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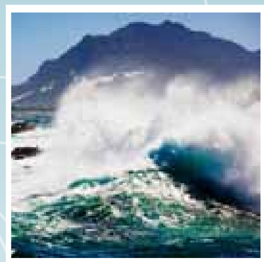
# The Law of MARINE AND HYDROKINETIC ENERGY

## A Guide to Business and Legal Issues



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## The Law of
# MARINE AND HYDROKINETIC ENERGY
### A Guide to Business and Legal Issues



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# WELCOME TO

# THE LAW OF MARINE AND HYDROKINETIC ENERGY

Dear Member of the Marine and Hydrokinetic Energy Community,

It is an exciting time to be part of the marine and hydrokinetic ("MHK") energy industry. MHK technologies and the vast potential presented by our ocean, tidal, and riverine resources have captured the attention of the media, regulators, politicians, the government, and the investment community.

The past four years have seen major developments in the United States. For example, the MHK industry has seen a significant increase in Congressional appropriations over budget requests for the U.S. Department of Energy ("DOE") Advanced Water Power Program. Congressional appropriations for research and development increased from $10 million in 2008 to $40 million in 2009, and then to $50 million in 2010. Of the total appropriations each year, 70 to 90 percent was allocated to MHK technology advancement. In 2010 alone, DOE awarded $37 million to accelerate the technological and commercial readiness of 27 emerging MHK technologies through its Marine and Hydrokinetic Technology Readiness Advancement Initiative. In 2010, the Obama Administration began the process of reorganizing the Minerals Management Service into separate bureaus with distinct missions and formed the National Ocean Council, tasking it with the development of a comprehensive coastal and marine spatial planning process for the nation's coasts and the Great Lakes.

Despite the increase in financing available for research and development, MHK projects remain subject to a plethora of real property issues; regulatory and permitting requirements; interconnection, transmission, and power purchase negotiations; financing challenges; tax matters; construction contracting; and intellectual property issues. In addition, like wind and solar power projects, MHK projects face challenges unique to variable energy resources such as grid integration costs.

Recognizing these challenges, and as part of our commitment to the growth and success of the MHK industry, the Stoel Rives Marine and Hydrokinetic Energy Team produced **THE LAW OF MARINE AND HYDROKINETIC ENERGY** as a successor to three editions of The Law of Ocean and Tidal Energy. **THE LAW OF MARINE AND HYDROKINETIC ENERGY** draws on experience our team has developed from working actively on MHK projects and as a market leader in renewable energy law.

This book is just one aspect of our commitment to the MHK industry. Stoel Rives attorneys have been actively involved in developing legislation and in regulatory proceedings in support of MHK development. We are proud to be a founding and active board member of the Ocean Renewable Energy Coalition, a national MHK trade association. In addition, we are actively involved in the National Hydropower Association's Ocean, Tidal and New Technologies Council and have held Council leadership roles. Finally, we regularly cover developments in MHK and other renewable energy resources on our Renewable + Law Blog (http://www.lawofrenewableenergy.com) and in our Energy Law Alerts (to receive alerts sign up at http://www.stoel.com/subscribe).

We hope you find this book useful and will contact us with any comments.

Sincerely,

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***About the "Law of" Series:*** This volume is one in a series that Stoel Rives has produced over the past seven years; others include *The Law of Wind—A Guide to Business and Legal Issues* (in its sixth edition), *Lava Law—Legal Issues in Geothermal Energy Development* (in its sixth edition), *The Law of Biofuels—A Guide to Business and Legal Issues* (in its second edition), *Lex Helius: The Law of Solar Energy—A Guide to Business and Legal Issues* (in its second edition), *The Law of Biomass—A Guide to Business and Legal Issues* (in its first edition), and *The Law of Algae: Business and Legal Issues of Producing Algae Biofuels* (in a Wiki edition). The "Law of" books are updated periodically to reflect changes in the renewable energy industry and regulatory environment. These books and the other resources mentioned above are intended to provide a general overview of the legal issues involved in developing and financing a renewable energy project, but should not be used as a substitute for the advice of qualified legal counsel.

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# Chapter One
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Choice of Corporate Structure and Entity—

*William L. Clydesdale, Kevin T. Pearson, Ethan I. Samson*

The developer or owner of a marine or hydrokinetic power project will typically hold a variety of real property rights, maritime rights, equipment, permits and regulatory approvals, and intellectual property rights. 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 marine or hydrokinetic power project through a subsidiary created specifically for that purpose.

**A. Insulation from Risk.** The use of a single-purpose subsidiary to own a marine or hydrokinetic power project allows the parent company to limit its potential liability to the value of the project assets. 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 marine and hydrokinetic 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, ownership of the assets of the project in a single-purpose subsidiary enables a project lender to protect its collateral package from other creditors. For more information about financing, see Chapter 11.

**C. Exit Strategy.** The use of a subsidiary also facilitates transfer of all or portions of the project. It is easier to sell a marine or hydrokinetic 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, isolation of the assets in a subsidiary simplifies the transaction.

**II. Choice of Entity.** The choice of the type 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. Subtle differences exist, however, among entities based on various factors, such as taxation, liability, and transferability issues.

**A. Taxation.** Corporations are separate tax-paying entities. As a result, the income of a corporation is generally subject to two levels of tax: one at the corporate level and one at the shareholder level when distributions are made, stock is sold, or the corporation is liquidated. Partnerships and LLCs are "pass through" entities that are generally not subject to income tax; rather, 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 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 regarding deductibility, 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 the tax credits (for example, if it has insufficient net income) and cannot carry the credits forward or backward to a tax year in which the credits can be used, the credits expire. Partnerships and LLCs that are taxed as partnerships, however, may 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 10, this may be an especially important consideration if a developer wishes to monetize any available tax credits. 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 also must be used, if at all, at the corporate level. Losses of a partnership or an LLC, however, are passed through to its partners or members, who may be able to use them against their income, including income from other sources. The ability of individual partners and members (as opposed to the corporation) 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, upon either its initial organization or its admission of additional owners, may trigger recognition of gain with respect to contributed property unless certain 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.** Generally, corporations may engage in tax-free reorganizations, whereas a partnership, or an LLC that is treated as a partnership for tax purposes, may not.

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

C. **Liability.** Shareholders, limited partners, and members generally are not liable for debts of the entity beyond their capital contributions, whereas general partners generally are liable for 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 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 debts and obligations of the entity.

D. **Management and Operations.** A corporation must follow formalities prescribed by law, such as holding annual shareholder meetings and annual board meetings and maintaining records of actions of its 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.

E. **Transferability.** Corporate stock is freely transferable, subject to restrictions under federal and state securities laws, whereas economic and management rights in a partnership or LLC 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, sale of all interests in a multiple-member LLC to a single buyer may be treated as an asset purchase by the buyer, with accompanying tax benefits.

**F. Financing.** As discussed more thoroughly in Chapter 11, although project financing is best done through a subsidiary, the type of entity that owns the ocean 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 marine or hydrokinetic 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 to it, it is very important to understand that some property rights, permits, and contracts may have restrictions on transfer that would be triggered when the parent company attempts to transfer the rights and permits to the newly formed subsidiary. Transfer approval processes may be public (in 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 require the approval of FERC under section 203 of the act.

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# Chapter Two
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Intellectual Property – Protections and Pitfalls—

*Douglas L. Batey, John A. Rafter, Jr.*

**I. Race to Market.** In the real estate business, it may be location, location, location, but for marine and hydrokinetic energy companies, particularly newer companies, the distinction in the marketplace is typically based on proprietary technology. Marine and hydrokinetic energy technologies are being developed for wave power, tidal power, in-stream power, ocean thermal energy conversion, and salinity gradients. Many small firms and inventors and a few larger companies are attempting to commercialize hundreds of technology designs. Some pilot projects are underway or on the verge of commencement, but large-scale commercial success has eluded developers.

Developers have to deal with scientific and engineering challenges, shortages of capital, regulatory challenges, and often a lack of infrastructure. In effect, there is a race to the marketplace. Winners can't be predicted now, but there will be winners.

Technology developers want to make money and accordingly hope that their technology will be widely adopted. But widespread use does not necessarily result in profits for the developer. To avoid free-riders, the developer must ensure that its invention does not become a public resource. If others can freely copy the first inventor's invention, or freely copy a successful product, the first inventor or manufacturer may reap little benefit from its innovation. This is where the intellectual property laws come in -- these laws can be used to ensure a financial return to the inventor of a successful product by barring unauthorized copying.

**II. Legal Rights.** Intellectual property rights include patents, trade secrets, copyrights, and trademarks. In the development of marine and hydrokinetic energy, the two most important of these legal rights for most companies will be patents and trade secrets.

**III. Patents.** A U.S. patent gives the patent owner the right to exclude others, during its term, from making, using, selling, or importing products in the U.S. that would infringe the patent. A patent term begins on the grant of the patent and ends about 20 years from the date the patent application was first filed. The patent owner's right to exclude others from using the invention applies even if a second comer independently developed the same invention. In other words, ignorance of the patent is no defense.

To be patentable, an invention must be new, useful, and nonobvious in view of the prior art. It may be a machine, an article of manufacture, a process, or a composition of matter. Laws of nature and mathematical formulas per se are not patentable.

**A. Patent Application Process.** Patent applications are made in writing and in the name of the inventors, signed by the inventors, and filed with the U.S. Patent and Trademark Office. (The owner's rights under a U.S. patent apply only in the U.S., but similar patent protection can be obtained in all industrialized nations if filing and timing requirements are met.) The application must include a specification that describes how the invention is made and used, and the best mode of realizing the invention. The application must also include the claims, which describe in particular terms the unique aspects of the invention for which legal protection is sought. The claims and specifications generally are published 18 months after the first filing date. However, an applicant in the U.S. can avoid publication if it agrees not to file the application anywhere outside the U.S. and requests "nonpublication" when the application is filed. Either way, the specification, including the final claims, will be published in the issued patent. It usually takes approximately 18 to 36 months or longer from filing the patent application to issuance of the patent. Patent law is technical, and to maximize the scope and the value of a patent, patent counsel should normally be retained for advice and to write and prosecute the application.

A patent owner can sue a patent infringer for damages and in some circumstances for a court ordered injunction to prevent the infringer from any further use of the invention. The patent owner can therefore use the patent to prevent competitors from using the invention, or it may license the patent to others in exchange for royalty payments.

Patent protection is potentially very powerful, but protection can be lost if filing and timing requirements are not met. Companies involved in technology development must be aware of these requirements and should consult with patent counsel early on -- especially before any public use or disclosure of the invention. Compliance procedures should be implemented at the start of any technology development project.

**B. Bars to Patentability.** One of the more problematic U.S. patent requirements is the so-called "one-year bar." If the invention is described in a printed publication anywhere in the world, or if it is sold, offered for sale, or used publicly (non-experimental, or not subject to a nondisclosure agreement) in the U.S., more than one year before the U.S. patent application is filed, all patent rights are lost. Any publication, such as in an academic journal, Website, or trade magazine, starts this one-year grace period, and so does demonstrating or using the invention at a trade show, or selling the invention or offering it for sale. Particularly vexing may be that the inventor's purchase or testing of prototypes may start the one-year grace period. Once any of these events takes place, the one-year clock starts ticking, and patent counsel should be immediately consulted about starting the application process.

The timing requirements are even stricter if foreign patent protection is to be obtained. In most foreign countries, any publication or public disclosure of the invention anywhere in the world before filing of the patent application will cause loss of patent rights in that country. So if foreign patent protection is desired, strict nondisclosure and nonpublic use procedures must be followed until the U.S. patent application is filed. In most industrialized countries, counterpart patent applications can claim the benefit of an earlier filing date of a U.S. patent application as the effective filing date for the foreign application, provided the foreign application is filed within one year of the U.S. filing date.

In most of the world, priority between multiple inventors of the same invention is based on the filing dates of their respective patent applications. The first to file wins. The U.S. patent system, however, uses a "first-to-invent" system rather than a "first-to-file" system. In the U.S., the inventor who first conceived of the invention and reduced the invention to practice with reasonable diligence has priority, even if someone else filed their patent application first. Nonetheless, the first-to-file usually wins anyway given the priority advantages accorded the first filing.

**C. Record Keeping.** In order to have evidence to back up a claim of having invented something at an earlier date, inventors must keep good records. The uncorroborated testimony of the inventor may not be enough, particularly if the inventor has a pecuniary interest in the outcome. Written records such as an engineer's lab notebook should show all activities related to the invention. Entries should be periodically signed and dated (*e.g.,* weekly or monthly) by a witness who is not an inventor. Ideally, the witness should have some knowledge of the subject matter and may be an employee of the same company.

**D. Ownership of the Patent.** Companies with employees researching for or developing new technologies or products should take steps to ensure the company's ownership of patentable inventions made by the employees. Under law in most U.S. states, the employer owns the rights to inventions that are made by employees within the scope of their employment. When the employee owns the invention, in some cases the employer may still have a nonexclusive "shop right" to use the invention, without compensation to the employee. This right can occur when the invention was developed on the employer's time or using the employer's materials, facilities, or equipment, even though it was outside the employee's regular duties. That outcome is not usually a satisfactory because the company may not have full ownership of the invention.

It is best to avoid uncertainty by addressing this issue with an invention agreement. The employer should require all new employees, as a condition to being hired, to sign an agreement assigning to the employer all inventions made by the employee during the course of employment. This type of agreement is extremely common in all industries that rely on technology development.

Some states have laws limiting the allowed scope of such agreements and requiring special notices to the employees, so state laws should be checked. The invention agreement should also cover the employee's confidentiality obligations and protection of the employer's trade secrets. A similar type of agreement should also be used for all independent contractors doing technology development work, to ensure that the company paying for the contractor's work will own the patent for any invention developed by the contractor.

**E. Patent Search and Due Diligence.** To make sure the invention is new, it is often advisable to search for earlier developments in the field. This search typically involves searching U.S. as well as foreign patents, as well as other publications such as scientific and technical journals, to find related inventions. There are online patent databases such as www.USPTO.gov and various service providers that can assist in conducting a complete search.

Just because a wave energy design may be patentable does not mean that it does not infringe someone else's patent. A search may uncover a competitor patent that may restrict a company's ability to exploit their own invention. Competent patent counsel is a must in such a circumstance.

**IV. Trade Secrets.** Trade secrets are important in marine and hydrokinetic energy development, whether or not patent protection is available. Unlike patents, trade secrets do not expire and can be continued indefinitely, so long as the information remains confidential. However, trade secrets do not prevent third parties from independently developing and using the same information.

A trade secret is any information, including a formula, method, program, device, or technique, that has economic value because it is not generally known and is not readily ascertainable by proper means, provided the owner takes reasonable measures to maintain its secrecy. For example, the mechanism of a product that can be reverse-engineered by taking it apart is not a trade secret. On the other hand, a manufacturing process that is a secret and that cannot be determined by studying the finished product would be a trade secret. Likewise, the source code for a computer program that is kept secret because the software is only distributed in object code form would be a trade secret. And even if a product is not protected by patent law and is subject to being reverse-engineered once it is on sale, trade secrecy during the development process will protect the company's head-start advantage of being the first to market with that particular product.

**A. Protective Procedures.** To ensure that a company's trade secrets are protected, the following steps should be taken:

- Have all employees sign written confidentiality agreements as a condition of employment. These provisions can be included as a part of the employee's invention assignment agreement.
- Label all written documents, drawings, etc. that are considered confidential with a suitable "confidential and proprietary" legend.
- Use physical and electronic security to restrict access to sensitive information to those persons with a need to know.
- Include the company's confidentiality policies in employee manuals.
- Require all third parties who may have access to the company's confidential information, such as vendors, consultants, and potential customers, to sign written nondisclosure agreements.
- When an employee leaves, conduct an exit interview to collect company materials and to confirm the employee's ongoing obligations as to trade secrets.

**V. Copyrights.** Copyrights protect the expression of an author's ideas. They apply to materials such as articles, white papers, manuals, brochures, and computer software. Copyright protection is automatically available when a work is created, and no copyright notice or filing is required. Using a copyright notice, however, and registering the copyright with the U.S. Copyright Office will provide additional remedies if enforcement becomes necessary. A notice at the beginning of the work, for example, "© 2007 by John Smith, Inc.," will suffice.

Copyrights do not protect ideas or information, only the author's particular expression. A copyrighted work cannot be copied or used to create a derivative work based on the copyrighted work, but the ideas communicated by the work may be used without violating the copyright.

**VI. Problems with Independent Contractors.** One potential trouble area is ownership of copyrights. Copyrightable work developed by employees in the course of employment will be owned by the employer, but copyrightable work developed by an independent contractor will be owned by the contractor unless the parties agree otherwise. If the contractor owns the work, the company that hired the contractor will have a license to use the work, but the scope of the license may not be clear. It may seem counterintuitive that the contractor will own the copyright when the company is paying the contractor to create the work, but that is the result under the copyright law unless the parties agree otherwise.

The bottom line: The company should have a written agreement with all independent contractors, clearly stating that the company will own the inventions, patents, trade secrets and copyrights in all works created under the contract. There should also be an employee invention agreement as described above to cover the employer's ownership of the copyright in all works created by the employee.

**VII. Trademarks.** A trademark is an identifying word, picture, or symbol that a seller of goods uses to identify and distinguish its product from the products of other sellers. (Service marks protect services much as trademarks protect products.) Trademarks protect the seller's commercial interest in tying its products to itself. For example, think of IBM computers. The products could be as complex as devices to convert ocean wave energy to electricity, or they could be as mundane as a loaf of bread.

**A. Trademark Registration.** Trademarks are protected both by the common law of the states and by federal statutory law. Federal protection is generated by using a trademark and filing a trademark registration application with the U.S. Patent and Trademark Office, assuming the application is approved. However, trademark protection can also be derived from the common law simply by using a trademark in commerce. Federal registration gives broader and stronger protection and is highly recommended.

If two sellers are attempting to use the same or a similar trademark for the same or similar goods, generally the first user will have priority. If there is a likelihood of confusion between the two marks, the first user will be able to prevent the second comer from using the trademark for those goods.

**B. Conduct a Search.** A trademark search should always be conducted before commencing use of a trademark. This will avoid building up goodwill in a trademark and then having to change trademarks because of a prior user. There are companies that will conduct a trademark search for a few hundred dollars, and complete search results can be obtained in a few days. Interpreting the search results is a matter of legal analysis and is best conducted by trademark counsel.

**C. Proper Trademark Use.** A trademark owner should take care in the use of its trademarks. Generally speaking, a trademark should always be used as an adjective (*e.g.*, Nike shoes) and never as a noun, to avoid having the mark become the generic term for the product (*e.g.*, thermos). A "TM" symbol should be used adjacent to any mark used in commerce to give notice of the company's intent to use the name or symbol as a trademark. However, it is improper to use the registration notice (®) unless and until a trademark actually is registered with the U.S. Patent and Trademark Office.

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# Chapter Three
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Siting and Permitting Marine and Hydrokinetic Energy Projects—

*Chad T. Marriott, John A. McKinsey,*
*Michael P. O'Connell, Cherise M. Oram*

**I. Introduction.** Marine and hydrokinetic energy projects have the potential to produce significant amounts of clean and renewable power. If fully developed, new hydrokinetic technologies could double the amount of hydropower production in the United States from just below 10 percent to close to 20 percent of the national supply.[1] Like many projects in protected coastal and riverine environments, however, these projects require a developer to navigate complex governmental permitting requirements and procedures. Ocean and tidal projects, in particular, will face challenges not raised by traditional hydropower and new in-river technologies.

**II. Overview of Licensing and Permitting Requirements.** The siting of a marine or hydrokinetic energy project will involve numerous federal, state, tribal, and non-governmental entities charged with or having substantial interests in laws, regulations, and programs regulating hydropower facilities, water quality and in-water discharges, state and federal lands located beneath the sea, coastal resources and marine sanctuaries, underwater and other cultural resources, shipping and navigation, crabbing and fishing, endangered and threatened species, marine mammals, migratory birds and seabirds, and recreation and public safety, among other things. Projects must be licensed by the Federal Energy Regulatory Commission ("FERC"), and FERC's extensive licensing regime is the framework within which all other state, tribal, and federal environmental approvals must be obtained. Ocean projects on the outer continental shelf ("OCS"), which commences between three and nine nautical miles seaward from the coastal baseline, depending on the state, must obtain leases from the Department of Interior's Bureau of Ocean Energy Management ("BOEM"), formerly the Minerals Management Service ("MMS"),[2] while ocean projects on the seabed landward of the OCS and in-stream hydrokinetic projects must secure rights from states that own the submerged or submersible land out to the OCS boundary.

In addition to FERC and BOEM, relevant agencies and stakeholders include:

- U.S. Army Corps of Engineers ("Corps")
- U.S. Coast Guard

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[1] *See* Hydroelectric Infrastructure Technical Conference, Docket No. AD06-13-000, transcript at 12, 22 (Dec. 6, 2006) (testimony of George Hagerman). The Electric Power Research Institute ("EPRI") has estimated the technical research potential for wave technology in the U.S. at 90 GW nameplate capacity. *Assessment of Waterpower Potential and Development Needs*, EPRI, (2007), *available at* http://www.aaas.org/spp/cstc/docs/07_06_1ERPI_report.pdf. EPRI has also conducted a five-state study of the technical potential of tidal in-stream energy conversion ("TISEC") and found 300 MW of feasible technical potential and an estimated 3,800 MW of theoretical potential in Alaska. *North American Tidal In-Stream Energy Conversion Technology Feasibility Study*, EPRI (2006), *available at* http://oceanenergy.epri.com/attachments/streamenergy/reports/008_Summary_Tidal_Report_06-10-06.pdf; *Job Creation Opportunities in Hydropower*, Navigant Consulting (2009), *available at* http://hydro.org/wp-content/uploads/2010/12/NHA_JobsStudy_FinalReport.pdf (estimating MW potential in Alaska based on estimated generation reported in EPRI TISEC study). Florida Atlantic University's Center for Ocean Technology estimates that ocean currents off the coast of Florida represent 4-10 MW of theoretical potential in that region. *See Job Creation Opportunities in Hydropower, supra*.

[2] On May 19, 2010, Secretary Salazar signed a Secretarial Order that divided the conflicting missions of MMS into separate entities. MMS was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") in mid-June. On October 1, 2010, the revenue collection arm of the former MMS became the Office of Natural Resources Revenue. On January 19, 2011, Secretary Salazar detailed the structure of the two bureaus that will separately house (1) the resource development and energy management function of BOEMRE, administered by BOEM and (2) the safety and enforcement functions of BOEMRE, which now are enforced by the Bureau of Safety and Environmental Enforcement ("BSEE"). The BOEMRE will officially split into BOEM and BSEE on October 1, 2011. This document anticipates that change and refers to BOEM as the agency responsible for managing development of the nation's offshore resources. BOEM functions include leasing, plan administration, environmental studies, National Environmental Policy Act analysis, resource evaluation, economic analysis, and the renewable energy program.

- National Marine Fisheries Service ("NMFS")
- U.S. Fish and Wildlife Service ("USFWS")
- Federal land owner agencies
- Affected tribes
- State agency administering Coastal Zone Management Act ("CZMA")
- State agency administering Clean Water Act ("CWA") section 401 water quality certification
- State lands managers
- State fish and wildlife agencies
- State water resources managers
- State and tribal historic preservation offices
- State energy facility siting councils
- County commissions
- Local governments
- Ports
- Fishing and crabbing commissions
- Non-governmental interest groups (environmental, fishing, recreational)
- Public utility districts and investor-owned utilities
- Private landowners
- Cable committee

The Federal Power Act ("FPA"), pursuant to which FERC issues hydrokinetic licenses, preempts all state and local laws concerning hydroelectric licensing, with the exception of proprietary water rights and state approvals required by federal law. However, FERC may require a license applicant to comply with state and local requirements that do not make compliance with FERC's license impossible or unduly difficult. In addition, despite preemption, the FPA requires FERC to consider state and local concerns.

Given the number of stakeholders with potential interest in, and agencies with some role in regulatory approval for, marine and hydrokinetic energy projects, project proponents should begin stakeholder consultation as early as possible. Moreover, until such projects are deployed and their effects are monitored, proponents should be prepared to engage in robust adaptive management that, combined with the best available data and best professional judgment, can address the uncertainties associated with some of these projects. Project proponents and other stakeholders may choose to enter into settlement agreements like those frequently entered into in conventional hydropower dam proceedings, setting forth terms and conditions that the parties request FERC include in the project license. The terms and conditions can provide for specific minimization and mitigation measures, monitoring, and adaptive management. Comprehensive settlement agreements also may include terms and conditions that fall outside of FERC's jurisdiction and will not be enforced by FERC as part of the license but may be agreed to among settlement agreement parties to resolve concerns of interested stakeholders relating to a project.

## III. FERC.

### A. Licensing Requirements.

1. **Jurisdiction.** In 2002, FERC asserted jurisdiction over ocean, tidal, and other hydrokinetic projects pursuant to the FPA, which requires that a non-federal hydroelectric project be licensed by FERC if, among other things, it is located in navigable waters of the United States and is connected to an interstate electrical grid.[3]

2. **Licensing.** The FERC licensing process is complicated, with one default and two optional licensing processes, each requiring applicants to file a variety of pre-licensing documents and to consult with and perform studies requested by various agencies. The hydropower industry's recent experience is mostly in the context of relicensing existing hydropower dams, where the relicensing process takes at least five years but may stretch many years beyond that.

3. **Preliminary Permits.** Before seeking a license, a project proponent has the option of first applying for a preliminary permit. The purpose of a preliminary permit is to maintain priority for a site during the permit's three-year term while the permittee determines the project's feasibility, consults with stakeholders, performs baseline studies, and develops a license application. FERC has issued preliminary permits for "wave," "ocean current," "tidal current," and "in-river current" hydrokinetic project technologies.[4] As a result of a 2010 memorandum of agreement between FERC and MMS (now BOEM), FERC will not issue preliminary permits for projects on the OCS. For OCS projects, developers must obtain leases from BOEM.

FERC has adopted a "strict scrutiny" policy with regard to issuance and oversight of preliminary permits for hydrokinetic projects. FERC's "strict scrutiny" policy limits the size of preliminary permit areas to encourage competition and to prevent "site banking." In addition, to ensure that permit holders are actively pursuing

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[3] *AquaEnergy Group, Ltd.*, 101 FERC ¶ 62,009 (2002), *on reh'g*, 102 FERC ¶ 61,242 (2003) (*citing* 16 U.S.C. §§ 796(8), (11), 817(1)).

[4] *See* Federal Energy Regulatory Commission, Hydrokinetic Projects (Mar. 8, 2011), http://www.ferc.gov/industries/hydropower/indus-act/hydrokinetics.asp (listing issued and pending licenses and preliminary permits).

project exploration, FERC requires permittees to file semi-annual reports. Where sufficient progress is not being shown, FERC may cancel the permit in order to make the site available to other potential developers.

4. **Verdant Order.** Under the 2005 "Verdant Order," a developer may forgo a FERC license only if (a) it is testing an experimental technology for a short period of time for the purpose of conducting studies and (b) any power generated from the test facility is not transmitted into, and does not displace power from, the national energy grid.[5] These test projects must still obtain other federal and state approvals, as may be necessary, such as CWA section 404 discharge permits, section 401 water quality certifications, Endangered Species Act ("ESA") section 7 consultations, and Marine Mammal Protection Act ("MMPA") authorizations, and others.

**B. Pilot Project.**

1. **The Policy.** In 2007, FERC announced a Pilot Project Policy intended to reduce regulatory barriers to hydrokinetic demonstration projects. Pilot project licenses are available for projects that are (1) small (5 MW or less), (2) removable or able to be shut down on relatively short notice, (3) not located in waters with "sensitive designations," and (4) for the purpose of testing new technologies or determining appropriate project sites. Pilot project licenses will generally be issued for short terms, such as five years, and require that the licensee either apply for a longer term (30- to 50-year) standard license or decommission and restore the site at the end of the pilot project license term.[6] FERC has suggested that it should be able to issue pilot project licenses within a six-month licensing period, compared to five or more years for traditional hydropower dam licenses.

While the Pilot Project Policy reduces the steps required for obtaining a FERC license, it does not change other requirements for obtaining a license, namely the satisfaction of other applicable laws like the ESA, MMPA, CZMA, and CWA. FERC has recognized that the success of the Pilot Project Policy will depend on the cooperation of other state and federal agencies, in particular by identifying necessary environmental studies early in the licensing process and issuing permits in due course. In issuing the Pilot Project Policy, FERC indicated that the shorter license term and smaller project size should reduce the scope of the environmental studies necessary to authorize a pilot project license.

2. **Additional Guidance Issued.** In 2008, FERC issued a 33-page white paper that updates its Pilot Project Policy, describing in further detail FERC's process for obtaining short-term licenses for demonstration projects.[7] In particular, FERC envisions that most hydrokinetic projects will begin with a short-term pilot project license to test the technology, determine appropriate sites, and gather information on

[5] *Verdant Power LLC*, 111 FERC ¶ 61,024 (2005); *see also Maine Maritime Academy*, 130 FERC ¶ 62,234 (2010) (citing the *Verdant* Order and finding that the Maine Maritime Academy's proposal to deploy and test hydrokinetic devices as part of its Tidal Demonstration and Energy Center did not require a license).

[6] *See Supplemental Notice of Technical Conference with Agenda and Soliciting Comments*, Docket No. AD07-14-000 (FERC Aug. 31, 2007), *available at* http://www.ferc.gov/EventCalendar/Files/20070904090518-supplemental.pdf.

[7] Federal Energy Regulatory Commission, Licensing Hydrokinetic Pilot Projects (Apr. 14, 2008), *available at* http://www.ferc.gov/industries/hydropower/indus-act/hydrokinetics/pdf/white_paper.pdf; *see also Supplemental Notice of Technical Conference*, *supra*, note 6.

environmental and other effects. However, the Pilot Project Policy does not prevent applicants from seeking long-term licenses should they identify other methods of addressing those uncertainties.

At the end of a pilot project license, the white paper explains, a licensee may apply for relicensing, which will involve all of the same permitting and environmental review requirements that an original license requires. However, a licensee will need to submit its Notice of Intent ("NOI") to relicense and build out the project five years prior to expiration of the pilot project license in accordance with the FPA or, in other words, coincident with obtaining the pilot project license. FERC's white paper indicates that it may be willing to extend the pilot project license term in order to delay the statutorily mandated NOI requirement, an action that would still need to be taken fairly early in the pilot project license term to be effective.

The additional guidance does not resolve how licensees will protect potential build-out areas from other developers who may file for preliminary permits, pilot project licenses, or traditional licenses in the same area. However, it indicates that FERC will entertain requests for project boundaries around pilot projects that are large enough to accommodate future build-out. License applicants may also choose to request additional preliminary permits for projected build-out areas to protect them for an additional three-year period. Such additional permit applications would be subject to competition pursuant to FERC's rules.

### C. Conditioned Licenses.

1. **The Policy.** In 2007, FERC issued a Policy Statement providing that FERC would issue conditioned licenses, in appropriate cases, for hydrokinetic projects before it received other authorizations required by law.[8] A conditioned license authorizes construction and operation of a project only after the licensee obtains any outstanding federal, state, or tribal approvals. A conditioned license could be issued for a pilot project or traditional license.

The Policy Statement emphasizes that issuing conditioned licenses would enable licensees to begin development of plans and consultations not requiring construction and improve the ability of developers to secure financing without diminishing the importance of other authorizations required by law.

FERC has been criticized in the past for taking years to issue conventional hydroelectric dam licenses. In many cases, FERC's licenses have been delayed pending issuance of CWA section 401 water quality certifications ("401 Certifications"), ESA biological opinions, or other authorizations required by federal law. But while hydropower dam licensees continue generating during any such delays, in the case of hydrokinetic projects seeking original licenses, timely issuance of licenses and movement toward generation are critical to those projects' economic success. FERC's conditioned license policy is intended to alleviate that concern in part.

2. **Rehearing Request on First Ocean Energy Conditioned License.** FERC issued its first conditioned license—and first hydrokinetic license—to Finavera Renewables Ocean Energy, Ltd. ("Finavera") on December 21, 2007, for the Makah Bay Offshore Wave Pilot Project ("Makah Bay Project").[9] FERC's license

[8] *Policy Statement on Conditioned Licenses for Hydrokinetic Projects*, 121 FERC ¶ 61,221 (2007).

[9] *Finavera Renewables Ocean Energy Ltd.*, 121 FERC ¶ 61,288 (2007).

provided that no on-site project construction or installation could begin until Finavera submitted copies of all other authorizations required under federal law.

The Washington Department of Ecology ("Ecology") petitioned FERC to rescind the Makah Bay Project license because FERC had not first obtained a 401 Certification. CWA section 401 provides that "[n]o license or permit shall be granted until the certification required by this section has been obtained or has been waived." Ecology also alleged that FERC violated a similar limitation established by section 307 of the CZMA by issuing the license before Ecology had concurred that the Makah Bay Project is consistent with the state's coastal zone program. Shortly thereafter, Ecology issued its 401 Certification and CZMA consistency determination but did not withdraw its rehearing request.

On March 20, 2008, FERC issued an Order on Rehearing and Clarification and Amending License ("Rehearing Order") amending the Makah Bay Project's conditioned license to incorporate Ecology's 401 Certification and CZMA consistency determination.[10] As amended, the license authorized Finavera to commence construction. While stating that Ecology's arguments on rehearing were mooted by the agency's approvals, the Rehearing Order nevertheless explained that its conditioned license did not violate sections 401 and 307 of the CWA and CZMA, respectively, because it did not authorize construction activities and therefore did not authorize activities for which a water quality certification or CZMA consistency concurrence was required.

Ecology filed a petition for review of FERC's conditioned license order and Rehearing Order in the District of Columbia Court of Appeals.[11] On February 6, 2009, Finavera filed an application with FERC to surrender its license, stating that "due to the current economic climate and restrictions on capital necessary to continue development of this early-stage experimental Project, the Project has become uneconomic."[12] FERC issued an Order Accepting Surrender of License on April 21, 2009.[13] Ecology subsequently filed a motion to voluntarily dismiss its petition for review of FERC's conditioned license order and Rehearing Order, and the Court of Appeals dismissed the petition on June 2, 2009.

3. **License Applicant Concerns.** FERC's policy on issuing conditioned licenses, as clarified by the Rehearing Order, may benefit some license applicants by allowing them to commence construction planning. However, the policy leaves at least two issues of concern for license applicants. First, FERC characterized both its conditioned original license order and its order amending Finavera's conditioned license as "final unless a [timely] request for rehearing is filed." Under the FPA, strict time limits apply to requests for rehearing. FERC's policy of issuing conditioned licenses and amendments authorizing construction as final orders subject to rehearing may create confusion for licensees (and intervenors) regarding when to request

[10] *Finavera Renewables Ocean Energy Ltd.*, 122 FERC ¶ 61,248 (2008).

[11] The Court of Appeals held briefing on Ecology's petition in abeyance pending its decision in a case involving FERC's issuance of conditioned orders in a Natural Gas Act proceeding for a proposed liquid natural gas terminal near the mouth of the Delaware River. In *Delaware Department of Natural Resources & Environmental Control v. FERC*, 558 F.3d 575 (D.C. Cir. 2009), the Court of Appeals dismissed Delaware's petition for lack of standing. The Court held that Delaware lacked standing to pursue its CZMA challenge to a conditioned order that did not authorize any construction activity because FERC's order preserved Delaware's power to block the project through the exercise of its CZMA authority upon final approval of the project by FERC "prior to construction."

[12] *Application to Surrender License*, Docket No. 12751 at 1 (FERC Feb. 6, 2009).

[13] *Finavera Renewables Ocean Energy Ltd.*, 127 FERC ¶ 62,054 (2009).

rehearing, and may lead to the filing of duplicative rehearing requests to avoid an unintended waiver of the right to seek rehearing and judicial review of FERC's orders.

Second, because conditioned licenses for pilot projects will generally be issued for five years, significant delays by state and federal agencies in issuing their required authorizations could jeopardize the effective terms of these licenses. In addition, the FPA requires a licensee to commence project construction within two years of receiving a license, so permitting delays—particularly where approvals may contain important new conditions—may frustrate construction planning. Virtually acknowledging this issue, several FERC Commissioners issued statements thanking Ecology for expediting its review of the Makah Bay Project, expressing hope for a better working relationship with the State of Washington, and indicating that FERC staff and Washington were discussing a Memorandum of Understanding ("MOU") that would facilitate development of hydrokinetic projects (see Section III.C.5, below, for a discussion of recent MOUs with the States of Oregon, Washington, Maine, and California).

4. **Conditioned License FAQ Issued.** In 2008, FERC issued a Frequently Asked Questions ("FAQ") paper on conditioned licenses.[14] In it, FERC emphasized that its preference is to have all federal authorizations completed prior to licensing, but the agency shed no new light on when it would deem a conditioned license "appropriate." In response to an inquiry on that subject, the FAQ states: "Commission staff interprets the use of the word 'appropriate' in the Policy Statement to mean that the decision to issue a conditioned license will be made on a case-by-case basis after considering the specific circumstances of the case." The FAQ acknowledges that license applicants may request a nonconditioned license but states that the final decision to issue a conditioned license rests with FERC.

The FAQ also explains that, as with the Makah Bay Project license, FERC will issue a new order authorizing on-site construction once it receives all necessary approvals. The order will incorporate any additional conditions received with the federal and state authorizations. FERC states without discussion that it does not anticipate the need to suspend or extend the period for rehearing requests (which, in any case, is statutory) and does not address the question of when licensees and intervenors should request rehearing given its policy of issuing two "final" orders. Until this question is settled, licensees are wise to request rehearing of conditioned licenses to avoid waiving their right to later seek rehearing and judicial review of associated approvals.

5. **FERC MOUs with Oregon, Washington, Maine, and California.** FERC entered into a MOU with the State of Oregon regarding the development of wave energy projects in Oregon's Territorial Sea effective March 26, 2008.[15] The FERC-Oregon MOU is intended to coordinate FERC and Oregon procedures and schedules during the licensing process. In addition to notification, scheduling, and general coordination provisions, the MOU indicates that Oregon intends to prepare a comprehensive plan for siting wave energy projects in its Territorial Sea. FERC, in turn, agrees that if Oregon prepares such a plan, it will consider the extent to which proposed projects are consistent with the plan when issuing preliminary permits and licenses.

[14] Federal Energy Regulatory Commission, Conditioned Licenses (Apr. 14, 2008), *available at* http://www.ferc.gov/industries/hydropower/indus-act/hydrokinetics/pdf/faq.pdf.

[15] Federal Energy Regulatory Commission, Memorandum of Understanding Between the Federal Energy Regulatory Commission and the State of Oregon by and Through Its Departments of Fish & Wildlife, Land Conservation & Development, Environmental Quality, State Lands, Water Resources, Parks & Recreation, and Energy (Mar. 26, 2008), *available at* http://www.ferc.gov/legal/maj-ord-reg/mou/mou-or-final.pdf.

FERC has expressed an interest in reaching similar MOUs with other states that have hydrokinetic project opportunities. FERC entered into similar MOUs with Washington[16] and Maine[17] in 2009 and with California[18] in 2010.

## IV. BOEM.

**A. BOEM-FERC Jurisdiction over OCS Projects.** The Department of the Interior's BOEM has jurisdiction to lease OCS land for ocean, current, solar, and wind projects pursuant to the Outer Continental Shelf Lands Act and the Energy Policy Act of 2005 ("EPAct 2005").[19] However, BOEM does not have jurisdiction to lease state submerged or submersible land, including the seabed in a state's Territorial Sea and riverbeds for tidal and in-stream hydrokinetics. The OCS is defined as the area of ocean beyond three nautical miles from coastal shorelines, or nine nautical miles off the coasts of Texas and Florida, and extending to about 200 nautical miles.

MMS (as the predecessor to BOEM) and FERC initially took conflicting positions regarding FERC's authority to issue licenses for hydrokinetic projects in connection with rules proposed by MMS on the OCS for the Alternative Energy and Alternative Use ("AEAU") program authorized by the EPAct 2005 and in response to applications for preliminary permits for hydrokinetic projects proposed to be located in part on the OCS. In a March 17, 2009 press release, however, MMS and FERC announced an agreement to work together to facilitate permitting of renewable energy projects on the OCS, including hydrokinetic projects. A MOU subsequently issued by both agencies confirms FERC's authority to license hydrokinetic projects on the OCS under the FPA and that MMS (now BOEM) will issue leases, easements, and rights of way on the OCS for such projects.[20] To avoid confusion, the MOU provides that FERC will not issue preliminary permits for hydrokinetic projects on the OCS. The MOU also describes that FERC will conduct National Environmental Policy Act ("NEPA") review for hydrokinetic license applications for OCS projects and that MMS may at its discretion be a cooperating agency for any OCS hydrokinetic project. The MOU also provides that where MMS (now BOEM) participates as a cooperating agency in a FERC-led NEPA process, that agency will not be precluded from intervening on behalf of the Department of Interior in licensing or exemption proceedings for that project.

[16] Federal Energy Regulatory Commission, Memorandum of Understanding Between the Federal Energy Regulatory Commission and the State of Washington by and Through Its Departments of Ecology, Fish & Wildlife, Natural Resources, Community Trade and Economic Development, and State Parks and Recreation Commission, and the Governor's Office of Regulatory Assistance (June 4, 2009), *available at* http://www.ferc.gov/legal/maj-ord-reg/mou/mou-wa.pdf.

[17] Federal Energy Regulatory Commission, Memorandum of Understanding Between the Federal Energy Regulatory Commission and the State of Maine by and Through Its Governor and Departments of Conservation, Environmental Protection, Inland Fisheries and Wildlife, and Marine Resources, State Planning Office, and Governor's Office of Energy Independence and Security (Aug. 19, 2009), *available at* http://www.ferc.gov/legal/maj-ord-reg/mou/mou-ma.pdf.

[18] Federal Energy Regulatory Commission, Memorandum of Understanding Between the Federal Energy Regulatory Commission and the California Natural Resources Agency, the California Environmental Protection Agency, and the California Public Utilities Commission Regarding Coordinated Review of Hydrokinetic Facility Authorizations in Marine Waters Within the State of California" (May 18, 2010), *available at* http://www.ferc.gov/legal/maj-ord-reg/mou/mou-ca.pdf.

[19] 43 U.S.C. § 1337(p).

[20] Federal Energy Regulatory Commission, Memorandum of Understanding Between the U.S. Department of the Interior and Federal Energy Regulatory Commission (Apr. 9, 2009), *available at* http://www.ferc.gov/legal/maj-ord-reg/mou/mou-doi.pdf.

**B. AEAU Program.** On November 6, 2007, MMS announced plans for an AEAU program governing the sale of leases for ocean, tidal, and wind projects on the OCS. In support of its proposal, MMS released a Programmatic Environmental Impact Statement ("PEIS") examining potential environmental effects of such a program. The PEIS focused on wind and wave technologies in water less than 100 meters deep and on ocean current technologies in water less than 500 meters deep.

**C. Final MMS AEAU Rule.** On April 29, 2009, MMS (now BOEM) issued a final rule for granting leases, easements, and rights of way for renewable energy project activities and alternate uses of existing facilities located on the OCS, as well as methods for sharing revenues generated by this program with nearby coastal states. These rules are published at 30 C.F.R. part 285. Renewable energy projects covered by the rules include, but are not limited to, offshore wind, wave, current, and solar energy projects. While the final rule did not vary significantly from MMS's July 2008 proposed rule, MMS did make some relevant changes in response to comments from industry and non-governmental organizations.

Leases for hydrokinetic and other OCS uses authorized under the final rule will be assigned using a competitive format, unless no competitive interest exists. The final rule allows BOEM to use one of four auction formats for each competitive lease: (1) sealed bidding, (2) ascending bidding, (3) two-stage bidding, and (4) multiple-factor auction. The new multiple-factor auction format allows for nonmonetary factors, like the use of innovative technology suited to a specific site, to be a determinative factor. Under the proposed rule, any tie in the bidding process would have been broken through random selection. In contrast, the final rule provides that ties will be broken through an additional round of bidding.

Noncompetitive leases are awarded after a qualified entity requests a lease in an area not otherwise proposed for competitive bidding or excluded from leasing by statute. An unsolicited request will be considered after BOEM issues a public notice of the request and determines that no competitive interest in the area exists.

Leases can be issued for both commercial activities and assessment or technology testing activities. Commercial lessees selected by BOEM through a competitive lease process have six months to submit a Site Assessment Plan or 60 days if there is no competitive interest, and then up to five years to conduct site assessment activities. As provided in a guidance document jointly issued by MMS and FERC on April 4, 2009, the Construction and Operations Plan ("COP") described in the MMS rules is not required for projects requiring a FERC license. The FERC license application replaces the COP. These preliminary lease terms are subject to automatic extension if necessary for BOEM review and approval of necessary permits.

Commercial leases have a standard operations term of 25 years, which will provide the access and operational rights to produce, sell, and deliver power on a commercial scale through spot market transactions or long-term power purchase agreements. As stated in both the proposed and final rules, the standard 25-year lease term for operations may be modified. An operations term longer than 25 years could be established under a particular lease. In its AEAU rule, MMS declined comments requesting open-ended leases because that could perpetuate the use of inefficient or obsolete operations.

Under the final rule, commercial leases can be renewed beyond 25 years, but only after BOEM considers the (1) design life of existing technology, (2) availability and feasibility of technology employed, (3) environmental and safety record of the lessee, (4) operational and financial compliance record of the lessee or grantee,

(5) competitive interest and fair return, and (6) effects of the lease on generation capacity and reliability in the regional electrical distribution and transmission system.

Limited leases are for periods up to five years and provide access rights to conduct activities, such as site assessment and technology testing, which is the same term for which FERC will issue licenses for hydrokinetic pilot projects. Under a change in the final MMS rule and as allowed by FERC's pilot licenses, operations on limited leases may interconnect with the transmission grid for power sales. The MMS/BOEM rules do not allow limited leases for hydrokinetic pilot projects to be converted to commercial leases without first following procedures for soliciting competitive leases.

A number of parties commented that the OCS lease process should give limited lease holders site priority for subsequent commercial leases on the same site. MMS declined to make any specific provisions in the final rule due to the competition requirements of subsection 8(p) of the Outer Continental Shelf Lands Act. However, MMS stated in its responses to public comments that it may be able to provide limited lease holders extra weight in the competitive commercial lease process through the drafting of specific terms and conditions in the limited lease.

**V. State Agency Jurisdiction.** Even if FERC or BOEM is the lead federal agency, two federal laws—the CZMA and the CWA—provide coastal states with significant authority over marine and hydrokinetic energy projects. These authorities are discussed below.

**A. Coastal Zone Consistency.** Section 307 of the CZMA provides that any applicant for a federal license or permit to conduct activities affecting any land or water use or natural resource within or outside the coastal zone shall provide in its application to the licensing or permitting agency a certification that the proposed activity complies with the enforceable policies of the state's federally approved state coastal zone program. At the same time, the applicant must provide a copy of that certification together with necessary information and data to the state or its designated CZMA agency. Each coastal state must have procedures for public notice of and comment on such certifications.

The state or its designated CZMA agency has up to six months from its receipt of the certification to notify the federal licensing or permitting agency that it concurs with or objects to the consistency certification. No federal license or permit can be issued until the state or its designated CZMA agency concurs with the applicant's certification, or the state's concurrence is deemed to have been given by its failure to act on the certification within that six-month period. If a state objects to a certification, the federal licensing or permitting agency can issue the license or permit if the Secretary of the U.S. Department of Commerce, on his or her own initiative or upon an appeal by the applicant, finds that the activity is consistent with the objectives of the CZMA or is otherwise necessary in the interests of national security. Thus, before FERC can issue a license authorizing construction,[21] BOEM can issue a lease, or the Corps can issue a permit for an ocean energy project, an applicant

[21] As noted in Section III.C, above, FERC may issue a conditioned license authorizing a licensee for a hydrokinetic project to conduct activities other than construction in coastal areas subject to state authority under the CZMA. In that case, a further license order would be issued by FERC authorizing construction in coastal areas subject to state jurisdiction if and when a state concurs with a CZMA certification or waives its authority to do so and all other permits are obtained or waived in accordance with applicable law. The State of Washington's Department of Ecology sought review of a conditioned license for the Makah Bay Project after Ecology's request for rehearing was denied; Ecology's rehearing request contended that FERC lacked authority under the CZMA to issue a conditioned license. Ecology voluntarily dismissed its petition for judicial review of FERC's rehearing order after FERC issued an order allowing Finavera to surrender its license application.

must submit a certification to the appropriate state agency that the activity is fully consistent with the applicable state's coastal management program.

**B. Water Quality Certification.** Under section 401 of the CWA, an applicant for a federal license or permit to construct or operate a facility that may result in any discharge to navigable waters of the United States must provide the federal permitting agency with a water quality certification issued by the state in which the discharge will occur, stating that the discharge will comply with applicable provisions of the state's federally approved water quality standards. Federal regulations require that a 401 Certification contain a statement that "there is a reasonable assurance that the activity will be conducted in a manner which will not violate applicable water quality standards."[22] Any certification issued under section 401 may, in addition, set forth effluent limitations and other limitations necessary to ensure that any applicant for a federal license or permit will comply with other appropriate requirements of state law. Under subsection 401(d), such conditions become terms and conditions on any federal license or permit. Each state must have procedures for public notice of and comment on applications for such certifications.[23]

A federal licensing or permit-issuing agency cannot issue its license or permit until the certification required by section 401 has been obtained or waived.[24] The state agency to which an application for a 401 Certification is submitted has a reasonable period of time, not to exceed one year after receipt of a certification application, to act on a request for a certification. If the state fails or refuses to act on a request within a reasonable time, the requirement for a 401 Certification is waived by operation of law. State agencies often are unable to make their certification decisions within the first one-year review period. In that circumstance, state 401 Certification agencies often give certification applicants the option of letting the state make its "reasonable assurance" determination on a record the state believes is inadequate to support a certification, leading the state to deny certification, or to withdraw and resubmit the certification application, restarting the one-year review period. This process may go through several such cycles before the state agency believes it has an administrative record that will support its 401 Certification.

Decisions by state 401 Certification agencies are subject to review in accordance with state laws. Many states provide for review of the state certifying agency by an administrative appeals board or commission, such as Washington's Pollution Control Hearings Board. From these bodies, review of state 401 Certifications is available in state court. Following exhaustion of these administrative remedies, the U.S. Supreme Court can review, and occasionally has reviewed, federal law issues under section 401 raised by a state certification decision or waiver.

**C. State Coastal Permitting Authorities.** Jurisdiction of coastal state agencies is generally limited to the Territorial Sea. Only Oregon has enacted rules specific to marine and hydrokinetic projects, but many other state agencies appear receptive to the prospect of marine and hydrokinetic energy and willing to work with stakeholders to develop a workable process.

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[22] 40 C.F.R. § 121.2(a)(3).

[23] Whether some ocean energy projects do not involve a discharge requiring a section 401 Certification has generated considerable discussion at FERC and elsewhere. There has been no definitive resolution of this issue.

1. **California.**

a. **Coastal Development Permit.** Development within California's coastal zone[25] may not commence until a Coastal Development Permit ("CDP") has been issued by either the California Coastal Commission ("CCC") or a local government that has a CCC-certified Local Coastal Program ("LCP"). After certification of an LCP, CDP authority is delegated to the appropriate local government, but the CCC retains original permit jurisdiction over certain specified lands (such as tidelands and public trust lands). The CCC also has appellate authority over development approved by local governments in specified geographic areas, as well as certain other developments. Access to or through, or use of, lands administered by the California State Lands Commission ("CSLC") may also be necessary for development of marine and hydrokinetic energy projects in the state's Territorial Sea because most California coastal land is administered by that agency.[26] The California Public Utilities Commission ("CPUC") may also be involved in the permitting of a marine or hydrokinetic energy facility if the facility is proposed, at least in part, by a regulated, investor-owned utility.[27]

b. **California Environmental Quality Act.** The CCC, CSLC, and CPUC must satisfy the California Environmental Quality Act ("CEQA") before issuing discretionary permits or approvals. CEQA, similar to NEPA, requires an evaluation of the potential for a project to have significant adverse environmental effects and mitigation where such significant impacts could occur. One agency, the "lead agency," will conduct the environmental review. Normally, for projects involving a CDP, this will be the CCC. Other agencies—"responsible agencies"—participate in that process and depend upon the lead agency to complete the process. Once CEQA is satisfied, the lead and responsible agencies can complete their permitting or approval process.

2. **Oregon.**

a. **Energy Facility Siting Council.** The Oregon Department of Energy's Energy Facility Siting Council ("EFSC") manages the development of renewable resources and is charged with siting energy facilities with generating capacities of 25 MW or more, excluding hydroelectric projects. Hydroelectric projects requiring water rights are administered by the Oregon Water Resources Department ("OWRD"), the lead agency during FERC licensing of hydroelectric projects. OWRD is obligated to seek EFSC's input on the matter of the need for power. FERC's general assertion of jurisdiction, if unchallenged, would preempt EFSC. OWRD does not have jurisdiction in the Territorial Sea.

b. **Department of State Lands.** In October 2007, the Oregon Department of State Lands, which is responsible for managing state-owned lands within the beds and banks of the ordinary high-

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[24] *But see* Memorandum of Understanding, *supra*, note 17.

[25] The coastal zone is defined as extending seaward to the state's outer limit of jurisdiction and inland to the point designated on the maps adopted by the California legislature. In developed urban areas, the coastal zone generally extends inland much less than 1,000 yards; in certain habitat, estuarine, and recreational areas, the coastal zone can extend as far inland as five miles from the mean high tide line.

[26] The San Francisco Bay Area, however, is administered by the San Francisco Bay Conservation and Development Commission, not the CCC.

[27] Two other agencies that can be involved in energy projects are the California Energy Commission ("CEC") and the California Independent System Operator ("CAL-ISO"). The CEC's involvement in non-thermal power plant projects is limited to determining fund or renewable energy program eligibilities. CAL-ISO must complete its own processes to allow interconnection of a generating facility.

water mark and administering fill and removal permits, adopted "Rules Governing the Placement of Ocean Energy Conversion Devices On, In or Over State-Owned Land Within the Territorial Sea."[28] These rules apply to (1) ocean energy monitoring equipment and ocean energy facilities placed on, in, or over state-owned submerged and submersible land in the Territorial Sea for a research project, demonstration project, or commercial operation; and (2) other equipment and structures that are necessary for ocean energy monitoring equipment or an ocean energy conversion device. The rules permit the department to issue temporary use authorizations and ocean energy facility leases. However, a developer will not be authorized to use the area subject to a temporary use authorization or an ocean energy facility lease until the holder has received all other authorizations required by the department and other local, state, and federal entities for the installation, construction, operation, maintenance, or removal of the ocean energy monitoring equipment or the ocean energy facility. Finally (and importantly from the standpoint of site control for such a facility), while the holder of a temporary use authorization "shall be given a first right to apply for an ocean energy facility lease" for the same site, the rules give the holder no other preference, and the Department of State Lands will use the same criteria to approve or deny the application as it would for any other applicant. For more information on this rule, see Chapter 4, Section I.A.

c. **Other Relevant Agencies.** The Oregon State Marine Board regulates state waterways, including the Territorial Sea, primarily to ensure boater safety. Oregon's Department of Fish and Wildlife manages the state's fish and wildlife resources. The Oregon Department of Environmental Quality administers the state's water quality laws and water quality certification under section 401 of the CWA. The Department of Geology and Mineral Industries reviews projects for geologic hazards for water management and coastal hazard management. OWRD regulates the appropriation of waters of the state. The Oregon Parks and Recreation Department issues Ocean Shore Permits that authorize any alteration of or construction on or under the state's ocean shore, including pipelines, cable lines, and conduits. These state agencies all assert statutory oversight over and possess management expertise regarding the natural resources affected by hydrokinetic energy. Project proponents should review their rules during the planning and siting process to determine the necessity of compliance with these rules.

### 3. Washington.

a. **Energy Facility Site Evaluation Council.** Washington's Energy Facility Site Evaluation Council ("EFSEC") is responsible for reviewing applications for siting of energy facilities generating 350 kW or more, including ocean energy generation facilities of any generating capacity seeking certification through the EFSEC process. EFSEC's recommendation for approval or denial of a proposal is delivered to the governor for approval, denial, or remand to EFSEC for further proceedings. While an assertion of FERC jurisdiction over an ocean energy project would likely preempt EFSEC jurisdiction and gubernatorial approval power over ocean energy facilities, FERC typically directs FPA license applicants to seek state and local permits and approvals, reserving final authority to determine whether such permits and approvals conflict with FERC's license.

b. **Department of Ecology.** The Department of Ecology administers the state's Ocean Resources Management Act and is responsible for establishing guidelines and policies for the management

[28] Or. Admin. R. 141-140.

of ocean uses, implemented through the state's Coastal Zone Management Program. The Department of Ecology's policies also serve as the basis for enumerated counties adjacent to the Territorial Sea in their implementation of shoreline management master programs under the state Shoreline Management Act. These programs are used for consistency evaluation purposes in a FERC permitting process.

c. **Department of Natural Resources.** The Department of Natural Resources ("DNR") is charged with the management of all state lands, including the seabed in the Territorial Sea. Use of state aquatic lands for ocean power generation facilities requires procurement of a lease or other land use authorization from DNR.

**VI. Environmental Review.** Marine and hydrokinetic energy projects are attractive sources of clean, renewable energy because they should have limited adverse environmental impacts if properly sited. Nonetheless, ocean energy projects raise a number of potential coastal resource impact concerns for regulatory agencies and members of the public, including visual impacts, space preclusion, and conflicts with commercial fishing and other recreational users of the coast, shading of the marine environment, changes to littoral transport patterns, and interference with whale migration routes.

**A. Federal Environmental Review.**

1. **NEPA.** Before FERC or BOEM can issue a license or lease, respectively, for an ocean power project, and before the Corps can issue a section 404 CWA permit or section 10 Rivers and Harbors Act permit, as applicable, each must comply with NEPA, a procedural statute that requires federal agencies to consider the environmental impacts of a proposed decision before making the decision.

Under NEPA, the lead federal agency ordinarily must prepare an Environmental Assessment ("EA") or an Environmental Impact Statement ("EIS") before making a final determination as to whether the project license, lease, or permit will be granted. An EA usually takes less time to prepare—two to six months in many cases—than an EIS, which takes a year or more. An EA is sufficient if the project will not have a significant environmental impact. When appropriate and feasible, a project proponent can propose or agree to mitigation measures reducing project impacts below the significance level that otherwise would require the action agency to prepare an EIS.

The federal NEPA process can be coordinated with a state environmental review process conducted by a state for state permitting or leasing determinations. In appropriate situations, the federal agency may also "tier" its NEPA document for a current proposal to a prior EIS, including a programmatic EIS, thus reducing the time and effort to prepare an adequate NEPA document for the proposed new agency action. An example is the OCS AEAU PEIS prepared by MMS for energy development on the OCS. The PEIS evaluates offshore wave, ocean current, and wind technologies for development on the OCS between 2007 and 2014. EAs and EISs for project-specific proposals for BOEM leases, easements, or rights of way on the OCS can tier to this broad programmatic EIS.

2. **ESA.** The ESA is the federal statute designed to protect endangered and threatened fish, wildlife, and plant species and the ecosystems on which they depend. The ESA is administered by NMFS as it pertains to marine species and by USFWS as it pertains to marine birds and terrestrial species (each, a "Service").

Each federal agency involved in licensing or permitting an ocean energy project has a unique obligation pursuant to section 7 of the ESA to consult with the applicable Service if that action "may affect" a species listed as either threatened or endangered under the ESA. The purpose of this consultation is to ensure that the proposed project is not likely to "jeopardize the continued existence" of a listed species or "destroy or adversely modify" a species' designated critical habitat. Generally, a project proponent will prepare a draft biological assessment and submit it to the lead federal agency for its adoption and submission to the applicable Service. If the action is likely to adversely affect an ESA-listed species or its critical habitat, formal consultation and preparation of a biological opinion by the applicable Service is required. Issuance of the biological opinion will conclude formal consultation. The regulatory time frame for consultation is 135 days, with additional extensions allowed under certain conditions. However, consultation on a complex project or one with uncertain impacts may last a year or more despite the law's time frame.

If the Service's biological opinion concludes that the proposed action is not likely to jeopardize the listed species and is not likely to destroy or adversely modify its designated critical habitat, the Service will issue an incidental take statement ("ITS") detailing the amount and extent of the anticipated incidental take and imposing conditions to minimize the impact of that take on listed species and their habitats. Conversely, if the biological opinion concludes that the action is likely to jeopardize the listed species or destroy or adversely modify its critical habitat, the proposed project may not move forward without changes that eliminate its potentially jeopardizing effects.

3. **Essential Fish Habitat.** In addition to consultation under the ESA, the federal agencies (FERC, BOEM, and/or the Corps) must consult with NMFS pursuant to the Magnuson-Stevens Fishery Conservation and Management Act ("MSA") with respect to any essential fish habitat ("EFH") affected by the ocean project being authorized. EFH refers to those waters and substrates identified by fishery management councils as "necessary to fish for spawning, breeding, feeding or growth to maturity."[29] If NMFS determines that the action would adversely affect EFH, it will recommend measures that the federal agency or agencies and the project proponent may take to conserve such habitat. NMFS often incorporates its EFH recommendations into its ESA biological opinion for an action, if one is required. Unlike the terms of an ITS under the ESA, however, EFH recommendations need not be implemented by the federal agencies to maintain compliance with the MSA. Rather, the MSA requires the agencies to respond in writing with a description of measures they intend to implement (or require the project proponent to implement) and their reasons for forgoing any of NMFS's recommendations, if applicable. NMFS may circumvent the action agency's rejection of EFH recommendations by including such recommendations as terms and conditions in its biological opinion.

4. **Marine Mammal Protection Act.** Primarily applicable to offshore projects and not in-stream hydrokinetics, the Marine Mammal Protection Act ("MMPA") makes it illegal to harass, injure, or kill marine mammals, and includes penalties of $10,000 to $20,000 per violation and up to one year in jail. The MMPA includes two authorization processes to allow project proponents to obtain coverage for harming marine mammals: an incidental harassment authorization ("IHA") or a letter of authorization ("LOA"), each of which is explained in detail below. Neither of these processes is available to non-U.S. citizens or corporations.

[29] 16 U.S.C. § 1802(10).

For marine mammals that are also listed as threatened or endangered under the ESA, an IHA or LOA is required before undertaking an action if NMFS (or FWS in the case of certain marine mammals) determines that the action is "likely to adversely affect" the marine mammal, and therefore requires formal ESA section 7 consultation to analyze those impacts. This is because the ESA requires that an MMPA authorization be obtained before NMFS issues an ITS authorizing a take of an ESA-listed marine mammal.

If formal consultation is not required for an ESA-listed marine mammal, neither the ESA nor the MMPA requires a project proponent to obtain an IHA or LOA. Likewise, nothing in the MMPA requires a project proponent to obtain an authorization for marine mammals not listed under the ESA. Thus whether or not a project proponent chooses to get an IHA or LOA for those species or for an ESA-listed marine mammal absent formal consultation will depend solely on the project proponent's evaluation of the risk that it may harm a marine mammal.

There are two primary differences between an IHA and a LOA. The first is their application. An IHA authorizes harassment, which includes acts of annoyance with the potential to injure or disturb, whereas an LOA can authorize various types of "take," including harassment, injury, and mortality. The second difference is their terms. An IHA is valid for up to one year, whereas an LOA is valid for up to five years. In addition, an LOA requires issuance of regulations, and is therefore likely to take longer to obtain.

To issue either an IHA or LOA, NMFS must find that the harassment (for an IHA) or the more general take (for an LOA) will have a "negligible impact" on the species or stock, meaning that the action will not adversely affect its annual rates of recruitment or survival. In addition, NMFS must find that the harassment or take will not have an adverse impact on subsistence uses of the species or stock that cannot be mitigated. IHAs and the regulations for LOAs must set forth the specific, permissible forms of harassment, as well as minimization, monitoring, and reporting requirements.

In addition to the IHA or LOA authorization process, NMFS may conduct a NEPA review when issuing either type of authorization. Although a categorical exclusion ("CE"), or exception, from the NEPA EA or EIS process exists, NMFS appears conflicted as to whether a CE is appropriate for an IHA or LOA. Whether NMFS ultimately issues its own NEPA document or instead adopts the NEPA document of the lead federal agency authorizing an ocean energy project will likely depend on whether it believes the NEPA document adequately analyzes marine mammal issues.

5. **National Historic Preservation Act.** Section 106 of the National Historic Preservation Act ("NHPA") requires each federal agency to take into account the effects of its action, known as an "undertaking," on properties listed on the National Register of Historic Properties. Regulations adopted by the Advisory Council on Historic Preservation require each federal agency to determine, in consultation with the relevant State Historic Preservation Office ("SHPO") or Tribal Historic Preservation Office ("THPO"), as appropriate, whether any properties listed on or eligible for listing on the National Register of Historic Properties are in the area of potential effects ("APE"). If any of these historic properties fall within the APE, the action agency must determine, in consultation with the SHPO or THPO, and other interested parties, including Indian tribes and Native Hawaiian organizations, whether the action will have an effect on such properties, whether the effects will be adverse, and, if so, whether there are mitigation measures that would avoid, minimize, or mitigate such adverse effects.

When there are historic properties adversely affected by a proposed project subject to FERC jurisdiction, FERC typically enters a memorandum of agreement ("MOA") or programmatic agreement ("PA") with the SHPO or THPO, licensee, and in some cases the Advisory Council on Historic Preservation on how to resolve those adverse effects. This agreement is then incorporated into the project license by reference when the license is issued. Because it is not always possible to determine all the effects of various activities that may occur under a license at the time the license is issued, the MOA or PA for a FERC project typically provides, and FERC requires as a license condition, that the licensee develop and implement a Historic Properties Management Plan ("HPMP"). Through an approved HPMP, FERC can require appropriate consideration and management of project effects on historic properties. This is how FERC complies with its procedural duties under section 106 of the NHPA. FERC has detailed Guidelines for the Development of Historic Properties Management Plans available at its Web site.

6. **Fish and Wildlife Coordination Act.** It will be necessary to consult with NMFS, USFWS, and the relevant state department of fish and wildlife regarding the Fish and Wildlife Coordination Act ("FWCA"). To prevent loss of or damage to fish or wildlife resources under the FWCA, construction, maintenance, and operation of the facility must be in accordance with the terms and conditions required by USFWS, NMFS, or the corresponding state agency. This consultation is typically incorporated as part of the FERC licensing process.

**B. State Environmental Review – EA Requirements.**

1. **California.** Every project sited in California that is subject to discretionary approvals by local, city, county, or state agencies, including onshore and offshore facilities located within the state, is subject to CEQA. CEQA is not a substantive environmental law. CEQA requires that agencies inform themselves and the public of all the environmental impacts, including cumulative impacts, of the proposed project before the project is approved and include mitigation measures to avoid potential impacts to the environment when feasible. In practical terms for ocean energy projects, this means that the potential environmental impacts of a project—and to a lesser extent alternative and similar projects that may, along with this project, cause cumulative impacts—must be ascertained, and the project proponent must demonstrate that (1) its current project, with feasible mitigation measures, will have no immediate or cumulative significant impacts, or (2) any significant impacts are unavoidable, but the benefits of the project outweigh its potential to cause significant impacts.

Under CEQA, an initial study, in the form of a comprehensive checklist that must be supported by the administrative record, is conducted in coordination with the lead agency, providing a discretionary approval to determine if there is a "fair argument" that the proposed project may have a potentially significant impact on the environment. This includes, among other potential impacts, determining whether a state- or federal-listed endangered, rare, or threatened species or its habitat, as designated under the federal ESA or its state counterpart, would be affected. If the initial study, after reviewing the full scope of potential impacts, shows that there is no fair argument that there is a potential significant impact, a negative declaration—that is, a declaration by the lead agency stating that the project will have a minimal or no significant impact to the environment—must be completed before project construction may begin. If the finding of no potential impacts can be made after adding mitigation measures, a mitigated negative declaration can be prepared. On the other hand, if the initial study reveals the fair argument that a significant impact may occur, even after mitigation, the project developer, at its own cost, must commission an Environmental Impact Report ("EIR") that includes in-depth discussions of direct impacts, alternatives, and cumulative impacts. It also provides a detailed description of plans for mitigation and monitoring of those impacts during construction and operation of a project. In planning a project, the timing of a CEQA document may be critical. Depending on the sophistication of the project and the lead agency itself, a negative declaration can take several months to complete, and an EIR as long as several years. Although there is a statutory deadline that requires that an EIR be completed within one year, it is frequently extended by a project proponent, as it has little recourse.

2. **Oregon.** Unlike California and Washington, Oregon does not have a comprehensive environmental review statute. Under the EFSC rules for siting energy facilities in the state, however, each energy facility applicant must show that its proposed project satisfies the statewide planning goals, avoids impacts to fish and wildlife, meets all state water law requirements, and avoids impacts to scenic areas, archaeological sites, and other protected resources. If a project is not subject to EFSC review, similar rules and reviews also may apply. A project developer should work closely with its consultants and counsel to understand the rules and regulations relating to environmental impacts, identify potential impacts early in the siting process, and seek to develop alternatives or mitigation options before starting any permitting and review process.

3. **Washington.** Washington's State Environmental Policy Act ("SEPA") is substantially similar to CEQA. As with CEQA, SEPA allows agencies to deny projects with significant unmitigated adverse impacts if feasible alternatives exist. The level of environmental review applied to a project is established by the lead agency after reviewing the applicant's completed Environmental Checklist, which is a state-mandated form. If the lead agency determines the project does not present any significant adverse environmental impacts, it receives a Determination of Non-Significance ("DNS"). Projects presenting the potential for major environmental impacts receive a Determination of Significance, obligating the proponent to prepare an EIS similar in substance and procedure to California's EIR. Projects for which environmental impacts can be readily mitigated without significant analysis receive a Mitigated DNS that imposes mitigation conditions to reduce impacts below the level of significance that would trigger the need to prepare an EIS. As a result of regulatory reform measures, environmental review is combined with underlying project review in a consolidated process to streamline and expedite the permitting process. Washington's EFSEC applies SEPA in proceedings for site certifications for energy projects under EFSEC jurisdiction.

**VII. Coastal and Marine Spatial Planning.** Primarily a concern for offshore projects and not in-stream hydrokinetics, Coastal and Marine Spatial Planning ("CMSP") is a relatively new and important issue that will impact project development.

**A. Federal Efforts.** To address potentially competing uses in and on the nation's oceans and coastal areas, President Obama established an Interagency Ocean Policy Task Force in June 2009 and directed it to develop a recommended framework for effective coastal and marine spatial planning. Following the release of its Interim Report and its Interim Framework in 2009,[30] the task force published its Final Recommendations on July 19, 2010, which included a working definition of CMSP:

[30] White House Council on Environmental Quality ("CEQ"), Interim Report of the Interagency Ocean Policy Task Force (Sept. 10, 2009), *available at* http://www.whitehouse.gov/assets/documents/09_17_09_Interim_Report_of_Task_Force_FINAL2.pdf; CEQ, Interim Framework for Effective Coastal and

> CMSP is a comprehensive, adaptive, integrated, ecosystem-based, and transparent spatial planning process, based on sound science, for analyzing current and anticipated uses of ocean, coastal and Great Lakes areas. CMSP identifies areas most suitable for various types or classes of activities in order to reduce environmental impacts, facilitate compatible uses, and preserve critical ecosystem services to meet economic, environmental, security and social objectives.[31]

The nine regional plans envisioned in the Final Recommendations may eventually yield "preferred" areas for marine and hydrokinetic energy development. They may also identify areas where offshore energy development should not occur. The process is in its early stages, and project proponents will want to stay abreast of regulatory developments as they are adopted.

**B. State Efforts.** Several states, including Washington, Rhode Island, Massachusetts, and Oregon, have made efforts in CMSP to help determine the most appropriate uses for areas in the states' Territorial Seas. For example, the Washington legislature passed Substitute Senate Bill 6350 on March 19, 2010 ("SSB 6350"). SSB 6350 establishes a marine interagency team and tasks it with assessing and recommending a framework for conducting marine spatial planning and integrating it into existing state agency management plans. However, the team will not be able to make headway beyond its initial efforts until non-state funding is secured. Another example is Rhode Island's Special Area Management Plan ("SAMP"), a project led by the state's Coastal Resources Management Council. The SAMP was designed to refine the designation of Rhode Island's near-shore waters from "multipurpose" to more specific use zones. As time goes on, more coastal states will likely be engaging in some form of CMSP, whether through the regional processes outlined in the Final Recommendations or independently. Project proponents should be aware of the CMSP process that may be ongoing in their target states and should engage state agencies early in the development process about how to stay abreast of developments as they happen.

## VIII. Permitting the Onshore Facility.

**A. Permitting Authorities.** Many of the offshore and onshore elements of an ocean energy project will be permitted under a single permit or authorization; however, certain permits may be specific to the onshore facility, and consequently, a state agency—rather than a federal agency—may be the primary permitting authority.

1. **Federal Permits.** In the event a project is located offshore of federal lands, the onshore facilities, such as a substation and operations and maintenance facilities, may be located on lands managed by the U.S. Forest Service, National Park Service, Department of Defense, or another federal agency. Federal permitting requirements will turn on the agency responsible for managing the onshore lands, so a project developer should

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Marine Spatial Planning (Dec. 9, 2009), *available at* http://www.whitehouse.gov/sites/default/files/microsites/091209-Interim-CMSP-Framework-Task-Force.pdf.

[31] CEQ, Final Recommendations of the Interagency Ocean Policy Task Force, at 41 (July 19, 2010), *available at* http://www.whitehouse.gov/files/documents/OPTF_FinalRecs.pdf; *see also* Executive Order No. 13547 (July 19, 2010) (adopting the Final Recommendations).

determine early in the siting process which agency is responsible for managing the onshore lands and what permitting or authorization processes may be involved in locating any necessary onshore facilities on the particular federal land.

2. **State Permitting.** In California, a CDP is issued by the CCC or a qualified local agency. The CCC position on some projects has been that it maintains jurisdiction even if the project is subject to the CEC's siting authority. In Washington, where the Shoreline Management Act sets forth certain permitting standards and guidelines that are incorporated by local governments in their respective development programs, the state and local shoreline master programs should be consulted to determine whether a substantial shoreline development permit or exemption therefrom will be required. In addition, Washington's Office of Regulatory Assistance maintains an online interactive permit assistance center that helps determine project permit requirements based on the project's parameters and is a useful project-scoping tool.

3. **Land Use.** In every jurisdiction, land use entitlements are required. For example, in Oregon, each county has its own land use designations and development criteria, which are dictated by statewide land use requirements. When permitting the onshore components of a project, cross-references must be made to the statewide planning goals, regulations set forth by the Department of Land Conservation and Development, and the local zoning code and comprehensive plan. It is critical to have a firm understanding of the play between state guidelines and local codes, as well as case law interpreting a local government's permitting authority. Because county land use codes often outline discretionary determinations of public need, public safety, and compatibility with other land uses, it may be necessary to consult interpretive case law, opinions, and other resources before presenting a project for permitting. There may be overlay zones, hazard areas, and other considerations to resolve to permit onshore facilities. A solid understanding of the local zoning and permitting laws is essential before undertaking any permitting requests.

Finally, some states require that the local permitting body conduct an environmental review based on state environmental review statutes during the land use or siting permitting process. Both Washington and California require this review: Washington under SEPA, and California under CEQA. Oregon does not have comprehensive environmental review statutes. The net effect of state statutes such as SEPA and CEQA is to increase process time and cost, and open the project to further public review and potential litigation.

4. **Cable Crossing Permits.** Each state has its own permitting process relating to crossing a public beach with cables, pipelines, or other onshore facilities. A project developer should consult the laws specific to its state. The following discussion of cable crossing permits as issued in Oregon may be illustrative for purposes of siting the onshore facilities of a project on or across state lands in other West Coast states.

In Oregon, if a cable, conduit, or pipeline crosses the beach, a permit from the Oregon Parks and Recreation Department ("OPRD") is required. OPRD has authority to issue such a permit upon payment of "just compensation" by the permittee, and if issuing the permit will affect privately owned lands, OPRD will not issue the permit until the permittee has obtained an easement, license or other written authorization from the private owner, which must be approved by OPRD. Any compensation paid to the private owner does not need OPRD approval.

To obtain a permit, a project developer must first submit an application to OPRD. For a cable or conduit, the application must include proposed plans describing the location, nature, scope and purpose of the project, the materials and equipment to be used and the estimated time for completion, as well as the names of all owners of oceanfront property that abuts the property identified in the application. The application must also include information about any necessary permits or other authorizations from local, state, or federal government agencies. Once the application is submitted, public notice of the application is posted and provided to adjacent oceanfront landowners that share property boundaries with the project site. During the public notice period, which lasts at least 30 days, the applicant or any member of the public is entitled to request a public hearing on the proposed project, which OPRD may schedule and hold if it chooses. After the public hearing or at the termination of the time frame for requesting a public hearing, OPRD makes a determination to grant or deny the permit.

In determining whether to grant a permit, OPRD considers (1) the implications for natural, scenic, recreational, economic, and other resources located in the project area; (2) the need to preserve and have access to these resources and enjoy recreational uses; (3) the physical characteristics of the area and the suitability of the area for particular uses, including future development; and (4) public opinion in response to the project application. OPRD examines these factors in light of the information contained in the application to determine whether to issue the permit. OPRD then grants or denies the permit, and it may condition the permit on certain modifications to the project plan so that it meets the requirements of OPRD's rules and regulations.

Depending on the nature of the onshore facilities at issue, other state agencies from which permits might be required include the state department of fish and wildlife, the state water resources board or agency, the state parks department, and the state cultural resources agency.

**IX. Indian Tribes and Native Hawaiian Organizations.** Indian tribes can affect ocean energy projects in several ways. If a project is located within an Indian reservation, FERC must make a finding that the license will not interfere or be inconsistent with the purpose for which the reservation was created or acquired, and will be subject to any conditions the Secretary of the Department of the Interior deems necessary for the adequate protection and utilization of the reservation. Section 10(e) of the FPA directs FERC to set reasonable annual charges for the use of tribal lands.

Indian tribes frequently play a significant role in licensing projects outside Indian reservations. Treaties between the United States and Indian tribes in some coastal areas secure to tribes rights to take fish, whales, and other marine mammals. If an ocean energy project has the potential to adversely affect such resources, FERC must address those impacts when issuing its license. Under section 106 of the NHPA, FERC must make a reasonable good-faith effort to identify any Indian tribe or Native Hawaiian organization that might attach religious and cultural significance to historic properties affected by a proposed action on those properties. Historic properties include properties of traditional religious and cultural importance to Indian tribes and Native Hawaiian organizations outside Indian reservations.

**X. Conclusion.** Many components of the regulatory framework governing marine and hydrokinetic energy projects are still developing. While well intended, some of the policies and procedures developed for new hydrokinetic technologies may do more to complicate than streamline project permitting. Nevertheless, those developers who take a leading role will be in a position to help shape these regulatory policies as they develop, and ensure they fit this new and exciting industry.

# Chapter Four
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Marine and Hydrokinetic Energy Lease Agreements—

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The security, flexibility, "financeability," and cost-effectiveness of a marine or hydrokinetic energy project's onshore and offshore property rights are a key part of the project's overall value. In capturing this value, the developer must deal with and coordinate between two sets of landowners: the governmental owner of the tidelands and submerged lands on which the energy-generating and energy-collecting portion of the facility will lie, and the owner of the upland property on which transmission, substation, and interconnection facilities will lie—which may be either a governmental or a private landowner. In both cases, the means to capture this value will often be a lease or an easement agreement ("Offshore Lease" or "Onshore Lease," respectively). For our purposes here, Offshore Lease is a generic term that includes leases granted (1) by state agencies for submerged or submersible lands within the state's territorial sea and beneath the state's navigable rivers and (2) by the Department of the Interior ("DOI") Bureau of Ocean Energy Management for areas of the U.S. Outer Continental Shelf ("OCS").

Onshore Leases will be familiar territory for those versed in siting energy facilities. They will be typical real estate transactions involving leases negotiated with the private or governmental landowner, as necessary to site the onshore facilities needed to support the marine or hydrokinetic energy project. Such onshore site control might also take the form of a purchase of land in fee, or there may be a combination of leased land, owned land, and easements. One important strategic consideration in acquiring onshore property rights is that emerging state regulations specifically tailored to marine and hydrokinetic energy developments express a preference for compatibility with existing uses of onshore land adjacent to a development. Therefore it may be advantageous to acquire a broader interest in adjacent onshore lands than that needed for facility siting (*e.g.,* purchasing the tract of land on which the onshore facilities are to be located rather than negotiating easements of limited scope).

Depending on where the project is located, Offshore Leases can involve one or two governmental entities. Because a state controls the submerged and submersible lands beneath its navigable rivers as well as those within its territorial sea,[1] the majority of Offshore Leases will need to be negotiated with the relevant state agency charged with managing those lands. Currently, the majority of western coastal states issue such leases under traditional land-management frameworks. The one exception is Oregon, which has adopted regulations specific to ocean energy facilities.[2]

If a project is to be located on the OCS, then the federal government also has jurisdiction over the facility siting. The DOI Minerals Management Service ("MMS") was tasked under section 388 of the Energy Policy Act of 2005 ("EPAct"), Public Law No. 109-58, with issuing rules governing leases, easements, or rights-of-way for alternative energy ("other than oil and gas") and alternate uses of existing facilities located on the OCS.

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[1] States' exclusive jurisdiction over near-shore waters varies. Within the Gulf of Mexico, Texas and Florida have exclusive jurisdiction from the baseline from which the breadth of the territorial sea is measured out to nine nautical miles and Louisiana has exclusive jurisdiction out to three imperial nautical miles. All other coastal states have exclusive jurisdiction out to three nautical miles (approximately 3.3 statute miles).

[2] *See* OAR ch. 141, div. 140.

Renewable energy projects covered by the rules issued in 2009 include, but are not limited to, offshore wind, wave, current, and solar energy projects. For more about these rules, see Chapter 3, Section IV.

The rest of this chapter details the strategic considerations associated with obtaining leases from the relevant state and federal agencies, and then discusses some of the emerging issues associated with these types of leases. Because Onshore Leases supporting energy facilities will be similar for those associated with other types of energy projects, this chapter focuses on the emerging issues associated with Offshore Leases.

## I. Offshore Leases on State Submerged or Submersible Lands.

**A. Oregon.** In response to the flurry of proposed ocean energy facilities in Oregon, the Department of State Lands ("DSL") adopted rules in December 2007 that are specific to leasing state submerged lands for ocean energy projects. The DSL rules, found in chapter 141, division 140, of the Oregon Administrative Rules ("OAR"), apply to ocean energy facilities and ocean energy monitoring equipment (both commercial and research or demonstration projects) on state-owned bedlands within Oregon's territorial sea—that is, out to three nautical miles—which Oregon defines as "submerged and submersible lands." Upon application, DSL grants either a temporary use authorization for a demonstration project or an ocean energy facility lease for a commercial project. Both authorizations depend on DSL's formal determinations, among others, that (a) the facility meets Statewide Planning Goal 19 (pertaining to the conservation of marine resources and ecological function), the Oregon Territorial Sea Plan, and the Oregon Ocean Resources Management Plan and (b) the facility will not substantially impair uses or developments already in place within the identified area. The application process includes a required pre-application meeting with DSL staff as well as "[a]ffected ocean users and other governmental agencies," submission of application materials, and a review process that includes an opportunity for public comment. The division 140 rules provide for compensation to DSL in the form of a flat fee for temporary use authorizations or, for a facility lease, a royalty-based or revenue-based payment mechanism established at the discretion of the DSL director. Note that the placement in the territorial sea of ocean energy monitoring equipment or ocean energy facilities that are not part of a demonstration or commercial project is subject to DSL's general leasing rules under OAR chapter 141, division 82 or division 125, unless the placement is part of a research project by an educational or a research institution.

Although the DSL rules provide the primary source of regulatory oversight for ocean energy projects within the state's territorial seas, other state law may also be implicated. For example, the Oregon Water Resources Department licenses hydroelectric projects through Oregon Revised Statutes ("ORS") chapter 543. Under ORS 543.014, wave energy projects are exempt from the chapter 543 licensing process if they are located within Oregon's territorial seas, have a nominal generating capacity that does not exceed 5 MW, and do not require a federal hydroelectric license. Even for exempt projects, however, the Oregon Water Resources Commission retains authority to investigate, hold hearings, and review reports and data to ensure that the natural resources of Oregon are protected. ORS 543.015, 543.050(3), 543.055, 543.060.

In addition, the 2009 Oregon legislature passed House Bill 3013, implementing a program to establish state "marine reserves"—discrete ecologically significant areas along Oregon's coastline that would be closed to all extractive and development activities. Codified at ORS 196.540 to 196.555, the marine reserves statute created pilot reserve projects at two locations near Depoe Bay and Port Orford, as well as a process to identify and study other potential sites. House Bill 2009, currently pending in the 2011 legislative session, would create as many as six additional reserve areas.

**B. Washington.** Unlike Oregon, Washington has not adopted rules specific to leasing of state lands for marine or hydrokinetic energy projects, but it may be next in line to do so because of proposed tidal projects within Puget Sound. Leases of state-owned aquatic lands are obtained through the Washington State Department of Natural Resources ("DNR"), which manages state-owned aquatic lands, including tidelands, shorelands, harbor areas, and bedlands.

Article XV, section 1, of the Washington State Constitution prohibits any sale or lease to private entities of aquatic lands beyond established harbor lines—generally those areas within or near the corporate limits of a city. Under the Aquatic Lands Act, DNR may lease other aquatic lands within the state, including offshore areas within the territorial seas. DNR is obligated to manage aquatic lands to balance public benefits for Washington citizens; under 2005 amendments to the Aquatic Lands Act, two such enumerated benefits include promotion of water-dependent uses and utilization of renewable resources.

**C. California.** In California, the State Lands Commission ("SLC") enjoys broad authority to lease state lands. Most, but not all, potential locations for ocean and tidal energy will be on state-owned land controlled by the SLC. A notable, large exception to this, however, is the San Francisco Bay Area, where the Bay Conservation and Development Commission was granted the state authority and control. Also, major inland waterways vary in their ownership or control between the SLC, local municipal government, and private entities. For these locations, the specific entity retaining authority over the site will determine applicable procedures or requirements for leasing. The remainder of the state-owned oceanfront and offshore property in the coastal zone of California is leased by the SLC. The California Coastal Commission ("CCC") regulates permitting and uses over the same zone, so, in addition to obtaining a lease from the SLC, permits will be required from the CCC or its designee as explained in Chapter 3.

In determining whether to grant a lease, SLC considers the following factors: consistency with the public trust doctrine, protection of natural resources and other values, and preservation or enhancement of the public's access to state lands. A lease or permit must be obtained for a number of uses, including the installation of buoys, moorings, docks, recreation facilities, piers, and wharves. Additionally, a lease or permit is also necessary to obtain rights-of-way for uses such as roadways, power lines, and pipelines.

Leases or permits for submerged lands are generally issued only to riparian- or littoral-use right holders. SLC regulations also provide that such leases and permits may be granted to the most qualified applicant irrespective of riparian or littoral status. The SLC must comply with the California Environmental Quality Act ("CEQA") before executing a lease. Generally, this will require environmental review of the potential effects of the intended use of the leased land. CEQA is discussed further in Chapter 3. The environmental review required for lease execution can usually be coupled with the permitting processes, but this defers certainty on the acquisition of land use rights until later in the development process. Alternatively, environmental review for lease purposes can be completed as part of the leasing process, but this will not complete the environmental review requirements for the project. The California Coastal Act and CEQA will be applied during permitting.

Onshore facilities will also require that land use rights be acquired from the party holding them. This could be a private party, a state agency such as the SLC, or a local agency. When leases or easements must be obtained from a regulated utility (for example, an easement to cross a transmission line), such leases or easements will likely require approval by the California Public Utilities Commission, which must also satisfy CEQA before approving the lease.

**II. Federal Leasing.** Section 388 of EPAct named DOI as the lead federal agency to oversee designated alternative energy and "marine-related uses" on the OCS. Under EPAct, DOI authority to grant leases, easements, or rights-of-way on the OCS to facilitate development of alternative energy resources and allow for alternative uses of existing facilities on the OCS has been delegated to the Bureau of Ocean Energy Management ("BOEM"). Under an order issued by Secretary Salazar on January 19, 2011, BOEM assumed authority previously delegated to the MMS to "manage and oversee alternative-energy related projects on the OCS."

Prior to transfer of authority to BOEM, MMS issued rules governing renewable and alternate uses of the OCS. *See* 30 C.F.R. pt. 285. Shortly before issuing those rules, MMS and the Federal Energy Regulatory Commission ("FERC") negotiated a memorandum of agreement clarifying each agency's authority on the OCS. In short, BOEM issues leases for OCS projects while FERC issues license for hydrokinetic projects on the OCS. For a further discussion of BOEM's leasing program and FERC's licensing authority, see Chapter 3, Section IV.

**III. Issues Associated with Both State and Federal Leases.**

**A. State Ownership Issues for Tidelands and the Ocean Bed.** In obtaining the proprietary approvals necessary for siting a marine or hydrokinetic energy project, it is important to begin with an understanding of the boundaries of state versus private ownership, the effect on ownership when those boundaries shift, and the public trust issues that arise on state-owned lands.

**1. Public Versus Private Ownership.** The "bed" of a waterway, including the ocean, is the land underneath the water to the line or "mark" of ordinary low water or ordinary low tide in Oregon and California, or to the line of navigability in Washington. The "bank," or shore, is the area between the bed and the line or mark of ordinary high tide. This area is also called "shorelands" in Washington and "submersible lands" in Oregon, and is sometimes called "tidelands" in Oregon, Washington, and California. In surveys, this line roughly coincides with the "meander line" established by the original surveys in the 18th and 19th centuries by the Government Land Office, predecessor to the Bureau of Land Management. In the absence of a tidelands or other grant in the upland owner's chain of title, the meander line usually marks the boundary between public and private ownership.

**2. Changes in the Shoreline.** Given the dynamic movements of the tides, it is common for ocean water boundaries to fluctuate. The law generally classifies these fluctuations as either "accretive" (gradual) or "avulsive" (sudden). Generally, if the change is perceptible—if you can see it happening—it is avulsive. When a water boundary moves by accretion, the property boundary moves with it. When a water boundary moves by avulsion, the property boundary stays the same. For example, when the shoreline moves further landward through gradual erosion, the upland property owner may own progressively less real estate.

Questions of ownership for changing water boundaries are answered by state law. In some states—California, for example—the answer may differ depending on whether the shoreline movement is natural or caused by human action. In Oregon and Washington, the natural-artificial distinction does not matter, though the law is not absolutely clear on this point.

3. **The Public Trust Doctrine.** State-owned submerged lands and shorelands are generally imprinted with certain rights held by the state in trust for the public. For example, in 1969 the Oregon Supreme Court decided that the dry sand beaches in Oregon were subject to public rights, in the nature of an easement, even in places where the beaches are not state-owned. The scope of the public trust differs from state to state, but it is safe to say that the shore zone of any coastal waterway is probably encumbered by broad public-use rights. Although the law is not absolutely clear on this point in all coastal states, it is commonly thought (particularly by state resource agencies) that public trust rights cannot be conveyed out of state ownership, even when the state sells or leases the land subject to the trust. This can mean that any limitation on public rights of, for example, fishing or recreational access will need to be specifically discussed and negotiated during the leasing process. Normally, state agencies have enough flexibility to allow leases that exclude the public when safety issues are implicated.

B. **The Scope of the Property Subject to Offshore or Onshore Leases.** The portion of a landowner's real property that will be subject to either an Offshore or Onshore Lease may be a very contentious issue during negotiations. There is a natural tension between a developer's desire to include as much of the real property in the lease as possible and a landowner's desire to limit the property subject to the lease to only those portions necessary for the construction, maintenance, and operation of the project facilities on the property.

1. **Basic Issues.** There are several reasons a developer may want to maximize the amount of property that will be subject to an Offshore or Onshore Lease:

- In today's competitive environment, developers often begin acquiring rights in real property before they have enough data and information about the relative proximity of the offshore and onshore sites, access to suitable transmission lines, and environmental and energy-producing attributes to accurately determine the most productive and cost-effective layout and relationship for the marine or hydrokinetic facilities. By leasing most or all of the landowner's property, the developer gains flexibility to respond to changes in the project layout and design that may become necessary as a result of, for example, a more convenient landfall for the cable or electrical connection to the offshore facility, landowner concerns about the impact on continued landowner or public use of the property, the requirements of governmental permitting authorities, security, and a desire to minimize the time and expense required to construct the project.

- By maximizing the amount of property subject to the leases, the developer can maximize the size and location of the marine or hydrokinetic energy project and benefit from economies of scale in reducing development costs and increasing productivity.

The effective capture of energy from marine and hydrokinetic energy devices is largely dependent on the environmental conditions to which the property is subject. Any obstruction (*e.g.,* an offshore object such as an oil platform) that interferes with the current or wave height over the property can have a dramatic, negative impact on the ability of the devices located on the property to generate energy. A developer will want control over the size and kind of structures that can be constructed near the property by the landowner or third parties during the term of the leases. An effective way to gain this control is to encumber as much of the property as possible and have noninterference covenants in both the Offshore and Onshore Leases that limit the landowner's right to interfere with the energy generation potential of the property.

The landowner's primary motivations for limiting the amount of property that is subject to the leases are to limit the impact of the project on the landowner's other activities on the property (especially when the landowner plans or others have the right to continue using the property in this manner while the project is operating on the property), to preserve the opportunity to lease excluded land for other purposes, and a basic reticence to give up a measure of control over too much of one's property.

2. **Potential Resolutions.** There are several techniques to help resolve conflicts between landowners and developers over the amount of property to be included in Offshore and Onshore Leases:

- During the planning stage, consult with the landowner regarding the location of the proposed ocean power facilities. This may reassure the landowner and can provide the developer with useful information about the property.

- Tie a portion of the payments required under the leases to the total number of acres to be encumbered.

- Offer a phased approach under which the landowner will agree to lease or grant easements over all or most of the property to the developer during the construction phase of the marine or hydrokinetic energy project. After construction has been completed, the developer will quitclaim to the landowner the developer's interest in portions of the property that did not become part of the project, excluding necessary buffers around the power facilities to allow ample room for operation and maintenance activities. In such an arrangement, a developer will want to include terms in the leases that clarify that the landowner's commitment not to interfere with the energy potential of the property also applies to the released property.

- A developer may seek a right of first refusal or other restriction on the released property, limiting the landowner's ability to re-lease or sell the property so that the property will not be used for a purpose that will interfere with the marine or hydrokinetic energy project. Before taking this approach, however, the parties should make sure that this arrangement will not violate local land use laws.

- The developer may agree to lease only those specific portions of the property believed to be necessary for the marine or hydrokinetic energy project (*e.g.,* strips of land for transmission lines, roads, and related facilities). This can be risky if the developer does not have enough information to accurately determine the most advantageous locations for its ocean power facilities.

**C. Purpose of Agreement and Use of Property.** Another contentious issue involves the purpose of the Offshore and Onshore Leases and uses the developer may make of the property to accomplish this purpose. Of course, the obvious purpose of these leases is the construction and operation of a marine or hydrokinetic energy project. 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.

A developer 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 constructing and operating a project. For its part, the landowner may wish to see these rights limited to only those clearly delineated activities and facilities necessary to construct and operate the project on the landowner's property.

**D. What Facilities Go on Whose Land?** For marine and hydrokinetic energy projects, a developer might control properties of neighboring landowners in order to aggregate the littoral accessibility or water surface that it takes to site the project. Putting aside the surface of the ocean, few landowners other than the government own enough littoral land (with access to transmission lines) to provide necessary littoral access on their property. Inevitably, once the developer conducts its oceanographic, transmission, environmental, and construction studies on feasible properties and has located an area of ocean surface where energy recovery is likely, some littoral properties will stand out above others as better candidates for cable landings and substations, whereas others may be more suitable for transmission lines and roads that serve the onshore facility. Each landowner will want to be compensated for its property's role in producing renewable energy. For example, the landowner may negotiate to receive special minimum payments if its property is used primarily for transmission lines and roads. Generally, the landowner desires such payments to be large enough to compensate for the fact that the landowner will not be receiving royalty payments on the sale of electricity on its property.

A landowner may also require that the developer pay additional compensation for the right to place certain special facilities on the subject property. For example, when the developer wants to place a substation that will serve the entire marine or hydrokinetic project on one landowner's property, the landowner may feel that it is entitled to additional compensation for the added burden and loss of usable property caused by construction of such substation.

**E. Landowner's Continued Use of the Property.** An important feature of marine and hydrokinetic 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 in substantially the same manner as the landowner had been using it before entering into the Offshore or Onshore Lease. The onshore facilities necessary to collect and transmit the energy captured from a marine or hydrokinetic project are often minimal when compared to the area of open water necessary for the offshore facilities. For this reason, the landowner may be able to continue to conduct its activities on the property throughout the life of the project on the property, provided that such activities do not and will not interfere with the construction and operation of the energy project.

**F. Payments.** Payment is the final issue to consider when entering into Offshore Leases. When entering into leases with private parties, there are countless ways to structure rentals, royalties, and other lease payments. For example, in other types of renewable energy projects, such as wind energy, developers may pay the landowner either a lump-sum payment or annual payments for the rights granted in the agreement. In the case of Offshore Leases, however, governments may require a percentage of annual gross income or the volume of commodities passing over the leased premises, or an amount based on the fair market value of adjacent uplands. There being few Offshore Leases for marine and hydrokinetic energy projects, there is little precedent to predict what rent developers will pay.

States will likely have discretion in determining payments, as the process is unlikely to be uniform until government agencies have more experience with marine and hydrokinetic energy projects. As a result, developers will have to negotiate with state agencies throughout the leasing process.

Leases of federal land on the OCS may be determined by competitive bidding, as described in Chapter 3, Section IV, which adds another layer of uncertainty when determining the value of leases for marine and hydrokinetic energy projects.

**IV. Conclusion.** Although critical to a marine or hydrokinetic energy project, the matters discussed above are by no means the only issues a developer must consider. For example, issues related to indemnities, assignments, and financing will be key components of an Offshore or Onshore Lease. Crafting an Offshore or Onshore Lease that provides a developer with the necessary flexibility and security to develop the marine or hydrokinetic energy project requires experience, creativity, and skill.

# Chapter Five
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Land Title Matters—

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Before a marine or other hydrokinetic energy project can be developed, interests in land—both offshore and onshore—must be acquired. Typically, a lease or an easement is the chosen form. If title to the real estate were to fail after installation and construction of the project, losses and defense costs could be significant. For these reasons, the savvy developer requests and obtains a search and examination of the title to the real property on which a marine or hydrokinetic energy project will be sited,[1] and purchases a policy of title insurance in the amount of the investment in the project. A survey of the leased area is also advisable.

This chapter will explain and discuss the recurring points a marine or hydrokinetic energy developer, purchaser, or financer must address to minimize risk of loss arising out of a failure of or defect in land title for the onshore real estate portion of such a project, and to manage effectively 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 know the role a particular company plays in the industry before deciding whether and how to do business with that company.

Title policies are issued by or on behalf of underwriters. The underwriter is usually a large insurance corporation doing business in many states and in a number of countries. Title policies for marine and hydrokinetic energy projects may be written in amounts reaching into the many millions of dollars; consequently, in the event of a claim it is important to know the financial condition of the underwriter behind a policy. To evaluate this information, it is advisable to look at annual reports, rating agencies, and internal limitations.

The annual reports provide the shareholder surplus and claim reserves. Shareholder surplus represents the funds available to the company after all actual and contingent liabilities have been satisfied. Rating agencies, similar to bond and other insurance company evaluation tools, provide both grades (*e.g.,* "A" or "B") and dollar ratings (*e.g.,* single-capacity limits for policy amounts, which tell how large a title policy a company may issue without threatening the stability of the company in the event of a major loss). Most companies also have internal guides and limits for how large a policy they should issue. Knowing and understanding how these factors work, both independently and collectively, will permit the project developer to select a title underwriter that can issue a policy that will adequately protect this substantial asset. It will also suggest when co-insurance or reinsurance may be indicated.

Throughout the United States, underwriters issue title insurance policies through agents. These agents are title companies authorized to do business in a particular jurisdiction and permitted by title underwriters to issue the underwriters' policies. It is the underwriter, not the title agent, that provides the financial backing for the policies issued. The local agents perform a search of the land title records that are located and maintained in a county auditor's, clerk's, or recorder's office. Those county records may be collected by the title agent in a title

[1] In the chapter on siting we discussed acquisition of a lease or an easement for the portion of the project that is offshore. This chapter focuses on onshore elements of the facility and the need for protection for those facilities.

plant, a replica of the county records. Whether maintained in a public facility or by the title agent, the local agent physically searches and examines these public records.

It is important to know whether you are dealing with an underwriter or 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, the onshore portion of marine and hydrokinetic energy projects may span county lines, and the ability of a local agent may be limited to providing a search and examination of only public records for one county, whereas an underwriter may have the ability to engage multiple agents in two or more counties. Moreover, because local agents typically do not have the ability to issue title insurance policies without the authorization of an underwriter, it is important to know which underwriter supports a particular agent, in order to anticipate what can be insured and what may not be insurable.

The title insurance industry is not always standardized and is anything but completely objective. Who you know still counts for something. Professional and personal relationships based on experience, knowledge, and trust with company officers and counsel are essential. The selection process is driven in part by calling on those relationships to deliver a needed service or product.

**B. Pricing and Response Time**. The renewable energy industry presents several challenges to the title industry, perhaps none quite so taxing as pricing services and products, and anticipating delivery dates. Not all title underwriters and their agents are alike in their ability to price their services and products, and to deliver them in an efficient and timely manner.

To begin, it is necessary to know whether the project is located in a state that has promulgated, filed, or negotiable insurance rate structures. If so, the rates are controlled by state law, usually under the authority of the insurance commissioner for that state. A state with promulgated rates will not permit an underwriter or its agents to adjust rates. In a state with filed rates, the underwriter and its agents must set and follow regulated rates, but those rates can be subject to variations and interpretations. In a state without regulatory oversight, the market drives pricing. Often, states with the most regulation are also characterized by a business environment with lower motivation to perform title work in an efficient and timely manner. Knowing the regulatory environments in each state, and having the contacts to navigate these seas, can save paying tens of thousands of dollars more than is necessary or waiting extended periods for delivery of title work.

## II. Negotiating Title Policy and Endorsement Premiums.

**A. Obtain Written Proposals**. The title industry is not controlled by a single underwriter or a group of agents. There are several large title underwriters, and thousands of affiliated and independent agents. Just looking in the phone book and calling a local agent to request title searches or commitments does not provide the most competitive pricing. Rather, a concerted and balanced process of requesting, evaluating, selecting, and monitoring written bids or proposals is preferable. This process can be formal or informal, extended or expedited, and exclusive or inclusive. The point is to get the necessary information from companies doing business in the area, and then consider which company can provide the best price and the most competitive service in a particular geographic area. Some will do better in the western states, and some in the eastern states; some are able to accommodate special requests only in certain areas. To reiterate: 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-effective service before any title work is ordered.

**B. Working with National Title Services**. Although marine and hydrokinetic energy development is local, title underwriter and agent resources are available nationwide. Knowing how to select the right agent or affiliate is key. There are a number of national title service offices in all regions of the country. Marine and hydrokinetic energy development is relatively new to the title industry, however, and it is important to select an office that understands and has the ability to handle these energy projects, which may be sizable and complex.

## III. Reviewing the Preliminary Commitments and Reports.

**A. Title Reviews**. A marine or other hydrokinetic energy project may include many parcels of land for the location of the substation and transmission lines. The search and examination process produces many preliminary commitments or preliminary reports. It is always necessary to obtain all documents recorded in the public records to (1) determine the person or entity vested in title, (2) determine whether title is subject to liens or mortgages that create unacceptable risks to the project, and (3) discover all defects or other encumbrances, such as easements for utilities, road rights-of-way, mineral and timber rights, or other interests held by persons or entities not vested in title, which might prevent construction of the project as planned. It is vitally important to obtain the title information as soon as possible and review it thoroughly to make certain that all interests of record are discovered, disclosed, and analyzed carefully. Understanding what it all means and how it will affect a particular project can make the difference between successful execution of a plan and a lingering (and perhaps fatal) problem.

**B. Determining Whether to Undertake Curative Measures**. Once all the information contained in the preliminary commitments or reports for title insurance has been reviewed, it is necessary to cull that which must be corrected or cured from that which may be permitted to remain on the title, *i.e.,* information that will not impair the vitality of the project. Most often mortgages must be addressed in some manner that will permit the lender's interest to coexist with the project. Easements or rights-of-way are also problematic: some must be adjusted to allow construction of the proposed projects; others may not create a risk to the project. If a leasehold or easement interest is obtained from someone claiming to own the land, when in fact fee simple title of record is vested in another, the title company will require correction of the title before a policy can be issued. Understanding the interconnectedness of these interests is imperative to a successful marine or hydrokinetic energy project.

## IV. Survey Maps.

**A. Uses**. Surveys are used for different purposes. Sometimes the need is to know the property corners and boundaries. Other times topography information is needed. Lenders often have survey requirements, as do permitting authorities. In some cases a survey may not be necessary at all. And title companies will sometimes require a survey map before agreeing to issue certain kinds of title coverage, *e.g.,* American Land Title Association ("ALTA") extended-coverage owner's and lender's policies of title insurance. 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 needed for the project. More often than not, a marine or hydrokinetic energy project will require an extended-coverage owner's policy of title insurance, which often necessitates a certain form of survey map, certified to the title company and the developer.

**B. Forms**. Two forms of survey maps are generally produced by professional land surveyors. An ALTA/ACSM survey is one certified by the surveyor to meet certain minimum detail requirements established by ALTA in conjunction with the American Congress on Surveying and Mapping ("ACSM"). This survey is the industry gold standard. The minimum detail requirements for this survey have been revised as of 2005. The surveyors use a vernacular all their own, and understanding their forms and practices is essential to purchasing the right products and services for a particular project.

The other form of survey is a boundary survey, which is much less expensive, much quicker to perform, and 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.

Do you need a survey? Must it be an ALTA/ACSM survey or a boundary survey? How do you order each form in the most cost-efficient and timely manner? These are relevant and recurring questions that must be carefully considered.

**C. Pricing**. Survey pricing is not standardized. 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 and on time? The negotiation dance on pricing is full of traps. It is extremely important to have these negotiations early on, and in a manner that will promote reliable work from the surveyor and still keep the project on budget.

## V. Drafting Title Requirements into Purchase and Sale Agreements.

**A. Reviewing Proposed Terms**. Title requirements contained in a marine or hydrokinetic energy facility purchase and sale agreement may appear to be boilerplate. On the other hand, a developer who has experienced the sorts of difficulties that can arise because the cost of a title policy is much greater than anticipated; because options for disclosing, curing, or allocating risks associated with title defects, liens, encumbrances, or other matters were unknown; or because the optimal finished product was unfamiliar, knows the importance of negotiating the terms concerning title and survey matters up front.

**B. Negotiating Terms Effectively**. Often it is necessary to 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 confirmation as to what it will—and will not—do in a particular deal. Sometimes it is better to make concessions in a particular transaction rather than argue needlessly. Knowing when to do this is the key. Who pays for the search and examination process? Who pays for the preliminary commitments? How much will the title company charge for its premium? Will endorsements be necessary, or will there be added or contingent charges? And how do you find the answers to these and other questions?

## VI. Curing Title Defects.

**A. Document Preparation**. The best start to the curative process requires selection, preparation, and completion of the most appropriate documents. For mortgages, it is necessary to evaluate whether a subordination agreement is required, or if a nondisturbance and attornment agreement will do. For an easement, the developer needs to evaluate whether a consent and crossing agreement is necessary, or if a modification of an existing easement will suffice. Sometimes a curative document may not be needed at all. Although some developers rely on preprepared forms in this case, customized legal agreements are necessary. It is awkward and slow to draft curative documents from scratch, which is why the preferred approach is to draw on prior work, while at the same time knowing when and how to tailor specific sections in a form document for your needs.

**B. Negotiations with Third Parties**. A utility, a lender, a mineral owner, another landowner, or some other person or business holding an interest in the title to the property intended for the project substation, generation tie line, or other facility is rarely interested in helping to solve the developer's problems. Such parties would just as soon not return a call, and may avoid dealing with the matter entirely. How do you get their attention? How can solutions be proposed in the most nonthreatening manner possible? You must be able to negotiate with people in an effective manner. Generally, a title underwriter will not provide title coverage while problems remain outstanding. Sometimes, problems can be solved with help from a knowledgeable title underwriting counsel. It is important to understand issues around third parties and learn how best to navigate them.

**VII. Weathering the Title Insurance Underwriting Process**. Usually the person from whom the title developer orders title work is not the same as the underwriting counsel. Underwriting counsel decides whether to accept a defect, issue an endorsement, approve a policy provision, or provide other consideration in insuring title to a marine or hydrokinetic energy project. The route to a final policy is tortuous, and the motivation, ability, and authority of the title underwriter can vary greatly on any given transaction. The developer must know (1) which title services and products to order; (2) how to evaluate critically the preliminary commitment and the requirements it contains; (3) whether, when, and how to request revisions or amendments to the commitments; (4) what endorsements are available; and (5) what underwriting criteria will be applied to each. The reward is a successful project, and the consequences for not knowing these and related aspects of the title underwriting process can be devastating. The problem is exacerbated by the timing of such problems, which often do not arise until the late phases of a project, and usually when there is insufficient time to review and discuss all possible options. Is an indemnity advisable or even available? Can and will an endorsement be acceptable? Must a curative measure be undertaken? What precisely are the options, and how will each play out in a particular scenario?

**VIII. Financing: Anticipating Lender Requirements**. Institutional lenders, Wall Street investors, and private financers have different requirements for title insurance, survey maps, and other title matters. But that does not mean that the borrower is without options concerning these matters. Which title company to select, the terms for the search and examination, the premium, and the underwriting process are all subject to considerable negotiations and variation. It is extremely helpful to have useful advice on lender title requirements, and to be able to employ the title process in closing a finance transaction. Letting the lender control the process, on the other hand, can be more expensive and perhaps more difficult for the project owner or purchaser.

**IX. The Closing Process**. Many questions arise during the closing process. The range of questions varies greatly from project to project. Some projects do not require an escrow closing, other projects need only modified closing processes, and some projects require a table closing. Which is which, and when is one more appropriate than the other? The costs associated with a table closing can be significant. Making sure that the process is on track and able to close efficiently, before the closing is scheduled, is crucial. At the closing table, many complex decisions are made. Understanding the closing process and the title process, and how they interact, can be invaluable. Many decisions require the developer, owner, or borrower to accept risks, pay money, or make concessions. Knowing which of these may be appropriate and the risks that can be avoided is essential.

## X. Maintaining Title Insurance Coverage over Time.

**A. Corporate Reorganizations and Transfers of Interest**. A title insurance policy provides indemnification for the insured in the event of a covered loss only so long as the insured interest remains. When a corporate reorganization occurs, *e.g.,* limited liability company interests are adjusted or transferred, deeds are granted, or other interests are created, assigned, or released, coverage under a very expensive title policy could be lost entirely. It is possible to avoid policy termination by knowing when and how to work with a title insurer to purchase policy endorsements that will prevent termination. Coverage may be extended or amended, or other action may be taken to avoid unintended consequences of what otherwise should have been a simple corporate reorganization or restructuring of assets. Before any changes are made, however, it may be necessary to evaluate existing coverage and determine whether simple and inexpensive options are available. The consequences of not doing so may be termination of 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 marine or hydrokinetic energy project is developed, the interest in the land, lease, or easement may have a market value significantly lower than the finished project. And, over time, the value of this interest may increase. Typically, the amount of 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 years or more? The value of the project may not be static. If the dollar value of the asset is dynamic, it may be necessary to increase the amount of title coverage. Sometimes this can be accomplished by purchasing endorsements to an existing policy. Other times a new title policy may be necessary. The point is that the title insurance covering the owner of the project should be evaluated regularly, and risks associated with a partial or complete failure of title should not be unattended.

**C. Subsequent Financings or Equity Participations**. When lenders accept a security interest in a marine or hydrokinetic energy project, they will require a mortgagee's policy of title insurance. The project owner and borrower will typically pay the premium for this form of policy. The liability insurance for this title policy is the amount of the loan secured by the asset. But it is important to understand that the title policy insures the lender, not the owner. The title coverage purchased will not provide any indemnification to the owner in the event of a failure of title. So it is important for the owner to maintain title coverage independent of the lender's coverage. Further, it is often helpful to be aware that when a lender's policy is purchased, simultaneous coverage may be available at significantly reduced premiums. It is much less expensive to insure the title twice at the same time than it is to insure it once for the lender and then again later for the owner, or vice versa.

**D. Conclusion**. The more experience a developer gains over time, the more readily apparent it becomes that the title industry is a minefield that, if negotiated successfully, can help the bottom line enormously. Land title really does matter, and these matters can be made easier to understand and address with the help of an experienced professional who is knowledgeable in the title and survey industries.

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# Chapter Six
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Regulatory and Transmission-Related Issues—

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Long before a marine or hydrokinetic power 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. Marine and hydrokinetic projects are in the early stages of obtaining transmission interconnection and service, and as more is learned about the operation of these projects, developers will need to consider the particular application of specific transmission issues to marine and hydrokinetic energy. This chapter presents a general discussion of these issues only. 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 in part the Public Utility Holding Company Act of 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), thereby opening the door to certain utility acquisitions and mergers that had been prohibited since 1935.

Although nonexempt renewable 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 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, 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 marine and hydrokinetic generation companies are public utilities under Part II of the Federal Power Act ("FPA"), developers are subject to FERC's regulation under that Part, including rate regulation, electric reliability rules, and other regulations. However, a developer may avoid rate regulation under section 205 of the FPA for certain small projects by obtaining status as a QF. In addition, 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. These other regulatory issues are addressed 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 Securities and Exchange Commission oversight for independent power producers that qualify as EWGs, and today that exemption is with respect to PUHCA 2005. EWG status is available to any generator of electricity, regardless of size or fuel source, so long as such entity is exclusively in the business of owning and/or operating electric generation facilities for the sale of energy to wholesale customers.

Independent power producers should be aware of several issues associated with EWG status. First, the "exclusively own and/or operate" requirement mentioned above typically requires the creation of a special-purpose entity to own the marine or hydrokinetic generation facility and sell its electric output. Second, EWGs are restricted to wholesale sales and therefore cannot take advantage of retail sales 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.

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 any 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, marine and hydrokinetic project 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 marine and hydrokinetic power 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, which are referred to as QFs. Before the passage of the Energy Policy Act of 2005, PURPA was important to renewable power developers for several reasons, one of which was the exemption for QFs producing up to 30 MW from most of the provisions of the FPA and from certain types of state utility regulations. The Energy Policy Act of 2005 (and FERC's interpretation thereof) limited the applicability of these exemptions, making the eligibility requirements narrower than in the past. However, the Energy Policy Act of 2005 also eliminated PURPA's ownership restrictions, which has generated new interest in utility ownership of QF facilities—increasing the value of both new and existing QF projects.

In addition, the Energy Policy Act of 2005 narrowed the advantages that renewable power generation QFs previously enjoyed compared to EWGs. First, as mentioned above, QFs no longer enjoy broad exemptions from the requirements of the FPA. Significantly, only certain QFs continue to enjoy an exemption from the need to obtain market-based rate authority from FERC in order to sell wholesale power at market rates. Specifically, sales of energy and capacity made (1) by QFs 20 MW and smaller, (2) pursuant to a contract executed on or before the effective date of FERC's applicable rules, or (3) 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. The potential loss of this "must buy" requirement could be significant because state-established avoided cost rates have often exceeded prevailing wholesale market prices, and such published rates have been an effective negotiating tool for gaining favorable pricing under non-QF renewable energy sale agreements.

One clear advantage of QFs over EWGs is that PURPA does not restrict the ability of QFs to make retail sales to the extent such sales are allowed under state law. Another distinction between QFs and EWGs is that QFs are generally interconnected under state regulators' interconnection rules, which may or may not be advantageous for a particular project, depending in part on the rules of the state(s) in which the project is located. A QF may have an option to interconnect under FERC rules. In addition to these advantages of obtaining QF status, FERC has now exempted certain small generating facilities from the requirement to make a filing with FERC in order to claim QF status. Under FERC Order No. 732, facilities with a net power production capacity of 1 MW or less need only meet the technical requirements for QF status, and that status will not be dependent upon the applicant's having made a filing with FERC. Despite the exemption from filing requirements, QFs of 1 MW or less will continue to be subject to FERC oversight.

In addition to the general rules on QF certification applicable to various types of resources, additional certification requirements apply to hydroelectric small power production facilities. To date, FERC's regulations on QF certification have not been updated to clarify how or if these rules will apply to marine and hydrokinetic technologies. If FERC applies these rules to such projects, the rules may not pose additional requirements beyond those imposed by the FERC licensing process under Part I of the FPA. However, given that we are in largely uncharted waters with respect to QF certification of marine and hydrokinetic energy technologies, project owners should consult with experienced counsel before proceeding with QF certification applications.

**C. Other Ongoing Regulatory Requirements.** Whether a marine or hydrokinetic project developer is an EWG or a QF, or has FERC approval to sell power at market-based rates, the 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; 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 to 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 marine and hydrokinetic 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, marine and hydrokinetic energy 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 that 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 to 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 established standard interconnection procedures and a standard interconnection agreement for generators with a capacity of 20 MW or less ("Small Generators"). More recently, however, certain regional transmission organizations, such as the Midwest Independent System Operator ("ISO") 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 or construction. Queue reform is happening across the nation, and consequently, it is important to engage knowledgeable counsel in order to remain aware of how the interconnection process varies from one region to the next.

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

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

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. In certain transmission systems, however, such as those controlled by the Midwest ISO or the PJM Interconnection, the interconnection customer will not be entitled to all or even a portion of this reimbursement. For most interconnections of Small Generators, it is unusual to have network upgrades. The nature of the network upgrade reimbursement (partial or full) may also impact whether and to what extent tax gross-ups must be included in the payment by the interconnection customer.

Determining the point of interconnection for purposes of distinguishing between interconnection facilities and network facilities is an area of potential dispute between the parties. Transmission providers have an incentive to design interconnections in a manner that places the majority of the new facilities on the customer's side of the interconnection, thereby depriving the customer of a transmission credit to offset the costs of such facilities. Consistent with FERC precedent, only 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.

2. **Technical and Operational Issues.** Interconnection agreements address such technical and operational issues as reactive power factors, responsibility for electrical disturbances, metering and testing of equipment, exchange of operating data, and curtailment events. In connection with its adoption of standard procedures and agreements in Order No. 2003, FERC commenced a separate rulemaking to establish certain technical standards applicable to interconnection of large wind generating plants that would be included in Appendix G of the Large Generator Interconnection Agreement. This rulemaking resulted in Order No. 661, which adopted several rules of interest to the wind energy industry. The rules address supervisory control and data acquisition capability requirements and operational restrictions and requirements related to reactive power factor and low-voltage ride-through. Although Order No. 661 is not automatically applicable to marine and hydrokinetic energy projects, FERC left the door open to take a similar approach for non-wind technologies. Marine and hydrokinetic energy developers may wish to consider whether these provisions would be helpful to transmission issues as additional operational and technical experience is gained.

B. **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, nondiscriminatory basis pursuant to a transmission tariff that will govern the terms by which such service is provided. Upon receiving a request for service, the transmission provider will evaluate available transmission on its system and determine whether additional transmission facilities need to be constructed to accommodate the requested service. In major parts of the United States, the transmission provider is a Regional Transmission Organization ("RTO") or 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 scope of this chapter.

Under FERC's general transmission pricing policy, generators pay the greater of the incremental costs or embedded costs associated with requested transmission service. Incremental costs refer to the additional system costs (*e.g.,* construction of new facilities and upgrades) resulting from the requested service. Embedded costs reflect an allocation of system costs to the various users, generally based on megawatts of service. Once a generator executes its transmission service agreement, it is locked into taking (or, at a minimum, paying for) transmission service for the initial term of its agreement.

These transmission pricing rules may be different if the transmission provider is an RTO/ISO. The rules of the existing and proposed RTOs/ISOs may in fact be much more favorable to marine and hydrokinetic power generation than FERC pricing. For example, an RTO/ISO may recover the fixed costs of the applicable transmission system from end users, with a generator facing only transmission congestion charges. The RTO/ISO also may eliminate rate "pancaking," which is the imposition of multiple transmission charges for use of more than one 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 renewable energy power operators with intermittent resources. Generation imbalance service is a product that allows a generator to deliver an amount of energy that differs from the amount it had prescheduled for an hour. Although marine and hydrokinetic energy is expected to be more predictable than wind energy, certain types of technology have more intermittency, which must be considered in terms of imbalance requirements and penalties. Depending on the type of technology involved, in addition to potentially being able to self-supply ancillary services, project owners may have opportunities to sell certain ancillary services to other renewable generators. Whether these opportunities exist will depend in part on a transmission provider's tariffs and operating protocols and on what other resources are available to provide these services in a given region. These opportunities are part of a broader discussion currently taking place about how best to cost-effectively and reliably integrate new variable generation into the transmission grid. Throughout the country, transmission providers are revisiting existing protocols for the integration of variable energy resources. FERC is also in the process of developing guidelines on these issues. Consulting with experienced counsel will help keep project proponents apprised of the latest developments related to the provision of ancillary services and the integration of renewables into the grid.

**IV. Greater Access to the Transmission Grid.** In 2007, FERC issued Order No. 890, which reformed open access transmission tariff ("OATT") rules and was designed, in part, to improve transparency of transmission service and reduce transmission barriers for new projects. Order No. 890 was the first major reform of the OATT since it was enacted over a decade ago. The details of Order No. 890 and its progeny are too voluminous to be adequately covered in this chapter, so only a few key points will be discussed. A major obstacle to making more transmission capacity available is the fact that under current practice, long-term requests for service from a new generator may be denied based on the unavailability of transmission in only a few hours of a year, even though firm service is nonetheless available for the large majority of hours of the year. To address these concerns, FERC created two options: conditional firm service and modified redispatch service. These two services provide options for intermittent resources that can generally be constructed more quickly than the transmission upgrades necessary to deliver power on a firm basis.

Conditional firm service addresses the "all or nothing" problem transmission customers have faced, and it is a partial solution to the lack of available firm transmission capacity. Under this service, a conditional firm customer could enter a long-term contract for the capacity that is available on a path. The customer has firm service except for time periods designated in the contract and would have priority over nonfirm service for the hours in which available transfer capability ("ATC") is not available. Similarly, some transmission providers have transformed the conditional service concept to offer conditional interconnection service as well, which service may be available while an interconnection customer awaits the construction of more extensive upgrades.

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

Implementation of Order No. 890 is an ongoing process, and new developments may have occurred by the time you read this chapter. You should consult knowledgeable attorneys to obtain an updated report on this and other FERC proceedings.

**V. Reliability Standards.** Many electric power generation facility owners and operators are subject to mandatory reliability standards that include ongoing, audited obligations and potential sanctions for compliance failures. FERC's Order No. 672 certified the National Electric Reliability Corporation ("NERC") as the continent-wide Electric Reliability Organization ("ERO") responsible for proposing and enforcing mandatory reliability standards. As the ERO, NERC is responsible for monitoring and improving the reliability and security of the bulk electric system and, to do so, NERC has the authority to propose and enforce mandatory reliability standards and assess fines upward of $1 million per day for noncompliance. 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 marine and hydrokinetic project 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, and project developers should consult with a knowledgeable attorney regarding such requirements. Although initially exempted from registration, QFs are also required to comply with the reliability standards.

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.

**VI. Summary.** Recent developments have made access to the transmission grid both easier and more economical. In particular, standardized interconnection procedures and agreements for Large Generators and Small Generators subject to Order Nos. 2003 and 2006 help streamline the interconnection of renewable power sources with the transmission grid, and reformed procedures may help to speed clearing of interconnection queues that have become bogged down. Similarly, FERC's clarification of low voltage ride-through and other issues in Order No. 661 has promoted standardization of technical requirements for interconnection of marine and hydrokinetic energy. Nevertheless, much work remains in order to fully utilize existing transmission infrastructure and promote new transmission in key regions to allow new marine and hydrokinetic generation to reach markets.

# Chapter Seven
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Design, Engineering, Construction—

*Alan R. Merkle*

This chapter provides an overview of the contractual structures that will likely apply to construction of marine and hydrokinetic energy projects, including design and engineering, procurement of the related technology and equipment, the location and placement of marine and hydrokinetic energy technology, and the construction of the substation and ancillary facilities. One significant caveat: Development of a marine or hydrokinetic energy facility differs significantly from ordinary construction projects on terra firma. Placement and installation of the chosen technology and the collection of the project power output necessarily involve activity and operation in the ever-changing and challenging marine and riverine environments. Consistent with other offshore projects, one should anticipate marine and hydrokinetic energy facilities will be modular in nature with individual modules being assembled onshore and then placed offshore through use of dive boat, heavy-lift vessels, or other workboat support services.

This discussion is written from the perspective of a marine or hydrokinetic energy project developer; the information set forth below should, however, also interest design and engineering, construction, and operations and maintenance contractors. As with any complex negotiated transaction, there is ample opportunity for creative legal strategies to properly address the risks and rewards inherent in such projects.

**I. Construction-Related Agreements.** Critical to the actual development of any marine or hydrokinetic energy project are the various agreements a project developer must enter into in relation to:

- design, engineering, and manufacturing;
- procurement of necessary equipment (marine or hydrokinetic energy technology and related components such as control systems and collection and transmission equipment) and materials to construct the onshore facilities, such as substations, roads, lay-down areas, maintenance facilities, transmission lines, and any other structures necessary to transfer the energy to the grid;
- obtaining construction, installation, and balance-of-plant services necessary to construct the ocean energy facility and the ancillary facilities; and
- warranty and insurance arrangements set forth in the agreements.

Engineering, procurement, and construction agreements are often referred to as "EPC agreements." These agreements may also provide for, or anticipate, other services, including warranty services or operations and maintenance services for marine and hydrokinetic energy generation and related facilities.

There are occasions when design and engineering, procurement, and construction services are addressed in a single agreement (a "full-wrap agreement"), usually when there is a single general contractor for the project. It is also common to have separate agreements, such as design and engineering agreements, construction agreements (sometimes referred to as "balance-of-plant agreements"), and procurement agreements, using one or more contractors for each of the various services or elements of the project. Depending on contractual structure, warranties, insurance, and other matters may be addressed in a single master agreement or in separate agreements.

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**II. Design and Engineering Services.** Marine and hydrokinetic energy, for our purposes here, includes power produced from waves, tides, and currents in oceans, estuaries, and tidal areas, as well as free-flowing water in rivers and streams. Because this industry is in its early stages and primarily focused on developing demonstration and small commercial projects, there is no standardization in design for any of the technologies. Manufacturers of marine and hydrokinetic energy technologies produce devices and products to suit specific requirements. Those requirements are in part dictated by the aquatic regime in which the project will operate, such as shoreline, nearshore, or offshore, and the current, wave, or tidal conditions. Thus a marine or hydrokinetic energy technology supplier may offer a project developer variations of its technology so the developer can select parameters applicable to the specific regime in which the project may be located. Each variation may be designed and engineered by or for the technology supplier. When a developer acquires the marine or hydrokinetic energy technology, consideration should be given whether, or to what extent, the developer also acquires the producer's design and engineering services. These services may include the technology producer's design legacy arising from its previously sold and in-use products, control and monitoring system experience, components and materials experience, and event mitigation packages. Licensing and intellectual property matters are addressed in Chapter 2.

**III. Balance-of-Plant Design, Engineering, and Construction Services.** As described above, developers of marine and hydrokinetic energy projects may acquire certain design and engineering services along with the energy generation equipment supplied by the manufacturer. Additional design and engineering work will need to be performed at the project site, including oceanographic, bathymetric, weather, geotechnical, and environmental studies; micro-siting; design and engineering of the underwater power cable location, placement, attachment, and landing; shore-side substation; distribution and transmission site, including foundations; road design and other earthworks; environmental mitigation; and related activities. These design and engineering services, and related procurement and construction work, may be performed by the technology supplier under one or more agreements or by a third party on behalf of the project developer.

**IV. Typical EPC Contractual Structure for an Ocean Project.** Given the multiple factors influencing the development of a marine or hydrokinetic energy project, no single contractual structure is required for all such projects. However, the following example of a contractual structure used for a renewable power project development illustrates, in a limited way, how a typical project developer addressed the relevant issues.

In this example, a U.S. project developer wanted to acquire a supplier's energy generators (the design and engineering of which were proprietary) and to use the supplier's services in the installation of the generators, as well as related services for the start-up and testing of the generators. The project developer also wanted to acquire either the supplier's control and monitoring system or the system of a third-party supplier. The project developer also sought to acquire certain (a) operations and maintenance and (b) warranty-related services from the supplier.

The project developer and the supplier entered into an energy generator supply agreement whereby the project developer agreed to purchase a specific number of energy generators from the supplier, along with the supplier's services to install, commission, start up, and test the generators at the project developer's site (any necessary leases or easements for the site were obtained from the appropriate governing authorities). Pursuant to their agreement, the supplier agreed to deliver the energy generators to the project developer's site and to provide the personnel and materials (excluding the balance-of-plant work) necessary to install, start up, test, and place in service the energy generators.

The project developer then entered into a balance-of-plant agreement with a general contractor wherein the contractor agreed to design and construct other necessary facilities for the project, such as on-shore foundations, roads, lay-down areas, transformers, and maintenance facilities, as well as the under-sea collection and power cables to shore. Care was taken in both sets of agreements to avoid interference, duplication, or omission between the scopes of work of the supplier and the balance-of-plant contractor, and to ensure that, collectively, the agreements would result in a fully constructed, integrated, and operational project.

Issues the parties addressed in the energy generator supply and balance-of-plant agreements included the scope of work, interfaces, measures of completion, warranty obligations of the supplier and balance-of-plant contractor, limitation of liability (particularly as it related to the supplier's and balance-of-plant contractor's failure to complete their obligations by certain key dates, such as certain power purchase commitments and incentives such as production tax credit, cash grant, and accelerated depreciation deadlines), and related insurance issues. These issues are discussed below:

**A. Scope of Work.** In the example above, the parties emphasized the description of the scope of work set forth in the agreement. The scope of work should describe, in detail, the actual design, engineering, and construction obligations of the energy generator supplier or contractor. Generally, whatever is not provided for in the supplier's or contractor's scope of work is the project developer's responsibility to complete or to contract with third parties to complete. An energy generator supplier's scope of work typically includes design and manufacturing of the energy generators, including its principal parts and components, as well as installation, start-up, and testing of the energy generators. The supplier's services could also include control systems, event mitigation packages, and related warranty work. The balance-of-plant contractor's scope of work is typically more limited, as it usually excludes energy generator installation-related services and focuses on engineering and construction of any roads, service facilities, collection equipment, substation or transmission facilities, and related work. As with other aspects of such an agreement, the scope-of-work provisions will likely be heavily negotiated.

**B. Completion/Start-Up Obligations.** By whom, when, and how the energy generators are to be placed in service is usually set forth in the scope-of-work provisions of the relevant agreement. Given a supplier's in-depth knowledge of its products, the energy generator supplier is often the party delegated to install and commission the energy generators it supplies. This work may also be undertaken by the project developer (with assistance from the supplier) or by a third-party contractor on behalf of the project developer. In either case, attention is given in the agreement to the stages of completion, such as actual delivery of the energy generators to the project site, installation of the energy generators, and their commissioning, start-up, and testing. Once these progress milestones are established, completion is generally evidenced by the supplier's certifications of, for example, "mechanical completion" or "substantial completion," depending on technology; "final completion"; and "final sign-off." Given the novelty of each new technology, some minimal "reliability test run" may be a component of achieving a "completion" milestone. Each such certification is considered an incremental measure that each energy generator must satisfy in order to progress to the next measure. As with other supply or construction-related agreements, progress payments by the project developer to the supplier or contractor (as set forth in the relevant agreement) would be based, in part, on the milestones described above. For instance, the project developer would typically pay the energy generator supplier a certain amount toward the agreed-on contract price when its order is submitted and make additional payments upon (a) the delivery of the energy generators and related components to the project site, (b) the installation of the energy generators, (c) the installation and related testing of the control and monitoring system, and (assuming the foregoing stages are executed properly) (d) the final sign-off by the parties on the project.

**C. Warranty and Guarantee Obligations.** Warranty-related obligations are likely to be an issue of substantial negotiation between parties to energy generator supply, installation, and balance-of-plant agreements. The nature and scope of a contractor's warranties will, however, depend on what services, materials, and equipment the contractor provides. An energy generator supplier's warranties may include a general parts warranty (the definition of a defect can be important when determining what is included or excluded as a defective or nonconforming part or component in an energy generator), a power output guarantee (this refers to the measurement of an energy generator's (or a group of energy generators') power performance), an availability warranty (this refers to the time the equipment may be out of service for breakdowns or failure to function), and related matters. For a contractor providing services and materials other than energy generation technology, such as balance-of-plant services, the warranties would be limited in scope relative to those of an energy generator supplier, but would still include warranties relating to parts and materials used in construction and any engineering services provided.

The issues that contracting parties consider in respect of warranties include (a) the period or term of a particular warranty and whether the term can be extended (an energy generator supplier may offer certain extended warranty services for an agreed-on price), (b) the definition of a defect and a serial defect (important in projects in which multiple energy generators use identical parts and components; whether a defect is a serial defect is often determined by calculating the number or percentage of the same part or component containing the same defect), (c) limitations on a warranty due to third-party services (such as operation and maintenance services), and (d) the remedial measures a contractor may take to cure any defect. Additionally, a project developer may desire that any third-party or subcontractor warranties the energy generator supplier or contractor possesses in respect of any parts or components used in its energy generators are "passed through" to the project developer.

**D. Limitation of Liability.** As with other construction-services and procurement agreements, an energy generator supplier or other contractor will seek to limit its liability to a project developer. The provisions in a relevant agreement will usually exclude liability for consequential, indirect, incidental, or special damages. A contractor will usually seek to have whatever damages for which it may be liable limited to liquidated damages of a set amount, which may be an agreed-on percentage of the value of the relevant agreement. Although the parties may specify the actual maximum aggregate liability of the contractor, by agreement the parties may also carve out of any such limitation certain specific categories of damages. For instance, the contractor could agree that it would be liable for certain delay-related damages arising from the project developer's failure to (a) satisfy its contractual commitment(s) (under a power purchase agreement) due to an event in the contractor's control or as a risk assumed by the contractor, or (b) obtain a certain time-sensitive benefit or credit (such as a production tax credit). Parties will also typically exclude indemnities for third-party damages from any limitation of liability provision.

**E. Tax Credits.** A marine or hydrokinetic energy project's economic viability may depend on obtaining certain benefits provided under state and federal law for renewable-resources energy projects, including the federal production tax credit ("PTC") and the federal investment tax credit ("ITC"). The PTC and ITC are currently extended through December 31, 2013 for ocean energy projects. The loss of the PTC or ITC, or of any similar state or federal benefit, can adversely affect the development, as it may not be remediable (unlike other delay-related damages for failure to achieve a benchmark under a power purchase agreement, in which the related damages would likely be limited to whatever damages, charges, or other costs the project developer would, generally, have to pay to the power purchaser) and would have long-term economic consequences for a project. PTC- or ITC-related damages are usually the subject of much negotiation between the energy generator supplier or contractor and the project developer. Insurance coverage may be available for certain delay-related risks, including failure to qualify for a PTC or ITC. For a broader discussion of state and federal tax credits that may be or are available for ocean energy projects, see Chapter 10.

## V. Other Issues.

**A. Financing Issues.** As with other power projects, the construction and start-up costs associated with new renewable energy projects are likely to require some form of substantial debt financing or joint venture financing to fund the design, engineering, procurement, construction, and initial operations of the project. Financial institutions and potential investors asked to finance or invest in a project may demand the opportunity to review and comment on a project's design and engineering, procurement, and construction agreements (as well as related operations and maintenance and warranty agreements, if separate) before committing funds. Of special interest to prospective lenders and investors are provisions in the agreements providing the lender or investor the ability to enter into the project if the project developer (as the borrower) or the project defaults and that specify the extent and nature of any damages available to a project developer from a contractor. Additionally, financial institutions may 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 in the negotiated agreements. For instance, lenders will often be interested in the project's financial and operational viability (as may be reflected in a feasibility study), and much of that interest will necessarily focus on the project developer's rights or recourse 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, usually meaning that the terms and conditions of such agreements are based on typical commercial terms and standards.

**B. Performance and Payment Guarantees Issues.** Depending on the balance sheet of the suppliers and contractors, a project developer may require the various contractors to procure, for the benefit of the project developer, performance and payment guarantees, or bonds, to ensure (a) timely performance of contractors (whether engineers, constructors, or procurement contractors), (b) performance on the project has been completed pursuant to the terms of the relevant agreements, and (c) no liens or undesired security interests are lodged against the project in relation to unpaid subcontractors. These guarantees are described below.

- *Performance Guarantee Bond:* A performance guarantee is usually issued by a bank or surety company, selected or approved by the project developer, for an agreed-on sum. This sum is payable upon the project developer's demand in the event the contractor fails to (a) perform its contractual obligations or (b) perform such duties in a timely manner as specified in the relevant agreement. For instance, when the contractor defaults or cannot complete the project, the project developer may call on this bond or guarantee to pay another contractor to complete the project. The project developer will want to reserve its other rights against a defaulting contractor in the event the performance bond does not fully cover the project developer's costs (i) of completing the project or (ii) associated with damages the project developer may owe to a third party as a result of any default by the project developer.

- *Payment Guarantee/Bond:* A payment guarantee or bond is intended to ensure that, in case the contractor defaults on the project, no liens or other security interests will attach to the project developer's property or the project. A lien claim, normally filed against the project developer's property, may be "bonded over" so that it attaches instead to the payment guarantee or bond. Lenders, upon their review of the agreements, may demand or require such payment guarantees to enhance the lenders' security interests in the project.

The project developer or the lenders may require other security from contractors, such as parent guarantees, standby letters of credit, 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 a project developer's ability to call in performance or payment bonds or other assurances (such as a standby letter of credit) that a project developer may possess. Further, contractors will usually demand some form of reciprocal security issued by the project developer or its parent company, including parent guarantees, payment guarantees, and the like.

Similarly, depending on the developer's balance sheet, the vendors may require similar financial guarantees from the developer for commitments made prior to the closing of financing.

C. **Liens/Releases Issues.** When the project developer makes periodic payments to contractors, the developer should obtain a lien release from each contractor. A lien release will help protect the project developer from liens being filed on the project by subcontractors who have not been paid by a primary contractor. Such liens are undesirable because once filed, they can delay or interfere with the project's financing. Worse still, 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.

D. **Insurance and Indemnity Issues.** A project developer should obtain appropriate indemnities and insurance coverage from the various parties with whom it contracts, including the energy generator 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 include a general indemnity for personal injury, death, and property damage claims; contractor and subcontractor lien indemnities; an indemnity for taxes (other than those attributable to the developer); an indemnity for violation of applicable laws; and an indemnity for intellectual property infringement claims. Appropriate insurance policies include commercial general liability, workers' compensation and employer's liability, automobile, errors and omissions (for design and engineering services), and builder's all risk (for the project). Such policies should name the project 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 by the insured and the scope of the project. It is advisable for project developers to consult with an insurance or risk management specialist to ensure that appropriate types and levels of coverage are obtained.

**E. Early-Stage Technologies.** As with many industries with early-stage technologies, true arm's-length developer-supplier-contractor relationships may be hard to facilitate. Often, vendors of unproven commercial-scale technology find they must actually develop a project or two themselves in order to demonstrate to nonvendor developers, investors, and lenders that the equipment is sound and reliable. Accordingly, we should expect to see the first few true commercial-scale projects to be developed by various marine and hydrokinetic energy equipment vendors, in combination with contractor and financial partners. The issues outlined here will still be the subject of discussions between the parties, but it is likely the allocation of risks will be somewhat different in early-stage projects than in projects using more proven technologies.

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# Chapter Eight
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Power Purchase Agreements—

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## I. The Basics.

### A. The Parties.

1. **The Seller.** The seller will usually be the developer and owner of a marine or hydrokinetic energy facility[1] that will generate both energy and environmental attributes ("output"). But the seller may also be a power marketer that will buy the output of such a plant and sell it to one or more purchasers. If a company is reselling output, the resale power purchase agreement ("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 terms that the power marketer does not wish to pass through to the ultimate buyer.

2. **The Buyer.** The buyer is often a utility that will purchase the marine or hydrokinetic project's output to serve its load. The utility may also be motivated by a renewable portfolio standard, renewable energy standard, or other regulatory policy that encourages the development of marine and hydrokinetic energy and other forms of renewable energy. In a state that permits direct access to retail customers, the buyer may be a retail purchaser, such as a manufacturing facility that wishes to hold itself out as a green company. Power marketers may also 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), enabling the owner to finance the plant.

3. **Credit Support Provider.** The PPA will require the buyer to buy the output that the seller delivers. It may 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, post a letter of credit, deposit cash collateral, or pledge other security to ensure that amounts due under the PPA will be paid. Utilities commonly require developers to post some form of performance assurance for both the development and operational phases of a project, while utilities generally resist posting any type of credit support, except in some cases in response to a credit downgrade.

### B. Regulatory Matters.

For a discussion of the regulatory issues that a seller of energy must address, see Chapter 6.

## II. The Term.

### A. Project Financing.

If a marine or hydrokinetic energy facility is financed with limited recourse financing, the term of the PPA should be sufficient to amortize the project debt. Capital costs per megawatt hour ("MWh") of energy produced may be relatively high for these facilities because, similar to solar and wind energy

[1] For our purposes here, marine and hydrokinetic energy facilities are facilities that convert energy from waves, tides, and currents in oceans, estuaries, and tidal areas, differences in ocean temperature, and free-flowing water in rivers and streams, to electrical energy.

 

projects, they produce energy only under certain conditions. For example, a marine or hydrokinetic facility with an installed capacity of 100 MW that has a 33 percent capacity factor will, on average, produce only 33 average MW of electricity. To produce the revenues needed to amortize the project debt, the term of the PPA must usually be in the range of at least 20 years.

If the term of the PPA is 20 years, lenders will generally be willing to amortize the debt over a 15- to 17-year period. In project financings, the debt amortization period generally needs to be shorter than the PPA term, to allow work-out time in case the project encounters financial difficulties in later years. Generally, only the base term of the PPA is taken into account, because the lender has no assurance that the purchaser will elect to continue the PPA into a renewal term. Importantly, the lack of substantial, reliable output data for many marine and hydrokinetic technologies, coupled with high capital costs, makes investment in these projects a high risk for lenders. Without reliable output data, lenders may be less willing to finance a marine or hydrokinetic project because the project's revenue stream from electricity generation might appear to be somewhat speculative.

**B. Useful Life.** Since the purchaser under a PPA effectively pays for the entire capital cost of the project (plus a profit to the owner), the purchaser normally will want the PPA to capture the entire value of the project by covering the entire economic life of the facilities.

**C. Effective Date.** The PPA will be binding on the date it is signed (often called the "effective date"). This ensures that the purchaser 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.

**D. 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" or "COD." For example, the term might end on the 25th anniversary of the January 1 next following the commercial operation date. Thus, if the term were 25 years and commercial operation began on November 1, 2010, the term would end on January 1, 2036. In other PPAs, the term begins on the commercial operation date and extends for a specified number of years.

Because the commercial operation date often sets the term, the point at which the price switches from a low "test energy rate" to a "contract rate," and the point at which delay damages for failing to meet the guaranteed COD are either avoided or ended, it is important to define "commercial operation date" carefully. "Commercial operation date" can be defined as the date on which all energy generation equipment and all other portions of the project necessary to put it into operation with the interconnection facilities and the transmission system (1) have been tested and commissioned and (2) are authorized and able to operate and deliver energy to the grid in accordance with prudent utility practices. The PPA should clearly and objectively state the standards for achieving commercial operation and provide that disputes about whether COD has occurred will be resolved quickly by an independent engineer.

In some cases, "commercial operation date" is also defined in a manner that allows the project owner to achieve commercial operation even if it has not installed all of the energy generation equipment called for by the PPA. For example, the PPA may call for an installed capacity of 25 MW, but the commercial operation date may occur when 20 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 proposed capacity has achieved commercial operation. If the seller achieves commercial operation for substantial project completion but thereafter fails to complete the project, it may be liable to the buyer for liquidated damages.

The question of whether a project has achieved "commercial operation" sometimes produces disagreements. The developer typically wants to make the standards for commercial operation as objective as possible so that, if push comes to shove, a third party can decide whether commercial operation has occurred, whereas utilities usually try to preserve some discretion to decide whether or not the project has achieved commercial operation. To avoid triggering expensive dispute resolution mechanisms such as mediation, arbitration, or litigation, PPAs often include a "technical dispute" provision that authorizes each party to submit certain disputes to an independent engineer who can make a binding determination about specified matters such as whether or not commercial operation has occurred.

**E. Termination Before the Commercial Operation Date.** PPAs usually include "off-ramp" provisions that enable one or both of the parties to terminate the PPA if certain events occur or fail to occur. Common reasons for early termination include (1) failure of a public utility commission to approve a PPA or to allow the utility to include payments made under the PPA in rates; (2) inability to obtain an interconnection agreement or needed transmission rights; (3) inability to obtain offshore or onshore leases, rights-of-way, or other land rights required to build and interconnect the project; (4) inability to obtain permits required to build or operate the project; and (5) failure to obtain project financing. Termination rights require careful negotiation to make sure that all possibilities have been considered. A party is usually required to use diligent or reasonable efforts to satisfy the conditions set forth in the PPA before it can invoke the failure to satisfy such a condition as a reason to terminate the PPA (*e.g.,* the seller could not assert the inability to obtain a permit as a basis for terminating the PPA unless the seller had used diligent efforts to obtain the permit).

## III. Purchase and Sale.

**A. Delivery Point.** The PPA will require the sale of energy to occur at a specified delivery point. Title and risk of loss pass from seller to buyer at the 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 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. In some cases, the seller may arrange for transmission services and then assign the transmission rights to the buyer upon execution of the PPA; if so, the seller needs to reserve the ability to recover the assigned transmission rights in the event of a buyer default under the PPA.

Transmission ancillary services can be fairly costly and should be specifically allocated in the agreement.

**B. Pricing.**

1. **Contract Rate.** Price is the most important part of the PPA. The price may be flat, escalate over time, or contain other features, such as positive or negative price adjustments for time-of-use deliveries. 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 marine and hydrokinetic energy facilities may include nodes that can function independently of other nodes, the PPA may require the purchaser to buy power from the nodes as they are installed, connected to the transmission grid, and made operational, even though the project as a whole has not achieved its commercial operation date. 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.

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, 125 percent of the estimated annual output.

**C. Environmental Attributes.** Environmental attributes are credits, benefits, emissions reductions, environmental air-quality credits and emissions-reduction credits, offsets, and allowances resulting from the avoidance of emission of a gas, chemical, or other substance that would otherwise have resulted from generation of an equivalent amount of energy from a nonrenewable source. These environmental attributes will attach and be available to the marine or hydrokinetic power 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, investment tax credits, and any other financial incentives (such as those that may be provided under a state program) that may be attributed to the marine or hydrokinetic facility 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 warrant the current or future use, character, or value of the attributes, or whether and to what extent they will be recognized at law. In effect, the purchaser assumes the risk that the law or the market might change in a way that reduces the value of the environmental attributes. In California, nonmodifiable terms approved by the California Public Utility Commission make it more difficult to allocate change of law risk to the offtaker. California utilities will usually require the developer to use "commercially reasonable" efforts to comply with changes in the standards applicable to eligible renewable resources—the negotiation, of course, is over what constitutes "commercially reasonable."

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 yet tax wholesale energy sales, that may change as states seek new sources of tax revenue. Wyoming recently imposed a $1 per MWh excise tax on wind generation. And energy projects may be exposed to other unexpected and sometimes surprising charges during the long term of the PPA. Recent examples include Bonneville Power Administration's "integration charge" in the Pacific Northwest (currently applicable to wind resources but proposed to apply to solar projects) and FERC's November 2010 Notice of Proposed Rulemaking on Integration of Variable Energy Resources, which, if adopted as a final rule, would enable transmission providers to charge for intra-hour balancing services as long as certain market structures were in place. The parties may wish to consider including provisions in the PPA that would allocate tax liability and other costs that might result from future legislation or regulatory developments.

## IV. Permitting and Development.

A. **Commitment to Develop.** The PPA will make the project owner responsible for developing and constructing the project. The seller usually prefers a PPA that requires it to sell the project's output only if the project is actually built. A buyer tends to view such a PPA as a put and will usually insist that the seller make some commitment to develop the project. Many tense 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 milestones.

B. **Status Reports.** The buyer is typically interested in the on-going development of the project, since 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 the marine or hydrokinetic energy technology 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 where a delay in achieving an interim milestone is not likely to delay a project's completion date. Sellers sometimes 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. 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 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-upon cap, 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. The buyer wants to prevent the seller from "arbitraging" the project by absorbing the delay damages and then reselling the project's output at a higher price, and so may require the developer to agree to offer the project at the agreed-upon price and terms if the project is completed within some period after the PPA has been terminated. If the seller is willing to agree to this provision, it will often seek to include language that enables it to adjust the offered price if the delay in project construction occurs because of force majeure that requires expensive adjustments (*e.g.,* costly permit conditions) or because the project is delayed beyond an important start of construction or placed in service date for tax credit purposes.

## V. Interconnection and Transmission.

**A. In General.** The PPA usually requires 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 further reading on interconnection and transmission-related issues, see Chapter 6.)

**B. Shaping.** Transmission may be very expensive for marine and hydrokinetic energy projects because the variable nature of the resource can produce generation imbalance penalties, and the party responsible for transmission away from the project has to pay for the maximum transmission capacity that the project may need, even though the project will deliver that much energy only part of the time. Alternatively, the party responsible for transmission can purchase transmission at the expected output of the project, and rely on short-term firm or non-firm transmission purchases for generation above the average, which could increase the risk of curtailments to the project during high generation periods. To reduce these costs, a project owner may enter into an integration and exchange agreement (often called a "shaping agreement") with a utility that has a load that can be served by the project.

In general, a shaping agreement allows a project to deliver energy into the utility's system as the energy is generated. The intermittent energy serves the utility's load. In the following week or month, the utility redelivers the energy that it has received as a flat product at an agreed-upon point of delivery. Not surprisingly, the utility will charge a fee for this service. Shaping can also be accomplished through market transactions, but this typically requires the developer or the non-utility provider of the shaping services to have access to a sophisticated trading desk that enables the shaping parties to take deliveries of the intermittent energy and then redeliver as a flat and firm product on agreed-upon terms and conditions.

**VI. Performance Standards.** A seller will usually prefer to enter into an "as-delivered" PPA, which means that the seller is obligated to deliver only what the project actually produces. A buyer, however, will often 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 in the market to the extent that the project fails to perform as expected. Performance guarantees enable the buyer to plan around the facility's expected output 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. The period is usually biannual or annual. The PPA often 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. The owner should offer such a guarantee only if it is very confident about (1) the resource data collected at the project site, (2) equipment reliability, and (3) capacity factor.

Marine and hydrokinetic technology manufacturers may not provide output warranties to project developers. The technology manufacturer may provide equipment warranties, but it may not be willing to take risks that the developer is expected to manage (such as the location of the project and the expected frequency and reliability of waves, currents, river flow, or tides). Rather, the project owner will probably be expected to assume the risk that conditions at the project will produce enough energy to meet the project's revenue and performance requirements. To the extent that the manufacturer and the project owner are affiliated companies (*i.e.,* vertically integrated), as was the case in the early years of solar energy project development, the manufacturer and the owner may be required to assume the performance risks in addition to capital costs for technology development because a project lender may be uncomfortable with performance risk. Thus, project proponents often find themselves searching for other revenue sources to bridge the gap between the technology development costs and the operational risks that the project proponent may be required to assume.

**B. Availability Guarantees.** The owner of a marine or hydrokinetic energy facility may be more willing to offer the purchaser a mechanical availability guarantee than to offer an output guarantee. Such an availability guarantee requires the power generating technology in the project to be available a certain percentage of the time, after excluding hours lost to force majeure and a certain agreed-upon amount of scheduled maintenance. Mechanical availability percentages may decline over the life of the project in order to reflect wear and tear on the devices.

Marine and hydrokinetic technology manufacturers may provide availability warranties that support the project owner's mechanical availability guarantees, but thos warranties may only last for the first few years of the project. Thus, the seller will be on its own if it chooses to give a mechanical availability guarantee that covers the period after the manufacturer's warranty expires. The same problem facing vertically integrated technology development companies described in Section VI.A above also applies to availability guarantees here.

**C. Power Curve Warranties.** The seller might also ask the technology manufacturer to warrant the ability of the power generating technology to produce a specified output under specified wave, current, or tide conditions. The power curve represents a calculation of the amount of energy that the device is rated to produce at different conditions. Power curve warranties are intended to compensate the project owner for lost revenues resulting from inefficient technology operation—*i.e.,* a device's failure to operate within a certain percentage of the power curve. Power curve warranties are not usually passed through to buyers under PPAs.

**D. 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. Because market indexes 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 seek to cap liquidated damages on an annual or aggregate basis.

**E. Termination Rights.** To protect against chronic problems at an unreliable marine or hydrokinetic energy facility, the PPA usually allows the buyer to terminate the PPA if the output or mechanical availability of the project is below a stated minimum for a certain number of years.

## VII. Curtailment and Force Majeure.

**A. Curtailment.** The PPA often describes circumstances in which either party has a right to curtail output. For example, the seller may have a right to curtail deliveries if the plant is affected by an emergency condition. The PPA may permit the buyer to curtail for convenience, in which case the PPA usually requires the buyer to pay the purchase price for the curtailed generation and the after-tax value of any production tax credits that the seller would have earned had the buyer not curtailed the plant's output. Facility curtailments caused by transmission congestion or conditions beyond the point of delivery are often handled in the same manner, although the topic of curtailment is frequently a difficult issue in PPA negotiations. The buyer may be willing to assume the risk of transmission curtailments if it is relying on non-firm transmission (which will be curtailed before firm transmission). Difficult or not, the curtailment issue must be addressed carefully in drafting, because it is also a tough issue in PPA litigation. *See TXU Portfolio Mgmt. Co. v. FPL Energy, LLC et al.*, No. 05-08-01584-CV, 2010 Tex. App. LEXIS 5905 (Tex. App. July 27, 2010), *reh'g overruled by TXU Portfolio Mgmt. Co. v. FPL Energy, LLC*, No. 05-08-01584-CV, 2011 Tex. App. LEXIS 459 (Tex. App. Jan. 14, 2011).

**B. Force Majeure.** If energy is curtailed at a party's discretion 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 disaster disables the transformer at the delivery point, 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 generally 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 items that the parties agree are *not* force majeure events.

## VIII. Operation and Metering.

**A. Operation and Maintenance.** The PPA generally outlines the seller's responsibility to operate and maintain the project in accordance with prudent utility practices. Such duties typically include regular inspection and repair, as well as completion of scheduled maintenance. To make it clear that the parties do not intend to allow the buyer to use the prudent utility practice standard to improve upon the output guarantee or mechanical availability guarantee, the PPA will often provide that the liquidated damages due for a failure to achieve guaranteed output or mechanical availability are the buyer's sole remedy for underperformance by the power facility.

B. **Metering.** The metering provision is used to determine the quantity of output for which the seller will be paid. The PPA usually requires one party (typically the seller) to install and maintain a meter. The other party typically has the right to install a check meter. If the seller's meter is out of service or generating inaccurate readings, the PPA should specify how the parties will determine the project's output. Tests should be conducted regularly to verify accuracy of the seller's meters. The PPA usually states how often such tests will occur, at whose expense, and what form of notice will be given to each party. The PPA should specify how much variance in the meter's accuracy will be permitted and how repair or replacement of defective meters will be handled.

C. **Real-Time Data.** The PPA may require the seller to provide the buyer with real-time data (including meteorological data; wave, current, or tidal data; and output data). Due to the high penetration of variable resources in some balancing authority areas, buyers increasingly are not only requesting access to real-time data but are also seeking automatic generation control or other tools that enable the buyer to call on the seller to provide fast-response dispatch control.

## IX. Billing and Payment.

A. **Billing and Payment.** The PPA will describe how invoices are prepared, when they are issued, and how quickly they are paid. The billing provision often states that an invoice is final if it is not challenged within a certain period of time (usually one or two years). The PPA usually sets forth procedures for raising and resolving billing disputes, and the interest rate and penalties that apply to late payments.

B. **Right to Audit.** The buyer will typically have the right, upon reasonable notice, to access those records of the seller necessary to audit the reports and data that the seller is required to provide to the buyer under the PPA.

**X. 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 material defaults, such as the seller's failure to use commercially reasonable efforts to achieve a material project milestone;
- the bankruptcy, reorganization, liquidation, or other similar proceeding of any party; and
- a material default by a party's guarantor.

The default clause should specify how long the defaulting party has to cure a default. If the default is not cured within the agreed-upon period, the nondefaulting party usually has the right to terminate the agreement and pursue its remedies at law or in equity, to suspend performance of its obligations, or to seek specific performance and injunctive relief. The remedies clause may also limit remedies or place a cap on a party's damages—for example, in some PPAs the buyer's only remedy for the seller's failure to achieve a given milestone is to terminate the PPA without seeking damages, or to terminate it while retaining only project development security.

**XI. 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 (1) authorizing the seller to assign the PPA as collateral; (2) requiring the buyer to provide consents, estoppels, or other documents needed in connection with financing; and (3) 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 equity investors. The parties' understandings on these points are often set forth in agreed-upon forms of collateral assignment agreement that are attached to the PPA as exhibits.

**XII. Boilerplate and Examples.** The PPA will also address the "boilerplate" matters such as confidentiality, representations and warranties, governing law, the limitation of consequential damages, dispute resolution, consent to jurisdiction, and waiver of jury trials. Because the transaction between the parties may involve complex calculations, the PPA should also include a number of carefully considered examples that illustrate how those calculations will work in certain scenarios.

# Chapter Nine
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Environmental Attributes—

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**I. Environmental Attributes as a Separate Commodity.** Renewable energy consists of two distinct commodities: the electricity generated by the renewable energy project and the environmental attributes of that electricity. These environmental attributes include the benefits, emissions reductions, environmental air-quality credits and emissions-reduction credits, offsets, and allowances resulting from the avoidance of emission of a gas, chemical, or other substance that would otherwise have resulted from generation of an equivalent amount of energy from a nonrenewable source.

A Renewable Energy Certificate ("REC") reflects the environmental attributes from one megawatt hour ("MWh") of electricity from a renewable energy source. A REC is created for each MWh of renewable electricity that is generated. RECs are also referred to as "environmental attributes," "green tags," "renewable energy credits," and "tradable renewable energy certificates." These environmental attributes may be sold with the electricity, or the electricity and the environmental attributes may be sold separately.

Projects that generate electricity using a renewable resource, such as wave, tidal, or in-stream energy, may have the rights to sell the RECs associated with the generation if the facility has the ownership rights to the environmental attributes from the electricity. A renewable energy project may not have such rights if the electricity is being sold to an entity that is counting the electricity for compliance purposes, the environmental attributes are being used to satisfy a separate compliance requirement, or the RECs have already been committed or sold under a separate arrangement. Two types of markets exist for the sale and purchase of RECs: compliance markets and voluntary markets.

**II. Compliance Markets.**

**A. Generally.** Compliance markets for RECs have resulted from the passage of state Renewable Portfolio Standards ("RPS"), which require certain utilities to include a minimum amount of renewable energy as part of their overall provision of electricity. In a compliance market, buyers of RECs are typically utilities seeking to meet the state's RPS requirement. Currently, 29 states plus the District of Columbia and Puerto Rico have RPS policies in place. Certain states have more aggressive RPS policies that require more than 20 percent of power in their state to come from renewable energy resources (California: 33 percent by 2020; Oregon: 25 percent by 2025; Minnesota: 25 percent by 2025; Illinois: 25 percent by 2025; New York: 29 percent by 2015; Connecticut: 23 percent by 2020; New Jersey: 22.5 percent by 2021; Delaware: 25 percent by 2026; Massachusetts: 22.1 percent by 2020; New Hampshire: 23.8 percent by 2025; Nevada: 25 percent by 2025; and Hawai'i: 40 percent by 2030). Seven other states have set voluntary goals for adopting renewable energy instead of portfolio standards with binding targets (including Virginia, which has set a goal of 15 percent by 2025).

Some states allow compliance with their RPS through purchase of RECs. As illustrated in state examples below, in order for customer generation to qualify as a REC, the renewable resource must meet the criteria of "renewable resource" under the individual state's RPS law. The definition of "renewable resources" and other eligibility requirements vary state by state, and can include the vintage of the resource, geographic restrictions on generation, emissions criteria, requirements that the REC and the electricity need to be sold together, and individual state policies favoring certain types of generation over others. These mandatory RPS policies create a greater demand for renewable energy provided by the RPS policy, higher prices for the energy that is produced, and a large market for renewable energy projects based on each state's requirements as related to its overall energy needs.

### B. Resource-Specific Incentives.

1. **Carve-Outs.** Some states require utilities to procure a certain percentage of energy from generators with certain characteristics. For example, New Jersey requires that a certain percentage of the kilowatt-hours sold in the state by electric power suppliers and basic generation service providers be from offshore wind energy. This is an example of a "carve-out" from the state's RPS. The RECs generated by these facilities are called offshore wind renewable energy certificates, or "ORECs," and the suppliers and providers meet the state mandate by purchasing a proportionate number of ORECs. From a policy perspective, carve-outs are a market driver—they serve to incentivize the development of particular technologies by mandating that utilities purchase the output. As of the date of this publication, no state has a carve-out for wave, tidal, or ocean thermal power, or any other marine renewable energy resource.

2. **Multipliers.** Rather than establishing a carve-out for a particular renewable resource type, other states provide resource-specific incentives by allowing utilities to count one MWh of renewable electricity from a favored resource for more than one REC for purposes of compliance with the state's RPS. For example, the Colorado RPS currently permits solar electricity from a facility located in the territory of a cooperative or municipal utility that begins operation before July 1, 2015 to receive 300 percent credit for RPS-compliance purposes. Thus, a Colorado utility purchasing the output of a solar facility that meets those requirements may claim three RECs for each MWh of electricity generated by that facility for purposes of the utility's compliance with the state RPS. Such incentives are often referred to as "REC multipliers."

Another example of a REC multiplier can be found in the Washington State RPS. At this time, a utility can receive 200 percent credit toward compliance with the Washington RPS for each REC generated by a distributed generation resource (*i.e.,* a generation facility or any integrated cluster of such facilities with a capacity of 5 MW or less) if the utility (1) owns the facility, (2) has contracted for the electrical output of the project and the associated RECs, or (3) has contracted to purchase only the associated RECs.

Importantly, however, although REC multipliers count for state RPS compliance, they do not actually generate multiple RECs from a single MWh of renewable electricity. Thus, while a utility may be credited for compliance purposes as if it held two RECs for each MWh of electricity generated by a qualifying facility, it is unclear whether the additional "credit" is itself a marketable good.

REC multipliers have proven to be a significant driver for solar energy project development in particular. However, as of the date of this publication, no state has established a REC multiplier for wave, tidal, or ocean thermal power, or any other marine renewable energy resource.

## III. Eligibility Concerns.

**A. Eligibility.** Whether a renewable energy project is eligible to sell RECs depends on a number of factors. The output from the project or facility must be sold to a local utility or to an entity that is counting this electricity for compliance purposes. The RECs must not have been committed or sold under another agreement. Similarly, the environmental attributes must not be used to satisfy a separate compliance requirement (in other words, there is no double-counting of RECs). Other factors that may affect certification of a facility include location, fuel source, emissions, and co-firing with nonrenewable resources. With regard to location, offshore energy projects may have a unique concern. Because offshore renewable energy projects may be located on the outer continental shelf—and therefore in federal waters outside the state's territorial sea—we advise careful scrutiny of geographic eligibility requirements under state RPS laws.

**B. Data Verification.** Data verification tracking systems for RECs are under way, including the Western Renewable Energy Generation Information System ("WREGIS") for the western United States and the Midwest Renewable Energy Tracking System ("M-RETS") for the Midwest. These systems will issue, register, and track RECs for use in verification and compliance with state regulatory programs, and may also be used for voluntary market programs. WREGIS and M-RETS will track RECs from the time they are generated until the time they are used and retired for compliance with the RPS, and will protect against multiple counting and selling of the same renewable energy. Additionally, the Green-e and Environmental Resource Trust programs independently audit renewable electricity production to verify that the power and the RECs were produced by a renewable energy generation facility, delivered in the specified amount, and not double-counted or claimed by more than one entity. Aspects of RECs that must be verified include the quantity and the vintage (*i.e.,* in what year they are being measured and applied). Current tracking systems track each unit from its "birth" to its retirement; each unit of generation is assigned a unique ID that includes its attributes: the date it was generated, the facility location, the date the facility went online, the type of renewable resource, the emissions profile, and the eligibility of the unit for programs like RPS. There is no set price for RECs. However, many states have a penalty price for failing to meet an RPS requirement; for example, California imposes a penalty of $50 per MWh, up to a cap of $25 million. These penalty amounts may serve as a price cap for the compliance REC market.

**IV. Voluntary Markets.** In compliance markets, the customers for RECs are utilities seeking to comply with state RPS mandates. In voluntary markets, the buyers are individual consumers, profit and non-profit businesses, and governmental entities that seek to offset electricity consumption and demonstrate support for renewable energy. In some cases, utility customers purchase RECs through utility "green-pricing" programs. In voluntary markets, RECs are separated (*i.e.,* "unbundled") from their original MWh generation of electricity and sold to a broker or marketer. Purchasers of RECs through a voluntary market do not have to change utility service in order to support renewable energy. The sale of RECs into a voluntary market offers a generator greater flexibility, as resources do not necessarily have to comply with specific state RPS mandates. However, the trade-off is that RECs generally sell for a lower price into a voluntary market.

# Chapter Ten
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Tax Issues—

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The tax system often is used to provide incentives for particular types of investments the government wants to encourage, including marine and hydrokinetic energy. These incentives raise tax planning issues that go well beyond those involved in general structural, choice-of-entity, and other financing considerations, and create the potential for significant economic benefit. The available incentives also have been subject to frequent changes as federal and state energy policies have evolved. The following discussion is only a general summary and is current as of the date shown above. 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 marine and hydrokinetic resources. This credit is known as the "production tax credit" (the "PTC").

**A. Requirements for Claiming the Credit.** The PTC for marine and hydrokinetic energy 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 during the taxable year. Each of the following requirements must be satisfied for a taxpayer to claim 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 marine and hydrokinetic energy, which includes energy derived from (i) waves, tides, and currents in oceans, estuaries, and tidal areas, (ii) free-flowing water in rivers, lakes, and streams, (iii) free-flowing water in an irrigation system, canal, or other man-made channel, or (iv) differentials in ocean temperature. Marine and hydrokinetic energy does not include any energy derived from any source other than those listed above that utilizes a dam, diversionary structure, or impoundment to produce electricity.

**3. Qualified Facility.** The electricity must be produced by a facility that is located in the United States, is owned by the taxpayer claiming the PTC, has a nameplate capacity rating of at least 150 kilowatts, and was originally placed in service on or after October 3, 2008 and before January 1, 2014. A marine or hydrokinetic energy 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.

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 0.75 cents, adjusted each year for inflation, multiplied by the number of qualified kilowatt hours of electricity produced and sold by the taxpayer during the year. For electricity produced and sold during 2010, the inflation-adjusted PTC amount for marine and hydrokinetic energy was 1.1 cents per kilowatt hour.

C. **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.

D. **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 forward 20 tax years from the year the credit arose.

E. **Sunset Date.** To qualify for the PTC, a facility must be originally placed in service before January 1, 2014. Proposals to extend PTC sunset dates are a matter of frequent discussion, and it is possible that the sunset date could be extended beyond January 1, 2014 by future legislation.

II. **The Investment Tax Credit.** Sections 46 and 48 of the Code allow the owner of a qualified marine or hydrokinetic energy facility that is placed in service on or after January 1, 2009 and before January 1, 2014 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 cost of a facility rather than on the amount of electricity produced and sold. The amount of the ITC for a qualified marine or hydrokinetic energy facility is 30 percent of the tax basis (generally the cost) of the qualifying property that is placed in service during a taxable year.

A. **Requirements for Claiming the ITC.** The ITC applies only to "energy property," which is defined for purposes of marine and hydrokinetic energy facilities to include only property that meets the following requirements:

1. **Electricity-Producing Equipment.** The property must be equipment that is used to produce electricity from marine and hydrokinetic energy. 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 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, owned by the taxpayer, and originally placed in service on or after January 1, 2009 and before January 1, 2014.

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

**C. 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, the tax basis of the qualifying components of a marine or hydrokinetic energy facility with respect to which the ITC is claimed generally will be 85 percent of the cost of those components.

**D. 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.

**E. No Cutback for Government Financing.** The ITC for a marine or hydrokinetic energy project, 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.

**F. 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 for a particular year, the taxpayer is not entitled to a refund of federal income tax on account of the credit. Any unused portion of the credit generally may first be carried back one tax year and then forward 20 tax years from the year the credit arose.

**G. Sunset Date.** To qualify for the ITC, a facility must be placed in service before January 1, 2014.

**III. U.S. Treasury Department Grants.** The American Recovery and Reinvestment Act of 2009 allows the owner of a qualified ocean power 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 is designed to function in the same manner as the ITC for which the owner of a qualified project otherwise would have been eligible.

**A. Qualification for Grant.** To qualify for a grant, a marine or hydrokinetic energy project must (i) meet the qualification requirements for the ITC and (ii) be placed in service during 2009, 2010, or 2011 or, if construction is begun in 2009, 2010, or 2011, be placed in service on or before January 1, 2014. To be treated as having begun construction, the applicant must have engaged in physical work of a significant nature. In addition, the applicant will be treated as having begun construction if the applicant has paid or incurred 5 percent or more of the cost of the facility (excluding certain costs). There is substantial uncertainty regarding how these tests will be applied, and developers are urged to consult their tax advisors concerning this issue.

B. **Disqualified Persons.** A grant may not be paid with respect to a project if certain persons own an equity or profits interest in the project, either directly or indirectly through a pass-through entity, such as a partnership. Disqualified persons include, among others, federal, state, and local governments; certain tax-exempt organizations; cooperative electric companies; Indian tribal governments; and certain foreign persons.

C. **Amount of Grant.** Like the ITC, the amount of the grant generally is 30 percent of the tax basis (generally the cost) of qualifying property.

D. **Excluded from Income.** A grant generally is not included in the taxable income of the recipient for federal tax purposes. An exception applies to certain lease transactions. Treatment of the grant for state income tax purposes varies from state to state.

E. **Basis Reduction.** The tax basis of the property is reduced by one half of the amount of the grant, in the same manner as if the ITC were claimed. An exception applies to certain lease transactions.

F. **Recapture.** A grant generally is subject to recapture if, within five years after a facility is placed in service, the recipient stops using it in a manner that qualifies for the grant or sells or otherwise disposes of the property to a person who would not have been eligible for the grant if that person had originally placed the property in service.

G. **No ITC or PTC Allowed.** No ITC or PTC may be claimed with respect to property for which a grant has been claimed.

H. **Timing of Payment.** The U.S. Treasury Department is required to pay a grant to a qualifying project owner within 60 days after the date the project owner applies for payment or the date the facility is placed in service, whichever is later.

I. **Application Deadline.** An application for the grant must be filed before October 1, 2012.

IV. **Bonus Depreciation and MACRS Depreciation.** In addition to tax credits or grant payments, marine and hydrokinetic energy 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. These losses result primarily from bonus depreciation and accelerated depreciation deductions under the modified accelerated cost recovery system ("MACRS").

A. **Bonus Depreciation.** An owner of qualifying property placed in service in 2010, 2011, or 2012 generally is entitled to deduct 50 percent of the adjusted basis of the property in the year in which the property is placed in service. The remaining 50 percent of the adjusted basis of the property is depreciated over the regular tax depreciation schedule. An owner of qualifying property that is acquired after September 8, 2010 and placed in service before January 1, 2012 is entitled to 100 percent bonus depreciation. To qualify for bonus depreciation, property generally must have a recovery period of 20 years or less. Thus, property that otherwise would qualify for 7-year MACRS depreciation, for example, generally will qualify for bonus depreciation.

**B. MACRS Depreciation.** Qualifying components of marine and hydrokinetic energy facilities are also eligible for greatly accelerated depreciation deductions.

**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 obtain the benefit of 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 an ocean 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 establishing a safe harbor for structuring these partnership transactions with respect to wind facilities. A number of specific requirements must be satisfied to fit within the safe harbor guidelines. As an 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 and the grant, 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 a project, including when choosing the type of entity that will own a facility and the various financing alternatives available. The grant in lieu of the ITC provides a new financing option for developers of ocean power facilities to consider. Even developers that opt for the grant, however, may still desire to involve tax-motivated investors to take advantage of the accelerated depreciation and other tax benefits associated with a project. A comparison of the economic benefits of the PTC, the ITC, and the grants 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 marine and hydrokinetic energy 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. The economic downturn has caused many states to revisit tax incentives previously offered to businesses, including renewable energy businesses. States are generally narrowing their incentives, either by interpreting existing law narrowly or by legislative change, sometimes with retroactive effect.

**VI. Net Income Tax States.** The vast majority of states impose a net income tax. Notable exceptions among the coastal states are Washington and Texas. 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 marine or hydrokinetic project will generally create "nexus" with the state or states in which the project is located and will generally allow those states to tax the income of the company that owns or operates the project. For example, a wave park that is moored offshore is likely to be within the territorial boundaries of the coastal state and, in fact, is likely to be affixed to land owned by the state. Any facilities located onshore, such as operation and maintenance facilities, substations, and the like, as well as maintenance vessels that have their home port or license, or both, in the state, also will likely create nexus with the state. Less substantial activities, such as consulting, may create nexus with a state as well. Projects straddling more than one state may give rise to tax in all affected states and may be subject to special provisions of federal law or interstate compacts regulating state and local taxation.

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), limited liability companies ("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 allocation and apportionment. In western states, including California, Idaho, Montana, and Utah, the company's overall business income from all sources is apportioned to the state based on the company's property, payroll, and sales within the state. However, reflecting a national trend, Oregon's apportionment is now based entirely on sales. For purposes of apportioning sales of electricity among different states, some states, such as California, source the sale based on where the majority of income-producing activity related to the sale occurs. Other states may use different sourcing rules. Oregon, however, takes the position that sales of electricity are sourced to the state where delivery occurs.

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 marine and hydrokinetic energy and other alternative energy projects. It is important to understand the nature of each incentive, as there is considerable variation among the states. Also, as noted above, some state incentives may reduce the amount of the federal incentives available for the project.

For example, Oregon has adopted a business energy tax credit (the "BETC"). The BETC program allows an Oregon taxpayer that owns and operates a qualifying renewable energy facility to claim a credit against Oregon income tax to offset the eligible costs of construction of the project. The BETC is available for projects that use ocean energy, water power projects, and small hydroelectric projects (no more than 10 MW of installed capacity). The amount of the credit is 50 percent of the eligible costs, up to a maximum total credit amount of $10 million. The total credit amount is claimed over five years, and unused credits may be carried forward for up to eight years. A developer may sell the BETC outright, at a discount established by the state and recalculated quarterly.

Certain other incentives, including federal grants, and potentially including the federal grant in lieu of the ITC, may reduce the amount of the BETC. Legislation and administrative rules adopted in late 2009 and early 2010 impose statewide caps on the BETC for renewable energy projects and give broad discretion to the Oregon Department of Energy to attach conditions and restrictions on individual projects. The BETC is now awarded in a process similar to competitive bidding, based on a defined amount of credit available statewide. In addition, a recent increase in the discounted price that must be paid for the BETC likely will make it more difficult to sell the BETC.

**VII. Sales and Use Taxes.** Nearly all states impose a sales tax. Notable exceptions among the coastal states are Oregon and Alaska, although some Alaska localities impose a sales tax or a gross receipts 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.** Some states have adopted exemptions for the purchase of machinery and equipment used to produce electricity from certain renewable resources. Those exemptions generally have not yet been extended to include equipment used to produce electricity from wave or other ocean energy. In 2009, however, Washington expanded its sales and use tax incentive for certain alternative energy generation equipment to apply to machinery and equipment used in generating electricity from tidal or wave energy. The incentive is a 100 percent exemption from July 1, 2009 through June 30, 2011 and a 75 percent rebate from July 1, 2011 through June 30, 2013. However, the Washington legislature, like many state legislatures, is considering substantial changes to, and limitations on, this sales tax incentive and also is considering substantial changes to the tax system as a whole.

**VIII. Property Tax.** Virtually all states impose a 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. Marine and hydrokinetic energy projects present an interesting issue in that the land to which a project may be moored is likely within the boundaries of the county but may not be within the boundaries of any other local taxing district. This may mean that only countywide property taxes apply, and that taxes imposed by cities, school districts, and other local jurisdictions within the county do not. Because the property tax rate for any one piece of property is generally the aggregate of all tax rates of all local jurisdictions in which the property is situated, this could mean a substantial and automatic tax savings even if no incentives apply.

**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, the facility's output is a factor in determining whether central assessment applies.

**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.

**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. Property Tax Incentives.** Property tax normally would apply to marine and hydrokinetic projects even though the generation equipment may be affixed to public land. In most states, property affixed to government land is taxable unless a specific exemption applies. Therefore, as part of due diligence in constructing or acquiring a marine or hydrokinetic energy facility, it is worthwhile to inquire whether any property tax incentives are available. Property tax incentives can be particularly advantageous because property tax liability typically applies throughout the life of the project. In contrast to income tax, property tax is often highest in the early years before the project is profitable.

Property tax incentives often are in the control of county or other local government authorities. Therefore it is important that county boundaries generally extend to riverbeds and offshore to the same extent as the state's boundaries (usually three miles, but farther in the case of Texas and Florida). This means that a wave park should be eligible for property tax incentives that are otherwise available countywide.

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 the participation of cities.

**IX. Excise Taxes.** When considering operation of marine and hydrokinetic energy facilities, 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 3.873 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, some California cities impose gross receipts taxes for the privilege of doing business in the locality. California imposes a fee based on gross receipts for the privilege of doing business as an LLC. All potentially applicable taxes, including state and local excise taxes, should be carefully analyzed in determining the costs and benefits of operating a marine or hydrokinetic energy facility.

# Chapter Eleven
# THE LAW OF MARINE AND HYDROKINETIC ENERGY
## —Project Finance for Marine and Hydrokinetic Power Projects—

*Edward D. Einowski*

**I. Introduction.** Securing a power source by harnessing the energy in moving water is something humankind has been doing for centuries. Indeed, water-driven mills provided the original motive force for the industrial revolution. The energy provided by these mills was crucial to the development and production of the machine tools that made the steam engine possible—the steam engine that, owing to its portability (it didn't need to be located by a river), ultimately replaced water-driven mills as the primary motive force for a time. With the development of dynamos in the latter part of the 19th century, moving water once again became a primary motive force as the mill technology was adapted and put to use in spinning the turbines in hydroelectric projects that were the first large-scale producers of electric energy.

Although water power is one of the oldest resources tapped to meet our energy needs, historically it has tended to focus on the energy available in rivers and streams, leaving untapped the vast amount of energy available in the movement of ocean tides and currents. And though the basic technology needed to capture ocean energy is not new, it is only in recent years that developers have begun to pursue it on large scales.

Given the relative newness of large-scale marine and hydrokinetic energy projects, the industry cannot point to a standard model for how these projects are to be financed. As with other technologies without a long track record of successful project financings, the particulars of the standard model for financing marine and hydrokinetic energy projects will be developed over time on a project-by-project basis as issues are identified and addressed, and developers, bankers, attorneys, and consultants gain more hands-on experience in the area.

But though the development of a more or less standard template for financing marine and hydrokinetic energy projects will have to await the outcome of the efforts to be made in the coming years, there is nevertheless a wealth of knowledge derived from the financing of other energy projects (as well as the financing of other major capital projects) that will doubtless set the basic outline for structuring financings for marine and hydrokinetic energy projects. The adaptation of the project financing structures developed in other areas to marine and hydrokinetic energy projects will be the focus of this chapter.

**A. The Search for Credit.** Debt financing for capital projects—be it marine or hydrokinetic energy project or another resource—is essentially a search for credit: the fashioning of a loan package providing adequate assurance (creditworthiness) the loan will be repaid in a timely manner and the risk of default (nonpayment) is reduced or mitigated within levels acceptable to the lender. Creditworthiness and risk of nonpayment are two sides of the same coin: the greater the nonpayment risk, the higher the required creditworthiness of the borrower, and vice versa.

**B. Risk Shifting.** Much of the drama in putting together marine and hydrokinetic 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 seeks to shift technology risks to the equipment manufacturer and construction contractor while preserving for itself as much of the cash flow and appreciation in project value as possible. The lender will likely seek to shift risk to the project owner by taking paramount positions in the project revenues and assets, and to third parties such as the equipment manufacturer and construction contractor by getting the benefit of the warranties and contractual obligations of these participants, all to enhance the prospect of the loan being repaid on schedule.

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

In broad terms, two basic approaches address credit and risk allocation issues in a manner that will generally meet the objectives of the participants involved: full recourse (or balance sheet) financing, and limited recourse (or project) financing.

## II. Full Recourse (Balance Sheet) Financing.

**A. Defined.** In balance sheet financing, payment of the debt is backed by the legal obligation of an entity with sufficient financial resources (*i.e.,* its balance sheet) to underwrite the risk that the project will be successful and the debt will be repaid. It is "full" recourse in that the lender can enforce debt payment out of any and all unencumbered assets of the entity providing the balance sheet support; the lender is not limited to the project assets or other specific collateral. Balance sheet financing, however, is usually unsecured, with the lender taking no lien on or security interest in any tangible or intangible assets of the borrower. Despite the lack of a lien on specific assets, the fact that the lender has recourse to the entire financial strength and resources of the balance sheet provider makes this an attractive structure if the balance sheet, as most succinctly highlighted by the old joke:

Q: What does it take to get a $100 million loan from a bank?

A: $1 billion in cash collateral!

Balance sheet backing rarely comes from the entity serving as the project owner; these tend to be single-purpose entities ("SPEs") with no substantial assets other than the project. Rather, the balance sheet most typically is provided by an affiliate of the project owner—an upstream parent or other affiliate with the requisite financial profile.

**B. Availability of Balance Sheet Financing.** Balance sheet financing is generally available only to the more substantial players in the electric industry—investor-owned utilities, power marketers, energy generator manufacturers, or others whose long-term unsecured debt is rated at least investment grade by one of the national rating agencies.[1] Indeed, backing a loan with the balance sheet of an entity that has substantial liquid and

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

tangible assets, acceptable levels of debt, and a proven track record of earnings can result in a risk posture to the lender that, in many respects, is the functional equivalent of overcollateralizing a loan with cash collateral.[2]

**C. Focus Shifted Away from Project.** 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 marine or hydrokinetic energy project being financed. The reason is simple: A lender primarily relies on the overall credit strength of the balance sheet provider and recourse to all its unencumbered assets and revenues to enforce payment of the debt. The viability of the project to be financed is thus only one small piece of the credit picture. Whether or not the project will be successful is less of a concern because repayment of the debt is dependent on the results of the balance sheet provider's overall operations rather than on the ability of the financed project to operate and produce the needed revenues.

**D. Limiting Factors.** Balance sheet financing may not be an option for many marine or hydrokinetic energy projects. Developers of projects may be smaller, independent companies that do not have the type of balance sheet that lenders require.

Even when an available balance sheet would support the project financing, there is often an unwillingness to use it. It is a question of opportunity cost: The more the balance sheet is used to support project debt, the less it will be available for other corporate purposes (such as acquisition of other companies or to posture balance sheet debt so it will not adversely affect the company's stock price). Thus, even for more financially well-heeled players in the energy industry, balance sheet financing may not be an attractive course to pursue. The alternative is limited recourse financing.

## III. Limited Recourse (Project) Financing.

**A. Defined.** With limited recourse, or project, financing, debt is backed only by project assets and revenues these assets generate. If the project fails to produce revenues needed to pay expenses and service the debt, the lender cannot pursue nonproject assets or revenues of those who own equity interests in the project. Under the express terms of the loan documentation, recourse is limited to the assets of the entity owning the project and project assets and revenues.

This limited recourse character is reinforced by the ownership structure of the project. Renewable energy ventures tend to utilize SPEs to own the project. The sole asset of the SPE is its interest in the energy facility. Indeed, the loan documentation will typically include a covenant that prohibits the SPE from engaging in activities other than the ownership and operation of the project financed. The legal form chosen for the SPE (*e.g.,* corporation, limited liability company, and limited partnership that has as its ultimate general partners corporations or limited liability companies) is such that, in the absence of an undertaking such as a guaranty of the debt by the equity owners, limits the liability of the equity owners to the project assets. Thus, by both contractual provisions of the loan documentation and the very nature of the SPE's structure, a lender's recourse to enforce payment of the debt is limited to the project assets and its revenue-generating capability.

[2] Though, as any lender will be quick to point out, cash collateral in the hands of the lender is better security than any balance sheet—the difference between a bird in the hand (the cash collateral) and one in the bush (the earnings value of the balance sheet).

**B. Betting the Farm.** In a limited resource project financing, the project owner "bets the farm." Assuming that debt is properly structured to eliminate or acceptably mitigate the lender's risk, the lender antes up on this bet by making the loan. Structuring a limited recourse project financing focuses on features that serve to eliminate or mitigate the lender's risk. This, in turn, leads directly to exhaustive examination of all aspects of the project—conditions at the site, nature and adequacy of site rights and permitting for the site, reliability of equipment used, legal obligations and creditworthiness of key project participants (such as the output purchaser and the equipment manufacturer), availability of transmission, transmission system handling of imbalance penalties for variable resources, etc. Indeed, from a lender's standpoint, all aspects of the project must be thoroughly vetted to ensure the project will operate successfully (*i.e.,* pay its bills) even in a worst-case scenario.

**C. Project Viability vs. Collateral Value of Project Assets.** Lenders generally insist on—and get—a first-priority lien on all project assets. The tangible collateral securing the loan is of secondary importance to the lender. The reason is simple: As a general rule, in a foreclosure situation, tangible collateral can usually be sold only at a price that produces a relatively small fraction of the amount needed to pay the debt it secures. A lender is far more likely to be repaid if the project operates successfully and produces needed revenues than by liquidating project assets in foreclosure. Therefore the detailed examination of the project for purposes of project financing is aimed primarily at determining the likelihood the project will operate as planned. The lender will insist on putting in place security arrangements with the project participants that are calculated to ensure the project will in fact perform up to expectations even in the face of a worst-case occurrence.

Indeed, in many cases, limited recourse debt financing may not be available until the project achieves full commercial operation, as the project owner is often required to guaranty the debt on a full recourse basis during the construction period. This is particularly true for projects that utilize a relatively new and untested technology: In the absence of a long track record of successful installation and operation of a new technology, lenders are often unwilling to take the construction and start-up risk. Thus they may well insist on breaching the wall of limited recourse by requiring a guaranty of the construction debt from a creditworthy entity, with the guaranty to remain in place until the project is completed and operations have stabilized. The extent to which this will be required may well depend on the complexity of the new technology involved. For example, hydrokinetic energy project that employs what is basically a system of levers raised and lowered by the tides to convert the tidal energy into rotary energy may not be viewed as subject to great technological risk, as the mechanical devices employed have long been in use in other applications. Contrast this with the more complicated chemistry and technologies involved in using cellulose-based feedstock to produce ethanol on a commercial scale—the potential pitfalls in utilizing such a cutting-edge technology may well be perceived to be far greater than the risks of applying lever technology to a new application such as hydrokinetic energy.

Even in the case of this type of hydrokinetic energy technology, closer examination may reveal risks that must be addressed. For example, will the levers become encumbered with seaweed or organic growths such as barnacles that will ultimately impede their efficient operation? Technology risk will be carefully evaluated in the project financing process, and even technologies that are tried and true in other applications may need to prove themselves in the new application before lenders are completely comfortable with the risk. Until the lenders are satisfied, one can expect them to require risk mitigation devices such as guaranties from creditworthy parties.

**D. Capacity Factor and Fuel Risk.** For generating resources powered by fossil fuels, mitigation of fuel risk is a fundamental matter to be addressed in the project financing process, in terms of both availability (*i.e.,* the need to secure a firm, long-term fuel supply) and price volatility. When using the ocean or a river as the motive force, it may seem at first blush that these issues are not germane. The tides, for example, have been moving in and out for centuries on cycles determined by the moon's periodic orbit around the earth, thus assuring availability. And once an appropriate site has been secured, the "fuel" costs have been pinned down for the life of the project—in effect, the fuel comes with the site.

However, such a view is overly simplistic. The point of addressing fuel availability and price volatility in fossil fuel projects is to ensure that the project will be able to generate electricity as planned. And while the "fuel" issues facing marine and hydrokinetic energy projects may not be the same as those encountered in a fossil fuel project, the same basic issue must be addressed: Will the motive force be available in the amounts and at the times needed to reliably produce power? Consider, for example, whether a tidal project will have sufficient flow to produce energy in the periods between tidal inflow and outflow, or the problems of dealing with calm seas in a wave energy project. And consider the unplanned outages that result from weather occurrences such as storms, hurricanes, or tsunamis. Even with the free "fuel" provided at an aquatic site, consider whether there may be some fuel price risk in the form of things such as environmental protection facilities that may be needed after the project has operated for a period of time as part of an adaptive management plan.

Particularly in the context of limited recourse project financings, the fuel or motive force issues are fundamental, for they go directly to the core issue of the project's ability to produce the electricity that will generate the revenues needed to pay the project debt. As with other renewable energy resources, such as wind, one key method of quantifying the risks associated with motive force is the determination of a "capacity factor" for the project. "Capacity factor" is a convention developed for expressing the amount of electric energy a project can be expected to produce over a given period of time. The capacity factor is a metric that determines the amount of electric energy expected to be produced based on the installed nameplate capacity of the project and the factors that affect the availability of the motive force to power the project to utilize this installed nameplate capacity. For example, the turbines in a hydrokinetic energy project may have an installed nameplate capacity of 100 MW. Thus, if sufficient motive force were available to run the turbines at full capacity on a continuous basis, the project would produce 100 MW of electric energy 24 hours a day, seven days a week. However, although the tides are certainly regular, they do not produce a constant motive force: The energy that can be accessed during ebb tide may be very little compared to that which is available when the high tide has peaked and is rolling back out to sea. Thus, if sufficient motive force is only available at certain times, the project's capacity factor (*i.e.,* the actual amount of electric energy the project produces) will be significantly lower than its installed nameplate capacity. For example, in a recent study prepared for the California Energy Commission, a wave energy conversion project's annual energy capacity was assumed to be 50 percent—meaning that if the installed nameplate capacity of the project was 100 MW, on average one would expect the project to actually produce only 50 MW of electric energy.

**E. Oceanographic Studies.** The capacity factor for a marine or hydrokinetic energy facility may be estimated based on oceanographic studies (resource assessments) of the site conducted during the developer's initial site assessment. For projects utilizing wave or tidal energy, the general pattern of waves or currents must be determined so as to enable one to predict with some degree of confidence the electric output of the project.

Studies of such things as the wave height, wave frequency, bathymetry, and marine life assessments at a site are also key pieces of information that need to be evaluated in assessing the economic viability of the project.

In addition to providing information needed to generate a capacity factor for a site, these studies should inform how multiple devices may be arrayed in order to optimize production. Production can be optimized by putting as many hydrokinetic energy devices on the site as can effectively capture the ocean or free-flowing water resource, but without creating inefficiencies such as turbines being placed too close together so that downstream turbines suffer from the wake effects of upstream turbines.

Developers will cause a site study to be prepared in order to have the information a lender will need to consider financing the project. The lender, in turn, will have its own independent consultants review the developer's study in detail, and may even commission its own independent study. As with any study of this nature, reasonable experts can have different views as to the proper method for conducting the study, the significance to be attached to particular data points, and the overall conclusions to be drawn. Thus it is not unusual for the lender's and the developer's experts to have extended discussions over the methodology employed and conclusions to be drawn from the collected data.

There always seems to be the temptation—at least for developers of renewable energy projects—to shorten the period over which data relative to the determination of the capacity factor is gathered and studied. For example, some wind projects have been financed based on wind data from a period as short as one year. One must, however, be cautious in proceeding on the basis of studies based on such relatively short time periods, especially when the factors affecting the availability of the motive force are driven by the weather, which can undergo significant variability year to year. Longer-period information provides greater confidence that the capacity factor will be accurate going forward. After all, "one swallow does not a summer make." Although it may be expedient for the developer to move forward with the project based on shorter-period information, reliance on a capacity factor based on inadequate data can be a disaster for the developer as well as for the lender should the actual capacity factor prove to be substantially lower than that planned for.

**F. No Free Fuel.** Because the motive force for marine and hydrokinetic energy projects effectively comes with the site, one might be tempted to conclude the fuel is free. There is, in fact, no line item expense for fuel costs in a hydrokinetic energy project pro forma as there would be with a fossil fuel-fired plant. The fuel costs of such a facility are, however, embedded in the project's capital costs when considered in relation to the project's productivity. Consider the following: If it cost $1 million per MW of installed nameplate capacity to build a gas-fired power plant that can operate at full output 24 hours a day, seven days a week, and it also costs $1 million per MW of installed nameplate capacity to build a hydrokinetic energy facility with a capacity factor of 50 percent, then the cost per MW of the ocean energy facility is essentially twice that of the gas-fired plant, when traced through to the actual electric energy that will be produced.

However, unlike the above example, the capital costs of marine and hydrokinetic energy facilities are significantly higher per MW of installed capacity than most other types of renewable resources. The cost of constructing such projects can only be estimated because, as of the date this chapter was penned, no commercial-scale power purchase agreement has been signed in the United States for a hydrokinetic power project. The cost used by

Energy Focused Resources to model the value of wave power in December 2009[3] ranged from $2.65 million (on the low end) to $3.65 million (on the high end) per MW of installed capacity. By way of contrast, the cost of constructing a wind energy project is approximately $1.8 million per MW and the cost of constructing a gas-fired plant is in the range of $800,000 to more than $1 million per MW of installed capacity.[4] Thus, out of the box, a marine or hydrokinetic energy facility's capital costs are significantly higher than alternative resources. These higher capital costs are one reason why the price for renewable energy is, on average, higher than the cost of energy produced by fossil fuels, and why many renewable energy projects can only be made economically attractive if subsidized by things such as production tax credits and accelerated depreciation.

Thus the choice of renewable energy as fuel source has very real costs. Far from being free, using a renewable as a fuel source results in direct, tangible, out-of-pocket costs currently in excess of costs associated with choosing another, nonrenewable fuel source. Renewable energy will not become an economically free fuel unless the industry evolves to the point when the all-in out-of-pocket costs of producing renewable energy power are equal to or less than the all-in out-of-pocket costs of producing fossil fuel-generated power minus the fossil fuel costs.

Fortunately, the current market price for the electricity produced from renewables (including the "green tags" or environmental attributes sold along with the power, though perhaps to a different buyer than the buyer of the power) is, in many markets, significantly higher than the price for power generated by means of fossil fuels. This differential is a fair proxy for the value of the green tags, and can be viewed as the marketplace's (or, in those markets in which a mandatory renewable portfolio standard is in effect, the state government's) acknowledgment that the environmental benefits of green power have real economic value. It is this differential, along with subsidies such as the production tax credit and, more recently, the Section 1603 grant in lieu of tax credits in the 2009 American Reinvestment and Recovery Act that enable a renewable energy facility to be a viable alternative in the current marketplace. And this differential is likely to grow as competition for renewable energy increases in response to adoption of renewable portfolio and greenhouse emission standards.

**G. Performance Guaranties.** Risk associated with the equipment employed also exists. Because hydrokinetic energy is a variable resource, it is essential that the project produce the maximum amount of electricity from the available ocean or river resource in order to produce the maximum amount of revenue. And this means the equipment used must function as intended and be available when the opportunity to generate electricity arises. As in the project financing of other types of renewable resources, performance risks associated with equipment will be addressed with various guaranties provided by the equipment manufacturer and, to a lesser extent, by guaranties provided by the contractor responsible for installing the equipment.

The following types of performance guaranties (which are typical in connection with other renewable projects) can be expected to be sought in connection with marine and hydrokinetic energy projects:

1. **Mechanical Availability:** The mechanical availability guaranty ensures reliability of the technology—that, from a mechanical standpoint, the technology will be ready to produce electricity whenever

[3] *Utility Market Initiative*, Prepared by Pacific Energy Ventures, LLC on behalf of the Oregon Wave Energy Trust, Task 3.3.1 at 3 (Dec. 2009), *available at* http://www.oregonwave.org/our-work-overview/market-development/utility-market-initiative/ (last accessed Mar. 29, 2011).

[4] The dollar figures quoted in this sentence are current as of spring 2011.

its design conditions are met. In other renewable regimes, as technology has been proved and improved, typical mechanical availability guaranties provide for a guaranty of a mechanical availability percentage of 95 percent or higher in each contract year. To the extent the project falls below the guarantied mechanical availability percentage in a given contract year, the energy technology manufacturer is liable for liquidated damages. Those damages are usually calculated by reference to the cost of replacement power (or cost to cover) in an amount equal to the forgone production due to failure to meet the guaranty.

2. **Guarantied Output:** Although the mechanical availability guaranty is aimed at providing assurance that the technology will be mechanically available to produce electricity, the output guaranty is aimed at ensuring that a certain level of total output (electricity production) will be achieved over time. The output guaranty starts by reference to the project's mean annual output. Mean annual output, in turn, is a negotiated figure usually expressed in terms of a certain number of megawatt hours ("MWh") in each contract year. In existing renewable energy regimes, the output guaranty may be 75 percent of the mean annual output. The guaranty ensures that the average annual output for the calculation period in question (*i.e.,* the actual amount of MWh produced during such period) will be not less than the output guaranty.

As with the mechanical availability guaranty, breach of the output guaranty results in the energy generator manufacturer being liable for liquidated damages calculated by reference to the cost of replacement power (or cost to cover) in an amount equal to the forgone production due to failure to meet the guaranty.

From the developer's standpoint, the output guaranty is a much more risky proposition than the mechanical availability guaranty. The equipment manufacturing typically backstops (in one form or another) the mechanical availability guaranty. But equipment manufacturers are typically not willing to take the risks associated with weather and other factors that can influence the actual output of the project. Aside from design or manufacturing defects, mechanical availability can generally be ensured by proper maintenance of the equipment, whereas no effort of diligence can avoid fluctuations in the availability of usable hydrokinetic motive force caused by things such as the weather.

3. **Power Curve Warranty:** The power curve warranty is aimed at ensuring the efficiency of the technology. A project may meet the mechanical availability and output guaranties, but not be producing as much electricity as it could under the same conditions due to inefficiencies resulting from poor design, manufacture, or installation. To determine compliance with the power curve warranty, one or two energy-generating devices in the project are selected for testing upon completion of construction. Each piece of equipment is tested to determine its actual power curve (how much power the energy-generating device produces under various conditions). As with the other performance guaranties, to the extent the actual power curve of the tested equipment is less than the guarantied power curve, the equipment manufacturer may be liable for liquidated damages calculated by reference to the cost of replacement power (or cost to cover) in an amount equal to the forgone production due to failure to meet the guaranty.

4. **Parent Guaranty:** Performance guaranties from the equipment manufacturer and the construction contractor (or their respective creditworthy parents) are common features that lenders look for in financing renewable energy projects. The terms, duration, and costs of such guaranties are generally matters of intense negotiation. Based on experience with renewable technologies that have come to the fore in recent years,

one can expect that, in order to establish their product in the marketplace, the manufacturers of newer technologies such as wave, tidal, and in-stream power equipment will be more flexible and generous in offering such guaranties while the technology is relatively new than they will as it matures and gains wider acceptance. For example, in the early part of this decade, manufacturers of wind turbines typically offered warranties with terms of five years and at prices that were relatively low. But as the wind technology established itself as generally reliable and the demand for wind turbines rose in 2005 and 2006, the warranty period shrank to two or three years and the price for obtaining the warranties went up dramatically.

**H. Security Arrangements—Creating a Sealed System.** Thus far we have focused on those elements of project finance aimed at vetting the risk associated with the ability of the project to perform to expectations. We now turn to security arrangements for project debt.

In the context of a limited recourse financing, security arrangements are the foundation on which the financing rests, as the lender has recourse only to the project assets and revenues to enforce payment. The lender therefore seeks control (by means of security interests, mortgages, and contract assignments) of all project assets (including all key project agreements) and all project revenues (also by means of security interests, but coupled with lockbox arrangements as described below).

The lender seeks to create a sealed system of security arrangements in which all project assets and revenues are, to the fullest extent possible, sealed off from other creditors, with the lender exercising control over the assets and revenues to ensure they do not escape the system and jeopardize repayment of the debt. This is the essence of the project finance bargain: The lender limits its recourse to the project assets and revenues in exchange for a financing structure that effectively preserves all project assets and revenues for the sole benefit of the lender.

Key aspects of the security arrangements that create the requisite sealed system are:

1. **Power Purchase Agreement:** The power purchase agreement ("PPA") is the core of the credit picture in a project financing; it is the source of all revenues needed to make the project successful. As such, assignment to the lender of the project owner's rights under the PPA forms the centerpiece of security arrangements. In addition to a price for power that will support project operating expenses and debt service based on the expected production (*i.e.,* the capacity factor), lenders have looked for PPAs with the following features:

- *Term:* The term of the PPA (not including renewals) is several years longer than the term of the financing. The additional years provide the lender with "work-out" room in the event the project encounters difficulties during the latter years of the financing, when aging facilities may make problems more likely.

- *Purchaser's Creditworthiness and Credit Maintenance Provisions:* The output purchaser under the PPA must be a creditworthy entity or have its obligations guarantied by a creditworthy entity. Because of their dependence on PPA revenues for repayment of the project debt, lenders often seek credit maintenance provisions. Such provisions hold that if the power purchaser's credit rating falls below a certain level,[5] the power

[5] In lieu of using a credit rating as the trigger, other triggers, *e.g.,* maintenance of a specified level of tangible net worth, are sometimes employed, either by themselves or in combination with a credit rating requirement.

purchaser is required to post collateral to better secure its obligation to pay for the power delivered. In recent years, power purchasers—particularly regulated electric utilities—are generally not willing to provide such credit assurances in the renewable power context, especially when they are acquiring the renewable resource to comply with a locally imposed renewable portfolio standard. But when the purchaser is pursuing a renewable resource on its own motion (as many distributing utilities are doing these days for a variety of reasons that go beyond renewal portfolio standards), one may see a greater willingness to include credit maintenance provisions in the PPA.

- *Reciprocal Credit Maintenance Provisions:* Reciprocal credit maintenance requirements (*i.e.,* in which both the seller and the purchaser agree to maintain a certain credit posture and to post collateral if the posture is not maintained) are common in PPAs for fossil fuel- (gas- and coal-) fired resources. Such provisions are less common in PPAs for renewable power, for several reasons. First, renewable energy facility developers were, historically, independent companies without the substantial financial resources to support a credit maintenance requirement. Second, because renewable energy is a variable resource from which one cannot count on having a given amount of power available for delivery at any given time, the purchaser is not harmed by a failure to deliver in the way it would be, for example, with a gas-fired base-load resource that can be counted on to deliver a given amount of power 24 hours a day, seven days a week.

  Some project lenders may not favorably view a renewable energy PPA requiring the project owner to agree to a credit maintenance requirement. The reason for this is that at the very time the project owner is encountering financial difficulties (reflected in the credit rating downgrade that serves as the trigger for the credit maintenance provision), it may be called on to post additional collateral as security for its PPA obligations—collateral that it may not have available or that will further undermine its financial position if posted as required. The result is a default under the PPA that can give the power purchaser a right to terminate. Risk of termination may not be welcomed by the lender, which is keenly interested in seeing that the power purchaser has the ongoing obligation to purchase power during the entire PPA term (or at least until the project debt is fully repaid).

- *Security Provided by Project Owner:* There is a growing trend in many markets for the purchasing utility to require that the owner of the renewable energy project post cash, a letter of credit, or a guaranty from a creditworthy entity as security for its obligations under the PPA. Although this has long been a fairly standard feature of PPAs for the output of thermal plants, it is a relatively new development for renewable energy projects. Although initially exempted from such requirements, as renewables such as wind have become more established, many purchasing utilities have begun to insist on these collateral requirements as a matter of course. It remains to be seen whether the fact that marine and hydrokinetic energy projects are in their very early stages of development will cause purchasing utilities to relax or forgo this sort of collateral requirement as they did in the early days of wind. If such collateral is required, it will present another challenge to integrate it into the project financing.

- *Provisions Recognizing Lender's Rights:* The PPA should provide that the output purchaser authorizes the project owner to assign the owner's rights under the PPA to the lender as security for the project debt and recognizes the right of the lender to cure defaults and perform the owner's obligations under the PPA.

- *Transmission Curtailment Risk:* Although not universally required, a PPA provides better security for the lender (and better revenues for the project owner) if it shifts risk of transmission curtailment to the output purchaser. This is done by providing that, during periods of transmission curtailment, the output purchaser will be obligated to pay for the power that would have been produced and delivered (based on environmental conditions during the curtailment period) had the curtailment not prevented the plant from operating. Based on recent developments in the wind energy area, purchasing utilities are less willing to assume the curtailment risk than they have been in the past. If this trend carries over to marine and hydrokinetic energy projects, it will place a further burden on the economic viability of projects, making interconnection with a constraint-free transmission system all that more important.

2. **Assignments of Key Contracts and Permits:** To ensure that it has control (via the security arrangements) over the entire project as a going concern, the lender will also require first-priority assignments of all key project contracts and permits. On the contract side, this requirement could include energy-generation device supply agreements, construction contracts, interconnection agreements, parts supply agreements, equity contribution agreements among the owners of the project owner, operation and maintenance ("O&M") agreements (if the energy facility is to be operated by a third-party operator), leases or rights-of-way for the project site, and, of course, the PPA.

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

It can be more problematic to obtain a valid and enforceable assignment of a needed project permit. Under applicable law, a permit is often granted to a specific entity (*i.e.,* the project owner), without a provision for assignment of the permit to a third party. Sometimes the very nature of the permit is such that it may no longer be valid in the hands of anyone other than the original permittee. To resolve that problem, the lender may take a first-priority security interest in the equity ownership interests of the project owner (*e.g.,* the stock of the project owner if it is a corporation, or the membership or partnership interests in the project owner if it is a limited liability company or partnership). Thus, in a foreclosure situation, the lender forecloses on the equity ownership interests, taking over ownership of the project owner and the permits held by the project owner; the permits themselves are never transferred from one entity to another. This succession may still require some action on the part of the lender to effectively complete the foreclosure. It nevertheless provides a path for the lender that may not otherwise be available (or be subject to significant legal doubt) were it to attempt to foreclose directly on a security interest in a permit.

3. **Flow of Funds and Lockbox Arrangements:** The final piece of the puzzle needed to create a sealed system to protect the lender is creation under the credit agreement of a flow of funds (often called a "waterfall") and an accompanying lockbox arrangement. The purposes of these provisions are to require that project revenues be applied in a manner that will ensure timely repayment of project debt, and to place the lender in the position of controlling the revenues to see that they are, in fact, so applied.

A lockbox arrangement requires all persons making payments to the project owner under the project agreements to pay those amounts into an account controlled by the lender. Thus all PPA payments flow directly into this account, as do warranty or liquidated damage payments under the energy-generation device supply agreement and balance of plant contract. Typically, the account in question is an account established with the lender itself, if the lender is the type of financial institution capable of handling such an account. Alternatively, the account may be established with a third-party financial institution, in which case the lender's rights with respect to the account will be memorialized pursuant to a custodian agreement among the lender, the project owner, and the custodian financial institution.

It is the flow-of-funds, or waterfall, provisions in the credit agreement that govern the lender's (and, by negation, the project owner's) rights with respect to the project revenues captured by the lockbox arrangement. Given that under limited recourse financing the project debt will be repaid only if the project operates more or less according to projections, the flow-of-funds provisions generally specify a priority of application of project revenues that has as its primary goal the maintenance of the project operations so that the project will continue to produce power and earn the needed revenues from power sales. It does this in part by directing the project revenues first to those expenses needed to keep the project operational, and in part by requiring the funding of various subaccounts in a manner that will, in effect, create reserves to protect against adverse events that could interrupt the flow of project revenues.

Monies are paid out of the lockbox in accordance with the priorities, or waterfall, established under the credit agreement. Disbursement of lockbox monies is made against a requisition presented by the appropriate party (the project owner or the O&M operator), accompanied by the relevant invoices documenting expenditures for which disbursement is sought. It is not unusual for the lender to remit lockbox monies directly to the party to whom they are owed, to avoid misapplication by the project owner or O&M operator.

A typical flow-of-funds provision will provide that project revenues will be applied for the following purposes in the order of priority set forth below:

- *O&M Expenses:* Project revenues are first applied to payment of the ongoing O&M expenses of the project. For this purpose, O&M expenses are generally defined to capture cash outlays the project must make to stay operational, and to exclude noncash items such as depreciation expense. A typical flow-of-funds provision will, over time, trap project revenues in the O&M subaccount until an amount (or reserve) equal to six months' O&M expenses is on hand.

- *Debt Service:* Project revenues are next applied to payment of debt service on the project debt. Again, typical flow-of-funds provisions will, over time, capture project revenues at this level of the waterfall until the debt service subaccount has on hand an adequate debt service reserve amount (typically six months' debt service on the project debt, but sometimes as much as one year's worth).

- *Reserves:* Project revenues are next deposited into various reserves, which typically include a major maintenance reserve account and a debt service reserve account. For projects that may be subject to unpredictable increases in operating costs (for example, the price of natural gas in connection with a gas-fired project), an operating or liquidity reserve may also be required. Debt service reserves are typically required to be funded at financial closing, most often out of the proceeds of the debt financing. Other reserves, such as a major maintenance reserve, may be allowed to be funded over time out of project revenues in amounts such that sufficient funds will be on hand to pay for anticipated items of major maintenance on project assets and to provide a source of funding to cover the cost of major unanticipated equipment failures.

- *Distributions to the Project Owner:* Finally, any remaining project revenues are deposited in a subaccount that is variously called a "sweep account," a "distribution account," or a "surplus cash account." Subject to restrictions imposed under the credit agreement, project revenues that end up at this level of the waterfall are available for distribution to the project owner. Generally such distributions are permitted only on a quarterly basis, and then only to the extent the subaccounts higher up in the waterfall are fully funded at the time of the proposed distribution and there is no default under the credit agreement.

**IV. Conclusion.** A great many more topics could be covered under the heading of marine and hydrokinetic project finance, including insurance requirements, integration of third-party equity investments into the debt financing structure, monetization of production tax credits, transmission and imbalance charges, and details of force majeure provisions in PPAs and other major project agreements. The foregoing treatment provides a framework for approaching these and other topics, for the essential dynamic is the search for credit and the corresponding effort to reduce or eliminate risk.

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Doug Batey is a partner in the firm's Seattle office with broad experience advising companies and executives on legal and business issues, including mergers and acquisitions; corporate, securities and commercial law; and corporate governance. His practice experience also includes commercial contracts and business disputes, as well as the protection, licensing and distribution of technology and intellectual property. Doug is also the primary author of the firm's blog concerning the law of limited liability companies (www.llclawmonitor.com).

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Jennie Bricker is a partner and practices natural resources law, with a focus on water law, waterways, and wetlands. Recognized as one of the state's experts on navigability for title, Jennie advises riparian property owners about their rights to submerged and submersible lands on Oregon waterways. She also assists clients in obtaining permits under Clean Water Act Section 404 and the Oregon Removal-Fill Law.

Law clerk, the Honorable Otto R. Skopil, Jr., Ninth Circuit Court of Appeals (1997 98); legal systems administrator (1994-1997), editor (1992-1994), Dark Horse Comics, Inc.; assistant editor, Spectroscopy magazine (1991-1992); lecturer in English, University of Maryland, European Division (1989-1990); Graduate Teaching Fellow in women's studies, University of Oregon (1986-1988).

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Prior to joining Stoel Rives, Bill practiced corporate finance and mergers and acquisitions with Baker & McKenzie in New York and Hong Kong.

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Bill Holmes is a partner of the firm and immediate past chair of the renewable energy initiative. Bill concentrates his practice in the area of energy law, with a special emphasis on wind, geothermal, biomass, tidal and ocean power, and other forms of renewable energy. He also has extensive experience with real estate law, water law, and general corporate transactions.

Bill represents clients in the negotiation of major power purchase agreements on both the "buy" and the "sell" sides. This experience includes work on numerous major wind and renewable energy power purchase agreements.

Bill also advises clients in the negotiation of acquisition agreements for energy assets and companies, EPC agreements, O&M agreements, management agreements, LLC agreements, energy project development agreements, fuel supply agreements, and related documentation. He has represented renewable energy clients in negotiations with a range of counterparties, including Idaho Power, PacifiCorp, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Snohomish PUD (SnoPUD), Sacramento Municipal Utility District (SMUD), Public Service Company of Colorado (PSCO), Kansas City Power & Light, and Southern California Public Power Authority (SCPPA).

Bill joined Stoel Rives as an associate in 1985 and has been a member of the firm since 1992. Before joining the firm, he served as law clerk to Judge Louis F. Oberdorfer, United States District Court for the District of Columbia (1984-1985).

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Greg Jenner is a partner in the Tax practice group. Before returning to Stoel Rives in 2008, Greg served 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, including all legislative proposals, regulatory guidance and tax treaties. The Office of Tax Policy is also responsible for providing the official estimates of all federal government receipts for the President's budget, fiscal policy decisions and Treasury cash management decisions.

Greg has broad experience in virtually all federal tax matters, with particular focus on planning and implementing complex tax-related transactions, partnerships and joint ventures, and mergers and acquisitions. He has worked extensively on energy-and insurance-related tax issues, and has successfully represented taxpayers in federal and state tax controversies, in both audit and litigation. At Stoel Rives, Greg has increasingly focused on planning for renewable energy projects, particularly the incentives enacted as part of the American Recovery and Reinvestment Act of 2009. Greg is a frequent speaker on renewable energy tax planning, agriculture tax issues, and tax and budget policy.

In addition to his most recent service at Treasury, Greg has been active for many years in the federal tax policy process. Prior to his 10 years in private practice from 1992 to 2002, Greg served as Special Assistant to the Assistant Secretary of the Treasury (Tax Policy) (1989-1992). He also served as Tax Counsel for the U.S. Senate Committee on Finance (1985-1989), where he was proud to help write the Tax Reform Act of 1986.

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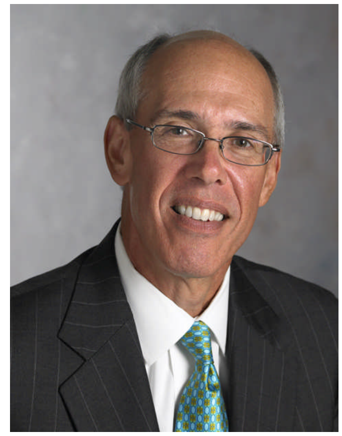


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Jason Johns is an associate in the Energy Development group where he focuses his practice on energy regulation before the Federal Energy Regulatory Commission (FERC) and state utility commissions, electric reliability issues, transmission development and policy, and natural gas transportation and distribution agreements. His clients include owners, investors and developers throughout the energy industry, with particular emphasis on the wind, natural gas, solar, geothermal, biomass and hydropower sectors. Jason has worked on wind integration rate cases in the Pacific Northwest, and he also has significant experience in drafting and negotiating power purchase agreements. In addition, Jason is registered as a patent attorney before the U.S. Patent and Trademark Office and his work with energy clients is informed by his passion for chemistry, physics, and engineering.

Recently, Jason co-authored two white papers for the Energy Foundation, a partnership of major foundations interested in sustainable energy. The white papers discuss potential solutions to the barriers to transmission development in the Western Interconnection, and Jason spoke on this topic to energy industry and political leaders at the 2010 annual meeting of the Western Governors' Association.

Prior to his legal career, Jason worked as a pharmaceutical chemist specializing in the purification and development of synthetic adjuvants—pharmacological agents that modify the immune system's response to a vaccine. As a chemist, Jason also assisted a non-profit effort led by the Bill and Melinda Gates Foundation to develop a method for purifying a vaccine used to treat leishmaniasis, a disease particularly prevalent in developing countries.

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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. Patent and Trademark Office

STOEL RIVES LLP
ATTORNEYS AT LAW

# Adam C. Kobos

**Experience**

Adam Kobos is a partner in the Tax section of the firm's Benefits, Tax and Wealth Management group. His practice encompasses a wide variety of federal and state tax issues, including:

- Taxable and tax-free corporate mergers and acquisitions;
- Transactions involving partnerships, S corporations, limited liability companies and other pass-through entities;
- Tax aspects of compensation arrangements, including stock options, restricted stock, and bonus plans;
- Debt and equity offerings and other financial transactions;
- Tax controversy matters; and
- State and local tax aspects of transactions.

Adam regularly represents clients who develop or invest in renewable energy projects, including wind, solar, biomass, hydroelectric and other renewable energy generation facilities and biofuel production facilities. His renewable energy practice focuses on federal, state and local tax incentives and transaction structures that enable both developers and investors to maximize the value of those incentives.

To learn more, please visit: www.stoel.com/adam_kobos

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**Education**

- Stanford Law School, J.D., 2002
  Order of the Coif
- Harvard University, A.M., 1998
- Amherst College, A.B., 1995, *summa cum laude*
  Phi Beta Kappa

**Admissions**

- Oregon
- California
- U.S. Tax Court

# Charles S. Lewis, III

**Experience**

Carl Lewis is a partner of the firm practicing in the Seattle office. Carl's practice focuses primarily on federal income tax, particularly with respect to planning and implementing sophisticated tax-motivated transactions, partnerships and joint ventures, financial instruments, and mergers and acquisitions. Carl has represented owners, developers, operators, buyers and sellers for over 25 years in tax-critical transactions ranging from partnerships, joint ventures and LLCs with skewed tax allocations, to leveraged leases, to multi-billion-dollar mergers. These projects have included cogeneration projects, biomass generators, coal and gas-fired plants, synthetic fuel projects, wind plants and biofuels projects, and have been located throughout the United States and in Europe, Australia, The Philippines and South America. Recently, Carl assisted a client in creating, designing and implementing a sale and leaseback structure to monetize the remainder of nearly $12 million in Oregon pollution control tax credits. Subsequently, Carl helped the company use this structure again—with the addition of a complex lessee partnership, O&M agreement and operating agreement to bring in an additional tax credit investor when the original investor's tax appetite was insufficient—to monetize an additional $17 million in tax credits with respect to another facility.

Carl joined Stoel Rives in 1978 and is Tax Counsel for the firm.

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**Education**

- Willamette University College of Law, J.D., 1978, *magna cum laude*
  CJS Award (1976-1978)
- Lewis and Clark College, B.S., 1975, *magna cum laude*
  Delta Mu Delta, business honorary, OSCPA Accounting Student of the Year, 1975
- University of Southern California, 1971-1972

**Admissions**

- Washington
- Oregon
- U.S. Tax Court

# Robert T. Manicke

**Experience**

Robert Manicke practices in the firm's Portland office. He is the firm's lead partner for state and local taxation, and his practice also emphasizes employment tax matters. He regularly represents clients in the Oregon Tax Court and before state revenue authorities, the Portland Revenue Bureau and the Internal Revenue Service.

His transactional practice includes state and local tax incentives, state and federal tax rulings, and state and local tax legislative projects. He has extensive experience with energy-related tax incentives, including the Oregon Business Energy Tax Credit, the Strategic Investment Program and the Enterprise Zone Program. Robert also represents health care clients in matters relating to tax exemption, employment tax and insurance tax.

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**Education**

- University of Illinois College of Law, J.D., 1992, *summa cum laude*
  Order of the Coif
  Board of Editors, *University of Illinois Law Review*
- Willamette University, B.A., 1984, *cum laude*

**Admissions**

- Oregon
- California
- Washington

**Languages**

- Dutch
- German

STOEL RIVES LLP
ATTORNEYS AT LAW

# Chad T. Marriott

**Experience**

Chad Marriott is an associate in the Energy Development group, where he is an active member of the firm's Ocean and Hydropower, Wind, and Solar Energy Initiatives. Chad engages with project developers on a variety of matters ranging from the drafting and negotiation of joint development agreements, membership interest purchase agreements, real property instruments, and power purchase agreements to advising on permitting and licensing issues for new hydropower and hydrokinetic projects under Part I of the Federal Power Act. His clients include owners, investors, and developers- including both independent power producers and electric utilities. Chad is currently a board member of the Ocean Renewable Energy Coalition ("OREC") and has served as a vice chair for the Hydro Power Committee of the American Bar Association's Section on Environment, Energy, and Resources.

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 energy and tidal energy project development and contributed to the *Siting Methodologies for Hydrokinetics* handbook published on behalf of the U.S. Department of Energy in 2009.

Chad also served as a legal research and writing tutor, University of Oregon, 2007-2009; summer associate, Stoel Rives LLP, 2008; legal intern, House Committee on Oversight and Government Reform, U.S. House of Representatives, Washington, D.C., 2007; and law clerk, U.S. Department of Justice, Environment & Natural Resources Division, Sacramento, 2007.

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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*
  Senior Associate Editor, *Oregon Law Review*
  Fredric R. Merrill Award, *Oregon Law Review*, 2009
- Indiana University, M.S., 2005
- University of Utah, B.A., 2001

**Admissions**

- Oregon

STOEL RIVES LLP
ATTORNEYS AT LAW

# Jennifer H. Martin

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**Experience**

Jennifer Martin is a partner of the firm practicing in the Energy Group and Renewable Energy Initiative. Her practice focuses primarily on representing renewable energy developers in the negotiation of major power purchase agreements on both the "buy" and the "sell" sides. This experience includes work on many major wind power purchase agreements. Jennifer also advises developers in navigating the regulatory timelines and obligations for securing interconnection agreements and transmission agreements, and negotiating interconnection agreements in organized markets such as PJM, the Midwest ISO and SPP, and with individual utilities. Jennifer also represents renewable energy clients on a variety of energy-related regulatory matters before state and federal agencies. She has experience before state public utility commissions in the Western United States and the Federal Energy Regulatory Commission representing both utility and independent power producer interests.

She has represented renewable energy clients in negotiations with a range of counterparties, including the Tennessee Valley Authority (TVA), Pacific Gas & Electric (PG&E), Bonneville Power Administration (BPA), Sacramento Municipal Utility District (SMUD), Northern States Power (NSP), Salt River Project (SRP) and Northern Indiana Public Service Company (NIPSCO).

Judicial Clerk, Minnesota Supreme Court, 1999-2000; Senior Note and Comment Editor, *Journal of Gender Race and Justice* at University of Iowa College of Law, 1998-1999; summer law clerk, Stoel Rives, 1998; research assistant, Professor David Baldus, University of Iowa College of Law, 1997-1999; clerk, Circuit Court of Cook County, 1993.

To learn more, please visit: www.stoel.com/jennifer_martin

**Education**

- University of Iowa College of Law, J.D., 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 Circuit
- U.S. Court of Appeals for the D.C. Circuit
- United States Supreme Court

# Sean E. McCarthy

**Experience**

Sean McCarthy is of counsel in the Corporate practice group. He served as the managing partner for the firm's California offices. Sean's legal practice focuses on the formation and licensing of underwritten title companies, the qualification of title insurance companies applying to conduct business in California and other states, title insurance/escrow litigation, and advocacy before the California Department of Insurance, California appellate courts, the California Supreme Court and the United States Supreme Court. Sean also has extensive involvement with legislative and insurance regulatory matters as well as major civil litigation pertaining to wetlands. Sean has authored numerous articles and has lectured frequently on real property and title insurance matters.

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**Education**

- University of California, Davis, J.D., 1970
- California State University, Hayward, B.A., 1967

**Admissions**

- California
- U.S. District Courts for the Eastern and Northern Districts of California
- U.S. Supreme Court

STOEL RIVES LLP
ATTORNEYS AT LAW

# John A. McKinsey

**Experience**

John McKinsey is a partner of the firm representing energy and industrial clients. He serves as lead counsel for the siting of major industrial development projects in California. Over the course of his career, John has completed over $2B in plant infrastructure projects. In addition, he provides extensive leadership and guidance in the areas of compliance and regulatory matters involving products, facilities and operations. John has represented clients before numerous regulatory agencies including the California Energy Commission, California Air Resources Board, California Department of Fish and Game, State Lands Commission, United States Department of Fish and Wildlife, the California Coastal Commission and numerous regional governmental agencies including air quality districts, water boards, cities, and counties. He has extensive experience in the regulation of air quality, public health, marine and aquatic biology, environmental justice, visual impacts and electrical power transmission, interconnection and congestion.

John gained significant engineering and applied science knowledge and skills while serving in the United States Navy on submarines as a nuclear power plant operator and supervisor and leading electrician. His background enables him to readily understand industrial, technical, chemical, and energy related processes, facilities and issues and translate them with clarity for other parties and governmental agencies.

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**Education**

- University of California, Davis School of Law, J.D., 1999
- California State University, Sacramento, B.A., 1996, cum laude, Economics

**Admissions**

- California
- U.S. District Court, Eastern and Northern Districts of California

STOEL RIVES LLP
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# Alan R. Merkle

## Experience

Alan Merkle is Chair of the firm and a member of its Energy Development practice group. He concentrates his practice primarily on energy and infrastructure, with particular focus on project development transactions and related matters.

Alan regularly leads due diligence teams in mergers and acquisitions of energy projects and companies; drafting and negotiating project specific power generation equipment supply, operation and maintenance; and warranty, balance of plant and EPC construction agreements. Alan serves as a strategic advisor to numerous company Boards regarding targeted growth and strategic initiatives. Representative clients include developers, owners, engineers, contractors, manufacturers and suppliers, including a large number of leading wind project developers, as well as major players in the biofuels, ocean energy and traditional thermal and nuclear power industries.

Alan also handles complex claims, litigation, arbitration, mediation and other alternative dispute resolution matters for a broad range of clients. In addition to his advocacy work, he regularly serves as a neutral on Dispute Review Boards and as a mediator and arbitrator. Prior to practicing law, Alan managed the technical and business sides of major energy, construction, engineering, and manufacturing operations, including 12 years with General Electric Company. He is a registered professional engineer in Washington, Oregon and Idaho.

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## Education

- Northwestern School of Law of Lewis & Clark College, J.D. 1982, *cum laude*
  Cornelius Honor Society
  Certificate of Environmental and Natural Resources Law, 1982
  Associate Editor, *Environmental Law*
- University of Idaho, M.B.A., 1971
- University of Idaho, B.S., Mechanical Engineering, 1969
- Boise State University, A.S., Civil Engineering, 1967

## Admissions

- Washington
- Oregon

# Michael P. O'Connell

**Experience**

Michael O'Connell's practice focuses on energy, environmental and Indian law. Michael has assisted wind, solar, ethanol, wave and tidal hydrokinetic and conventional hydropower energy developers, gas-fired generation, oil and gas exploration and gas pipeline clients. Michael has assisted these clients in siting and permitting matters, including NEPA reviews, endangered species consultations, 401 water quality certifications, wetlands permitting and mitigation, stormwater permitting, and coastal zone management consistency determinations.

Michael's energy law practice draws upon more than 30 years experience in Indian law to assist clients on a broad array of matters, including energy projects located outside and on Indian reservations, permitting and operation of projects affecting tribal interests, new and renewed rights of way over tribal lands, treaty and executive order fishing right and ceded lands issues, real estate transactions including leases, taxation, employment, negotiating waivers of tribal sovereign immunity, settlements, risk assessments and litigation. In 2005, the Washington Supreme Court upheld action by the Washington Utilities and Transportation Commission allowing PacifiCorp to recover in rates costs of a tax by the Yakama Indian Nation. Michael argued that case for PacifiCorp.

Prior to joining the firm, Michael was General Counsel to the Hopi Tribe and served in the Office of Reservation Attorney for the Confederated Tribes of the Colville Indian Reservation and Quinault Indian Nation.

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**Education**

- University of Denver College of Law, J.D., 1977
  Editor-in-chief, *Denver Law Journal*
  Order of St. Ives
- Brockport State College, B.A., political science, 1969

**Admissions**

- Washington
- Colorado
- Arizona
- U.S. District Courts of Washington, Arizona and Colorado
- U.S. Court of Appeals for the Ninth Circuit
- U.S. Court of Federal Claims
- U.S. Supreme Court
- Puyallup Tribal Court
- Tulalip Tribal Court

# Cherise M. Oram

**Experience**

Cherise Oram is a partner in the Environment, Land Use and Natural Resources practice group. She focuses her practice on federal environmental and natural resources law with an emphasis on endangered species and energy facility permitting and compliance issues. Cherise has extensive experience on issues arising under the Endangered Species Act, Federal Power Act, Marine Mammal Protection Act, Magnuson-Stevens Fishery Conservation and Management Act, National Environmental Policy Act, Clean Water Act and Administrative Procedure Act. Representative clients include developers and owners of hydropower dams, wave and tidal energy projects, wind energy projects, liquid natural gas (LNG) facilities, and oil and gas facilities in complex permitting matters. She formerly worked in the National Oceanic and Atmospheric Administration's Office of General Counsel representing the National Marine Fisheries Service (NOAA Fisheries Service) on endangered salmon, hydropower dam, and forestry issues in California.

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**Education**

- Law & Marine Affairs, University of Washington School of Law, LL.M., 1998
- American University, Washington College of Law, J.D., 1997
- University of Washington, B.A., 1993

**Admissions**

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

# Kevin T. Pearson

### Experience

Kevin is a partner of the firm practicing in the Tax section of the firm's Benefits, Tax and Wealth Management group. 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.

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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

STOEL RIVES LLP
ATTORNEYS AT LAW

# John A. Rafter, Jr.

**Experience**

John Rafter is a partner of the firm practicing in the Intellectual Property group. His background includes experience obtaining patents for clients in a wide range of technology fields such as mechanical, optical systems and bar code scanning, medical products, cleantech and wind, computer technology and software, internet/business method, motion picture/video equipment and lighting. He is experienced in managing major client patent portfolios, preparing patent opinion letters and negotiating licenses. He has also represented clients in enforcing or defending intellectual property rights via patent, trademark and trade dress litigation in several districts of the federal courts, patent interference proceedings before the U.S. Patent and Trademark Office Board of Appeals and Interferences and trademark opposition proceedings.

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**Education**

- Loyola Law School of Los Angeles, J.D., 1986
- University of Notre Dame, B.S. Mechanical Engineering, 1979

**Admissions**

- Oregon
- California
- U.S. Patent and Trademark Office
- U.S. District Court for the Central and Northern Districts of California
- U.S. District Court, Oregon
- U.S. Court of Appeals for the Ninth Circuit
- U.S. Court of Appeals for the Federal Circuit

STOEL RIVES LLP
ATTORNEYS AT LAW

# Ethan I. Samson

**Experience**

Ethan Samson is an associate in the Corporate practice group. He represents and advises public and private companies with respect to mergers and acquisitions, securities law compliance, debt and equity financings and general corporate matters.

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**Education**

- Lewis & Clark Law School, J.D., 2007, *cum laude*
  Managing editor, *Lewis & Clark Law Review*
  Certificate in business law
  Dean's list (all semesters)
- Hobart College, B.A. urban studies, 2000
  Minor in American history
  Editor-in-chief, *The Herald* student newspaper
  Member of the Chimera Society

**Admissions**

- Oregon

# Mary G. Sennes

**Experience**

Mary Sennes is an associate of the firm practicing in the Corporate group. She provides advice and assistance to clients in a variety of business transactions including mergers and acquisitions, public and private offerings of securities and, general securities law compliance contract negotiations. Mary's experience ranges from complex billion dollar merger and acquisition transactions to counsel for start-up companies. Mary works with attorneys in specialty areas throughout the firm to ensure comprehensive and efficient solutions for her clients.

To learn more, please visit: www.stoel.com/mary_sennes


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**Education**

- William Mitchell College of Law, J.D., 2004, *magna cum laude*
  Assistant Editor, *William Mitchell Law Review*, 2003-2004, Staff Member, 2002-2003
- University of Notre Dame, B.A., 2000, *cum laude*

**Admissions**

- Minnesota

STOEL RIVES LLP
ATTORNEYS AT LAW

# Marcus Wood

## Experience

Marcus Wood is a partner and Chair of the Energy Development practice group. He focuses his practice on energy provider and energy facility developer clients. Marcus has extensive experience representing independent power company owners of conventional and renewable energy projects, as well as regulated electric, natural gas and water utilities. He practices before the Federal Energy Regulatory Commission and before utility regulatory bodies in the states of Oregon, Washington, California, Idaho and Wyoming, in investigations and in rate proceedings, and has been a leader in efforts to create Regional Transmission Organizations.

Marcus has represented numerous parties in the acquisition and financing of interests in, and in the disposition of, the output from cogeneration and other conventional electric generation facilities, as well as wind-powered and geothermal energy resources. He regularly assists clients on the structuring of energy projects and the operating contracts, power sales contracts and transmission contracts required for such projects. He also has extensive experience advising sellers, purchasers and exchangers of electric capacity and energy, as well as advising both transmission service providers and purchasers of electric transmission and related services.

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## Education

- Yale University Law School, J.D., 1974
- Vanderbilt University, B.A., 1969, *cum laude*
  Phi Beta Kappa

## Admissions

- State bar of Oregon
- U.S. District Court
- U.S. Court of Appeals for the Ninth Circuit
- U.S. Court of Appeals for the District of Columbia Circuit

STOEL RIVES LLP

ATTORNEYS AT LAW

# Stoel Rives Supports Renewable Energy

Stoel Rives purchases Renewable Energy Credits known as RECs or “green tags” to offset 100 percent of its firmwide electricity usage. The emissions that are avoided through this green power purchase is roughly equivalent to the annual greenhouse emissions from 1,208 passenger vehicles or 748,617 gallons of gasoline. We purchase our RECs from firm clients 3Degrees and Bonneville Environmental Foundation. With our green power purchase commitment, we are one of the first law firms nationwide to qualify as a member of the U.S. EPA Green Power Partnership’s Leadership Club and the ABA-EPA Law Office Climate Challenge programs.

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3Degrees Bringing Climate Solutions Down To Earth

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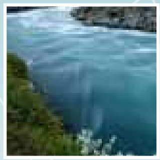
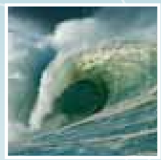
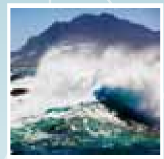
# MARINE AND HYDROKINETIC ENERGY
A Guide to Business and Legal Issues

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*The Law of Marine and Hydrokinetic Energy 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 nearly 400 attorneys in seven states.*

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

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*Alaska California Idaho Minnesota Oregon Utah Washington*