LEX HELIUS: THE LAW OF SOLAR ENERGY
—Regulatory and Transmission-Related Issues—

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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 developments 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 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 generally what procedures might apply on 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: PUHCAs, EWGs, and QFs. The Energy Policy Act of 2005 was signed into law on August 8, 2005, repealing in part the Public Utility Holding Company Act of 1935 ("PUHCA 1935") and enacting the Public Utility Holding Company Act of 2005 ("PUHCA 2005"). By opening the door to certain utility acquisitions and mergers that had been prohibited since 1935, PUHCA 2005 is likely to trigger a consolidation of the electric utility industry, which will present both challenges and opportunities for solar developers.

Under PUHCA 1935, nonexempt renewable energy project companies were subjected to extensive regulation by the Securities and Exchange Commission (the "SEC"). Although the SEC will no longer be regulating nonexempt renewable energy project companies (such as solar developers), PUHCA 2005 has (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 PUHCA 1935 for independent power producers that qualify as EWGs. EWG status is determined by FERC, and the EWG status begins once the independent power producer files an application 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 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 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 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 wholesale 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 approval, *i.e.,* power-marketing rights, before an EWG can sell bulk wholesale power at market prices. FERC generally grants market-based rate approval, 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 markets, and have satisfied restrictions on affiliate abuses contained in FERC regulations. FERC has recently adopted new criteria for demonstrating satisfaction of these requirements, which should be reviewed with knowledgeable attorneys before filing for market-based rate approval. Once FERC grants market-based rate approval, the EWG will have ongoing filing requirements.

B. Qualifying Facility Status. The Energy Policy Act of 2005 changed the rules for QFs, introducing both risk and opportunity. Developers of new solar projects will want to familiarize themselves with these changes.

During the energy crisis in the late 1970s, Congress passed the Public Utility Regulatory Policies Act of 1978 ("PURPA") to encourage the development of cogeneration and small 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 and from certain types of state utility regulations. The Energy Policy Act of 2005 (and FERC's interpretation thereof) has limited the applicability of these exemptions, making it more difficult for projects to obtain such exemptions. On the other hand, the Energy Policy Act of 2005's elimination of PURPA's ownership requirements is likely to generate new interest in utility ownership of QF facilities—increasing the value of both new and existing QF projects.

The Energy Policy Act of 2005 has also narrowed the advantages that renewable power generation QFs previously enjoyed compared to EWGs. First, as mentioned above, 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 authority from FERC to sell power at market-based rates before selling energy from the project as discussed above. Specifically, (1) sales of energy and capacity made (2) by QFs 20 MW and smaller, (3) pursuant to a contract executed on or before the effective date of FERC's applicable rules, or (4) pursuant to a state regulatory authority's implementation of PURPA remain exempt from Sections 205 and 206 of the Federal Power Act. 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 purchase. A utility may now petition FERC for an exemption from PURPA's mandatory purchase requirement if it can demonstrate that a QF in its service territory would have nondiscriminatory access to competitive wholesale markets for energy and capacity that meet certain standards. The potential loss of this "must buy" requirement could 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 are often interconnected under state regulators' interconnection rules, which may or may not be advantageous for a particular project. However, if the QF's owner sells any of the QF's output to any entity other than the interconnecting utility, the QF's interconnection will be subject to federal jurisdiction.

C. Other Ongoing Regulatory Requirements. Whether a solar developer is an EWG or a QF, or has FERC approval to sell power at market-based rates, the solar developer may also be subject to other filing and

reporting obligations at FERC. For example, FERC's prior approval may be required before the developer disposes of FERC-jurisdictional facilities, subject to certain value thresholds. This prior approval requirement generally applies to indirect disposition of such assets, which can include the sale of project membership interests to investors, and accordingly, consultation with a knowledgeable FERC attorney is advised in connection with any plans by the developer to restructure, sell, or otherwise dispose of its assets. Likewise, FERC may require updates to the market-based rate filing, EWG application, 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, and therefore consultation with knowledgeable attorneys is recommended.

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." (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 generation owner will want to ensure that it is not regulated as a public utility if it sells power to third parties. 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 compared to the location of the generation. In California, for example, generally an entity that sells electricity to third parties is a public utility regulated by the California Public Utilities Commission. 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 obtain project financing and 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 above must negotiate agreements to interconnect with the transmission system of the applicable transmission provider. In addition, a developer will need to obtain any necessary transmission service to deliver project output to the purchasers of that output. 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 jurisdiction by FERC, and therefore transmission service agreements and generation interconnection agreements are generally subject to regulation by FERC. Interconnection to utilities exempt from FERC interconnection rules raises unique questions, 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 provider that owns the transmission system with which the project will be connected. FERC's Order No. 2003 establishes standard interconnection procedures, including a standard interconnection agreement for generators larger than 20 MW ("Large Generators"). Similarly, FERC Order No. 2006 establishes standard interconnection procedures, including a standard interconnection agreement for generators with a capacity of 20 MW or less ("Small Generators"). More recently,

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

however, certain regional transmission organizations, such as the Midwest Independent System Operator, the California Independent System Operator, and the Southwest Power Pool, have reformed their interconnection procedures and agreements in response to crippling backlogs and delays in the existing queues. 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. Queue reform is happening across the nation, and each reform to FERC's traditional approach to interconnection responds to the problems faced in a particular region. Thus, it is important to engage knowledgeable counsel in order to remain aware of how the interconnection process may vary from one area to the next.

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 any renewable energy project, if it is located in a remote place without 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 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 pay the upfront cost of any required upgrades, but the transmission provider will reimburse the interconnection customer by providing transmission credits. However, in certain transmission systems, such as those controlled by the Midwest Independent System Operator or the PJM Interconnection, the interconnection customer will not be entitled to all or part of this reimbursement, and cost allocation and refund methodologies are often in flux. Interconnection customers may not receive full reimbursement for network upgrades elsewhere in the country as well, and the nature of the network upgrade reimbursement (*i.e.,* partial or full) may also impact whether and to what extent tax gross-ups must be included in the payment by the interconnection customer.

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 transmission credit to offset 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, network upgrades are unusual. Agreements to reclassify interconnection facility costs as network upgrades, or vice versa, have not been found to be "just and reasonable" and have been rejected by FERC, although some transmission owners or operators continue to seek changes allocating additional costs to generators.

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 pay close attention to the technical requirements and control area charges proposed in the interconnection agreement and ask a knowledgeable attorney to review them for conformity with FERC policy. In connection with its adoption of standard procedures and agreements in its Order No. 2003, FERC began a separate rulemaking to establish certain technical standards applicable to interconnection of large wind generating plants that would be included in Appendix G of the Large Generator Interconnection Agreement. This rulemaking resulted in FERC Order No. 661, which is not applicable to solar projects or other intermittent resources other than wind. Nonetheless, FERC left the door open to take a similar approach for non-wind technologies. The rules address supervisory control and data acquisition capability requirements, as well as operational restrictions and requirements related to reactive power factors and low-voltage ride-through. Solar developers may wish to consider whether these provisions would help with transmission issues, as additional operational and technical experience are gained. Finally, 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. Distributed solar generation interconnecting at low voltage may be governed by state utility commission rules. 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, and if the interconnection is for purposes of making wholesale sales, FERC's generation 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, then the developer may face additional issues and negotiations that are beyond the scope of this summary, but should be considered and discussed with a knowledgeable attorney.

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 toward 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 effectively 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 receives a credit for 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 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 a billing period.

There are usually several restrictions that 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 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, standby 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, and equipment charges for specialized metering or safety equipment.

Because net-metering laws and rules vary from state to state, a solar developer should consult a knowledgeable attorney about the applicable rules.

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. 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. In addition, acquiring adequate transmission service is essential to obtaining debt or project financing on reasonable terms and conditions.

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 a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") rather than the actual owner of the applicable transmission facilities. Acquiring transmission service from nonjurisdictional 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 megawatts of service. 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, the customer may want to consider making a sale to a third party, rather than becoming a transmission customer of the transmission provider with which the developer interconnects.

These transmission pricing rules may be different if the transmission provider is an RTO. The rules of the existing and proposed RTOs may in fact be much more favorable to solar power generation than is FERC pricing. For example, an RTO may recover the fixed costs of the applicable transmission system from end users, with a generator facing only transmission congestion charges. The RTO also may eliminate rate "pancaking," which is the imposition of multiple transmission charges for use of more than one transmission owner'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. Of these products, generation imbalance service often poses the most difficult issues for renewable energy power operators with intermittent 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 an hour. Although solar energy is expected to be more predictable than wind energy, certain types of solar technology have more intermittency, 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-scale imbalances; however, these penalty-type imbalance charges punished intermittent resource generators for variations in output over which the generators lack control.

Acknowledging that existing energy imbalance charges under Schedule 4 of the open-access transmission tariff ("OATT") and the generator imbalance charges described in FERC Order No. 2003 are the subject of "significant concern and confusion in the industry," FERC found that imbalance charges varied widely, were excessive, and penalized transmission customers whose actual generator or energy imbalances deviated from corresponding schedules without reference to the actual cost of providing imbalance service. This approach made sense if customers could predict generation output with a high degree of accuracy and control the quantity dispatched. FERC recognized, however, that the penalty did not make sense when applied to intermittent generation, which cannot be forecasted as reliably and for which the customer has little control over dispatchability.

Accordingly, FERC adopted rules in Order No. 890 that designed a tiered structure for imbalance charges, with increasing imbalance charges as the imbalance increases into the next largest tier. Order No. 890 also provides at least two benefits to intermittent resources. First, the rules provide for monthly netting of imbalance charges within the first tier. Second, intermittent projects are not subject to the third tier of deviation charges. Although these new 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 intermittent resources within their control areas. In addition, certain transmission providers are considering the imposition of a generator regulation charge, or other within-hour balancing charge to intermittent resources. This type of charge should be discussed with a knowledgeable attorney.

V. Greater Access to the Transmission Grid. FERC's Order No. 890 series is designed, in part, as an effort to improve transparency of transmission service and reduce transmission barriers for new projects. These

amendments may result in increased and improved access to the transmission grid for renewable energy developers. Order No. 890 is the first major reform of the OATT since it was created in 1996.

A major obstacle to making more transmission capacity available is the fact that under current 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 firm service is nonetheless available for the large majority of hours of the year. To address these concerns, FERC created two new options: conditional firm service and modified redispatch service. These two services provide new options for intermittent resources that can generally be constructed more quickly than the transmission upgrades necessary to deliver power on a firm basis.

Conditional firm service addresses the "all or nothing" problem transmission customers currently face. Conditional firm is a type of transmission service that renewable advocates have promoted as a partial solution to the lack of available firm transmission. Under this service, a conditional firm customer could enter a long-term contract for the capacity that is available on a path. The customer would have firm service except for time periods designated in the contract and would have priority over nonfirm service for the hours in which available transfer capacity ("ATC") is not available.

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 requires transmission providers to offer and study the use of redispatch service to create additional long-term firm capacity on a transmission system. Under the rule, customers would agree to pay the costs of redispatch service during the periods when firm ATC is not available. As useful as these new services may be from an operational perspective, it is not clear yet whether acquisition of conditional service or redispatch service will be sufficient to obtain third-party financing for solar projects.

Even though the details of Order No. 890 are too voluminous to be adequately covered in this chapter, one important aspect of Order No. 890 is that it may increase access to existing transmission capacity and/or promote transmission expansion in key areas. Order No. 890 (1) establishes a consistent methodology to determine ATC and make certain elements of ATC more consistent, (2) requires transmission providers to participate in an open and transparent regional transmission planning process, (3) reforms pricing policies related to imbalances, credits for customer-owned transmission facilities, and capacity reassignment, (4) revises rules under which a transmission provider must provide rollover rights and require the provision of hourly firm point-to-point service, and (5) requires transmission providers to post all business rules, practices, and standards on the Open Access Same-Time Information System, and to include credit review procedures in their OATT.

VI. Reliability Standards. Recent developments in federal law have transformed historically voluntary standards into mandatory reliability standards that include ongoing, audited obligations and potential sanctions for compliance failures. FERC issued Order No. 672 on February 3, 2006, qualifying the National Electric Reliability Corporation ("NERC") as the continent-wide, FERC-certified 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. The Federal Power Act requires that all reliability standards must be just, reasonable, not unduly discriminatory or preferential, and in the public interest. 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 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, and a solar developer should consult with a knowledgeable attorney regarding such requirements. Though initially exempted from registration, QFs are now required to register with the appropriate regional entity and to comply with the reliability standards as well.

Overall, the mandatory reliability standards pose a challenge to an industry that recognized voluntary standards for many years. 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 California Public Utilities Commission (the "CPUC"), which regulates investor-owned utilities, the California Energy Commission (the "CEC"), which regulates publicly -owned utilities 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 ("PV") and CSP.

One focus has been on increasing opportunities, and reducing transaction costs, for solar generation, especially solar PV, between 1 and 20 MW seeking to sign contracts with California utilities. For many of these smaller projects, participation in the annual Renewable Portfolio Standard ("RPS") solicitation process—by which California's investor-owned utilities request offers from renewable generation projects in order to meet California's requirement that they obtain 20 percent of their energy from renewable resources by 2010—involves significant transaction costs that can significantly impair the profitability of the project. California currently has a feed-in tariff program for its three major investor-owned utilities that allows renewable projects of up to 1.5 MW to sign standard contracts, with a standard price, that must be accepted by the utilities until an overall megawatt cap is reached. CPUC is currently examining whether to expand this feed-in tariff to apply to projects up to 10 MW in size, and to allow projects up to twenty megawatts to participate in the program, although utilities would have the opportunity to decline contracts from projects between 10 and 20 MW. The CPUC is also considering increasing the prices paid under this program. Proposed legislation currently being considered by the California legislature would also expand the availability of feed-in tariffs.

California's investor owned utilities have also engaged in numerous efforts to increase opportunities for solar projects, and other smaller renewable energy projects. In connection with its annual RPS solicitation, Southern California Edison has offered two standard contracts, one for projects up to 5 megawatts, and one for projects between 5 and 20 MW. These standard contracts are intended to lower the transaction costs for smaller projects seeking to participate in Southern California's annual procurement of renewable resources. Unlike the feed-in tariffs, however, these contracts have to be approved by CPUC once executed.

Southern California Edison also recently received approval from the CPUC to develop 250 MW of its own solar PV projects, and to solicit an additional 250 MW of solar PV from independent developers. Southern California Edison has indicated that it is chiefly interested in projects between 1 and 2 MWs. The CPUC is currently working with Edison to implement a procedure for soliciting offers under this program. Both Pacific Gas & Electric and San Diego Gas and Electric have also submitted proposals to the CPUC to allow both utility-development and third-party development of solar PV projects. Those proposals are currently being evaluated by the CPUC. Publicly - owned utilities have also been increasingly active in seeking solar projects as well.

Another focus of California regulatory agencies has also been accelerating the permitting process for solar projects. Late last year, the CEC, which has responsibility for permitting solar thermal projects that are 50 MW or greater, signed a memorandum of understanding with the California Department of Fish and Game to provide a streamlined permitting process for renewable energy projects. The CEC, the California Department of Fish and Game, the Federal Bureau of Land Management, and the U.S. Fish and Wildlife Service also signed a memorandum of understanding, agreeing to develop a conservation plan for the Colorado and Mojave Deserts that would allow for solar and other renewable energy development, while minimizing environmental impacts. The California legislature has also been considering various ways of altering the permitting process for renewable generation, with the goal of improving the process.

California is also involved in efforts to accelerate the siting of transmission needed for renewable generation as well. The Renewable Energy Transmission Initiative, a statewide initiative managed by a coordinating committee composed of the CPUC, the CEC, the California Independent System Operator, and several publicly - owned utilities, is currently developing a conceptual transmission expansion plan for California to reach remote renewable resources.

Obtaining transmission interconnection can be one of the more time-consuming aspects of developing a renewable project, depending on the size of the project and where it is interconnecting to the transmission system. Generally, FERC has jurisdiction over the transmission system, although for certain types of interconnection, such as net-metered projects or QFs that sell all of their generation to a utility, FERC has ceded interconnection authority to the states. Therefore, for certain projects interconnecting to utility lines, the project interconnects pursuant to rules established by the CPUC. In most cases, however, interconnection will be made under the OATT for the entity that controls the transmission line to which the project is interconnecting. In California, that could be a municipal utility such as Los Angeles Department of Water and Power or Sacramento Municipal Utility District, for transmission lines owned by those entities. For transmission lines owned by the major investor-owned utilities in California—San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric—interconnection at the distribution level would be made through the utility. For transmission - level interconnection on utility lines, however, the California Independent System Operator has been ceded control of those lines and would be the entity to which an interconnection application would be made. The California Independent System Operator has recently revised its interconnection procedures for large generators in excess of 20 MW, in an attempt to accelerate the process for interconnection.

Given the frequently - changing regulatory environment, especially in California, it is best to consult with experienced regulatory counsel concerning permitting, interconnection, and contracting issues sooner rather than later.

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 the 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.