

THE LAW OF WIND

A Guide to Business and Legal Issues

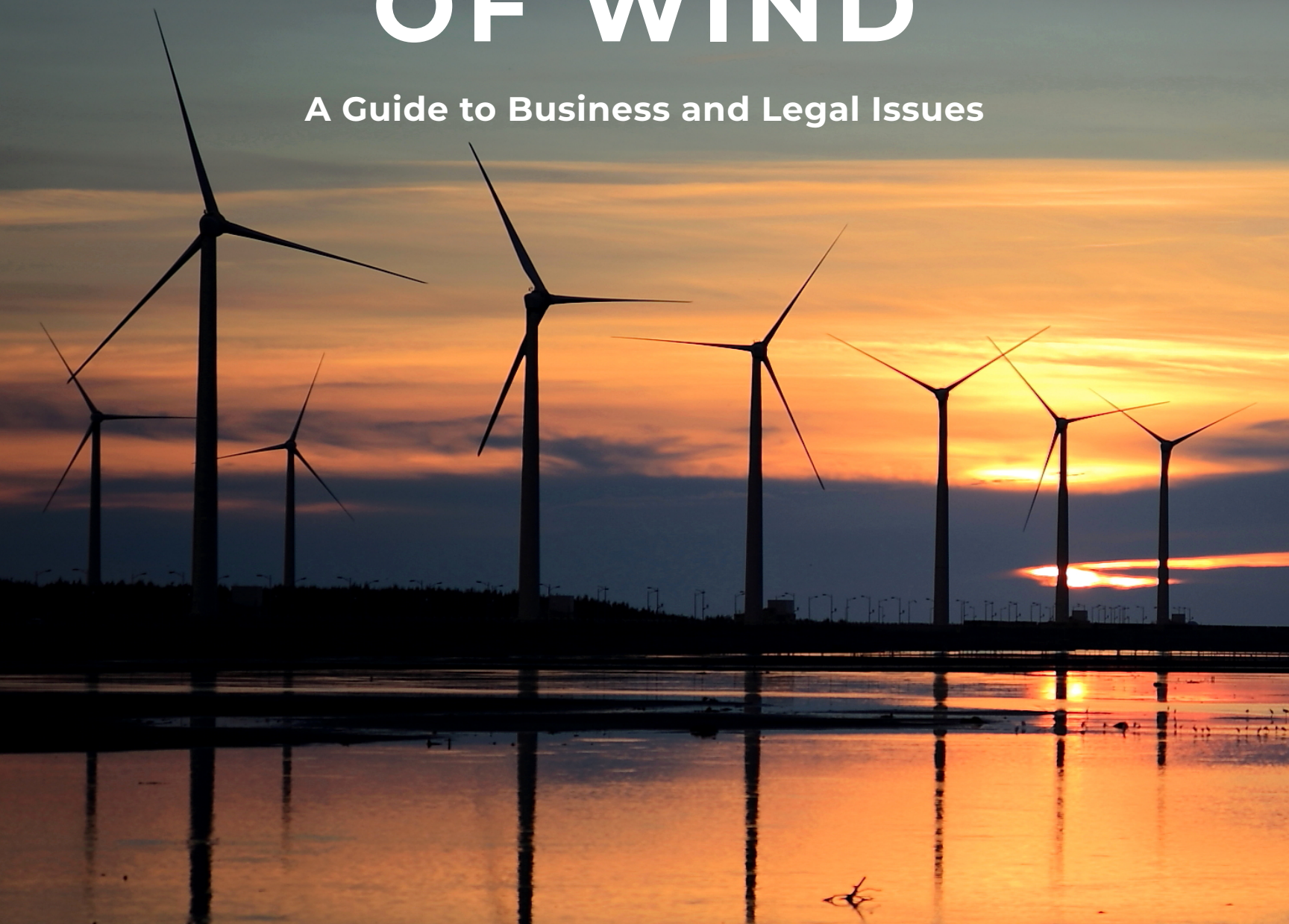


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Resume and Contact Information

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WELCOME TO THE LAW OF WIND

Dear Member of the Wind Power Community,

Two decades ago, utility-scale wind-powered electric generation was still an untried novelty in the United States. In those days, some utilities purchased wind power as a result of requirements imposed by their state regulators. Others did so in order to garner some favorable PR as the public grew more concerned about the contribution of fossil fuel generation to climate change. But as developers got better at siting, building, and operating wind projects; equipment manufacturers improved the productivity of their machines; and utilities suffered the economic hits that resulted from what was then a volatile natural gas market with prices sometimes spiking by several hundred percent in a short period of time, the value of wind as part of the resource mix in an integrated generation portfolio slowly began to be realized. Notwithstanding the intermittent nature of wind, utilities came to appreciate its ability to produce significant megawatts at a price that was fixed for the life of the offtake agreement.

This trend has continued to the present. The industry has shown itself capable of continuing to improve wind project output, lowering the price to where, for several years now, it is price competitive with natural gas—and this in a fracking environment where the price of natural gas has been at all-time lows and its pricing volatility has yet to re-emerge. And despite an unfavorable political climate that seeks to promote a resurgence of coal-fired generation, the electric industry continues to retire coal plants, speaking loudly as to its vision of the future notwithstanding the short-sightedness of the current group of politicians in Washington. The loss of the production tax credit in the next few years will no doubt require some adjustment and re-posturing. But when one considers that the price of wind has been reduced from over \$90 per MWh in the early 2000s to well under \$25 per MWh in recent years, there is every reason to have confidence that the industry will meet this challenge as well.

As one of the first law firms to focus on wind energy, Stoel Rives is pleased to have worked with so many talented industry players over the years to help bring wind generation to its current level of success. Our dedication to assisting the industry in moving forward is demonstrated by the significant time and effort we have devoted to preparing and keeping current materials like *The Law of Wind* and its companion publications in other areas of renewable energy. As attorneys, we take seriously our duty to help educate the industry and the public in general on the legal aspects of developing, constructing, financing, and operating wind energy resources.

This represents the ninth edition of *The Law of Wind*. As the industry has matured, much of the legal environment has become well known, perhaps even routine in many instances. And yet there are still significant developments that require tracking. The impact of the 2017 tax reform act, the integration of storage solutions, and the continued build-out of the transmission system to bring wind power from


windy sites to load all continue to present new challenges for the industry to meet and the law to accommodate. With this edition we once again renew our dedication to the wind industry and our commitment to provide informed, experienced advice to all who share our dream of a cleaner energy future.

We hope you find *The Law of Wind* 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).



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Chapter One
THE LAW OF WIND
—Wind Energy Lease Agreements—
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At the core of a wind energy project's overall value is the security, flexibility, cost-effectiveness, and stability of the land rights for the project. The tool for capturing this value typically is a wind energy lease or easement agreement that creates and protects a developer's interest and investment in the property and project, and provides reliable income to the landowner, while offering the developer the flexibility to transfer all or portions of the project over its lifetime.

I. Form of Agreement/Use of Option. A real property ground lease or easement rights for developing a wind project site with its accompanying wind resource easement and noninterference covenants (generally, together, a "Wind Energy Land Agreement") is similar, in many ways, to an agreement for a ground lease or other agreement for the temporary use of land for commercial or industrial development. A Wind Energy Land Agreement provides for the developer's entry onto and investigation of the property, and sets forth the term; the scope of the permitted uses of the property by the developer and the landowner; the amounts and methods of payment for the leasehold and/or easement interests; the allocation of insurance and other costs between the parties; the transferability and financing of the development; notice, default, and cure provisions; and other matters that may be required by applicable law, the specific needs of the parties, or the particular circumstances. However, Wind Energy Land Agreements are unlike a common, commercial ground lease arrangement in their treatment of the scope and use of the property, and, when well crafted, should anticipate changes in the ownership of the project and the property, and changing uses of the project property. This chapter outlines some common concepts, provisions, and potential issues in a typical site control arrangement.

Wind Energy Land Agreements can take many forms. A developer will usually develop its own preferred form consistent with its business model, the laws of the particular state(s) and jurisdictions in which it operates, and pricing and operating assumptions. That form will be refined over time to address changes in law or practice and those driven by experience or observation to better achieve best practices. The basic Wind Energy Land Agreement typically provides the developer with an initial period to investigate the underlying property and related parcels that it proposes to develop for its project. After the initial period, if the project goes forward, project construction and operation follows. Among other things, the typical form provides the developer flexibility regarding if, when, how, and where to develop; the right to terminate as to all or any portions of the site; and protective provisions for project lenders and/or others holding or acquiring interests in the project through or under the developer.

It is not uncommon for a developer to use an option that precedes, and gives the developer the exclusive right to enter into, a more permanent Wind Energy Land Agreement rather than entering directly into the project leases or easements up front. The use of an option gives the developer the option term to do

its due diligence on the property before entering the longer-term agreement, in place of or in addition to any preliminary investigation/contingency period that may be provided in the more permanent site control agreement.

Sometimes, the use of an option is driven by particular state law. Other times, it is simply a function of the developer's historic practice. For instance, options are customarily used by wind developers in California to avoid property tax reassessment of the project site that would be triggered under California Proposition 13, both at the commencement and again at the end of the lease term, if the lease term ran 35 years or more (including extension options). Handling the initial due diligence during the option period before entering into the long-term lease allows more time for the actual wind project operations, if the option is exercised, during the lease term without triggering the re-assessment limit. By using the option and entering into the actual lease only after the initial investigation period is finished, the developer maximizes the term of the lease available for income-producing operations without having to trigger potentially expensive property tax reassessment.

Use of an option also has disadvantages. Options carry a higher risk of avoidance in a landowner bankruptcy and a greater priority risk than a Wind Energy Land Agreement. Stand-alone options (options that are not part of an existing lease) may not be considered interests in real property under a particular state's law (or insurable under a policy of title insurance) until exercised. However, the properly written and documented option is a common tool to secure the developer's right to obtain its more permanent Wind Energy Land Agreement. To be enforceable, an option should detail all the material terms and conditions of the Wind Energy Land Agreement it envisions. Without a clear statement of the actual terms of the long-term agreement contemplated by an option (or an objective method of filling in the blanks), an option may be merely an unenforceable agreement to agree regarding the final form of Wind Energy Land Agreement to become effective on exercise of the option. Experienced developers' forms of option usually have the actual complete form of Wind Energy Land Agreement attached or the terms included in the option to become effective on exercise of the option to avoid challenges based on lack of material terms.

While beyond the scope of this chapter, in some cases a wind developer may piggyback onto a prior Wind Energy Land Agreement through a sublease, subeasement, or the like, or through a partial assignment or split of the prior agreement into two or more separate split or partial assignment agreements. Those each have similar concerns as a direct Wind Energy Land Agreement with the added issues of dealing with the prior interest holders and underlying landowner to ensure that the derivative interest is protected and secure notwithstanding any problem with or termination of the prior agreement

II. The Scope of the Property Subject to the Wind Energy Land Agreement. One of the core issues during negotiations between landowners and project developers is the total amount of the landowner's property that will be subject to a Wind Energy Land Agreement. A natural tension exists between a developer's desire to include in the agreement as much of the real property as possible to allow flexibility and protection in locating its project and a landowner's concern that its activities and

rights will be limited by a Wind Energy Land Agreement that extends beyond the actual amount of land needed for the construction, maintenance, and operation of the wind energy facility on the property.

A. The Interests at Issue. Developers frequently seek to maximize the amount of property subject to a Wind Energy Land Agreement for several reasons. First, in today's competitive, wind-energy project environment, and because access to and evaluation of a site typically requires an agreement with the landowner, developers usually acquire real property rights before they have done significant site-specific due diligence. They typically require time to obtain wind data and information about the property's topography and environmental attributes, the location of existing title encumbrances, and access to transmission facilities to determine the most productive and cost-effective layout for the wind energy facilities on the property. Consequently, the developer will seek to obtain property rights, such as through a Wind Energy Land Agreement, across large areas of property to ensure its rights are broad enough to provide flexibility to ongoing siting and other due diligence investigations, changing conditions, permitting requirements, or new data. In addition, economies of scale play a role. By maximizing the amount of property the developer controls, the developer can better maximize the size and efficiency of the possible wind energy project or projects and benefit from economies of scale in reducing development costs and increasing productivity.

Second, the effective generation of wind energy from wind turbines is largely dependent on the annual average wind speed over the subject property. Any obstruction, natural or artificial (*e.g.*, a tall building, silo, or row of tall trees), that interferes with the flow and speed of the wind over the property can have a dramatic, negative impact on the efficiency of downwind wind turbines to generate energy and could create turbine-damaging turbulence. A developer will want control over the size and kind of structures and other obstructions that can be constructed or placed on the property by the landowner and third parties during the term of the Wind Energy Land Agreement. An effective way to gain this control is to encumber enough property to construct, operate, and protect the project and its wind resource and to include noninterference covenants in the Wind Energy Land Agreement that limit the landowner's right to interfere with the wind flow over the property.

On the other hand, some landowners may be motivated to limit the amount of land subject to the Wind Energy Land Agreement. That could be because the landowner wants to limit the impact of the wind energy project on its other activities on the property (especially when the landowner is a farmer or rancher and plans to continue using the property in this manner while the wind energy project is operating on the property) or to preserve the opportunity to lease the excluded land for other purposes (*e.g.*, cell towers), or the landowner may simply be reluctant to give up a measure of control over too much of the property.

B. Potential Resolutions. There are several means to help incentivize landowners to be more receptive regarding the amount of property to be included in the Wind Energy Land Agreement. These include:

- Tying a portion of the payments made to the landowner under the Wind Energy Land Agreement to the total number of acres encumbered by the agreement.
- Consulting with the landowner during the planning stage regarding the location of the proposed wind power facilities on the property. This may reassure the landowner and also provide the developer with useful information about the property. However, the developer should retain the final authority to determine if, how, and where to site its project facilities.
- Offering a phased approach under which the landowner agrees to lease and/or grant easements to the developer over a greater swath of the property through the investigation and construction phases of the wind energy project (or some other fixed date). After construction has been completed, the developer may carve back the area leased to drop from the lease (but often reserving and preserving the exclusive wind rights and noninterference covenants on) portions of the property that are not part of or needed for the wind energy project. This approach should take into account any “phased” development that the developer may intend for the project and any applicable project boundary buffers or setbacks or the like that may be triggered by such action. In all events the developer should ensure that it retains a suitable buffer area around the wind power facilities to allow ample room for operation and maintenance activities and possible future repowering or relocation of the wind turbines. Further, while rarely seen, a developer may consider adding a right of first refusal to lease or obtain easement/occupancy rights on the released property. This would provide the developer with more flexibility if the landowner proposed to lease to a third party or otherwise encumber the released property for a purpose that, notwithstanding the noninterference covenant, might be incompatible with the wind project or on terms that were attractive to the developer. Before taking this approach, however, the parties should make sure that this arrangement will not violate applicable permitting requirements or other local land use laws (such as a requirement that the leased premises be a legally created parcel), and should also be aware that such provisions increase the ongoing time and expense of administering the Wind Energy Land Agreement.

III. Purpose of Agreement and Use of Property. Another common issue involves the purpose of the Wind Energy Land Agreement and the uses the developer may make of the property to accomplish this purpose. The obvious purpose of a Wind Energy Land Agreement is to allow the developer to determine the feasibility of and then construct and operate one or more wind energy projects. However, the developer and landowner may disagree about the scope and extent of the rights in the property that the developer needs to accomplish this goal. Typically, developers will want the right to take any action on, and make any use of, the property that the developer believes is necessary to accomplish the goal of

evaluating, constructing, and operating its proposed wind energy project(s) on or about the property. This generally includes the right to grant rights to others within the scope of developer's allowed uses where needed or desirable to the developer. For its part, the landowner may wish to see these rights limited so that the landowner has more control over what, where, and how the developer may develop the property and to have more flexible financial terms that contemplate landowner consent and/or additional charges for third-party use or certain types of developments (such as substations, operations and maintenance ("O&M") sites, or the like) as discussed below.

A. What Facilities Go on Whose Land? For most large wind energy projects, a developer must control the properties of numerous neighboring landowners to aggregate the large number of acres required to fully site the project. Few landowners own enough windy land (with access to transmission capacity) to have a utility-scale wind energy project located completely within the boundaries of their properties. Inevitably, once the developer has conducted its wind, transmission, environmental, permitting, and construction studies on each property, some will stand out above the others as better candidates for locating wind turbines, while others may be more suitable for transmission lines, roads, and other facilities that serve the wind turbines.

Usually, the most lucrative and long-term source of income for the landowner from a Wind Energy Land Agreement is based on the energy generated from project turbines on the landowner's property. More turbines on the landowner's land usually means more income to the landowner, and this continues as long as the turbines generate electricity. Accordingly, as a general rule in such a case, no landowner wants to have project transmission lines and roads on its property that serve wind turbines on a neighbor's property while having few or no wind turbines on the landowner's property. A landowner may negotiate to condition the developer's right to extend the term of the agreement beyond the initial evaluation and development phases on the developer's installation and operation of a minimum or fixed number of wind turbines on the landowner's property or the monetary equivalent in payments to the extent of any shortfall in turbine number, or special minimum payments if its property is used primarily for transmission lines and roads or project purposes other than turbines. There are various ways to address appropriate compensation to landowners with no turbines on their property, including such concepts as community shares or pooling where a set percentage of annual project revenues is shared among those "no turbine" owners based on their relative land areas under contract to the developer.

A landowner may also negotiate for additional compensation for the developer's right to place various project facilities on the property. For example, when the developer wants to place on one landowner's property a substation or an O&M facility that will serve the entire wind energy project, the landowner may believe it is entitled to additional compensation for the added benefit to the developer and added burden on the owner and loss of usable property caused by construction of such a facility on its property. The same may be true for transmission lines, collector lines, access and crane roads, and other features that remove land area from the landowner's continuing farm or other use or that preclude wind development by other competing developers even if no facilities at all are placed on its property. In

many cases, a developer will agree to pay such compensation if the landowner will not otherwise be adequately compensated as a result of turbines being located on the landowner's property.

Finally, in some circumstances (such as when the project permits or applicable zoning impose setback requirements or to protect the free flow of wind to the project turbines), the developer may need to include a landowner's property in the project's "footprint" and encumber it with a Wind Energy Land Agreement even though no physical project facilities will be located on the property. Such arrangements typically provide for a fixed periodic payment to the landowner. Sometimes these concerns and requirements can be met by a less intrusive setback covenant, noise waiver, or restrictive covenant agreement that meets the applicable permit or project requirements without being a full-blown Wind Energy Land Agreement.

B. Landowner's Continued Use of the Property. A unique and attractive feature of wind energy projects is that, in most cases, even after the project is built and operating, the landowner may continue to use a great majority of the subject property as it had before entering into the Wind Energy Land Agreement. That is so because only a small portion of the subject property is used for wind turbines, roads, transmission lines, and related facilities. Some areas, such as the actual turbine pads and immediate surrounding areas, O&M sites, substation sites, and the like, will be for the exclusive use of the developer and off limits to the landowner. Other areas such as shared roads or other facilities would be available for joint use under the terms of the agreement. The remaining property suffers little or no impact from the wind energy project, apart from the physical presence of the facilities and the restrictions against interference with or use of the wind resource. Consequently, most Wind Energy Land Agreements provide that the landowner may continue to conduct its farming, ranching, or timber harvesting activities on the property outside the actual project facility footprint, provided that such activities do not and will not interfere with the construction and operation of the wind energy project.

C. Shared Use of Site Resources. Some Wind Energy Land Agreements contemplate developer access to and use of resources on the project site, such as water and aggregate/rock for use on the project. Water rights, of course, are subject to the limitations on use and point of application under applicable law and so may or may not be available to the developer in connection with the construction or upkeep of its project. For instance, an "irrigation" water right may not lawfully be used for non-irrigation wind project purposes. Aggregate, sand, and rock from an existing quarry or deposit on the project land can save a developer time and money and provide another revenue stream to the landowner. Pricing on such resources is a subject for negotiation by the parties. If the developer contracts for and will rely on the availability, quality, and quantity of and access to such resources, additional due diligence is called for to determine and evaluate the value and quality of the resource and any third-party rights that might interfere with the developer's intended use, as well as any additional permits or approvals required from any agency or third party to extract or apply the materials (and any required remedial activities).

IV. Term. A Wind Energy Land Agreement usually provides for an initial term of three to 10 years to provide the developer with time to study the feasibility of wind energy conversion on the property.

Developers that use options and complete their due diligence and permitting during the option period may omit this aspect in their more permanent agreement and go directly into the construction of the project facilities upon exercise of the option and entering into the Wind Energy Land Agreement. During this initial term or option period, the developer collects wind data from anemometer or meteorological (“Met”) towers installed on the property; performs geotechnical, environmental, and other studies on the property; and assesses the condition of title to the property. Assuming that the wind data and other studies demonstrate that the property is suitable for development and the balance of the other properties needed for the longer planned project are also under the developer’s control, the developer obtains necessary siting permits and constructs the wind energy project on the property.

Note that, in addition to length-of-term concerns such as the California Proposition 13 reassessment trigger at 35 years discussed above, some states have enacted statutory provisions that limit the effective period of wind leases or options to lease or the like to a set number of years. *See, e.g.*, N.D. Cent. Code § 17-04-01, -03 & -05 (wind leases, options, and easements are void if no development occurs within five years of the commencement of the interest); S.D. Codified Laws § 43-13-17 and -19 (term of a wind easement or lease may not exceed 50 years and the easement/lease are void if no development of the potential to produce energy from wind power associated with the easement/lease has occurred within five years).

The Wind Energy Land Agreement typically provides the developer with an automatic right to extend the agreement past the initial investigatory phases for an additional period or periods ranging from 30 to 50 years (or even longer, subject to applicable state law restrictions). The developer typically agrees to one of the following: (1) pay the landowner a periodic minimum payment during the extended term, (2) pay the landowner a payment upon commencement of the extended term, or (3) install a certain number of wind turbines on the property that generate electricity (or commences paying an enhanced minimum payment stream). The number of wind turbines that the developer may be required to install on the property to trigger the automatic right to an extended term without having to pay a greater minimum payment to maintain the agreement in effect is subject to negotiation by the parties. In setting the proposed initial and extended term of a Wind Energy Land Agreement, the developer should take into account any requirements or restrictions imposed by applicable state law. As mentioned above, certain states, particularly in the Midwest, impose strict timelines that must be met to keep the Wind Energy Land Agreement in effect, and, depending on the state, development of the project must commence or commercial operations must begin within specified time periods, even if the Wind Energy Land Agreement contains a more flexible provision. Where the statutes apply, the statutes will govern over any conflicting provisions in any Wind Energy Land Agreement.

The developer may also reserve the right to further extend the term for additional renewal periods, often ranging from 20 to 30 years, and to “repower” all or part of the project at some point during the extended term or otherwise extend the life of the project. “Repower” typically means replacing all or a significant number of the wind turbines on the property, installing additional wind turbines on the property, or both. The net result of these successive terms is an agreement that has the potential to run

for more than 70 years (again, subject to applicable state law restrictions). The unusual length of the Wind Energy Land Agreement may be troubling to a landowner, especially when the property is a family farm or ranch that the landowner envisions conveying to successors or heirs. The landowner may be reluctant to sign an agreement that may continue encumbering the property long after the landowner envisions transferring control of the property. Further, the length of the agreement may create concerns about the landowner's ability to sell the property at some later date or give rise to questions about the long-term viability of the developer. The landowner will want some assurance that the developer or its successors will have the financial means to operate the project for the term of the agreement and to restore the property at termination. Dealing with a reputable developer with a long track record of successful projects is one way an owner can get more comfort that his developer has the experience, ability, and wherewithal to develop a successful project that benefits them both. While the income from an operating wind project often significantly increases the market value of the owner's underlying land, whether and how much of an effect a project has on land value must be determined on a case-by-case basis.

On the other hand, the ability to continue to farm, ranch, etc. the bulk of the property and the income stream generated from the landowner's Wind Energy Land Agreement may allow some families to keep the property in the family and not be forced to sell or split up the property due to reliance on farming, ranching, etc. income alone or other factors. Subject to restrictions on severing the income stream from the land ownership under applicable law or under the Wind Energy Land Agreement, the income stream from a Wind Energy Land Agreement also may be a bargaining chip in any future sale (to keep it, split it, or let it go with the land). It will surely be a feature in determining the value of the property in any sale or financing of the farm, ranch, etc.

V. Payments. Wind Energy Land Agreements typically provide that the developer will pay the landowner periodic payments for the rights granted in the agreement. Less commonly in recent years, the developer pays the landowner a single, lump-sum payment. One common issue that is encountered by developers regardless of the type of payment is dealing with multiple owners; changes in ownership due to death of the original owners, leaving scattered heirs in ownership (some of whom may be minors); or change in ownership resulting from sale or transfer of part(s) of the burdened lands or divorce or other means. An agreement that makes provisions for potential multiple landowners/payees can help lessen the administrative burden on the developer. The agreement could provide the developer the option to pay to a single address by joint check, or allow the developer to pay into an escrow, and let the various owners determine among themselves who is entitled to what payment(s), etc., or other arrangements. For a developer, having to track and deal with and determine who gets paid what in light of changing and increasing numbers of persons holding some interest in the underlying project lands or right to payments from the Wind Energy Land Agreement can be time-consuming and contentious, and can expose the developer to multiple, competing claims.

The same issues arise if the developer needs to amend the underlying agreement or get some consent from the landowner. This burden on the developer is made heavier, more expensive, and riskier if one

adds the complications and pitfalls related to the attempted or actual severance of wind rights or the income stream from a Wind Energy Land Agreement (discussed below) and keeping track of those interests. “Severance” is separating all or some of the “wind rights” and/or income stream from the ownership of the underlying land. Where there are multiple owners and any severed or reserved wind rights or income rights, the developer can face a daunting task to keep real-time track of, evaluate, and properly deal with the different interests.

A. Lump-Sum Payment. In the early days of the modern wind power boom, some developers would offer the landowner a one-time lump-sum payment as consideration for the rights granted in the Wind Energy Land Agreement. This lump-sum payment typically was paid upon mutual execution of the agreement and, with a few minor exceptions, was the only payment the landowner received under the agreement, apart from special separate payments, such as payments for disturbance to land that was enrolled in the federal Conservation Reserve Program (commonly referred to as “CRP”) or similar programs where such disturbance triggers a requirement for the landowner to reimburse payments received or pay a penalty, or other disturbance or damage payments. A lump-sum payment may be attractive to a landowner because it provides the landowner with a large amount of money up front, without concerns about the developer’s ongoing financial health and ability to make annual payments. However, attempting to calculate the time value of the lump-sum payment against future annual payments can be difficult and time-consuming. Further, such large, lump-sum payments can have undesirable tax consequences for a landowner and leave the property encumbered by the ongoing operations and burdens without any continuing payment stream, which would almost certainly depress the value and marketability of the property.

B. Periodic Payments. Periodic payments from the developer to the landowner are the most common payment structure in today’s Wind Energy Land Agreements. Frequently, the payments are structured to include some combination of the following:

1. Initial Payment or Signing Bonus. The developer will pay the landowner an up-front payment for signing the agreement. The amount of this signing bonus varies widely, depending on factors such as the property’s perceived potential for wind power generation, the degree of competition between developers for use of the property, and the negotiating skills of the parties and their advisors. Where the agreement is an option, most if not all states’ law requires separate consideration to make the option binding. The amount of consideration to make an option binding can be minimal, but it must be actually paid to have the binding effect. Mere recitals that adequate consideration has been paid may not bind the parties where the recital is untrue. (*See, e.g., Or. Rev. Stat. § 42.300.*)

2. Pre-Operation Minimum Rental Payments. Once the Wind Energy Land Agreement is in effect, the developer typically pays the landowner annual, quarterly, or monthly rental or option payments for the initial period of time during which the developer measures the wind flow over the property, performs studies, obtains siting permits to construct the wind energy project, and actually constructs the project. Again, the payment amount depends on several factors. The parties may

agree that the payments will be calculated by multiplying the number of acres of property subject to the agreement by an agreed dollar figure. In some cases, there are installation and/or periodic fees for Met towers or other facilities placed on the property. A landowner may prefer to be paid on a monthly or quarterly basis, but developers typically prefer to pay annually to reduce administrative burden and decrease the chance of missing a payment and the attendant risk of defaulting under the agreement. In most cases, these minimum annual, quarterly, or monthly rental payments often cease once the wind energy project is operating and the landowner begins receiving payments based on the sale of electricity generated by the wind turbines on the property that exceed the minimum payment.

3. Installation Fees. Some Wind Energy Land Agreements provide that the developer will pay the landowner a one-time installation fee for each wind turbine installed on the property by the developer. The installation fee is often calculated using the total megawatts of installed capacity (based on nameplate capacity) of wind turbines or other power-generation facilities constructed on the property, rather than on a per-turbine basis. This is because the manufacturer's "nameplate" megawatt rating for the type of turbines that the developer installs on the property varies, and thus tying the payment only to the number of turbines may not reflect the generating potential of the turbines installed, which can result in a significant difference in the installation payment to the landowner.

4. Operating Fees/Rent. Generally, once the project starts producing energy, operating fees are paid to the landowner by the developer. The fees are usually the most lucrative aspect of the Wind Energy Land Agreement for the landowner. For that reason, the operating fee provisions are often where much attention is focused in negotiating the agreement. The Wind Energy Land Agreement commonly provides for a continuing, base minimum periodic payment to the landowner during the operations phase of the project. If and when wind turbines are installed on the property and begin delivering electricity on a commercial basis to a purchasing utility or other purchaser pursuant to a power purchase agreement ("PPA") or similar document or, if the developer is an end user or utility, when such energy is available for use, the developer will begin paying the landowner operating fees based in some respect on the output of those wind turbines, to the extent those fees exceed the continuing, base minimum periodic payment. Operating fees are usually calculated over an annual period. These operating fees are often based on (1) a percentage of the gross revenues received by the developer from the sale of the electricity generated by wind turbines on the property; (2) a fixed rate per kilowatt-hour or megawatt-hour of electricity generated by wind turbines on the property, with the rate being determined based on the expected capacity factor of the wind turbines on the property; or (3) a per-turbine or per-acre annual lump-sum payment that has no strict relationship to the amount of electricity generated by wind turbines on the property.

When operating fees are a percentage of gross revenue, what to exclude from gross revenues for purposes of calculating the percentage-based payment is frequently a topic of much discussion. Tax credits are typically excluded, while insurance proceeds payable with respect to lost power sales revenue or turbine production are often included. Further, operating fee provisions that work for a

privately owned facility that is selling the project power under an arm's-length PPA to a third-party off-taker may not be appropriate where the project operator is an end-user, a public utility, or an affiliate of the off-taker. If the project is owned and the output used by a utility to serve its utility customers, the formula for calculating operating payments typically takes a different form than that for a project owner selling to a third-party off-taker. In addition, as discussed above, a Wind Energy Land Agreement may provide for the payment of some minimum amount to the landowner during the operations phase of the agreement, based on the number of turbines installed on the property, their nameplate ratings, the amount of acreage subject to the agreement, or other factors.

VI. Additional Considerations. In recent years, new legal issues have emerged in the area of Wind Energy Land Agreements. Two of these issues are (1) attempts by landowners to convey all or portions of the property subject to the agreement while “severing” or reserving “wind rights” to the conveyed property or royalty or participation rights in wind project proceeds derived from the property and (2) restrictions or reporting requirements relating to foreign ownership of certain types of land.

A. Severance of Wind Rights/Income Stream. Subject to applicable law, a landowner that conveys its property in fee may reserve certain rights to that property. Historically, such reserved rights may include easement rights for access, utility service, encroachment, view, and other matters, or a severed mineral right, including the right to explore for and develop oil and gas or other minerals. The law in the United States is, for the most part, well developed in connection with such reservations. To the contrary, reservations or severing of “wind rights” has not (to date) been scrutinized in depth by the appellate courts outside of a few reported cases. The most often cited case is *Contra Costa Water District v. Vaquero Farms, Inc.*, 68 Cal. Rptr. 2d 272 (Ct. App. 1997) (recognized severance of wind rights in a condemnation action under California law). The Kansas Supreme Court upheld a complete county ban on commercial wind farms in *Zimmerman v. Board of County Commissioners of Wabaunsee Co.*, 218 P.3d 400 (Kan. 2009), and deferred its consideration in that same case of the argument that severed wind rights are a separate property interest that can support a takings claim under the U.S. Constitution. The court's follow-up decision on the takings issue did not turn on whether severed wind rights were a cognizable property interest under Kansas law, but on the discretionary nature of the conditional use permit (“CUP”) required to construct the proposed wind farm. Because the CUP was completely at the discretion of the county Board (*i.e.*, no right to construct the wind farm), there was no taking.

Some states, such as North Dakota, South Dakota, and, more recently, Kansas, have statutory prohibitions on severance of wind rights and limit the length of terms for wind project leases and easements, or require certain development actions to occur within a certain time to preserve the contracted for wind rights. See N.D. Cent. Code § 17-04-01 through -06 (certain development and permitting milestones within five years); S.D. Codified Laws § 43-13-19 (commencement of wind resource development must begin within five years (requires site permit or CUP and active interconnection request in process), no severance of wind rights except pursuant to a lease with a term not more than 50 years, requires annual payments); Kan. Rev. Stat. § 58-2272 (also includes solar).

A number of states have statutes that expressly contemplate and impose certain requirements for creation of wind leases and wind easement rights that burden one property for the benefit of other property, but those do not specifically address the issues of a landowner severing wind rights in other contexts.

Unfortunately, some landowners transferring their property have begun attempting to reserve rights with respect to existing or future wind projects on the property using conveyance instruments and contractual provisions that are far from clear. This compounds the complexity and uncertainty of the legal effect of their actions. The same issues arise in other transactions or proceedings, such as divorce or dissolution proceedings where the parties or courts seek to allocate and split assets once commonly owned, or in estate plans that may be drafted without a full understanding or appreciation of the issues raised by the proposed allocation of rights. If a landowner seeks simply to retain the rights to revenue from wind energy facilities on property to be transferred, the landowner should work closely with counsel to ensure that what they want to do is lawful, allowed under and consistent with their Wind Energy Land Agreement, and clearly documented on the record. Apart from whether the proposed action is allowed by state law or permitted under the Wind Energy Land Agreement, there must be clear direction to and protection of the wind developer from any risk related to the proposed split interests.

The same is true if the goal is to retain a wind easement for the unrestricted flow of wind and/or reserve a right to the transferring owner to control or have some say in future development of the property for wind purposes, and there is no Wind Energy Land Agreement currently encumbering the property. In each case, such rights would need to be set out in the conveyance instrument with clarity and in detail, and in compliance with applicable law. Even with clarity, such arrangements can make a property less attractive to a developer because of the added complexity and uncertainties they entail. Vaguely drafted language in these conveyance instruments or language that does not comply with applicable statutory requirements benefits no one and is likely to cause confusion for (and result in disputes among) the landowners, the wind developer, and third parties seeking to deal with the property in some manner. In any event, it is probably a very good practice for a landowner contemplating such a move to work with its developer *before* finalizing any such arrangement to better ensure there will be smoother sailing once it is in place.

From the developer's perspective, allowing any severance of the wind rights or income stream from the ownership of the underlying land burdened by the Wind Energy Land Agreement raises concerns about the future relationship among the parties and the ability to adjust to changing circumstances, as well as additional administrative burdens and internal costs. For instance, it is not uncommon for a developer to seek changes to its initial Wind Energy Land Agreement to accommodate changed conditions encountered after (or not contemplated in) the original agreement. Where the landowner is the person to whom the payments are made by the developer, the landowner has an incentive to cooperate, especially where failure to cooperate may mean the loss of the income stream otherwise provided by the agreement. If the wind rights and/or payment stream have been severed from the underlying land ownership, that incentive is absent: the landowner merely owns land burdened by and has obligations

under the Wind Energy Land Agreement. Other than whatever the landowner can extract from the developer in exchange for any concessions the landowner is willing to make to accommodate the developer's request, unless the landowner otherwise has the clear and enforceable duty to take the requested course, there will be no incentive for the landowner to cooperate where the proposed change to the Wind Energy Land Agreement does not lighten the burdens on the land and/or landowner. The same result applies where a landowner sells or factors its income stream to a third party for a discounted present value of the overall contract value.

B. Federal and State Reporting Requirements. Finally, the federal government and some states impose reporting requirements and/or restrictions on some interests (such as restrictions on corporate ownership or ownership by foreign entities) in certain types of land. The federal acts include (but are not limited to) the Agricultural Foreign Investment Disclosure Act of 1978, 7 U.S.C. § 3501, *et seq.* ("AFIDA") and the International Investment and Trade in Services Survey Act, 22 U.S.C. § 3101, *et seq.* ("IITSSA"). A number of states, generally in the Midwest, also have restrictions/prohibitions on alien ownership or interest in agricultural lands and/or special provisions regarding corporate ownership/interest in agricultural lands and their own reporting requirements, though those specific state laws will not be addressed here.

Under AFIDA, foreign persons (including foreign nationals and entities organized or formed under the laws of foreign governments and domestic entities in which a foreign person has a significant interest or substantial control) must file a report with the U.S. Department of Agriculture within 90 days of acquiring or transferring any interest in "agricultural land." Leasehold interests of 10 years or more are "interests" subject to AFIDA, so most utility-scale energy project leases would be covered. Under AFIDA "agricultural land" is land in the United States used, or, if currently idle, land used within five years, for farming, ranching, timber production, or forestry production, except tracts that are not more than 10 acres in size in the aggregate. Tracts totaling 10 acres or less in the aggregate and that produce annual gross receipts in excess of \$1,000 from the sale of farm, ranch, forestry, or timber products must also be reported. Failure to report or late reporting may subject these entities to a monetary penalty capped at 25 percent of the fair market value of each real property interest.

IITSSA is separate from AFIDA and is administered by the Bureau of Economic Analysis. IITSSA applies to any foreign person that acquires, directly or indirectly, a 10 percent or greater interest in a U.S. person. Any of the following acquisition events triggers the obligation to report: (a) a foreign person establishes any new U.S. subsidiary or other type of for-profit U.S. entity, (b) a foreign person acquires an existing U.S. business enterprise, or (c) a foreign person acquires a 10 percent or greater voting interest in an existing U.S. business enterprise. Acquisition must be reported within 45 days of the acquisition event and can be indirect, through an existing U.S. affiliate.

Once a foreign person enters into a transaction that triggers IITSSA, that person must file various forms at prescribed times unless it qualifies for a reporting exemption based on the size of the acquisition transaction or the magnitude of the activities of the U.S. person acquired. Even if the foreign person is exempt from the other requirements of IITSSA, in most cases it must file an initial report in order to

establish and preserve the exemption. Civil penalties, including fines and injunctive relief, can be assessed on those foreign persons that fail to comply with IITSSA. Willful failure to file may result in additional fines and imprisonment. Criminal penalties also can be imposed in appropriate circumstances.

Developers and landowners should consult with counsel to determine if such laws apply to their interests and Wind Energy Land Agreements.

C. Issues Raised by Multiple Owners/Severed Rights. For a developer, having to track and deal with changing and increasing numbers of persons holding or claiming some interest in the underlying project lands or right to payments from the Wind Energy Land Agreement can be time-consuming and contentious, and can expose the developer to multiple competing claims and increased risk. Payment issues related to multiple owners are addressed in Section V of this chapter.

Similar issues arise if the developer needs to amend the underlying agreement or get some consent or estoppel from the landowner in relation to the current project, to meet a lender, government, or permitting requirement. Whose consent or certification is required? What comfort does the developer have that it is dealing with all of the right people? This is another area where a sophisticated and responsive title company can be a great help, even if only to help identify interested parties and the underwriting requirements that need to be satisfied to insure the transaction (if insurable) and to chart a plan to ensure an insurable result. The developer must then locate the required counterparties and obtain their individual and/or collective agreement to the proposed solution. Another day in the life of a developer.

VII. Co-Location. Co-location can have a number of meanings. One meaning is joint use of an area by two or more different entities. Another is different projects using different energy resources on the same area, such as wind generators (active generation of electricity) and storage serving those generators (passive available electricity) or active solar. In one sense, virtually every Wind Energy Land Agreement contemplates co-location of different operations: the wind farm use and the continuing underlying use by the landowner of the property outside the project facility footprint. Likewise, one sometimes sees a project that is initially documented as a single, large site that is later split or broken into multiple smaller sites, each with its own wind power project under a stand-alone “split” Wind Energy Land Agreement or partial assignment of the original site control agreement(s). In such cases, the original site control agreement usually contemplated the right to split the larger site into separate stand-alone sites. The separate, derivative stand-alone agreements typically include provisions to protect the stand-alone and separate nature of each such split or partial assignment. They should also avoid any cross-default or the like that might otherwise be attendant to a derivative right and preserve any common use of needed access or other features that serve more than one site.

A. Shared Facilities. It is not uncommon for projects in close proximity, especially those originating from the same underlying developer and original site agreement(s), to share certain project facilities. Economies of scale gained by sharing facilities between related or nearby projects can make

otherwise marginal project sites economically feasible. Sharing the use of and spreading the costs of permitting, developing, operating, and maintaining such facilities as common substations and switching stations and related new transmission upgrades or line extensions, O&M and supervisory control and data acquisition facilities, access roads, and other necessary facilities that can serve more than a single project can reduce the out-of-pocket costs to each participating project. In some cases, one project may host and construct the substation site or O&M site and sublease or grant some other derivative right to other projects to use the facility. In others, the participating projects might co-own the facility. These joint-use agreements are often entered into before the facility is constructed. Such arrangements can help maximize the efficient use of resources and finances and address concerns of lenders and others regarding the financial burden that a single project might otherwise sustain in undertaking the development work.

B. Storage. Energy storage is the focus of increasing interest in the renewable community. Efficient and reliable energy storage technologies are seen as one solution to enhance the integration of intermittent resource electricity onto the power grid, to reduce or eliminate imbalance charges to the project, as well as to increase the ultimate efficiency and economics of an energy project. Storage technologies can benefit a range of energy producing technologies, not just intermittent renewable sources. Any electricity producing project that could more efficiently use or sell its output to better meet the timing of energy supply and demand could benefit, including intermittent, nondispatchable projects such as wind and solar.

Whether and how co-location of storage and the electricity transmitted to and out of the storage facility might be treated under the Wind Energy Land Agreement compensation provisions is beyond the scope of this discussion. Is the storage facility before or after the project meter? How does the agreement contemplate charges based on production? Are the additional charges based on area taken up by a storage facility? How does an applicable PPA treat stored energy? These are all good questions and one can expect developers and landowners alike to revisit the forms of Wind Energy Land Agreements as storage becomes more widespread.

While energy storage co-location is not limited to co-location of a wind project and related storage facility by the same developer as part of the same project, or by a third-party storage developer to support the wind project, those seem the most likely scenarios, at least currently. An energy storage facility located on a project site that is owned by a third-party storage developer or that serves a different project (or is shared in some respect between two or more projects) would implicate the same concerns and issues as other shared or third-party facilities generally. The developer considering such a third-party arrangement would have to confirm whether, how, and under what conditions its Wind Energy Land Agreement allowed such third-party rights and what, if any, additional compensation and other obligations might be owed to the landowner. Likewise, the developer would have to satisfy the concerns of its lender(s) and investor(s) as to the arrangements.

Energy storage solutions that involve battery technology are probably the most compact and localized of the current storage technologies. The siting of a bank of batteries within a project area could provide

enough energy, depending on the scale, to provide a separate profit center in its own right or just balance the periodic fluctuations of a wind farm that may be balanced on, for instance, a five-minute interval. Apart from any benefit to a project's bottom line that a larger storage system might bring from sales of the stored electricity, a project that included enough immediately available storage capacity to cover its balancing interval window could avoid many of the imbalance charges that might otherwise be imposed.

Adding a series of electric car batteries removed from junked electric cars to a wind project, with a few per turbine (for instance) to offset imbalance issues, should not materially affect any other project facility or require extensive additional land or infrastructure. A larger, high-volume battery farm serving the same wind farm or another project or projects would require lines into the bank from the generators and out of the bank to the substation, together with communications lines and some staging/secure area, but otherwise would be a discrete, localized installation not unlike other fixed facilities. Other storage technologies, such as pumped hydro, compressed air, or the like, would be more land/area intensive and require much more complicated permitting and site control due diligence and agreements.

Among the various storage-related energy projects that might be candidates for co-location with wind could be a typical hydro-generation facility in connection with a storage reservoir. For what it is worth, in at least one well-known case, *Contra Costa Water Dist.*, 68 Cal. Rptr. 2d 272 (better known for its holding regarding the severability of wind rights), the California Court of Appeal recognized the relative compatibility of wind and hydro-electric generation in the same general area. The *Contra Costa Water District* court, with the benefit of additional briefing on the issues, held in part that it was "satisfied that private windpower generation is fully compatible with the Water District's public uses [reservoir and related uses, including mitigation areas] for the land being taken." *Id.* at 277.

C. Combined Wind/Solar Agreements. Though still the exception rather than the rule, occasionally one will see a combined wind/solar energy site agreement that allows either or both of wind *and* solar development on the same premises. Besides the synergistic benefits that might be obtained by proximate projects sharing certain infrastructure and improvements, co-location of wind and solar projects has other ramifications for both the developer(s) and the landowner. For the landowner, the questions include how much land will be used/unavailable to the landowner, what will the compensation be for loss of use of the land, how will any expected royalty or power production payment be calculated, and how are wind and solar treated differently in the agreement regarding siting requirements, compensation schedules, etc. While it is unlikely to expect intense solar development over the entire expanse of a large wind project site, it is not so difficult to imagine that solar development may more heavily affect certain individual wind project parcels and areas than others and thus be of concern to a landowner who is approached with a wind and/or solar site control agreement.

For the developer (really both parties), just adding "and solar" to the definitions in the developer's base agreement likely will not work very well. How does commencement of construction on one project affect any other proposed or sister project? Does any contractual obligation to build or terminate go away if either a wind or solar project hits commencement of construction or other contractual milestone

in the allotted time even if the other form of renewable resource has not yet been exploited under the agreement? Extra care would be required in crafting any footprint carve-back provision applicable to a wind project (where the agreement calls for the area for potential project facilities (as opposed to noninterference and exclusive wind rights, which would continue on the larger area) to be carved back from the larger premises to the actual facilities locations (plus buffer)) to preserve the possibility of future solar development outside of that footprint.

Another variable for developers with combined wind and solar site control agreements in states that impose statutory limits on the length of time before a particular project reaches commencement of construction or before development is commenced (like North Dakota and South Dakota for wind and Kansas for both wind and solar) is whether failing to meet the deadline terminates the agreement entirely (even for the other resource) or whether the site control agreement might continue for solar notwithstanding that the agreement would be terminated under the statute as it relates to wind development.

Unlike the conventional wind project, a typical utility-scale PV solar project is a very land-intensive operation that requires exclusive use of broad swaths of property. Other than roof-top PV projects on existing buildings or structures that do not interfere with the surface use of the land, a utility-scale PV project typically precludes other uses of the surface within the project footprint. Even if the solar project does not cover the entirety of a landowner's property, carving up a large piece into separate high-density solar areas can render the balance of the property unsuitable for continued economic use for farming or the like. Also, pricing and financial incentives differ between wind and solar projects. Accordingly, the site control agreement that contemplates or permits a possible combined wind and solar development presents a more complicated set of issues to everyone involved.

While wind and solar can co-exist and share the economies of scale and joint-use facilities discussed above, proximity of a high-density solar project to a wind project does raise other concerns. For the wind project, does the area set aside or used for solar development leave enough area in case future conditions require or support the addition or relocation of wind turbines from the original project sites? The solar project footprint could also occupy land that would otherwise be suitable for satisfying wind project mitigation measures that become necessary over time through adaptive management.

With any co-location of projects, care must be taken to ensure crane and other access routes, laydown areas, and the like (and potential alternates) are preserved for future use that will not unduly burden either of the co-located developments or operations. One might expect a significant buffer area between the solar development sites and the wind facilities, especially the towers. Where wind developers micro-site their turbine locations and are cognizant of and avoid turbine wake or wind shadow effects, solar developers are concerned with shadows that might be cast onto their solar arrays. Thus, even if permitted by project permits, the site agreement, and the wind developer (and its lender), no solar array likely would be located in the area swept by any wind turbine's shadow. Beyond the potential shading, in areas where icing occurs, solar developers would also be cautious of areas where ice might be thrown from turbine blades. Where solar development occurred before a co-located wind project, and generally

in connection with any ongoing operations, precautions to control dust and particulates caused by construction activities would also have to be addressed. This sensitivity of solar to airborne particulates also mitigates against any solar project being co-located with or near intensive farm, timber, aggregate, or other uses that can cause regular and continuous dust or particulate problems. Similar concerns for solar in proximity of tree farms or the like that periodically produce significant amounts of pollen or airborne seeds or with the potential for overspray of various chemicals or liquids.

VIII. Conclusion. Although critical to every Wind Energy Land Agreement, the matters discussed above are by no means the only issues the parties to the agreement must consider. For example, issues related to indemnities, ability to assign or sublease, financing provisions, crop damages, and methods of providing security for removal of the wind project equipment at the end of the term are additional key components of a Wind Energy Land Agreement that are frequently the subject of intense negotiation. Crafting a Wind Energy Land Agreement that provides a developer with the necessary flexibility and security to develop a wind energy project requires skill, experience, and creativity.

Chapter Two
THE LAW OF WIND
—Title Insurance and Survey Matters—
Eugene A. Frassetto, Sarah Johnson Phillips

Developing a wind energy project requires the developer to own or control the land on which the project is to be sited. Large wind projects are not generally developed by the actual owner of the underlying land. Accordingly, the most common means to establish the land rights for the project on a particular parcel or parcels of land are a lease or an easement (or a combination of the two). If title to the project lands fails during or after construction of the project (or after the wind developer becomes obligated to third parties with respect to project development or operation), losses and defense costs to the developer would be significant. Accordingly, in addition to all of the other investigations and due diligence efforts that go into evaluating a project site and project feasibility, developers typically conduct a thorough search and examination of title to the project lands and purchase a policy of title insurance representing the amount of its investment in the project real estate and improvements. A survey of the project lands showing easements and encumbrances, improvements, setbacks, and physical features important to the siting, construction, and operation of the project (and the proposed site plan for pending projects) is also a valuable and necessary tool in the title review. This approach applies as well to an acquisition of, investment in, or financing of an existing wind energy facility.

This chapter will briefly outline certain points a wind energy developer, purchaser, investor, or financing party should consider to minimize or to spread the risk of loss arising out of a failure of or defect in title to land, and to effectively manage the expense of doing so.

I. Selecting a Title Company.

A. Relevant Factors to Consider. There are many title companies doing business throughout the country. It is important to understand the role a particular company plays in the industry before deciding whether and how to do business with that company. Not all title companies or offices are equally experienced in or equipped to handle the large-scale, multi-parcel transactions that constitute the typical wind farm project. Also, not all states offer the same coverages. Commercial title insurance as we know it is not even offered in Iowa, which has a state-sponsored title program available. As a work-around for Iowa projects, developers often make arrangements with a title company outside of the state to provide coverage under a more typical American Land Title Association (“ALTA”) commercial policy. (ALTA policies are discussed briefly below.)

Working with a regional or national title services division of one of the major title companies with broad experience in wind development can provide access to a full range of resources and personnel that may not be as readily available if title arrangements are handled at the local or even state level for each project. Many of the large players in the title industry have addressed this niche by establishing national and/or regional title service offices in all regions of the country, some with internal working groups

specifically focused on wind development. Although wind development is local and the role of the local title office usually is an important one, title underwriter and agent resources are available nationwide. Selection of an experienced, flexible, and responsive title company and office can help the developer avoid some of the common pitfalls, delays, and frustrations attendant to its title due diligence efforts. The specialized experience and greater resources available to one of these focused national or regional units can help shape and expedite the title review and curative process by providing input and addressing curative details and solutions with a view to a final title insurance product that will satisfy the title insurance requirements for the planned transactions. Typically such offices are better acquainted with and able to accommodate the lengthy process and staying power required to assemble and analyze parcels and identify proper landowner signatories, integrate survey work, and deal with title curative issues, lenders, and other issues relating to title on the scale of a typical wind farm. That said, strong local connections are also important. Unless the national office sends its own personnel or contracts for the local title search, the local title company agent for the larger national company will do the title search legwork at the county level.

Title policies are issued by or on behalf of title insurance underwriters. The underwriter is usually a large corporation doing business in many states and perhaps even in a number of countries. The specific entity doing business and issuing the actual title policies in a particular state or country may not be the parent company, but an entity specific to and authorized to issue insurance in that jurisdiction.

Title policies for wind energy projects are often written in amounts reaching into the hundreds of millions of dollars. All title companies are not equal when it comes to financial strength or regulatory or internally imposed limits on coverage that they may offer or underwrite without bringing in other title companies to share the risk under a title policy. For those interested in the details, there are numerous sources of information relating to the financial status and standing of a title company, including annual reports (showing the company's shareholder surplus and claim reserves), ratings of the company by rating agencies, and the underwriter's own internal limitations. Such information, or the requirements of the developer's internal risk management team, lender(s), or investor(s), may also dictate which company(ies) may be engaged to underwrite the title risk (issue the proposed project title policy) and when reinsurance (requiring other insurers to participate in the policy risk) may be advisable or required.

Throughout the United States, underwriters issue title insurance policies either directly or through agents. Title agents are title companies authorized by title underwriters to issue their policies, although title agents do not provide the financial backing for the policies issued. Rather, local title agents search and examine the local land title records that are maintained in a public facility (usually located in the auditor's, clerk's, or recorder's office for the applicable county) or, where available, as collected in a title plant (a replica of the county records assembled and maintained by one or more local agents).

It is important to know whether you are dealing directly with an underwriter or with a local agent, because the availability, pricing, and timing for the services and products are driven by the resources available to that company. For example, wind energy projects or transactions involving wind energy

projects often span county and even state lines, and the ability of a local agent may be limited to providing a search and examination of only local records, whereas an underwriter may have the ability to engage multiple agents in two or more counties or in two or more states.

Moreover, local agents typically do not have the ability to issue title insurance policies without the authorization of an underwriter. It can make a difference depending on which underwriter or underwriters support a particular agent to anticipate what is or is not insurable based on that underwriter's issuing guidelines or requirements and/or reinsurance limits. Further, if using a local agent to close a project transaction, one should consider obtaining a closing protection letter from the issuing title insurer where such is allowed under state law. The purpose of a closing protection letter is to document the responsibility of the insuring title company regarding escrow closings conducted by its agents, which typically have substantially less financial strength than the underwriting insurer. The typical closing protection letter provides the developer assurances from the issuer against loss by reason of acts by the agent contrary to the written closing instructions for the transaction relating to the status of title, the obtaining and recording of documents, and the collection and payment of funds. Some states disallow use of a closing protection letter, and the enforceability of such a letter is not clearly established in other states. However, where a closing protection letter is not expressly prohibited, it is still better to obtain one than not if closing is not handled directly by the underwriting insurer.

B. Pricing and Response Time. The size, numbers of parcels and owners, and values of projects in the wind industry present significant challenges to the title insurance industry. There are usually numerous properties involved in a wind energy project such that it can take significant time to search title and property ownership over sometimes hundreds of parcels. In addition, property ownership is dynamic and changing over time and must be monitored. Not all title underwriters and their agents are alike in their ability to price their services and products, do the actual legwork to complete the title searches and periodic updates, and deliver in an efficient and timely manner. It is not uncommon for a rural county (where most significant wind developments occur) to have only one agent or only a few agents. This can present timing and logistical challenges considering the pace and technical demands of one or more large commercial wind project transactions in that county, in addition to the agent's other day-to-day work. This situation is aggravated in circumstances in which multiple large projects are overlapping or competing for the time and resources of the local title or escrow officer. In some cases, an underwriter may send its own people to examine the county records without going through the local agent to avoid delay related to overworked or uncooperative title examiners and bottlenecked title plants. Sometimes these delays are unavoidable, but, in any case, they can be real constraints on the timing of the review and managing of title issues, and often they are beyond the control of the issuing title company, developer, or anyone else.

Pricing of title services is not uniform across all providers and jurisdictions. To determine pricing, it is necessary to know whether the project is located in a state that uses promulgated, filed, or negotiable rate structures. These rate structures are controlled by state law, usually under the authority of that state's insurance commissioner. A state with promulgated rates will not permit an underwriter or its

agents to adjust rates unless formally approved by the state regulatory body. In a state with filed rates, the underwriter and its agents must set and follow regulated rates, but those rates can be subject to variation and interpretation. In a state without regulatory oversight or that allows more flexibility, the pricing is driven by the market. Being aware of the regulatory environment in each state and having good contacts with title companies are essential in navigating the issues encountered in insuring a wind energy project.

II. Negotiating Title Policy and Endorsement Premiums. As discussed previously, the title industry is not controlled by a single underwriter or group of agents. There are several large title underwriters and thousands of affiliated and independent agents. To ensure competitive pricing (in states where competitive pricing is available), developers may undertake a focused request for proposal (“RFP”) process to aid in evaluating and selecting written bids or proposals from available companies. Such a process is intended to give the developer more information to determine which company can provide the best price (when it is able to do so under the applicable state’s regulatory framework) and the most competitive and responsive service in a particular geographic area. Some title companies are more flexible and responsive in certain geographic areas and on certain underwriting issues than others. It is useful to consider a title company’s resources and pricing in the area where the project will be located. The title industry is extremely competitive, and thus it is important to establish a relationship with the title company that will provide the most cost- and time-effective service before any title work is ordered. That said, experienced developers typically have standing relationships with one or more national title companies, offices, and particular title underwriters with whom they regularly work. Reliability, responsiveness, experience, and creativity of the title company and underwriting staff are very important factors that also weigh in the balance in choosing a title company.

III. Reviewing the Preliminary Commitments and Reports.

A. Title Review. A typical wind energy project includes many parcels of land and often covers thousands of acres stretching over multiple counties or parishes. The title search and examination process produces many preliminary title “commitments” or preliminary title “reports.” Though sometimes used interchangeably in casual discussions, in most cases there are technical differences between a “title commitment” and a “title report.” A true commitment, like an insurance binder, once complete, provides the proposed insured with the contractual right to obtain the policy described in the commitment upon satisfaction of the commitment’s terms, conditions, and requirements. A true commitment is also enforceable in its own right respecting certain losses and costs incurred by the proposed insured, subject to the limits of liability and terms of the commitment. A title report, on the other hand, is typically just a report from the title company summarizing record title based on its review of the record documents with little or no insurance or risk-sharing component.

Basic title review requires one to obtain and review those documents referenced in the title commitments and reports. Frequently, a survey is required to locate the documentary exceptions and to show how they relate to the planned project infrastructure and site. Legibility of some documents can be challenging, and sometimes one must seek alternative sources of documents. Where only a

memorandum or short form of an agreement is recorded, one must obtain the full agreement that is memorialized in order to determine its impact on the property. An actual review of these documents is required to (1) determine the person or entity vested in title (in order to verify signatories to the wind lease or easement, or to create a curative document when needed), (2) determine whether the title is subject to liens or mortgages or other claims that may pose unacceptable risks to the wind project, and (3) discover and analyze defects or other encumbrances, such as easements for utilities, road rights-of-way, reservations of mineral or timber or other rights, covenants limiting the use of the land, or other interests held by persons or entities other than the landowner that are revealed in the commitment or report and that might interfere with or even prevent development, construction, and ongoing operation of the project as planned.

The developer should also obtain from the landowner and review copies of all known “off-record” (that is, unrecorded) leases, contracts, and other agreements relating to the subject property, including those for which a memorandum or short form is recorded. Off-record agreements are very common on wind sites, from farm leases to manure-spreading agreements, hunting leases or entry rights, conservation reserve program contracts, and a full range of various other rights and interests that the developer must review, evaluate, and determine whether and how to address going forward.

It is best to obtain and thoroughly analyze the title information early in the process to make more certain, to the extent one can in such situations, that all identified record and off-record interests affecting the site are discovered, disclosed, and analyzed. It is also important to get periodic title updates so that newly recorded matters affecting title can be identified, evaluated, and addressed in the due diligence process. Understanding the meaning and risks of the title information revealed by the commitments or reports and how it will impact a particular project can make the difference between successful execution of a plan and lingering problems or the inability to develop, construct, and operate the project as planned.

B. Determining Whether to Undertake Curative Measures. Once all of the information contained in the preliminary title commitments or reports and the available off-record agreements and survey information has been reviewed, one must distinguish those title issues that must be corrected or cured from those that may be permitted to remain on the title, *i.e.*, those that will not adversely impact the project or the ability to finance or sell the project. If a leasehold or an easement interest is obtained from someone claiming to own land, when in fact the title commitment or report indicates that all or part of the fee simple title is vested on the records in whole or in part in another person or persons, the title company will require correction of the title or execution of the lease or easement by all owners of record before a policy insuring the lease or easement can be issued without exception, for the interest of the other person(s).

One common example of where the vested fee owner and the proposed landlord are not the same person is where the landlord is a contract vendee purchasing the property under a land sale contract. In such a case, the contract seller would be the vested owner of record to the title to the underlying land. The developer should require the approval and written agreement of the vested fee owner/contract seller

to honor and be bound by the lease or easement at issue to ensure that the developer's land interest will survive any foreclosure or forfeiture of the contract by the purchaser. Most often mortgages (like the land sale contract situation described above) must be addressed in some manner that will permit the lender's interest to coexist with and not threaten the project. The same is true for farm leases and other prior rights that can coexist with the wind farm. Prior easements or rights-of-way and other encumbrances burdening the project site can also be problematic. Some must be terminated or modified to allow construction and/or operation of the proposed project; others may not create a risk to the project at all. Depending on the nature of the encumbrance and its relationship to the project operations or facilities, a title company may require curative documentation to insure over (or remove) or insure as subordinate even encumbrances that are placed of record *after* the project site control agreement is recorded. This suggests that periodic date downs of title work will help the developer, title company, and surveyor keep better track of and address matters relating to the project site that may need to be addressed in connection with the issuance of a title policy.

In order to better evaluate title and survey issues and needed curatives, it is important to know where the project facilities will be located in relation to other facilities and interests. These include access and crane roads; collector, transmission, and other lines; topographic features (what appears flat on the map may be a cliff or a ravine); meteorological tower, turbine, and operation and maintenance facilities; substation sites; etc., as well as where existing improvements, setbacks, easements, wetlands, and protected bird, wildlife, and plant habitat occur on the project site. All area features and rights that may limit or prohibit use or development should be identified and located in a manner that allows the persons reviewing the title and survey to evaluate the various existing conditions and encumbrances and the proposed project layout to determine what curative measures need be taken.

Another important factor to evaluate during the title due diligence process is whether the easements serving the project site are sufficient for project development and operation. The oversized and specialized vehicles and equipment required to deliver and construct the wind project facilities require specialized access roads, sometimes even requiring alterations to the public roads serving the project site. Development may not be possible if the access road serving the project area is a twisting, 15-foot-wide, private easement over adjacent lands owned by one or more third parties or the easement provides that it is limited to agricultural use or to certain times or seasons or other limited use. Unless the developer has alternative, viable access that meets project requirements the site would not be developable. Problems can relate to both the width of the easement (insufficient for the turning radii of large vehicles and cranes utilized during construction) and the scope of use (wind farm development, despite the "farm" label, is typically not considered an agricultural use). Likewise, an easement that is tied to (is appurtenant to) a particular parcel or parcels sought to be accessed and potentially developed cannot typically lawfully be used to access other parcels or areas, even if those other parcels or areas are adjacent to or accessible from the appurtenant (benefitted) parcels. Are there alternative access routes? Does the wind energy land agreement limit the developer's access only to certain established or designated routes? Or does it allow the developer more flexibility in accessing the project site and

facilities? Understanding how these interests affect and relate to the project is imperative to the successful development, construction, financing, and operation of a wind project.

IV. Survey Maps.

A. Uses. Surveys are a necessary part of the project site and title evaluation due diligence. The developer needs to know the property corners and boundaries, where existing residences and other improvements are located, and where encumbrances such as easements, setbacks, and other features are located. A developer must have accurate and complete information to site its wind facilities in a manner that can coexist with prior encumbrances or determine whether some curative measure needs to be taken. Topographic information usually is needed to determine areas that may have problem slopes or require special engineering solutions for project facilities. Lenders often have survey requirements, as do permitting authorities. Different types of surveys can provide a wide variation in usable information. An adequate survey will often reveal details that are crucial to efficient and secure project development and that are not otherwise obvious from a mere inspection of the surface of the land or review of related documentation. A well-done survey is a useful and necessary tool in reviewing the title and performing due diligence of the site for encroachment, boundary, setback, project facility locations, access, and other issues. Title companies will usually require a survey map (typically an ALTA survey, discussed briefly below) before agreeing to issue certain kinds of title coverage, such as extended coverage owner's and lender's policies and certain endorsements that relate to survey matters.

Before ordering a survey map, it is important to know the intended use for the final product. It is also important to know whether the title company requires a survey for the particular form of title insurance coverage(s) needed for the project and what type of survey is required. More often than not, a wind energy project developer (and in virtually all cases, a project lender) will require an extended coverage owner's policy of title insurance, which often dictates the need for a certain form of survey map, certified to the title company and to the wind developer.

B. Forms. Two common forms of survey maps produced by professional land surveyors are the ALTA/NSPS (American Land Title Association/National Society of Professional Surveyors) land survey and the boundary survey. An ALTA/NSPS survey is certified by the surveyor to meet certain minimum detail requirements established by ALTA in conjunction with NSPS. The ALTA/NSPS surveys are the gold standard for the respective industries and are the most useful in reviewing and evaluating the configuration and layout of a site, its physical features, the location of improvements and easements, and observable signs of third-party use and other matters, depending on the scope of work called for from the surveyor. The ALTA/NSPS survey standards and the optional "Table A" items were last revised in 2016. Surveyors frequently use a vernacular all their own, and understanding their forms and practices is essential to purchasing the right product and services for a particular project.

A boundary survey usually is much less expensive and much quicker to perform, but is much less reliable, especially for an area of land that has not been platted and probably has not been surveyed since the federal government established patents and granted lands during the 19th century. The 2016

ALTA/NSPS standards require the ALTA survey to meet local “boundary survey” requirements where local law imposes stricter requirements than the basic ALTA/NSPS standards do.

Generally, unless the site is relatively small and simple and there are no easements or encumbrances of record affecting a site (or those that exist are easily locatable by reference to the property boundary), a boundary survey will not give one enough information to do a thorough and prudent title review and analysis, especially someone who has not been onsite and walked the entire property with a trained eye for detail, encroachments, and signs of third-party use. Also, unless the survey of either type includes an overlay of the existing or proposed project site-plan details (*e.g.*, project improvements, utilities, setbacks, access and crane roads, turbine pad footprints, collection and transmission lines and fixtures, and other related improvements, substations/switchyards, operations and maintenance buildings, etc.), a reviewer may not be able to determine which existing easements or encumbrances (other than blanket encumbrances) or planned facility configurations or locations raise issues that may need to be addressed in the due diligence phase.

Is a survey needed? Must it be an ALTA/NSPS survey or a boundary survey? Does the developer have a detailed project site-plan overlay for the survey? What optional “Table A” items offered under the ALTA/NSPS standards are required? To whom must the survey be certified? What are the developer’s responsibilities vis-à-vis getting the surveyor the access and documentation it requires to perform the survey? How will survey timing fit with the developer’s overall project planning, title review contingency period, and overall due diligence period? These are relevant and recurring questions that must be carefully considered.

C. Pricing. Survey pricing is not standardized and will depend in part on the scope of work required and the timing of the survey and complexity of the site. Surveyors, like many other vendors, are often willing to negotiate. They may provide discounts or other incentives to commercial customers for volume business, or to compete aggressively against other local businesses. On the other hand, a relatively inexpensive proposal may be illusory. Will the surveyor be able to complete the survey project as planned, on time, and in a comprehensive, accurate manner, acceptable to the developer, title company, and other parties involved? As with title insurance, past experience with the surveyor and an understanding of the surveyor’s experience, reliability, thoroughness, and other intangibles is a factor that can weigh heavily in the choice of a project surveyor and can offset or outweigh any apparent bargain price proposal from an unknown or untested party. Although no negotiations or contract will guarantee that everything comes in on budget and on time, it is extremely important to have these negotiations early on in the process, and in a manner that will promote reliable work from the surveyor and still help in the effort to keep the project on budget and on time.

V. Drafting Title Requirements into Wind Energy Agreements.

A. Reviewing Proposed Terms. Title requirements contained in a wind energy land agreement or a wind energy facility purchase and sale agreement can appear to be boilerplate. On the other hand, an experienced wind developer is aware of the sorts of difficulties that can arise and knows

the importance of the terms and scope of agreements for title and survey services. There will be enough surprises even with proper planning and execution without adding to the mix by skipping, unnecessarily deferring, or ignoring important steps in project evaluation and development. Without proper planning, the developer may experience the unwelcome surprise of unanticipated title policy premiums or the unavailability of desired or required title coverages because they are unfamiliar with the pricing, underwriting requirements, or range of title insurance coverages or endorsements that may be available to address the particular issues raised by their project site conditions. Or the developer may experience the delays and frustrations and added cost relating to last-minute gathering and analyzing of the requisite information and documentation, cure, and allocation of risks associated with title defects, liens, encumbrances, or other matters that were unknown to the developer at the onset, or that the landowner was not required to provide pursuant to the site agreement. Having a well-written agreement does not guarantee that all of the terms and conditions called for in the agreement will be complied with as and when contemplated by the agreement. However, addressing the issues one can foresee early on helps later when one has to deal with the unanticipated or changing issues that almost certainly will arise during the review and due diligence process.

B. Negotiating Terms Effectively. As discussed above, the prudent developer will engage early and work with the title insurance underwriter to obtain advice and assurances concerning the title company's resources and willingness to make commitments. The guesswork can be eliminated or reduced significantly by procuring a title company's written confirmation as to what it will and will not do in a particular transaction. Where possible, these confirmations should be reflected in the title commitment, along with what it will take to satisfy any related conditions.

Who pays for the search and examination process? Who pays for the preliminary commitments? How much will the title company charge for its premium? Are there termination fees for any title report(s) or commitments if no policy is ultimately issued? Will endorsements be necessary? Will there be added or contingent charges?

Over the last decade, title companies have been taking new and harder looks at their underwriting criteria and risk appetite. Coverages and endorsements that may have been readily available and issued in the past may be less so or harder to get, even from companies with which one has had a continuing relationship. An example is the move by most major title companies to do away with creditors' rights coverage, whether by issuance of a CRED-DEL endorsement deleting the creditors' rights exclusion in the 1992 or 2006 or other policy form, using a 1970 policy jacket that did not include that exclusion or issuing affirmative coverage under an ALTA 21 or similar creditors' rights endorsement. Even a developer who has had a long-term and mutually productive relationship with an insurer or insurers may find it useful to look for opportunities to engage other insurers if the usual insurer(s) changes underwriting policies, shrinks available coverages, or raises premiums for the same coverage(s) that are available, or available on better terms, from another acceptable title insurer.

Relatively recent changes to the ALTA title policy endorsements include changes to the relatively new ALTA 36 series of endorsements regarding electric energy projects. Changes to the ALTA endorsement

forms have both expanded and contracted certain aspects of title coverage. The ALTA 36 series of endorsements provide electric energy project-specific coverages for both lease and/or easement interests. These endorsements have been expanded from their original “wind” project scope to include a range of electric energy projects and related definitions and coverages. The ALTA 36 base leasehold and easement endorsements are to be used for energy projects in place of the corresponding ALTA 13 leasehold endorsements, which do not include the energy-specific terms. The endorsements include an expanded title valuation section to make clear that the computation of loss or damage for a covered defect affecting one parcel (or fewer than all parcels) includes resulting loss or damage to the “integrated project.” Also, the basic ALTA title policy only insures against title risks for real property interests. Because typical wind facilities installed by a developer under a lease or easement are to be removed at or before the end of the lease/easement term (and thus could be determined to be personal property under applicable law, *see In re Oak Creek Energy Farms, Ltd.*, 956 F.2d 1167 (9th Cir. 1992)), a number of the new coverages include coverage relating to “Severable Improvements.” The carve backs to some other common endorsements include express exclusion of costs of remediation resulting from environmental damage or contamination, and loss of some of the coverage historically offered by a “comprehensive” endorsement to an owner’s policy.

VI. Curing Title Defects.

A. Document Preparation. The curative process requires the selection, preparation, and completion of appropriate documents to address the particular title matters requiring curative action discovered during title and survey due diligence. The developer’s due diligence and development team should have a protocol and develop an overall plan to address title due diligence matters. What is required, whether from a prudent developer standard, by lenders or investors, project permits, or applicable law? What is desired but perhaps not absolutely required for the development of the project? Does the developer have viable work-arounds that it can implement if necessary or if desired curatives are not available? The process of identifying, determining the proper curative approach, and seeking and obtaining title curatives that satisfy the developer, title company, lender(s), and other interested parties can be very time-consuming. Because the lead time on project due diligence and development often spans years, the developer must also keep up to date on changing ownerships, encumbrances, and conditions throughout that period, which can add parties and complexity to the due diligence and title curative process.

For mortgages and prior leases, it is necessary to evaluate whether a subordination agreement is required, or if a nondisturbance and attornment agreement will suffice, and whether the prior lender or lessee will agree to provide such comfort to the wind developer. A common issue for farm lessees that are asked to subordinate or agree to honor a subsequent wind lease or easement is the extent to which the wind lease or easement will interfere with the farmer’s operations or damage the farmer’s crops or other facilities. These are matters that must be worked out on a case-by-case basis, depending on the nature of the underlying agreements affecting title to the project lands and the scope of project activities that affect the leased areas. The developer will want to ensure that the curative arrangements made

with a tenant farmer, for instance, are consistent with the developer's obligations to the landowner under its site control agreement. If possible, the developer will want to avoid having to double pay for the same damage or crop loss—once under the site control document to the landowner and again under a related subordination or nondisturbance agreement to the tenant farmer. For existing easements encumbering the project lands, the developer should evaluate whether a consent and crossing agreement is necessary, or if a modification of an existing easement, such as confining an otherwise blanket easement to a specific, limited location, will suffice (and be available). Sometimes a curative document may not be needed at all, depending on the intended locations of the wind project facilities and whether or not they “intersect” with existing easements. Although some developers rely on prepared or “pre-printed” forms, customized agreements are often necessary to address a particular situation.

B. Negotiations with Third Parties. A utility, a lender, another landowner, or some other person or business holding an interest in the title to the property intended for use as part of the wind project may not be interested in helping to solve the wind developer's title issues. How do you get their attention? How can solutions be proposed in a nonthreatening manner? Successful projects result from the ability to negotiate with people in an effective manner. Generally, a title underwriter likely will not provide title coverage over a particular title exception or encumbrance while apparent problems with that item remain outstanding. Frequently, problems can be solved with help from a knowledgeable title underwriting counsel. It is important for the developer to understand the issues raised by third-party rights and how best to navigate them.

VII. Weathering the Title Insurance Underwriting Process. Often the person from whom the developer orders title work is a customer service or account manager, rather than the title underwriter. The title underwriter is the person with authority at the title company who assesses title risk, decides whether and under what circumstances to accept or insure over a title defect, issues an endorsement, approves a policy provision, or provides other insight or information in insuring title to a wind project. The route to a final policy is often drawn out and involved, and the motivation, ability, and authority of the title underwriter can vary greatly on any given transaction and from underwriter to underwriter. The developer should have a sense for (1) which title services and products are available and which to order, (2) how to evaluate critically the preliminary commitment or report and the exceptions and requirements it contains, (3) whether, when, and how to request revisions or amendments to the commitments or reports, (4) what endorsements are available and their cost, and (5) what underwriting criteria will be applied to each. These criteria can and do vary from site to site and from state to state and even from title company to title company.

If the developer's land rights are in the form of options to lease or the developer is acquiring the optionee's position in a project, one important factor in the availability and timing of obtaining title insurance is whether lease options are insurable under a title policy in the project state. In some jurisdictions, a stand-alone option to lease must be exercised and the lease must be in effect before title insurance coverage is available. A developer may require, as a condition of closing the acquisition of

project site control agreements that include options, that the options be exercised and the leases in place such that title insurance can be issued on the project site interests at the closing of the acquisition.

The better the development team understands and deals with these issues, the more assurance they have of a successful wind project and the prudent protection that such a policy can provide. The consequences of not understanding and effectively dealing with the title underwriting process can be devastating to the project. The problems that a developer may face in dealing with title and survey issues are exacerbated if the process of completing detailed title and survey review and analysis is delayed. The later one discovers a potential problem the less time there is to review, analyze, and pursue the most prudent, cost-effective, and efficient curative options in the ordinary course.

For certain title issues, an indemnity or affidavit from one or more third parties might be sufficient, at least for title insurance underwriting purposes, to remove an exception from the policy or to allow the title company to insure the offending exception as subordinated to the developer's (or lender's) insured interest. If so, is an indemnity or affidavit advisable or even available? Even if the indemnity or affidavit satisfies the title company, does it actually cure the underlying issue that it seeks to address? Having an exception or defect removed from or insured over on a title policy does not ensure that the underlying problem is resolved or even affected by the proffered instrument, only that the insured policyholder has a potential claim against the title insurer if there is a loss that has been insured against under the policy, and then only up to the policy limits. Who must give the indemnity or affidavit? Are they willing (or can they be convinced) to do so? Is an endorsement available to cover the issue, and will an endorsement be acceptable? Must a more direct curative measure be undertaken that actually fixes the underlying problem (such as a quitclaim from a neighbor whose fence line encroaches onto the project site leased from the adjacent landowner, which would eliminate any adverse possession right that may have accrued)? What are the options and how will each play out in a particular scenario? If the developer accepts a risk on title, how will that fare if and when the developer seeks third-party financing or investment or goes to sell the project?

VIII. Financing: Anticipating Lender Requirements. Institutional lenders, Wall Street investors, and private financing parties may each have different requirements for title insurance, survey maps, and other title matters. With the range of services, insurance products, and qualified title companies, the developer or borrower is not without options concerning these matters. Which title company to select; the terms for the search and examination, and, in some states, the premium; and the underwriting process are subject to considerable negotiation and variation. It is extremely helpful to have useful input or recent experience on lender or investor title requirements for the particular lender or investor, especially in the particular jurisdiction, and to be able to employ the title review and curative process in closing a financing transaction. Letting the lender or investor control the process, on the other hand, though sometimes unavoidable, can be more expensive and perhaps more difficult for the wind project owner or purchaser as the project owner or purchaser will pay for its lender's (and maybe the investor's) due diligence efforts as well as their own.

IX. The Acquisition Closing Process. Many questions arise during the closing process. The range of questions varies greatly from project to project and with the experience, policies, and sophistication of the parties. Some projects do not require an escrow closing, other projects need only a modified closing process, and some projects or parties require a table (in-person) closing. Which is which, and when is one more appropriate than the other? The costs associated with a table closing can be significant, though they are most often seen in connection with corporate-/entity-level transactions and on real property transactions on the East Coast and other areas where “escrow” closings are not as common.

It is important for the parties to monitor and confirm that the process is on track to close as contemplated before the closing is scheduled. Is there enough lead time for the finalization, circulation, execution, and return of closing documents? Will the parties have adequate access to deliveries, emails, faxes, notary services, etc. to be responsive to the time pressures of a closing? If a party’s signatories are out of state or out of the country and that party is required to provide notarized originals of any documents required to complete the closing, is the form of notarization or authentication acceptable in the state where the closing is taking place and to the title company? Have all special, state- or county-specific recording requirements been addressed in the closing documents? Is distribution to remote county recorders or other filing offices required and accounted for? Which closing documents may be signed and submitted by fax or electronically, and which require originals in hand in escrow in order to close? How many original counterparts of each are required? Does the transaction involve any local, state, or federal filing, recording, or reporting requirements?

Again, there are usually last-minute items or changes that require prompt attention and action in connection with every closing, so it is best to be organized and deal with the known factors early on to give one room and time to focus on those last-minute items that may not be as foreseeable or avoidable. Because these transactions can be very fluid, important decisions may have to be made and last-minute arrangements documented at the closing table or time of closing. Understanding the closing process, the title process, and how they interact can be invaluable. Many decisions require the developer, owner, or borrower to accept risks, take action, pay money, or make concessions. Knowing which risks can be avoided, what actions are appropriate, how to properly document any agreed-upon arrangements, and how to most efficiently deal with the details of a closing are essential tools.

X. Maintaining Title Insurance Coverages over Time.

A. Corporate Reorganizations and Transfers of Interest. A title insurance policy provides indemnification for the insured developer in the event of a covered loss to the insured real property interest only so long as the insured interest remains in the hands of the insured developer, subject to carry-over “warranty” coverage that can cover developer liability to a third-party grantee for title defects that were insured against under the developer’s policy and that are implicated in a later warranty conveyance by the developer. When a corporate reorganization occurs, *e.g.*, into a limited liability company or partnership, interests are adjusted or transferred, property is deeded or conveyed, or other interests are created, assigned, or released, the developer’s affirmative coverage under a very

expensive title policy can be lost entirely, depending on the type of policy and nature of the change to the insured entity.

In certain circumstances, an insured developer can purchase endorsements to a pre-2006 ALTA policy that will allow the policy coverage to run to a successor, including one of the so-called “Fairway” endorsements (where available) to continue coverage in a successor after any change in partners in a partnership or members in a limited liability company, and the “substitute insured” endorsement that covers, among other circumstances, transfers by deed, without monetary consideration, to an entity wholly owned by the named insured(s). The ALTA 2006 owner’s policy has a revised definition of the “insured” that would automatically continue (but not expand or change the effective date of) the policy coverage to the benefit of certain successors to the insured, similar to the substitute insured endorsement and the “Fairway” endorsement.

In many cases, it is possible to avoid loss of coverage that might otherwise be triggered in connection with certain corporate and entity changes or reorganizations by knowing when and how to work with a title insurer and its policy to purchase endorsements that will prevent termination and expressly continue coverage to the successor entity. Coverage may be extended or amended or other action may be taken with appropriate coordination with the insurer to avoid the unintended consequences of what otherwise should have been a simple corporate reorganization or restructuring of assets. Before any changes are made, however, one should review the actual policies; evaluate existing coverages and available, supplemental products; and determine whether simple and inexpensive options are available. The consequences of not doing so may be loss of the developer’s affirmative title coverage and the unintended risk of not having title coverage, or the cost of purchasing a new title policy at significantly greater expense.

B. Sufficient Liability Limits. When a wind energy project is developed, the interest in the project’s site control land, lease, or easement interests themselves may have a market value significantly lower than the all-in value of the finished project. Further, over time, the value of this interest may increase, though not all value, assets, or risks would be insurable under a title insurance policy, even a newer energy project-specific policy. Typically, the amount of title insurance needed is based on the cost to acquire the land and develop the project—the sum of all “hard” and “soft” costs. But will that amount be sufficient in five years? In 10 or more years? The value of the project may not be static. As noted above, many of the most valuable facilities under a wind easement or lease may be deemed personal property and not even insured under a basic title policy, regardless of the stated coverage amount. If the dollar value of the insurable assets increases, it may be advisable to increase the amount of title coverage, realizing that the date of the policy will remain the same and the policy has an exclusion for matters created, agreed to, or suffered by the insured, as mentioned below, so no interim title defects will be covered, only those that existed on the original effective date and would otherwise be covered by the policy. Sometimes upgrading the project title coverage can be accomplished by purchasing endorsements to an existing policy. Other times a new title policy may be necessary.

ALTA owner/lessee title policies that predated the 2006 ALTA policy form each contained a coinsurance clause (Section 7(b) Conditions and Stipulations) that reduced insurance coverage pro rata on any partial loss if the original policy underinsured (*i.e.*, insured at less than 80 percent of the total value of the insured estate on the policy date) or if the insured premises were improved to more than 120 percent of the insured value after the policy date. These coinsurance provisions were not carried over into the 2006 ALTA policy form that is now the standard in most states. However, the coinsurance provisions still apply for policies issued under the old forms that contained the coinsurance language.

The point to keep in mind is that the title insurance covering the owner's interest in the project real estate and related insurable interests should be evaluated regularly, and the risks associated with a partial or complete failure of title should not be ignored. Any insured, secured financing or refinancing of a project is an opportune time for a developer to consider purchasing a new title policy. At loan closing, the developer would purchase its own "upgraded" policy at full price, but be entitled to a much lower, often nominal, premium for a simultaneously issued lender's policy for its lender, plus the cost of endorsements its lender requires. The developer's new owner's/lessee's policy could take into account any appreciation in value of the insured project estate. While the new title policy would most likely not cover title exceptions or defects agreed to, caused by, or accepted by the insured developer, regardless of when they occurred, due to an exclusion from coverage on all policies, the new policy could provide for expanded coverage in other areas and take advantage of the improvements in the 2006 ALTA form (where available) over that of prior policy forms.

C. Subsequent Financings or Equity Participations. When a lender loans money to a project developer or purchaser secured by a mortgage or deed of trust lien in a wind energy project's real estate interests, the lender customarily requires a mortgagee's policy of title insurance to insure the priority and validity of its mortgage or trust deed lien on the developer's/project owner's interest in the project (leaseholds, easements, and facilities). The wind energy project owner/purchaser and borrower typically pay the premium for their lender's policy, though who pays the premium for the buyer's title policy in a project sale transaction is a matter for agreement by the parties and is sometimes influenced by local custom or practice. The liability insurance coverage for the lender's title policy is the amount of the loan secured by the asset. It is important to understand that the lender's title policy insures only the lender and its successors and assigns with respect to the insured loan, not the developer/borrower. The title coverage purchased for the lender will not provide any coverage to the developer/borrower in the event of a failure of or other defect in title. In fact, under typical loan documents and title documents and indemnifications and assurances required by the title company and lender from the developer/borrower in connection with the loan and issuance of the lender's title policy, the developer/borrower may be liable to the lender and/or title company for title defects, either directly or through subrogation. This is true no matter how many times the project is financed, though the liability to the title company may be extinguished by the developer/borrower's own policy. It is important for the developer to maintain its own adequate title coverage independent of the lender's coverage. Further, it is valuable to remember that when a lender's policy is required, the developer/borrower may upgrade its existing coverage simultaneously with the issuance of the new lender's policy at significantly

reduced marginal premiums for the entire package, as described above. It is much less expensive to insure the title twice at the same time (lender policy and developer policy) than it is to insure it once for the lender and then again later for the developer, or vice versa.

One often sees developers insure title to the bare, undeveloped leased project lands at a lower, bare-land rate before development. Developers sometimes also just hold the commitments/reports open and do not obtain title insurance at all until development is ready to go, or even after actual development is occurring or finished if the developer funds construction out of its own pocket. The latter practice is much riskier for the developer because the developer will spend a lot of money investigating, planning, and permitting its project and ordering the various components and commencing or even completing work for the development, and will not have title coverage until the developer purchases the policy (subject to any binding commitment rights it may have). The developer initially insuring at the bare-land valuation would typically order the full-blown “built-out value” policy coverage during the first round of financing (which is often when the real development work begins, but may be after project completion), when it can piggyback the coverages and save premium dollars.

XI. Conclusion. Much attention in energy transactions is paid to negotiating the power purchase or off-take agreement(s), interconnection agreements, and the like, for obvious reasons. For developers and project owners that are not themselves end-users of the electricity generated by the project, apart from tax or other incentives that may be available, this is how they will recover their investment in the project and seek to achieve economic success. However, production of the electricity requires the development and operation of the project facilities on the project lands. Effectively evaluating and ensuring secure real property interests and rights early on will provide more assurance of a successful project. The more experience the wind developer gains over time in dealing with title and survey issues, the more readily apparent it is that title to the project lands really does matter and can affect the bottom line enormously, and that even a single title issue can render a project “fatally flawed” if it affects a crucial element of the project and no economic work-around is available. These matters can be made easier to understand and address with the guidance of an experienced professional who is knowledgeable in the title and survey industries and the help of a veteran wind project development team.

Chapter Three
THE LAW OF WIND
—Siting and Permitting Wind Projects—
Barbara D. Craig,
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Although wind energy projects are commonly praised for producing green power, they rarely receive preferential permitting treatment. Wind energy projects raise local land use, environmental, and community concerns similar to those raised by other commercial and industrial projects. Concerted opposition to large projects by local and nationwide wind opponent groups can cause schedule delays and pro forma impacts so significant as to halt project development. This has sensitized potential project purchasers and financiers, who scrutinize permitting and environmental issues very closely.

In this climate, project developers can achieve a significant competitive advantage by doing permitting right: imposing a disciplined focus on site assessment and fatal flaw analysis, “permitability”-oriented project design, and strategic consultation with interested agencies, communities, interest groups, and other identified stakeholders.

I. The Permit Process. Wind energy facility siting processes are highly localized. There is enormous variation from state to state and even from location to location. Factors such as the need for transmission lines or access roads, facility size, facility and equipment location, land ownership, and federal involvement may determine the number of agencies and the level of government involvement for a particular project.

A. Federal Siting. Wind projects proposed on federally managed land must secure land rights (typically called “rights-of-way”) and undergo the associated environmental review under the National Environmental Policy Act (“NEPA”) and related statutes. This is particularly relevant in those western states such as Utah and Nevada where much of the land, including much of the prime wind area, is located on federal lands. A deeper discussion of challenges and opportunities related to this subject is found in Chapter 5.

B. State Siting. A few states, including Oregon and Minnesota, have state siting councils or boards that have “one-stop” mandatory siting jurisdiction over permits for wind energy facilities exceeding certain sizes. California has a state siting body that has no jurisdiction over wind energy facilities. Washington has a siting council that may take jurisdiction over issuing permits for wind energy facilities of any size, but only if requested by the applicant. The Washington State Supreme Court addressed the state’s authority to approve projects in *Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council*, 197 P.3d 1153 (Wash. 2008) (en banc) (“Kittitas”). In *Kittitas*, a developer sought to have the Washington Energy Facility Site Evaluation Council (“EFSEC”) exercise its discretion, preempt local regulations, and approve a project after the developer was unable to successfully obtain a land use consistency determination from the local jurisdiction in which the

developer had proposed the project. Following an affirmative decision by EFSEC to preempt and Governor Chris Gregoire's approval of a site certificate for the facility, several residents and the Kittitas County Commission appealed, arguing that EFSEC could not preempt the County's authority under the Growth Management Act. The Washington Supreme Court rejected their arguments and upheld EFSEC's ability to offer "one-stop" licensing for large wind energy projects. Many of the principles articulated in the *Kittitas* decision will be helpful to wind developers fighting similar battles in other states.

C. Local Siting. In states where projects do not trigger state siting jurisdiction, and in states with no state siting process, wind energy projects are permitted by the local jurisdiction. For typical rural wind energy projects, this is almost always a county (as opposed to a city governing body). Windy states with no state siting process include California, Montana, New Mexico, Colorado, Idaho, Iowa, Nevada, Texas, and Utah. In Oregon, for projects that do not meet the mandatory minimum threshold for state jurisdiction (104 MW), state law requires that all energy facilities proposed in agricultural areas must be allowed, subject to a conditional use permit, with criteria defined by state law.

D. Comparative Advantages. On average, siting wind energy facilities through a state siting process takes longer than doing so through a local process, as more documentation is typically required at the state level. In Oregon, for instance, the issuance of a site certificate for a wind project may take from 12 to 18 months or more if there is heavy opposition. However, Oregon allows for an expedited (nine- to 12-month) review process for wind energy projects that will have up to 300 MW of nameplate capacity, although in practice, the expedited process has not resulted in much time savings. In comparison, siting at the local level can be completed in as little as three to six months if no significant environmental reviews are required and if there is little opposition to siting the project.

Despite the longer period required for state siting, it offers several advantages over local siting. Generally, these advantages are important for difficult or highly contentious projects and are less important for straightforward, locally supported projects. First, state agency or board review and approval tend to be based on more objective and carefully prescribed criteria adopted through public rule-making processes, resulting in decisions that are subject to less potential political or other subjective bias. Second, the process for appealing site approvals is often expedited and streamlined under state permitting.

There is a commonly held view that it is easier to permit wind energy projects at the local level, but this may not be true for all projects. When the option exists, a decision to pursue a particular permitting route should be made carefully and on a case-by-case basis, with careful consideration of potential project opposition risks.

State siting typically requires a higher level of involvement from other state departments such as fish and wildlife, environmental quality, water resources, parks, and cultural resources agencies. State siting is usually far more costly to the applicant due to significantly more complex regulations, required studies, agency review costs passed on to the applicant, and added processing and review time. However, done well, state permitting typically is a "one-stop shop" approach, where permitting through

multiple agencies is consolidated into a single master permit approval document. In local permitting, such agencies may not even be notified, and, if they are, their recommendations may be afforded a different level of significance than may be attached by a state reviewing body.

II. Local Permitting. For local siting applications, an applicant works with local planning commissions, zoning boards, and county boards and staff. The county governing body, *e.g.*, a board of commissioners or board of adjustment, typically approves and issues a permit for siting and development. In most counties throughout the United States, a wind power project is conditionally allowed in rural land use zones. Rather than being expressly allowed or prohibited, wind energy facilities are typically subject to a discretionary review by the appropriate local authority and issuance of a conditional use permit that contains the conditions attached to the approval.

To secure a conditional use permit, an applicant must show that the project will be compatible with adjacent land uses (typically farming or ranching). Many counties have developed utility or wind overlay zones (or use-specific code provisions) that further dictate where and how wind energy projects can be sited. Additionally, conditional use ordinances often require review by and consultation with state or federal agencies in the permitting process. For instance, if the project could negatively impact wildlife species listed by state or federal agencies as threatened or endangered, the appropriate state and/or federal agencies will have to be consulted. State and federal wildlife agency review may also occur as a matter of course through the environmental review process.

In addition to the actual development permit, some states require that the local permitting body conduct comprehensive environmental review based on state statutes modeled after NEPA. Washington and California require this review, Washington under its State Environmental Policy Act (“SEPA”), and California under its California Environmental Quality Act (“CEQA”). Though SEPA and CEQA are procedural evaluative tools and do not mandate specified results, the net effect of such statutes is to increase process time and cost, and the probable imposition of additional mitigation requirements. Oregon, Nevada, Wyoming, Utah, New Mexico, and Idaho do not have comprehensive environmental review statutes.

III. Federal Environmental Review. Wind energy projects that require a federal agency to take action or make a decision “enabling” the project trigger NEPA review. NEPA is a procedural statute that requires federal agencies to consider the environmental impacts of a proposed decision before making the decision. In the context of wind energy projects, NEPA can be triggered by the need to acquire a right-of-way or special use permit from the Bureau of Land Management (“BLM”), the U.S. Forest Service (“Forest Service”), or another land-managing federal agency; the need to interconnect with a Bonneville Power Administration (“BPA”) or Western Area Power Administration (“WAPA”) main transmission line or substation; entering into a power purchase agreement with BPA or WAPA; and the need to secure a Clean Water Act section 404 removal/fill permit from the U.S. Army Corps of Engineers.

Early consideration should also be given to the question of NEPA applicability to various federal loan and grant programs. While federal financing typically involves a discretionary action that triggers NEPA,

there is a specific carve-out of its application to the Section 1603 Energy Property Grant program created under the 2009 American Recovery and Reinvestment Act. Depending on the level of environmental review required, the process can take one month (for decisions that have been categorically excluded from individual NEPA review), two to six months (for an environmental assessment to be prepared that concludes that the federal action will not significantly impact the environment), or more than a year (for an environmental impact statement (“EIS”) that analyzes in much more detail the impacts of a project in an area that is considered to be environmentally sensitive). When a state-level environmental review is already under way for a wind energy project, the federal agency may piggyback on the state process and incorporate the environmental documentation from the state process into the federal NEPA review. In appropriate situations, the federal agency may also “tier” a decision to a prior NEPA review and thereby reduce the amount of time and material that must be prepared for the new decision. An example of this would be BPA’s relying on a prior “programmatic” EIS that evaluated future energy development in the Northwest in order to support a decision as to whether to allow an interconnection to a BPA transmission line as part of a specific wind project.

In 2005, the BLM published its Final Programmatic Environmental Impact Statement on Wind Energy Development on BLM-Administered Lands in the Western United States (“Wind PEIS”), which focuses on public land administered by the BLM in 11 western states, excluding Alaska. Upon releasing the final document, the BLM announced that “this EIS proposes a consistent, agency-wide approach to wind energy permitting that will support and expedite site-specific analysis of individual wind projects.” In plain English, this means that the BLM has laid the environmental groundwork to speed up the permitting of wind energy in the 11 western public-land states. As of July 2016, the BLM had authorized 40 wind energy development projects, with applications for another 20 projects pending.

In addition to the Wind PEIS, the BLM also announced a wind energy development policy in December 2008, which provided further guidance on processing right-of-way applications for wind projects on public lands.¹ Further, on December 19, 2016, BLM published a final rule revamping its leasing regulations to include competitive processes, incentives for development in “designated leasing areas” (identified in the rule and relevant resource management plans), and new payment and bonding requirements for wind energy development rights-of-way. 81 Fed. Reg. 92,122 (Dec. 19, 2016). Much of what was included in the formal rulemaking derived from existing policies, described above, that the agency had issued in prior years. The rule went into effect on January 18, 2017.

The Forest Service has not prepared a programmatic EIS for wind energy development but has generally followed the BLM’s lead. In 2011, the Forest Service issued internal guidance related to the issuance of permits for wind energy uses on National Forest System lands, including “direction on authority, objectives, responsibility, definitions, and references for use in authorizing wind energy uses on National Forest System lands.” Forest Service Handbook 2709.11, Chapter 70. This guidance provides direction on siting turbines and other facility components, evaluating protected resources, and

¹ See U.S. Dep’t of the Interior, Bureau of Land Mgmt., Instruction Memo. No. 2009-043, Wind Energy Development Policy (Dec. 22, 2008).

addressing issues unique to wind energy in the special use permitting process. Thus, although the Forest Service lacks a national special-use wind-siting program and still makes its decisions about wind energy development on a case-by-case basis at the individual National Forest level, developers should carefully review the Forest Service's guidance.

A. Key Substantive Issues. Substantive issues are important to developers for two reasons: cost and risk. Accordingly, fatal-flaw analysis of the following “big-ticket” items should be part of any project planning.

B. Avian Impacts. Impacts on avian species has been a high-profile issue in the siting of wind energy projects for two reasons. The first reason is the number of birds killed, particularly at Altamont Pass in California, where turbine technology consisted of fast-moving blades and lattice towers that offered perching opportunities. Also, mortality rates have been affected historically by a lack of knowledge about avian flyways and migration patterns. Failure to adequately account for these factors in siting decisions contributed to unexpected avian mortality rates. Today, avian mortality rates are dramatically lower due to advances in turbine technology and tower construction, and better siting decisions. Nonetheless, avian impact concerns remain an important issue for wind project permitting, particularly in regard to bat species, whose behavioral patterns have historically been less studied and understood by biologists because of their nocturnal nature.

Second, avian impacts are an important issue because almost all avian species and some bat species are protected by one or more of the following federal laws: Endangered Species Act (“ESA”), Migratory Bird Treaty Act (“MBTA”), and Bald and Golden Eagle Protection Act (“Eagle Act”). Although these laws differ in scope and approach, all generally prohibit some form of “take” (*i.e.*, injury or killing) of protected species. The application of these laws to wind energy projects is challenging. The ESA provides two mechanisms for obtaining permits for incidental take of protected species, including a formal Section 7 consultation under the ESA, or a Section 10 “incidental take permit” (“ITP”) that authorizes the take of a species that is “incidental to, and not the purpose of, carrying out an otherwise lawful activity.” A project need not have a federal nexus to receive Section 10 take authorization. However, an ITP must be accompanied by a Habitat Conservation Plan that receives U.S. Fish & Wildlife Service (“FWS” or the “Service”) approval. The time required for either of these processes is often incompatible with project timelines.

The MBTA does not have a mechanism for permitting incidental take associated with a wind project; however, since 2009, Eagle Act regulations have provided for both standard Eagle Take Permits, which authorize individual instances of “take,” and programmatic Eagle Take Permits, which authorize recurring “take” that is unavoidable even after conservation measures are implemented. In December 2013, the FWS published in the Federal Register a final rule to extend the maximum term for programmatic permits to 30 years, subject to a recurring five-year review process through the permit life. In addition, in 2013, the FWS issued its final Eagle Conservation Plan Guidance (“ECPG”). Designed to promote compliance with the Eagle Act and the MBTA, the ECPG specifies in-depth guidance for

conserving bald and golden eagles in the course of siting, constructing, and operating wind energy facilities.

In 2014, the American Bird Conservancy filed a lawsuit challenging the Service's 2013 revisions to its eagle permit rule under NEPA. The court set aside the 30-year rule, concluding that the Service violated NEPA by relying upon a categorical exclusion. On December 16, 2016, the Service issued a revised rule that includes changes to the regulations and issued a final Programmatic Environmental Impact Statement ("PEIS"). The revisions to the 2016 eagle rule went into effect on January 17, 2017, and include changes to permit issuance criteria, duration (including a maximum permit term of 30 years), compensatory mitigation standards, and permit application requirements (81 Fed. Reg. 91,494 (Dec. 16, 2016)). The new rule eliminated the individual and programmatic permit distinctions and now refers to the permits as ITPs. The Service now has the ability to issue ITPs under the Eagle Act for terms of up to 30 years.

Prior to the FWS's release of the ECPG in April 2013, the industry norm was to proceed with development without seeking an Eagle Take Permit. Given the then-evolving regulatory landscape, wind developers were opting to prepare Avian Protection Plans or Bird and Bat Conservation Strategies ("BBCS") documenting coordination with the Service and the implementation of agreed-upon conservation measures pending the release of a 30-year programmatic permit. At the time, this procedure operated effectively to reduce the developers' exposure: provided the individual developer was taking the agreed-upon measures to protect the species, the Service would typically investigate any "take" that occurred and then decline to take further action based on a conclusion that the developer was a "good actor" and was pursuing a responsible approach toward Eagle Act compliance. Since the ECPG was issued, however, there has been greater scrutiny on Eagle Act compliance issues. Now that a 30-year ITP is available, the FWS routinely recommends that wind developers apply for an ITP even for low risk sites. Given this "new normal," we believe that the risk of enforcement or prosecution for unauthorized "take" of eagles is now greater than it was prior to the release of the ECPG. Perhaps the strongest evidence of this trend is the past settlement agreement between Duke Energy Renewables and the U.S. Department of Justice regarding 14 golden eagle fatalities at Duke Energy Renewables' Top of the World Windpower Project and Campbell Hill Windpower Project in Wyoming. Although the settlement resolved charges brought under the MBTA, the agreement required Duke Energy Renewables to develop Eagle Conservation Plans and apply for and "diligently pursue" Eagle Take Permits for both wind projects. Although the Service continues to actively promote compliance with its eagle permitting program, the assertive criminal enforcement approach seems to have become tempered somewhat by the Chief's Directive on civil settlement agreements on "legacy takes." Since the issuance of the Chief's Directive, the Service seems to be focused on actively resolving "legacy takes" through civil settlement agreements and encouraging project operators and developers to pursue an ITP. Although the opportunity to resolve "legacy takes" through civil settlement is a welcome shift from criminal enforcement, the cost of resolving alleged violations—even through civil settlement—remains significant.

Even with the focus on civil settlements, there continues to be a heightened awareness of the risk of proceeding without “take” coverage under the ESA and/or the Eagle Act, even where risk to protected species is relatively low. As such, project operators and developers should assess their projects and craft appropriate strategies to comply with the avian statutes, including development of an eagle conservation plan to support the issuance of an ITP. Because the issuance of an ITP is a federal action that requires compliance with NEPA, including the preparation of an environmental assessment or EIS, project schedules must account for the NEPA timeline.

Importantly, although there is no legal requirement that project developers or operators apply to obtain an ITP under the Eagle Act, failing to secure “take” coverage under the Eagle Act may invite enforcement or prosecution under the MBTA. Because an applicant must demonstrate compliance with other federal wildlife statutes as part of the NEPA process and there is no available ITP under the MBTA, seeking “take” coverage under the Eagle Act is one of the more effective MBTA compliance strategies, particularly when the ITP incorporates a robust BBCS. Additionally, an ITP for bald or golden eagles issued by the Service under the Eagle Act and the 2016 eagle rule serves as authorization for bald and golden eagles under the MBTA. 50 C.F.R. § 22.11.

The importance of adequately assessing permitting strategy for protecting species at a proposed site is emphasized by the Indiana bat case. In *Animal Welfare Institute v. Beech Ridge Energy LLC*, 675 F. Supp. 2d 540 (D. Md. 2009), no federal permits were required nor was there a federal nexus for the siting and development of the wind project. The developer’s pre-project studies demonstrated that no Indiana bats occupied the areas in or near the project’s location. Thus, no ITP was obtained. Suit was filed seeking an injunction to halt construction on the basis that the project would unlawfully “take” the protected species in violation of the ESA. The trial judge found that (1) hibernacula (caves used for hibernating) were located near (six to 10 miles) the project site; (2) the physical characteristics of the project site made the presence of Indiana bats more likely; and (3) acoustic evidence at the project site suggested that the bats were present. Based on such findings, the court concluded that an ITP was, in fact, required under the ESA and in the absence thereof, issued an injunction halting construction.

C. Other Wildlife. Wind energy projects can also disturb other wildlife and plant species. It is important to assess whether any of the species present in the project area are listed as federal or state threatened or endangered species or state species of concern. In some states, wildlife agencies request evaluation of impacts to big game species, reflecting concerns over state efforts to manage these species and associated habitats (including wintering areas) for recreational (hunting) purposes. Initial knowledge of potential impacts to habitat is generally determined through a database inventory of species likely to occur in the project vicinity, combined with site visits that typically require a spring survey for plants and some animal species.

D. Habitat (Including Soil Erosion). The final footprint of a wind energy facility is small in relation to the landmass over which the entire project, including transmission lines, is spread. Still, wind energy projects typically involve substantial grading for road and turbine base construction, with impacts on a wide variety of plant and animal species. In active agricultural areas, this issue may be of

minimal importance. However, most productive wind energy sites will likely include some areas of native habitat or native species occupying previously undisturbed areas. In many western states, wildlife habitat is classified in one of several categories based on its importance to various species, and mitigation ratios are set accordingly; in some cases, no disturbance at all is allowed to the most valuable habitat types.

Soil erosion due to road and facility construction can also be a problem. Project planning should include an attempt to avoid sensitive habitats, consider mitigation for habitat impacts that cannot be avoided, and provide for soil conservation and any necessary erosion-control measures.

E. Visual Impacts. Modern onshore wind turbines can be over 400 feet tall at the hub, with blades extending the total to 500 feet or more, although as wind turbine height has increased, so has generation capacity, resulting in fewer turbines that more efficiently generate greater power. Wind turbines are typically sited in open areas and on ridge lines with little available in the way of visual buffers. Offshore turbines are even taller, with no buffer to ameliorate their visual effects. Lights on the turbines, which are typically required by the Federal Aviation Administration (“FAA”) and the Department of Defense (“DOD”), can have nighttime visual impacts as well. In addition, associated substations and transmission lines can add to the visual impact of a wind project.

There appears to be a split in sensibilities between those who consider wind turbines an eyesore and those who like the visual effect of the turbines. From either perspective, for areas with broad vistas, wind energy projects can result in a fairly dramatic change to rural landscapes, with turbines typically standing in a sentinel-like manner along ridge lines or in rows through pastures and fields. When wind energy projects are sited in relatively close proximity to populated areas or areas of scenic importance, visual impacts may be particularly acute. Visual modeling is usually required to assess the potential impacts of wind energy projects. Mitigation for visual impacts typically includes painting turbines a neutral color that blends into the landscape. However, aside from avoidance, options for full mitigation of visual impacts are limited, although turbine lighting requirements from the FAA have been revised over the last several years to eliminate strobes and to reduce the number and placement of turbine lights at wind energy facilities while preserving the safety of aircraft. The FAA and DOD have established a “Clearing House” process to jointly evaluate and issue determinations concerning the potential hazards to air traffic and military radar installations.

F. Cultural Resources. Pre-project site review for indicia of historical and cultural resources addressed by the National Historic Preservation Act is also critical. Native Americans have occupied the continent for millennia, and it is not uncommon to discover fossil and cultural resources, including those of significance to Native American tribes, at potential wind project sites. A thorough site evaluation is generally necessary before and during construction. When appropriate, the early and constant involvement of local Native American tribes is advisable. Mitigation may also be necessary. Such mitigation typically requires avoiding protected sites and moving the sites if they cannot be avoided. In addition, it may be necessary to have an expert in native culture or paleontology on site

during construction to protect identified sites and alert the work crew to additional sites that may be unearthed during construction.

G. Storm Water and Federal Water Crossing Permits. Factors such as road construction, steep terrain, and the proximity of streams and rivers require storm water management, including compliance with local, state, and federal storm water regulations. The presence of wetlands and streams will raise numerous other concerns relating to habitat and water resource management and may involve ESA issues through Clean Water Act section 404 consultation and/or state removal or fill laws. In addition, some wind energy projects will need to cross water bodies subject to U.S. Army Corps of Engineers jurisdiction. This includes streams flowing into navigable waters and river power line crossings. Myriad issues may arise, including salmon habitat impacts and potential impacts on bird species listed under the ESA. Federal Rivers and Harbors Act section 10 permits can often lead to the need to consult with federal wildlife agencies as well.

H. Land Use Compatibility. Compliance with applicable land use criteria will be required. Each county has its own land use criteria, which may be dictated by statewide land use requirements. County land use codes often have vague standards and criteria, requiring (or allowing) highly discretionary determinations of public need, public safety, and “compatibility” with other land uses, although with the growth of the wind industry, local jurisdictions have become increasingly aware of and sophisticated at tailoring local regulations to address wind energy facilities.

I. Wake Effect. An additional siting issue increasingly of concern to local jurisdictions is that of “wake effect,” a situation in which an upwind turbine is proposed for installation so close to a downwind turbine (owned by somebody else) that it may reduce the wind efficiency of the downwind turbine and consequently its productivity and profitability. Another effect of a turbulent air regime through the downwind turbine is increased and erratic wear and tear on the turbine’s components. Turbine manufacturers’ specifications and warranties may address turbine placement distances for purposes of avoiding such negative effects, and failure to abide by those requirements may jeopardize warranty coverage. In the absence of setback standards that expressly or in application eliminate wake effects, developers and landowners are seeking to have local permitting agencies force proposed turbine sites deeper into the developer’s property. Often, the demand to the siting agency by a developer or landowner is accompanied by an attorney’s letter to the neighboring project developer that damages may be sought due to wake effect-driven loss of profits (if a turbine exists where a new upwind turbine is proposed) or by a preemptive letter to a potential downwind developer that they assume the risk of loss themselves if they site a turbine too closely to an existing upwind turbine. Developers are cautioned to carefully examine the substantive setback criteria and procedural processes that may enable a county to impose wake-effect avoidance setbacks.

J. Noise. Some states, particularly Oregon, Washington and California, have statutes that limit the amount of noise that can be emitted by a wind energy project. All states and jurisdictions that impose such noise standards do so using a dBA scale, as this decibel scale reflects noise that is typically audible to the human ear. Wind turbine noise decreases rapidly over distance and tends to be masked

by the background noise of the wind itself. However, wind energy projects are typically sited in locations with very low ambient noise levels, which can make limits on the allowed increase in ambient noise generated by the project difficult to meet in locations with homes nearby. Noise-related concerns tend to be expressed by those with homes located closest to the wind turbines. In Oregon, the noise statutes do not expressly allow an applicant to simply get permission from a nearby resident to exceed the maximum statutory noise limits (such as through a noise easement). As a result, applicants may be required to purchase the residence or refrain from siting turbines near the residence. Noise modeling and ambient baseline noise monitoring may be required as part of the permitting process. It is periodically propounded by some wind energy project opponents that in addition to audible noise measured by the dBA scale, wind turbines should also be regulated by use of a dBC scale that measures low-frequency (inaudible) sound waves, or infrasound, theorizing that infrasound may cause adverse health effects when experienced repeatedly and in close proximity to the emitting source. However, while wind turbines may emit a low whooshing sound that is audible to the human ear (correctly regulated by application of an audible noise dBA scale), wind turbines do not emit considerable infrasound, and there is no credible, peer-reviewed medical data attributing low frequency noise and infrasound to human health effects. No permitting jurisdictions in the United States apply a dBC scale to wind turbines.

IV. Timing. To develop a project-specific assessment of issues that may cause permitting delay, consider whether any of the following apply:

- Whether avian baseline data will be required and, if so, whether a full year (four seasons) or more of baseline data will be required as part of the permit application.
- Whether any surveys in spring or other seasons will be required for certain plant or wildlife species as part of the permit application.
- Whether a take-avoidance or a take-compliance strategy will be pursued to address liability concerns created by the ESA, MBTA, and Eagle Act.
- Whether a state environmental process (*e.g.*, SEPA/CEQA) or federal NEPA process will be required and, if so, whether an EIS (which in the case of NEPA typically takes at least a year to prepare) or a less comprehensive environmental document will be required.
- Whether a cultural and archaeological site survey will be required and how long it will take to complete such a survey (if the survey will be completed by a Native American tribe, it may take much longer than expected).
- Whether the locality will require a conditional use permit for installation of meteorological towers to assess the wind feasibility of the site. If so, this may add weeks or months to the site evaluation process.

- Whether an easement or lease from the BLM or other federal agency will be required for the project (and, if so, what level of NEPA review will be required).

An early assessment of potential public opposition and appropriate strategies to respond to controversies and opposing environmental opinions is also strongly advised. With the increased demand for renewable energy, the siting of wind energy facilities is becoming more controversial as more remote project locations become developed, resulting in new projects being proposed in less remote areas and areas with greater environmental or visual consequences. It is important to follow local code changes and state legislation as these are proactive vehicles for project opposition, and it is also valuable to engage public agencies and other interested parties early in the siting process to reduce the likelihood of later controversy.

Chapter Four
THE LAW OF WIND
—Offshore Wind in the United States—
Cherise M. Gaffney, Chad T. Marriott

I. Why Offshore? As of the date of this publication, there is one operating offshore wind project in the United States: the five-turbine, 30 MW Block Island Wind Farm off the coast of Rhode Island. The Block Island project began commercial operations in December 2016. Several other projects have been proposed over the past several years, and a few have advanced to various stages of development, off the coasts of Massachusetts, New Jersey, New York, Virginia, Maryland, Ohio, and Michigan. With the success of the Block Island project, recent developments in turbine technology, and a continuing push by coastal states without significant onshore wind resources to help satisfy state renewable portfolio standards (“RPS”), interest in offshore wind in the United States has continued to increase (albeit cautiously). The National Renewable Energy Laboratory has estimated that several states, including Michigan, Ohio, New Jersey, both Carolinas, Maine, and Massachusetts, may be able to supply more than 100 percent of their 2004 state electricity consumption through offshore wind sited in waters at less than 30 meters in depth at locations within 50 nautical miles of shore. Because offshore wind resources are generally greater and more stable than onshore wind resources, some of these states see offshore wind as a potentially viable alternative for satisfying utilities’ RPS obligations. In addition, offshore wind represents potential new opportunities for economic development and job growth through establishment of infrastructure and manufacturing bases in these states.

II. Federal vs. State Jurisdictional Waters. Both the outer continental shelf (“OCS”) and the Great Lakes have demonstrated strong potential for offshore wind. The first distinction that must be made is which agency has jurisdiction over the submerged lands upon which the wind energy project will be placed. Each state bordering the Atlantic Ocean or Pacific Ocean has jurisdiction over submerged lands out to three nautical miles offshore pursuant to the Submerged Land Act of 1953. Texas, Florida, and Louisiana have jurisdiction over submerged lands in the Gulf of Mexico out to nine nautical miles offshore. Beyond the state jurisdictional borders, jurisdiction to grant leases, rights-of-way (“ROWS”), and rights-of-use and easements (“RUEs”) on the OCS for most energy projects lies with the Bureau of Ocean Energy Management (“BOEM”), a division of the U.S. Department of Interior, pursuant to the Outer Continental Shelf Lands Act as amended by the Energy Policy Act of 2005 (“EPAAct”). EPAAct gave BOEM (formerly the Minerals Management Service) jurisdiction over renewable energy projects, such as wave, wind, and solar energy, and other projects that make alternative use of existing oil and natural gas platforms in federal waters. In the Great Lakes, each state has jurisdiction over submerged lands out to the center of each lake. This jurisdictional distinction is important because leasing regulations differ based on whether a project is to be sited in federal or state jurisdictional waters.

A. The Federal Leasing Process. As stated above, EPAAct granted BOEM jurisdiction over renewable energy projects on the OCS. BOEM grants competitive and non-competitive commercial

leases, limited leases, ROWs, and RUEs for renewable energy development activities, including the siting and construction of offshore wind farms on the OCS. A commercial lease issued by BOEM conveys the access and operational rights necessary to produce, sell, and deliver renewable energy generated on the OCS. A commercial lease provides the lessee full rights to apply for and receive authorizations to assess, test, and produce renewable energy on a commercial scale over the long term (approximately 30 years). A limited lease will convey access and operational rights for activities on the OCS that support the production of energy, but do not result in the production of electricity or other energy product for sale, distribution, or other commercial use exceeding a limit specified in the lease. Other land interests that may be granted include ROWs for construction and use of cables or pipelines for transmitting, distributing, or otherwise transporting energy, as well as RUEs for the use of existing OCS facilities for activities not otherwise authorized by the BOEM rules.

The BOEM regulations also require a comprehensive environmental review before a lease may be entered into. Specifically, a Site Assessment Plan (“SAP”), a Construction and Operations Plan (“COP”), and a General Activities Plan (“GAP”) are required to be submitted for BOEM review and approval. The SAP and the COP will be used for commercial leases, while the GAP will be used for limited leases and grants. The SAP describes the activities (*e.g.*, installation of meteorological towers, meteorological buoys) a lessee plans to perform for the characterization of its commercial lease, including the project easement, or to test technology devices. A COP will be required before a lessee may conduct any activities pertaining to construction of facilities for commercial operations under the lease. The COP describes the construction, operations, and conceptual decommissioning activities the lessee plans to undertake under the lease and project easement. A GAP will be required before a lessee or grantee may begin activities on a limited lease (including a project easement, as applicable) or ROW grant or RUE grant. The GAP describes the site assessment and/or development activities. If the action by BOEM of approving these plans is found to be a major federal action significantly affecting the quality of human health or the environment, BOEM will need to comply with the National Environmental Policy Act (“NEPA”). NEPA compliance is discussed in greater detail in [Chapter 3](#). For each approval that is found to trigger NEPA, either an Environmental Assessment or an Environmental Impact Statement will need to be prepared.

BOEM’s regulations also specify the amount of financial assurance that is required to be posted by the lessee for each phase of development: a \$100,000 basic lease-specific bond or another BOEM-approved financial assurance before BOEM will issue the lease; a possible second assurance if BOEM determines that it is necessary due to the complexity, number, and location of facilities in the SAP; and a third assurance before BOEM will approve a COP or before the Federal Energy Regulatory Commission issues a license for a hydrokinetic project. Additional payments or deposits are required and vary depending on whether the application is for a competitive or non-competitive lease. A \$300,000 bond or financial assurance is required for a limited lease, ROW grant, or RUE grant, or an amount sufficient to guarantee compliance with the terms and conditions of the limited lease or grant. Prescribed rental amounts that will be paid by a lessee during the term of a commercial and limited lease are generally \$3.00 per acre per year. Commercial lease rental payments will be paid during construction, and an operating fee will

be paid during commercial operation that will be calculated according to a formula based on the project's nameplate capacity and anticipated capacity factor and the annual average wholesale electric power price for the state where the transmission makes landfall.

B. Federal Offshore Policy Initiatives. In addition to specific regulations for siting and constructing offshore wind projects, federal agencies are also engaged in interagency initiatives intended to promote the growth of the offshore wind industry and streamline the federal permitting process.

1. National Offshore Wind Strategy. First released in February 2011, the National Offshore Wind Strategy¹ ("Strategy") is the product of the Department of Energy's ("DOE") Office of Energy Efficiency and Renewable Energy Wind and Water Power Program. The Strategy seeks to bolster DOE's Offshore Wind Innovation and Demonstration Initiative through a joint effort with the Department of the Interior ("DOI") to "spur the rapid and responsible development of offshore wind energy." With the goal of deploying 10 GW of offshore capacity at a cost of \$0.10 per kWh by 2020 and 54 GW at \$0.07 per kWh by 2030, the Strategy strives to reduce the costs and timelines associated with offshore wind projects through a "suite of three focus areas – Technology Development, Market Barrier Removal, and Advanced Technology Demonstration."

An updated strategy was jointly released by DOI and DOE in 2016,² emphasizing a renewed emphasis on collaborative efforts to facilitate offshore wind development. In the refreshed strategy, DOE commits to reducing the "levelized cost of energy through technological advancement," and DOI "aims to enhance its regulatory program" by reducing burdens on regulated stakeholders. In addition to reducing costs and timelines for establishing offshore wind energy projects, the refreshed strategy also emphasizes the importance of increased understanding of the potential costs and benefits associated with offshore wind energy.

2. National Ocean Policy Implementation Plan. In a similar vein, the National Ocean Policy Implementation Plan ("Plan") was released by the National Ocean Council in April 2013.³ The National Ocean Council, which was established by Executive Order 13547 in July 2010, is composed of 27 federal agencies. Broader in scope than the National Offshore Wind Strategy, the Plan is designed to benefit "(1) The Ocean Economy, (2) Safety and Security, and (3) Coastal and Ocean Resilience by supporting (4) Local Choices, and providing foundational (5) Science and Information." Specific to facilitating offshore wind, the Plan seeks to galvanize federal agencies to, among other things, advance mapping technology and data access, and facilitate the permitting process through improved information exchange among federal, state, and local entities.

¹ See https://www1.eere.energy.gov/wind/pdfs/national_offshore_wind_strategy.pdf.

² See <https://energy.gov/sites/prod/files/2016/09/f33/National-Offshore-Wind-Strategy-report-09082016.pdf>.

³ See <https://www.boem.gov/national-ocean-policy-implementation-plan/>.

C. The State Leasing Process. Each state with jurisdiction over submerged lands on which energy projects may be sited must establish its own leasing process for those submerged lands. Texas has a program, administered by the Texas General Land Office, under which it leases submerged lands, the revenues from which flow to the Texas Permanent School Fund. A preliminary step to creating a leasing process that some states (Rhode Island, New Jersey, and Michigan) have taken is a form of “ocean zoning,” or identification of prudent sites within state jurisdiction for the siting of offshore energy facilities. Specifically, the Rhode Island Ocean Special Area Management Plan, led by the Rhode Island Coastal Resources Management Council, defined use zones for the state’s coastal waters to protect and enhance current uses as well as plan for future uses, such as renewable energy development. Michigan’s Great Lakes Wind Council submitted a report to the Governor in September 2009 identifying most favorable areas, categorical exclusion areas, and conditional areas to the development of offshore wind projects in the Great Lakes, and in 2010 submitted recommended legislative changes to amend the state statute governing issuance of leases for submerged lands to facilitate offshore wind projects. And the Great Lakes Wind Atlas, developed by researchers at Cornell University and the Technical University of Denmark, uses information from multiple sources to estimate the wind conditions in the Great Lakes region and has found strong potential in the north-central area of Lake Michigan and along the southern coast of Lake Superior.

III. Federal, State, and Local Permitting. For a comprehensive discussion on the siting and permitting of wind projects, see [Chapter 3](#). Several issues common to both terrestrial and offshore wind development include evaluation of avian impacts, visual impacts, and wake effect. With offshore wind development, BOEM leads federal environmental review for OCS projects, and the U.S. Army Corps of Engineers (“Corps”) leads the federal environmental review for Great Lakes projects. The triggering action for BOEM will be its issuance of the land interest, such as a commercial lease, while the triggering action for the Corps will be issuance of a permit under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act. Unlike the OCS projects, however, Great Lakes projects will have a greater state focus, as the state will be drafting and coordinating the permitting and leasing process. Other federal statutes that may be triggered by offshore wind development include the Coastal Zone Management Act (“CZMA”), Marine Mammal Protection Act, Migratory Bird Treaty Act, Marine Sanctuaries Act, and Endangered Species Act. State approvals will include state shoreline permits and/or determinations of consistency with the state’s Coastal Management Program, as well as energy siting permits for energy facilities. Finally, many coastal states authorize local governments to issue permits for shoreline areas. These local permits may be a condition precedent to receiving the state’s consistency determination under the CZMA, which in turn is necessary before a federal approval (such as a Corps permit) may occur. Special attention should be paid to the local process as it relates to the overall permit strategy.

Chapter Five
THE LAW OF WIND
—Federal Land Issues with Siting and Permitting—
Aaron C. Courtney, Timothy L. McMahan

Wind energy developers are comparing siting opportunities on state and private lands, weighed against the potential opportunity to develop on federal land offering appropriate project sites. This trend appears to have cooled somewhat in the recent years as the increasing generation capacity and efficiency of new generation turbines have reopened consideration of nonfederal lands with access to nearby transmission systems. Plus, increasing demands for wind energy to satisfy state renewable energy portfolio requirements and emerging state climate change policies have led to a fresh look at nonfederal lands. Development on federal lands can require compliance with a daunting collection of federal regulations that only add to the already complex and often onerous requirements imposed by many states. And within the context of these risks, federal policy and permitting practices remain unsettled in a changing political landscape.

Foremost among these challenges are the land control issues arising from federal rights-of-way (“ROWS”) processes and permitting, as well as satisfying the document-intensive procedural requirements of the National Environmental Policy Act (“NEPA”), 42 U.S.C. § 4321, *et seq.* Additionally, habitat preservation and other natural resource protection concerns that are not relevant to private or state land development can have significant consequences for activities on federal lands. Less obvious are the potential environmental liability issues that can exist on federal lands associated with historical land use practices such as mining. Finally, a host of antidevelopment advocacy groups exist and have significant experience in challenging projects in federal court under federal laws. These groups tend to be more sophisticated and better funded than local entities that have historically created the bulk of opposition to wind power project development.

Nevertheless, project development on federal land can present opportunities for risk management that are difficult to come by or simply unavailable absent a federal nexus. Development on federal land also can allow a project proponent to avoid some of the difficulties posed by often esoteric local regulations.

This chapter outlines the numerous challenges created by development on federal land and the regulatory nuances associated with such activities. Given the vast expanses of wind-resource land under the control of the U.S. Bureau of Land Management (“BLM”), this following chapter focuses primarily on the regulatory processes followed by BLM and concludes with a more general discussion of tools for navigating through what for many in the industry could be uncharted waters.

I. Development on BLM Lands. Section 211 of the Energy Policy Act of 2005, Pub. L. No. 109-58, established a goal that the Department of Interior, through BLM, approve 10,000 MW of nonhydropower renewable energy projects on public lands by 2015. In anticipation of that legislation, in October 2003 BLM initiated the preparation of a Programmatic Environmental Impact Statement, under NEPA, for

wind energy development. On June 24, 2005, BLM released the *Final Programmatic Environmental Impact Statement on Wind Energy Development on BLM Administered Lands in the Western United States* (the “Programmatic EIS”). A Record of Decision (“ROD”) was signed on December 15, 2005 to implement the Best Management Practices (“BMPs”) and land use plan amendments identified in the Programmatic EIS.

While the Programmatic EIS laid the environmental groundwork for permitting wind energy developments in the 11 western public-land states, it provided little in the way of actual permitting guidance. Would testing facilities be treated like full-blown energy developments? Would competing applications be subject to competitive bidding? What level of bonding and NEPA analysis would be required? These and other questions, as well as federal pressure to streamline the permitting process, prompted BLM to issue an instruction memorandum, Wind Energy Development Policy IM 2006-16, on August 24, 2006 (the “2006 IM”). Though it expired on September 30, 2007, the 2006 IM established the basic framework used today for permitting wind energy facilities on BLM lands. That framework was carried forward and supplemented by BLM’s revised Wind Energy Development Policy IM 2009-043, issued on December 22, 2008 (the “2008 IM”).

II. BLM Wind Energy ROW Grants. Project development usually proceeds in two phases: (1) a site testing and monitoring phase and (2) if the wind resource is viable, a project construction and operation phase. BLM permits all wind facilities, whether for testing and monitoring or for project construction and operation, through use of ROW grants authorized by the Federal Land Policy and Management Act (“FLPMA”), 43 U.S.C. §§ 1701-1784. To accommodate the above development schedule, BLM offers three types of BLM wind energy ROWs: a Site-Specific Grant for Testing and Monitoring (“Site-Specific Grant”), a Project Area Grant for Testing and Monitoring (“Project Area Grant”), and a Development Grant for project construction and operation.

A. Site-Specific Grants. A Site-Specific Grant may be issued for testing and monitoring facilities such as meteorological towers (“met towers”). The area authorized for use under a Site-Specific Grant will be limited to the minimum area necessary for construction and maintenance of the facility—that is, one Site-Specific Grant would be issued for each met tower and would cover only the minimum area necessary to accommodate the met tower. The term of a Site-Specific Grant is limited to three years. The minimum rental fee is \$100 per year, and the minimum bonding requirement is \$2,000 per met tower.

B. Project Area Grants. Though Project Area Grants are also designed to accommodate testing and monitoring facilities, they provide several distinct advantages. First, a Project Area Grant may cover not only the individual met towers, but also the entire proposed project area, including required access routes. The term is also extendable: provided that the developer submits an application for a Development Grant and a Plan of Development prior to the end of the initial three-year term, BLM may extend the Project Area Grant for an additional three years. Rent during this term equals \$1 per acre per year, or \$1,000 per year, whichever is greater, and the minimum bonding requirement is \$2,000 per met tower.

Important to developers, a Project Area Grant also precludes competing applications for the same lands for the term of the grant, including the extension. Applications are processed on a first-come, first-served basis, and are not subject to competitive bidding unless required by the land and resource management plan. This means BLM will usually process the first complete application with attached cost recovery fees before all others. This term of exclusivity allows a developer to fully assess site viability without fear of competing developers that might otherwise be willing to proceed on incomplete information. However, because project financing and viability frequently depend on the terms of this exclusivity, and because BLM regulations are very specific about the timing of the extension request and the extent of the draft Plan of Development, it is advisable to review BLM policy carefully and maintain an open dialogue with counsel and BLM staff as the end of each term draws near.

C. Development Grants. If the project proves viable and the developer satisfies BLM's permitting prerequisites, including all environmental analysis and completion of the Plan of Development, BLM may issue a Development Grant for up to 30 years, with provision for renewal. The annual rental fee for a Development Grant is based on the anticipated total installed capacity in MW on public lands, as described in the Plan of Development. The fees are phased in over two years to accommodate project construction. The rental fees equal \$1,039 per anticipated MW in the first year, \$2,078 per anticipated MW in the second year, and \$4,155 per MW thereafter. As with a Project Area Grant, the rental fees are to be paid annually in advance, on a calendar-year basis, and are prorated for partial years. Additionally, BLM will require a minimum bond of \$10,000 per turbine.

III. 2008 IM Substantive Revisions and Subsequent 2016 Rulemaking. For those familiar with the 2006 IM, the following outlines the major substantive revisions made by the 2008 IM:

- The 2008 IM recognizes the existence of Visual Resource Management ("VRM") objectives in many land and resource management plans, but stresses that VRM objectives may be met through strategic placement of facilities and thoughtful design treatments that visually integrate the facilities into the landscape setting.
- The 2006 IM universally precluded wind energy development from all Areas of Critical Environmental Concern ("ACECs"). The 2008 IM allows wind energy development in an ACEC to the extent that it would be consistent with the management prescriptions of that individual ACEC.
- While testing and monitoring facilities, including met towers, will require an FLPMA ROW, geotechnical testing activities for foundation designs or other purposes may be authorized by a land use permit.
- Bonding is no longer discretionary, and the Development Grant rental fees have almost doubled.
- Attachment 1 to the 2008 IM modified and clarified several of the BMPs first espoused in the ROD.

- Attachment 2 to the 2008 IM details the required elements of a Plan of Development for purposes of obtaining a Project Area Grant extension and a Development Grant.

Finally, on December 19, 2016, BLM published a final rule revamping its leasing regulations to include competitive processes, incentives for development in “designated leasing areas” (identified in the rule and relevant resource management plans), and new payment and bonding requirements for wind energy development rights-of-way. 81 Fed. Reg. 92,122 (Dec. 19, 2016). Much of what was included in the formal rulemaking derived from existing policies, described above, that the agency had issued in prior years. The rule went into effect on January 18, 2017.

IV. NEPA Analysis Associated with BLM ROW Grants. Like with all BLM ROWs, an applicant for a wind energy ROW initiates the application process by submitting form SF-299. The application triggers, among other things, BLM’s duty to conduct the environmental analysis required by NEPA. Unless an activity falls within a Categorical Exclusion (“CX”), BLM must conduct an Environmental Analysis (“EA”) to determine whether the proposed agency action would significantly affect the quality of the human environment. 42 U.S.C. § 4332(2)(C). The EA will either make a Finding of No Significant Impact (“FONSI”) or conclude that the agency action requires further study in the form of an Environmental Impact Statement (“EIS”). If BLM issues an EA/FONSI, then BLM may take the proposed federal action without further NEPA analysis. If, on the other hand, BLM concludes that an EIS is warranted, it will undertake a significantly more detailed analysis that will contemplate alternatives to the proposed action and mitigation for projected impacts on the environment. For purposes of expediting private development on federal land, a CX or an EA/FONSI is preferable to an EIS.

According to the 2008 IM, BLM may, in some instances, grant a “short-term right-of-way authorization” under a CX. The CX identified by the BLM NEPA Handbook, H-1790-1, Appendix 4, Section E.19 (January 30, 2008), encompasses “issuance of short-term (3 years or less) rights-of-way or land use authorizations for such uses as storage sites, apiary sites, and construction sites where the proposal includes rehabilitation to restore the land to its natural or original condition.” The 2008 IM does not further clarify the nature of the “short-term” authorizations eligible for the CX, although it seems that a nonrenewable Site-Specific Grant is the most likely candidate.

Discussions with agency staff reveal a preference for an EA when considering large Project Area Grants. The level of required environmental analysis increases with the acreage and number of met towers requested. In most circumstances, BLM will require, at a minimum, vegetation, wildlife, archaeological, and cultural studies. The 2008 IM indicates that “[s]ite testing and monitoring right-of-way applications should be processed within a 60-day timeframe, consistent with the requirements of 43 CFR 2804.25.” However, in recent experience, BLM frequently takes much longer.

NEPA requires that an EA consider potential cumulative impacts. However, the 2008 IM is clear that an EA for a Project Area Grant “should not address wind energy development facilities, as the installation of wind turbines is not proposed during site testing and monitoring.” Consequently, the EA for a Project

Area Grant may be limited in scope to the environmental effects of the met towers. Furthermore, the EA is to tier off of the BMPs and mitigation measures included in the Programmatic EIS. The site-specific NEPA analyses are to include micrositing considerations, monitoring program requirements, and appropriate site-specific stipulations.

With regard to a Development Grant, the 2008 IM indicates that the environmental analysis is to tier off of the Programmatic EIS and “focus just on the critical, site-specific issues of concern.” While the 2006 IM posited that an EA “will usually be sufficient,” the 2008 IM is more conservative, stating that while tiering to the Programmatic EIS may allow for preparation of an EA, the “level of NEPA documentation necessary will be determined based on the context and intensity of the proposed action and how much analysis may be tiered to the Programmatic EIS.” Despite this language, experience suggests that almost all major wind developments on federal land will require an EIS.

V. U.S. Forest Service Wind Energy Permitting. Like BLM, the U.S. Forest Service (the “USFS”) authorizes wind energy facilities pursuant to Title V of FLPMA. The USFS has developed a series of regulations for issuing Special Use Permits on federal lands at 36 C.F.R. subpart B. Following BLM’s lead, in 2011 the Forest Service issued internal guidance related to the issuance of permits for wind energy uses on National Forest System lands, including “direction on authority, objectives, responsibility, definitions, and references for use in authorizing wind energy uses on National Forest System lands.” Forest Service Handbook 2709.11, Chapter 70. This guidance provides direction on siting turbines and other facility components, evaluating protected resources, and addressing issues unique to wind energy in the special use permitting process. Thus, although the Forest Service lacks a national special-use wind-siting program and still makes its decisions about wind energy development on a case-by-case basis at the individual National Forest level, developers should carefully review the Forest Service’s guidance.

VI. Other Potentially Applicable Federal Laws. In addition to the unique federal land control issues described above and arising under FLPMA and NEPA, certain other federal laws and regulatory programs only apply on federal lands. For example, the Archaeological Resources Protection Act, 16 U.S.C. §§ 470aa-470mm, creates a program for managing and protecting archaeological resources on public lands. Similarly, some federal lands are subject to use rights of tribes, see [Chapter 6](#), that do not exist on private land (*e.g.*, rights to hunt and gather foods under treaties securing tribes’ rights on “open and unclaimed lands”).

Federal land development also requires compliance with federal land resource management plans and, if necessary, the ability to navigate through administrative appeals and judicial review procedures that can be complicated and time-consuming. Further complicating matters, such management plans and administrative review processes are often specific to the authorities of each individual federal agency.

Other laws, while potentially applicable to private land development, have greater impact on federal lands. For example, the National Historic Preservation Act, 54 U.S.C. § 300101, *et seq.*, requires extensive

consultation with tribes and mitigation plan development in instances where project development could impact cultural resources on federal lands.

Moreover, of great significance in the context of wind energy development is the fact that the regulatory scope of the Endangered Species Act (“ESA”), 16 U.S.C. § 1531, *et seq.*, increases exponentially on federal lands. For example, certain protections not provided to imperiled plant species on private or state lands do apply on federal lands. Furthermore, project development on federal lands often triggers the requirement for the land management agency to consult with the natural resource agencies (the National Marine Fisheries Services and the U.S. Fish & Wildlife Service) to ensure that a proposed project will not jeopardize a listed species or adversely modify the species’ critical habitat. ESA consultations can be time-consuming and expensive, and often result in species protection measures that can significantly impact design and operation of projects.

VII. Liability Risks. Development on federal land can open the door to liability risks not normally encountered when constructing wind projects on private lands. Most notably, liabilities associated with historical hazardous waste contamination may arise, as may exposure to lawsuits in federal court brought by sophisticated, well-funded antidevelopment nongovernmental organizations (“NGOs”).

Unlike most nonfederal lands, significant portions of federal lands have experienced mineral exploration and mining. Often these activities leave behind a legacy of contaminated tailings and other hazardous wastes, and they do so in forms not always recognizable to the untrained eye. Under the strict and joint and several liability schemes found within many federal and state cleanup laws, entities that disturb these areas of historical contamination—for example, through road building and turbine pad construction—can find themselves responsible for remediating these sites, at significant cost, despite not having caused or contributed to the original contamination. Additionally, mitigating against such risks by avoiding contaminated areas on a project site can create design and operational challenges that add time and expense to a project.

In addition to potential liability arising from historical contamination, developers of federal land often face significant scrutiny and challenges by sophisticated NGOs. Unlike local antidevelopment groups or neighbors that might try to impede the development of a wind project on nonfederal lands, many regional and national NGOs are well funded and focused on federal land issues. Such groups often do not hesitate to use litigation, see [Chapter 15](#), in the federal courts to advance their interests, and thus have significant legal and technical expertise in complex federal administrative and judicial processes. The pressure these groups can bring to bear on the federal agencies whose authorizations are needed to develop a project on federal land can be considerable and should not be discounted.

VIII. Navigational Tools. Despite their complicated regulatory nature, federal lands provide viable and significant opportunities for wind project development. Understanding and addressing the challenges before embarking on a project should enable a developer to take advantage of the benefits of federal lands while satisfactorily managing any risks.

For example, when developing on BLM lands, project proponents should familiarize themselves with the 2008 IM ROW process and manage project development in a manner that preserves application seniority pursuant to the requirements of this federal guidance. To this end, environmental analyses should tier off of the Programmatic EIS whenever possible. Although NEPA compliance can be expensive and create delay, the process and documentation created thereunder should be embraced as a project planning tool rather than deemed a mere nuisance.¹

Similarly, although ESA consultations can create delay, if they are considered and incorporated from the outset in project planning, timing issues can be avoided. Moreover, notwithstanding the expense of engaging in an ESA consultation, the result—a biological opinion and incidental take statement—can provide protection against the ESA’s significant civil and criminal liability provisions for incidental harm inflicted upon imperiled species by the construction and operation of a wind farm. Such protections are often worth the time and expense of an ESA consultation and are not normally available on nonfederal lands (unless associated with a federal permit or funding).

As to potential liability risks associated with federal lands, affordable and practical strategies exist for minimizing these risks. For example, to best insure against liability arising from exacerbating historical hazardous waste contamination on a site, a project proponent should conduct a Phase I environmental site assessment to identify areas of risk, so it can avoid or otherwise address these areas. Such assessments can also provide statutory defenses to liability under federal cleanup laws, as well as to liability arising under many equivalent state statutes. Regarding the potential exposure to third-party challenges to an agency’s authorization of a project under federal environmental laws, the vulnerability is only as great as the weakness of the supporting administrative record. Consequently, in addition to any NGO outreach, project proponents should work closely and cooperatively with relevant federal permitting agencies and other interested stakeholders to ensure the creation of a strong administrative record.

Finally, it is noteworthy that development on federal land can allow a project proponent to avoid some of the difficulties posed by often esoteric local and state land use regulations. To the extent state environmental regulatory programs overlap with the federal authorizations needed for a project, federal and state agencies are becoming more experienced in ensuring that the parallel processes do not conflict. In fact, through a process facilitated by Stoel Rives attorneys, BLM and the Oregon Department of Energy recently signed an unprecedented Memorandum of Understanding that seeks to streamline

¹ Project developers should also be prepared to utilize the resources of BLM Renewable Energy Coordination Offices, which are located in most states to facilitate ROW application processing, environmental review, and coordination between other relevant federal agencies.



the agencies' siting and permitting processes and facilitate cooperation among federal and state agencies for commercial wind projects in Oregon.

In sum, although the federal regulatory maze can be daunting, it is not insurmountable, and certainly not a reason to miss out on the potentially significant development opportunities presented by siting wind projects on federal lands.

Chapter Six
THE LAW OF WIND
—Tribal Laws and Land Issues—
Gary R. Barnum

Many Indian tribes own extensive blocks of land with significant wind resources. Tribal land provides wind 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 Wind Energy Land Agreement securing all site control and related easements necessary to conduct a wind resource assessment and other studies and to construct, own, operate, and maintain a wind 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 wind energy project developers on tribal land. This chapter provides a brief overview of issues affecting wind energy project development on tribal land.

I. Wind Energy Land 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. § 415, an Indian tribe, as lessor, can lease tribal land for 25 years and may agree to an option extending the lease for an additional 25 years. Specific tribes listed in section 415 can also lease tribal land for 99 years. Most section 415 leases must be approved by the Bureau of Indian Affairs (the “BIA”). Currently, section 415 authorizes two tribes, the Navajo Nation and the Tulalip Tribes of Washington, to lease tribal land for up to 75 years without BIA approval.

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 (the “NHPA”), and the Endangered Species Act (the “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 because 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 of its actions on any property, including

traditional cultural properties, listed on or eligible for listing on the National Register of Historic Places and must consult with tribes and other interested parties on measures to avoid, minimize, and mitigate any adverse impacts of its action on such properties. 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. Other federal laws apply if human remains, funerary objects, sacred objects, or archaeological resources are encountered before or during project development 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. Federal laws of general application, such as the Clean Water Act and Clean Air Act, generally apply on tribal land.

Tribal government corporations operating under charters issued by the Secretary of the Interior under 25 U.S.C. § 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 wind flow from being disturbed by development on other tribal land, it may be appropriate to combine a section lease of tribal land with an “encumbrance” on other tribal land under 25 U.S.C. § 81. A section 81 encumbrance of tribal land for seven years or more must be approved by the Indian tribe and BIA.

Wind project developers may determine that a right-of-way is necessary for project-related transmission lines, roads, or other project activities. Traditionally, the BIA grants rights-of-way across tribal land with tribal 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. Once an Indian tribe and the BIA enter a TERA covering wind energy development, the tribe can enter into wind energy leases and other business agreements and issue rights-of-way easements for projects on tribal land for 30 years, renewable for another 30 years by the tribe, all without further BIA approval.

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 to determine the effect of tribal laws and regulations on a wind energy project. When appropriate, a

developer can request a tribe to adopt new tribal laws or amend existing tribal laws to facilitate financing and other aspects of a wind energy project on tribal land.

Nontribal project developers may be subject to applicable state and tribal taxes. Careful review should be conducted to determine whether a Wind Energy Land 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 tax.

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. 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 dispute resolution clause in an agreement with an Indian tribe typically includes a clause 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 can 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 wind energy development agreements.

Chapter Seven
THE LAW OF WIND
—Power Purchase Agreements and Environmental Attributes—
Jason Johns, Jennifer Martin

I. The Revenue Stream. When a wind 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—wind 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 wind 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 wind 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 contracts for differences 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. They are not contracts where the “buyer” (*i.e.*, the counterparty to the seller/wind 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 wind 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 wind energy.

II. The Parties.

A. 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 wind 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 wind 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.

B. The Buyer. The buyer is often a utility that purchases the wind 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

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 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 contracts for differences), 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.

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.”

C. Credit Support Provider. The PPA will require the oftaker 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 oftaker 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 oftaker, but the utility oftaker almost never posts security in favor of the seller. Traditionally, most oftakers 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 oftaker should it default in its PPA obligations. That said, oftakers 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 oftaker credit support question if the oftaker is a subsidiary of a large corporate oftaker without assets or a community choice aggregator with no credit rating and a short operating history. In some cases, an oftaker will not agree to post credit support upfront 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 wind plant generally is not cash rich (to the contrary—they tend to be funded on a "just in time" basis by their parent). And because most wind 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 tax equity).

Guarantees 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 foregone 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 wind 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 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 year 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.

III. 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 turbines in 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 turbines 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, an unanticipated permitting or land issue, or expiration of the production tax credit prevents the project from being completed at its full expected installed capacity.

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 buyer or to some other clearly defined payment.

IV. 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 a wind turbine can generally function independently of other wind turbines, the PPA may require the purchaser to buy power from the turbines 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 Midwest 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, *i.e.*, an averaged collection of nodes, 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. For a wind project, either the floor price or the payment mechanism must be set to include the value of the lost production tax credits calculated on an after-tax basis.

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 wind 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." The PPA should make it clear that production tax credits, wind 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.

V. 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 turbines 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.

VI. 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 14](#).)

VII. 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 wind years. Some output guarantees, however, are calculated and compensated annually, as buyers now expect greater precision from developers.

Wind turbine manufacturers generally do not provide output warranties to project developers. Rather, the project owner assumes the risk that the wind at the project will produce enough energy to meet the project's revenue requirements.

B. Availability Guarantees. An availability guarantee requires the wind turbines 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 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 turbines. 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.

Wind turbine manufacturers typically provide availability warranties that support the project owner's mechanical-availability guarantees for the first few years of the project. However, such warranties generally last only five years or less, and the seller is usually on its own if it chooses to give a mechanical-availability guarantee that covers the period after the manufacturer's warranty expires.

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 wind 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.

VIII. 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 and the after-tax value of the production tax credits that the seller would have earned had the buyer not curtailed the plant’s output. 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 the facility by damaging a transformer, 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.

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.

IX. 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 non-defaulting 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.

X. 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.

XI. Buyer Options to Purchase the Project or Special Purpose Entity. Many utilities have shown a strong interest in owning wind 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 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 contracts for differences 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 wind 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 wind plant owner the difference between the market price and the strike price. In this way, the wind 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 re-sell 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 wind 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 wind 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 renewable energy credits (“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 (“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 Act² 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, who 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 who will comply with the recordkeeping and reporting requirements.

XII. Retail Sales Structures. As Renewable Portfolio Standard (“RPS”) 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 incentivize 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 wind energy developer: (1) the wind 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

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. Please see the Power Purchase Agreements: Distributed Generation Projects chapter in *The Law of Solar Power* 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 wind 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 structure 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 Eight
THE LAW OF WIND
—Design, Engineering, Construction,
and Turbine Purchase Agreements—
J. Anthony Girolami, Karl F. Oles

This chapter provides an overview of the contractual structures commonly applied to the construction of wind energy projects, including (i) design, engineering, and construction of project infrastructure facilities (*e.g.*, access roads, foundations, crane pads, substations, transmission lines, and maintenance facilities), (ii) procurement of wind turbine generators and related equipment, (iii) erection of wind turbine generators, and (iv) construction of ancillary facilities. This discussion is written from the perspective of a wind energy project developer; however, the information set forth below should interest design and engineering, construction, and operations and maintenance contractors and major equipment suppliers. As with any complex negotiated transaction, there is considerable value to be gained or lost by all parties and, therefore, significant potential for creative legal and commercial strategies to enhance value for all sides.

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

- design and engineering;
- procurement of wind turbine generators (including nacelles, blades, and towers);
- assembly, erection, installation, and commissioning of the wind turbine equipment;
- materials and services to construct balance-of-plant facilities, such as foundations, roads, crane pads, lay-down areas, collection systems, interconnection and transmission facilities, substations, and maintenance and support facilities;
- service and maintenance of the wind turbine equipment; and
- operation and maintenance of the completed facility.

Frequently, engineering, procurement, and construction tasks are combined in a single agreement (an “EPC agreement”). Separate agreements may provide for or anticipate other services, such as warranty services or operations and maintenance services for the completed facility.

Sometimes, all the design and engineering, procurement, and construction and erection services for the entire project are addressed in a single agreement (“full-wrap agreement”) pursuant to which a single

entity is responsible for executing the entire project. However, full-wrap agreements are vendor specific, not an option with all wind turbine suppliers, and are more common for wind projects outside the United States. In North America it is more common to break up the execution of the works into separate agreements, such as design, engineering, construction, and erection agreements (“balance-of-plant agreements”), and procurement agreements for major pieces of equipment, using one or more contractors for each of the various services. Depending on how the contract is structured, warranties, insurance, and other matters may be addressed in a single master agreement or in individual agreements.

II. Design and Engineering Services. Wind power projects require design and engineering expertise that is unique to this sector of the power generation industry. Historically, relatively few companies have designed and manufactured wind turbine generators. However, with the growth and maturation of the industry, new vendors enter the market from time to time. There is a certain degree of standardization in the design of wind turbine generators, and each vendor manufactures a limited range of wind turbine generators to suit market requirements. Although smaller units used to be more common, most onshore units are now in the 2.5 – 3.6 MW range with some 5 MW, 6 MW, and even 7 MW units installed in Europe. Similarly, tower heights have increased in the last decade from nominally 60 meters to 100 meters and more, with rotor sizes to match. Larger units are also the norm in offshore projects. Turbine capacity is, in part, dictated by the operating parameters of a project, which in turn are dictated by the project’s location and meteorological conditions. A turbine supplier may offer a developer several variations of its wind turbine products so that the developer can select different tower and hub heights, blade lengths, control systems, and related equipment to optimize power production in different environments. Each of these variations is designed and engineered by or for the turbine supplier. When a developer acquires wind turbine generators, it also acquires license rights in certain vendor technology. This technology may include the turbine vendor’s turbine control and monitoring system experience, components and materials experience, and weather mitigation packages. Many variations of Supervisory Control and Data Acquisition systems are now available. Also, the interconnecting utility grid requirements may dictate various low or zero voltage ride-through control characteristics.

III. Balance-of-Plant Design, Engineering, and Construction Services. As described above, developers of wind energy projects generally acquire licenses to use vendor technology as part of the wind turbine generators purchased. This still leaves substantial design and engineering work to be performed, including geotechnical studies, micro siting, design and engineering of crane pads and turbine foundations, road design and other earthworks, environmental mitigation, and related activities, as well as collection systems, switch yards, substations and interconnection, and, possibly, transmission lines. This design and related procurement and construction balance-of-plant work could be performed by the turbine supplier under one or more agreements but is more typically provided by a third party contracting directly with the project developer pursuant to a balance-of-plant agreement.

IV. Typical EPC Agreement Structure for a Wind Project. In light of the multiple factors influencing the development of a wind energy project, no single contractual structure applies to all projects. However, the following example is typical of how many developers address certain common issues.

In this example, a project developer wishes to acquire wind turbine generators (the design of which is proprietary) and to use the turbine supplier's services to commission the wind turbine generators. The developer also wants to contract with the turbine supplier to provide certain operations and maintenance and warranty-related services.

The developer and the turbine supplier enter into a turbine supply agreement whereby the project developer agrees to purchase a specific number of wind turbine generators from the turbine supplier, along with the turbine supplier's services to deliver the turbine equipment to the project site and commission the same.

The project developer also enters into a balance-of-plant agreement with an experienced contractor whereby the contractor will design and construct the other necessary facilities for the project, such as turbine foundations, roads, crane pads, lay-down areas, collection systems, substations, transmission lines, and maintenance facilities. The contractor will also receive, inspect, unload, and erect the turbine equipment. Care must be taken in the relevant agreements to carefully match up the work scope and schedule interfaces between the turbine supplier and contractor. The agreement must avoid interference, duplication, or omission between the scopes of work of the turbine supplier and the balance-of-plant contractor, and it must ensure that, collectively, the agreements will result in a fully constructed, integrated, and operational project. Depending on the complexity of the project, the project sponsor may wish to enter into an interface agreement with the turbine supplier and the balance-of-plant contractor to carefully align the execution of each party's scope of work. Close coordination between the turbine supplier and the balance-of-plant contractor decreases the likelihood of the occurrence of construction and commissioning delays.

The issues that the parties address in the turbine supply and balance-of-plant agreements include the scope of work, payment provisions, measures of completion, warranty obligations, and limitation of liability (particularly as it relates to the turbine supplier's and balance-of-plant contractor's liability for failure to complete their obligations by certain key dates tied to the developer's power purchase commitments). These issues are discussed below.

A. Scope of Work. The scope of work should describe, in detail, the actual design, construction, and equipment installation and schedule obligations of the contractor. A turbine supplier's scope of work typically includes the manufacture and delivery of the wind turbine generators, including principal parts and components such as nacelles, hubs, blades, and towers, as well as the commissioning of the wind turbine generators. The turbine supplier's services might also include aviation lighting and weather mitigation packages as options to the turbine equipment. Depending on the turbine supplier, its scope may also include transportation to a port of entry or to the project site.

The balance-of-plant contractor's scope of work may include transportation, if not provided by the turbine supplier, and will typically include crane pad and wind turbine foundation engineering and construction, road design and construction, earthworks, collection and electrical systems, transmission lines and structures, and erection of turbine equipment and related work. As with other aspects of such an agreement, the scope-of-work provisions will probably be heavily negotiated. Some developers routinely contract with separate entities for each of the sub-disciplines mentioned above. Care must be taken to carefully integrate and coordinate the scopes of each to minimize conflicts or gaps in the scope.

B. Payment Provisions. In order to ensure timely procurement of wind turbines and other materials and the progress of the balance-of-plant works, the project sponsor must make timely payment to the turbine supplier and balance-of-plant contractor, respectively. In the case of the turbine supplier, the project sponsor typically provides a down payment in an amount agreed with the turbine supplier. The down payment is used to pay for long-lead-time items and to permit the turbine supplier with the resources necessary to initiate the manufacture and delivery process. The remaining balance of the contract price is typically paid to the turbine supplier upon (1) the shipment ex works of the wind turbines and related components, (2) the delivery of the wind turbines and related components to the project site, (3) the commissioning of the wind turbines, (4) the installation and related testing of the control and monitoring system, and (5) the final sign-off by the parties on the project. The actual percent of contract price due at each milestone and which milestones trigger payment are a matter of negotiation on each project. The project sponsor may wish to retain a portion of each payment under the turbine supply agreement to ensure that funds are available to cover any warranty issues that may arise following commissioning and startup of the project. In the event the project sponsor fails to pay the turbine supplier, such failure may permit the turbine supplier to suspend performance under the turbine supply agreement until payment is received. If the payment delay extends beyond a certain period of time, the turbine supplier may have the right to terminate the turbine supply agreement. Similar concepts usually apply to the balance-of-plant agreement. The project sponsor will provide the balance-of-plant contractor with an advance payment equal to an agreed percentage of the contract price in order to permit the balance-of-plant contractor to mobilize for execution of the works and to order long-lead-time equipment and materials. The remaining payments will be made upon the completion of certain construction activities ("milestones") by the balance-of-plant contractor. Upon completion of each milestone, the balance-of-plant contractor is required to submit a payment request to the project sponsor describing the completed milestone along with lien waivers from the balance-of-plant contractor and its subcontractors. Once the project sponsor has confirmed completion of a milestone, it will issue payment in accordance with the terms of the balance-of-plant agreement. Any non-justified payment delay would provide the balance-of-plant contractor the right to suspend performance or terminate the agreement if payment is not received within the time period specified in the balance-of-plant agreement.

C. Completion and Start-up Obligations. How, when, and by whom the wind turbine generators are to be commissioned should always be set forth in the scope-of-work provisions of the relevant agreement. Currently, almost without exception, the turbine supplier is responsible for

commissioning the wind turbine generators that it supplies. Accordingly, the sequence of events for a typical North American project is as follows. The turbine supplier delivers the turbine generators to the site, and they then become the responsibility of the contractor. The contractor then erects and makes the units “mechanically complete” and then turns the units back over to the turbine supplier. Once a unit is mechanically complete and backfeed power is available, the turbine supplier then commissions each unit and makes it ready to generate power to the grid. Commonly, for projects outside of Canada and the United States, the turbine vendor also erects the turbine eliminating one interface with the balance-of-plant contractor. These interfaces are key milestones in the development of the project, and failure by one party to timely perform its obligations will lead to schedule and cost impacts to other parties. Accordingly, the details of when and how those interfaces occur and are determined become very important. When these progress milestones are achieved, completion is generally evidenced by certifications of, for example, “delivery” (to be accomplished by the turbine supplier), “turbine mechanical completion” (to be accomplished by the contractor), or “commissioning completion” (to be accomplished by the turbine supplier). Each such certification is considered an incremental milestone that each wind turbine generator must satisfy in order to progress to the next milestone. Upon completion of all milestones the project will reach substantial completion. Failure to achieve substantial completion by a date agreed to by the parties may subject the balance-of-plant contractor to liquidated damages.

D. Warranty Obligations. Warranty obligations are likely to be an issue of substantial negotiation between the parties to turbine supply, installation, and balance-of-plant agreements. The nature and scope of a contractor’s warranties will, however, depend on what services, materials, and/or equipment the contractor is required to provide. A turbine supplier’s warranties generally include such things as a general parts or component warranty (the definition of a defect can be important when determining what is included or excluded as a defective or non-conforming part or component in a wind turbine or related facility), a power curve warranty (this refers to the measurement of a wind turbine generator’s power performance), an availability warranty (this refers to whether the wind turbine generators are actually available to generate power), a sound-level guaranty, and related matters. For a contractor providing non-turbine services and materials such as balance-of-plant services, the warranties would be limited in scope relative to those of a turbine supplier but would still include warranties relating to parts and materials used in any construction and engineering services provided.

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 (the turbine supplier may offer extended warranty services for an added price), (2) the definition of a defect and a serial defect if available (wind turbine generators use identical parts and components; serial defects are those that appear in multiple units or components), (3) warranty limitations arising from acts of third parties (such as operation and maintenance contractors) or certain conditions at the project site (such as weather and wind conditions outside of the wind turbine generator’s design parameters), and (4) the remedial measures that a contractor may take to cure any defect. Additionally, a project developer may require that any third-party or subcontractor warranties that the turbine supplier or contractor possesses with respect

to any parts or components used in its wind turbine generators are “passed through” to the project developer.

E. Limitation of Liability. Like other contractors and vendors, turbine suppliers and balance-of-plant contractors invariably seek to limit their liability to a project developer. A common request is for a waiver of consequential, indirect, incidental, and special damages. Such clauses and any exclusions contained therein must be negotiated carefully, because the definitions of such damages may be ambiguous. Both the turbine supplier and contractor will usually seek to have their respective liability for damages for late performance limited to liquidated damages of a certain value, with a maximum cap equal to an agreed-on percentage of the value of the relevant agreement. The parties may specify the maximum aggregate liability a contractor can have; however, the parties can, by agreement, carve out additional liability for the contractor. For instance, the contractor could agree that the contractual limit on its aggregate liability would not apply in cases where the developer has failed to (1) satisfy its contractual commitment under a power purchase agreement, or (2) obtain a certain time-sensitive tax benefit or credit because of contractor-caused delays.

F. Certain Tax Benefits. A wind energy project’s economic viability often depends on obtaining certain benefits provided under federal and state law for renewable-resources energy projects. Production tax credits (“PTC”) and investment tax credits are currently available only for projects on which the taxpayer began construction before January 1, 2019. The amount of the PTC stepped down by 20 percent in 2017, and steps down further by 40 percent in 2018 and by 60 percent in 2019. Accelerated depreciation (MACRS) is also part of the current federal scheme to support and provide incentives for wind development. In addition to federal tax incentives, many states provide tax incentives for wind energy projects. The project developer must be aware of the specific requirements that it must satisfy to obtain these benefits when negotiating the turbine supply and balance-of-plant agreements. A broader discussion of these issues is set forth in [Chapter 10](#) of this book.

V. Other Issues.

A. Financing Issues. A wind energy project developer often requires some form of substantial debt financing or joint venture financing to pay for the design, engineering, procurement, construction, and initial operation of the project. Financial institutions and potential investors will demand the opportunity to review and comment on the suite of turbine supply and balance-of-plant agreements (as well as related operations and maintenance and warranty agreements) before committing funds. Of special interest to prospective lenders and investors are any provisions in the agreements that provide the lender or investor with the ability to take over the project if the project developer (the borrower) defaults, and any provisions that specify the extent and nature of any damages available to a project developer from a contractor for late completion or for failure of the project to generate expected amounts of power. Additionally, financial institutions will want to comment on the payment plans, 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 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, a project developer should be prepared for the possibility that lenders and investors may want to make substantial changes to 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 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.

B. Performance and Payment Guarantees Issues. A project developer will usually cause the various balance-of-plant contractors to procure, for the benefit of the project developer, performance and payment guarantees in the form of payment and performance bonds or a standby letter of credit to secure the obligations of the various contractors (whether engineers, constructors, or procurement contractors) 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 subcontractors. Some of the issues arising with respect to these guarantees are described below.

- *Performance Bond:* A performance bond is usually issued by a bank or bonding company, selected or approved by the project developer, and states an agreed-on "penal sum." This sum is payable upon the project developer's demand if the contractor fails to perform its contractual obligations in a proper and timely manner. For instance, if the contractor defaults on or cannot complete the project, the project developer may call on the bond to pay another contractor to complete the project. The project developer will want to reserve its other rights against a defaulting contractor if the performance bond does not fully cover the project developer's costs (1) of completing the project or (2) associated with damages the project developer may owe to a third party as a result of any default by the project developer.
- *Payment Bond:* A payment bond is intended to ensure that if the contractor defaults on the project, its subcontractors and suppliers will be paid without the necessity of filing liens or other security interests against the project 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 require payment bonds or other guarantees to enhance their security interests in the project.

- *Standby Letter of Credit:* When project financing is involved, the project developer may require that the balance-of-plant contractor provide a standby letter of credit (“SLC”) issued by a financial institution (the “issuer”) approved by the project developer. The SLC essentially substitutes the creditworthiness of a financial institution for that of the balance-of-plant contractor and ensures timely payment of any amounts claimed under the balance-of-plant agreement. The amount of an SLC is typically a percentage of the contract price and is to be delivered as a condition for commencement of the work. In the event of a balance-of-plant contractor default, the project developer may draw upon the SLC by submitting a drawing request to the issuer. Upon receipt of the documentation required in the drawing request, the issuer will render payment to the project developer in the amount requested up to the stated limit of the SLC. In most instances, SLCs are issued and valid for a period of 12 months, which may require the balance-of-plant contractor to renew the SLC during the execution of the project. Failure to maintain or renew an SLC is typically regarded as a material default under the balance-of-plant agreement. Project sponsors typically favor SLCs due to their liquidity and ease of execution, while balance-of-plant contractors raise concerns regarding the cost associated with obtaining SLCs.

The project developer or the lenders may require other security from contractors, such as parent guarantees, reserve accounts, and other forms of assurance that the contractors will perform. The contractors will demand to be given ample opportunity to cure any default or delay and will seek to limit the project developer’s ability to draw on SLCs or call in performance or payment bonds without notice. Further, contractors will usually demand some form of reciprocal payment security issued by the project developer or its parent company, including parent guarantees, payment guarantees, and the like, particularly if the project developer’s only substantial asset is the project itself.

In connection with turbine supply arrangements, it is commonplace for the project developer to request that the turbine supplier deliver and maintain performance guarantees in the form of financial guarantees, parent company guarantees, and SLCs or a mix of such instruments. In return, the turbine supplier will condition its performance on the receipt of adequate payment guarantees including parent company guarantees, payment bonds, and SLCs.

C. Lien Release Issues. When the project developer pays a contractor, it should obtain subcontractor lien releases as confirmation that the contractor has paid its subcontractors. A lien release will help protect the project developer from liens being filed on the project. Such liens are undesirable because, once filed, they can delay or interfere with the project’s financing. Even worse, if a lien claimant is successful, such a lien could be used to force the sale of the project, or part of it, as well as to interfere with the sale of the project by the project developer. For projects outside the United States where no comparable mechanics’ lien/materialman’s lien regime is in effect, the project

developer is advised to obtain affidavits attesting to the receipt of payment in full by contractor and subcontractors. The receipt of payment affidavits will be a condition for receiving milestone payments and for certification of final completion.

D. Insurance and Indemnity Issues. A project developer should obtain appropriate indemnities and insurance coverage from the various parties with which it contracts, including the turbine supplier and balance-of-plant contractor, and should require those parties to obtain similar protections from their subcontractors and material suppliers for the benefit of the project developer. Relevant indemnities may include a general indemnity for personal injury, death, and property damage claims arising from the indemnitee's activities; the contractor's indemnity against subcontractor liens; an indemnity for taxes (other than those payable by the developer); an indemnity for violation of applicable laws; and an indemnity for intellectual property infringement claims. Appropriate insurance policies may 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). Such policies should, if permitted, name the developer and its financing party 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. A project developer should consult with an insurance or risk management specialist to ensure that appropriate types and levels of coverage are obtained.

VI. Current Developments.

A. International Markets. As the wind energy market continues to evolve, it is clear that wind energy will continue to play a dynamic role in the energy future of the United States, China, and Europe and increasingly in Latin America and Southeast Asia. The globalization of wind power in developing markets continues to advance as demonstrated by highly successful renewable energy procurement processes in Brazil, Mexico, Chile, and Argentina. South Africa has also looked to wind power to add renewable generation assets to its aging energy infrastructure to become Africa's green energy leader. We expect to see continued development of wind energy projects in international markets, which creates additional opportunities for equipment suppliers, specialized contractors, and operation and maintenance providers and for the transfer of technology to previously underserved communities.

B. Repowering. There are also new opportunities developing to repower first generation wind energy projects in the United States. The State of California was one of the first places in North America to implement wind energy projects on a large scale in the 1980s. With technological advancements in wind turbine design, developers are pursuing opportunities to repower existing sites with proven wind resources with modern wind turbines that are capable of producing greater generating capacity with fewer turbines.

Repowering projects may be either full repowering projects or partial repowering projects. In a full repowering, the old turbines, foundations, and electrical systems are decommissioned, demolished, and

removed from the project and thereafter new turbines are erected on fresh foundations designed specifically for the new turbines. When added to new collection circuits and control systems, the repowered site is capable of extending the life of a project for at least an additional 10-year period. Developers are able to reuse previously constructed access roads, pads, and lay-down areas and may upgrade substations and shared facilities rather than constructing new facilities, which reduces that overall cost when compared to a new greenfield generation facility.

Project developers may also carry out a partial repowering that allows existing wind power projects to be updated with equipment that increases energy production, reduces machine loads, increases grid service capabilities, and improves project reliability. A partial repower project involves the integration of new, upgraded parts and equipment with the existing project infrastructure. In many cases, a turbine supplier has developed a retrofit kit for existing turbines designed to improve the capacity and efficiency of the existing equipment. These changes typically take the form of installing new blades, rotors, drive shafts, and control systems while reusing the existing tower and foundation. With the increased capacity of repowered turbines, the developer may also be required to carry out upgrades to the existing electrical system and interconnection substation. The integration of existing infrastructure with new equipment may present a number of challenges. First, the existing infrastructure including towers and foundations must have sufficient structural integrity to support the load profile of the new turbines. If the wind regime at the project site is aggressive, the stress placed on the existing foundation may have decreased the structural integrity of the foundation rendering the existing foundation unsuitable for repowering without a costly retrofit. A second consideration involves obtaining adequate warranty protection. While new turbines and upgraded electrical equipment will typically come with a manufacturer's warranty, the protection afforded by the warranty may be impaired if the damage caused to the covered equipment is caused by a failure of the original equipment or infrastructure. This will result in greater risk to project developers. While repowering may appear to be a more cost-effective way of extending the life of a proven wind energy resource, the performance risks associated with integrating new equipment with older infrastructure may be challenging.

In either case, a repowered project will have to ensure that it does not exceed the performance criteria set out in the interconnection agreement with the grid operator. In the event a repowered project is expected to exceed the grid operator's operational parameters, the project developer may be obligated to perform additional interconnection studies at its own expense. Revenue may also be impacted. It is common in power purchase agreements to have a maximum production cap. In the event the repowered project exceeds the production cap, the project may be subject to a secondary pricing structure that would reduce the revenue of the project. Due to possible contractual constraints, project developers are encouraged to carefully review all existing contractual relationships and evaluate the operational and revenue impacts of repowering.

C. Offshore Wind. The end of 2016 witnessed the commencement of the first operational offshore wind farm in the United States. The Block Island Wind Farm developed by Deepwater Wind is located off the coast of Rhode Island. The 30 MW project consists of five General Electric 6 MW turbines,

and, though relatively small compared to utility-scale projects, its inauguration marks an important milestone for the renewable energy market in the United States.

According to the U.S. Department of Energy's ("DOE") National Offshore Wind Strategy report, offshore wind represents a significant opportunity to increase national renewable energy capacity. By the DOE's estimate, offshore wind has the potential to produce 7,200 terawatt-hours of electricity per year. As the market for offshore wind continues to mature, the expansion will create new opportunities for turbine vendors and contractors specializing in marine construction.

While offshore wind projects face a number of challenges including the overall cost of project execution, a number of developers are pursuing large-scale projects. Although the project does not currently have an offtake agreement in place, permits have been issued on the Fisherman's Energy Atlantic City Wind Farm off the coast of New Jersey. At completion, the project will generate 24 MW from six turbines each with a nameplate capacity of 4 MW. Further up the Atlantic Coast, the significantly more ambitious Cape Wind Project failed to receive sufficient financing to proceed, but many others are proceeding apace in New York, Massachusetts, Delaware, and elsewhere. The Pacific Coast is also seeing increased offshore wind development activity. Offshore wind developer Trident Winds is pursuing the development of a 650 MW floating wind farm off the coast of San Luis Obispo County, California. The Morro Bay Project will deploy 100 6.5 MW turbines and will be the first wind farm of its kind in the United States and a first for the California renewable energy market.

From a supply and construction perspective, the execution of an offshore wind project is a vast logistical challenge. Such projects typically involve multiple contracts and require the coordination of complex marine logistics in an evolving supply chain that increases the risk of delays, cost overruns, and weather-related delays. Multiple delivery and staging locations can give rise to Jones Act U.S.-flagged carrier issues. Also, as of this writing, there are no permanently stationed installation or maintenance vessels on either the West Coast or the East Coast capable of erection or major warranty work of large offshore units. Such vessels must come from Europe or the Gulf Coast. As a result, construction risk for offshore wind projects is higher than for land-based wind projects. Given the unique and challenging nature of offshore wind projects, successful execution will depend on the participation of experienced contractors and turbine vendors, prudent structuring of the interface between equipment suppliers and specialized contractors, as well as a reasonable construction schedule that takes into consideration the impacts of weather-related delays, and other risks commonly associated with complicated marine construction.

More information on offshore wind development is presented in [Chapter 4](#).

Chapter Nine
THE LAW OF WIND
—Project Finance for Wind Power Projects—
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I. Introduction. The universe of wind power project financing has seen a steady evolution over the past two decades. When the industry first began to see large “utility-scale” wind projects 20 years ago, early-stage development typically included equity provided by the developer and its owners/investors. But as development companies pursue larger, more expensive projects, the reliance on the owner/investors has often proven inadequate to provide the needed development capital. At the same time, competition for “shovel-ready” projects has increased, a trend that has accelerated as owner/operators have sought to acquire projects that can be “grandfathered” to qualify for the maximum amount of U.S. production tax credits (“PTCs”) available as the subsidy steps down in the coming years. As a result, developers have often entered into arrangements where a well-heeled strategic investor provides, through a combination of debt and equity, the needed capital, thus enabling the developer to proceed with project development while offering the strategic investor a first call on the project.

For wind projects ready to be built, financing continues to consist of tax equity partnerships, cash equity investments, and debt financing (most frequently through back-leverage debt). While the basic financing structures are all similar in essential outline, the details can vary significantly depending on the particulars of the project, the requirements and concerns of the investors, and the state of the market at the time.

The wind industry has seen marked consolidation over the past decade. While many windy places remain effectively untapped by the industry, most of the locations closest to load and existing transmission capacity and with the fewest significant environmental concerns have been developed. As a result, the days of “two guys in a pickup” out developing wind projects are largely gone, being replaced by arrangements between developers and strategic investors as referenced above. The number of strategic investors willing and able to assume the development and construction risk and bring new, large-scale wind projects to market has remained fairly constant, while the number of tax equity and cash equity investors has increased significantly since the depth of the recession. Niche markets remain for smaller-scale (30-80 MW) projects in certain parts of the United States, but the lender and investor profiles for those projects can vary in meaningful ways from the lenders and investors in larger-scale (100-300+ MW) projects. Today, only the most well-heeled developers and owner/operators with access to a substantial balance sheet can expect to survive through to permanent financing.

Financing (whether development, construction, or permanent) can be seen as the epicenter of wind project development. In order to weather the storms of investor and lender due diligence, all aspects of a project must be aligned such that the result is a fully functioning, revenue-generating, and legally

permitted project returning sufficient value to justify putting investor and lender dollars at risk. Accordingly, a wind project finance deal is not merely a negotiation of financial terms, but rather necessarily involves an analysis of real property rights, construction and development contracts, equipment warranties, power purchase and other offtake agreements like financial hedges, swaps and contracts for differences (whether with a utility or a commercial/industrial offtaker), interconnection rights, environmental permitting, and (of course) tax issues.

Tax issues, in particular, have dominated negotiations of wind project financing since the phase down of the PTC was agreed in December 2015, and will continue through the implementation of Congress' sweeping tax reform package artfully titled the "Tax Cuts and Jobs Act."

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 creditworthy parties that have the ability to mitigate those risks. Much of the drama in putting together wind energy 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 owner will seek 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 securing direct rights to the warranties and contractual obligations of third parties such as the equipment manufacturer and construction contractor, all to enhance the prospect of the loan being repaid on schedule. The tax equity investor, as well as any passive cash equity investor, will aim to push all project-specific risks onto the sponsor through broad representations and warranties that are backed up by indemnification obligations supported by parent guaranties and sweeps (or holdbacks) of the sponsor's 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:

- 1. Development Risk** – What is the likelihood that project assets like real property rights, interconnection queue positions and upgrades, transmission capacity, and environmental permits can be obtained in a manner (and on a timeframe) that can justify initiating negotiations of engineering, procurement, and construction ("EPC"); balance of plant; and turbine supply agreements?
- 2. Construction Risk** – What is the likelihood that the project will reach commercial operation without running over-budget or behind schedule or encountering insurmountable construction issues?
- 3. Technology Risk** – Will the technology incorporated into the project, including turbine blades and nacelles, transformers, supervisory control and data acquisition systems, and

environmental monitoring and mitigation equipment, perform as intended and has it been tested and proven?

4. Counterparty Risk – Will each project participant remain solvent and creditworthy and capable of performing its particular contractual obligations when required, such as the EPC contractor’s capacity to make good on warranty claims?

5. Revenue Risk – This is a specific species of counterparty risk focusing on the offtaker’s capacity to pay for the power generated by the project over the term of the offtake agreement (which is especially relevant with respect to commercial and industrial customers, in contrast to utilities). If the “offtake” is actually a contract for differences or a financial hedge or swap that depends on hub and node prices in a liquid market, a third-party pricing forecast is critical to assessing the revenue risk.

6. Operational Risk – Wind is an intermittent resource, so a critical question is whether the project can 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. No wind means no electricity, and no electricity means no revenues to pay project operating expenses and debt and to provide a return to the owner. And even with sufficient wind, particular attention must be paid to the ability to deliver the energy to load in the face of potential transmission constraints.

7. Political Risk – This refers to the risk of governmental action interfering with the project, ranging from denial of discretionary permits and approvals to exercise of eminent domain authority. Outside the United States, the potential for outright nationalization of projects should also be considered.

This risk shifting is accomplished by various legal undertakings by the participants: mortgages and security interests granted in the project assets, revenues, and key project agreements; warranties and contractual requirements for the equipment and the work performed in making it operational; various types of insurance to cover certain adverse events; guaranties of each participant’s obligations from creditworthy entities; and (of course) good old-fashioned indemnification (whether capped or uncapped, and whether backed in full or in part by a parent guarantee or not). The negotiation and documentation of these risk-shifting devices is the focus of activity in project financing, resulting in equity, tax equity, and loan documentation of substantial heft and complexity.

B. SPVs, Portfolios, and Recourse. In nearly all 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 and generally a limited liability company (“LLC”). 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 have its name on 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.

Purchasing the equity interests of the SPV is almost always a simpler proposition than assigning (and obtaining all necessary consents to assign) title to each asset individually in an asset purchase agreement. In a secured financing, a lender will want the parent company of the SPV to pledge the equity interests in the SPV as collateral, in addition to the pledge of project assets, to provide a simpler route to foreclosure in the case of a default.

In a portfolio financing, multiple projects can be financed together by transferring ownership of multiple project SPVs to the same holding company (provided such structure is permitted by each SPV's power purchase agreement ("PPA") and other project contracts), 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 only once a project has achieved commercial operation pursuant to the terms of its PPA in order to avoid shifting construction risk to the tax equity investor. However, that is not always the case. Portfolio financing in essence allows an investor to diversify its risk among multiple different assets 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.

Cash equity financings also often utilize a holding company to serve as the financing vehicle. In such cases, the project sponsor and the cash equity investor form a holding company that owns the non-tax equity interests in the project company (or in the holding company that owns a portfolio of projects, if a holding company structure is used at the tax equity level). Use of such an upper-tier holding company enables the sponsor and the cash equity investor to adjust their business relationship to suit their particular needs and largely removes these issues from discussion at the tax equity level.

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" financing in debt deals (the concept of recourse does not apply in equity and tax equity transactions because the investors are owners of the SPVs in question, whether directly or indirectly).

1. Full Recourse (Balance Sheet) Financing. If the financing provider has a claim against the balance sheet of the project sponsor/owner to support repayment of the debt, then the debt is said to be "full recourse" to the sponsor. It is "full" recourse in that the lender can enforce payment of the debt out of any and all unencumbered assets of the entity providing the balance sheet support to underwrite the risk that the debt will not be repaid. Balance sheet financing is usually unsecured, with the lender taking no lien on or security interest in any tangible or intangible assets of the borrower.

Balance sheet financing is generally only available to the more substantial players in the electric industry, *e.g.*, investor-owned utilities, power marketers, turbine manufacturers, and others whose

long-term unsecured debt is rated at least investment grade by one of the national ratings agencies.¹ With balance sheet financing, the focus is on the financial position and prospects of the entity providing the balance sheet, rather than on the legal, economic, and technical viability of the wind project itself. Whether the project will be successful is less of a concern than if the success of the project was the only route to repayment of the debt.

It is important to note that even substantial players in the industry with the capacity to back their debt with a balance sheet choose not to do so. Why? Opportunity cost. The more a company's balance sheet is used to support debt for one or more projects, the less it will be available for other corporate purposes like the acquisition of other companies or the maintenance of a balance-sheet debt posture that will not adversely affect the company's stock price. The alternative is "non-recourse" or "limited recourse" financing.

2. Limited Recourse (Project) Financing. If the financing provider has recourse only to the assets comprising the project in question, and not to the sponsor's assets generally, then the debt is said to be "non-recourse" or "limited recourse." (To be clear, the term is always meant as "full recourse" or "non-recourse" as to the sponsor. Even "non-recourse" claims of a lender still have recourse (1) to the project for loans made directly to the project company SPV and (2) to sponsor's interests in the project SPV for back-leverage loans.²) 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 all the value of the project taken from it through foreclosure, sale of the project, diversion of the project cash flow stream, equity dilution, or other remedy. While project debt financing generally means non-recourse financing, many deals will include specifically negotiated parent guaranties for various perceived risks and other credit support or capital contribution obligations that blur the lines of the non-recourse structure.

C. Milestone Terminology. The risks placed upon, and the benefits available to, investors in wind 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 plugging into concepts defined in other project contracts, the U.S. tax code and Treasury Regulations, or other sources. It is therefore 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

¹ The minimum investment grade ratings from Moody's Investors Service and Standard & Poor's Corporation are "Baa3" and "BBB-," respectively.

² It should be noted that loans made directly to the project company SPV are rare for wind projects as they have adverse impacts on the tax equity investors, and hence most debt financing for wind projects is back-leverage debt incurred at the sponsor level. Because tax equity investors are true equity owners, they are not secured by interests in the project assets. Instead, they may well have full recourse to the sponsor for various indemnification obligations.

and is usually the first point in the construction process at which a large sum must be funded (initial payments in connection with the turbine supply agreement will most often have been made prior to NTP, but sometimes those payments will be made concurrently with NTP). In some cases, sponsors will leverage their balance sheets to fund the NTP payments. In other cases, NTP is the kick-off point for construction debt.

- **“Commercial Operation Date” or “COD”** is the term generally used by a project’s PPA or other offtake arrangement to signify that Substantial Completion (discussed below), facility operation, and interconnection to the grid have occurred. An offtaker’s obligation to purchase power generally begins no later than COD, and in many cases, tax equity investors will not fund their committed investment until COD has been achieved, a sign that the project has been fundamentally de-risked from a construction standpoint.
- **“Begun Construction”** is the concept used by the IRS to determine a wind project’s eligibility for the PTC, as well as the value of the PTC for which it qualifies. In December 2015 Congress passed a phase-out of the PTC ending in 2020. The step-down in value of the PTC on a per-kWh basis began in 2017, and will be reduced to zero for wind projects that begin construction after December 31, 2019.
- **“Mechanical Completion,” “Substantial Completion,” and “Final Completion”** are terms most frequently used to describe the key completion milestones under an EPC contract. Mechanical Completion means completion of construction of the physical assets comprising the project but short of making the project operational and able to deliver energy to the grid (often accomplished by completing the construction of the project but not physically interconnecting it to the grid). Substantial Completion means completion of the project to the point where it has achieved COD and has been interconnected to the grid, but with “punch list” items (*i.e.*, items that are not essential to the achievement of COD) not yet completed. Final Completion means completion of all “punch list” items post-COD. Mechanical Completion and Substantial Completion are typically associated with solar project financing, and for good reason. Generally speaking, solar projects are financed (at least in part) by monetizing the U.S. federal investment tax credit (“ITC”), and those terms are critical to determining when the tax equity investor becomes an “owner” of the project.³ Wind projects, on the other hand, utilize the PTC, which does not hinge on funding by tax equity investors at any particular time.⁴ Final Completion, regardless of whether the project utilizes solar or wind power, signifies completion of the

³ For a more comprehensive discussion of the ITC, see [Chapter 10](#).

⁴ Fundamentally, the ITC would only be more valuable (relative to the PTC) for expensive, lower-producing facilities.

punch-list and the end of the EPC scope. These three terms are not universal, and some EPC contracts use other nomenclature or have fewer or more milestones.

III. Tax Equity Financing. Tax equity financing is a creature owing its existence to the U.S. tax code, and is subject to the whim of federal politics and tax policy. As discussed more thoroughly in [Chapter 10](#), the PTC permits an equity owner of a qualifying generation facility⁵ located in the United States to claim a tax credit based on an inflation-adjusted per-kilowatt hour price for electricity produced by that facility. The taxpayer need not own the facility on the date that it was placed in service to take advantage of the PTC; so unlike tax equity investors in solar projects that use the ITC, tax equity investors in wind projects can become owners at any time in the life of the wind project and still monetize the PTCs that arise from and after the time they become an equity owner (but they cannot claim any PTCs generated prior to becoming an equity owner).

An owner may also be able to claim accelerated or bonus depreciation with respect to the cost of an asset. Indeed, as the potential for comprehensive tax reform loomed over the tax equity market beginning in November 2016, tax equity investors looked hard at the value of bonus depreciation in the early years of a project's life to offset income that would be taxed at higher rates. In combination, these benefits can offer a sizeable reduction to the federal tax liability of a wind project owner, allowing the owner to offset its taxable income based on the output of the wind project.

Most wind project developers do not have taxable income sufficient to take advantage of the PTC or the large tax losses created through the depreciation of project assets.⁶ As a result, a relatively small group of financial institutions and corporations with significant federal tax burdens have emerged to invest in projects as tax equity owners. The work of structuring transactions to permit these tax liability-laden investors to match up with qualifying wind projects and claim the benefit of the PTCs and depreciation is the central function and challenge of wind tax equity financing.

To maximize the PTC 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 in order to claim the PTC.⁷ However, tax equity investors view themselves as purely financing providers, enticed to invest in the project only when offered a comparatively secure position resembling that of a lender. Tax equity investors are loathe to take on risks alongside the sponsor. Instead, they require certainty as to a

⁵ Importantly for wind projects, each individual wind turbine is a separate "facility" for PTC purposes.

⁶ Over time, we have seen more and more strategic investors enter the industry as owner/operators. As the operations of those investors in the United States has grown, their appetite to use the tax benefits themselves has also grown. Nevertheless, both traditional project developers and such strategic investors most often seek to leverage their position by bringing in third party tax equity investors. Tax equity investments allow owners of all stripes to bring forward a portion of their profit in the form of the premium paid by the investors for an interest in a project that has been virtually (if not entirely) de-risked from a construction standpoint, thereby replenishing capital that can be deployed elsewhere.

⁷ An investor cannot claim any PTCs to offset taxable income if the PTCs in question were generated prior to the investor being an equity owner of the project. Such pre-investment PTCs are thus "lost" in the sense that they have no value to the tax equity investors and hence are not part of the tax benefits monetized through the tax equity financing. To minimize any such loss of PTCs, tax equity financings are most often designed to have the tax equity investors become equity owners as close as possible to COD.

project's viability and construction completion before investing and demand that the transaction be structured to give them priority 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 in an operating agreement for the project company between the sponsor and the tax equity investors. 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 it.

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, having no ability to rely on a collateral security position in any project assets, the tax equity investor is exposed to potential risks of the sponsor's mismanagement of the project (*e.g.*, breach of a project contract or other event leading to diminution in a project's value). To counterbalance this risk, tax equity investors generally require that a creditworthy parent of the sponsor guarantee the 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, and, depending on the transaction, post-funding change in tax law.

Tax equity structures rely largely on the principle of bifurcation. In the partnership flip structure, the tax items of a partnership are allocated separately from the partner's respective cash flows and management rights.

A. Partnership Flip. Over the years, the partnership flip structure has become the standard vehicle for PTC-driven tax equity investments. The core of the structure is the operating agreement for the limited liability company that directly owns the wind project. When tax equity makes its investment (assuming the sponsor has not already brought in a cash equity investor at the project company level) the project company becomes a partnership, and the operating agreement sets forth the allocation of cash and tax benefits between the partners. As an LLC, the project company is a "pass through" entity for tax purposes, meaning that there are no income taxes due at the partnership level. Rather, taxes are paid on the partners' (or their upstream owners') corporate tax returns. Likewise, any tax benefits realized by the project company are allocated to the partners under the operating agreement and passed through to the taxpayer.

In a partnership flip transaction, the allocation of cash and tax benefits under the operating agreement will "flip" between the partners one or more times during the life of the partnership. In a typical scenario the tax equity investor will realize the vast majority (often 99 percent) of the tax benefits either until the end of the 10-year PTC period or an earlier stated date (a time-based flip) or until it reaches its target return (a return-based flip), after which the allocation "flips" and the sponsor receives the majority (usually, but not always, 95 percent) of the remaining tax benefits. Under the safe-harbor rules promulgated by the IRS that govern these transactions from a tax standpoint, the tax equity investor

must retain at least a 5 percent residual interest in the project company.⁸ From the sponsor's point of view, the tax equity investment⁹ allows the sponsor to maximize the value of tax credits that it could not otherwise use while retaining management control of the project and receiving a separately allocated portion of project cash.

While the sponsor is receiving only 1 percent of the tax benefits during the early years of project operations, cash generated by the project (*e.g.*, through the sale of electricity and renewable energy credits) can be, and most often is, distributed to the partners in completely different percentages than the tax profits and losses.¹⁰ The allocation of tax benefits and project cash, taken together, is negotiated between the parties up front to balance (1) tax equity achieving its target return within a defined period of time (generally between nine and 10 years) and (2) the sponsor receiving as much cash as possible during operations.

By utilizing this structure (often called a “disproportionate allocation partnership”), the sponsor minimizes the tax credits and deductions it receives, having effectively monetized the lion's share of such tax credits and deductions by allocating them to the tax equity investors in exchange for the tax equity investors' investment, while at the same time receiving what can be very substantial cash flow from the project in the form of its share of the distributable cash.

B. PAYGO. What happens in a time-based flip where the tax equity investors receive their target return before the end of the PTC period (*i.e.*, before the end of the 10th year after the last wind turbine at the project is placed in service)? After all, the project will not stop generating PTCs until the end of the PTC period. Sometimes, the tax equity investors will opt to stay in the deal during that period and agree to make capital contributions to the project company post-flip in exchange for the PTCs that the sponsor does not want or cannot use—referred to as a “PAYGO” (abbreviation for “pay-as-you-go”). The amount of the tax equity investors' additional capital contributions is often capped, and the price paid for the PTCs may be less than the \$24.00/MWh value of the PTC.

IV. Project-Level Debt.

A. Overview. Though debt financing has been overshadowed in the wind industry by the prevalence of tax equity, the progressive step-down of the PTC¹¹ portends that wind projects will

⁸ As noted above, the 5 percent residual interest is required for PTC qualification to ensure that the tax equity investor is truly an equity investor, and its investment is not treated as debt despite the various lender-like protections built into the operating agreement (*e.g.*, cash sweeps). Typically, the sponsor will have a buyout right with respect to the tax equity investor's interest in the project company after the flip. But if the buyout option is not exercised, the tax equity investor would be a long-term minority interest holder in the project company.

⁹ The tax equity investment typically amounts to approximately 40 percent of the total project cost, though depending on the particular tax equity financing structure employed and the nature of the project, tax equity may fund 50 percent or more of the total project costs.

¹⁰ Note that cash generated by a project does not always give rise to taxable income. Owing to depreciation and operating expense deductions, it is typically the case that in the early years of operation, a project generates significant cash flow but little, if any, taxable income.

¹¹ The PTC for projects that began construction in 2017 is 80 percent of its nominal value. The PTC for projects that begin construction in 2018 is 60 percent of its nominal value. The PTC for projects that begin construction in 2019 is 40 percent of its nominal value. For projects that begin construction after December 31, 2019, the value of the PTC is zero.

increasingly be financed 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, if secured by a perfected first lien on the project assets, have a claim for the amounts owed that is senior to 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 wind projects, it is useful to classify debt primarily in relation to a project's lifecycle. Roughly speaking, there are three categories of debt for wind projects, each discussed in more detail immediately below: (1) development-stage debt for the pre-construction period, (2) construction debt to finance the period of active EPC work, and (3) 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, wind resource assessments, 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 turbine manufacturers looking to ensure their product is used in the project. In certain instances, 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; a high interest rate; and a promise to grant the lender a right of first refusal to the next round of larger financing or, in the case of a strategic investor, the option to buy the project.

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 similarly 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 over budget 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 the sponsor's incentives, and to avoid extending loans beyond the project's expected collateral value, construction lenders generally require a certain minimum sponsor equity contribution as a condition to any construction loans being funded, 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 lender fees and expenses, with any excess required to be applied to debt service as mandatory prepayments. Since wind projects do not generate revenue during construction (other than payments for test power late in the construction process), 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 prohibit any cash distributions to equity holders during the construction period.
- 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 O&M contracts), all permits, all cash, and all equipment and materials.

In addition to taking collateral 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 collateral assignment of such material contract to the lender, which consent will include, among other things, an acknowledgement of the lender's rights, an agreement to give the lender notice of any default by the project owner, and a grant to the lender of certain rights to cure defaults by the project owner. 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 or other offtake arrangement), the consent also will include a provision directing those payments into an account controlled by the lender.

To ensure the project will benefit from a tax equity commitment, including after a foreclosure by the lender, 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 upfront, lenders generally disburse loans for budgeted project costs as such costs become due, and the loan proceeds are immediately applied to invoiced project costs then due. As standard contract payment terms require payment within 30 days of invoicing, projects typically borrow 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 counterparties, and the title company will require such lien waivers in order to issue a customary date-down endorsement to the title policy insuring the lender's security interest in the project.¹²
- A breach or default under any tax equity transaction document (in addition to a breach or default under any loan document or material project document, or any other event reasonably likely to have a material adverse effect on the project) 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

¹² For a more comprehensive discussion of title issues, see [Chapter 2](#).

portion of the construction debt, lenders are wary of any event that could jeopardize the tax equity investment.

If a project financing involves both debt and tax or cash equity, the construction loan will be sized to be repaid from some combination of the permanent term loan and the tax or cash equity investment. Thus, construction loans are often 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 wind project, a sponsor will typically trade its restrictive and expensive construction debt for (or convert it into) permanent financing, allowing recoupment of invested capital. It is often the case that the construction loan will be converted to permanent financing when certain conditions are met (the conditions generally being that the project has achieved commercial operation and the tax equity investment is funded). The permanent financing often has a comparatively gentler set of loan terms than during construction, since the tighter restrictions used to protect the lender against construction risks are no longer needed. 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 during construction.

It should be noted that the financing is “permanent” only in the sense that it is put in place post-construction (even permanent debt becomes due on a maturity date). 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. The term of the permanent financing may be as short as five years (with a balloon payment at the end of the term that will require another financing) and is not necessarily in place for the useful life of the project. Terms of 12 to 15 years are not unusual, although most permanent lenders will require that the term be somewhat less than the term of the related power purchase agreement, to allow a buffer in the event the project encounters performance problems. Thus, “long-term” debt or “take-out” financing (*i.e.*, that takes out the construction debt) is a more descriptive name than “permanent” debt.

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, lender expenses and debt service, 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 (subject to satisfaction of negotiated distribution tests as described below). 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 typically only permit distributions to the equity owners if the project can demonstrate compliance with a specified financial covenant, any required cash reserves for the project are fully funded, and no default or event of default exists. The financial covenant usually is a Debt Service Coverage Ratio (“DSCR”) test, which requires that net revenues (*i.e.*, those remaining after payment of operating expenses) over a certain period (typically a one-year period) exceed required debt service during that period by a certain ratio, *e.g.*, at least 1.25:1.00. If the distribution requirements are not met at the time the waterfall is run, available cash will be trapped in a secured account and the borrower will not be able to distribute the cash to the equity owners until such requirements have been met. Funds that remain in the secured account for a specified period of time as a result of a failure to meet the distribution requirements on successive testing dates often will be required to be used to prepay the loan.

2. Back-Leverage Debt. Because of the need to monetize the PTCs and depreciation through a tax equity financing, most wind projects do not utilize debt financing at the project company level. Under applicable federal income tax rules, the existence of debt at the project company level can result in large deficit reduction obligations on the part of the tax equity investors—something that tax equity investors seek to avoid or limit. Furthermore, at current PTC levels, the tax equity financing itself generally provides funding for about 40 to 50 percent of the project costs, and thus effectively replaces a large portion of the debt that might otherwise be incurred to finance the project. However, that still leaves a large percentage of the project costs to be funded by an equity contribution from the project sponsor—requiring an amount of available capital that wind developers without access to a substantial corporate balance sheet cannot readily provide. Hence the use of so-called “back-leverage debt.”

Back-leverage debt involves a loan at a level above the project company where the project sponsor (or more likely a holding company formed by the sponsor for such purpose) is the borrower. By moving the debt financing up the chain to the project sponsor, (1) the sole collateral securing the debt is the sponsor-side equity interests and the associated cash held by the holding company borrower, (2) tax equity avoids the consequences of unacceptable large deficit restoration obligations, and (3) the sponsor leverages its investment by using the debt to replace a portion of its equity contribution, enabling it to recycle that equity in to other projects.

But why is the sole collateral securing the debt the sponsor-side equity? Why would the back-leverage lender not take a security interest in any of the wind project assets? The answer is simple: tax equity will not allow its investment in the project to be put at risk for a borrowing that only benefits the sponsor, which is what would happen if the project assets were subject to a lien securing the sponsor

debt. In short, tax equity investors do not like to take this sponsor risk.¹³ 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 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 non-starters in permanent loans and will not allow any liens on the wind project assets. Instead, the lender is secured by a collateral assignment of the holding company's membership interest in the project company, often supported by a guarantee from the sponsor's parent.

Given that the back-leverage lender is not secured by the project assets, the lender pays particular attention to the holding company's right to receive project company cash flows sufficient to service the debt. The details of project company cash flow distributions vary depending on the particulars of the project, the perceived risks, the nature of any parent guarantee backstopping repayment of the debt, and the structure of the tax equity financing. But the ultimate goal is to structure an arrangement that, under various downside scenarios, is calculated to provide the sponsor with sufficient cash flow to service the debt and keep it out of the "nonperforming loan" category while not diverting funds from tax equity that would unduly delay the tax equity flip date.

V. Cash Equity Financing. As an alternative to back-leverage debt, some project sponsors seek to bring additional capital to the project by bringing in a "cash equity" investor in addition to the tax equity investors. Like back-levered debt, this cash equity financing effectively takes place at the sponsor level, although it can involve either a direct equity investment in the project company or investments by both the sponsor and the cash equity investor in a holding company that owns the sponsor equity in the project company.

Under a tax equity financing structure, the sponsor and tax equity investor own separate classes of membership interests in the project company. If the sponsor brings in a cash equity investor, it has two options: (1) the sponsor can sell the cash equity investor a portion of the sponsor membership interests in the project company or (2) the sponsor can sell the cash equity investor a portion of the membership interests in the holding company that owns the sponsor equity in the project company. Whether one structure is selected over another depends upon the terms of the deal between the sponsor and the cash equity investor. From tax equity's perspective, all sponsor-side equity should be treated the same (or, said differently, tax equity expects the same treatment from each other equity investor in the project company). It can therefore simplify negotiations somewhat by having the sponsor take the lead on negotiations with tax equity on behalf of the holding company. In that scenario, any special arrangements between the sponsor and the cash equity investor (*e.g.*, preferred returns) would be

¹³ As noted above, tax equity will seek to avoid taking any sponsor risk to the extent it can be avoided. A key means of protecting themselves against identified risks is through sponsor indemnification obligations supported by a guarantee from a creditworthy parent.

addressed solely between them in the “upstairs” holding company LLC agreement. Tax equity would have no insight into that arrangement, nor should it, since the sponsor and the cash equity investor would be sharing the holding company’s portion of project company returns. And if the cash equity investor is coming in during negotiation of the tax equity deal, then regardless of which structure is selected, the sponsor should expect that the cash equity investor will be involved behind the scenes in determining the holding company’s position on issues like allocations, distributions, cash traps, and indemnification obligations at the project company level.

The cash equity investor thus becomes an owner of the project company and shares in the return that would otherwise go to the sponsor. The sponsor generally provides the cash equity investor with indemnities and guaranties on various project stress points similar to those provided to the tax equity investor. In some cases, the cash equity investor may get exactly the same indemnities and guaranties, effectively de-risking cash equity’s portion of the holding company cash flows in exactly the same manner that tax equity protected its cash flows. That said, both the tax equity investor and the cash equity investor take on real project risk—if the project fails to perform, neither may realize the return it seeks.

Cash equity investments can be structured in a manner that makes them function like back-levered debt. Under such an approach, the cash equity investor gets a preferred return designed to amortize its investment over a target term and provide an agreed upon return. A preferred return interest is usually structured so that it constitutes “debt” for tax purposes, thus allowing the sponsor to deduct the “interest” (or return) portion of the preferred return.

But even if the preferred return functions like debt, the cash equity investor’s right to repayment is not the same as the right of a lender to repayment of its back-leverage loan. If the project performs well, the preferred return payment schedule will be met in a timely manner and upon payment of the preferred return, the cash equity investor will cease to have any rights to the project company (or holding company) cash flows (and typically has no further voting rights on project company matters). But since this is a true equity investment, the cash equity investor takes the risk that if the project does not perform properly, it may never realize its desired return. Unlike true debt, payment of the preferred return is not an absolute obligation, but rather one that is only paid to the extent the project generates sufficient cash flow.

Cash equity investors also have greater rights with respect to the management of the project company than the typical back-leverage lender. Whether as members of the project company or as members of the holding company that owns the sponsor equity interest in the project company, the cash equity investor typically has various rights and controls, including approval rights with respect to the project company budget and a long list of potential actions usually defined as “major decisions” or “fundamental decisions.” While lenders, through affirmative and negative covenants, can secure comparable rights, since they are not direct or indirect members of the project company, those rights are one step removed from the action and far less “hands on” than the rights afforded cash equity investors.

With the scheduled demise of the PTC, there is likely to be a rise in both traditional project level debt financing and cash equity financing of wind projects. As long as wind resources remain attractive to load-serving entities and commercial and industrial offtakers, history indicates that there will be ways of financing them.

VI. Conclusion. Many more topics could be covered under the heading of wind project finance: insurance requirements, interparty issues between tax equity investors and lenders, monetization of tax credits and other tax benefits, issues relating to transmission and imbalance charges, the fine details of the evolving offtaker market, and other major project agreements. While the foregoing treatment is not exhaustive, it nevertheless provides a framework for approaching these and other topics. No matter what aspect of wind project financing one examines, the essential dynamic at play will be the search for credit and the corresponding effort to reduce or eliminate risk.

Chapter Ten

THE LAW OF WIND

—Tax Issues—

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The tax system often is used to provide incentives for investments in certain types of projects the government wants to encourage, including wind power projects. These incentives raise tax planning issues that go well beyond those involved in general structuring, 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.

FEDERAL INCOME TAX ISSUES

I. The Production Tax Credit. Section 45 of the Internal Revenue Code of 1986, as amended (the “Code”), provides a credit against federal income tax for producing electricity from certain renewable resources, including wind. This credit is known as the “production tax credit” (the “PTC”).

A. Requirements for Claiming the Credit. The PTC for wind power applies to electricity that is (1) produced at a qualified facility during the 10-year period that begins on the date the facility was originally placed in service and (2) sold to an unrelated person. Each of the following requirements must be satisfied for a taxpayer to qualify for the PTC:

1. Produced by the Taxpayer. The electricity must be produced by the taxpayer seeking to claim the PTC. If more than one person has an ownership interest in a facility, production from the facility is allocated among the owners in proportion to their respective ownership interests in gross sales from the facility. A partnership (including an LLC that is treated as a partnership for federal income tax purposes) is treated as one person for purposes of this rule, which means that individual partners are not treated as owning separate, undivided portions of a facility that is owned by a partnership.

2. Qualified Energy Resources. The electricity must be produced from wind or another qualifying renewable resource.

3. Qualified Facility. The electricity must be produced by a facility located in the United States that is owned by the taxpayer claiming the PTC, that is originally placed in service after December 31, 1993, and the construction of which begins before January 1, 2020. A wind facility generally is considered to be “placed in service” for purposes of this rule when the facility is placed in a condition or state of readiness and is available to produce electricity. Each wind turbine that is capable of being separately operated and metered, together with its tower and supporting pad, is considered a

separate “facility” for purposes of this placed-in-service rule. The Internal Revenue Service (the “IRS”) has issued a number of notices—Notice 2013-29, Notice 2013-60, Notice 2014-46, Notice 2015-25, Notice 2016-31, and Notice 2017-4 (collectively, the “Notices”)—that describe two alternative methods for a taxpayer to be treated as having begun construction in a particular taxable year. Under the first method, a taxpayer must have performed physical work of a significant nature during the taxable year and must maintain a continuous program of construction thereafter. Alternatively, under the second method, the IRS will consider construction as having begun if the taxpayer paid or incurred 5 percent or more of the total cost of the facility in a particular taxable year, and thereafter made continuous efforts to advance towards completion of the facility. The Notices also contain special rules describing circumstances under which the continuous construction and continuous efforts requirements will be deemed satisfied. Generally, the continuous construction and continuous efforts requirements will be deemed satisfied if a facility is placed in service by the later of (1) the calendar year that is no more than four calendar years after the calendar year during which construction of the facility began or (2) December 31, 2018.

4. Sold by the Taxpayer. The electricity must be sold by the taxpayer claiming the PTC to an unrelated person during the taxable year.

5. No Advance Approval Required. There is no advance approval requirement for claiming the PTC. A taxpayer that is entitled to the credit simply reports it on the appropriate form attached to the taxpayer’s federal income tax return.

B. Calculation of the PTC. The PTC for any taxable year during the credit period generally is equal to 1.5 cents, adjusted for inflation, multiplied by the number of qualified kilowatt-hours (“kWh”) of electricity produced and sold by the taxpayer during the year. For electricity produced and sold during 2017, the inflation-adjusted PTC amount was 2.4 cents per kWh.

C. Phase-out of Credit for Wind Facilities. The amount of the PTC calculated for each year is reduced by 20 percent in the case of any facility the construction of which begins after December 31, 2016 and before January 1, 2018, 40 percent in the case of any facility the construction of which begins after December 31, 2017 and before January 1, 2019, and 60 percent in the case of any facility the construction of which begins after December 31, 2019 and before January 1, 2020. Facilities with respect to which construction begins on or after January 1, 2020 currently are not eligible for the PTC.

D. Disqualified Wind-Generated Electricity. Disqualified wind-generated electricity is not taken into account in computing the PTC. With certain exceptions, disqualified wind-generated electricity generally is electricity that is (1) produced at a wind facility that is placed in service by the taxpayer after June 30, 1999 and (2) sold to a utility pursuant to a contract originally entered into before January 1, 1987, whether or not the contract was amended or restated after that date.

E. Cutback for Government Financing. The amount of the PTC is reduced for facilities financed in whole or in part with certain government grants, proceeds of tax-exempt bonds, subsidized

energy financing (financing provided under a federal, state, or local program designed to provide subsidized financing for energy conservation projects), or other tax credits. The IRS has ruled that certain state tax credits do not reduce the PTC.

F. Nonrefundable Credit. The PTC is a “nonrefundable” credit. If a taxpayer entitled to the PTC 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 any excess credit. Any unused portion of the credit generally may first be carried back one tax year and then be carried forward 20 tax years from the year the credit arose.

G. Sunset Date. As described above, to qualify for the PTC a taxpayer must have begun construction on the facility before January 1, 2020. The sunset date has been extended a number of times since Section 45 was first added to the Code (once retroactively after the PTC had expired for a number of months). Proposals to extend the sunset date are a matter of frequent discussion, and it is possible that the sunset date could be extended beyond the current deadline by future legislation.

II. The Investment Tax Credit. Sections 46 and 48 of the Code allow the owner of a qualified wind facility that is placed in service on or after January 1, 2009 and construction of which begins before January 1, 2020 to elect to claim the investment tax credit (the “ITC”) in lieu of the PTC. 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. For facilities on which construction began before January 1, 2017, the amount of the ITC for a qualified wind facility is 30 percent of the tax basis (generally the cost) of the qualifying property that is placed in service during a taxable year. The amount of the ITC is reduced by 20 percent in the case of any facility the construction of which begins after December 31, 2016 and before January 1, 2018, 40 percent in the case of any facility the construction of which begins after December 31, 2017 and before January 1, 2019, and 60 percent in the case of any facility the construction of which begins after December 31, 2018 and before January 1, 2020. Facilities on which construction begins on or after January 1, 2020, are currently not eligible for the ITC.

A. Requirements for Claiming the ITC. The ITC applies only to “energy property,” which is defined for purposes of a wind facility to include property that meets the following requirements:

1. Wind Equipment. The property must be equipment that is used to produce electricity from wind. The property must be (1) tangible personal property or (2) other tangible property (not including a building or its structural components) that is an integral part of the wind facility.

2. Depreciable or Amortizable. The property must be eligible for depreciation or amortization deductions for federal income tax purposes.

3. Qualified Facility. The property must be part of a qualified facility that is located in the United States, is owned by the taxpayer seeking to claim the ITC, and construction of which begins before January 1, 2020.

4. **No PTC Allowed.** The property cannot be part of a facility for which the PTC has been allowed.

5. **Irrevocable Election.** The owner of the property must make an irrevocable election to claim the ITC rather than the PTC.

B. **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 ITC. Thus, for facilities the construction of which began before January 1, 2017, the initial tax basis of the qualifying components of a wind facility with respect to which the ITC is claimed generally will be 85 percent of the cost of those components.

C. **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.

D. **No Cutback for Government Financing.** The ITC, unlike the PTC, generally is not reduced with respect to facilities that are financed in whole or in part with the proceeds of tax-exempt bonds, subsidized energy financing, or other forms of government-supported financing.

E. **Nonrefundable Credit.** The ITC, like the PTC, is a nonrefundable credit. If a taxpayer entitled to the ITC does not have sufficient income tax liability to use the entire credit in the year in which the project is placed in service, 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 first be carried back one tax year and then be carried forward 20 tax years from the year the credit arose.

F. **Sunset Date.** To qualify for the ITC, a taxpayer must have begun construction on a facility before January 1, 2020. See Section II above for an explanation of the “beginning of construction” requirements.

III. **U.S. Treasury Department Grants.** The American Recovery and Reinvestment Act of 2009 allowed the owner of a qualified wind facility that is eligible for the ITC (including by reason of an election to claim the ITC rather than the PTC) to elect to receive a grant from the U.S. Treasury Department in lieu of claiming the ITC or the PTC 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. Grants are no longer available for wind projects placed in service after December 31, 2013.

IV. **Depreciation.** In addition to tax credits or grant payments, wind 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.

A. MACRS Depreciation. Qualifying components of a wind farm are eligible for greatly accelerated depreciation deductions, typically over a five-year period based on the double declining balance method of depreciation.

B. Bonus Depreciation. An owner of qualifying property that is acquired and 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. For qualifying property acquired after September 27, 2017, an owner of qualifying property 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.

V. 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 taxable income) may nevertheless be able to benefit from various tax incentives by entering into an arrangement with an investor that can use credits, losses, or both. For example, a taxpayer could enter into a partnership with an investor that is willing to contribute cash to help finance a wind power facility. The partnership could then operate the facility and, within certain limits, the tax credits and losses could be allocated to the partner that can use them. In 2007, the IRS published guidance (Revenue Procedure 2007-65) establishing a safe harbor for structuring these partnership transactions. A number of specific requirements must be satisfied to qualify for the safe harbor. In the alternative, a taxpayer could develop a facility, place it in service, sell it to an investor, and then lease it back from the investor. This second alternative, known as a “sale-leaseback,” is available with respect to the ITC, but generally is not available with respect to the PTC. These and other potential techniques for “monetizing” tax credits and losses involve risk and require careful tax planning. These considerations should be taken into account in the very early stages of project development, including when choosing the type of entity that will own a facility and the various financing alternatives available. A comparison of the economic benefits of the PTC and the ITC 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.

STATE AND LOCAL TAX ISSUES

In addition to federal income tax issues, construction and operation of wind 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. Despite widespread economic recovery, rapidly rising pension and health care costs have caused many states to narrow their tax-based direct development incentives, either by interpreting existing law narrowly or by legislative change, sometimes with retroactive effect.

I. 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.

A. Nexus, Business Structure, and Apportionment. Siting a wind 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.

B. Income Tax Incentives. Some income tax states offer incentives to promote the development of wind power 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.

Hawaii and Montana, as examples, offer income tax credits for certain alternative energy systems, including wind systems. Hawaii provides a tax credit equal to the lesser of 20 percent of the cost of a wind 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 wind 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 and 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.

Oregon formerly offered a similar investment-based credit, known as the Business Energy Tax Credit (the “BETC”), for development of wind 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.

II. 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.

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

B. 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.

C. Sales Tax Incentives. A number of states, including Washington, Colorado, and Nevada, have adopted an exemption or partial abatement from sales tax for machinery and equipment used in wind facilities. As noted above, some of these exemptions have recently been narrowed or are subject to sunset dates.

III. 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:

A. “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, a facility with a generating capacity of 50 megawatts or more may be subject to central assessment.

B. 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 wind power have been successful in some states, such as Colorado.

C. 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.

D. 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.

E. Property Tax Incentives. As part of due diligence in constructing or acquiring a wind 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 and, in contrast to income tax, property tax is often highest in the early years before the project is profitable. For example, 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.

F. Taxes in Lieu of Property Tax. States may impose taxes in lieu of property tax. Minnesota, for example, imposes a wind energy production tax in lieu of property tax on wind facilities.

The owner of a wind energy conversion system must report the annual production (in kWh) of the facility to the Minnesota Department of Revenue by February 1 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 varies based on the nameplate capacity of the facility. In addition, a developer of a new or existing facility may be able to negotiate with the applicable county to establish a payment in lieu of the wind energy production tax based on production capacity, historical production, or other agreed-upon factors. Similar to Minnesota, Idaho imposes a wind energy production tax in lieu of property tax on wind facilities equal to 3 percent of the gross wind energy earnings, which are defined as the gross receipts of a wind energy generator from the distribution, delivery, and sale of electrical energy generated, manufactured, or produced by means of wind energy within Idaho to a customer for direct use or resale.

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

A. 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.

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

Chapter Eleven
THE LAW OF WIND
—Choice of Entity Structure—
William L. Clydesdale, Kevin D. Johnson, Kevin T. Pearson

The developer or owner of a wind power project typically holds a variety of real property rights, equipment, permits and regulatory approvals, and intellectual property. Creating the optimal corporate structure and entity to hold these assets is an important first step toward the project's success. Planning early helps avoid costly transitions later.

I. Use of Subsidiaries. There are many reasons to develop, own, or operate a wind power project through a subsidiary created specifically for that purpose:

A. Insulation from Risk. The use of a single-purpose subsidiary to own a wind power project allows the parent company to limit its potential liability to the value of the assets of the project. If a company holds several projects directly or owns other assets, a creditor with respect to one project can seek recovery against all of the company's assets.

B. Financing. Financing for wind power projects is typically provided on a stand-alone, limited recourse basis in which the lender looks primarily to the cash flow and assets of the project to satisfy debt service obligations. In this regard, the ownership of the project assets in a single-purpose subsidiary enables a project lender to protect its collateral package from other creditors. For more information about financing, see [Chapter 9](#).

C. Exit Strategy. The use of a subsidiary also facilitates a transfer of all or portions of the project. It is easier to sell a wind project by transferring ownership interests in a subsidiary that owns the project than to identify and transfer commingled assets. Even if a company prefers to sell assets, the isolation of the assets in a subsidiary simplifies the transaction.

II. Choice of Entity. The choice of entity to own the project, whether a corporation, partnership, or limited liability company ("LLC"), is generally less significant than the choice to use a subsidiary. However, subtle differences exist among the entities based on various factors, such as taxation, liability, and transferability issues.

A. Taxation. Corporations are separate taxpaying entities. As a result, the income of a corporation is generally subject to two levels of tax: one at the corporate level and again at the shareholder level when distributions are made, stock is sold, or the corporation is liquidated. Partnerships (including LLCs that are treated as partnerships for tax purposes) are "pass-through" entities that are generally not themselves subject to income tax; rather, the income, deductions, gains, and losses flow directly to the partners or members, who report these amounts on their individual returns.

1. **Distributions.** Corporate distributions must generally be made on a pro rata basis to shareholders while partners in partnerships and member interests that are taxed as partnerships have more flexibility in allocating profits, losses, and credits, including the production tax credit, and in making distributions on a non-pro rata basis. Partners and members can also generally allocate profits or credits in one way and losses in another. Moreover, subject to various limitations in the tax laws, partners and members generally may use partnership and membership losses against other taxable income.

2. **Tax Credits.** A corporation (rather than its shareholders) must use tax credits. If it cannot use tax credits (for example, if it has insufficient net income), and if it cannot carry the credits forward or back to a tax year in which the credits can be used, the credits expire. Partnerships and LLCs that are taxed as partnerships, however, pass credits through to their partners or members, who generally may use them to offset their separate tax liability, including their tax liability from other activities or operations, subject to a variety of limitations. As discussed in [Chapter 9](#), this may be an especially important consideration if a developer wishes to “monetize” tax credits through a tax equity financing arrangement. The ability of individual (as opposed to corporate) partners or members to use tax credits may be limited by the “at risk” and “passive activity” limitations imposed by tax rules.

3. **Losses.** Corporate losses must also be used, if at all, at the corporate level. Losses of a partnership or an LLC that is taxed as a partnership, however, are passed through to its partners or members, who may be able to use them against their separate income, including income from other sources. The ability of individual (as opposed to corporate) partners and members to use losses may be limited by the “at risk” and “passive activity” limitations imposed by tax rules.

4. **Contributions.** Contributions of property (as opposed to services) to a corporation, either upon its initial organization or admission of additional owners, may trigger the recognition of gain with respect to the contributed property unless certain control requirements are satisfied. On the other hand, except in certain limited circumstances, contributions to partnerships or LLCs in exchange for an ownership interest are generally not taxable events.

5. **Reorganizations.** Corporations generally may engage in tax-free reorganizations, whereas a partnership or an LLC that is taxed as a partnership generally may not.

6. **State Taxes.** Applicable state taxes may favor the selection of one legal structure over others.

B. Liability. Shareholders, limited partners, and members are generally not liable for the debts of the entity beyond their capital contributions, whereas the general partner is generally liable for the debts and obligations of the partnership. In certain circumstances, such as when the entity fails to comply with corporate formalities or when the subsidiary is undercapitalized, owners may be held liable for the debts of the entity. Because corporations generally must comply with more formalities than partnerships or LLCs, there may be less risk that limited partners or members of an LLC would be liable for the debts and obligations of the entity.

C. Management and Operations. Corporations must follow the formalities that are prescribed by law, such as holding annual shareholder meetings and annual board meetings and maintaining records of actions of the board of directors. Partners and members generally determine how the partnership or LLC is managed in the partnership or operating agreement and generally have more flexibility regarding management of the entity.

D. Transferability. Corporate stock is readily transferable, subject to restrictions under federal and state securities laws, whereas economic and management rights in a partnership or an LLC (represented by a partnership interest or membership interest) are severable and may not be transferable as a unit. In each case, there may be special transfer requirements in a shareholders' agreement, partnership agreement, or operating agreement. Owning the project through a subsidiary LLC may facilitate a sale of a partial interest in the project because the sale of a membership interest or issuance of a new membership interest is generally tax-efficient to the acquirer. Also, from an exit-strategy perspective, an LLC does not lock a potential buyer into the corporate form. This flexibility can be advantageous if investors are interested in owning and operating the project. Further, the sale of all interests in a multiple-member LLC to a single buyer may be treated as an asset purchase by the buyer, with the accompanying tax benefits.

E. Financing. As discussed more thoroughly in [Chapter 9](#), although financing is best done through a subsidiary, the type of entity that owns the wind power project generally does not have an effect on financing.

III. Benefits of Early Choice of Structure and Entity. Many developers tend to begin work on a prospective wind project in the name of the parent corporation and create a project-specific subsidiary when the project is relatively far along. Although this process has a degree of logic, it is very important to understand that some property rights, permits, and contracts may have restrictions on transfer that would be triggered if and when the parent company attempts to transfer the rights and permits to the newly formed subsidiary. Transfer approval processes may be public (in the case of permits) or may reopen previously negotiated contract terms. For these reasons, choices of entity and structure should be settled as early as possible. In addition, transfers of assets that have become subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act may trigger a requirement to obtain the approval of FERC, under section 203 of the Act, for the transfer.

IV. Community Wind Projects. Community wind projects are structured with partial or full local ownership. For example, farmers, local governments, and educational institutions would invest in partial or full ownership, usually in a smaller wind project. The purpose of community wind projects is to foster a return on equity for investors from the local community, not just wind lease payments or local tax revenue. They also, in the cases of local government or educational institution ownership, are often designed to demonstrate a commitment to renewable energy on the part of the institution.

Some states have statutes that are designed to promote community wind projects by establishing a potentially favorable tariff for energy sold by the project, if the project meets certain community



ownership requirements. For example, Minnesota had a community wind statute for several years, but repealed it in 2016 due to lack of use. Other states still maintain incentives for community wind projects, such as Nebraska's sales tax exemption for qualifying community energy projects.

Because of the manner in which the statutes are structured and because of the difficulty of financing projects without the large tax equity investor benefits of the federal production tax credit, community wind projects have proven difficult to develop and, as the wind development industry has matured, focus has shifted toward community renewables models that are less capital intensive and have lower barriers to entry for local participants, such as community shared solar.

Chapter Twelve
THE LAW OF WIND
—Labor Issues—
James M. Shore

I. Organized Labor Issues. As in any construction project, wind power project developers will face the question of whether to use union labor. The Carpenters Union, Ironworkers Union, International Brotherhood of Electrical Workers, Laborers Union, and Plumbers and Pipefitters Union cover almost any job that is performed on a construction site. There are arguments both for and against the use of union workers. Opponents assert that union labor simply raises the cost of a project for no reason. By contrast, unions argue that union craftspeople are the most skilled and, therefore, projects will have fewer accidents and a higher-quality product.

Whatever one's opinion may be, it is important to be aware of the issues surrounding organized labor. It is also important to understand the way in which these issues can go directly to a project's bottom line, whether as increased labor cost or as increased permitting and mitigation costs caused by union opposition at the early stages of a project.

A. Organizing. Lately, unions have stepped up their efforts to organize workers in new fields and industries. For example, in the Northwest, the International Brotherhood of Electrical Workers has focused its efforts on contractors engaged in gas pipeline expansion projects. Organizing construction workers is different from the typical organizing that takes place in other private industries. Federal labor law allows construction unions and employers to enter into prehire agreements. This means that the employer and the union can enter into a collective bargaining agreement before a single employee is hired. Such agreements are illegal in other industries.

Because prehire agreements are legal in the construction industry, organizing typically focuses on the contractor. The unions focus on getting the contractor to sign an agreement rather than on soliciting employees. If a contractor refuses, the unions will usually picket the site and engage in other pressure tactics to force the contractor to relent and sign an agreement.

1. Picketing. Picketing is the most common tactic used at construction sites. The union will strategically place pickets at the entrances to a site, in hopes of stopping union deliveries, preventing any union subcontractors from entering, garnering public support, and generally disrupting operations. Contractors and project managers can limit the effectiveness of any picketing campaign by establishing separate reserved gates. If such gates are established correctly, the union will be limited in where it can picket, thus allowing deliveries and work to proceed without significant interruption.

2. Legal Challenges. A new union strategy that has proven costly to employers is the funding of lawsuits against union-free employers. The most common suit is for wage and hour violations such as the failure to pay overtime properly. Unions have also attacked companies by filing

multiple safety complaints with the Occupational Safety and Health Administration. The goals are transparent. First, the union wants to increase the cost of remaining union-free by forcing the employer or contractor to incur legal expenses. Second, the union's lawsuit is meant to show employees the union's power to protect employees from "greedy" employers.

3. Other Types of Pressure. In addition to picketing and legal challenges, unions have increasingly turned to the media and politics to put pressure on businesses and contractors. Rather than concentrating on the "bread-and-butter" economic issues, which tend to be boring to the average mass-media consumer, unions have turned to "hot-button" moral and ethical issues to increase the heat on nonunion companies. Unions are now joining forces with community, health and safety, immigration, and environmental groups such as Greenpeace. For example, to pressure the increasingly nonunion lumber industry, unions have joined forces with environmental groups to protest logging.

A more potent weapon for unions has been political pressure. If a wind project will involve public land or the cooperation of local government, it is important to keep in mind that union members may form an important part of the local politicians' constituencies. The unions may pressure politicians to condition governmental cooperation on the use of union labor. The issue of prevailing wages will also be championed by unions.

4. Salting. Salting is a very common tactic in construction trades and is becoming more popular in private industry. A union will "salt" a work force by sending a paid union organizer to apply for a full-time position on the job site. The organizer will openly state on his or her application that he or she is applying for work in order to organize the work force. If the organizer is qualified for the position, this puts the employer in a difficult situation. The employer can either hire the organizer or refuse to hire the individual and face a possible discrimination charge. Another salting technique is to flood the job site with applications from union members. This places the employer in the same untenable position.

5. Permit Extortion. In recent years unions have become fairly sophisticated at identifying energy projects at a very early permitting stage and at opposing projects that have not signed a prehire agreement. Unions often raise a wide variety of environmental issues. They can be very dangerous opponents because they have the resources to hire lawyers and technical consultants. Unions often make a large issue out of "local hiring" and tend to get a good reception for this theme with local- and state-level decision-makers.

B. Elections Before the National Labor Relations Board. The law does not require an employer to voluntarily recognize a union in the construction industry or any other industry. If an employer refuses to agree to a union's demand for recognition, the union can petition the National Labor Relations Board ("NLRB") to conduct an election. To get an election, the union must have the support of 30 percent of the employee group that it seeks to represent. To win an election, the union must garner support from a majority of the group.

Before the election, there is a period during which both the union and the employer may campaign. During that time, certain legal rules must be followed. In fact, the restrictions apply whenever an employer has knowledge of a union drive. For example, an employer may not promise increased benefits to induce employees to reject the union and cannot change wages, hours, and working conditions in an attempt to dissuade employees from voting for the union. In addition, an employer may not threaten employees or punish them for supporting the union. Similarly, an employer cannot spy on union meetings or question employees about their union affiliation. The NLRB has interpreted these rules broadly, so employers must be wary when speaking with employees about unions. There are many subtle interpretations, and employers faced with organizing are encouraged to seek legal counsel.

II. Union Organizing May Arise in Operations as Well. Union organizing is not limited to construction. Unions may attempt to organize the employees who operate or maintain the wind farm. There has been at least one election in California in which a union attempted to organize wind farm employees. The simplest way to avoid or defeat a union organizing drive is to manage the work force fairly so that employees do not feel the need to seek outside representation. An organizing drive, however, is not the end of the road. Employers have been successful both in union elections and at the bargaining table.

III. Collective Bargaining. A common misperception about unions is that once a union wins an election, the employer must then pay so-called “union wages.” That is simply not true. Unless the employer is in the construction industry and has signed a prehire agreement, the determination of wages, hours, and working conditions is left to the collective bargaining process. During the collective bargaining process, nothing is automatic or guaranteed. Employees can end up with the same, more, or fewer wages and benefits than they currently enjoy. In fact, wage rates may decrease because of bargaining. Moreover, an employer is not legally required to come to an agreement with the union. The only requirement is that the parties bargain in good faith.

IV. Conclusion. Obviously, this article cannot cover the full expanse of labor law and the conflicts and challenges that might develop. However, labor issues are usually one of the last considerations in planning and developing projects such as wind farms. Knowing the risks, costs, and options will allow developers to better plan for any issues that may arise.

Chapter Thirteen
THE LAW OF WIND
—Regulatory and Transmission-Related Issues—
Jason A. Johns, Jennifer H. Martin

Long before a wind energy developer begins generating the first megawatt of power, the developer must decide on a regulatory structure for the project, negotiate and execute transmission and interconnection agreements, and purchase necessary transmission ancillary services. This chapter presents a general discussion of these issues. 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. Regulatory Structure Issues—PUHCA, EWGs, and QFs. The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 (“PUHCA 1935”), in part, and enacted 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 eliminated certain restrictions that prevented the consolidation of the electric utility industry, and corporate affiliations allowed under PUHCA 2005 present both challenges and opportunities for wind energy developers.

Although nonexempt wind energy project companies are no longer subjected to extensive regulation by the Securities and Exchange Commission, PUHCA 2005 has (1) granted state regulators and the Federal Energy and 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. However, wind energy project companies may obtain exemptions from these requirements, with the two most common exemptions occurring when a project owner obtains status as either an exempt wholesale generator (“EWG”) or a qualifying facility (“QF”). Each of these categories is summarized below.

In addition, because privately owned wind generation companies are public utilities under Part II of the Federal Power Act (“FPA”), developers are subject to FERC’s regulation as a “public utility,” including rate regulation, electric reliability rules, and other regulation. However, a developer may avoid rate regulation under section 205 of the FPA for certain small projects by obtaining status as a QF. Furthermore, a developer of a project of any size can obtain market-based rate authority if it can make the necessary showings; such authority exempts the developer from the need to justify its rates on a cost basis. But one way or the other, a developer selling energy at wholesale must obtain either authority from FERC to do so or an exemption from such regulation. These other regulatory issues are addressed in Sections A, B, and C 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 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 engaged 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 wind generation facility and sell its electric 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. Finally, EWGs are restricted in their ability to enter into certain types of transactions (such as leases) with affiliated regulated utilities. EWG status does not give a developer any authority to sell power; EWG status primarily provides nothing more than an exemption from PUHCA regulation.

Rates for wholesale power sales by EWGs are subject to FERC regulation under section 205 of the FPA. 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. Power sellers that have market power may nevertheless obtain market-based rate approval by showing that the seller has adequately mitigated its market power. Because FERC often revises or modifies its criteria for satisfying these requirements, wind developers should contact knowledgeable attorneys before filing for market-based rate approval. Once FERC grants market-based rate approval, the EWG will have ongoing filing and reporting requirements and must comply with FERC’s rules regulating market behavior.

B. Qualifying Facility Status. The Energy Policy Act of 2005 also changed the rules for QFs, introducing both risk and opportunity. Developers of new wind projects, as well as sellers under existing QF contracts (especially with contracts that will be expiring soon), 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, including wind projects, all which are referred to as QFs. Before the passage of the Energy Policy Act of 2005, PURPA provided valuable benefits to wind energy developers, one of which was the exemption for wind QFs producing up to 30 MW from many provisions of the FPA 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 the eligibility requirements narrower than in the past.

The Energy Policy Act of 2005 narrowed the advantages that wind generation QFs previously enjoyed compared to EWGs. First, as mentioned above, QFs no longer enjoy broad exemptions from the requirements of the FPA. 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 March 17, 2006, or (4) pursuant to a state regulatory authority's implementation of PURPA remain exempt from sections 205 and 206 of the FPA. 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. Utilities may now petition FERC for an exemption from PURPA's mandatory purchase requirement if the utility can demonstrate that a QF in its service territory would have nondiscriminatory access to wholesale markets for energy and capacity that meet certain standards—something that is routinely done in regions with an organized wholesale energy market. The potential loss of this "must buy" requirement could be significant because utilities' appetite for renewable energy has been reduced as Renewable Portfolio Standard requirements are met, 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. For a wind project that is 30 MW or smaller, QF status is more advantageous than EWG status. Above 30 MW, a wind developer might choose EWG status, QF status, or both, depending on the circumstances.

C. Other Ongoing Regulatory Requirements. Whether a wind developer is an EWG or a QF, or has FERC approval to sell power at market-based rates, the wind 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 wind developers, and therefore consultation with knowledgeable attorneys is recommended.

II. Transmission and Interconnection Issues. To obtain project financing and gain access to markets for project output, wind project developers 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 project sites.

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. In regions where the transmission system is owned and operated by separate entities, FERC will require that both of those entities sign the interconnection agreement. FERC Order No. 2003 established standard interconnection procedures and a standard interconnection agreement for generators larger than 20 MW (“Large Generators”). Similarly, FERC Order No. 2006 establishes standard interconnection procedures and a standard interconnection agreement for generators with a capacity of 20 MW or less (“Small Generators”). Since that order was issued, however, certain regional transmission organizations, such as the Midcontinent Independent System Operator (“ISO”), Southwest Power Pool, and the California ISO, 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 continues to happen across the nation—sometimes even outside of the ISO markets—and each reform to FERC’s traditional approach to interconnection responds to the problems faced in a particular region. But it also means that what was once a generally uniform process across the country might now look very different depending on the region where a project is being developed.

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.

B. 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. Because wind projects typically span large geographical areas and are often located in remote places, substantial new facilities and facility upgrades may be required.

Order Nos. 2003 and 2006 directly assign the costs of interconnection facilities and distribution upgrades to the interconnection customer. Network upgrades (*i.e.*, upgrades to the transmission system at or beyond the point of interconnection) are treated differently, however, and even though the costs of upgrades may initially be borne by the interconnection customer, those costs may be reimbursed to the interconnection customer in the form of transmission credits or cash payments. In certain transmission systems, however, such as those controlled by the Midcontinent ISO or the PJM

Interconnection, the interconnection customer will not be entitled to all or even part of this reimbursement.

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 such facilities as are necessary to reach the point of interconnection are properly classified as interconnection facilities. 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.

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. An alternative is for the project owner to sell some or all of the output under a contract shifting the transmission obligation to the purchaser. This typically requires that the contract terms qualify the sale for designation as a network resource by a load on the transmission system to which the project is interconnected. In addition, acquiring adequate transmission service is essential to obtaining debt or project financing on reasonable terms and conditions.

Transmission providers are required by FERC to offer transmission service on an open, nonpreferential 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 ISO rather than the actual owner of the applicable transmission facilities. Acquiring transmission service from transmission providers not subject to FERC's jurisdiction under sections 205 and 206 of the FPA raises additional questions that depend on the nature of the entity, the scope of its transmission facilities, and other issues beyond the purview 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. Wind projects, because of their remote locations, may necessitate substantial system upgrades that will result in the transmission customer paying an incremental cost rate that exceeds its pro rata share of the system costs.

Although the average output of wind projects is in the 30 to 40 percent range, during periods of adequate wind flow, wind projects can operate at or near full capacity. As a result, the owners of wind projects typically need to have available transmission service to accommodate the full project capacity. One result is that much of this transmission capacity will go unused during periods when wind flows amount to less than full operation. Another result is that the cost of transmission for a wind project will normally be substantially higher on a per-megawatt-hour (“MWh”) basis than the cost of baseload thermal generation. Sometimes combinations of firm and nonfirm transmission, or transmission and redispatch, can be more cost-effective than purchasing transmission for the project’s maximum capacity. The challenge is convincing third-party financiers to accept such arrangements.

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 wind generation than FERC pricing, because an RTO eliminates rate “pancaking,” which is the imposition of multiple transmission charges for use of more than one transmission owner’s transmission facilities.

III. Ancillary Services—Imbalance Charges, and Firming and Shaping Products. Project owners will be required under the transmission provider’s tariff to either 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 wind operators. Generation imbalance service is a product that allows a generator to deliver an amount of energy to the electric grid that differs from the amount it had prescheduled for an hour and compensates the transmission provider for the cost of delivering the scheduled amount of energy to the generator’s point of delivery.

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 wind 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 variable 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 wind 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.

To avoid imbalance charges, wind project operators may look to other generation suppliers to provide firming and shaping products to accommodate their variations in output. Such products consist of arrangements whereby the supplier will take or provide energy, as applicable, in hours when the actual generation differs from the scheduled amount. Several transmission providers in the Pacific Northwest have sold a limited amount of shaping and storage service, generally using the hydro system's flexibility to store and shape wind into peak and off-peak blocks.

In addition to imbalance charges, some transmission providers require certain wind generators to pay for a wind integration service, which is typically a capacity charge that may be designed similar to the load regulation charges found in Schedule 3 of the transmission provider's tariff. Transmission providers have justified these new charges by citing the variability of wind within the hour or shorter scheduling increment and the resulting strain that such variability places on the transmission system. Wind integration charges are rare, but where they exist they can be costly and highly complex in design.

IV. Reliability Standards. Developments in federal law have transformed historically voluntary standards into mandatory reliability standards with accompanying obligations and potential sanctions for failure to comply. In compliance with federal law requiring it to do so, FERC issued Order No. 672 in 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 upward of \$1 million per day for noncompliance. Pursuant to the FPA, all reliability standards must be just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC has delegated to designated regional entities the authority to monitor and enforce the reliability standards. In addition to their delegated duties, regional entities may also enforce region-specific reliability standards.

The reliability standards may apply to users, owners, and operators of the bulk electric system, and the specific applicability of a particular standard is specified therein. The regional entities are tasked with maintaining a Compliance Registry, which lists organizations against which the reliability standards are enforceable. If a bulk electric system user, owner, or operator fails to register with the Compliance

Registry, then the regional entity may take steps to register that user, owner, or operator. The Compliance Registry lists organizations by function, and compliance is analyzed by reference to function-specific reliability standards.

As is most relevant to wind developers, NERC requires that certain generator owners and operators register with the Compliance Registry. A generator owner is an organization that owns generating units, and a generator operator is an organization that operates generating units and supplies energy. There are minimum requirements before a generator owner or generator operator is required to register, but consider that these requirements are not always straightforward. For instance, although a single wind power facility may itself be too small to trigger mandatory reliability standards, its sharing interconnection facilities with other facilities (either affiliated or not) might be aggregated for purposes of determining whether the combined facilities are subject to NERC standards.

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 appropriate steps to determine whether they should register with the appropriate regional entity, to understand each function, and to implement a comprehensive program that will track and ensure compliance.

Chapter Fourteen
THE LAW OF WIND
—Litigation—

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I. Introduction. As with any development, wind energy projects can become the subject of litigation in state and federal courts. In addition, regulatory litigation before state utilities commissions and the Federal Energy Regulatory Commission (“FERC”) can have profound effects on the viability of wind projects. Litigation can involve any of the topics previously discussed, as well as a host of other disputes that may develop during the operational life of a wind project. Anticipating what disputes may arise and proactively planning for their resolution, whether through litigation or otherwise, will increase the odds of a favorable result. This chapter outlines some issues to consider when disputes first develop and discusses areas in which litigation may arise in the development and operation of a wind energy project.

II. When to Involve Litigation Counsel. Frequently, litigation counsel is first retained only when litigation becomes inevitable, either because a party has been sued or a dispute has reached the stage in which a party determines that a lawsuit must be filed. Involving litigation counsel before that stage is reached, however, can reap numerous benefits. Litigation counsel can advise on alternative dispute resolution (“ADR”) procedures that can avoid the costs involved in litigation in state or federal court, and can ensure that actions taken during the early stages of a dispute do not prejudice any ultimate litigation. Furthermore, gaining an early understanding of the merits of any potential litigation can help resolve the dispute in an appropriate manner.

In selecting litigation counsel, a potential client should consider the counsel’s expertise in the legal subject matter. It is essential to locate counsel that specializes in the types of legal issues that are involved in the dispute—for example, environmental issues or labor and employment. It is also important, however, to consider counsel’s knowledge of the wind energy industry and the energy industry in general. Counsel that has knowledge of the industry can greatly increase the odds that litigation will be successfully resolved.

III. Finding the Appropriate Forum: State and Federal Courts, Regulatory Agencies, and ADR. Where to engage in litigation presents an important decision for a client. What forum is available and appropriate for any given dispute depends, among other things, on the issues, the amounts in dispute, and the parties involved. The benefits and disadvantages of each available forum should be given careful consideration before one is chosen. Options may include state or federal court, administrative litigation before various regulatory agencies, or some form of ADR, such as mediation or binding arbitration.

When a dispute involves issues of federal law, or the parties are from different states, federal court may be an option. The regulation of the energy sector by both FERC and numerous state utilities commissions, as well as myriad other state and federal agencies, often makes litigation before various

regulatory agencies a prerequisite before any litigation in state or federal court. Often, if the dispute concerns a contractual matter, the contract will specify the forum where the litigation must be filed and which law should govern the dispute. The contract may also specify that some form of ADR must be used, either prior to or instead of litigation in state or federal court. Even if not required to engage in ADR pursuant to the terms of an existing contract, the parties may agree to participate in ADR after the dispute develops.

There are a variety of ADR methods. They include:

Mediation. Mediation is a form of negotiation guided by a neutral party, the mediator. Mediators have no authority to impose a resolution of the parties' dispute. Their role is to help the parties to communicate settlement offers and other information. Because the communications between a mediator and a party are not disclosed unless the party gives permission, mediators are well suited to give candid and objective assessments of each party's position in a dispute. They may also help the parties formulate a negotiation strategy that leads toward settlement.

Arbitration. In arbitration, a private party, the arbitrator, is given authority to resolve the parties' dispute. The parties can agree to the rules governing the arbitration process, which may be similar to the rules of court governing litigation in state or federal courts. Some ADR providers (such as the American Arbitration Association) publish sets of arbitration rules.

Dispute Resolution Board. A dispute resolution board ("DRB") is a panel of people experienced in construction matters that is assembled (usually) at the beginning of the parties' relationship. Its use is generally limited to major construction projects. The DRB members become familiar with the parties and the project and are available to respond to disputes that arise. Because they are chosen by both parties for their expertise, DRB members' opinions may have considerable weight. Sometimes DRBs are given quasi-arbitral powers to decide disputes.

Other ADR methods are limited only by the parties' imaginations.

The chief benefit of ADR is that the parties are usually able to choose their own mediators, arbitrators, and DRB members. This gives parties the opportunity to select people who have expertise in the industry and the issues involved in the dispute. By contrast, judges are simply assigned, giving the parties little control over who will decide the dispute.

Other aspects of ADR that must be considered include the parties' control over the rules of the process, which may speed a just resolution (or may deny a party a fair opportunity to present its case); the private nature of ADR proceedings, which can protect sensitive business information (or remove a threat of publicity that might have made a party more willing to settle); and the finality of arbitration decisions, which saves the costs of appeal (but could leave a party disadvantaged by an erroneous decision that cannot be challenged effectively).

Experienced parties do not automatically choose court resolution or ADR for all their business relationships. Instead, they evaluate the advantages and disadvantages of each available method and choose the one best for them in each situation.

IV. Areas Where Litigation May Arise. Litigation may arise in a variety of areas during the development and operation of a wind energy project.

A. Real Property and Environmental Litigation. Like any large development project, wind power projects may generate local opposition. Although many people welcome wind projects as an environmentally friendly alternative energy source that can generate clean energy as well as new local jobs, others see wind farms as a visual impairment and a potential threat to avian wildlife. When outreach, education, and consensus building break down, opponents of a project may resort to litigation. Litigation can lead to costly delays, and litigation strategy often focuses on allowing a project to continue development pending resolution of the claim.

1. Challenges to Local and State Permitting Decisions. An opponent to a wind power project may attempt to delay or prevent a project by participating in the permitting decision. When local opposition is particularly strong, this opposition may result in the local or state planning agency denying permits. The permit applicant generally must challenge the denial of its permit through an internal administrative appeal process and then, if necessary, to the appropriate courts. An opposition group may appeal the grant of a permit for a wind project through the same procedure. The permit holder may then need to intervene in the opposition group's challenge to protect its interests.

In a 2008 decision of great importance to the wind energy industry, the Washington Supreme Court upheld a wind project approval that had been challenged by local residents. *See Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council*, 197 P.3d 1153 (Wash. 2008) (en banc). Stoel Rives represented Horizon Wind Energy, which received approval to construct its Kittitas Valley Wind Power Project from the Washington Energy Facility Site Evaluation Council ("EFSEC"). Even though Horizon Wind Energy worked collaboratively with the EFSEC, then Washington Governor Chris Gregoire, and many governmental agencies and nonprofit groups, some local residents and the Kittitas County Commission opposed the project and argued that the EFSEC could not preempt the county's authority under the Growth Management Act. The Washington Supreme Court rejected their arguments and upheld the EFSEC's ability to offer "one-stop" licensing for large wind energy projects. Many of the principles articulated in the *Kittitas* decision will be helpful to wind developers fighting similar battles in other states.

Proper defense of a permit decision begins by actively participating in the permit process and making sure that the local government or state agency follows all necessary steps and has all relevant information necessary to support the grant of the permit. The decision of the permitting agency is then substantially easier to defend during the appeal process. As discussed in detail in [Chapter 3](#), several states also have broad environmental review statutes that provide fertile ground for challenges to wind energy development. For example, the California Environmental Quality Act ("CEQA") requires any

governmental agency in California that makes any type of discretionary decision that potentially has an impact on the environment to conduct an environmental review, and may require that an environmental impact report be prepared before approval of the project. Washington has a statute similar to CEQA, the State Environmental Policy Act (“SEPA”). Like CEQA, SEPA allows agencies to deny projects with significant unmitigated adverse impacts if feasible alternatives exist.

2. Challenges to Federal Permit Decisions. For some wind power projects, such as those on federal land, the project proponent must seek federal permitting and lease approval. The federal action required to approve these projects creates a federal nexus and a host of potential mechanisms to challenge the wind power project. Federal agencies, such as the Bureau of Land Management (“BLM”), must comply with numerous federal mandates before authorizing a project on federal land. Failure to comply with any one of these federal mandates gives rise to a potential citizen suit under the Administrative Procedure Act (“APA”). Among other federal requirements, the BLM’s approval of wind development projects will commonly need to comply with the National Environmental Policy Act, the Federal Land Policy and Management Act, and the Endangered Species Act (“ESA”).

Challenges to BLM decisions to grant a right-of-way or allow a project first must be taken to the Interior Board of Land Appeals (“IBLA”). Following appeal to the IBLA, the opponents of a project may then challenge the agency action in federal court under the APA. APA cases generally are limited to reviewing the “record”—the information considered by the agency at the time it made a decision. Consequently, the key to defending such actions is to participate early in the decision-making process and make sure the agency’s decision is adequately supported by the information in its possession. If the agency action is deemed arbitrary and capricious or otherwise contrary to law, the permit or approval may be invalidated and sent back to the agency for further consideration, resulting in substantial delay.

3. Post-Construction Challenges.

a. Nuisance. The permitting process provides many opportunities to challenge a project. However, post-construction challengers must demonstrate that the operation of the wind power project violates some state or federal law and that a private lawsuit is authorized. Preeminent among these challenges is a common-law nuisance lawsuit. The theory behind a nuisance lawsuit in the context of a wind power project is that the project operator is using its land in a manner that “substantially and unreasonably” interferes with a nearby property owner’s ability to “use and enjoy” his or her own property. Plaintiffs will allege that a wind power project creates too much noise, casts too much shadow or shadow flicker, or creates a visual impairment. Nuisance suits generally seek monetary damages for compensation and, in rare cases, may be awarded injunctive relief to abate the nuisance.

Nuisance suits have not proven very successful against wind power projects, largely because it is difficult to show that the impairment to an adjoining property owner is substantial and unreasonable. For example, in *Rankin v. FPL Energy, LLC*, 266 S.W.3d 506 (Tex. App. 2008), the plaintiffs brought public and private nuisance claims against the Horse Hollow wind farm. The Texas court noted that the law

recognized very few restrictions on the lawful use of property, and that there is no nuisance action for “aesthetical impact.” At trial, the jury found that the plaintiffs’ claims based on noise allegedly produced by the turbines did not create an improper nuisance. As in *Rankin*, most states generally do not recognize visual nuisance absent extreme circumstances, and shadow and noise issues would likely rise to substantial and unreasonable levels only where affected landowners are immediately adjacent to wind power projects. A qualified consultant can model shadow, shadow flicker, and noise issues before a project is built and help avoid any potential conflicts. Where such conflict nonetheless arises, the same modeling can be used in defense of the project.

b. Federal Wildlife Laws. Several other federal laws present litigation potential related to ongoing operations. The ESA, the Bald and Golden Eagle Protection Act (“BGEPA”), and the Migratory Bird Treaty Act (“MBTA”) all prohibit injuring or killing particular species. Of the three, only the ESA contains a citizen suit provision allowing a party other than the federal government to file a civil action against a wind power project. Suits under the BGEPA and the MBTA may be initiated only by the federal government.

Unfortunately, the operation of wind turbines may result in injury to birds and bats. Although bat species in particular appear to be highly susceptible to turbine strikes, the potential for an ESA suit is relatively small absent a significant number of documented injuries to protected species. However, the listing of additional bat species as threatened or endangered under the ESA could increase the chances of an ESA citizen suit in the future. Should the possibility of an ESA citizen suit become more likely, there are means to avoid ESA liability through the development of habitat conservation plans. There are no current mechanisms to avoid liability from the federal government under the BGEPA or the MBTA. As a result, every wind project should work closely with federal wildlife officials to ensure that all reasonable and practical mitigation measures to limit avian impacts are incorporated into the design, placement, and location of turbines.

4. Examples of Real Property and Environmental Litigation.

a. Avian Impact Issues. *Kerncrest Audubon Soc’y v. City of L.A. Dep’t of Water & Power*, No. CV-255604, 2007 WL 2208806 (Cal. Ct. App. Aug. 2, 2007) (unpublished). This matter involved a CEQA challenge to the proposed Pine Tree Wind Development project in Kern County, California. Stoel Rives represented the developer in the litigation. Plaintiff contended, among other things, that the final environmental impact report failed to study the project’s impacts on nocturnally migrating songbirds and failed to consider Pine Tree’s individual and cumulative growth-inducing impacts in Los Angeles. The plaintiff’s petition was denied, and the denial was affirmed on appeal.

Ctr. for Biological Diversity, Inc. v. FPL Grp., Inc., No. RG04-183113, 2006 WL 2987634 (Cal. Super. Ct. Oct. 12, 2006). The plaintiff brought claims against wind energy projects in the Altamont Pass, asserting that the turbines killed and injured thousands of wild birds in violation of the California Fish and Game Code and federal laws protecting eagles and migratory birds. The court granted judgment on the

pleadings in favor of the defendants. Stoel Rives represented one of the wind turbine operators in this litigation.

b. Other Environmental Challenges. *Flint Hills Tallgrass Prairie Heritage Found., Inc. v. Scottish Power, PLC*, 147 F. App'x 785 (10th Cir. 2005) (unpublished). Plaintiffs filed an action in federal district court in Kansas, alleging that defendants' construction of wind turbine projects in Butler County, Kansas and elsewhere would cause permanent and irreparable damage to the Flint Hills regional environmental system. Stoel Rives represented the defendants. The district court dismissed the complaint for failure to state a claim, and the dismissal was affirmed on appeal.

B. Contractual Disputes: Leases, Power Purchase Agreements, Construction, Insurance Coverage, and Operation and Maintenance Agreements. Another frequent subject of litigation involves disputes over the performance of myriad contracts associated with a wind energy project, including leases, power purchase agreements ("PPAs"), construction contracts, insurance contracts, and operation and maintenance ("O&M") agreements. Retaining experienced counsel to assist with the drafting of such contracts can help avoid future disputes and provide a clear roadmap for resolution should a dispute over contract performance arise. Although contracts may specify that ADR be used either as a prerequisite to the initiation of a lawsuit or as an alternative to litigation in state or federal court, thought should be given to the pros and cons of ADR, as discussed above.

1. Leases. As noted in [Chapter 1](#), the term of a lease agreement can extend for 70 years or more. The long terms of these agreements can result in disputes developing later in the relationship, especially if ownership of the property subject to the lease changes hands, by either sale or transfer to successors or heirs. Disputes can also develop concerning what facilities are sited on the land, as discussed in more detail in [Chapter 1](#). For example, Stoel Rives has successfully represented a wind developer in litigation with a landowner whose property was initially leased but not ultimately used in an adjacent wind project.

2. PPAs. As explained in [Chapter 7](#), the term of a PPA may extend for 20 years or more from the commercial operation date. Disputes can arise early in the relationship when certain project milestones are not timely met, or later in the relationship when unanticipated regulatory changes result in material changes to the economics of the transaction for one or more parties.

PPAs must be carefully drafted in order to avoid ambiguities that can give rise to litigation. For example, in *FPL Energy, LLC v. TXU Portfolio Management Company, L.P.*, 426 S.W.3d 59 (Tex. 2014), the parties disputed who bore the risk of insufficient transmission capacity in several PPAs. The Texas Supreme Court ultimately determined that the PPAs allocated that risk to FPL, the owner of the wind farms. The parties also disputed whether the liquidated damages provisions applied to the failure to provide both energy and renewable energy credits ("RECs") or whether it only applied to the failure to provide the required volume of RECs. On this issue the Texas Supreme Court ruled in FPL's favor, finding that the liquidated damages provisions applied only to RECs. The Court ultimately determined that the

liquidated damages calculation did not bear a rational relationship to actual damages, however, and declined to enforce it.

If litigation arises, the damages provisions in a PPA can also be contested. For example, the court in *FPL v. TXU* held that a liquidated damages clause providing for a deficiency rate of \$50 per MWh was an unreasonable and unenforceable penalty. Therefore PPAs should state that liquidated damages are not a penalty and should also ensure that the liquidated damages represent the best estimate of actual damages at the time of execution. Likewise, that court held that production tax credits (“PTCs”) were “consequential damages” and were not recoverable under a PPA that limited recovery for consequential harm. To avoid this problem, PPAs should expressly mention PTC compensation and include language that makes clear that PTCs are not considered consequential damages.

3. Construction. Construction contracts often include detailed provisions allocating risks and costs expected to arise during the construction process. These provisions are intended to anticipate problems and provide agreed resolutions so that disputes can be avoided. However, sometimes disputes arise despite the parties’ best efforts.

Major construction projects are complex, involving large numbers of participants and generating large volumes of paperwork. Construction disputes are correspondingly complex, which makes them expensive to analyze and resolve. All parties have an incentive to avoid the expense of full-blown disputes if they can. For this reason, construction contracts often contain provisions intended to make the dispute resolution process more efficient and more predictable.

4. Insurance Coverage. Most businesses have a package of insurance policies that cover them and their employees against liability for bodily injury and property damage claims by third parties outside the organization. These policies are commonly known as comprehensive general liability (“CGL”) policies. CGL policies may cover the organization and its employees against claims by third parties for slander, invasion of privacy, misrepresentations, and false advertising. These CGL policies may also cover the organization for automobile liability and employment practices (such as claims for employment discrimination or wrongful discharge). Sometimes these coverages are contained in separate policies. CGL policies are very valuable because they usually provide both defense coverage and coverage for indemnity. Often the defense coverage is not limited by the amount of insurance available to pay claims.

Businesses also commonly have a form of property insurance that protects the business against losses to its own property from natural or unexplained causes (such as lightning, fire, flood, earthquake, or collapse). These policies usually do not provide any defense to the business but provide indemnification for its property losses. Businesses can also be covered under a third person’s insurance policy as a result of a contractual requirement or business arrangement. Larger businesses will also typically have a form of directors and officers liability insurance (“D&O Insurance”). D&O Insurance protects the company’s directors and officers against claims for securities fraud or other alleged breaches of duty to the shareholders. Finally, many businesses will typically have some sort of fiduciary liability policy that

protects any of its officers, directors, or employees acting as fiduciaries of the company's ERISA plans. Many other types of specialized coverages are also available, such as excess insurance, business interruption, pollution liability, and difference in conditions.

Almost all insurance policies for business require a form of notice whenever there is a claim or a potential situation that might result in a claim. Some policies have very specific notice requirements (like notice within 60 days of the loss, followed by submission of a proof of loss within 90 days of the initial notice) or limitations on suit against the insurance carrier (like one year from the date of loss). Other policies may require a specific form of notice or specific details about the claim. The notice provisions of the policy must be followed carefully by the company in order to properly initiate the duties of the insurance carrier for the claim.

Insurance coverage disputes typically arise when the company gives notice of the claim to the appropriate insurance carrier and the insurance carrier states it will refuse to defend and/or pay the claim. Sometimes the insurance carrier with a defense obligation will agree to defend the company but will reserve its rights to deny coverage under certain provisions of the policy if certain facts develop in the litigation. In all cases when this occurs, it is extremely important that the company have a full and complete copy of its insurance policy to review. The policy should be reviewed by a competent insurance professional versed in the type of insurance at issue. Often insurance coverage disputes turn on nuances in policy language; it is therefore very dangerous for a company to rely on conventional thinking about the scope of coverage that may be available under its insurance policies. For example, property policies are often very complex, do not follow any particular form, and provide a variety of coverages that may not be thought of as part of property damage (such as temporary repair, removal of damaged property, and automatic coverage for a failure to follow the terms of the policy). Obtaining the complete policy is also just as important for those situations when the company is named as an additional insured under someone else's policy. (Relying on the certificate of insurance for coverage is very risky, as the certificate is not the policy and the company may not be insured as it thought it was going to be even if the certificate shows that the insurance exists. Moreover, in some states, such as Oregon, an insurance broker is not liable if it issues a certificate that incorrectly states the existence or scope of insurance.)

When a defense is being provided by the insurance company with a reservation of rights to later deny coverage, the company needs to monitor the underlying litigation closely to see if the facts as developed will fit into the carrier's list of reservations. Furthermore, the company should satisfy itself that the defense provided by the carrier is satisfactory both as to scope and as to the competence of counsel for that kind of case. Once the carrier decides to provide a defense to the company, it is obligated to provide a good-faith defense. That typically means a complete and thorough defense with competent defense counsel. If the company is not satisfied, it has the right to complain and request a new defense team. And if the carrier decides to defend only certain claims and not others, the company will need to provide its own counsel for those uncovered claims.

If the company and its insurance carrier are at loggerheads and a suit against the insurance company is needed to obtain the full benefits of the policy, the company should consider the timing of the suit. If possible, it is desirable to first resolve the underlying claim so the company does not have to fight a two-front war, one against the claimant and one against the insurance company. Second, most states provide that a company that must sue an insurance company to obtain coverage will be entitled to recover its attorneys' fees and costs incurred in such litigation in addition to any damages it sustained because of the breach of the insurance policy. Finally, most states allow generous rewards for prevailing on a bad-faith claim against the insurance company.

5. O&M Agreements. Once a project begins commercial operation, project owners may engage a third party to operate and maintain the wind project. Disputes may develop between the parties concerning responsibility for losses in production and other disputes. For example, Stoel Rives successfully represented an O&M company in litigation with a project owner over nonpayment of O&M fees and allegations that the O&M company performed inadequate maintenance, resulting in lost production. The project owner won a jury verdict in excess of \$1 million.

C. Tax and Royalty Payments. As explained in detail in [Chapter 10](#), wind power projects raise numerous federal, state, and local tax issues that can develop into administrative litigation with various federal, state, and local taxing agencies. In addition, federal law provides opportunities for private citizens to seek to enforce tax and royalty obligations under the False Claims Act. The False Claims Act extends liability to any person who knowingly makes or uses a false record or statement to avoid or decrease an obligation to pay taxes or royalties. A suit under the False Claims Act may be brought by either the attorney general or a private citizen. A private citizen who successfully brings such a claim is entitled to a share of the proceeds from the lawsuit, providing a significant incentive for private citizens to file False Claims Act claims.

D. Public Company Litigation. By choosing to “go public,” a company subjects itself to a whole new category of potential litigation based on state and federal laws and regulations that govern the company's internal management and its relationship with its shareholders. These regulations require corporate accountability for the truth of financial statements and transparency in corporate operations, and are designed to ensure that the public company acts responsibly and fairly toward its shareholders. If a public company fails to comply with these regulations, or if the company's directors and officers fail to place the interests of the company above their own, the company may be exposed to potential liability. Every company should be aware of and understand the risks associated with going public and the possible litigation that could result from the derogation of the obligations owed to company shareholders. Three types of actions that a public company may face are securities fraud actions, derivative suits, and class actions.

1. Securities Fraud Actions. Securities fraud actions generally arise out of alleged violations of Rule 10b-5 of the Securities Exchange Act of 1934, which is directed at preventing fraud and manipulation in securities transactions. Essentially, Rule 10b-5 prohibits any corporate director, officer, or board member, or anyone else in possession of material inside information, from making any

false statement or failing to disclose material information in connection with the purchase or sale of any security. Typical claims include allegations that a shareholder was induced into purchasing stock and paying a higher price than the stock was fairly and reasonably worth or that the shareholder was induced to sell the stock for a lower sum than its true value because of false and fraudulent statements made by the company, such as at the time of a merger or acquisition. Recently, securities fraud actions have included allegations of improper backdating, in which a plaintiff alleges that a company falsified the date of a stock grant as a way for an employee to make additional money from the exercise of the stock option.

Securities fraud actions, particularly class actions, often result in large settlement payouts to plaintiffs by public companies. However, with the enactment of the Private Securities Litigation Reform Act of 1995, which imposes heightened pleading requirements on plaintiffs purporting to bring securities fraud complaints, and with increased pressure by the Department of Justice and the Securities and Exchange Commission on public companies to conduct internal investigations, the number of securities fraud complaints has decreased in the past few years. Nonetheless, every public company (usually led by outside counsel) should take precautions in its representation and disclosure of financial information to protect itself from possible securities fraud claims.

2. Derivative Litigation. A public company also may face a shareholder derivative suit, which is an action brought by one or more shareholders of a corporation on behalf of the corporation to enforce the corporation's rights or to prevent or remedy a wrong to the corporation. The cause of action belongs to the corporation itself, not to the shareholders bringing the action. Therefore the derivative suit may be used only to seek redress for wrongs that injure the corporation as a whole, not for individual injuries that the plaintiffs may have suffered. In essence, derivative suits are used to protect the corporation and its minority shareholders against abuses by its directors and officers, by making directors and officers accountable to the corporation's shareholders.

A shareholder has several hurdles to overcome to maintain a derivative action. Before filing the derivative suit, the shareholder must make a demand on the corporate directors, officers, or managers to bring the suit, which gives the corporation an opportunity to remedy the wrong before engaging in litigation. The demand requirement is excused only in limited circumstances, such as when the shareholder can demonstrate that demand would be futile. Additionally, the shareholder must have owned stock at the time that the alleged wrongful conduct occurred in order to have standing to maintain the derivative suit. Furthermore, a shareholder must fairly and adequately represent the interests of all of the shareholders enforcing the rights of the corporation. If a shareholder cannot satisfy these requirements, the derivative action is likely to be dismissed.

3. Class Actions. Public companies should also be aware of the potential liability exposure that can result from class action suits. The class action device has been widely popular in securities litigation involving public companies, largely because of its tendency to bring about big-dollar settlements. In one sense, a class action is similar to a derivative suit in that one shareholder—or a small number of shareholders—may bring an action on behalf of another party. In a derivative suit, that other

party is the corporation itself. In a class action, however, the shareholder (or shareholders) may bring an action on behalf of all other shareholders to recover for the same individual injuries that the initiating class member has suffered. Whereas the derivative suit is limited to addressing wrongs to the corporation as a whole, a class action may seek relief for any individual injuries caused directly to the shareholders.

Class actions involving public companies are subject to the same requirements that apply to all types of class action suits. A class action may arise only if the class members are too numerous to be joined, if their claims involve common questions of law and fact that are typical to the class, and if the class representative will fairly and adequately protect the interests of the class. Because a shareholder class action can involve thousands—or even millions—of individuals, a public company’s potential liability can be exceedingly high, and therefore many public companies choose to settle the class action rather than fight the class claims through litigation. This makes the class action device potentially lucrative for many class action plaintiffs and potentially worrisome to directors, officers, and board members of public companies. However, a public company that understands the risks, costs, and options in dealing with class action suits will be better prepared should one arise.

E. Labor. As explained in detail in [Chapter 13](#), litigation may arise from labor contracts and other employment disputes on a wind project. Experienced employment attorneys are essential to resolving these types of disputes efficiently, without causing unneeded delay or expense on the project.

F. Administrative Litigation. Regulatory proceedings at FERC, state utility commissions, or other state agencies with regulatory jurisdiction over energy transmission and sales can have significant effects on a wind project’s bottom line. A good example of this is the emergence of tradable RECs in recent years. Before the adoption of renewable portfolio standards and green tag markets, PPAs would not specify which party was entitled to claim the RECs. With the development of a market for tradable RECs, separate and apart from the sale of the energy generated by the project, disputes developed over which party—seller or purchaser—was entitled to claim the RECs. FERC further muddled the waters by issuing a declaratory judgment allowing each state to make its own determination of which party owned the RECs. This in turn led to state regulatory litigation over REC ownership. See *Petition for Declaratory Order and Request for Expedited Consideration, Am. Ref-Fuel Co., Covanta Energy Grp., Montenay Power Corp. & Wheelabrator Techs., Inc.*, FERC Docket No. EL03-133-000 (June 16, 2003). It often pays to ensure that proceedings at relevant agencies are monitored regularly to provide an opportunity to actively participate in any regulatory proceedings that may have an effect on the project before a decision is reached.

Chapter Fifteen
THE LAW OF WIND
—Securities Regulation—
Ronald D. McFall

Wind industry businesses seeking to raise capital in the United States for investment in their business activities must concern themselves with U.S. securities laws. As discussed below, many wind 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, wind 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, projects that seek investment from larger numbers of investors may not be able to claim the exemptions available for sales of securities solely to accredited investors.

Given the range of possible transaction structures and participants (and the importance of the facts and circumstances of each arrangement), a wind 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.

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 wind industry participants and, finally, the resale of securities by affiliates of the issuer and other investors.

I. Introduction. The Securities and Exchange Commission (“SEC”) regulates and enforces the securities laws in the United States. The SEC also empowers and oversees the activities of various self-regulatory organizations, such as the National Association of Securities Dealers, Inc., and the various exchanges and other systems on which securities are traded, such as the New York Stock Exchange and the National Association of Securities Dealers Automated Quotation System (“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 a securities commission that, most often, functions under the authority of the Secretary of State.

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 or 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 clearly 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”) clearly apply to sales made to purchasers resident in the state.

II. 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.¹

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.² The line between 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.

¹ There is some slight variation in the definition, but all variations are generally to the effect described above.

² 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.

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.

- Agreements or instruments of any kind are securities if, as a matter of fact, they meet the definitional test of an investment contract described above.

An agreement or instrument may constitute or contain a security regardless of its form. For example, a complex agreement relating to a project may contain numerous provisions to which securities law do not apply while also containing a security that must adhere to securities laws. Similarly, an instrument may constitute stock if it creates an equity interest in a business, even if the word “stock” is not used.

III. What Do the Securities Laws Regulate? As noted, 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.

A. 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.³ As described in more 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.

B. 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.

³ 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 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.

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.

C. 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.

IV. 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

(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.^[4]

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.⁵

⁴ Section 10(b) of the Securities Exchange Act of 1934, as amended, and Rule 10b-5 promulgated thereunder.

⁵ 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

(continued . . .)

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 “Rule 10b-5 claims,” referring to the regulation under which they exist. Rule 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 Rule 10b-5 obligation described above, certain disclosure obligations may impact businesses seeking to obtain capital in a registered offering of their 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.⁶

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 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 Rule 10b-5 liability if that person (known as a “tipper”) 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 Rule 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

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.

⁶ 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 Rule 10b-5 will drive the issuer’s obligations to prospective investors.

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 Rule 10b-5 liability. For example, a tipper can be liable only if the provision of the information was in some way in violation of a duty of the tipper *not* to provide the information. Inadvertent or fortuitous disclosures or disclosures for a proper business purpose cannot be the basis for tipper liability. Similarly, a person who declined to participate in a securities transaction cannot sue under Rule 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, Rule 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 might forget that Rule 10b-5 applies as well. Such a failure can have serious consequences, even if all of the registration and exemption 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 Rule 10b-5 obligations 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 Rule 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.

V. 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 (“Exchange Act”) and will have to file with the SEC annual and quarterly reports, and other reports upon the occurrence of specific events.⁷ 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

⁷ 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 non-exempt equity security held of record by more than either (a) 2,000 persons or (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.

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. Issuers that are and intend to remain private generally rely on one or more of several exemptions. The most frequently claimed exemptions are those for securities that are not sold, either directly or indirectly, to the general public.⁸ These exemptions, available only to issuers and generically known as “private offering exemptions,” allow 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.”

1. 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

⁸ 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.

(continued . . .)

were not known and identified as potential investors who were qualified to receive the offer, would violate the conditions for reliance on the exemption.⁹

Under the Jumpstart Our Business Startups Act adopted by Congress in 2012 (“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.¹⁰ In general, financial institutions, institutional investors of significant size, and relatively wealthy individuals are accredited investors.¹¹

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 would invalidate the exemption not only 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.

2. Investor Identity Restrictions. Federal securities regulations permit private placements to be made to an unlimited number of accredited investors. In general, financial institutions, institutional investors of significant size, and relatively wealthy individuals are 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.

The regulations also permit private placements to be made to up to 35 nonaccredited investors. 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 fact that selling securities to nonaccredited investors increases the risk of legal action if things do not go well for the investment.

⁹ 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.

¹⁰ 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.

¹¹ 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 the 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.

(continued . . .)

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.”¹² 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 investors.” These investments are more likely to be debt offerings, 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.

C. A 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.

VI. 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 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. However, sales by affiliates of the issuer are also subject to restriction and can be resold only upon satisfaction of certain conditions.¹³

¹² 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.

¹³ 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.

A. 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.

B. 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.¹⁴ 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.

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

D. 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

¹⁴ This restriction also applies to persons who, at the time of the resale, had recently been affiliates of the issuer.

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.

E. 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.

Chapter Sixteen
THE LAW OF WIND
—Foreign Corrupt Practices Act—
Kennon Scott

With globalization, an increasing number of companies once thought to be only national, regional, or local now operate in the global marketplace. Many companies operating in the wind energy industry commonly participate in the global marketplace horizontally, with some portion of their chain of production and sales occurring outside the United States, and vertically, in that they have non-U.S. owners or they own or invest in non-U.S. entities. While foreign owners of major U.S. wind companies have long dominated the domestic industry, we have also begun to see U.S. wind companies—whether or not foreign owned—begin to venture into other countries as the U.S. market has suffered in recent years and foreign countries offer attractive incentives for new wind generation.

Accessing the global marketplace brings many advantages to a wind 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 wind 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 wind 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

¹ 15 U.S.C. § 78dd-1, *et seq.*

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 unavoidable due to their involvement in bid and tender processes, customs issues, and licensing and permitting. For example, a recent trend in Latin America is for wind power developers to participate in government sponsored auctions. This, as with any activity involving contact with government officials, should be closely monitored.

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

² "Issuer" is defined *infra* at 5.

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 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 percent 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 wind 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

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.*

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 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.

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.

(continued ...)

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 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 wind 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

¹⁰ *Id.* at 925.

¹¹ *Id.* at 925-27.

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).

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-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 Depositary 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

¹⁷ 15 U.S.C. §§ 78m, 78dd-1.

¹⁸ 15 U.S.C. § 78dd-2.

¹⁹ 15 U.S.C. § 78dd-3(a).

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 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. ("Teva") 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, 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.

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(f)(2)(B).

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

A. Third-Party Agents. Wind 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 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 wind 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

Wind 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 wind 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, wind 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, wind 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, wind 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

²³ *FCPA: A Resource Guide to the U.S. Foreign Corrupt Practices*, *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).

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. Wind 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.

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, wind 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, wind 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 2013, Ralph Lauren Corporation ("RLC") agreed to pay approximately \$1.6 million in fines and penalties and enter into non-prosecution 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 issuer²⁴ 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. Wind 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

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).

(continued . . .)

misconduct from continuing after the acquisition.”²⁷ Thus, to reduce the risk of successor liability under the FCPA, wind 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 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 *Alba* complaint.³³

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

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).

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 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 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 wind 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' payment of the massive fines demonstrates 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 wind 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 wind 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 wind 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 wind 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. Wind 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. 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. Wind 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 wind 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 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.

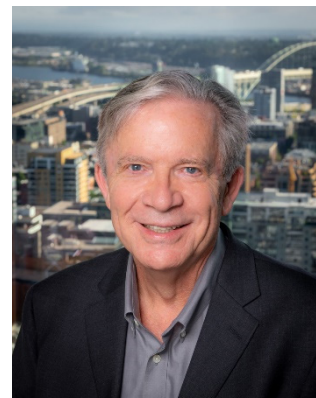
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Prior to joining Stoel Rives, Bill was an associate at Baker & McKenzie in New York. He was born and raised in Hong Kong and speaks and reads Chinese.

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Barbara Craig is a forester turned attorney and as such she brings an understanding in science, biology and public policy that provides for forging creative solutions to conflicts relating to federal permitting. She began her practice during the northern spotted owl debates and the President's Forest Plan that was followed by the Salmon Summit commenced by Senator Hatfield. She focuses her practice on federal and environmental law and has followed iconic landscape species debates that have affected her clients, including forestry companies and associations, ports, pulp and paper interests, developers and owners of hydropower dams, wind energy projects, solar projects, utilities, and oil and gas facilities.

Barbara has extensive experience on issues involving the Endangered Species Act (ESA), National Forest Management Act (NFMA), Federal Land Policy and Management Act, Federal Power Act (FPA), Natural Gas Act, Marine Mammal Protection Act (MMPA), Migratory Bird Treaty Act (MBTA), Bald and Golden Eagle Protection Act (Eagle Act), National Environmental Policy Act (NEPA), National Historic Preservation Act (NHPA), Clean Water Act (CWA) and Administrative Procedures Act. In particular, she has a thorough knowledge of this complex area of ESA and has successfully completed Section 7 consultations, developed Section 10 Habitat Conservation Plans, Safe Harbor Agreements, Candidate Conservation Agreements and proposed 4(d) rules.

Barbara received her B.S. in Forest Management from Oregon State University in 1980 and worked for the U.S. Forest Service as a project forester for five years in the Leavenworth Ranger District in the Wenatchee National Forest in Washington. As a project forester, she was responsible for all aspects of timber management, including NEPA documents, silvicultural prescriptions, sale design, field layout, contract compilation and appraisal. She was a member of the Redmond Hotshot Crew, fighting forest fires in the region. Before joining the U.S. Forest Service, she worked as a private contractor for four years, procuring labor contracts in forestry for activities such as reforestation, slash piling, fire-line construction and precommercial thinning.

Barbara worked for the U.S. Forest Service while attending law school and graduated from Lewis & Clark Law School, J.D., 1987. She received a Certificate in Environmental and Natural Resources Law and is a member of the Cornelius Honor Society.

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Sarah Stauffer Curtiss helps clients understand and comply with environmental and land use laws, navigate complex permitting processes, and develop compliance solutions that enhance business opportunities. On Oregon land use matters, Sarah helps clients secure permits from local governments. She has worked with city and county planning departments throughout Oregon, and regularly represents clients before local governing bodies and the Oregon Land Use Board of Appeals. She also represents energy and utility clients on permitting and compliance matters related to project development and expansion through the Oregon Energy Facility Siting Council (EFSC).

Her federal environmental expertise covers a myriad of environmental laws, including the Endangered Species Act (ESA), the Bald and Golden Eagle Protection Act (BGEPA), the Migratory Bird Treaty Act (MBTA), the Federal Land Policy and Management Act (FLPMA), the National Environmental Policy Act (NEPA), the National Historic Preservation Act (NHPA), the Wild and Scenic Rivers Act (WSRA), and the Clean Water Act (CWA).

Licensed to practice in Oregon and Washington, Sarah prides herself in helping clients develop innovative solutions to problems and on working collaboratively with clients, consultants, and agency staff.

During law school, Sarah served as an environmental law clerk at the U.S. Attorney's Office in Portland (2006-2007) and as a judicial extern for the Honorable Robert E. Jones, U.S. District Court for the District of Oregon (2006). Before attending law school, Sarah was a seventh-grade English teacher with Teach for America in Houston, Texas (2001-2004).

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Prior to law school, Kate worked for five years with the U.S. Forest Service's National Headquarters as a strategic planner in the agency's Fire and Aviation Management staff. She also served as a Conservation Fellow for Senator Max Baucus.

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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).

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Prior to joining Stoel Rives LLP, Anthony founded and managed the Girolami Legal Group, a business law firm in San Diego, California. He was also counsel with the Mexico City office of Chadbourne & Parke (2006-2009) and a senior associate at Shearman & Sterling LLP in New York and São Paulo, Brazil (2003-2006). Anthony is fluent in Spanish and Portuguese.

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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.

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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 ten 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 1989-1992, 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 2017 and beyond.

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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

Jason 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.

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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

KEVIN D. JOHNSON

PARTNER

Kevin advises and represents companies and local governments on issues involving environmental, energy, land use, and natural resources law. He develops effective strategies and solutions to address such matters as:

- siting and development of facilities;
- regulatory compliance and response to enforcement actions;
- federal, state and local permitting;
- due diligence in transactions; and
- property contamination issues.

Clients particularly rely on Kevin for his experience with energy projects -- including bioenergy (waste-to-energy), biofuels (ethanol and biodiesel), wind and solar energy, and natural gas. He also assists in addressing issues associated with waste management facilities, agribusiness operations, natural resources industries, and redevelopment projects.

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Education

William Mitchell (now Mitchell Hamline) College of Law,
J.D., Environmental Law
Focus, 1993

Hamline University, M.A.,
Public Administration, 1989

University of Minnesota, B.A.,
Journalism, 1983

Admissions

Minnesota

U.S. District Court for the
District of Minnesota

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.

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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

CHAD T. MARRIOTT

PARTNER

Chad Marriott serves as counsel to sponsors, owners, and investors, as well as commercial and industrial customers, in the development, sale, acquisition, and financing of renewable and thermal energy projects throughout the United States. His breadth of experience in finance, M&A, and state and federal utility regulation keeps him actively engaged as a member of Stoel Rives' Energy Development team.

In the past few years, Chad has served as sponsor's counsel for the negotiation of \$1.6 billion in tax equity financing for more than 1.5 GW of wind projects from North Dakota to Texas, in addition to separate equity investments in more than 900 MW. In addition, Chad has negotiated the tax equity financing for a 100 MWac portfolio of solar PV projects and acted as primary federal energy regulatory counsel for the tax equity and back-leverage debt financing of more than 350 MWac in the Southwest, Southeast, and Northeast regions.

Prior to joining Stoel Rives, Chad was a consultant with Pacific Energy Ventures, LLC where he advised on siting and regulatory issues related to wave- and tidal-energy projects and contributed to the *Siting Methodologies for Hydrokinetics* handbook published on behalf of the U.S. Department of Energy in 2009. He also served as a legal intern for the U.S. House of Representatives Committee on Oversight and Government Reform in Washington, D.C. and as a law clerk for the U.S. Department of Justice, Environment & Natural Resources Division in Sacramento.

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Education

University of Oregon School of Law, J.D., 2009; Certificate in Sustainable Business Law; Program Fellow, *Environment & Natural Resources Law Center*; Fredric R. Merrill Award, *Oregon Law Review*, 2009

Indiana University, M.S., 2005

University of Utah, B.A., 2001

Admissions

Oregon

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).

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Education

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

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.

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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.

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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

RAMONA L. MONROE

PARTNER

Ramona has over 20 years of experience representing natural resource companies in matters involving title, leasing, transactions, financing, and compliance with state and local government requirements. Oil and gas companies rely on Ramona to prepare title opinions and assist with asset transactions, surface use and access issues, pipeline rights-of-way, matters arising under unit agreements and joint operating agreements, financing transactions, and compliance with Alaska's unique oil and gas regulations. Ramona represents mining companies in transactions, access issues, joint ventures, other exploration and project development matters, and prepares title reports on state and federal mining claims. She also represents wind and solar energy developers with respect to leasing and clearing title to obtain financing. Ramona also represents clients with issues arising under the Coastal Zone Management Act and state coastal management programs.

Ramona serves as a trustee-at-large of the Rocky Mountain Mineral Law Foundation. She has been included in *The Best Lawyers in America*® (currently: Oil & Gas Law), 2018.

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Education

Lewis and Clark Law School,
J.D., 1993

University of Washington,
B.A., international studies,
1988

Admissions

Alaska

Oregon

Washington

JOSEPH E. NUSSBAUM

PARTNER

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 area of energy finance.

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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



KARL F. OLES

PARTNER

Karl Oles is a partner of the firm practicing in the Construction and Design group. For more than 30 years, he has helped owners, architects, engineers, and contractors solve complex legal problems through negotiation, mediation, arbitration, and trial. Karl has also drafted, negotiated, and analyzed multimillion-dollar design and construction contracts on a wide variety of construction projects. He has served as an arbitrator on the American Arbitration Association's construction panel. He is coauthor of the current standard treatise on Washington lien law.

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Education

University of Washington
School of Law, J.D., 1986

University of California at Los
Angeles, M.A., 1982

University of London, M.A.,
1978

Pomona College, B.A., 1977,
magna cum laude

Admissions

Washington

U.S. District Court for the
Eastern and Western Districts
of Washington

U.S. Court of Appeals for the
Ninth Circuit

KEVIN T. PEARSON

PARTNER

Kevin is a partner and the chair 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>



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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

JEREMY D. SACKS

PARTNER

Jeremy Sacks is a partner in the Litigation Practice Group, chair of the firm's Energy Litigation Initiative, and chair of the Portland office Trial group. His practice focuses on complex litigation in a variety of businesses, including the energy and health care industries. He has experience litigating business torts, contract disputes, securities fraud, False Claims Act issues, shareholder disputes, class actions, licensing disputes, and antitrust claims. Jeremy also has substantial experience conducting internal corporate investigations and handling export and import matters. He has represented individual and corporate clients, both regional and national, in a variety of private, state and federal forums.

Jeremy was a litigator at the Washington, D.C., office of Fried, Frank, Harris, Shriver & Jacobson from 1994 to 1998. During 1993-1994, Jeremy was a staff volunteer at the NAFTA Office of the Executive Office of the President and an intern at the Office of the Deputy United States Trade Representative.

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Education

Georgetown University Law Center, J.D., 1994, *cum laude*; Articles Editor, *Law and Policy in International Business*

Wesleyan University, B.A., 1991, with high honors in the College of Social Studies; Phi Beta Kappa

Birkbeck College, University of London, 1989

Hansard Scholars Programme and research assistant to Ann Widdecombe, M.P., House of Commons, 1989

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 non-exempt. 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.

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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.

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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

JAMES M. SHORE

PARTNER

For over 30 years, Jim Shore has helped employers and entrepreneurs in a variety of industries address their business needs and toughest labor and employment law challenges. His practice includes: (1) employment litigation and trial work, including wage/hour class actions, wrongful discharge, discrimination, harassment, and OSHA cases; (2) labor-management relations, including arbitrations, NLRB charges/hearings, collective bargaining with unions, election campaigns and strike planning/response; (3) advice and litigation assistance involving trade secrets, restrictive covenants, data theft and other areas where employment and intellectual property issues intersect; (4) business transactions and reorganizations; and (5) daily human resources and labor advice. Jim also manages sensitive internal investigations for clients. Drawing from his experiences as an in-house attorney and director of labor relations for a major Northwest corporation, Jim likes to proactively engage with clients in order to both effectively address their immediate needs and achieve the best long-term business result.

Jim is inducted as a Fellow in the College of Labor and Employment Lawyers for his sustained outstanding performance in the profession and as a leading Washington State labor and employment lawyer by the *Chambers USA* peer and client rating process, *Best Lawyers in America*® and *Super Lawyers*®. Jim is AV rated by Martindale-Hubbell®, and is a member of the Washington, Oregon and California bars.

Jim is a frequent speaker and trainer in Washington and across the U.S., and blogs at Stoel Rives World of Employment.

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Education

Hastings College of the Law,
University of California, J.D.,
1987, *magna cum laude*;
Hastings Law Journal, 1985-
1987; Order of the Coif

New College of Florida, B.A.,
1983

Admissions

Washington

Oregon

California

HEATHER L. STEWART

OF COUNSEL

Heather Stewart is Of Counsel in the firm's Corporate group. Heather is experienced in project finance and commercial finance matters, with a particular focus on construction, bridge and term debt financing of renewable energy projects.

Before joining Stoel Rives, Heather was a senior associate at Orrick, Herrington & Sutcliffe LLP in San Francisco (2008-2012) and Portland (2012-2017) and an associate at Thelen Reid Brown Raysman & Steiner LLP in San Francisco (2002-2008). She represented sponsors and developers in the financing of renewable and conventional energy projects, and also advised companies in a variety of industries on mergers and acquisitions and general corporate matters.

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Education

Duke University School of Law, J.D., 2002; Research Editor, Staff Editor, *Law & Contemporary Problems*

Dartmouth College; B.A., English, 1999, *cum laude*

Admissions

Oregon

California

THE LAW OF WIND



The Law of Wind will be updated periodically, but to stay informed of developments in the 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.

Stoel Rives is proud to purchase Renewable Energy Credits to offset 100 percent of its firmwide electricity usage.



Alaska California Idaho Minnesota Oregon Utah Washington
and Washington, D.C.