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Offshore wind power in the US: Regulatory issues and models for regulation

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ABSTRACT

The first offshore wind farm became operational in 1991 in Vindeby, Denmark. By 2008, large offshore wind farms had been built in Denmark, the UK, the Netherlands, Ireland, and Sweden with a total capacity of 1200 MW. Offshore wind farms have the potential to generate a significant fraction of US electrical consumption, but the US currently lacks offshore wind farms and is still developing a regulatory system. At the state level only Texas has a leasing system for offshore wind. Since all offshore land is the property of the state and cannot be legally developed without a lease from the government, these absences have stalled development. We review and compare regulatory and leasing systems developed in Europe and the US to inform a discussion of the major issues associated with the development of an offshore leasing and regulatory system. We focus on the tradeoffs between encouraging a sustainable energy source and ensuring environmental protection and public compensation. We conclude that there are likely multiple effective methods of regulation.

1. Introduction

Onshore wind energy is experiencing rapid growth in the US and around the world (Wiser and Bolinger, 2008) and offshore wind energy development is experiencing rapid growth in Northern Europe, yet despite significant potential, there are currently no offshore wind parks in the waters of the United States or Southern Europe. In part, this is due to the superior winds and shallow waters of the Baltic and North Seas, and the subsidies offered by European governments to offshore wind developers, but the lack of a comprehensive regulatory system in the US and several European countries may also be slowing development.

Several European countries as well as some US coastal states and the US federal government are developing regulations for offshore wind power (Eberhardt, 2006). In US federal waters (between 3 and 200 nautical miles from shore), the Minerals Management Service (MMS) is the lead agency in coordinating offshore wind development. The Energy Policy Act of 2005 gave the MMS authority to lease offshore wind energy on the Outer Continental Shelf (OCS). In December 2007, MMS published its Record of Decision (ROD) in response to the programmatic Environmental Impact Statement (EIS) on alternative energy uses on the OCS (Luthi, 2007), and in July 2008, MMS proposed regulations for an offshore alternative energy program and asked for public comments. In April 2009 MMS released final regulations for an offshore renewable energy program.

The regulatory system most applicable to offshore wind energy may be the regulation of the offshore oil and gas industry since in both cases private developers seek to produce energy, a commodity needed by the public, through the use of public marine resources. However, there are significant differences between these two industries. In the offshore wind industry, developers must take out large loans and spend several years before any revenue is generated. When they do begin generating income, the income will be spread out slowly over many decades, and the risk to revenue stream can come from many sources—environmental, market and regulatory. The difference between the cost and sales price of offshore wind energy is quite low. In contrast, the offshore oil industry, although requiring significant capital, generally produce large amounts of revenue quickly and recoup initial investments within the first few years of production. Additionally, while the price of oil is highly variable, the ratio of sales price to cost is far higher than it is for offshore wind energy. As a result, regulations, especially the production of site specific EISs and lease fees that may have little impact on the oil and gas industry, could cripple the offshore wind industry (Schellestede, 2008).

The major issues regulators will have to address include: (1) lease terms and conditions, including phases of development rights, lease fees, and the length of leases; (2) competition and the approval process, including how to select sites and what criteria to use in permitting leases; (3) environmental impact assessments, including data requirements and alternative methods for National Environmental Policy Act (NEPA) compliance; (4) monitoring operational issues, including safety and environmental compliance; and (5) ensuring decommissioning. A brief synopsis of the ways in which several regulatory authorities have dealt with these regulatory issues is summarized in Table 1.

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Table 1
Major lease terms and components for selected offshore wind regulatory authorities.

Major issue	UK	Denmark	BLM (onshore)	Texas	MMS (proposed)
Lease terms: leasing fees and royalties, phased access	Developers pay application fee of £2500 and one time lease fee of up to £500,000 depending on size of site. Developers are eligible for capital grants; exempt from climate change levy (4.3 p/kWh), can sell renewable obligation credits (5 p/kWh; Toke, 2007)	Price of electricity agreed upon in tender. Recent tender price 13.2 c/kWh. No phased access. Lessees have three years from lease to construct wind farm	Phased access system granting data collection and competitive exclusion rights. Fee for commercial development $2365 per MW of capacity	Phased access in which developer has right to terminate lease. $20,000 phase 1 fee and 3.5–5.5% royalty during operation	First five years of lease used for assessment. Royalty rates and bonus bids vary competitively
Term limit	40 or 50 years with a renegotiation after 20 or 25 years	25 years	None	30 years	30 years
Competitive process	Government selects sites with input from developers. Process has preceded in rounds, not unlike MMS five year plans	Set lease areas and hold competitive bidding	First come-first served basis. Competing applicants encouraged to form cooperative agreement	Set lease areas and hold competitive bidding	Competitive auction for sites with competitive interest. Use highest bonus bid or royalty rate
Approval criteria	Feasibility of development plan	Lowest feed in price per kWh		Highest bidder	Highest bidder
Environmental analyses	BERR completed SEA for areas to be leased. Developers complete EIS for sites	Developer conducts site specific EIS after competition. Exceptions may be made by DEA	Use CX's for data monitoring and EA for commercial development. Occasional use of EIS	Has to comply with COE NEPA requirements. Has to conduct avian and bat studies if EIS is not required	Multiple opportunities for environmental analysis. Site specific EIS usually required
Operational issues: environmental and compliance monitoring, safety	Developers conduct monitoring and submit reports	Each developer submits operational plans and conducts their own environmental monitoring	Little discussion of operational issues	Monitoring conducted by lessee with reports issued to state	Developers conduct monitoring according to approved plan and issue reports. MMS conducts inspections
Decommissioning	Surety bonds or other financial instrument required. Allow for repowering or reuse of facilities	Developer must submit approved financial guarantee to DEA	Bonds are required; amount of bond determined on site specific basis	Surety bonds, cash deposit or letter of credit required	Surety bond or other guarantee required. Detailed decommissioning plan does not need to be submitted until two years before end of lease

The purpose of this paper is to discuss the ways in which regulators could encourage the development of an offshore wind power industry that is economically viable and that considers the ecological costs and ensures public benefits. This paper does not deal with the various laws with which a regulatory system would have to comply; for these issues we direct the reader to Santora et al. (2004) or Firestone et al. (2004). While it will be a challenge for regulators and developers to negotiate this complex milieu of already existing laws and regulations, we focus on the leases for offshore wind and their regulations.

When establishing a regulatory system it is often difficult to quantify the costs and benefits involved and to create a system that is comprehensive, yet flexible and robust to future uncertainty. All regulations are a series of tradeoffs in which regulators must balance conflicting policy goals. In the case of offshore wind, regulators must balance encouraging a low carbon, renewable energy technology with damage to local ecosystems and viewsheds and potential conflict with other offshore users (Bisbee, 2004). Each regulatory decision will either encourage or discourage offshore wind development and could affect the rate of development and its eventual scale.

We first discuss the relevant European regulatory and lease frameworks for offshore wind power and then describe three relevant leasing systems in the US. We use these descriptions to discuss issues and tradeoffs involved in the development of an alternative energy leasing policy. We do not intend this paper to offer support for any particular regulatory scheme, only to offer a review of the regulatory options and their potential impacts.

2. Regulatory systems in Europe

Many European nations have either no method for regulating offshore wind farms or have little successful experience in promoting their development. The UK and Denmark are two exceptions. They both have several large operational offshore wind farms and have several others under construction. In this section we review the regulatory regimes of these two nations along with two other nations, Germany and the Netherlands. Both Germany and the Netherlands have less formalized offshore wind regulations that allow developers more freedom but which have so far resulted in fewer operational wind farms.

2.1. United Kingdom

The submerged land of the United Kingdom's territorial sea is the property of the Crown Estate[1] (Scott, 2006). As a result, the Crown Estate must grant a lease for offshore wind development within the UK's territorial sea. Beyond the territorial sea, the Crown Estate must still grant a license for development. While the Crown Estate is the landowner, the Department of Business and Regulatory Reform (BERR), formerly Department of Trade and Industry, is the lead government agency involved in offshore permitting (Peloso, 2006).

The Crown Estate has thus far conducted two "rounds" of leasing. The first round took place in April 2001 and resulted in 18

[1] The Crown Estate is the land once considered the property of the monarch (i.e. public lands) and the name of the organization that governs those lands.

agreements between the Crown and energy developers. The second round took place in December 2003 and resulted in 15 agreements (Crown Estate, 2004). A third round was announced in June 2008 (Smith, 2008). In all rounds, the agreements were only with the Crown Estate and developers had to obtain permits with other government agencies (Peloso, 2006; Scott, 2006). In the first round, developers were required to choose sites of interest. In the second round, developers were required to submit proposals that fell within one of three strategic areas designated by the government, areas for which a Strategic Environmental Assessment (SEA; similar to US programmatic environmental impact statement) had been completed.[2]

To participate in the round two leasing process, companies registered by submitting a brief business development plan that included potential areas of developmental interest. The companies then submitted tenders composed of financial information, a description of the project, a 50 page business development plan and a decommissioning plan (Crown Estate, 2004). This entire process took about nine months to complete.

The Crown Estate used four criteria to evaluate tenders including the financial and technical capacity of the applicant, the development plan (i.e. what the applicant was offering), the business development plan, and the decommissioning plan. The highest weight was given to the business plan that included financial plans, plans for obtaining other required permits, and plans for construction and operation. This section of the tender was to form the basis of the legally binding lease. The development plan also included a description of the environmental site specific studies the applicant would conduct in the creation of the EIA. Priority for competing applications was given to the most qualified applicant; financial considerations from the perspective of the Crown were not considered. Instead flat rate fees were used. All applicants were required to pay an application fee of £2500. If applicants were successful they were required to pay a one-time option fee of £25,000–£500,000 depending on the size of the development and roughly equal to £2000–£5000 per km^2. This option fee was used to support research and education projects committed to the furtherance of the offshore wind industry (Crown Estate, 2004).

Leases provide developers seven years to obtain other necessary consents. In addition to the Crown Estate, developers must obtain a permit from the BERR for any electrical generating project over 1 MW in capacity (DTI, 2004). In its permitting decision, BERR primarily considers the navigational issues raised by wind farms. BERR may not grant a permit in any area essential to international navigation and must consider the cumulative impacts of other permitted wind farms on this decision. BERR also has the authority to close the area in and around a wind farm to public navigation.

Offshore wind projects require licenses from the Marine and Fisheries Agency (MFA). The MFA is the agency tasked with evaluating the environmental impacts of a proposed wind farm by executing the provisions of the Food and Environmental Protection Act (FEPA) and Coast Protection Act (CPA). The MFA issues guidance on the requirements for an EIA, which must be completed before MFA approval (DTI, 2004). MFA evaluates hydrological effects, effects on fisheries and other marine life, and effects on specially designated habitat.

BERR is also responsible for ensuring decommissioning of offshore structures. The developer must submit an acceptable decommissioning plan to BERR. The decommissioning plan may make allowances for repowering or reuse of facilities for other renewable energy generation. The decommissioning plan may leave some components in place (buried cables, monopiles, scour protection) if removing them would cause an undue ecological or economic burden (DTI, 2006). BERR requires that the developer provide some financial assurance that decommissioning will occur according to the agreed upon plan. BERR will accept financial assurances on a case-by-case basis, but generally accepted assurances include cash, surety bonds, or letters of credit. Liability for damages from the remnants of a decommissioned wind farm will remain with the owners in perpetuity.

BERR did not publish its plan for decommissioning until late 2006, well after several offshore wind parks were operational. This, combined with the changes between the first two rounds of offshore leasing, suggests that the UK has continuously modified its regulations as the industry has developed.

Thus, in the UK there are three main agencies, the Crown Estate, the BERR and the MFA, each of which are tasked with evaluating different components of offshore wind development. This system has been thought of as too complex and inferior to a "one-stop shop" approach set up by Denmark (EWEA, 2007; Firestone et al., 2004), however, the UK offshore wind industry seems to be developing despite this.

2.2. Denmark

Denmark has been leading the world in wind power usage for centuries and they continue to do so, especially in the offshore environment. Denmark established the world's first offshore wind farm at Vindeby in 1991, and the second at Tuno Knob in 1995. They also established the first commercial scale offshore wind farm at Middelgrund in 2001.

One reason for the success of the offshore wind power sector in Denmark is government policies on offshore wind power. Offshore wind development in Denmark is regulated almost exclusively by the Danish Energy Authority (DEA). This is different from many other countries in which offshore wind developers have to interact with a variety of governmental agencies. The DEA provides "one-stop shopping" for wind energy developers (DEA, 2009) and provides centralized planning and coordination for the promotion of offshore wind power.

The methods for gaining DEA approval have evolved over the past several years, but proceed through either a tender or open-door process. In the tender process, the DEA requests proposals for tenders at a specific site that has been pre-screened by DEA and the DEA releases a desired capacity. Interested applicants are pre-qualified based on financial, legal, and technical qualifications. Pre-qualified applicants are asked to submit tenders for a wind farm of specific capacity. The tenders are evaluated primarily on the basis of the feed-in price required for the project. The winner of the tender process must then complete an EIS and may complete preliminary studies. However, this requirement can be waived if a satisfactory EIS has already been conducted in the site selection process. The winning bidder is obligated to build the wind farm.

The open-door process involves an interested party applying to the DEA for a permit without a specific request by DEA and outside of the areas that have been pre-screened by the DEA. After the DEA receives the application, they will invite other interested companies to apply for the development of the same area, ensuring competition. As before, an EIS is conducted by the applicants. The DEA has so far not implemented the open-door process.

The feed-in prices can be quite high. The recent Rodsand II wind farm lease agreed upon feed-in price of electricity is 13.2 c/kWh. The Rodsand II lease lasts for 25 years and includes a permit

[2] As a result of the SEA, BERR removed any area within 8 km of the coast, as well as any shallow water, from consideration for wind development.

to conduct preliminary studies as well as a permit to build and operate a wind farm. The time between the request for tenders and the deadline for submitting tenders can be quite short; in the Rodsand case it was just under two months (DEA, 2008).

There is no national codification of operational issues. Instead, the winning bidder is required to submit safety, decommissioning, and environmental monitoring plans and is then required to carry out these plans. The developer is also required to submit an annual report summarizing the environmental studies carried out that year (DEA, 2008).

2.3. The Netherlands

The Dutch have set a goal of offshore wind farms with a total capacity of 6000 MW. Unlike the UK and Denmark, the Dutch set specific areas in which offshore development is excluded. Interest in a wind farm is initiated by the developers who send a proposal to the Ministry for Transport, Public Works and Water Management (Mast et al., 2007). The ministry replies with guidelines for the permit request and makes the proposal public. The permit request must include plans for construction, decommissioning, and an EIS. If granted, the permit allows the developer two years to complete construction. Additional permits for running cables to shore and across the shore are also required.

In the Netherlands developers are not pre-qualified, however, the requirement to complete construction within two years and the need for an EIS are intended to discourage speculation. The first-come, first-served method of awarding licenses virtually eliminates competition for sites. There is no competition among proposals for which best serves the national interest, instead, the only competition is to be the first to submit a suitable application. The Dutch do not institute fees for leases, but developers must pay for the EIA; again this is thought to discourage speculation.

In 2006, the Dutch had a subsidy for offshore wind projects of 0.097 € ($0.15) per kWh. However, the Dutch government decided that their renewable energy goal would likely be met without the subsidy and were worried that the subsidy would cost too much given the growing interest in offshore wind. Therefore, they set the subsidy to zero in late 2006 (Mast et al., 2007). In late 2007 and early 2008 the Dutch government developed a new renewable energy premium program in which renewable electricity generators are paid a premium over the first ten years of operation. The premium depends on the technology used and the price of electricity and has not been codified for offshore wind, but for onshore wind it is €0.028 ($0.044) per kWh (EREC, 2007a).

2.4. Germany

Germany has permitted more offshore wind parks than any other European state, but no wind farms are currently operational in German waters. In Germany, the provinces control the waters up to 12 mile from the shore while the federal government controls the rest of the EEZ. Most offshore wind projects in Germany are expected to occur in federal waters, however, as in the US, the German states will have input in the permitting process, especially the permitting of transmission cables.

Offshore wind project approval in Germany is a non-discretionary action of the German Federal Maritime Agency (Bundesamt fur Seeschiffahrt und Hydrographie, BSH). That is, German law prescribes conditions for the rejection of offshore wind projects. The only duty of the BSH is to determine if those conditions exist. If they do not, the developer has a legal right to develop the project (BSH, 2008). These conditions are that the project does not constitute a danger to navigation and does not pose an unacceptable risk to the environment.

The consent procedure begins with the developer submitting an application to BSH. BSH then solicits comments from other government agencies, principally the regional waterway and shipping authority that also has to give regulatory approval. There is then a second round of comments solicited from a larger group of stakeholders including the public. After this second round of commenting the developer is invited to hold a conference in which the developer presents their plans for development and the scope of the required environmental data is determined. The developer conducts an EIS and an analysis of the potential danger to navigation caused by their proposed wind

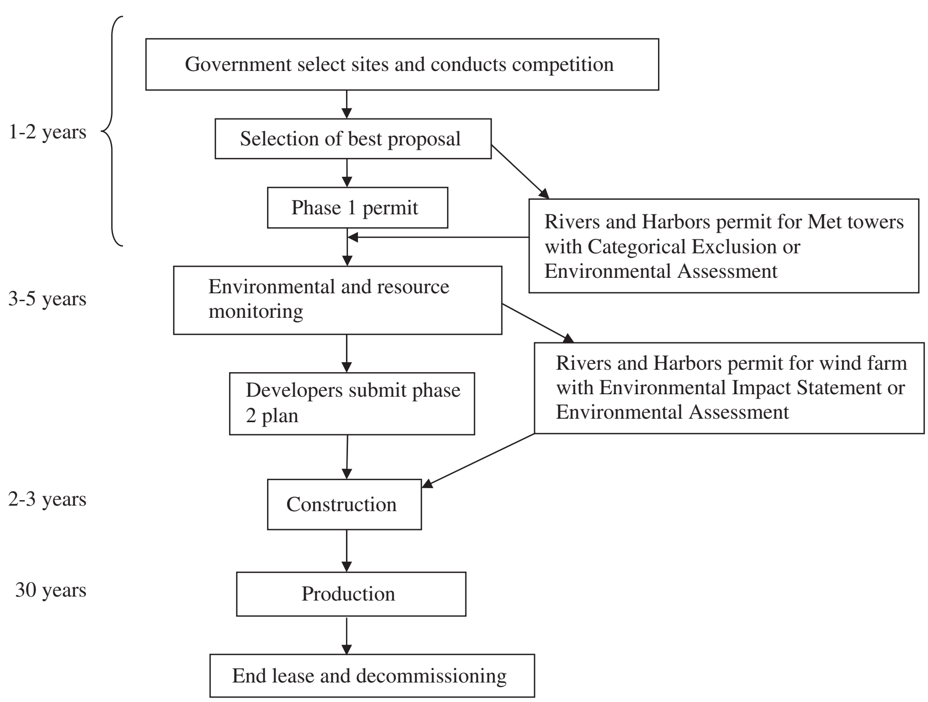

Fig. 1. Flow chart of regulatory process. Diagram is meant to illustrate the approach of Texas.

farm. After receipt of these documents, BSH passes them along to other relative authorities and makes them available to the public. BSH then decides if the proposal meets its criteria. At the same time, regional waterway and shipping administrators determine if the project poses a threat to navigation.

If the project is approved by both the BSH and the regional waterway and shipping authority, BSH approves the project for a term of 25 years. Construction must begin within $2\frac{1}{2}$ years and the developer must furnish a bond for decommissioning (BSH, 2008). The developer is guaranteed a fixed price for electricity under the feed-in-tariff that starts at about 9 euro cents ($0.14) per kWh (EREC, 2007b). The price declines slowly over time.

There are no allowances for competition in the German system. If two developers submit applications for the same area, the first complete and acceptable application is granted (BSH, 2008).

The German system has been successful in permitting offshore wind projects, but thus far, dismal in their construction. This could be due, in part, to the fact that the only competition is to be the first developer with an acceptable development plan. Thus, developers have an incentive to complete applications for as many areas as possible, as quickly as possible.

3. US programs

Two conceptual models for the regulation of offshore wind power are presented in Figs. 1 and 2 and represent the regulatory scheme for offshore wind energy in Texas (Fig. 1) and the federal Bureau of Land Management's (BLM) regulatory structure for onshore wind (Fig. 2). These models depict two ends of a spectrum of methods of regulation. Their main differences are whether the government or the developers choose the sites for development and if the government seeks to encourage competition among developers for the maximum financial benefit to the public.

The fact that two very different programs were developed nearly simultaneously in the US suggests that there are a number of feasible options for regulation. One reason for the difference between these two regulatory frameworks could be the relative interest in profit of the two agencies. The BLM stated that the development of onshore wind resources should have little budgetary impact and that their primary purpose is not to generate income for the government but to encourage wind energy development, consistent with the Energy Policy Act of 2005. The State of Texas also seems interested in the development of an offshore wind energy industry, however, they seem to be equally interested in maximizing the monetary benefit to the state (Patterson, 2005).

3.1. BLM guidelines

The BLM manages wind energy development on federal land. In 2003 they began the process of conducting a programmatic EIS. The EIS was released in June of 2005 and an Instruction Memorandum implementing the Record of Decision was published in August 2006.

The BLM policy is designed to encourage the "development of wind energy in acceptable areas" (BLM, 2006). Applicants may apply for a right-of-way for either a single meteorological tower, a series of meteorological towers in a larger area or commercial development. Applications for testing are conducted on first come basis (i.e. not competitively) and competing applicants for commercial energy development will be encouraged to form a cooperative agreement. Competitive leasing may occur if deemed appropriate in specific areas.

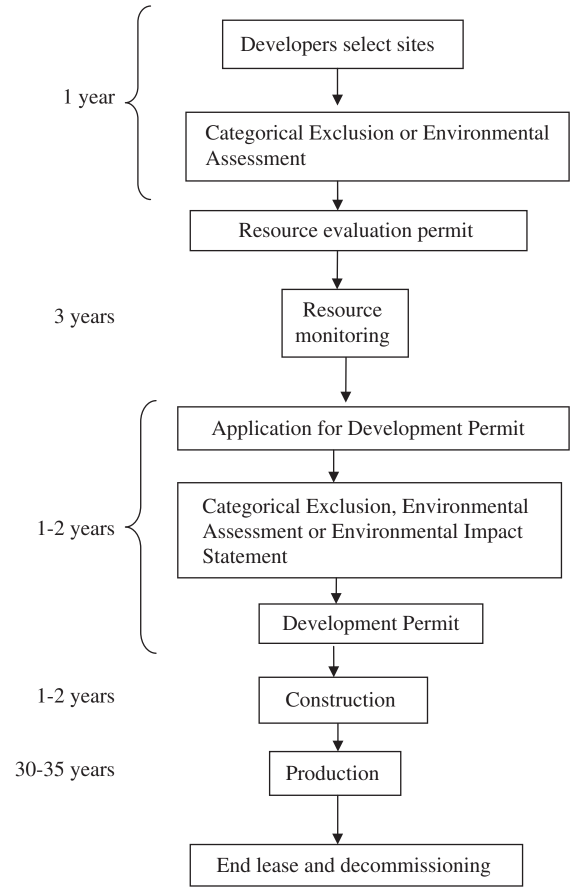

Fig. 2. Flow chart of regulatory process. Diagram is meant to illustrate the approach of the BLM.

A right-of-way for a single meteorological tower will last for three years and cannot be extended. The rental fee is $50 per year. The right-of-way does not establish any preferential rights to future wind energy projects in the area, and BLM may authorize multiple right-of-ways in the same area to multiple parties. The applications for meteorological monitoring should be processed within 60 days and are subject to minimal cost recovery fees.

A right-of-way for a larger site lasts for three years but has provisions for extension beyond the three year limit. The right-of-way precludes other wind energy development in the area over the three year term of the lease. However, the holder establishes no right to commercially develop the area. As part of the application approval, BLM may consult with the National Renewable Energy Lab to determine if the proposed number and location of monitoring sites is sufficient to accurately predict future wind conditions. If BLM determine that the application will adequately quantify the wind resource, then a NEPA process begins. The rental fee will be determined by the total project area (i.e. the area that excludes competing development) and will be $1 per acre or $1000, whichever is greater. Bonds are discretionary, and data collected are proprietary, but may be made public if the holder applies for commercial development rights.

The right-of-way for commercial development is not term limited and is expected to last at least 30 years. The BLM retains the right to permit other compatible land uses over the term of the lease. The rental fee is $2365 per MW of capacity per year and is phased in over the first three years of the project. This rate is designed to be a 3% royalty on production, assuming a 30% capacity factor and a 3 c/kWh sales price. It should be noted that the assumed 3 c/kWh sales price is below the average sales price

Table 2
Texas royalty system.

	Preproduction	Years 1–8	Years 9–16	Years 17–30
Minimum royalty	0	3.5%	4.5%	5.5%
Minimum annual royalty per MW		\$4100	\$5500	\$7000
Other fees	\$20,000 per year (approximately \$1 per acre)			

of wind generated electricity (Wiser and Bolinger, 2008), and as a result the royalty is actually less than 3%. The royalty should add about 0.09 c/kWh to the cost of generating electricity.

To ensure that speculators do not unduly control wind resources, applicants are required to provide information on their technical and financial capabilities. Additionally, the facilities for the monitoring of a wind resource must be constructed within 12 months of the approval of the application and the construction of wind turbines must commence within two years of the approval of an application.

The NEPA process for BLM wind energy decisions will generally end with either categorical exemptions (CX) or environmental assessments (EA). CXs may be applicable for site monitoring applications while environmental assessments, building off of the programmatic EIS developed by BLM will be sufficient for most wind farms unless there is either significant public controversy or a determination of significant adverse impacts. Additionally, it would be acceptable to consolidate local and state environmental reviews with the NEPA process (BLM, 2006).

3.2. Texas offshore wind program

Because of its Spanish history, Texas' waters extend 3 marine leagues (9 nautical miles) offshore of the Texas coast (as opposed to 3 nautical miles for other states). As a result, Texas has been able to develop its own offshore wind leasing program which has evolved over the past several years. In 2005, the Texas General Land Office (GLO) signed an agreement with Galveston Offshore Wind (a subsidiary of WEST) for an 11,355 acre lease 7 mile off the coast. In 2006, the GLO signed an agreement with Superior Renewable Energy (later a subsidiary of Babcock and Brown) for a 40,000 acre lease. Neither of these leases were conducted competitively. However, in October 2007, the GLO conducted a competitive leasing program and awarded WEST leases on four tracts of land totaling 73,000 acres. WEST was the only bidder, although there was interest from one other firm (Schellestede, 2008). The terms of both the competitive and non-competitive leases were similar, with the major difference being an increase in land rental rates from \$10,000 to \$20,000 per tract per year during the site testing and construction phases.

In the recent competition, the GLO released a set of bidding instructions stipulating which areas were available for lease, the minimum size (in MW) of the development and the minimum royalty rates. The GLO stated that the winning bidder would be the highest bidder that met or exceeded the minimums. The minimum lease rates were \$20,000 per year during site testing and construction, then a gradually phased in royalty that varied from 3.5% to 5.5% of gross revenue. There was also a stipulation that set minimum annual royalties on a per MW of installed capacity basis which would apply only if they were greater than the royalties as a percentage of gross revenue (Table 2). The term of the lease was 30 years.

The lease allows for phased access in which the lessee is first given research rights and then granted construction and operation rights. Within 60 days of the start of the lease, the lessee must submit a research plan to the GLO for approval. This must include the description of Environmental Impact studies which the developer will undertake. After this initial research plan, the lessee must submit a quarterly Phase 1 progress report to the GLO, then submit a final report and a production plan to the GLO. The production plan must contain language that affirms that the lessee will either conduct an EIS if required by the Army Corps of Engineers, or else submit a mitigation plan to the GLO. In addition the production plan must contain economic analyses, the construction schedule and a final description of the project. Once the production plan is approved, the lessee may begin construction. During construction the lessee must submit progress reports to the GLO quarterly and the lessee has 36 months to complete construction (for the first 250 MW of capacity). Thus, the initial competition and lease gives the lessee the rights to both site assessment and development.

The lessee is required to provide the GLO with either a surety bond, a letter of credit, or a cash deposit before undertaking construction. The lessee sets the price of this bond with approval from the GLO. The lessee owns all improvements on the site, however, the GLO has the right to receive the turbine foundations for use as artificial reefs upon cessation of production.

The lease contains stipulations whereby the lessee is exempted from payments in the case of Force Majeure. The lease does not include stipulations for repowering of the site.

4. Mineral management service regulations

4.1. Lease terms

The Minerals Management Service released final regulations in April 2009 (MMS, 2008, 2009). The regulations consist of a two tiered system in which developers can apply for either a limited lease or a commercial lease. A limited lease would be term limited to five years, would confer no developmental rights nor any preference for later commercial leases. MMS anticipates that limited leases will primarily be used for technology evaluation and does not advocate their use for commercial operations.

Commercial leases would be for 30 years and would include a six month planning period, a five year assessment period and a 25 year construction and production period. The developer would be allowed to cancel the lease if site assessment showed the lease area to be insufficient for development and would be required to submit a site assessment plan at the beginning of the lease and a construction and operations plan to proceed to the commercial development phase of the lease.

MMS proposes to collect two types of payments from commercial leaseholders, a rental fee of \$3 per acre during site assessment activities and a royalty of 2% of estimated gross revenue phased in over the first two years of operation. Limited lessees would only pay the rental fee. MMS studied the effects of this proposed rate by simulating 73 offshore alternative energy projects. They found that 55 of the 73 projects would be economically viable, but that the economic viability was unaffected by the proposed rate. They conducted a similar analysis of three hypothetical offshore wind farms built in 2010 or 2020 and found that the government's share of net revenue was 40% for the wind farms constructed in 2010, but 15% for those constructed in 2020. Finally, MMS compared the revenue to the government through rent and royalties to the production tax credit (PTC). They found that the royalties they assessed reduced the value of the PTC by at most 15%. In addition to royalties and rental fees, MMS will also require lessees to pay for NEPA costs.

4.2. Competition and approval criteria

The lease process would begin with MMS gauging competitive interest in a site. MMS may begin this process by issuing a call for information and nominations of areas to be leased, or may identify an area that a developer has expressed interest in. If MMS issues a call for nominations it will then evaluate the nominations, determine the area to be leased and issue a sale notice. The sale notice would notify the public of the lease location, invite interested parties to submit lease applications, and would specify how competing applications will be judged.

If there is competitive interest, MMS will conduct an auction. Commercial leases would be evaluated based on either the size of a cash bonus bid or the royalty rate. In general, one of these variables would be fixed to allow for straightforward comparisons. Limited leases would be evaluated only on the basis of a bonus bid. MMS would generally not consider the technical or economic feasibility of competing projects, nor would it dictate the electrical capacity of development and would instead focus the monetary benefit to the government as the deciding factor. MMS has indicated that it is open to using more subjective measures (technical merit, economic feasibility) to determine winning bidders, but is concerned about the equity of such a system. MMS will likely conduct competitions through either a sealed, single round bid process, a live or electronic auction or some combination of these methods. In the oil and gas leasing system sealed bidding is the dominant auction method.

If there is no competing interest, MMS will issue a non-competitive lease through a negotiation process.

4.3. Environmental analysis

MMS will generally conduct two stages of environmental analysis. For both non-competitive leases and competitive leases there will be an initial NEPA review during the issuance of a lease or lease sale and based of a site assessment plan. After the five year site assessment plan, lessees will be required to submit a construction and operations plan triggering a second NEPA review. Finally, two years before the end of the lease, the lessee must submit a decommissioning plan, which will again trigger a NEPA review.

For commercial leases, MMS proposes to conduct a site specific EIS before allowing activities to commence. It is possible that in the future EAs may be more widely used for NEPA compliance.

4.4. Operation

MMS has stated that they will take an adaptive management approach to regulation and will allow operators to validate their own performance. MMS will require developers submit detailed safety and environmental monitoring plans and self-report on their compliance annually. MMS will request that developers submit data on air quality, monitor the incidental take of threatened and endangered species and marine mammals, demonstrate the training of personnel, and conduct annual facility inspections to ensure compliance to be developed standards. MMS will also require operators to submit incident reports in the event of injuries or damage to facilities. MMS will conduct both scheduled and unscheduled inspections of facilities.

4.5. Decommissioning

MMS has recognized that large scale decommissioning will not occur for several decades and may change regulations to reflect future technological changes. Operators will have to furnish a surety bond for decommissioning. The size of the bond will be determined on a case-by-case basis. Operators will also have to submit a decommissioning plan two years before the end of the lease and must complete decommissioning within two years of the end of the lease. Operators will have to remove all structures to a depth of 15 feet below the mud line, similar to the requirement for oil and gas structures and wellbores. MMS may authorize facilities remain in place on a case-by-case basis.

5. Regulatory issues

5.1. Lease terms

5.1.1. Length of lease

In order for a regulatory system to allow for development to occur, the length of the lease must be long enough for companies to recoup their initial investment, which, in the case of offshore wind power, can be quite high. Lease durations of 30–50 years are generally preferred by industry (AWEA, 2006; Hobson, 2006) and are being used in the UK.

A lender is unlikely to allow for a loan to be financed for a term longer than the term of a lease. Therefore, long leases allow developers to finance loans over longer periods, reducing annual payments.

In addition, long leases allow developers to delay decommissioning as long as possible. The technologies and regulatory options available for decommissioning may change as the first wind farms are removed and it is possible that the costs of decommissioning may fall as learning occurs, but the use of marine vessels will always induce a fixed cost of the operation.

There are costs associated with long leases. Over the next 30–50 years there may be significant changes in the electricity industry in the US due to climate change, changing environmental regulations, and depletion of oil and natural gas. The effects of these changes are difficult to predict, but it is plausible that the profitability of renewable energy generation could increase dramatically in the coming decades. If this were to occur, then private companies could be making very large profits from the use of public lands and may be paying only very low rental fees or royalties to the federal government due to the lease conditions that were determined when the economics of offshore wind farms were very different. Even leases in which royalties are based on gross revenue may have this problem. In this case, even though the government's profit would increase as the profit of the developer increased, the public may demand a higher proportion of revenue from a highly profitable enterprise than they would from a barely profitable enterprise.

Long leases also do not allow for repowering. If a company repowers a wind farm it might have to shutdown turbines, which may not be allowable in a lease that includes minimum royalties be paid to the landowner. It is also likely that repowering would be expensive. For example, if a lease was for 30 years and repowering would be expected to occur after 20 years, then a company may decide that it would not be able to recoup the costs of repowering over the remaining 10 years of the lease.

Long leases will raise surety bonding requirements. In general, surety bonds are short-term instruments that require the insurer to estimate the financial viability of a company over 2–5 years. In the oil and gas industry, surety bonds can be longer which increases the risk to underwriters and the insurance premium and decreases the number of companies capable of insuring these projects. In the offshore wind industry, it would be very difficult for underwriters to project the financial viability of a company over a period of 3–5 decades; as a result, we would expect collateral requirements to be very high.

Clauses which allow for the renegotiation of specific terms under specific circumstances may help to deal with some of these issues. For example, regulators could insert clauses into leases that allow for renegotiation of royalty rates if the price of a kWh (and associated renewable energy credits) exceeds some threshold (perhaps 25 cents, adjusted for inflation). Similarly, regulators could allow for renegotiation if the developer could demonstrate that by repowering the site they could increase electrical output by some percentage.

5.1.2. Lease fees

Low lease fees that encourage development have been supported in the US by both industry and environmental groups (Coequyt, 2006; Cousins, 2006; Evans, 2006; Heimann, 2006; Hobson, 2006; Kennedy and Chasis, 2006; Pope, 2006; Quaranta, 2006). In Europe, lease fees are either non-existent, or overwhelmed by government subsidies. In Texas, royalties are more significant, up to 5.5% of gross revenue.

Lease fees include royalties and rental fees. Generally, royalties are used when one party owns something and allows another party to profit from its use. For example, in the oil and gas industry, the federal government owns the oil and allows a private company to extract it, with a royalty paid to the federal government. In the case of offshore wind, royalties may not be appropriate since the federal government does not own the wind. Instead, the public owns the land that wind turbines would use, thus, rental fees may be more appropriate.

However, in structuring a lease agreement it may be preferable to use royalties over rental fees. The use of low rental fees and higher royalty rates could allow for companies to pay lower upfront costs during resource assessment and construction phases and then to pay higher costs once the project begins generating power, and thus, revenue. Royalties may also ensure that the public benefits from the use of a public resource. If the value of renewably generated electricity increases, land rents would not capture this increase but a royalty on gross revenue could.

In deciding the proper rate for lease fees, regulators must decide what these lease fees are designed to collect. Should they collect the administrative costs, the opportunity costs or forgone competing uses, or the maximum public monetary benefit? If they are designed to cover only administrative costs then the leasing fees could be quite low. Similarly, since offshore wind projects should not exclude most other uses of the area (i.e. most commercial fishing, recreational fishing and boating, other alternative energy uses) the opportunity costs might also be low (Cousins, 2006). The primary opportunity costs lost would be from sand and gravel mining and trawling, which may or may not occur on the site. Conversely, if fees are designed to collect the maximum monetary benefit the fees would be limited only by the competitive process and the profitability of the projects.

Lease fees may or may not be balanced against already existing tax credits and other subsidies for renewable energy. The federal production tax credit gives producers of renewably generated electricity a tax credit of 2 cents/kWh over the first 10 years of generation. For comparison, the BLM charges about 0.09 cents/kWh. Similarly, almost all of the states that may eventually produce offshore wind energy (the exceptions being Louisiana, Virginia, Georgia, and Michigan) have renewable portfolio standards that create a market for renewable energy certificates. It would seem to make little sense for the government to financially encourage wind energy with tax credits and renewable energy mandates, while at the same time collecting large rental fees. However, the MMS has argued that these financial incentives are designed by Congress to represent the value of the societal benefit from renewable energy production. By this logic, regulators need not concern themselves with the societal benefit of offshore wind power and only need to consider the fair return to the public for the use of public land.

Finally, it is important to note that at this stage of development, lease fees can stymie development, but they cannot truly stimulate it. A high fee (5%) of gross income could potentially hinder development, but the converse is not equally true. Even if lease fees are so small as to be negligible, it is the underlying economics of offshore wind farms that will determine if they are built. Of course, low lease fees will cause developments to be more profitable and allow for development in areas that higher lease fees might foreclose, but only a subsidy of several cents per kWh would change the underlying economics of offshore wind farms and truly stimulate the industry (Snyder and Kaiser, 2009).

5.1.3. Timelines for development

Low lease fees could also retard development. If lease fees or rental rates are low enough that a company could cheaply secure rights to an area and thereby exclude competitors, then companies may attempt to rent large portions of land without the intent of ever developing them. Winergy has been accused of this (Kaplan, 2004). As a result, most leases have inserted timelines for development with developers having a specified amount of time (usually 3–5 years) to begin construction and operation.

Strict timelines could force a developer to begin construction when market conditions are not favorable. The cost of construction and turbines are the largest costs facing offshore wind development. These costs are dependent on commodity prices that can be volatile. Thus, strict timelines might force a developer to begin construction at a time when the costs of construction are temporarily high, endangering the financial viability of the project.

5.1.4. Phased access

Leases usually grant some type of phased access in which the lessee has a short-term right to evaluate a wind resource with the option for a longer term right to develop that wind resource. Phased access allows developers to reliably estimate the wind resource at a site, thereby estimating cash flow and removing a degree of uncertainty from their development decision. Phased access is widely supported by developers (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006). Phased access that does not include a preferential right for the developer doing the resource assessment to exploit the resource may stymie development. Resource assessments may be expensive and a company may be unlikely to enter into a lease allowing them access to an area for resource assessments if they are not granted the right to develop the resource. The only system in which there is no real phased access is in Denmark, where the government selects sites and conducts preliminary studies that essentially mirror the early phases of developer access elsewhere.

Regulators must also decide if they should allow leases for pilot projects that might follow different rules than large scale projects. For example, regulators could allow projects below a specific capacity to be processed on an expedited basis using less stringent environmental review (Firestone et al., 2004).

5.1.5. Project criteria

When conducting a competitive lease, the government can either specify the generating capacity of the planned development (as in Texas and Denmark) or they could allow developers to submit their own plans for the land to be leased. Allowing developers to decide the capacity of the proposed projects could give large developers an advantage over smaller developers. For example, a large developer may be able to reasonably propose a 300 MW development on a given area while a smaller developer or municipality may only be able to raise the capital for a 150 MW development. The larger development would provide more revenue to the government, and would be favored in any approval system based on wholly or partially on the financial benefit to the public. MMS has proposed to address this issue by comparing plans based on their per MW or per acre benefit to the government.

5.2. Competition and approval criteria

5.2.1. Competition

There are two main models for awarding leases. Regulators could either select sites (often with developer input) and hold a competitive process, or they could allow developers to select sites. If developers select sites, competition could be enhanced if they were presented with deadlines and regulations for the minimum distance to other wind farms, as in the UK. Deadlines would keep developers from rushing to be the first to submit a proposal rather than the best (as in Germany), while minimum distance requirements (for example, 10 km) would help to define when two proposals were actually competing.

If regulators select sites, competition could be simplified if they also set guidelines for development, especially the size of development, as in Denmark. This would make comparisons of alternative projects simpler, however, if the guidelines were too detailed it might also restrict creativity. Regulators selecting sites would also ensure that development occurred at a measured pace, much as it has in Denmark.

If a regulator decides to select sites it may take several additional years for offshore wind projects to commence while regulators conducts detailed studies. One option would be to follow the British example and to conduct leasing in two phases. The first phase would be developer driven in which developers would have to submit proposals for specific sites by a specific date. While this first phase was ongoing, regulators could identify potential suitable areas, begin the environmental review process and conduct a leasing competition similar to those it conducts for oil and gas leasing. In the long term, by beginning the environmental review process before competition, regulators might speed development.

5.2.2. Approval criteria

The degree of competition will in part decide the criteria by which proposals will be judged. If there is no competition then proposals may be judged on technical and economic feasibility, profitability, and environmental impacts. If there is competition, then additional criteria of compensation to the government may be added.

The use of profitability as an approval criteria has costs and benefits (Heimann, 2006; Pope, 2006). Its use would lower the possibility that developers would go bankrupt and therefore be unable to remove wind turbines and foundations, an important consideration for regulators. However, industry groups have argued that it would be difficult for regulators to accurately predict the economic return of an offshore wind project to a company and that private companies already have oversight of their financial decisions from investors and shareholders (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006).

The use of a profitability standard may retard development in the short term but might encourage development in the long term. Determining the profitability of a proposal would likely take a significant amount of time and resources, however, if regulators intend to establish a successful long-term leasing program, ensuring that the programs that are built remain profitable and operational is important.

5.2.3. Environmental analyses

The National Environmental Policy Act requires that the federal government consider the environmental impacts of all of its decisions. Similar laws apply in Europe. The most complete form of environmental analysis under NEPA is the EIS, a document that can take years to complete. Alternatively, NEPA allows for shorter EAs if significant environmental effects are unlikely or CXs if actions do not have significant environmental affects. MMS could require site specific EISs for every offshore wind power development, as favored by environmental organizations (Coequyt, 2006; Pope, 2006). This may be appropriate given the scope and nature of offshore wind energy (Kellermann et al., 2006; Öhman et al., 2007). Alternatively, MMS could conduct a programmatic EIS for offshore wind power (it has already conducted a programmatic EIS for alternative energy use in general) and use EAs and CXs (as favored by some representatives of industry Hobson, 2006). Site specific EISs will slow development compared to CXs and EAs, but will ensure NEPA compliance and will ensure that the environmental impacts of a specific project at a specific site are considered. Given that there has been local opposition to proposed wind farm development in the US (i.e. Citizens to Protect Nantucket Sound), it seems plausible that an MMS decision to issue a CX could be challenged in court (Brown and Escobar, 2007). Also, the environmental impacts of an offshore wind farm are likely to be site specific. A final compromise option would be for MMS to develop a programmatic EIS and allow site specific EISs to branch off of the programmatic EIS.

If regulators require site specific EIS (or their equivalent) for all offshore wind projects, there is an additional decision regarding the amount of data to require. Regulators could issue blanket guidelines for data or could allow data requirements to be developed for each EIS. Blanket data requirements will likely retard development unless they are so minimal as to be essentially meaningless. It is also not clear what long-term blanket data requirements are meant to achieve. For example, the US Fish and Wildlife Service has argued that three years of avian radar data be collected for each EIS (Bennett, 2006); however, they did not say how these data should be used.

5.3. Operational issues

Regulators must decide how to monitor the operation of offshore wind farms including environmental compliance and worker safety. Regulators must first decide who should conduct the required monitoring. The government, developers, or a third party could conduct the required monitoring. There is a clear conflict of interest if developers are allowed to conduct their own compliance monitoring, but this is likely to be the cheapest option and it is favored by developers (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006). Third party monitoring is likely to be more expensive, and government monitoring would require regulators to develop new institutional skills.

The methods for conducting environmental monitoring are also important. Adaptive management, in which a project is monitored for its environmental impact and project parameters are changed as issues are identified, is a widely used method for natural resources management (Holling, 1978). However, adaptive management requires both reliable data, and an ability to adjust operating parameters if an issue is detected. In the offshore wind farm environment it can be difficult to monitor environmental effects. Wind farms are spread over tens of square miles and dead animals will often disappear into the sea. Full-time onsite personnel, while expensive, may be required if adaptive management is to be successful. To date, none of the offshore wind farm installations are manned, but Horns Rev II is expected to be the first manned offshore wind farm. Furthermore, if an unforeseen problem arises it is not clear what mitigation measures could be taken. These mitigation measures would need to be explicitly identified in the lease. The alternative to adaptive management, a regulatory scheme in which all research is done prior to construction and all of the relevant issues are identified and optimal policies chosen before operation, may not be plausible in the case of offshore wind farms do to the fact that offshore wind farms are so novel and so much remains unknown about their operation and interaction with the environment.

Worker safety is vitally important for offshore wind farms, but has not been seriously addressed by regulators. Since the wind industry began in the 1970s at least 33 people have been killed installing and servicing wind turbines (Gipe, 2007). Most of these deaths have been caused by either falls, entanglement in the internal machinery of the nacelle, or vehicle accidents during transport. These deaths have resulted from worker error and equipment malfunctions. The offshore wind industry will share all of the dangers of the onshore industry and will have additional hazards. Like the onshore industry, maintenance on offshore turbines will require workers to regularly climb to the nacelles of turbines, several hundred feet above the surface. However, the offshore industry raises the additional hazard of gaining access to the turbine. Access can be through either boats or helicopters. Moving personnel and equipment from boats onto a boat landing on turbine tower could be hazardous even in moderate seas. As a result, there is interest in developing stable catamarans with specially designed bows to facilitate safe movement. In the offshore oil industry a great deal of personnel movement is carried out by helicopter, however, in the offshore wind industry this involves helicopters hovering nearby turbine blades that could be dangerous.

It is also not clear what engineering and safety standards should be used for the inspection and certification of offshore wind farms, as no standards currently exist for offshore wind farms. However, it is likely that new industry specific standards for design, construction, inspection, and operation may be developed and used by regulators.

Power purchase agreements (PPAs) are another important consideration for regulators. PPAs are contracts between an electricity producer and the grid operator in which the grid operator agrees to purchase a set amount of electricity at a set price for a set time. They provide a stable price for both parties over a long term. Without a PPA, a wind farm would have to sell its electricity on the spot market. From the perspective of a regulator, PPAs reduce the risk associated with bankruptcy. Currently, offshore wind leases do not contain clauses forcing developers to obtain PPAs, although they may be required by lenders or underwriters to reduce risk.

5.4. Decommissioning

Decommissioning has been largely neglected by regulators. In the MMS Cape Wind Draft EIS, a 718 page document, just a page and a half was dedicated to decommissioning. Likewise, the UK did not develop decommissioning guidelines until years after their first offshore wind farms were operational.

5.5.1. Bonding methods

There are a number of options for ensuring decommissioning. Surety bonds, letters of credit and escrow accounts could all be used to ensure that the funds required for decommissioning are available at the end of the lease or if the company goes bankrupt. An irrevocable letter of credit and a surety bond ensure that funds are available regardless of the financial standing of the developer. Depending on the terms of the escrow account, it may or may not ensure that the necessary funds are available throughout the lease since some escrow accounts do not require the full amount needed for decommissioning be deposited until several years after the start of operations.

Studies of alternative methods of decommissioning compliance in the oil and natural gas industry have indicated that surety bonds afford regulators with a high degree of certainty that the site will be decommissioned according to agency requirements, and do so with relatively low costs to either the government or the developer (Ferreira et al., 2004; Ferreira and Suslick, 2001). Not surprisingly, almost all bonds in the offshore oil and gas industry are surety bonds; it is reasonable to expect that most offshore wind structures will be bonded with surety bonds.

5.5.2. Decommissioning options

In the oil and gas industry every structure must eventually be removed. However in the offshore wind industry the wind resource is inexhaustible, so decommissioning will only need to occur in the case of bankruptcy, unprofitability, or if there are no repowering options available. At the end of a lease the lessee may have one of several desires. The lessee may want to repower the site, the lessee may want to keep the site in production, but not repower it (perhaps to forestall paying decommissioning costs), or the lessee may want to abandon the site. Regulators, in turn, have several options. If the lessee wants to repower the facility or otherwise keep it in production, they could either renegotiate or terminate the lease. If the lessee chooses to terminate the lease, regulators could either force the lessee to decommission the site or they could allow for an agreement in which a new third party takes over the lease site. Presumably, the new third party would inherit ownership of the turbine structures and transmission facilities and the liability for their removal. Under current oil and gas law, the previous owner would still be liable for decommissioning if the new owner declares bankruptcy.

In the case of bankruptcy, the liability for structure removal could eventually fall to the government (depending on if the site transfers ownership or is inherited by creditors). If the government becomes responsible for the site, it could either decommission the site using a surety bond, or it could auction off the rights to operate the site.

Regulators must also decide whether or not to allow the use of offshore wind foundations as artificial reefs (Kaiser, 2006). Monopiles and gravity foundations lack the structural complexity of jacketed foundations and may be less productive as artificial reefs, but studies at two wind farms in Sweden have shown greater diversity of fish and greater numbers of blue mussels were found near monopile foundations than in control sites (Wilhelmsson et al., 2006).

5.5.3. Decommissioning costs

If the government decides to decommission the site, it must ensure that the size of the bond covers removal costs. Importantly, there are no published studies on the appropriate value of these bonds for offshore wind facilities and there are reasons why bond values from the offshore oil industry may not be appropriate for the wind industry. First, anywhere from 25% to 50% of the costs of decommissioning oil and gas structures stem from the costs of plugging and abandoning wells that will not occur in offshore wind decommissioning (Kaiser et al., 2003). Second, oil platforms are usually 4- or 8-piled structures, whereas wind foundations are usually single piled, similar to caisons, although foundations in deeper water may have 3 or 4 piles. Offshore wind farms are also not in water as deep as oil and gas platforms.

Studies of decommissioning costs of oil and gas structures in the Gulf of Mexico suggest that the average cost for removing a 4-piled structure, discounting plugging and abandonment and pipeline abandonment operations, is $664,000. These data were from structures decommissioned between 1991 and 2001; adjusting for inflation and assuming a normal distribution of costs and years, the cost in 2008 would be $926,000. The cost for an 8-piled structure is approximately 1.5 times that of a 4-piled structure, thus, it would not be appropriate to assume that a 1-piled structure would cost one-fourth of a 4-piled structure. Instead, a 1-piled structure might cost 33–50% of a four-piled structure or $305,000 to $463,000. A wind farm might be composed of 100 or more turbines, but due to economies of scale, it is unlikely that the decommissioning costs will scale linearly. Thus, a 100 turbine wind farm should cost less than $50 million to decommission.

Importantly, $50 to $60 million in liabilities is the maximum amount that the US offshore oil and gas plugging and abandonment surety bond market can underwrite. One of the two major companies in this industry, RLI, has expressed some interest in the offshore wind market and may be willing to underwrite some projects. However, the surety bond market is extremely risk averse and they may require large amounts of collateral before issuing a bond.

6. Conclusions

It is difficult to draw meaningful conclusions from the handful of successful regulatory regimes in place. As more countries develop regulatory programs and the programs in place continue to succeed or fail the best practices for offshore wind regulation will become clear.

A number of commentators have concluded that the preferred way for nations to regulate the offshore wind industry is to setup a "one-stop shop" (as in Denmark) approach in which permitting authority is consolidated into a single governmental agency (Firestone et al., 2004; Peloso, 2006; EWEA, 2007). However, given the large amounts of time, capital and planning involved with the development of an offshore wind farm, it seems unlikely that the requirement to seek permits from numerous governmental agencies is a significant administrative burden on applicants. Both the MMS oil and gas leasing program and the UK offshore wind programs have been successful despite requiring permitting and consultation from a variety of government agencies. Furthermore, one could argue that Germany has been extremely successful in permitting offshore wind farms despite requiring input from multiple agencies.

We also note the lack of development in Germany, and to a lesser extent the Netherlands, and question whether that is associated with a regulatory system that rewards first, rather than best, applicants. Currently, there is not enough data to satisfactorily address this question.

In our view, the actual methods of regulation (approval criteria, EIS requirements, etc.) are likely less important than the fees charged and subsidies offered by governments (Bird et al., 2005; Reiche and Bechberger, 2004). It may be possible to ascribe the success of Denmark and the UK to convenient regulations, but it may be more likely that a mix of financial subsidies and amenable offshore sites has led to the development of the offshore wind industry in these countries. Therefore, if the US government seeks to encourage offshore wind projects, it may have more success through non-regulatory action (for example, the expansion of subsidy programs like the production tax credit) than by developing loose or streamlined regulations.

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