example, university deans and faculty may be government employees as well as employees of businesses that have government owners.

To avoid being held liable for corrupt payments made by agents, solar energy companies must take proactive measures including conducting due diligence on potential agents and joint venture partners to determine their expertise, relationship to government agencies, and reputation. An agent who has no experience in the relevant industry raises the question of how such agent can be helpful to the company absent using government connections improperly. Likewise, solar energy companies should be wary of agents who have family members in a foreign government or are overly friendly with officials at an agency (perhaps through prior employment).

Further, solar energy companies should conduct due diligence to determine whether the agent (including a potential joint venture partner) has been cited for FCPA or similar violations in the past or has otherwise shown disregard for regulatory compliance and contracts should be drafted in a manner to promote compliance. In addition to making FCPA-related representations and covenanting compliance with the FCPA, agents and joint venture partners should complete a questionnaire as to their experience with and relations to foreign governments and should be required to provide receipts for all expenses paid by the company. Agency and joint venture agreements should provide for immediate termination if the company determines that the agent is violating the FCPA or has made false representations to the company regarding FCPA compliance. Solar energy companies should consider providing FCPA training to agents (in a language in which the agent is sufficiently proficient) and should have agents certify that they have received such training.

[23] *FCPA: A Resource Guide to the U.S. Foreign Corrupt Practices Act*, *supra*, note 6, at 22 n.139. Moreover, companies should be aware that criminal liability does not require that the company know that the actions taken by its agents were a violation of the FCPA per se but only that the actions were unlawful in a general sense. *United States v. Kay*, 513 F.3d 461 (5th Cir. 2008).

Each foreign environment presents a different set of specific risks regarding the engagement of agents. Variables include the extent to which a foreign government operates through quasi-governmental entities, bookkeeping and recordation practices (such as how receipts and invoices are issued), the emergence of new schemes for kickbacks and secreting income pools for bribing, and other factors. Any company that has occasion to hire an agent to represent it outside the United States should have a compliance program in place. Prior to engaging agents, solar energy companies should consult with counsel who has current knowledge of risks and enforcement trends to confirm that their compliance program is adequate and to tailor the legal framework for the agent's work to the specific circumstances of the given countries.

B. Subsidiaries. Any company doing business beyond the borders of the United States through a subsidiary is potentially liable for any FCPA violations by the subsidiary. Two theories are typically pointed to, under which courts hold parents liable for FCPA violations by their subsidiaries. First, under the alter ego theory, a parent will be held liable for the actions of a subsidiary if the parent dominates the subsidiary by having control over ownership, shared directors, or shared officers, or by other means. Second, agency principles hold that a corporation will be liable for the crimes of its agents when committed in the scope of the agent's authority and the corporation gains some benefit. Neither of these theories places much weight on whether the subsidiary is wholly or partially owned.

In practice, given how the DOJ and SEC interpret the knowledge requirement, solar energy companies should be alert to the fact that they can be held liable for violations of the FCPA's anti-bribery provisions by their subsidiaries (both wholly owned and minority owned) simply by demonstrating conscious disregard or deliberate ignorance of the fact that bribes were made. Thus, as with agents, even if a parent did not authorize or encourage violations of the FCPA by its subsidiary, the parent may be subject to enforcement actions if it did not adequately take proactive measures to prevent its subsidiary's FCPA violations.

For example, in April 2017, Ralph Lauren Corporation ("RLC") agreed to pay approximately $1.6 million in fines and penalties and enter into nonprosecution agreements with the DOJ and SEC to resolve FCPA offenses caused by its Argentine subsidiary. The general manager of the subsidiary was accused of making corrupt payments to avoid inspections and other customs requirements. There was no allegation or suggestion that RLC had any knowledge of or otherwise participated in the bribery scheme. However, the subsidiary had no anti-corruption program, and RLC provided no anti-corruption training or education to the subsidiary.

In addition to violations of the FCPA's anti-bribery provisions, publicly traded parent companies can be held liable for their subsidiaries' violations of the accounting and controls provisions of the FCPA. As discussed above in Section I.B.2, the FCPA requires that issuers (1) make and keep books, records, and accounts that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the

assets of the issuer[24] and (2) devise and maintain a system of internal accounting controls consistent with specific requirements under the FCPA.[25] Subsidiaries (including non-U.S.) in which an issuer has a greater than 50 percent stake are fully subject to the FCPA accounting and recordkeeping provisions.[26] An issuer with a 50 percent or smaller stake is required to make a "good-faith attempt" to cause the foreign subsidiary to comply with the FCPA's accounting rules.

A continuing stream of DOJ and SEC enforcement actions emphasizes the importance of parent companies establishing a robust compliance program and plugging their subsidiaries into such a compliance program. Compliance programs should include at a minimum written policies, recurrent training (in languages other than English, if necessary), and internal auditing of controls. Additionally, parent companies should have agreements with subsidiaries they do not control (including joint venture partners and passive investment vehicles) that provide for FCPA representation and covenants by the subsidiary, termination in the event of actions or policies that create FCPA risk to the parent, annual certification, right to inspect books and records, and other FCPA compliance-enhancing provisions.

III. FCPA Successor Liability in the Mergers and Acquisitions and Joint Venture Investment Context. Solar energy companies face substantial risk of successor liability under the anti-bribery provisions of the FCPA when acquiring or investing in foreign targets. (While the considerations set forth in this section apply equally to companies contemplating investing in a foreign target or acquiring a foreign target, for ease of reading, "acquisition" in this section is meant to include both an acquisition and an investment transaction.)

DOJ and SEC enforcement actions indicate that successor liability may attach (1) if a bribe was paid to secure a benefit that the acquiring company will share and (2) if the acquiring company has knowledge of such corrupt payment. As with other aspects of FCPA enforcement, companies may be deemed to have known of the corrupt behavior if they demonstrate conscious disregard or deliberate ignorance of the fact that such payments were made. As a practical matter, the DOJ and SEC have declared that they usually only take action in successor-liability cases where the conduct involves "egregious and sustained violations or where the successor company directly participated in the violations or failed to stop the misconduct from continuing after the acquisition."[27] Thus, to reduce the risk of successor liability under the FCPA, solar energy companies must take proactive measures to identify and properly respond to pre-acquisition FCPA violations by targets. While asset acquisitions generally do not trigger FCPA successor liability, recent administrative rulings by the U.S. Department of Commerce in the context of

[24] 15 U.S.C. § 78m(b)(2)(A).

[25] 15 U.S.C. § 78m(b)(2)(B).

[26] 15 U.S.C. § 78m(b)(6).

[27] *FCPA: A Resource Guide to the U.S. Foreign Corrupt Practices Act*, *supra*, note 6, at 28.

(continued . . .)

export control violations, and favorable comments of such rulings by DOJ officials, suggest that the DOJ may seek to impose successor liability on asset acquisitions in the future.[28]

The DOJ has been somewhat inconsistent with respect to FCPA liability for the acquiring company *even if the foreign target was not subject to the FCPA prior to the acquisition*. In a 2008 opinion, the DOJ suggested pre-acquisition actions of a foreign target not previously subject to the FCPA could still lead to successor liability. In the DOJ's view, the acquiring company has an obligation to avoid compensating the foreign target for any past improper payments.[29] On the other hand, in 2012, the DOJ and SEC clearly announced that "[s]uccessor liability does not . . . create liability where none existed before."[30] The DOJ and SEC specifically declared that "if an issuer were to acquire a foreign company that was not previously subject to the FCPA's jurisdiction, the mere acquisition of that foreign company would not retroactively create FCPA liability for the acquiring issuer."[31]

IV. Private Actions. The FCPA does not contain a private right of action. In other words, under the FCPA, only the U.S. government may sue entities and individuals for bribing foreign officials. However, this fact has not stopped creative plaintiffs' attorneys from bootstrapping FCPA violations into other causes of action.

For example, in *Alba v. Alcoa*, Aluminum Bahrain B.S.C. ("Alba"), a Bahraini state-controlled company, sued its aluminum supplier, Alcoa, Inc. ("Alcoa"), for allegedly paying millions of dollars in bribes to Bahraini government officials.[32] Although Alba's complaint raised U.S. Racketeer Influenced and Corrupt Organizations Act and common-law fraud claims, these claims sounded eerily similar to standard FCPA claims. The DOJ and SEC soon intervened, prompting the federal court to stay discovery in Alba pending the U.S. government's FCPA investigation. Additionally, an ironworkers' pension fund filed a shareholders' derivative action in the same court against 22 current and former Alcoa officers and directors, essentially relying on the same FCPA-based allegations set forth in the *Alb*a complaint.[33]

FCPA-related private actions tend to be derivative actions like this one, in which shareholder claims that officers and directors breached fiduciary duties by causing or permitting the company to violate the FCPA. As the DOJ and SEC continue to increase their enforcement of the FCPA, and the global anti-bribery movement continues to raise FCPA awareness, private lawsuits like those described here will almost certainly increase. Indeed, such lawsuits may become a common tool for companies seeking justice

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[28] *In re Sigma Aldrich Bus. Holdings, Inc.*, Nos. 01-BXA-06, -07, -11 (Dep't of Commerce Bureau of Indus. & Sec. Aug. 29, 2002); *see also* 1 Foreign Corrupt Prac. Act Rep. § 5:23, Westlaw (database updated Apr. 2017).

[29] *See, e.g.,* DOJ Opinion Procedure Release No. 08-01 (Jan. 15, 2008).

[30] *FCPA: A Resource Guide to the U.S. Foreign Corrupt Practices Act*, *supra*, note 6, at 28.

[31] *Id.*

[32] *See* Complaint, *Aluminum Bahrain B.S.C. v. Alcoa, Inc.*, No. 08-cv-299 (W.D. Pa. Feb. 27, 2008).

[33] *See* Complaint, *Haw. Structural Ironworkers' Pension Trust Fund, derivatively filed on behalf of Alcoa, Inc. v. Belda*, et al., No. 08-cv-00614 (W.D. Pa. May 6, 2008).

against their competitors for winning contracts and gaining other business advantages through bribery of foreign officials.

V. Lessons Learned from Significant FCPA Enforcement Actions. On December 15, 2008, Siemens pleaded guilty in U.S. federal court to violating the FCPA. As part of its settlement with the DOJ and SEC, Siemens agreed to pay a $450 million criminal penalty and to disgorge $350 million in wrongful profits. On the same day, Siemens announced an agreement with German prosecutors to pay a €395 million ($569 million) fine for violating Germany's anti-corruption laws, adding to the €201 million ($285 million) that a Munich court sentenced Siemens to pay in October 2007.

The $1.6 billion penalty Siemens had to pay U.S. and German authorities is roughly 35 times larger than any previous anti-corruption settlement. This staggering figure does not include the €850 million ($1.2 billion) Siemens has reportedly paid to attorneys, accountants, and other service providers to deal with its global bribery scandal since late 2006. Nor does it include the significant sums Siemens was required to pay to an outside FCPA compliance monitor following the settlement with the DOJ and SEC.

A. Wake-up Call for the Global Solar Energy Industry. U.S. authorities estimate that Siemens paid $1.4 billion in bribes to foreign officials in Asia, Africa, Europe, the Middle East, and the Americas, and a significant portion of this illegal activity occurred in the energy industry. Indeed, starting in 2001, Siemens' PG and PTD divisions paid at least $356.9 million in bribes to foreign officials in multiple countries.

In recent years since the DOJ and SEC have learned of one company's violation of the FCPA, they have expanded the scope of their investigation to include other players operating in that industry. The business of solar energy companies is highly dependent on the discretion of governmental agencies (including development banks, which qualify as "foreign officials" under the FCPA). Siting, permitting, environmental review and enforcement, local community support, responding to RFPs, negotiating and performing under power purchase agreements, conducting project build-out, establishing generation interconnections and transmission tie-ins, obtaining transmission services, obtaining subsidies or tax advantages, safety compliance, and antitrust compliance, among other operations, are all aspects of an international energy company's business that often involve the discretion of a foreign official. Some of these officials expect bribes from companies (or third parties engaged by companies) in exchange for favorable treatment. The DOJ's and SEC's discovery of Siemens' corrupt activities cast a bright spotlight over the global energy industry, making it especially fertile territory for industry-wide FCPA dragnets.

Siemens paid the massive fines it did in connection with violations of the FCPA's accounting and recordkeeping provisions, demonstrating how important a compliance program is to ensuring that a company avoids FCPA violations and draconian fines. The Siemens settlement provides many additional lessons and reminders for solar energy companies, including:

- *Vicarious Liability for Third Parties.* Siemens' foreign business consultants played a significant role in bribing foreign officials to secure business advantages in the

energy industry. The FCPA can leave solar energy companies and individuals vicariously liable for the conduct of third parties such as consultants, distributors, and sales agents, even if the company lacks actual knowledge of their wrongdoing. Accordingly, the mere failure to recognize and investigate a foreign business consultant's suspicious activities may expose a company to FCPA liability. Such vicarious liability makes it especially important for solar energy companies to (1) conduct due diligence on their potential business consultants; (2) include FCPA-specific representations, warranties, covenants, audit rights, and termination rights in all business consultant contracts; and (3) train employees on how to recognize the red flags associated with business consultants' unsavory activities and report these red flags to management. Even compliance-conscious solar energy companies can become entangled in FCPA enforcement actions if they do not have robust compliance programs that are tailored to specific industries and geographic locales.

- *Tone at the Top.* The DOJ and SEC have publicly criticized Siemens' senior management for tacitly condoning bribery of foreign officials as a legitimate business strategy. Both agencies have also acknowledged an intention to pursue FCPA criminal penalties (including prison time) against Siemens executives, employees, and consultants who participated in the bribery schemes. In short, Siemens lacked the necessary "tone at the top" to foster a culture of FCPA compliance within the company. Solar energy companies can take a crucial first step toward avoiding this scenario by working with their attorneys to draft a clearly articulated policy against FCPA violations. This policy should highlight prohibited behavior, accommodate employees who blow the whistle on compliance violations, and set forth disciplinary procedures to address such violations.

- *Internal Accounting Controls.* The DOJ and SEC based their charges against Siemens almost exclusively on the FCPA's accounting and recordkeeping provisions. Siemens' subsidiaries attempted to cover up bribes by routing the money through slush funds or intercompany accounts and recording the illegal payments with misleading labels such as "commissions." To avoid illegal accounting tactics, businesses should centralize their accounting systems to ensure corporate headquarters review of all foreign financial transactions. Careful analysis of the financial records of employees and business partners abroad can enable businesses to quickly detect and eliminate conduct prohibited under the FCPA.

- *FCPA's Jurisdictional Scope.* Siemens is a German corporation with its principal place of business in Germany, and many of the bribes it paid abroad did not

implicate U.S. territory in any way. Nevertheless, Siemens is subject to the FCPA because it has listed its securities on the NYSE since 2001 and, therefore, qualifies as an "issuer" under the FCPA. Moreover, in many instances, Siemens routed bribes through U.S.-based banks, providing the U.S. government an additional jurisdictional basis for pursuing Siemens under the FCPA. These facts serve as a reminder of the FCPA's sweeping jurisdictional reach. All U.S. solar energy companies with international operations—and many of such non-U.S. companies—have FCPA liability exposure.

- *Cross-Border Enforcement.* The cooperation exhibited in the Siemens case between the DOJ and SEC, on the one hand, and the German enforcement agencies, on the other, is a noteworthy development in cross-border FCPA enforcement. Solar energy companies should recognize that the DOJ, the SEC, and their foreign counterparts share FCPA-related information about the non-U.S. operations of companies subject to the FCPA.

- *Cooperation with Government Investigations.* The DOJ and SEC have indicated that Siemens' total FCPA penalty could have been considerably larger than $800 million. Indeed, application of the Federal Sentencing Guidelines would have resulted in an FCPA criminal fine of between $1.35 billion and $2.7 billion. Due to Siemens' "exceptional" cooperation with the U.S. government's investigation and demonstrated commitment to remediating its operations, however, the DOJ and SEC exhibited leniency. Siemens' strategy of cooperating with authorities, rather than attempting to stonewall them—particularly in light of the DOJ's newly extended pilot program (*see* Section I.A above)—provides a model for future targets of FCPA enforcement actions.

VI. Action Items Summary. Compliance-savvy solar energy companies operating in the global marketplace must take proactive measures to mitigate the risk of vicarious and successor liability under the FCPA, including (among other measures):

- adopting and effectively disseminating comprehensible written FCPA compliance policies;

- mandating recurrent education programs for management, employees, and agents (of both the parent and its subsidiaries, and perhaps in languages other than English when appropriate);

- conducting due diligence on potential acquisition and investment targets, joint venture partners, and third-party agents;

- entering into agreements with third parties that contain adequate FCPA representations, covenants, and compliance-monitoring mechanisms;

- establishing ongoing compliance-monitoring practices of the activities of subsidiaries, joint venture partners, employees, and third-party agents; and

- taking appropriate remedial measures in the event that an FCPA violation is discovered in either pre-acquisition or pre-investment diligence or in the ongoing operations of the company; such remedial measures may require self-reporting to the DOJ.

FCPA compliance programs must be tailored to the geographic locations in which a company operates, the line(s) of business in which a company engages, the nature of a company's interaction with government officials, and the reliance that a company or its subsidiaries or agents has on discretionary actions of foreign officials, among other factors. In addition to being knowledgeable about the core proscriptions of the FCPA itself, a company and its counsel must be well-versed in and have current knowledge of the DOJ's and SEC's enforcement patterns, as can be discerned from such sources as DOJ's and SEC's 2012 jointly released FCPA Resource Guide, DOJ Guidance and Opinion Procedure Releases, and SEC No-Action Letters. FCPA enforcement patterns evolve over time. Compliance programs must be revised in light of these evolving enforcement patterns.

Chapter Thirteen
THE LAW OF SOLAR
—Securities Regulation—
Ronald D. McFall

Solar businesses seeking to raise capital in the United States for investment in their business activities must concern themselves with federal and state securities laws. In addition, solar businesses that intend to develop and operate community solar gardens may, by virtue of the contractual relationships involved in those projects, become subject to the securities laws. However, as discussed below, many solar industry arrangements feature parties or transaction structures that permit industry participants to avoid registration under applicable federal and state securities laws by relying upon one or more exemptions from such registration. In very general terms, solar projects that involve a limited number of sophisticated commercial and industrial participants will often be exempt from securities registration because the parties investing or subscribing qualify as "accredited investors" (as defined below). Conversely, depending on the number and nature of prospective subscribers, community solar gardens that seek subscriptions from large numbers of residential consumers may not be able to claim the exemptions available for sales of securities solely to accredited investors.

Given the wide range of solar industry transaction structures and participants (and the importance of the facts and circumstances of each arrangement), a solar industry developer or other participant should seek advance legal advice regarding the possible application of federal and state securities laws. In most circumstances, that legal advice will focus on the availability of exemptions from securities registration for the proposed transaction, but may also focus on whether or not the proposed transaction actually involves the offer and sale of securities.

The following sections of this chapter are intended to provide a general overview of federal securities regulation, with an emphasis on disclosure obligations, securities registration requirements, those exemptions from registration likely to be of most interest to solar industry participants and, finally, the resale of securities by affiliates of the issuer and other investors.

Introduction. The United States and each state have laws regulating the purchase, sale, and trading of securities. While the laws are generally similar in most respects, there are some important differences, so it is necessary to check both the federal law and the law of each state in which the fundraising or trading activity will occur.[1]

Federal securities laws are subject to regulation and enforcement by the Securities and Exchange Commission (the "SEC"). The SEC also empowers and oversees the activities of various self-regulatory organizations, such as the Financial Industry Regulatory Authority, and the various exchanges and other

[1] Except where we specifically mention that we are describing other law, this chapter generally describes the applicable provisions of the federal securities laws and regulations. In very general terms, the equivalent state laws are likely to be similar, but there may be differences or separate filing and fee requirements that must be observed.

systems on which securities are traded, such as the New York Stock Exchange and NASDAQ. These organizations enact their own regulations within the areas of their authority, but their regulations are subject to review and approval by the SEC. State securities laws are subject to regulation and enforcement by state securities authorities.

Neither federal nor state securities laws are explicitly restricted as to the geographical scope of their application. In practice, federal securities laws are applied principally to regulate transactions in the United States and its territories or transactions to which U.S. citizens or residents are a party. Even when no U.S. citizen or resident is a party, U.S. securities laws may be applied when substantial activity in connection with the transaction occurs in the United States, or in circumstances in which the nature of the transaction tends to undermine confidence in U.S. securities markets.

State securities laws apply to protect the citizens and residents of a state who are contacted within the state in connection with a transaction. Thus, for example, state laws regulating the sale of securities by the businesses that issued them ("issuers") apply to sales made to purchasers resident in the applicable state.

I. What Is a Security? Both federal and state laws define a security very broadly to include a wide variety of instruments, including stock and other forms of equity and certain debt instruments. In addition to the specific list of instruments that constitute securities, an "investment contract" is a security. An investment contract has been defined by courts to be a contract or instrument involving the investment of money or other value in a common enterprise with the expectation of profit resulting from the efforts of others.[2]

As an initial matter, it is important to determine whether a contemplated transaction involves a security, because the securities laws apply only if it does. The answer depends on a number of fact-specific issues, but here are a few general guidelines:

Almost any instrument evidencing ownership of a business, including stock, limited partnership interests, limited liability company interests, or other instruments having equivalent function, is a security. However, joint venture agreements, general partnership interests, and similar instruments representing ownership of a business that the owners will collaborate in running may not be securities.

- Securitized debt instruments, including bonds, debentures, and other instruments evidencing debt held similarly by a group of investors, are securities. Conventional, commercial loan arrangements, whether with traditional lenders or pursuant to private arrangement, are not securities, including syndicated loans with a group of traditional lenders.[3] The line between

[2] There is some slight variation in the definition, but all variations are generally to the effect described above.

[3] Some lenders in connection with conventional loan arrangements require warrants or other derivative interests in addition to the normal interest provisions of the loan documents. In such cases, the loan documents themselves may not be securities but the warrants are securities.

commercial and securitized debt has generated considerable judicial analysis and requires careful review in the case of novel or unusual interests.

- Derivative instruments, such as options, warrants, and other instruments evidencing the right to exchange the interest for a security or to purchase a security, are deemed to constitute the security into which they are convertible or for which they are exercisable, and may also be securities in their own right. Thus, for example, the sale of a warrant exercisable to buy stock is the sale of a security, as is the sale of the stock on exercise of the warrant. The existence of the warrant may also be a continuing offer to sell the stock.

Finally, an agreement or instrument may constitute or contain a security regardless of its form. Agreements or instruments of any kind may be securities if, as a matter of fact, they meet the definitional test of an investment contract described above. As a result, agreements such as those found in community solar garden subscriptions must be analyzed to see if they represent (i) an investment of money, (ii) in a common enterprise, (iii) with an expectation of profit, and (iv) from the efforts of others. However, because this analysis is very much based on the facts and circumstances of a particular arrangement, securities lawyers will typically advise clients to structure the transaction at hand in such a way that it can claim the benefits of an exemption from registration. Many exemptions contain "safe harbor" provisions that provide a greater degree of certainty than the uncertain weighing of factors involved in determining whether or not an agreement or instrument constitutes a security. Only if an exemption is not available or is not desirable from a business standpoint will the analysis turn to considering whether the bundle of rights and obligations made available to the investor or subscriber comprises an "investment contract" and therefore a security subject to the application of the securities laws.

II. What Do the Securities Laws Regulate? The securities laws regulate transactions in securities but do not regulate all such transactions. In general, securities laws regulate (1) purchases or sales of securities, (2) offers to purchase or sell securities, and (3) the activity of markets that trade in securities and those who use them. Securities laws generally do not regulate bona fide gifts of securities, nor do they attempt to control the nature of the instrument that constitutes a security or the rights of holders of such securities under such instruments. Such rights are generally controlled under state corporate laws or are determined by private agreement.

Purchases and Sales of Securities. Numerous laws and regulations govern the activity of persons who purchase or sell securities. The general purpose of these laws is to ensure that a transaction is fair to both sides by requiring a buyer or seller with knowledge of material facts relevant to the value of the securities to make that information known to the counterparty in the transaction.[4] As described in more

[4] Federal securities laws are limited to regulating the process whereby information is disclosed in connection with securities transactions. State laws, as interpreted by state regulatory bodies, are not limited in this way, and most state laws have defined transactions that they deem to be "unfair" and that are prohibited without regard to the extent and accuracy of disclosure. In practice, the difference is largely theoretical because the SEC will usually attempt to use its regulatory authority to make it difficult to engage in transactions that the SEC

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detail below, both federal and state securities laws regulate both the sale of securities by issuers (generally upon original issuance to raise capital) and the resale of those securities by others, in a secondary transaction.

Offers to Sell or Purchase Securities. Not only are purchases and sales of securities regulated, but offers to purchase or sell securities are independently regulated. Thus, for example, it is possible to violate a securities law by offering to sell a security even though no sale ever occurs. In practice, offers are rarely the subject of either public or private enforcement proceedings. In the case of public proceedings, the absence of harm resulting from the offer generally limits enforcement efforts to obtaining cease and desist orders against persons regularly making unlawful offers. The same lack of harm effectively precludes private enforcement action.

The fact that offers are rarely the subject of independent enforcement proceedings does not mean, however, that offers can be made with impunity. As discussed in more detail below, some rules relating to whether and how a security may be sold apply differently depending on whether, how, and to whom offers have been made. Accordingly, ill-considered offers to purchase or sell securities can cause a related sale of securities to be unlawful, even if it would have been permitted had the offers not been made.

Regulation of Trading and Trading Markets. If securities are held by a relatively large number of people, or if they are traded on an exchange or other trading facility, numerous regulations apply to the issuers of the securities, the markets on which the securities are traded, and those persons trading on such markets. Most of the rules applicable to the latter two categories are of only minor significance to energy businesses, but the first category can impose substantial regulatory cost and impose other restrictions and burdens on companies whose securities are traded in the United States. In general, these rules do not apply to companies whose securities are illiquid and closely held, or to companies whose trading markets are in countries other than the United States.

III. Purchases and Sales of Securities: Regulatory Overview.

A. Disclosure Obligations. U.S. securities laws provide a general disclosure standard by making it unlawful for a person, in connection with the purchase or sale of a security,

a. to employ any device, scheme, or artifice to defraud,

b. to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or

believes to be substantially unfair, while state regulators will ordinarily grant exceptions to unfairness prohibitions in exchange for restrictions on sales to persons most likely to be victimized by any unfairness.

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c. to engage in any act, practice, or course of business which operates or would operate as a fraud or deceit upon any person, in connection with the purchase or sale of any security.[5]

This requirement sets a standard for honesty and fair dealing in connection with securities transactions that is considerably more stringent than the standard applicable in other commercial contexts, in which actual fraud is unlawful, but in general the parties to an agreement are charged with protecting their own interests.[6]

Under this provision, a purchaser or seller of a security has a legal claim upon a showing that the counterparty made a false statement of a material fact (a material fact being a fact that a reasonable person would consider to be important in connection with the related investment decision). These claims are generally known as "section 10b-5 claims," referring to the regulation under which they exist. Section 10b-5 does not prohibit material omissions unless the information omitted was necessary to make a statement that was made not misleading. Accordingly, there is no *general* duty of complete disclosure in connection with securities transactions. As described below, however, there are numerous rules under which specific disclosure is required. Such rules can impact both the original issuance of a security and a subsequent resale of that security.

In addition to the general 10b-5 obligation described above, certain disclosure obligations may impact businesses seeking to obtain capital in a registered offering of its securities. Registration of securities with the SEC requires that detailed information be provided about the company issuing the securities, its business activities, the terms of the securities being offered, the terms of the offering and information regarding the risks of the investment. Certain exemptions from registration also specify, as a condition of claiming the exemption, the information to be provided to prospective investors.[7]

In addition to the disclosure requirements associated with the original issuance of securities, case law has, since the 1970s, held that, if a party to a securities sale is in possession of material, nonpublic information with respect to the business whose securities are the subject of the transaction, that party must disclose the information to the other party (or determine that the other party also has that information) in such a way that the other party can take that information into account in making its decision with respect to the transaction. Nonpublic information is information that has not been made available to the general public by press release, regulatory filing, or other method. The requirement is obviously most applicable to businesses buying or selling their own securities or to members of

[5] Section 10(b) of the Securities Exchange Act of 1934, as amended, and Rule 10b-5 promulgated thereunder.

[6] The application of different standards for securities transactions and normal commercial transactions has raised numerous issues concerning which standard is applicable to statements that are made in a commercial context but are seen and possibly relied on by parties in a securities transaction. As a very general proposition, a statement made in a regular commercial context that does not have the purpose or probable effect of conditioning the related securities market is not held to the securities standard. The matter is complex, however, and companies engaged in offering securities should discuss with counsel the appropriate policy with regard to general commercial disclosures.

[7] Please note that sales of securities solely to accredited investors do not require any specified body of information or form of disclosure; instead, the disclosure standard imposed by 10b-5 will drive the issuer's obligations to prospective investors.

management of the business engaged in such transactions. However, the scope of the requirement is not limited to those persons, and anyone engaged in a securities transaction can be liable for breach of the requirement if he or she goes through with the transaction without making the required disclosure. A breach of this requirement is actionable by the counterparty to the transaction, who may sue to recover the lost value of the investment, if any.

A person may have section 10b-5 liability if that person (known as a "tippor") improperly provided information to a third party who then improperly traded based on that information. Thus, an officer, director, or employee of a business may have section 10b-5 liability, even if he or she did not actually trade based on the information or profit from any such trade, if he or she improperly provided material nonpublic information to someone who did trade. If the officer, director, or employee provided the information in his or her capacity as an agent of the business, the business itself may be liable, which is why it is important for businesses whose securities are traded on any regular basis to take appropriate steps to prevent such disclosures.

There are a number of limitations to the scope of section 10b-5 liability. For example, a tippor can be liable only if the provision of the information was in some way in violation of a duty of the tippor *not* to provide the information. Inadvertent or fortuitous disclosures or disclosures for a proper business purpose cannot be the basis for tippor liability. Similarly, a person who declined to participate in a securities transaction cannot sue under section 10b-5 based on a claim that material information in the possession of the potential counterparty would have resulted in a decision to go through with the transaction. In general, however, trading while in possession of material nonpublic information can be the basis for a claim by the counterparty if the investment decision turns out to have been a poor one.

It is critical to keep in mind that, unlike the rules relating to registration and exemption discussed below, section 10b-5 applies to all sales of securities and all persons engaged in such sales. It applies to both sellers and buyers, and both to securities that are required to be registered as a condition of sale and to those that are exempt from such requirements. In particular, businesses involved in raising money through securities sales may tend to focus on the registration and exemption requirements and the disclosure requirements necessary to complete registration or to claim an exemption. In so doing, they might forget that the section 10b-5 rules apply as well. Such a failure can have serious consequences, even if all of the registration, exemption and required disclosure rules are carefully observed.

B. Registration and Exemption Rules. Federal and state securities laws impose duties on persons who propose to offer or sell securities. Unlike the section 10b-5 rules described above, these rules apply only to sellers of securities and do not impose any duty on buyers.

The core concept of these rules is that a security that is to be sold must be registered unless either the security or the contemplated transaction is exempt. Registration consists of filing a registration statement with the SEC or relevant state authority that meets the requirements for such documents. In theory, absent objection from the relevant authority within a prescribed period of time, the securities can be sold as long as a disclosure document, usually known as a prospectus, is delivered to the buyer

in time to permit the buyer to use the information contained therein to make an informed investment decision. In practice, the SEC has made clear that, except in situations generally involving large, established companies, it expects to review and comment on the registration statement, after which there will follow a dialogue with the SEC staff, resulting in one or more amendments being filed and reviewed. Once the SEC staff is satisfied with the registration statement, it "declares" the registration statement effective and sales can take place. While the issuer and the SEC are in discussions regarding the content of the final registration statement, offers, but not sales, can be made by means of a preliminary form of prospectus.

Billions of dollars' worth of securities trade every day in the United States, and it should be obvious that the cumbersome process of registration does not apply to the overwhelming majority of such sales. Most of these sales occur under a registration exemption that exempts sales by persons who are not the issuer of the security, who are not affiliated with the issuer, and who are not underwriters of the securities or dealers in securities. Separate exemptions cover most sales by dealers in securities and by underwriters after a period of time has elapsed from the underwriting, thus allowing regular market transactions to proceed in the ordinary course without precondition.

Other exemptions apply to certain kinds of securities, regardless of the type of transaction involved. Of particular interest to energy companies, sales of securities that are issued or guaranteed by a government entity in the United States, such as municipal bonds and other forms of governmental instruments that are often issued to support a particular project, are exempt from registration without regard to the kind of transaction in which they are sold. As noted above, however, the exemption is from the registration requirements only. The requirements of section 10b-5 will apply to the sale, and other securities laws may either apply to the sale itself or be triggered by the fact that the sale took place.

Given the breadth of these exemptions, the registration rules are an issue mostly for four groups: (1) businesses seeking to raise capital by issuing their own securities (issuers); (2) directors, senior managers, general partners, and persons with equivalent management responsibility, and substantial equity holders in connection with reselling securities of the business that they own or manage (affiliates); (3) owners of "restricted securities" in connection with the resale of those securities; and (4) underwriters of securities. Sales by issuers, resales of restricted securities and resales of securities by affiliates are discussed below.

IV. Sales by Issuers.

A. Public Offerings. Issuers raising capital by selling their securities are generally faced with a choice of registering the securities to be offered and sold or complying with the requirements of an exemption. Any securities can be sold without meaningful restriction if the issuer files a registration statement and delivers a prospectus to each investor. Securities sold pursuant to registration are unrestricted, except those purchased by affiliates or underwriters, so they are freely tradable in the hands of the general public.

One of the results of a registered securities offering is that the issuer will become a "public company." As such, it will be subject to the reporting requirements of the Securities Exchange Act of 1934 (the "Exchange Act") and will have to file with the SEC annual and quarterly reports, and other reports upon the occurrence of specific events.[8] This obligation will continue for at least a year and thereafter as long as there are more than a specified number of record holders of the securities (in most cases, 300). If the publicly owned securities are equity, numerous other provisions of the Exchange Act are also likely to apply, including provisions relating to the holding of stockholders meetings; trading of the securities by executive officers, directors, and holders of more than 10 percent of the securities; reports required to be filed by holders of more than 5 percent of the securities; and the conduct of tender offers for the securities. Finally, although it is not required by law, the likely result of a registered securities offering is that the securities will be listed on an exchange or other trading mechanism, causing the issuer to be subject to the rules of that facility.

For a company that is not already public, a decision to do a registered securities offering represents a choice of strategic direction in addition to the selection of a capital raising method. An initial public offering generally takes from six months to a year to consummate. The expense is quite large, and a considerable amount of the expense is not avoidable if the offering does not work. The volatility of capital markets creates risk that an offering that seems sensible at the time of the decision to proceed may appear less attractive at the time it is consummated. Following the offering, there is significant additional recurring expense. There is also a need to publicly report information that would normally be considered proprietary in a private company. Finally, the need to establish and maintain constructive investor relationships is time-consuming and can lead to management decisions that may not optimize the potential of the business.

The advantages of being a public company include access to public capital markets, which, after an initial period of time, can be accessed quite quickly and efficiently; increased flexibility in structuring acquisitions; and increased liquidity for stockholders. In general, a decision to go public is one involving economies of scale. In a larger business, the advantages of public status, combined with the ability to amortize the cost over a larger capital base, can make the alternative attractive. Smaller businesses are generally well-advised to remain private if they are able to do so.

B. Private Placements and Other Exemptions.

Private Placement Exemptions. Issuers that are and intend to remain private generally rely on one or more of several exemptions. Most frequently claimed are exemptions the general requirement for which is that the securities are not sold, either directly or indirectly, to the general public.[9] These exemptions, available only to issuers and generically known as "private offering exemptions," allow

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[8] Even without a registered offering, an issuer of securities can become subject to the requirements of the Exchange Act if it has total assets in excess of $10 million and a class of nonexempt equity security held of record by more than either (a) 2,000 persons <u>or</u> (b) 500 persons who are not accredited investors. Such a result could occur if a business engages in a series of exempt offerings over time.

[9] The use of private placement exemptions is not limited to private businesses. Public companies regularly engage in private placements as part of their capitalization program.

issuers to offer and sell securities without registration as long as (1) they are offered and sold only to a limited group of investors, and (2) the issuer takes steps to prevent immediate resale of the securities by restricting their resale. The securities so issued and so restricted are referred to as "restricted securities," subject to the rules on resale discussed in Section V below.

Offer Restrictions. The availability of the exemption for the offer and the sale depends on whether the issuer engages in "general solicitation or general advertising" in connection with the offering. The SEC rules define general solicitation or advertising to include any advertisement, article, notice, or other communication published in any newspaper, magazine, or similar media or broadcast over television or radio, and any seminar or meeting whose attendees have been invited by any general solicitation or advertising. Until the adoption of amendments to the private placement exemptions in 2012, any offer made by a general solicitation or advertising, such as newspaper advertisements, mass emails, or other forms of general distribution in which the individual recipients were not known and identified as potential investors who were qualified to receive the offer, would violate the conditions for reliance on the exemption.[10]

Under the "Jump Start Our Business Startups" Act adopted by Congress in 2012 (the "JOBS Act"), regulations have been adopted that permit general solicitation and advertising for certain private placements if (1) the issuer takes reasonable steps to verify that the purchasers of the securities are accredited investors, and (2) all purchasers of the securities are accredited investors.[11] In general, financial institutions, institutional investors of significant size, and relatively wealthy individuals are accredited investors.[12]

Issuers that engage in general solicitation and advertising of an offering face significant consequences if they rely on the new exemption but fail to meet the "reasonable steps" accredited investor verification standard. This is because the use of general solicitation or advertising not only would invalidate the exemption for those investors who were publicly solicited but also for the offering as a whole, thus leaving the issuer without an available exemption for the offering.

Investor Identity Restrictions. Federal securities regulations permit private placements to be made to an unlimited number of accredited investors. If the total amount to be raised in the offering exceeds $5 million, each investor must also be financially sophisticated enough (or have retained an advisor with such sophistication) to understand the merits and risks of the investment.

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[10] Using open-access websites constitutes public solicitation if they contain an offer of securities, but websites that are restricted to a group of potential investors whose suitability has been determined in advance are permitted.

[11] The private placement exemption for offers and sales that do not involve public solicitation remains in effect; businesses can choose to pursue a placement involving public solicitation if the securities are offered and sold only to accredited investors. If sales are to be completed to nonaccredited investors, the placement must be conducted without public solicitation to qualify for the applicable exemption.

[12] An individual is an accredited investor if (1) his or her net worth exceeds $1 million (generally excluding both the person's primary residence and debt associated with that residence), (2) his or her income exceeded $200,000 in each of the last two years, or (3) his or her joint income with spouse exceeded $300,000 in each of the last two years. A business or other entity that is not formed for the specific purpose of investing in the placement is an accredited investor if it has total assets in excess of $5 million.

The regulations also permit private placements to be made to up to 35 nonaccredited investors, provided that the issuer has not used any general solicitation or advertising. This provision has some limited utility in specific instances but is rarely used. The most important reason is that the informational requirements are substantially greater if the offering is made to any nonaccredited investor. Additional reasons include the fact that the effort required to solicit nonaccredited investors is disproportionate to the amount that they can prudently invest and the likelihood that selling securities to nonaccredited investors increases the risk of legal action if things do not go well for the investment.

Most private placements are made to a small group of institutional investors and/or very wealthy individuals. In the case of newer and smaller businesses, the former are known as "venture capital investors" and the latter are known as "angels."[13] In either case, the investment is likely to be in the form of preferred, convertible stock. More mature companies are funded by a group of institutions generally referred to as "mezzanine" or "institutional" investors. These investments are more likely to involve debt securities, possibly with an equity piece as an inducement. Fully mature companies and projects have access to a wide variety of private funding alternatives, and it is not uncommon for a project to be funded at various levels by different institutional investors.

Intrastate Offering Exemptions. In addition to the widely used private placement exemptions discussed above, another type of securities exemption may be of use in the solar industry. In particular, community solar garden projects focused on participation and subscription by consumers (rather than commercial or industrial parties) may have difficulty claiming the benefits of the private placement exemptions discussed above. The requirements of those exemptions regarding public solicitation and sales to nonaccredited investors would not be met if the solar developer wished to contact large numbers of potential subscribers, many of whom would not qualify as accredited investors. Although not regularly used, there is another type of exemption that may be of use in some limited circumstances. That is the "intrastate" exemption.

Under the Securities Act, an exemption from registration is available for securities that are offered and sold <u>only</u> to residents of the state in which the corporation offering the securities is both incorporated and doing business. A rule adopted by the SEC (Rule 147) provides additional clarity by specifying, among other factors, the portion of a company's business and assets that must be within the state in which the intrastate offering is to be conducted. This exemption has historically been of limited use, with many securities professionals concerned about the difficulty of being sure that offers and sales are made only to residents of a single state. In addition, most states have not historically had a parallel securities exemption, meaning that companies relying on the intrastate exemption for an exemption from federal securities registration might not be able to claim an exemption from registration <u>under state securities laws</u>, but would need to register with the applicable state. (Some renewable energy businesses, particularly those involved in biofuel production, have pursued such an approach by

[13] It is also not uncommon for relatively small amounts of seed capital to be raised from friends and family at the very initial stages of a business. These investments also generally qualify under a private placement exemption, if properly conducted.

claiming the federal intrastate exemption while registering in the state where the business is incorporated and operates.)

In connection with the securities law amendments described above, a new intrastate exemption was created by the adoption of Rule 147A. Intended as part of a series of changes to facilitate the formation of capital for start-up businesses, Rule 147A generally contains the same requirements as Rule 147 except that the issuer need not be incorporated in the state in which the issuer operates its business.

While the intrastate exemption has historically been of limited utility, it is an area in which the law is evolving. In particular, some changes in state securities laws in the past few years have focused on community-based capitalization efforts such as crowd-funding. Those changes may make a viable combination of an intrastate exemption at the federal level and a state exemption, depending on the particular facts involved and the particular state in which the offering is to be conducted. In any event, a solar enterprise should carefully consider the intrastate exemptions if the private placement exemptions are not available and the transaction in question involves the offer and sale of securities.

C. Brief Introduction to Integration. As noted above, offers and sales of securities may be exempt from registration if the nature and manner of the offering meet certain requirements. To determine whether the requirements have been met, it is necessary to define the "offering" that is required to meet the applicable requirement. Offers of securities deemed to constitute a single offering for this purpose are said to be "integrated."

There may be no area of securities law that is as metaphysical as integration analysis. Obviously, a single entity offering stock to a number of investors at a given time is engaged in a single offering. However, a question arises if an issuer is simultaneously offering stock to investors as a capital raising project and to employees on exercise of options that are a part of the issuer's compensation program. Similarly, if a company is doing a public equity offering at the same time that it is restructuring its securitized debt arrangements with institutional lenders, an integration question is raised. In a somewhat different way, if a number of related entities are simultaneously raising capital for a common project, an integration analysis is required.

The SEC has adopted regulations that specifically cause offerings made in certain conditions not to be integrated. For example, offerings separated by a specified lapse of time in which the issuer does not make similar offers or sales are nonintegrated by regulation. Where no such specific regulation applies, however, an analysis of the underlying issues is unavoidable and the outcome is often uncertain.

V. Sales by Holders of Restricted Securities and Affiliates. Affiliates of an issuer are defined as people or entities that control, are controlled by, or are under common control with, the issuer. In general, affiliates include senior management and large stockholders of the issuer as well as a corporate parent, subsidiary, or other related entities. As noted above, normal sales of publicly traded securities by persons other than the issuer of a security and holders of restricted securities are exempt from

registration without any meaningful precondition. Sales by affiliates of the issuer are also subject to restriction and can be resold only upon satisfaction of certain conditions.[14]

Resales of Restricted Securities. Certificates representing restricted securities normally contain a legend indicating that the securities may not be resold except pursuant to registration or an applicable exemption. In a sense, the legend states the obvious, since all sales of securities are subject to that restriction. The legend reinforces this requirement and also usually indicates that the issuer will not recognize or assist with any sale that does not meet this requirement to its satisfaction.

Restricted securities can be resold pursuant to registration as soon as the registration statement is effective. If no effective registration statement exists for restricted securities, an exemption will be required. By far the most commonly used exemption for resales of restricted securities exists under Rule 144, which generally permits such resales (1) after a period of time in which the reseller has held the securities, if certain conditions are met, or (2) without condition after a longer period, as long as the reseller is not an affiliate. The conditions, if applicable, relate to the manner in which the securities are sold, the number of securities sold in relation to either the number of publicly traded securities or the trading volume, the need to file a report with respect to the sale with the SEC, and the need for publicly available information about the issuer. For most sellers, meeting the conditions is not onerous except that doing so takes time and also takes the sale out of the trading routine under which unrestricted securities are normally sold.

Once the restricted securities can be resold without condition, it is customary for the holder of the certificates to apply to the issuer to have new certificates issued without the legend, which no longer applies and the existence of which can delay and complicate a trade, even when an ordinary trade is permissible.

Resales by Affiliates. Affiliates reselling restricted securities are subject to all of the restrictions applicable to those securities in the same way that the restrictions apply to nonaffiliates. In addition, affiliates must continue to meet all of the conditions applicable to resales under Rule 144, without time limit.[15] Affiliates selling unrestricted securities (for example, securities that they purchased in the open market or in a public offering) may do so at any time, subject to the applicable conditions.

Institutional Trading in Restricted Securities. The limitations on resales of restricted securities do not apply to transactions entirely among qualified institutional buyers ("QIBs"). QIBs are generally very large financial institutions, such as banks and insurance companies, that the SEC has determined not to be in need of the protection afforded to less sophisticated investors under the securities laws.

[14] These restrictions apply only to sales to which U.S. securities laws are generally applicable. Sales that take place entirely outside the United States may not be subject to limitation under U.S. securities laws.

[15] This restriction also applies to persons who, at the time of the resale, had recently been affiliates.

QIBs may freely trade restricted securities among themselves, and there are markets set up that facilitate such trading. The markets are, of course, restricted to QIBs.

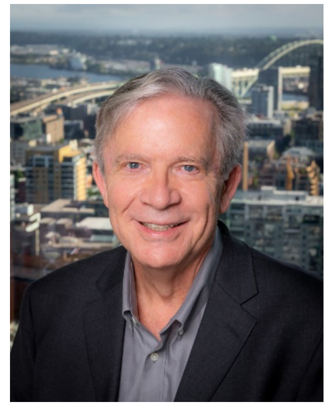
Private Resales of Restricted Securities. As written, the private placement exemptions apply to sales of securities by their issuers, and there exists no express rule under which an investor can resell restricted securities by limiting the offer and sale of the securities in the same manner that the issuer would limit such offers and sales if it were making the offer under a private placement exemption. Nevertheless, it is generally accepted that the resale of a restricted security is exempt if it is made under circumstances in which the sale would have been exempt as a private placement if made by the issuer. The analysis supporting this theory is excessively convoluted, but the principle is well established.

Insider Trading Considerations. As noted above, compliance with registration or exemption requirements does not relieve any participant in a securities sale from the obligation to make adequate and timely disclosure of material nonpublic information. This consideration is a particular issue for resales by affiliates, which may regularly be in possession of material inside information and, even if they are not, may be assumed to be in possession of such information. To avoid either the reality or the appearance of a problem in this area, affiliates are well-advised to consider carefully the timing of any sales of securities. In general, it is best to make such sales in the period closely following the release by the issuer of a periodic report on its condition. A number of issuers address this issue by creating policies (either mandatory or advisory) that discourage or prohibit trading except during periods in which such trading is least likely to pose a problem. The fact that any particular trade occurs in compliance with these policies does not ensure that there is no insider trading problem, and any and all such trades should be evaluated with the issue in mind.

The burdens that these considerations impose on affiliates can be alleviated, at least for the purpose of permitting affiliates to engage in a regular program under which they dispose of securities, by adopting a plan under which the securities are automatically sold at certain times and under certain conditions. An affiliate that adopts such a plan is deemed to have material nonpublic information only if it had the information at the time the plan was adopted. The affiliate's knowledge on the date of any particular sale is not relevant. Of course the plan must provide (subject to some general ability to make amendments to the plan from time to time) for the automatic execution of the sales.

GARY R. BARNUM

PARTNER



Gary Barnum is a partner of the firm. He has a broad corporate practice, with an emphasis in finance. Gary also has extensive experience in structuring joint ventures, tax-motivated transactions, partnerships, and mergers and acquisitions. Gary has represented a wide range of companies, including energy companies, financial service companies, manufacturers, retailers and other industry groups.

Transactions which Gary has handled include syndicated credit facilities, private placements (including 144A offerings), public offerings, leveraged lease and project financings, utility financings, asset-backed financings and securitizations, commercial paper programs, and derivative arrangements. Gary also has structured numerous joint ventures, partnerships (and limited liability companies), syndications, mergers and acquisitions., In addition to his significant experience with non-recourse and other project financing arrangements, he has also been involved with a wide variety of tax-motivated transactions, including federal and state energy credit transactions, low-income housing credits and state tax credit programs, and industrial development and pollution control projects.

To learn more, please visit: https://www.stoel.com/people/gary-r-barnum

P: 503.294.9114
gary.barnum@stoel.com

Education

University of Washington Law School, J.D., 1981, honors

University of Oregon, B.A., 1977, high honors

Admissions

Oregon

Washington

SARA E. BERGAN

ASSOCIATE

Sara Bergan is an energy law attorney who works primarily with renewable energy and cleantech clients on project development, project finance and energy and environmental regulatory matters.

In advising her clients, Sara is able to tap into her background and experience working on energy policy issues. Prior to joining Stoel Rives, Sara served for several years as the executive director of the Great Plains Institute, a Midwest nonprofit that brokers consensus energy and climate policy decisions among diverse stakeholders.

To learn more, please visit: https://www.stoel.com/people/sara-e-bergan

P: 612.373.8819
sara.bergan@stoel.com

Education

University of Minnesota School of Law, J.D., 2010, *magna cum laude*

Princeton University, M.P.P., 2006; Robertson Family Scholarship Recipient; Certificate in Science, Technology and Environmental Policy

Gustavus Adolphus College, B.A., Environmental Studies, 1997, *cum laude*

Admissions

Minnesota

Oregon

TAMARA L. BOECK

PARTNER

From “concept through completion” or “dirt to done,” clients have come to rely on Tami for her pragmatic business approach and 23 years of experience representing a wide variety of clients in all areas of project development. Whether it is advising clients regarding development insurance risks and coverage disputes, pre-project and project contracting risk management (RM) advice relating to project development, or dispute resolution in ADR or litigation, she approaches each matter with a focus on the client’s goal and best interests, utilizing a broad range of practical knowledge for her client’s benefit in mitigating disputes or representing clients in litigation where necessary. Tami’s early background representing insurers in coverage claims has also served her policy-holder clients well regarding project protection and coverage disputes.

She routinely advises owners, developers and general contractors primarily in California, Idaho and Nevada. Tami works with clients on a wide range of projects including commercial, residential and mixed-use projects, as well as construction-related aspects of oil and gas, mining, food processing, solar, wind, geothermal, biofuel, wastewater treatment and other industrial facilities. In addition to counseling her clients on ways to avoid protracted litigation through thoughtful negotiations and effective contracts, she handles construction disputes from mediation through litigation or arbitration, which often encompass significant business conflicts, project delay, workmanship and performance deficiency claims, as well as those matters involving lien laws, insurance coverage disagreements with insurers, claims involving toxic tort, product liability and catastrophic injuries. With her depth of experience, she is able to assist and protect her clients in arbitration or trial when a pragmatic business resolution is not available.

Tami presently serves as chair of the firm’s Real Estate and Construction Development group, and is a member of Stoel Rives’ Pro Bono Committee and Coaching and Mentoring Committee. Before joining Stoel Rives, Tami was a Shareholder for eight years at another West Coast regional law firm. She was also one of the founders of that firm’s California offices, its subsequent Nevada offices, and served as Shareholder-in-Charge of that firm’s former primary California office.

To learn more, please visit: https://www.stoel.com/people/tamara-l-

P: 208.387.4256
tami.boeck@stoel.com

Education

University of the Pacific, McGeorge School of Law, J.D., 1993, with distinction

California State University, Fresno, B.S., 1990, *cum laude*

Admissions

California

Idaho

Nevada

U.S. District Court, all districts of California

U.S. District Court for the District of Nevada

U.S. District Court for the District of Idaho

U.S. Court of Appeals for the Ninth Circuit

Eugene A. Frassetto

Partner

Gene Frassetto is a partner of the firm practicing in business law with an emphasis on complex real estate transactions. Gene has extensive experience in urban retail; industrial and commercial development transactions; rural farm, ranch, vineyard, wind-farm and renewable-energy transactions; and the real estate aspects of corporate transactions.

Gene has extensive experience in the acquisition, leasing, development and sale of electric generation facilities (both renewable and conventional), including wind farms, solar projects, gas- and coal-fired power plants; and biofuels facilities across the country. Gene represents many of the premier vineyard and winery operators in the Northwest in vineyard and winery operations, acquisitions, and leasing transactions; grape sales; alternating proprietorships; and other related transactions. He assists clients in complex real estate due diligence analysis and title insurance matters, including corporate merger and acquisition transactions.

Prior to joining Stoel Rives, Gene was a law clerk for Chief Justice Edwin J. Peterson of the Oregon Supreme Court (1984-1986) and a law clerk at Heltzel, Byers, Upjohn & Shaw in Salem, Oregon (1982-1984).

To learn more, please visit: https://www.stoel.com/people/eugene-a-frassetto

P: 503.294.9668
gene.frassetto@stoel.com

Education

Willamette University College of Law, J.D., 1984, *magna cum laude*; *Willamette Law Review*, staff, 1982-1983; Associate Editor, 1983-1984; American Jurisprudence Awards, Constitutional Law, Evidence, Criminal Law and Criminal Procedure; Willamette University Awards in Corporate Taxation; I.H. Van Winkle Award for Excellence in Constitutional Law, 1982

Oregon State University, B.S., Microbiology, 1976

University of California, Berkeley, 1968-1971

Admissions

Oregon

SETH D. HILTON
PARTNER

Seth Hilton is a partner in the Energy Development practice group. He focuses his practice on energy regulation and litigation, representing clients before a variety of energy regulatory agencies in California, including the California Public Utilities Commission and California Energy Commission, as well as in stakeholder proceedings at the California Independent System Operator. His clients include developers of thermal and renewable generation, energy storage developers, transmission developers, energy service providers, and investor-owned and publicly-owned utilities.

Seth also represents energy clients in state and federal court, and has significant experience in a wide variety of complex commercial litigation. That experience includes jury and bench trials as well as appellate matters, including successfully arguing before the Ninth Circuit Court of Appeals and the California Court of Appeal. Seth also has extensive experience in handling arbitration and mediation.

Following law school, Seth served as law clerk to the Honorable David V. Kenyon, United States District Court for the Central District of California. In 2003, Seth was appointed to serve on the California State Bar's Standing Committee on Federal Courts. Prior to joining the firm, Seth was an associate with Morrison & Foerster in the firm's Walnut Creek office.

To learn more, please visit: https://www.stoel.com/people/seth-d-hilton

P: 415.617.8943
seth.hilton@stoel.com

Education

University of California, Davis, School of Law, J.D., 1995; Order of the Coif; Senior Articles Editor, *U.C. Davis Law Review*; Articles Editor, *U.C. Davis Journal of International Law*

Harvard College, B.A., 1992, *cum laude*

Admissions

California

U.S. Court of Appeals for the Ninth Circuit

U.S. District Courts for the Northern, Central, Southern and Eastern Districts of California

GREGORY F. JENNER
PARTNER

Greg Jenner advises and represents clients on a wide range of tax transactions and issues. He heads the firm's Washington, D.C., office, is a partner in the tax practice group and is a past co-chair of the firm's energy team. Greg first came to Stoel Rives out of law school, returning to the firm in 2008 after three tours of duty in the government and significant private practice experience.

Government Experience

Greg has 10 years of combined experience at Treasury and on Capitol Hill. This experience provides him with unique and invaluable insights into legislative, tax policy, and budget processes, which in turn translates into value for the firm's clients.

He was privileged to serve as both Acting Assistant Secretary of the U.S. Treasury for Tax Policy (2004) and Deputy Assistant Secretary for Tax Policy (2002-2004). As Acting Assistant Secretary, Greg directed the Treasury's Office of Tax Policy, which is responsible for providing the Administration with policy analysis, advice and recommendations relating to all aspects of domestic and international issues of federal taxation. He advised President Bush and Secretaries Snow and O'Neill on tax policy issues, including launching the Administration's review of fundamental tax reform. Greg also served at Treasury from 1989 to 1992, as the Special Assistant to the then Assistant Secretary for Tax Policy.

Before joining Treasury in 1989, Greg began his tenure in Washington as Tax Counsel for the U.S. Senate Committee on Finance (1985-1989), where he helped write the Tax Reform Act of 1986, among other pieces of tax legislation. Greg's experiences throughout the tax reform process will prove invaluable to clients in 2018 and beyond.

Practice Focus

Greg has had broad experience in virtually all federal tax matters, with particular focus on planning and implementing complex tax-related transactions, partnerships and joint ventures. At Stoel Rives, Greg has increasingly focused on planning for renewable energy projects.

As the prospect for fundamental tax reform in 2017 increases, Greg will be focusing more of his efforts on the various proposals and their effects on various industries and sectors.

To learn more, please visit: https://www.stoel.com/people/gregory-f-jenner

P: 202.398.1794
greg.jenner@stoel.com

Education

New York University School of Law, J.D., 1979, *cum laude*; Law Review Note and Comment Editor; Order of the Coif

Portland State University, B.S., 1975, with highest honors

Admissions

District of Columbia

Minnesota

U.S. Tax Court

U.S. District Court for the District of Minnesota

U.S. Court of Federal Claims

Languages

Basic French

JASON A. JOHNS

PARTNER

P: 503.294.9618
jason.johns@stoel.com

Jason Johns advises independent power producers, utilities, investors, and large users of gas and power resources with matters arising in power markets and state and federal energy regulatory arenas. Jason appears regularly in proceedings before the Federal Energy Regulatory Commission and in negotiations at the ISO/RTO level, where he represents independent power developers and utilities. His experience includes the negotiation of major facility contracts, such as interconnection, transmission, and power purchase agreements, the prosecution of disputes at FERC, and counseling and defending clients on issues related to regulatory compliance.

Jason also works closely with large commercial and industrial users of electricity and gas, such as aerospace companies, pulp and paper mills, steel mills, and tech company data centers. In that role, Jason helps clients negotiate power and gas supply contracts, interstate pipeline capacity asset management agreements, and pipeline bypass agreements. Jason has also assisted these clients with demand management agreements, the installation of on-site resources (such as battery storage, fuel cells, and solar PV), and with retail and wholesale power purchase agreements for renewable energy and other resources. Jason also serves as a board member of The Climate Trust, a national leader in carbon offset projects and innovative climate change solutions.

Jason and his wife are parents to two growing boys, and they live just outside of Portland, Oregon.

To learn more, please visit: https://www.stoel.com/people/jason-johns

Education

University of Montana School of Law, J.D., with honors; Technical Editor, *Montana Law Review*

University of California, B.S., Chemistry

Admissions

Oregon

U.S. Court of Appeals for the Ninth Circuit

U.S. Patent and Trademark Office

Sarah Johnson Phillips
Partner

Sarah Johnson Phillips is a partner in the firm's Energy Development practice group, where she focuses on energy project development, buying, selling and financing energy projects, and energy regulatory matters. She advises large wind and solar project developers on permitting and real estate matters, including obtaining major project permits, negotiating leases and easements, and title work. She also has particular experience working on distributed solar and community-shared solar projects, including negotiating offtake agreements, leases, financing arrangements, M&A transactions, interconnection agreements, and regulatory matters. In addition, Sarah works with large energy consumers on a range of regulatory issues and proceedings affecting ratepayers and regularly appears before the Minnesota Public Utilities Commission.

Prior to law school, Sarah worked for five years in the renewable energy nonprofit sector in Minnesota, concentrating on energy policy, community wind energy and climate change issues.

To learn more, please visit: https://www.stoel.com/people/sarah-johnson-phillips

P: 612.373.8843
sarah.phillips@stoel.com

Education

University of Minnesota Law School, J.D., 2009, *cum laude*; Symposium Editor, Minnesota Journal of International Law; Dean's List, 2007-2008

Humphrey Institute of Public Affairs, University of Minnesota, M.S. in Science, Technology, and Environmental Policy, 2009

Carleton College, B.A., Geology, *cum laude*

Admissions

Minnesota

MORTEN A. LUND

PARTNER

Morten Lund is a partner of the firm practicing in the Energy Development group, and serves as chair of the Solar Energy Initiative. His experience includes development and financing of a broad variety of energy and infrastructure projects. Morten's project experience background covers the full life cycle of infrastructure projects, from early-stage development through construction, financing, and acquisition/divestiture. He has worked on a variety of infrastructure projects, including hydro-electric facilities, chemical facilities, wind and solar energy projects, forestry/paper facilities, combustion generator projects, large aircraft, cogeneration facilities, shipping fleets, and nuclear energy facilities. Morten also represents companies developing infrastructure technology, including water treatment technology, solar energy technology, and wind energy technology.

Morten was born in Oslo, Norway, and is a native speaker of Norwegian.

To learn more, please visit: https://www.stoel.com/people/morten-a-lund

morten.lund@stoel.com

Education

Yale University, J.D., 1995

Augustana College, A.B., 1992

Admissions

California

Wisconsin

Languages

Norwegian

JENNIFER H. MARTIN

PARTNER

Jennifer Martin is the co-chair of the firm's energy team and is a partner practicing in the Energy group. She represents energy clients in the negotiation of development-related agreements and advises on regulatory compliance related to deal structuring and implementation. In particular, clients have come to rely on Jennifer for her extensive experience with matters involving many aspects of developing, selling, or acquiring renewable assets, including negotiation and diligence of power purchase and sale agreements, interconnection and transmission arrangements and fuel supply agreements. Jennifer's experience also extends to corporate renewable transactions, including advising on structuring such transactions under various regulatory regimes and negotiating different types of retail supply arrangements to implement corporate sustainability goals. In this regard, Jennifer has advised clients on virtual power purchase agreements, direct access supply agreements, green energy tariff transactions and purchases from and investments in renewable energy projects. Her clients include owners, investors, developers, and corporate buyers.

Before joining Stoel Rives, Jennifer was a judicial clerk, Minnesota Supreme Court (1999-2000); summer associate at Stoel Rives (1998); research assistant, Professor David Baldus, University of Iowa College of Law (1997-1999); and clerk, Circuit Court of Cook County (1993).

To learn more, please visit: https://www.stoel.com/people/jennifer-h-martin

P: 503.294.9852
jennifer.martin@stoel.com

Education

University of Iowa College of Law, J.D., 1999; Senior Note and Comment Editor, *Journal of Gender, Race & Justice*, 1998-1999

University of Notre Dame, B.A., English and Gender Studies, 1995

St. Patrick's College, University of Notre Dame foreign study program, 1992-1993

Admissions

Oregon

Utah

U.S. Court of Appeals for the Ninth and D.C. Circuits

U.S. Supreme Court

Stoel Rives LLP

RONALD D. MCFALL
PARTNER

Ron McFall is a partner of the firm who is a business and transactional lawyer and leading expert in cooperative law. Originally trained as a securities and transactional lawyer, Ron has represented agricultural and consumer cooperatives and other producer-owned entities over the course of his entire 34-year career as an attorney. In that role, Ron regularly provides cooperative, securities and transactional advice to a variety of producer-owned and member-owned organizations in the food processing, agricultural, organic, consumer and renewable energy sectors. In recent years Ron has represented numerous cooperatives and other producer-owned businesses in a wide range of complex restructuring, merger and acquisition and joint venture transactions. Such transactions typically require an effort to balance the interests of cooperative members in their roles as both agricultural producers and owners of the cooperative; as a result, the transactions present complex issues related to cooperative governance, securities compliance and cooperative tax status. Ron also has extensive experience in securities offerings, particularly those offerings seeking equity investment for food processing, commodity processing and renewable energy facilities owned by cooperatives and other producer-owned organizations. Ron has represented cooperative, corporate and other clients both in registered offerings and offerings exempt from registration under federal and state securities laws.

To learn more, please visit: https://www.stoel.com/people/ronald-d-mcfall

P: 612.373.8807
ron.mcfall@stoel.com

Education

University of Chicago Law School, J.D., 1983

University of Iowa, B.A., 1979

Admissions

Minnesota

TIMOTHY L. MCMAHAN

PARTNER

Tim McMahan is a partner practicing in the areas of energy, land use, real estate development, environmental and municipal law. His principal office is in Portland, Oregon. Tim has extensive experience in representing energy facility developers, property owners and municipal clients in Washington and Oregon. Tim focuses his practice on leading interdisciplinary teams advocating for and defending energy facilities and other major infrastructure projects facing opposition. Tim chairs Stoel Rives' Climate Change Practice Initiative.

Prior to joining Stoel Rives in 1999, Tim served as the Port Townsend, Washington, City Attorney for over five years, during which he guided Port Townsend through downtown historic district preservation strategies and Growth Management Act implementation, successfully defended the city's Comprehensive Plan and Shoreline Master Program in agency and judicial litigation, and developed innovative strategies to protect Port Townsend's municipal water supply from spiraling demands.

To learn more, please visit: https://www.stoel.com/people/timothy-l-mcmahan

P: 503.294.9517
tim.mcmahan@stoel.com

Education

University of Washington, M.A., Urban Planning, 1991; Tau Sigma Delta architecture and allied arts honor society

Willamette University College of Law, J.D., 1986; Case Note Editor, *Willamette Law Review*

University of Puget Sound, B.A., European History, 1983

Admissions

Oregon

Washington

U.S. Court of Appeals for the Ninth Circuit

Jennifer L. Mersing

Of Counsel

Jennifer Mersing is an attorney in the Energy & Regulatory group. Jennifer's practice focuses on electric regulatory issues including Federal Energy Regulatory Commission (FERC) and certain state law matters. She advises electric utilities, transmission providers, large industrial consumers of power and energy marketers regarding issues under the US Federal Power Act (FPA), the Public Utility Regulatory Policies Act of 1978 (PURPA), and the Public Utility Holding Company Act (PUHCA).

Prior to joining Stoel Rives, Jennifer was an associate at White & Case in Washington, D.C. Before attending law school, she was a junior research fellow in the Trade, Equity and Development section at the Carnegie Endowment for International Peace.

To learn more, please visit: https://www.stoel.com/people/jennifer-mersing

P: 206.386.7664
jennifer.mersing@stoel.com

Education

Columbia University School of Law, J.D., 2008; Harlan Fiske Stone Scholar; Human Rights Internship Program Award; Journal of Transnational Law

College of William and Mary, B.S., 2004, *summa cum laude*; Phi Beta Kappa; James Monroe Honors Scholar; Office of Volunteer Services Summer Scholarship

Admissions

Washington

District of Columbia

New York

U.S. Court of Appeals for the District of Columbia Circuit

U.S. Court of Appeals for the

ALEXANDRA L. MERTENS

PARTNER

Alex Mertens is a partner in the Corporate practice group. Alex is experienced in energy finance matters and advises energy developers on issues concerning the acquisition, development, financing, and sale of energy projects, with a particular focus on negotiating equity, tax equity and debt financing agreements.

Before joining Stoel Rives, Alex was a senior associate at Fredrikson & Byron, P.A. in Minneapolis (2006-2011), where she represented emerging and established clients on a variety of business transactions, including mergers and acquisitions, capital raising, governance and commercial contract negotiation.

To learn more, please visit: https://www.stoel.com/people/alexandra-l-mertens

P: 206.386.7629
alex.mertens@stoel.com

Education

University of Michigan Law School, J.D., 2006

Haverford College, B.A., Economics, 2001

Admissions

Washington

Minnesota

District of Columbia

ANDREW P. MORATZKA

PARTNER

Andrew P. Moratzka is the chair of the firm's Energy Development practice group and focuses on litigation of various utility- and energy-related issues. Drew represents iron mines, paper companies, refineries, steel manufacturers and other large industrial customers in electric and gas rate cases and various regulatory matters at the state and federal level. He also represents independent power producers. In these roles, Drew regularly appears before state public utilities commissions and administrative law judges. Drew also has experience arguing energy-related and bankruptcy-related issues at the appellate level. Given his background, clients also retain Drew for utility contract negotiations and to consult on various legislative matters.

To learn more, please visit: https://www.stoel.com/people/andrew-p-moratzka

P: 612.373.8822
andrew.moratzka@stoel.com

Education

Northwestern School of Law of Lewis & Clark College, J.D., 2002; Cornelius Honor Society; Editor in Chief, *Journal of Small and Emerging Business Law* (n/k/a *Lewis & Clark Law Review*)

St. Olaf College, B.A., Mathematics and Economics, 1999

Admissions

Minnesota

U.S. District Court for the District of Minnesota

U.S. Courts of Appeals for the Seventh and Eighth Circuits

U.S. Supreme Court

Stoel Rives LLP

Brian J. Nese
Partner

Brian Nese co-leads the firm's energy team and is a partner in the Energy Development group and the Renewable and Thermal Energy Initiatives. Brian focuses his practice on representing renewable energy project developers, owners and operators in drafting and negotiating various project documents, including engineering, procurement and construction agreements, operation and maintenance agreements, balance of plant agreements, supply agreements, and real property agreements. Brian also assists project developers with mergers and acquisitions, financings and related due diligence.

Prior to joining Stoel Rives LLP, Brian was an associate at Stroock & Stroock & Lavan LLP, in Los Angeles, California, where he represented clients in a variety of matters, including dispute resolution, litigation, regulatory and enforcement proceedings.

To learn more, please visit: https://www.stoel.com/people/brian-j-nese

P: 858.794.4102
brian.nese@stoel.com

Education

University of Southern California Law Center, J.D., 2004; Order of the Coif; Staff, *Southern California Law Review*, 2003-2004

Georgetown University, B.A, 2001, *cum laude*

Admissions

California

U.S. Court of Appeals for the Ninth Circuit

U.S. District Courts for the Central and Southern Districts of California

Languages

Spanish

JOSEPH E. NUSSBAUM

PARTNER

P: 206.386.7596
joseph.nussbaum@stoel.com

Joseph Nussbaum is an associate in the Corporate group and a member of the firm's Energy Initiative. His practice centers on advising project sponsors and investors on the financing, acquisition and development of renewable energy projects and solar industry transactions. Joseph has experience negotiating energy and infrastructure leveraged financings and conducting project due diligence, with a focus on developer-side project finance, tax equity financings, secured and unsecured commercial lending, mezzanine and holdco loans, intercompany loan transactions, syndicated credit facilities and private placements. He has represented clients in the renewable energy, upstream and midstream oil and gas, power and shipping industries. Joseph frequently assists clients with drafting and negotiating term sheets and commercial contracts, including purchase agreements, engineering, procurement and construction agreements and other project agreements, and advises clients on compliance with credit facility obligations.

Prior to joining Stoel Rives, Joseph was an associate at Vinson & Elkins LLP in New York practicing in the finance group. During law school, Joseph interned at the U.S. Environmental Protection Agency Office of Regional Council in New York and the U.S. Court of International Trade.

To learn more, please visit: https://www.stoel.com/people/joseph-e-nussbaum

Education

Fordham University School of Law, J.D., 2010, *magna cum laude*; Member, *Environmental Law Review*

Yale University, B.A., History, 2005

Admissions

Washington

New York

KEVIN T. PEARSON

PARTNER

Kevin Pearson is a partner and a member of the firm's Executive Committee. His practice focuses principally on federal income tax law, including both transactional matters and tax controversy matters. As part of his transactional practice, Kevin regularly advises clients regarding all aspects of corporate taxation, including taxable and tax-free mergers and acquisitions, debt and equity offerings and other corporate finance transactions, consolidated return issues, and general corporate tax issues. He also regularly represents clients with respect to partnership, S corporation and limited liability company transactions and tax issues, as well as choice-of-entity issues, tax accounting issues, and general tax planning issues. Kevin frequently represents clients in renewable energy financing transactions, particularly those involving the federal production tax credit. In addition, Kevin advises both taxable and tax-exempt health care clients with respect to all types of tax, business and financial matters. As part of his tax controversy practice, Kevin regularly represents taxpayers in IRS audits and administrative appeals, deficiency litigation in the U.S. Tax Court, and refund litigation in U.S. District Courts and the U.S. Court of Federal Claims.

To learn more, please visit: https://www.stoel.com/people/kevin-t-pearson

P: 503.294.9622
kevin.pearson@stoel.com

Education

Georgetown University Law Center, LL.M., Taxation, 1998

Gonzaga University School of Law, J.D., 1996, *summa cum laude*; Articles Editor, *Gonzaga Law Review*, 1995-1996; National Moot Court

Linfield College, B.S., 1992

Admissions

Oregon

Washington

U.S. Court of Federal Claims

U.S. Tax Court

DAVID T. QUINBY

PARTNER

David Quinby recently served as chair of the firm's Energy Development practice group. He currently works out of the firm's Minneapolis and San Diego offices. David concentrates his practice on corporate, securities, project development and finance, and merger and acquisition matters, with a particular focus on energy and clean technology clients. He has worked with early stage developers and startups of major wind, solar and biomass companies; and traditional power companies and investors in such companies. He advises clients with respect to purchase and sale agreements, wind leases, feedstock and fuel supply agreements, offtake and power purchase agreements, EPC agreements, O&M agreements, private placement memorandums, venture capital investments, joint venture agreements, development agreements and related documentation.

David also has extensive experience representing public and private companies as both in-house and outside counsel, and has led numerous negotiations on complex transactions. Previously, David served as assistant general counsel at NRG Energy, Inc., a NYSE company, and as general counsel for NRG's $1.5 billion North American operating unit. Before joining NRG, David served as vice president, general counsel, and secretary of ValueVision International, Inc., a NASDAQ-listed direct marketing company. David is also a CPA with four years of public accounting experience.

To learn more, please visit: https://www.stoel.com/people/david-t-quinby

P: 612.373.8825
david.quinby@stoel.com

Education

University of Minnesota Law School, J.D., 1990, *magna cum laude*; Order of the Coif; *Minnesota Law Review*

Luther College, B.A., 1983, *magna cum laude*; Phi Beta Kappa

Admissions

Minnesota

California

Bart W. Reed
Partner

Bart W. Reed is Of Counsel in the Seattle office and practices with the firm's Real Estate and Construction group. With extensive experience in complex commercial and construction law, multistate litigation and ADR (representing clients in 28 states), Bart focuses his practice on construction and design issues and disputes, representing owners, developers, contractors, subcontractors, design professionals and sureties, in diverse matters on both public and private projects. His experience covers a wide range of issues affecting design and construction clients, including contract drafting/negotiation, nonpayment and surety claims, construction liens and payment bond claims, design disputes, construction defects, and scheduling issues in the defense and prosecution of delay/impact claims.

To learn more, please visit: https://www.stoel.com/people/bart-w-reed

P: 206.386.7568
bart.reed@stoel.com

Education

Mercer University Walter F. George School of Law, J.D., 2000

University of Georgia, B.A., 1996, with honors; Presidential Scholar

Oxford University, Jesus College, 1994, with honors

Admissions

Washington

Georgia

U.S. District Court for the Northern District of Georgia

U.S. District Court for the Western District of Washington

ADAM D. SCHURLE

PARTNER

Adam Schurle counsels on a variety of federal, state and local tax issues, including entity formation, corporate mergers and acquisitions, transactions involving partnerships, S corporations, limited liability companies and other pass-through entities, tax aspects of compensation arrangements, and tax controversy matters. Adam also advises companies and individuals on estate and gift taxes, employment taxes and international taxation.

A significant portion of Adam's practice is focused on tax advice for cooperatives, both exempt and nonexempt. He understands the unique economic and governance structure of cooperatives and the interplay of state and federal laws that affect them. Combining his understanding of cooperative business with his deep understanding of the tax treatment of cooperatives and their patrons, Adam assists these clients to achieve the best tax results possible in all areas of daily operations and mergers and acquisitions.

Adam works with energy developers, owners and investors on wind, solar, geothermal, municipal solid waste and biomass and other renewable energy projects. He helps these clients qualify for federal, state and local tax incentives and implement transaction structures that maximize the value of those incentives.

In his free time, Adam enjoys spending time with his wife and son, running, reading and caring for the family pets.

To learn more, please visit: https://www.stoel.com/people/adam-d-schurle

P: 612.373.8814
adam.schurle@stoel.com

Education

University of Florida Levin College of Law, LL.M. Taxation, 2013

University of Oregon School of Law, J.D., 2010; Order of the Coif; Managing Editor, *Oregon Law Review*

Tufts University, B.A., History and Environmental Studies, 2005, *cum laude*

Admissions

Minnesota

Nevada

U.S. District Court, District of Nevada

U.S. Tax Court

Kennon Scott

Associate

Kennon Scott is an associate in the Litigation group and assists clients in various stages of complex commercial litigation and arbitration. She has experience representing clients in commercial contract and insurance coverage disputes, shareholder class and derivative actions, and adversary proceedings in bankruptcy court. Kennon also has experience representing clients in government investigations of alleged FCPA violations, and reviewing and assessing client compliance programs and internal control functions.

Prior to joining Stoel Rives, Kennon worked as an associate at Willkie Farr & Gallagher LLP in New York.

To learn more, please visit: https://www.stoel.com/people/kennon-scott

P: 503.294.9328
kennon.scott@stoel.com

Education

New York University School of Law, J.D., 2009; Staff Editor, *Annual Survey of American Law*

Brown University, B.A., Development Studies, 2003

Admissions

Oregon

New York

ALLISON C. SMITH
PARTNER

P: 916.319.4759
allison.smith@stoel.com

Allison Smith focuses her practice in environmental and energy law. Her experience includes CEQA and land use litigation, conducting environmental due diligence, and permitting solar, wind, biomass, geothermal and gas-fired energy facilities. Allison also counsels companies on federal and state air quality and greenhouse gas regulations.

Prior to practicing law, Allison was a volunteer in the Peace Corps in Côte d'Ivoire and taught English in Tokushima, Japan, with the Japan Exchange and Teaching Program.

To learn more, please visit: https://www.stoel.com/people/allison-c-smith

Education

Tulane University Law School, J.D., 2005; Certificate in Environmental Law; Member, *Environmental Law Journal*; Order of the Barristers; Willem C. Vis International Commercial Arbitration Moot Court Competition, Quarter Finalist; Chair, Tulane Law School Summit on Environmental Law; Vice President, Environmental Law Society

University of Virginia, B.A., Environmental Science and Anthropology, 1996

Admissions

California

U.S. District Court for the Eastern District of California

THE LAW OF SOLAR

The Law of Solar will be updated periodically, but to stay informed of developments in the solar energy industry before the next edition, please sign up for our alerts at www.stoel.com/subscribe.

You can also visit our Renewable + Law blog at www.lawofrenewableenergy.com.

Stoel Rives is a leading business law firm with focused experience in the areas of energy and environmental law and more than 350 attorneys in seven states and Washington, D.C.

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