NAVIGANT

Offshore Wind Market and Economic Analysis

Annual Market Assessment

Prepared for:
U.S. Department of Energy

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Abbreviations

ABP	Associated British Ports
AC	alternating current
AIAA	American Institute of Aeronautics and Astronautics
AWC	Atlantic Wind Connection
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
CEQ	Council on Environmental Quality
COP	Construction and Operations Plan
DC	direct current
DD	Direct Drive
DFIG	Doubly fed induction generators
DOE	Department of Energy
EA	environmental assessment
EERE	Energy Efficiency & Renewable Energy
EIS	environmental impact statement
EPACT	Energy Policy Act of 2005
EWEA	European Wind Energy Association
FERC	Federal Energy Regulatory Commission
FiT	Feed-in Tariff
FONSI	Finding of No Significant Impacts
FTE	full-time equivalent
GBS	gravity-based structure
GDP	gross domestic product
GE	General Electric
GW	gigawatt
GWEC	Global Wind Energy Council
HVDC	high-voltage direct current
ISO	independent system operator
ITC	investment tax credit
JEDI	Jobs & Economic Development Impact
kV	kilovolt
kW	kilowatt
LCOE	levelized cost of energy
LIPA	Long Island Power Authority
m/s	meters per second
MI	mass impregnated
MMS	Minerals Management Service
MOU	Memorandum of Understanding
mph	miles per hour
MW	megawatt
MWh	megawatt-hour
NCF	net capacity factor
NEPA	National Environmental Policy Act
NIP	National Infrastructure Plan
Nmi	nautical mile
NREL	National Renewable Energy Laboratory
NRIP	National Renewable Infrastructure Plan
NYISO	New York Independent System Operator
NYPA	New York Power Authority
O&M	operations and maintenance
OEM	original equipment manufacturer
OREC	offshore wind renewable energy credit
OTB	Offshore Terminal Bremerhaven
PEIS	programmatic EIS
PJM	Pennsylvania-Jersey-Maryland
PMG	permanent magnetic generator
PPA	power purchase agreement
PTC	production tax credit
R&D	research and development
ReEDs	Regional Energy Deployment System
REO	rare earth oxide
ROI	return on investment
RPS	renewable portfolio standard
RTO	regional transmission organization
SAP	site assessment plan
UPR	unsaturated polyester resin
WAB	Wind Agency Bremerhaven
WEA	Wind Energy Area
WTG	wind turbine generator
XLPE	cross-linked polyethylene

Introduction

This report was produced on behalf of the Wind and Water Power Program within the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), as an award resulting from Funding Opportunity Announcement DE-FOA-0000414, entitled U.S. Offshore Wind: Removing Market Barriers; Topic Area 1: Offshore Wind Market and Economic Analysis.

The objective of this report is to provide a comprehensive annual assessment of the U.S. offshore wind market. The report will be updated and published annually for a three year period. Figures and tables that will be updated annually are indicated by the symbol ● next to the title, or by the symbol ◒ if the data will be updated only if new information becomes available. The report will provide stakeholders with a reliable and consistent data source addressing entry barriers and U.S. competitiveness in the offshore wind market.

The report was produced by the Navigant Consortium, led by Navigant Consulting, Inc. Additional members of the Navigant Consortium include the American Wind Energy Association, the Great Lakes Wind Collaborative, Green Giraffe Energy Bankers, National Renewable Energy Laboratory (NREL), Ocean & Coastal Consultants (a COWI company), and Tetra Tech EC, Inc. NREL's primary contributions were in Chapter 2, Analysis of Technology Developments, and in Chapter 4, Economic Impacts, through providing background on the JEDI model, developing the modeling input data they supplied, and benchmarking how the initial JEDI results compare with other estimates available in the literature.

Executive Summary

The U.S. offshore wind industry is slowly transitioning from early development to demonstration of commercial viability. While there are no projects in operation or even in the construction phase, there are nine U.S. projects in advanced development, defined as having either having been awarded a lease, conducted baseline or geophysical studies, or obtained a power purchase agreement. There are panels or task forces in place in at least 13 states to engage stakeholders to identify constraints and sites for offshore wind. U.S. policymakers are beginning to follow the examples in Europe that have proven success in stimulating offshore wind technological advancement, project deployment, and job creation.

This report is the first annual assessment of the U.S. offshore wind market. It includes the following major sections:

» *Section 1*: key data on the global development of offshore wind projects, with a particular focus on progress in the U.S.;
» *Section 2*: analysis of developments in the offshore wind technology sector;
» *Section 3*: analysis of policy developments at the federal and state levels that have been effective in advancing offshore wind deployment in the U.S.;
» *Section 4*: analysis of actual and projected economic impact, including regional development and job creation; and
» *Section 5*: analysis of developments in relevant sectors of the economy with the potential to affect offshore wind deployment in the U.S.

Section 1. Global and U.S. Offshore Wind Development

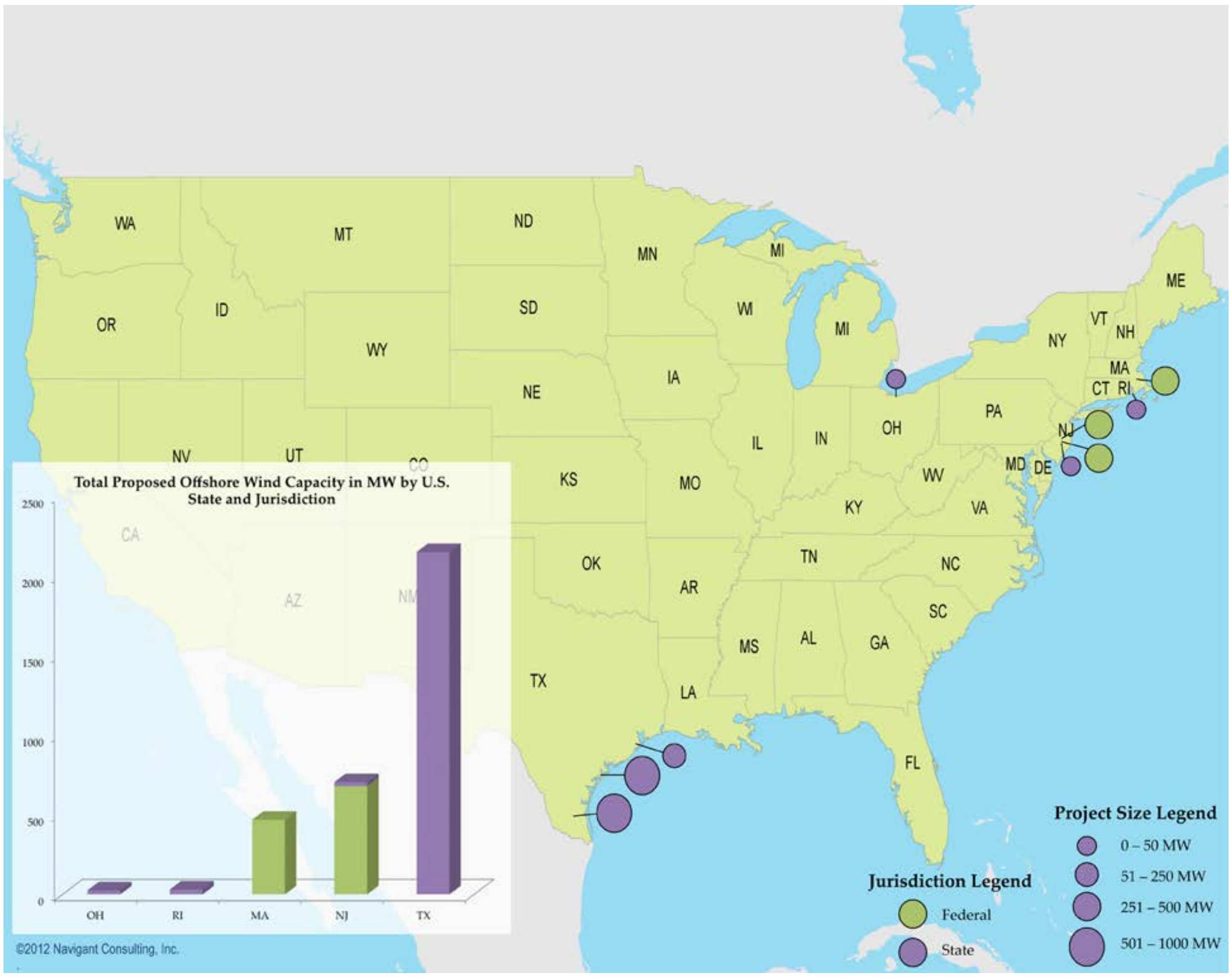
There are approximately four gigawatts (GW) of offshore wind installations worldwide. Nearly all of this activity has centered on northwestern Europe, which has led the industry's development since 1999, but China is gaining market position. Europe has seen 3 GW of offshore capacity additions over the past five years (2007-2011), and the rate of annual installations has grown from 225 MW installed in 2007 to nearly 1,258 MW installed in 2010.[1] The emerging Asian offshore market has also gained ground in recent years, with China adding 107.9 MW in 2011, bringing its cumulative installed capacity to more than 200 MW. Various forecasts have predicted between 55 and 75 GW of cumulative offshore wind capacity by 2020.

Thirty-three announced offshore wind projects lay in varying stages of development in the U.S., primarily along the Atlantic Coast. Nine of these projects have reached what this report considers an advanced stage of development. A map showing the announced locations and capacities of these nine advanced-stage projects appears in Figure 1. These nine projects represent 3,380 MW of planned

[1] BTM (a part of Navigant) has historically reported MW capacity installed in a particular year, regardless of whether it has been connected to the grid. Other sources, (e.g., EWEA) reports MW capacity based on the year in which it is connected to the grid.

capacity, but many of these projects still face challenges prior to achieving final development. As shown in the figure, three of these projects, representing about one-third of planned, advanced-stage capacity, lie in federal waters.

Figure 1. Proposed U.S. Offshore Wind Energy Projects in Advanced Development Stages by Jurisdiction and Project Size



Source: Navigant analysis

The average nameplate capacity of offshore wind turbines installed globally has grown from 2.98 MW in 2007 to 3.94 MW in 2011. This trend toward larger turbines will likely continue, driven by advancements in materials, design, processes, and logistics, which allow larger components to be built with lower system costs. The average turbine size for advanced-stage, planned projects in the U.S., however, is expected to range between 4.7 and 5.5 MW, indicating that the U.S. is largely planning to utilize larger offshore turbines rather than smaller turbines that have previously been installed in European waters.

Foundations for U.S. planned projects will likely follow similar trends as European projects, with mostly monopile substructures and increasing numbers of jackets and tripods. In the longer term, the most likely substructure types for the U.S. market will depend on site-specific requirements and the development of floating foundations.

Direct drive turbines will continue to gain market share. Some OEMs have begun designing offshore wind turbines that will utilize direct drive technology in an effort to alleviate costly downtime and maintenance issues associated with some traditional gearboxes. These potential costs will likely increase with the added logistical difficulty of performing such maintenance further offshore. Of the five U.S. projects that have committed to a turbine supplier, four will use direct drive technology.

Section 2. Analysis of Technology Developments

The added complexities of the offshore wind market mean that non-turbine costs may take on heightened importance relative to land-based wind. As a result, cost-reduction opportunities may arise not only from advancements in wind turbine technology but also from emerging trends and conceptual models in any one of several categories, including, trends in manufacturing, foundations, logistics and vessels, electrical infrastructure, and operations and maintenance strategies.

The design of offshore turbines will continue to deviate from that of land-based turbines. Significantly more attention is being paid to the demands of the marine environment. Design conditions unique to offshore wind turbines include higher wave loads, corrosive salt water, and a requirement for submarine electrical cabling and infrastructure. Offshore turbines are located further from human habitations and have significantly more challenging accessibility; as a result, newer offshore designs have enhanced turbine/nacelle access and area to perform more uptower repairs. Lower wind shear suggests that offshore turbines may not require towers as tall as might be preferred for land-based installations, despite a movement toward larger turbines.

Technological advancements and cost reductions in offshore turbines will likely be derived from incremental improvements in the various subsystems throughout the turbine. With <u>blades</u>, advanced composites including carbon fiber, new resins, epoxies and other materials are likely to be increasingly deployed. With <u>foundations</u>, it is likely that the combination of diverse seabed conditions, deeper water, and larger turbines will push the industry away from monopile foundations to alternatives such as jackets, tripods, gravity base structures, floating structures, and suction caissons. With <u>drivetrains</u>, high-energy density permanent magnets sourced from rare earth materials offer the potential to realize direct drive technologies, although new direct drive platforms lack an extensive performance record. It is not yet clear that direct drive generators offer superior performance and reliability under the actual working conditions experienced by offshore turbines. As a final example, lower cost power conversion is expected from deployment of higher voltage <u>power electronics</u>.

Today there are three primary conceptual models envisioned for producing, staging, and installing equipment: (1) import-dominated, (2) regional hub, and (3) dispersed manufacturing. These models source equipment as follows:

- *Import-dominated model*. The most likely major piece of equipment to be manufactured domestically is the foundation, since U.S. oilrig foundation fabrication experience could be transitioned to serve offshore wind, even for the initial projects.
- *Regional hub model*. Only the very specialized electrical infrastructure equipment might not be produced in the region where the equipment is installed.
- *Dispersed manufacturing model*. Production, fabrication, and investment are less centralized and would likely develop more organically as the industry matures and demand grows over time. Existing ports are adapted or retrofitted to accommodate the immediate staging, storage, lift capacity, and air draft needs of the industry, without trying to become exclusive sites for all future offshore manufacturing and staging activities.

As the industry matures, there will be a need for increased production of offshore wind vessels capable of installing 5+ megawatt (MW) turbines in deeper waters. Heavier rotors, nacelles, and foundations will require cranes with greater lifting capacity. Many of the vessels that have been taken from the offshore oil and gas industry for use in the offshore wind industry are too small, forcing contractors to make more trips to port. As the industry moves toward purpose-built vessels, these vessels will have larger storage capacity and larger cranes.

Much of the expertise gained in the oil and gas sector has been leveraged in the offshore wind sector. Early turbine installation vessels were jack-up barges repurposed from the oil and gas sector. Companies with expertise in oil and gas, such as Statoil and Fluor, have moved into offshore wind. Moreover, turbine foundation designs such as the jacket type have been adapted from the oil and gas sector.

There is a need for significant upgrades in ports since they were not designed with the offshore wind industry in mind. The three main wind-specific requirements for ports are sufficient quaysides, adequate laydown areas, and sufficient clearances. Quaysides generally need to be 200-300 meters long for vessels to be able to load and unload large components such as towers and blades. Laydown acreage is key for storage and preassembly of turbines and foundations. Overhead clearances of 100 meters are necessary to enable passage of vertically positioned tower sections, but, many vessels can accommodate horizontally positioned tower sections reducing the required vertical clearances. Lateral clearances must accommodate for either star or bunny ear rotor configurations.

The offshore wind industry faces similar transmission planning issues as the land-based wind industry. There has always been a "chicken and egg" dilemma when it comes to transmission expansion, often leading to project delays. Wind developers often will not build wind farms without sufficient transmission. Transmission operators often will not build new transmission lines without sufficient assurances that they will be able to recover their costs. Cost allocation methodologies are complicated as well, and require adequate advance planning time on the part of multiple stakeholders.

Improved siting of wind farms, new operations strategies and technologies, and enhanced access to turbines designed exclusively for the offshore market are anticipated to boost plant production and minimize operations expenditures. Operators tend to be focused on minimizing unplanned maintenance and replacing corrective maintenance efforts with more regular and more effective preventative maintenance. Advanced condition monitoring techniques might also include self-diagnosing systems, real-time load response, and enhanced abilities to manipulate and control individual turbines from an onshore monitoring facility. Coordinating preventative maintenance efforts with improved wind and weather forecasting should allow operators to minimize turbine production losses.

Section 3. Analysis of Policy Developments

U.S. offshore wind development faces significant challenges: (1) the relatively high cost of offshore wind energy; (2) a lack of infrastructure such as transmission and purpose-built ports and vessels; and (3) uncertain and lengthy regulatory processes. Various U.S. states, the federal government, and European countries have used a variety of policies to address each of these barriers with varying success.

For the U.S. to maximize offshore wind development, the most critical need is for stimulation of demand through addressing high cost. This critical need was addressed through a portfolio approach of policies by the U.S. land-based wind market, which has been stimulated through a mix of above-market Power Purchase Agreements (PPAs), Production Tax Credits (PTCs), Investment Tax Credits (ITCs), and Renewable Energy Credits to demonstrate compliance with Renewable Portfolio Standards (RPSs). Other examples of policies that have addressed this critical need include the Feed-in Tariff (FiT), which many European countries have used to stimulate offshore wind demand and U.S. states have begun adopting for smaller renewable energy projects.

Increased infrastructure is necessary to allow demand to be filled. Examples of transmission policies that can be implemented in the short term with relatively little effort are to (a) designate offshore wind energy resources zones for targeted grid investments, (b) establish cost allocation and recovery mechanisms for transmission interconnections, and (c) promote utilization of existing transmission capacity reservations to integrate offshore wind.

Regulatory policies cover three general categories: (a) policies that define the process of obtaining site leases; (b) policies that define the environmental, permitting processes; and (c) policies that regulate environmental and safety compliance of plants in operation. An example of effective leasing policy is the Bureau of Ocean Energy Management (BOEM) "Smart from the Start" policy of identifying appropriate areas for leasing in conjunction with state officials, conducting an initial environmental assessment under the National Environmental Policy Act (NEPA), and then issuing an initial lease for site assessment studies and a commercial lease for construction and operation of the facilities. An example of effective permitting policy is the BOEM process for coordinating the consultations and approvals of federal agencies during the leasing process and requiring Environmental Assessments for initial phases and a single Environmental Impact Statement for construction and operation as the Lead Federal Agency under NEPA. . An example of effective operating plant environmental and safety compliance is self-monitoring by owner/operators, balanced with government oversight in critical areas.

Section 4. Economic Impacts

A 500 MW reference plant installed in the mid-Atlantic in 2018 is estimated to have capital costs of \$3.04 billion or \$6,080/kilowatt (kW). Total operations and maintenance (O&M) costs are assumed to be approximately \$68 million/year or \$136/kW-year. On a per kW basis, these estimates are 2.5 to 4 times the cost of land-based wind. Offshore wind costs are expected to decrease by 3.7% per year in the near term, slowing to 1.5% per year by 2030. These cost estimates are key inputs to a new Jobs and Economic

Development Impact (JEDI) model for offshore wind and are sensitive to multiple assumptions such as water depth, distance to the nearest staging port, foundation type, and financing rates.

The Offshore JEDI model shows that a 500 MW reference wind plant could support approximately 3,000 job-years over the construction period and drive $584 million in local spending over the same period. During operation, the plant (and the resulting local impacts) could support 313 jobs each year in the local economy and $21 million per year in local spending. These numbers are strongly dependent upon the percentage of local assumptions and would increase by three to fourfold if all components and services were sourced from the region.

In the high-growth scenario, the U.S. offshore wind industry could support ~350,000 FTEs by 2030, but in the low-growth scenario, it could be ~50,000. Given the supply chain and industry dynamics of the offshore wind industry, most jobs are in indirect and induced industries. These results are strongly dependent on the domestic sourcing assumptions. For the North Atlantic region alone over the same time period, construction and operation of offshore wind plants in the region could support ~70,000 FTEs in the high-growth case and ~17,000 FTEs in the low-growth case.

In the high-growth scenario, the U.S. offshore wind industry could drive $70 billion (in 2011 dollars) per year by 2030 but in the low-growth scenario it could be ~$10 billion. Given the supply chains and industry dynamics of the offshore wind industry, most of the economic activity is in indirect and induced industries. These results are strongly dependent on the domestic sourcing assumptions. For the North Atlantic region alone over the same time period, construction and operation of offshore wind plants in the region could drive $14 billion per year in the high-growth case and $3.5 billion per year in the low-growth case. These results are strongly dependent on the local sourcing assumptions. If more components and services were sourced locally, the numbers could increase by three to fourfold

Section 5. Developments in Relevant Sectors of the Economy

The development of an offshore wind industry in the U.S. will depend on the evolution of other sectors in the economy. Factors within the power sector such as the capacity or price of competing power generation technologies will affect the demand for offshore wind. Factors within industries that compete with offshore wind for resources (e.g., oil and gas, construction, and manufacturing) will affect the price of offshore wind power.

Factors in the power sector that will have the largest impact include: (1) the change in the price of natural gas, and (2) the change in coal-based generation capacity. Natural gas-fired generation is wind's primary competitor in the U.S. Natural gas prices declined from above $4/MMBtu in August 2011 to below $2/MMbtu in April 2012, in large part due to the supply of low-cost gas from the Marcellus Shale.

Between January 2010 and March 2012, 106 coal plant retirements had either been planned or executed, representing 42,895 MW or 13% of the coal fleet. Continued coal plant retirements could increase the demand for offshore wind plants in the U.S.

1. Global and U.S. Offshore Wind Development

As of this report's writing, no offshore wind projects have yet begun construction in the U.S.; however, developers have announced plans for several dozen potential projects. While most of these remain in a conceptual planning stage, some have progressed to more advanced stages. As the U.S. market gets off the ground, project characteristics will likely follow the general trends occurring in the European offshore wind market. In particular, these trends include increasing turbine and plant capacities, technology advancements related to foundations and drivetrains, and increasing water depths and distances to shore. For the U.S., however, differences in wind resources and seabed conditions will influence the degree to which these factors align with global trends in the European or emerging Asian markets or even show consistency among each U.S. region.

This section presents an overview of the global offshore wind market and illustrates several of these trends in more detail. This analysis draws upon an offshore wind project database compiled from existing project databases and an ongoing review of developer announcements and industry new coverage.[2] This database comprises information related to several characteristics for each project, including but not limited to the following:

- Basic project data, including the project's capacity, location, water depth, and distance to shore
- A technology profile that includes turbine models and capacities, foundation types, drivetrain types, and other plant-specific information
- Key dates for planning/development, permitting, investment, construction, and completion
- Supplier data for components such as turbines, towers, foundations, substations, and other balance of plant items
- Financial and policy data such as power pricing, finance structure, and debt type, amounts, and maturity dates

Note that for planned projects, this data relies primarily on developer projections and news reports, and that the status and details of projects under development are subject to change.

[2]The authors would like to acknowledge BTM Consult, Green Giraffe Energy Bankers, and the National Renewable Energy Laboratory (NREL) for their contributions of project information they had previously collected. In addition, the team relied on publicly available information from the 4C Offshore Wind Farm Database (4C Offshore 2012) and the Global Wind Energy Council (GWEC 2012).

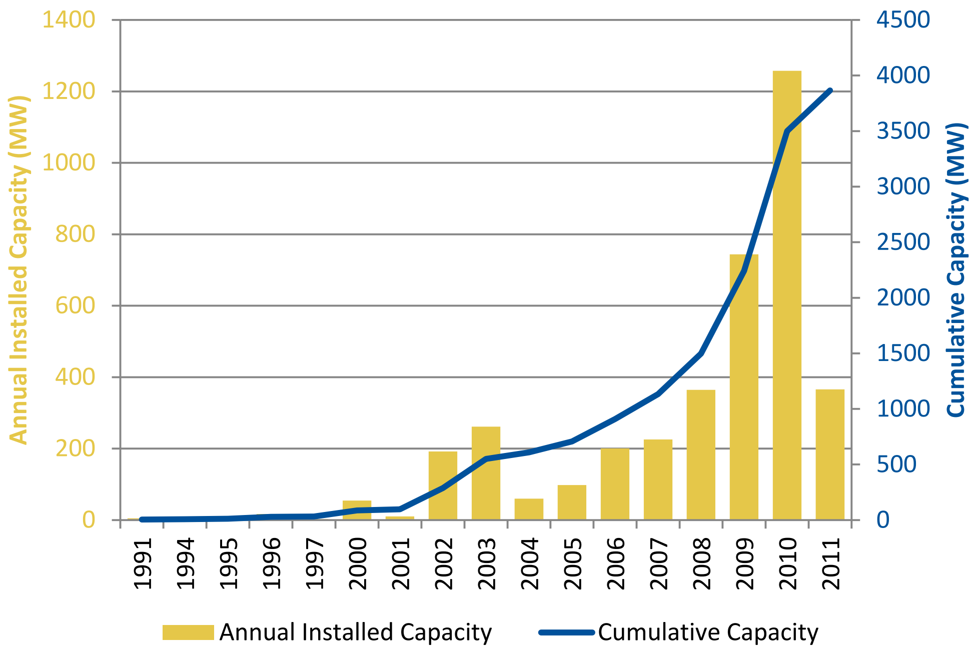
Summary of Key Findings – Chapter 1
» There are approximately 4 GW of offshore wind installations worldwide. » Thirty-three announced offshore wind projects lay in varying stages of development in the U.S, primarily along the Atlantic Coast, but only nine of these projects have reached an advanced stage of development. » The average nameplate capacity of offshore wind turbines installed globally each year has grown from 2.98 MW in 2007 to 3.94 MW in 2011. » Foundations for U.S. planned projects will likely follow similar trends as European projects, with mostly monopile substructures and some jackets and tripiles. » Direct drive turbines will likely continue to gain market share. » The offshore wind industry entails additional risks relative to land-based wind that make securing financing more challenging.

1.1 Global Offshore Wind Development

While the land-based wind market is geographically diverse, the offshore market has been primarily focused on northwest Europe. The offshore market was pioneered in Denmark in the late 1990s and early 2000s, driven primarily by fallout from the 1979 energy crisis, rising carbon dioxide per-capita emissions, and the Chernobyl accident. In 2008, the U.K. took the lead with Germany showing strong growth as well (BTM 2010). Collectively, Europe has seen nearly 3 gigawatts (GW) of offshore capacity additions over the past five years (2007-2011), with a rate of annual installations that has ranged from 225 megawatts (MW) installed in 2007 to 1,258 MW installed in 2010 (BTM 2012).[3]Figure 1-1 summarizes the historical growth of the European offshore wind market.

[3] Various sources use different approaches for reporting annual capacity estimates. BTM (a part of Navigant) has historically reported MW capacity installed in a particular year, regardless of whether it has been connected to the grid. Other sources, (e.g., EWEA) reports MW capacity based on the year in which it is connected to the grid. As a result, estimates of annual capacity additions may vary. For example, EWEA's estimate for 2011 European capacity additions shows 866 MW (EWEA 2012), while BTM's shows only 366 MW. This is likely a result of 500 MW installed in 2010 not being connected to the grid until 2011.

Figure 1-1. Historical Growth of the European Offshore Wind Market



Note: Shows capacity in the year it was installed, but not necessarily grid connected. Includes commercial and test projects.
Source: BTM 2012, a part of Navigant

The emerging Asian offshore market has also gained market share in recent years, with China adding 107.9 MW in 2011, bringing its cumulative installed capacity to more than 200 MW (BTM 2012).Table 1-1 provides a summary of the current global offshore market in number of projects, cumulative capacity, and number of turbines by country.

Table 1-1. Summary of Installed Global Offshore Capacity through 2011

Region	Country	Number of Operational Projects	Total Capacity (MW)	Total Number of Turbines Installed
Asia	China	4	211.4	75
	Japan	3	25.32	14
Europe	Belgium	2	195	61
	Denmark	16	874.65	406
	Finland	3	32.3	11
	Germany	6	205.8	53
	Ireland	1	25.2	7
	Italy	1	0.1	1
	Netherlands	4	246.8	128
	Norway	1	2.3	1
	Portugal	1	2.0	1
	Sweden	5	163.65	75
	United Kingdom	20	2,117.6	640
	Total	**68**	**4,102**	**1,472**

Note: Includes commercial and test projects. Individual phases of projects at a single site may be counted as separate projects.
Source: BTM 2012, a part of Navigant

As shown, current global offshore wind power capacity totals just more than 4.1 GW, with most development to date having occurred in northwest Europe, especially the United Kingdom. Some forecasts expect European countries to install an additional 16 GW of capacity before the end of 2016 (BVG Associates 2011a). While Europe (particularly the U.K. and Denmark) leads the global market, China is positioning itself to make rapid progress. As the world's largest land-based wind power market with 62 GW of operational land-based wind power at the end of 2011, China has announced plans to install 5 GW of offshore wind by 2015 and 30 GW by 2020 (GWEC 2012). Based on each country's announced targets and considerations about the political, economic, and supply chain factors influencing the market, various forecasts have predicted the global offshore wind market to reach between 55 and 75 GW of cumulative capacity by 2020 (IHS Emerging Energy Research 2010; BTM Consult 2010; BVG Associates 2011a).

1.2 U.S. Project Development Overview

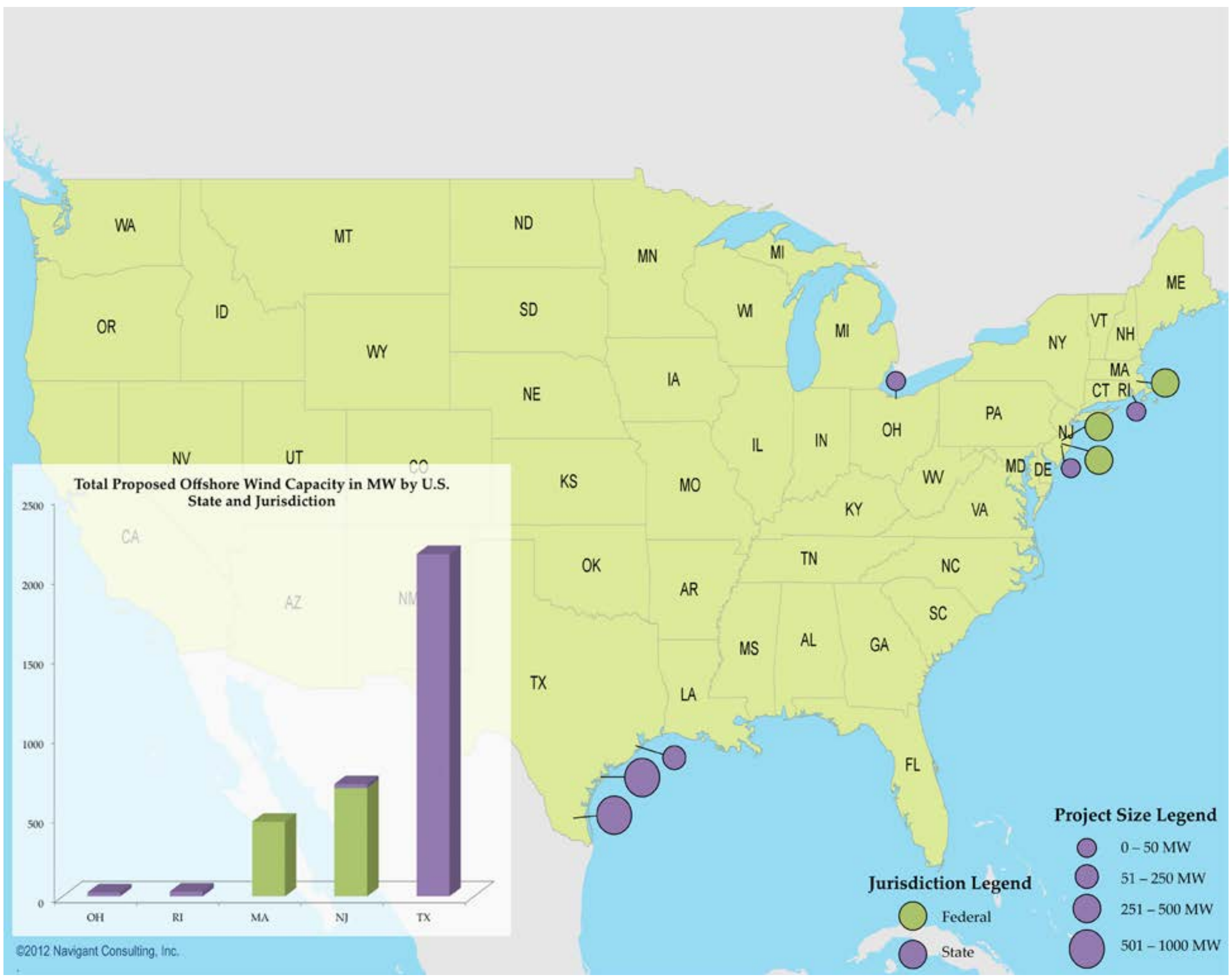
As of this report's publication, 33 announced offshore wind projects lay in varying stages of development in the U.S., primarily along the Atlantic Coast. Nine of these projects have reached what Navigant considers to be an advanced stage of development, which a project achieves by having accomplished at least one of the following three milestones:

- Received approval for an interim limited lease or a commercial lease in state or federal waters

» Conducted baseline or geophysical studies at the proposed site with a meteorological tower erected and collecting data, boreholes drilled, or geological and geophysical data acquisition system in use
» Signed a power purchase agreement (PPA) with a power off-taker

A map showing the announced locations and capacities of these nine advanced-stage projects appears in Figure 1-2.

Figure 1-2. Proposed U.S. Offshore Wind Energy Projects in Advanced Development Stages by Jurisdiction and Project Size



Source: Navigant analysis

These nine projects represent 3,380 MW of planned capacity. As shown in the figure, less than half of this capacity lies in federal waters (i.e., typically outside a 3 nautical mile state boundary). This greater distance from shore generally provides those projects with access to a marginally better wind resource; however, many market actors perceive the federal permitting process as more lengthy and subject to delays than what they may face at the state level (NREL 2010). Notably, the federal water boundary in

Texas lies further out at nine nautical miles, allowing a comparatively greater number of projects to fall under state jurisdiction. Table 1-2 provides additional details about each of the nine advanced-stage projects, including nameplate capacity, number of turbines, turbine make and model, turbine capacity, water depth and distance to shore, status notes, and an estimated completion date.

Table 1-2. Summary of Advanced-Stage U.S. Projects

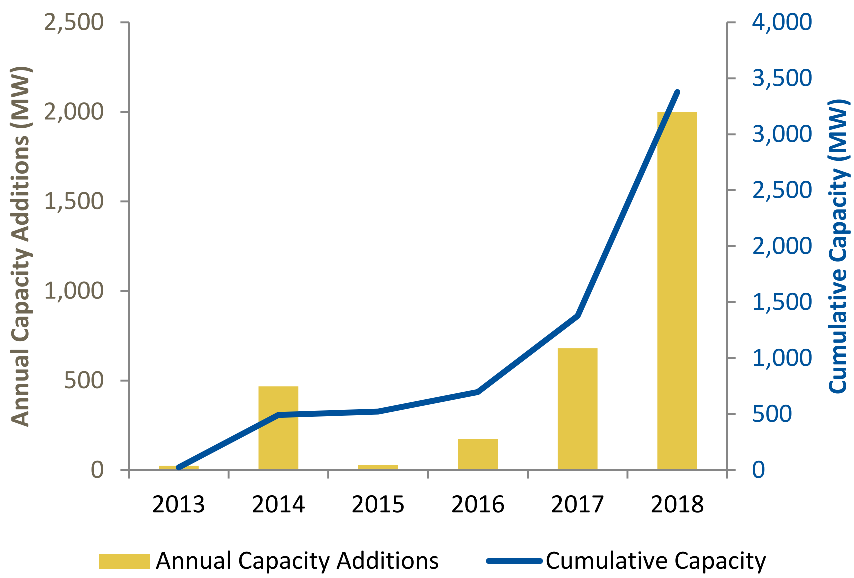
Project Name (State)	Proposed Capacity (MW)	Turbines (#)	Distance to Shore (miles)	Average Water Depth (m)	Projected Turbine Model	Status Notes	Target Completion Date[b]
Block Island Offshore Wind Farm (Deepwater) (RI)	30	5	3	N/A	Siemens SWT 6.0-120 (6 MW)[a]	National Grid has agreed to a 20-year PPA. U.S. Army Corps of Engineers permit application and environmental studies underway.	2015
Cape Wind Offshore (MA)	468	130	10	10	Siemens SWT 3.6-107 (3.6 MW)*	Project approved for federal waters and commercial lease offered in April 2010. In July 2012, the project commenced geotechnical and geophysical survey operations as part of its final design phase.	2014
Fisherman's Energy: Phase I (NJ)	25	6	3	11.5	XEMC-Darwind XD115 (5 MW)	Received final permits from Army Corps of Engineers	2013
Fisherman's Energy: Phase II (NJ)	330	66	12	17.5	XEMC-Darwind XD115 (5 MW)	Received a met tower rebate from the state and began baseline surveys in August 2009.	2017
Galveston Offshore Wind (Coastal Point Energy) (TX)[c]	150	60	7	14.5	XEMC-Z72-2000 (2.75 MW)	Received lease from Texas General Land Office	2016
Garden State Offshore Energy Wind Farm (NJ)	350	70	20	25	(5 or 6 MW)	Awarded an interim limited lease and began conducting baseline surveys in 2009.	2017
Lake Erie Offshore Wind Project (Great Lakes) (OH)	27	9	7	18	Siemens SWT-3.0-101(3 MW)	Developers have signed lease with State of Ohio.	2016
Baryonyx Rio Grande Wind Farm (TX)[c]	1000	100-200	4.5	22	(5 or 6 MW)	Received lease from Texas General Land Office in 2009. Army Corps of Engineers environmental studies underway.	2018
Baryonyx Mustang Island Wind Farm (TX)[c]	1000	200	10	20	(5 or 6 MW)	Received lease from Texas General Land Office in 2009	2018

a) These projects have committed to a specific turbine with a turbine supply agreement in place. All other stated turbines are based on developer statements and may change.
b) Dates shown in this table are based on developer statements and may change based on permitting, leasing, surveying, and other activities.
c) Leasing and permitting requirements for projects in Texas state waters do not involve the Federal Energy Regulatory Commission or the BOEM Minerals Management Service, and may move more quickly than projects in federal waters.
Source: Navigant analysis based on published project information, developer statements and media coverage

According to developer statements, all nine projects have target completion dates before the end of 2018, and developers for three of the projects – Block Island, Cape Wind, and Fisherman's Energy Phase I – are seeking to be the first offshore wind farm online in U.S. waters. Given historical trends, however, it is unlikely that all nine of these projects will achieve these targets due to delays or cancelations due to an inability to obtain PPAs, the expected expiration of the PTC at the end of 2012, low natural gas prices, and other issues. For example, a BOEM Wind Area auctioning process will help determine whether these projects can continue to move forward in these locations, or if other projects in earlier stages of development may ultimately replace them. In addition to the projects listed, the Department of Energy is seeking to support several pilot-scale demonstration projects. While these projects may not meet the above "advanced" project criteria, their smaller scale, receipt of targeted federal support, and state support may facilitate their installation and make them among the first projects in U.S. waters.

Assuming the nine advanced-stage projects do achieve their announced target dates, the initial growth of the U.S. offshore market would follow a trajectory like that shown in Figure 1-3.

Figure 1-3. Growth Trajectory for U.S. Offshore Wind if Announced Target Dates are Met



Source: Navigant analysis of collected project data

Given that larger capacity projects will likely be completed and come online in phases, one might expect the trajectory in the above figure to follow a more gradual upward trend. For comparison, in its first five years of commercial-scale projects (2000-2004), the European offshore market added a total of 578 MW. As mentioned in Section 1.1, in its most recent five years (2007-2011) Europe added a total of nearly 3 GW, with more than 1,600 MW added in 2010 and 2011 combined (see Figure 1-1).

As previously shown in Figure 1-2, the advanced-stage U.S. projects lie primarily along the northern Atlantic Coast (i.e., New England and the Mid-Atlantic) and the Texas Coast. Thus far, no proposed Pacific Coast or Southern Atlantic Coast projects have reached an advanced development stage. Each region with offshore wind potential has unique characteristics and potential barriers that may aid or hinder the development of offshore wind farms; the following subsections discuss some of these region-specific factors.

1.2.1 Northern Atlantic Coast

The Northern Atlantic Coast has the highest shallow water offshore wind potential in the U.S., with class 5 and 6 winds

This region comprises the New England states and most of the Mid-Atlantic coastal states (excluding Virginia). This region of the U.S. has the highest offshore wind potential in water depths that are accessible with current technology, with class 5 and 6 winds throughout (NREL 2010). Some shallow-water sites may be available along New England shores, but the seabed is typically deeper than in other parts of the Atlantic. The availability of large areas of shallow water increases further south off the coasts of New Jersey and Maryland. This region is subject to moderate hurricanes and nor'easters that may dictate the design and layout of offshore wind farms.

1.2.2 Southern Atlantic Coast

This region comprises the Atlantic coastline from Virginia south to Florida. Wind speeds are slightly lower than those in the Northern Atlantic states; however, the region has the advantage of large areas of shallow waters further from shore that are well suited for near-term offshore wind technologies. While hurricanes present a more significant concern than in the Northern Atlantic region, developers must assess such risks on a site-specific basis that considers the effects of coastal geography and latitude on storm tracks and intensity (NREL 2010).

1.2.3 Great Lakes

Eight states have coastlines along one of the five Great Lakes, which vary in their physical (e.g., bathymetry and wind resource), environmental, and socioeconomic characteristics. Consequently, local and state governance means that the acceptance and regulation of offshore wind will differ from one state to the next. The lakes present unique barriers, including greater concerns over blade and lake surface icing as well as the fact that existing offshore wind installation vessels will not fit through the Saint Lawrence Seaway. Conversely, they also offer advantages that include lower wave heights (which are factored into tower design) and potential synergies with Canadian offshore wind efforts. Recent resource mapping indicates that the Great Lakes region has a wind resource between class 4 and 6 (NREL 2010). Currently, plans exist for a single advanced-stage project in Lake Erie near Cleveland, Ohio.

1.2.4 Gulf Coast (Gulf of Mexico)

The Gulf Coast region comprises the Gulf of Mexico coastlines from Florida to Texas, where one project has reached advanced planning stages. Comprehensive wind data is not yet available for the entire region; however, existing studies indicate that the strongest wind potential may lie along the Texas coast from Corpus Christi south to the Mexican border. In addition, Texas's state boundary waters extend to nine nautical miles (nm) offshore compared to the 3 nm typical of other states, providing Texas an advantage in terms of permitting offshore wind outside of the federal permitting process. However, any turbines installed in this region will need to consider the potential for extreme hurricanes in their design and siting.

1.2.5 Pacific Coast

To date, no U.S. offshore wind projects have reached advanced planning stages along the Pacific Coast. In this region, the best near-term opportunities may lie in the shallower waters off the coast of California. Overall, the region's narrow continental shelf may limit the shallow-water resource and stunt offshore wind development until deep-water technology is further developed. If such deep-water and floating technology advances, the region's wind resources (consistently class 6 with some class 7 resource in California) and decreased risk of sea ice, hurricanes, or other catastrophic weather events provide for an attractive market for future development.

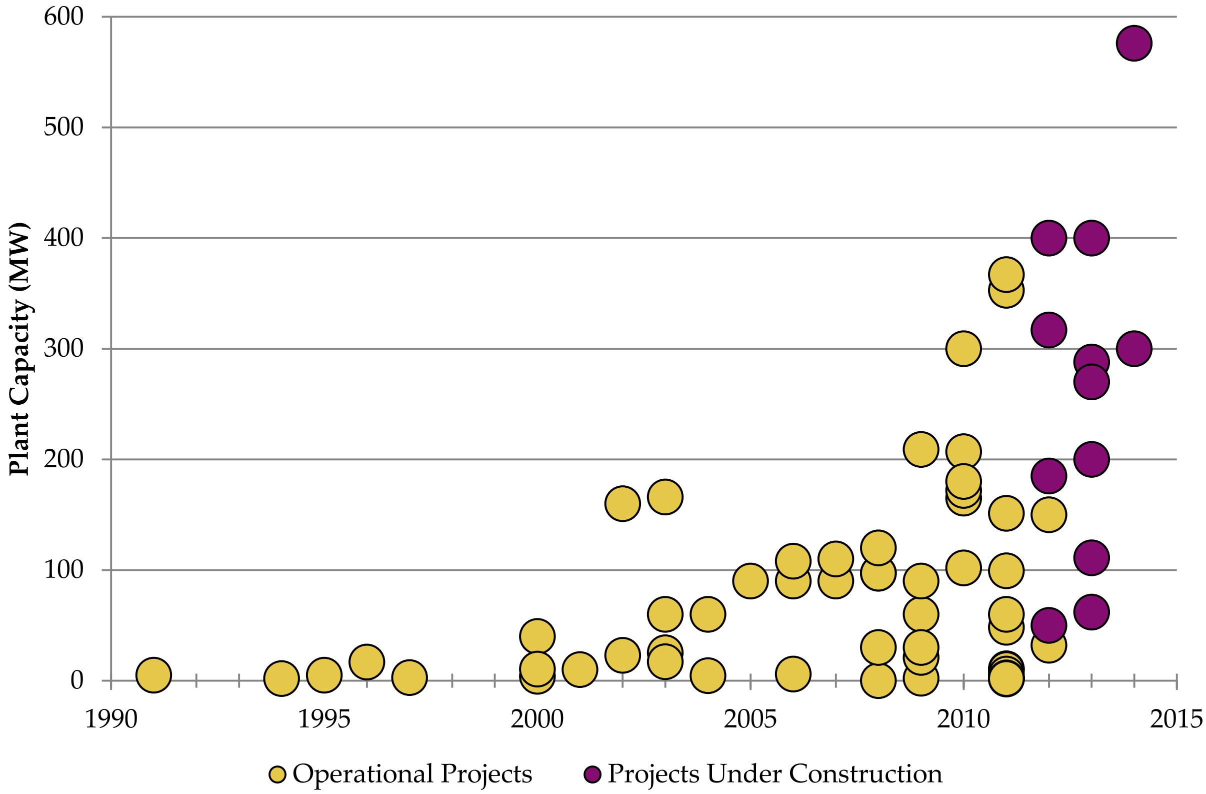
1.3 Market Segmentation and Trends

After more than ten years of developing and constructing offshore wind plants, the lessons learned by manufacturers and developers in the European market will provide key lessons for the U.S. offshore wind market by reducing technology risks and lowering costs. As previously noted, U.S. projects will likely follow general global trends in installed plant capacities, turbine sizes, technology advancements, depth, and distance to shore. However, some of the most state-of-the-art turbines have been developed specifically for European waters (e.g., wind conditions in the North Sea) and cannot be deployed in the U.S. waters without some design enhancements. This and other location- or market-specific characteristics will not allow the U.S. to follow European trends exactly. The following sections highlight and discuss each of these trends in more detail.

1.3.1 Plant Size

Over the past two decades, offshore wind farms have become larger in size and capacity. In the early 1990s, most plants were built for demonstration purposes. As developers become more confident in offshore wind technologies and demand increases, it is likely that plant sizes will continue to grow. These larger plants coincide with projects moving further from shore into deeper waters and using larger turbine designs to take advantage of stronger offshore winds. Figure 1-4 illustrates the increasing trend in plant sizes over time, with red bubbles showing the anticipated plant size for projects currently under construction according to their planned completion dates.

Figure 1-4. Global Offshore Wind Plant Capacities

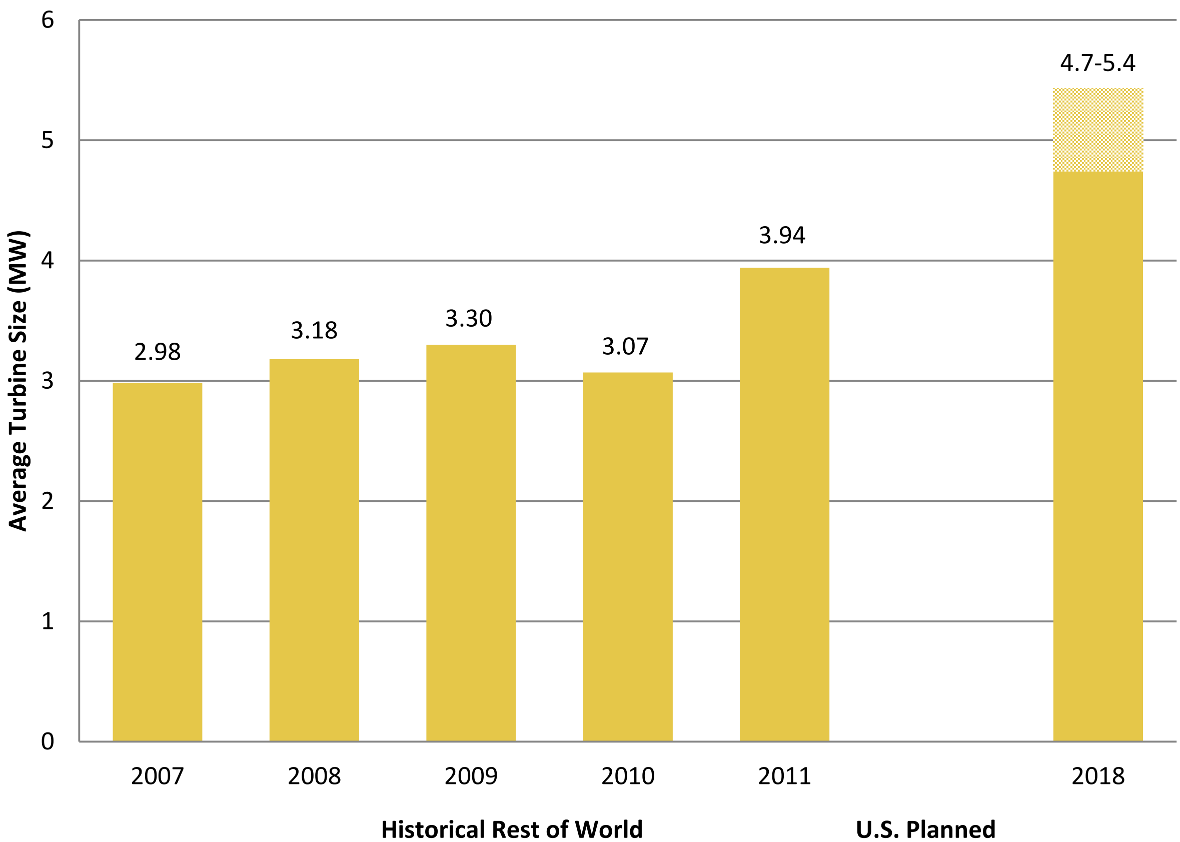


Note: Plant capacities are shown for the year each project reached completion.
Source: Navigant analysis

1.3.2 Turbine Capacity

The average capacity-weighted nameplate capacity of offshore wind turbines installed between 2007 and 2010 ranged from 2.98 to 3.30 MW. In 2011, however, the average size of newly installed turbines increased to 3.94 MW as projects have increasingly deployed 3.6 MW and 5 MW turbines. As shown in Figure 1-5, this trend toward larger turbines will likely continue, with U.S. advanced-stage planned projects expected to have an average size of between 4.7 and 5.5 MW, depending on the machine size chosen for the three projects that have not announced their intended turbine – Deepwater's Garden State Offshore Energy, Baryonyx's Mustang Island Wind Farm, and Baryonyx's Rio Grande Offshore Wind Farm.

Figure 1-5. Average Turbine Size for Historic Global and Planned U.S. Offshore Wind Farms



Note: Average turbine size is based on an annual capacity-weighted figure.
Source: BTM 2012; a part of Navigant

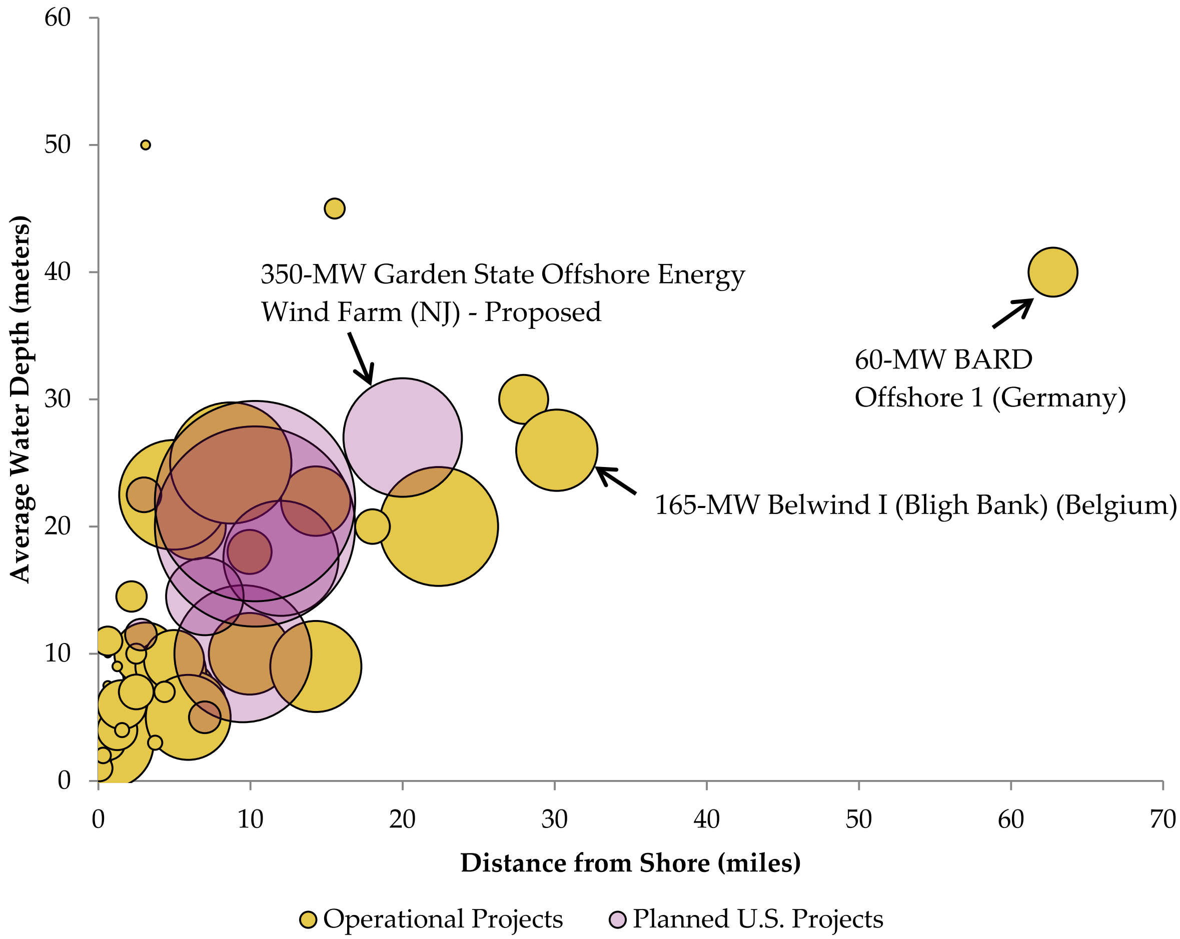
Notably, the expected average turbine size for U.S. planned projects is greater than that for European projects under construction. This indicates that the U.S. is generally planning to utilize larger turbines offshore immediately, rather than start with smaller turbines that have already been widely implemented in Europe.

The U.S. is generally planning to utilize larger turbines offshore immediately, rather than start with smaller turbines that have already been widely implemented in Europe.

1.3.3 Depth and Distance from Shore

As noted above, European developers are increasingly building offshore wind plants further from the coast and in deeper waters. A recent EWEA analysis of planned and under-construction projects shows that this trend will likely continue in that market (EWEA 2012). As shown in Figure 1-6, advanced-staged projects planned for the U.S. are generally planned for closer to shore than European projects currently in operation; however, some are sited in relatively deeper waters.

Figure 1-6. Depth and Distance from Shore for Global Offshore Wind Farms

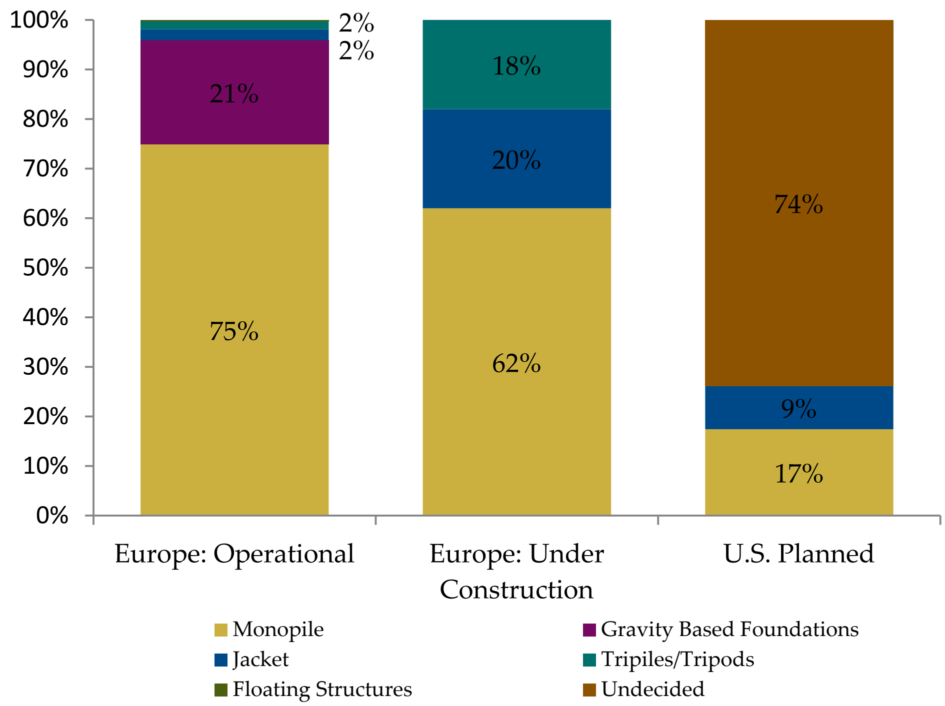


Note: Bubble size indicates projects' relative capacities; several projects are labeled for scale.
Source: Navigant analysis of BTM project data (BTM 2012)

1.3.4 Technology Types – Substructures

While most operating European offshore projects have used monopile and gravity-based foundations, jacket and tripod designs are gaining share as projects move into deeper waters and increase in size (EWEA 2012). Figure 1-7 shows the share of various substructure types (by number of turbines) in operating European projects, European projects currently under construction, and advanced-stage U.S. offshore wind farms.

Figure 1-7. Historic and Planned Substructure Types for Offshore Wind Projects



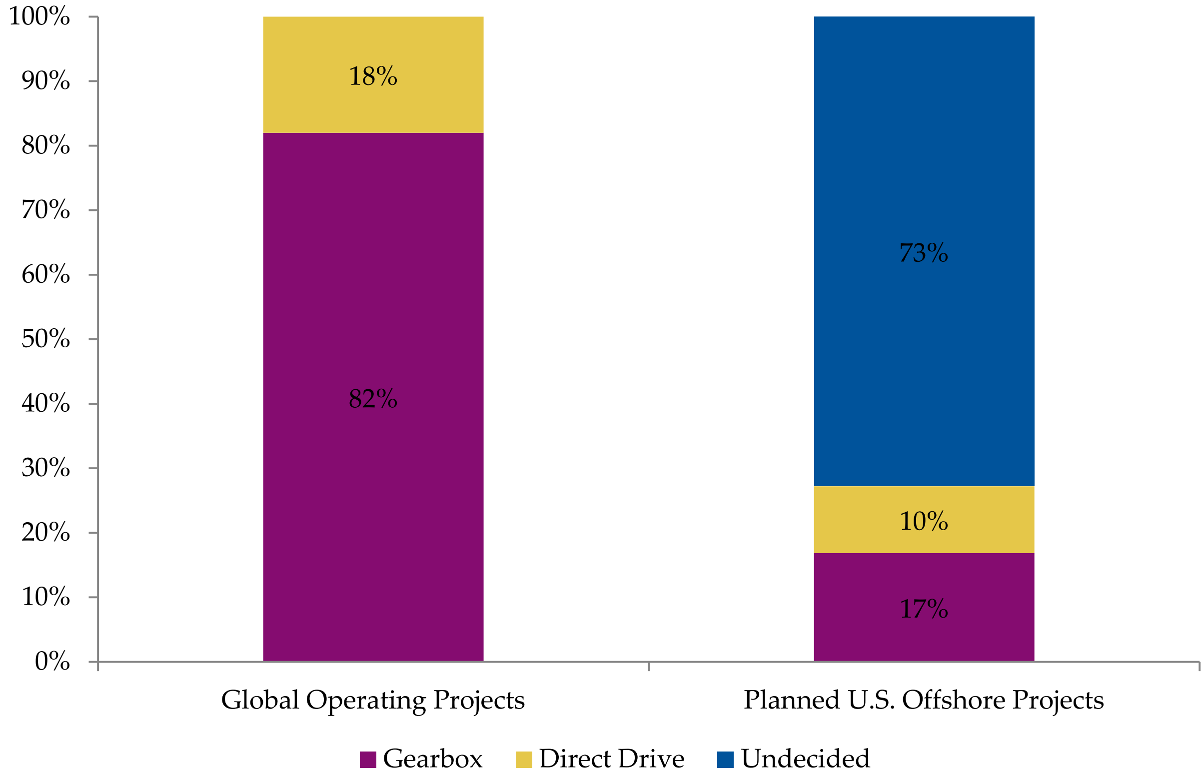
Note: Percentages are based on the number of turbines using each substructure technology.
Sources: EWEA 2012; Navigant analysis of announced U.S. project data

Currently, only three U.S. projects have committed to a substructure type—one project utilizing monopile substructures and two that plan to use jacket substructures; however, monopiles have been committed to a larger number of turbines (130 for Cape Wind). While substructure types are highly dependent on the project location and the turbine type and size selected, near-term planned projects in the U.S. will likely follow similar trends as European projects being constructed, with mostly monopile substructures and an increasing share of jackets and tripods. In the longer term, the most likely substructure types for a future U.S. market will depend on site-specific requirements and the viability of floating foundations.

1.3.5 Technology Types – Drivetrains

Some OEMs have begun designing offshore wind turbines that will utilize direct drive technology in an effort to alleviate costly downtime and maintenance issues that have arisen with some traditional gearboxes. For example, at the Horns Rev wind farm, 80 turbines needed to be removed and repaired due to the effect of saltwater and air on the generators and gearboxes, only two years after their installation. These potential costs will likely increase with the added logistical difficulty of performing such maintenance further offshore. Figure 1-8 illustrates the current share of drivetrain types for existing global offshore wind projects and planned U.S. offshore wind projects.

Figure 1-8. Historic and Planned Drivetrain Types for Offshore Wind Projects



Note: Percentages are based on the number of turbines using each drivetrain technology.
Sources: BTM 2011; a part of Navigant

Navigant's wind project database indicates that such direct drive turbines will continue to gain market share moving forward. Of the five U.S. projects that have stated plans for use of a specific turbine, four plan on using direct drive turbines. The direct drive turbines currently planned for use in U.S. projects include the Siemens SWT-6.0-120, Siemens 3.0DD-113, the XEMC Z72-2000, and the XEMC-Darwind XD115. However, as noted in Table 1-2's footnote, not all of these projects have firmly committed to turbines. In particular, the developers considering the XEMC turbines may reconsider due to possible regulatory discomfort associated with Chinese technology. The only project with a firm commitment to specific turbines is Cape Wind.

1.4 Financing Trends

The wind power market, including land-based wind, has historically faced financing challenges. For the U.S. land-based market in particular, obtaining financing has not been easy. Prior to the Section 1603 Cash Grant program, the federal tax credit-based incentive mechanism in the U.S. required the support of tax equity investors as fewer companies had sufficient tax liabilities to capture the tax credits. The relatively small pool of large tax equity investors has grown even smaller since the recent economic crisis, although it is starting to grow again.

The offshore wind industry, however, entails additional risks relative to land-based wind that make securing financing more challenging. There is additional technology risk, especially with 5.0+ MW turbines given their relatively short operating history. As projects move further offshore, technology risk will also arise from new foundation types and HVDC transmission lines. Weather and supply chain constraints will add additional construction and operating risk until new mitigation mechanisms are developed. Furthermore, regulatory risk will exist in some jurisdictions until clearly defined regimes for permitting and transmission development are established. As a result, lenders may charge risk premiums over the market interest rates for land-based projects. In a 2010 survey, 76% of respondents indicated that the risk premium for offshore wind projects is "high" or "significant" (KPMG 2010).

1.4.1 Rising Capital Requirements

The pursuit of economies of scale in offshore wind farms drives up project sizes. Larger project capacity and higher per-MW installation costs compared to land-based wind increase the amount of capital needed. The world's largest operational land-based wind farm, the 781.5 MW Roscoe Wind Farm in Texas, completed in 2009, cost more than $1 billion (O'Grady 2009). Given the higher per-MW costs of offshore projects, the total cost of offshore wind farms is already surpassing that of even the largest land-based wind farms. As of July 2012, the world's largest operational offshore wind farm was the 367-MW Walney Wind Farm in the U.K. The project cost an estimated $1.58 billion ("New 367 MW offshore wind farm opens in UK" 2012). As of the same date, there were five larger projects under construction, the largest of which was the $3-billion, 630-MW first phase of the London Array in the U.K. ("$3B pledge jump-starts massive offshore wind project" 2009). While still in the proposal phase, the nine Round 3 offshore wind development zones licensed by the U.K.'s Crown Estate range in size from 600 MW (Hastings Zone) to an enormous 9 GW (Dogger Bank Zone) ("New UK offshore wind farm licenses are announced" 2010).

1.4.2 Utility On-balance Sheet Financing

Most offshore wind projects through 2011 were financed on the balance sheets of their developers, generally utilities. Through October 2010, 81% of cumulative installed offshore wind capacity was owned by utilities such as DONG Energy, Vattenfall, SSE, RWE, E.ON, and Centrica (BTM 2010). Balance sheet financing costs less than project finance and is less time-consuming due to the lack of need for banks to conduct due diligence. However, the capital requirements for ever larger projects, such as those in U.K. Round 3, will begin to strain the on-balance sheet financing capacity of these utilities. As a result, utilities will need to explore alternative financing mechanisms.

1.4.3 Project Finance

The recent economic crisis made many investors more risk-averse, with many banks reducing their exposure to less established markets. This decreased the availability of project finance, but some appetite remains for well-structured deals with no unusual features. In the previously mentioned survey, respondents ranked availability of debt financing as the most critical issue facing the German offshore wind market (KPMG 2010).

> *Survey respondents ranked availability of debt financing as the most critical issue facing the German offshore wind market.*

Few projects constructed through 2011 were financed using project finance. The first offshore wind farm financed with non-recourse debt was the Princess Amalia Wind Farm (formerly Q7) in the Netherlands, which began operation in 2008. The C-Power and Belwind wind farms in Belgium were project financed, as was Centrica's Boreas project in the U.K. The proposed 400 MW Global Tech I wind farm in Germany also bucked the trend of utility balance sheet financing. Global Tech I represents the largest offshore wind project financing to date, leveraging funds from both the European Investment Bank (EIB) and the German Development Bank (KfW). It is one of just a few offshore wind projects to have secured in excess of €1 billion in financing.

1.4.4 Multiparty Financing

While most land-based wind farms are financed by a single entity, the multibillion-dollar offshore projects generally involve co-investment by consortia for risk-sharing and pooling of resources and expertise. Seven of the nine Round 3 development zones in the U.K. were awarded to consortia. The 9-GW Dogger Bank Zone was awarded to a consortium of four large utilities. Similarly, projects that have secured project finance (rather than balance sheet financing) have also generally done so through consortia of many banks and other institutions. The 288 MW Meerwind project involved seven commercial banks, a private equity firm, as well as an export agency and a development bank.

1.4.5 Importance of Government Financial Institutions

For larger projects, the support of government or quasi-government agencies has been critical. Most offshore projects that have been project financed in Europe have received support from some combination of the EIB, the Danish export credit agency, Eksport Kredit Fonden (EKF), and the German export credit agency, Euler Hermes (EH). The export credit agencies could facilitate the financing of U.S.-based projects by supporting turbine manufacturers such as Vestas, Siemens, and REpower.

Financing offshore wind projects in Germany has been facilitated by the availability of €5 billion from the German Development Bank (KfW). This financing complements other sources such as the EIB and export credit agencies, as well as commercial banks. The proposed Meerwind wind farm, mentioned above, is the first offshore project to reach financial closing under the KfW's program. The project is unique in that it did not include EIB funding.

1.4.6 New Financing Mechanisms

As the offshore wind sector matures, new investors are demonstrating interest. The mentioned Meerwind project in Germany included financing from U.S.-based private equity firm Blackstone. Previously, no private equity funds had been used in offshore wind projects. In 2011, DONG Energy sold 50% of the Anholt project to two Danish pension funds, a new source of financing in the sector. Parties are also exploring other alternative forms of financing such as project bonds.

1.4.7 Likely Financing Trends for Offshore Wind in the U.S.

As the development of offshore wind projects in the U.S. is predominantly driven by IPPs, offshore developers in the U.S. are unlikely to self-finance projects through balance sheet financing and will therefore need access to project financing. Project financing has been used for offshore wind projects in Europe for a small, but growing proportion of the projects built (currently around 30%). The banks likely to participate in U.S. offshore projects will initially be those European banks which have offshore project finance experience in Europe. They will likely assess U.S. projects in the same way they assess European ones. However, pricing and other market conditions may be subject to the terms of the U.S. wind project finance market, which at times have deviated from European terms and conditions. Given the size of proposed offshore wind projects in the U.S., loan support will also be critical.

As discussed in Chapter 3, offshore wind investors and lenders in Europe rely on support schemes that provide long-term revenue stream stability, either directly through FiTs or public payments such as green certificates, or indirectly through long-term PPAs made possible by the underlying regime. Projects in the U.S. to date, such as those in Massachusetts and Rhode Island, are reliant upon income received from regulated PPAs that provide a fixed price per MWh produced that is well above the wholesale price. Another support regime that has been proposed in New Jersey is the Offshore Wind Renewable Energy Certificate (OREC) system which, as a "contract for differences," is not that different from a feed-in-tariff. Both systems are expected to be bankable as they provide sufficient price support to make projects economically viable. The European experience shows that many different regulatory regimes can be made to work as long as the overall price level is compatible with the current installation costs of offshore wind and there is sufficient regulatory stability to cover the relatively long development and construction process.

The detailed financing assumptions used in this study can be found in Appendix D.

2. Analysis of Technology Developments

This section discusses recent and emerging technology trends and conceptual models for the industry that are likely to lower the future costs of offshore wind technology. While much of the section is dedicated to trends in wind turbine technology, trends in other aspects of the industry—from production to O&M—are included due to their heightened importance in offshore wind relative to land-based. The section is broken into the five primary sections that cover turbines (including trends in manufacturing and foundations), components, logistics and vessels, electrical infrastructure, and O&M strategies. Each section includes a discussion of the current status of the technology, examples of future innovations or conceptual models that offer the potential to drive down the delivered cost of power from offshore wind, and the barriers to realizing such innovations.

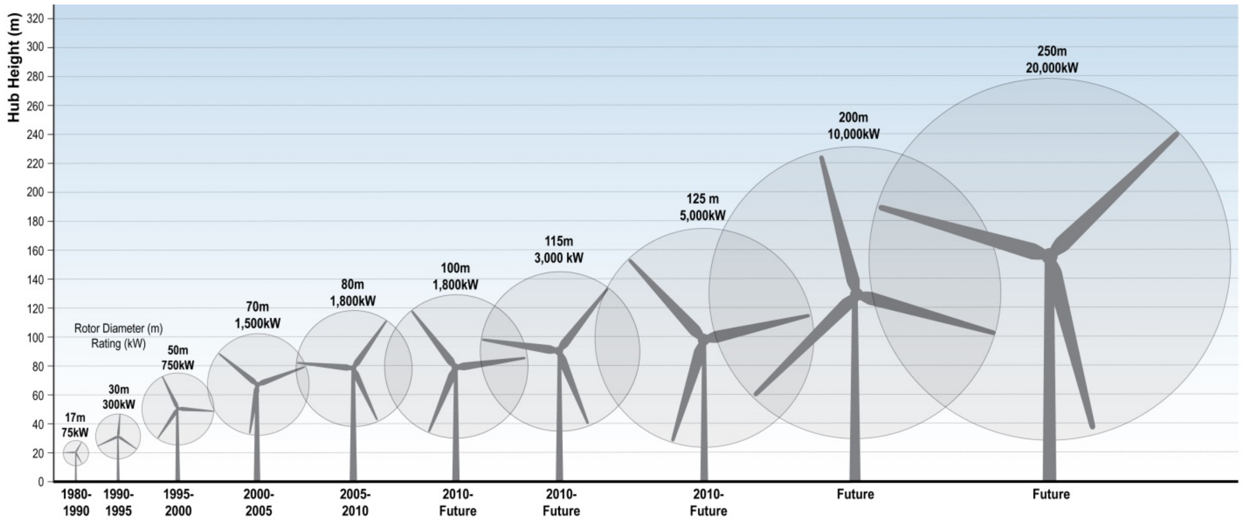
Summary of Key Findings – Chapter 2

- The design of offshore turbines will continue to deviate from that of land-based turbines.
- Technological advancements and cost reductions will likely be derived from incremental improvements within the various subsystems of the turbine.
- As the industry matures, there will be a need for increased production of offshore wind vessels capable of installing 5+ megawatt (MW) turbines in deeper waters.
- There is a need for significant upgrades in ports since they were not designed with the offshore wind industry in mind.
- The offshore wind industry faces similar transmission planning issues as the land-based wind industry.
- Improved siting of wind farms, new operations strategies and technologies, and enhanced access for turbines designed exclusively for the offshore market are anticipated to boost plant production and minimize operations expenditures.

2.1 Introduction

Wind power technology has changed dramatically since it entered commercial power markets in the early 1980s. The first wind power projects relied on turbines that were less than 100 kW in rated capacity, stood with hub heights on the order of 20 meters, and had rotors that were approximately 15 meters in diameter (Figure 2-1). Modern land-based machines range from roughly 1.5 MW to 3.0 MW, employ rotors ranging from 70 to 120 meters, and stand on towers that are typically 80 meters or more (Wiser and Bolinger 2011). Today's offshore machines are even larger, ranging from 3.0 MW to 6.0 MW, employing rotors in excess of 120 meters in diameter, and standing with hub heights of 70 to 100 meters (Figure 2-1).

Figure 2-1. The Evolution of Wind Turbine Technology over Time



Source: NREL

The substantial growth of wind turbines in the past 30 years has occurred as a result of various factors. Advancements in materials, design, processes, and logistics have allowed for larger components to be built with lower system costs (EWEA 2009). Larger components have facilitated turbine level economies of scale, increased energy capture, and lowered balance of plant costs on a $/kW basis (EWEA 2009). For example, turbine economies of scale have been supported by components such as controls and foundations that do not vary in cost in direct proportion to turbine size (EWEA 2009). Greater turbine size also enables fewer units to achieve the same installed capacity, helping to reduce total installation and balance of plant costs again on a $/kW basis. The former are achieved by reducing the total number of crane lifts and moves; the latter are achieved by reducing the amount of required project infrastructure in the form of roads, foundations, and electrical cabling (Chapman et al. 2012).

As a latent benefit, using fewer units also reduces the total number of moving parts within a plant as a whole. Fewer moving parts results in a lower frequency of equipment failures[4] and helps to reduce turbine downtime and technician field time (Chapman et al. 2012); however, increasing turbine sizes means that the magnitude of each individual turbine failure may be greater. In addition, increased turbine size has supported larger project sizes, allowing further economies of scale in development costs, substation and interconnection infrastructure, transmission tie lines, and O&M facilities, each of which are expenditures that are not directly proportional to project size (Chapman et al. 2012). For components such as blades and towers whose costs would theoretically increase in direct proportion to turbine size, innovations

Logistics limitations in the sizes of offshore turbines are significantly reduced where there is the potential for portside manufacturing and marine transport.

[4] Assuming of course the probability of any single component failure does not change.

have mitigated the otherwise expected cost increases, allowing turbines to realize significant energy capture improvements via higher hub heights and larger rotors (Lantz, Wiser, and Hand 2012).

The fundamental drivers for continued turbine growth are similar for both the land-based and offshore segments of the industry. However, the continued growth of land-based wind turbines is arguably limited by logistics constraints, including the turning radius of roads and overpass restrictions (Smith 2001) as well as FAA regulations, shadow flicker, sound, and visibility restrictions. Logistics limitations are significantly reduced if not eliminated where there is the potential for portside manufacturing and marine transport (Musial and Ram 2010). Issues such as flicker, sound, and aesthetics are assumed to be generally eliminated for distant offshore installations. Moreover, turbine scaling drivers tend to be even more compelling when examining offshore plant cost structures. Offshore capital costs are weighted significantly more towards installation and balance of plant materials and infrastructure relative to the land-based wind industry (Tegen et al. 2012), and offshore turbines are far more difficult to access for the purpose of conducting both routine and non-routine O&M activities (van Bussel and Bierbooms 2003). As turbine scaling has largely resulted in lower balance of plant and operations costs while simultaneously increasing energy capture, continued turbine scaling is expected to remain critical, particularly for offshore technology.

Achieving the vastly larger machines expected in future generations will require new R&D and innovations that continue to offset or mitigate the mass increases that would be assumed from classical scaling theory. Despite continued demand for new innovations, substantial gains are already being made. The continued scaling of offshore wind turbines and their divergence from land-based wind turbines can be observed in the recent installation trends (see also Section 1) as well as the new prototypes and concepts emerging in the market today. Existing prototypes in testing today include machines such as the Siemens 6.0-120 and 6.0-154 (Siemens 2011a), the Sinovel SL6000 (Wu 2011), the Alstom ECO 150-6.0 MW (Alstom 2012), and the BARD 6.5 MW[5] (RTMI 2011). Announced concepts under development include the Vestas V164-7.0 MW (Vestas 2011b) and the Gamesa G11X-5.0 MW (Gamesa 2012) among others. Rotor diameters on these future machines range from roughly 120 meters up to more than 160 meters and rated capacity ranges from 5-7 MW. Concepts further into the future envision scaling of offshore equipment to even larger sizes. At the European Union (EU) level, the UpWind Project conducted a comprehensive technical evaluation of the viability of a 20 MW turbine (UpWind 2011). The final study, released in early 2011, indicates that significant continued advancements in materials, design architectures, controls capabilities, and other factors are needed, but a 20 MW offshore wind turbine is feasible. Gamesa is also coordinating a multi-company joint endeavor among the private sector, government, and other Spanish research centers to develop a 15 MW turbine (Gamesa 2010) while DOE's Sandia National Laboratory has examined blade designs for a conceptual 13.2 MW turbine with a 200-meter rotor diameter (SNL 2012).

Despite the dramatic changes that have occurred over the past 30 years, the turbine concepts in the development pipeline today and those envisioned in the future will require a vast array of technical innovations throughout the turbine as well as in foundations, installation strategies, balance of plant equipment, and O&M practices. Advancements in manufacturing will be needed as the castings and

[5] Bard is currently soliciting potential buyers and may ultimately cease production of wind turbines.

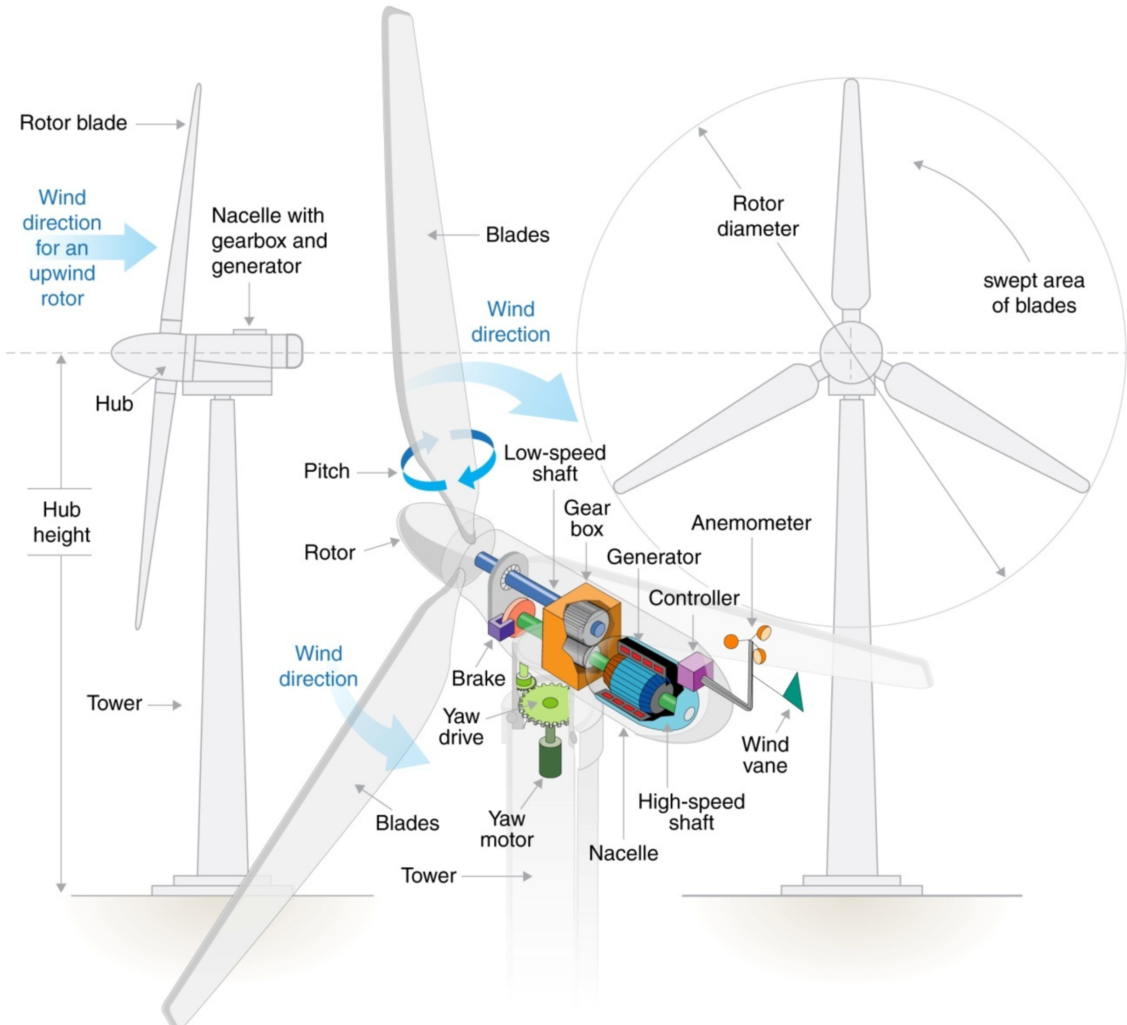
bearings for such large turbines push the limits of existing foundries and other players in the wind supply chain. New foundation designs, vessel capabilities, and innovative staging and assembly strategies will likely be as important as the development of future generations of wind turbines. Possible changes in design architecture and an ability to withstand a wider array of design considerations including hurricanes, surface icing, and rolling and pitching moments are also likely to be needed.

2.2 High-Level Industry Trends and Opportunities

Historically, offshore wind turbines have been marinized versions of their land-based counterparts. Existing turbines designed for the land-based environment were simply adapted to the marine environment. In some cases, adaptations were too modest or insufficient for the unique attributes of the marine environment. Today's offshore wind turbines are largely being developed exclusively for the offshore environment, with significantly more attention paid to the demands of the marine environment. As a result of their historical ties to the land-based wind industry, offshore turbines have relied on the conventional three-bladed upwind rotor horizontal-axis configuration (Figure 2-2). With some exceptions around drivetrain and possibly rotor designs, the majority of prototypes and concepts under development today suggest that the traditional topology will continue to dominate, at least through the next generation of offshore machines (Siemens 2011a; Vestas 2011b; Wu 2011; Gamesa 2012)

In reality, however, wave loads, corrosive salt water, and a requirement for submarine electrical cabling and infrastructure are not the only unique design considerations specific to offshore wind. Offshore turbines are located further from human habitations and have significantly poorer accessibility. Lower wind shear suggests that offshore turbines may not require towers as tall as might be preferred for land-based installations. Some marine environments are subject to increased risk from hurricanes at the lower latitudes or surface and blade ice in higher latitude locales. Tsunamis may also pose risks. Constrained overland transport may necessitate fabrication and storage in coastal locales. These additional considerations suggest that as the offshore industry matures, its turbines will continue to deviate from turbines designed for the land-based segment of the market.

Figure 2-2. Traditional Wind Turbine Topology



Source: NREL
Note: Offshore turbines also require a tower mounted transformer not shown here.

2.2.1 Regional Considerations

Developing offshore wind in North America introduces the possibility for additional technical considerations that must be addressed for development to move forward in specific regions. Principally these include hurricane risk, which persists along the southern portions of the Eastern Seaboard and Gulf Regions, and surface and blade icing in the freshwater locales of the Great Lakes and potentially other northern latitudes. Development in certain regions such as the Pacific coast or coastal Maine may also require floating technology (See Section 2.2.2 and Section 2.3.3).

Icing risks are primarily in the form of surface ice, which can place significant additional loads on turbine foundations and towers but also include blade ice (Musial and Ram 2010). Turbines placed in the Baltic Sea have successfully managed some icing loads, but icing in the Baltic Sea has likely been mitigated by the salt content of the water there (Musial and Ram 2010). The first freshwater offshore wind installation was completed in Lake Vanern, Sweden, in 2009 (4C Offshore 2012). As of the time of this writing, no significant icing issues are known there. Nevertheless, parts of the Great Lakes frequently observe significant surface ice buildup and this factor will need to be incorporated into both the siting and design of offshore turbines placed in the Great Lakes or in other northern latitudes. Engineering solutions exist for icing risks; however, it is not unreasonable to think that there will be an incremental cost for projects placed in localities with a potential for significant surface icing.

Hurricanes pose a different set of risks than icing. The principal risk associated with hurricanes is extreme wind gusts. Secondarily, extreme loads might also result from hurricane generated waves, sustained high winds, increased wave frequency, rapid directional wind changes, and other forces (Musial and Ram 2010). Today's turbines are not certified by the International Standards to withstand hurricane-force winds; typical extreme wind conditions for International Electrotechnical Commission (IEC) Class I turbines, the highest certified standard, require designing to a maximum wind gust of 70 m/s. Although outside of the formal design standards engineers generally expected IEC Class I turbine certifications to be sufficient for Category I and Category II hurricanes. They may also be sufficient for Category III hurricanes. However, gusts in excess of 80 m/s are not uncommon for 50-year storms and withstanding these types of conditions will likely require alternative design criteria (Musial and Ram 2010). Some OEMs (e.g., Vestas) have begun to offer anti-cyclonic technologies designed to address the extreme gust conditions created by hurricanes and typhoons for land-based installations in coastal regions and tropical island environments such as the Caribbean or South Pacific (Vestas 2012). Such approaches typically allow the turbine to maintain yaw and pitch control up to 150 m/s. By keeping the turbine blades feathered and faced into the wind, the turbine is able to shed much of the potential extreme loading that could result from hurricane-force winds (Vestas 2012). Manufacturers may also utilize tower reinforcement strategies or rely on smaller rotors (with a subsequent penalty on energy production) in order to further reduce loads from extreme wind events (Vestas 2011a). Similar to icing risks, the ability to address and resolve the challenges presented by hurricane-force winds is primarily an engineering one, but it will also depend on the ability to analyze risks in a uniform and consistent way. An incremental increase in cost and potentially lower energy production may result in future designs geared towards withstanding hurricane conditions.

2.2.2 Floating Technology

Deeper water installations require an increasing amount of steel and create a more challenging set of installation conditions. As shallow-water sites proximate to load are consumed or demand increases in regions such as Coastal Maine, the Gulf of Mexico or the West Coast, it could become preferable to shift to floating foundations rather than deep-water, fixed-bottom foundations. The development and commercialization of floating turbines would have profound impacts on both the wind industry as a whole as well as the offshore segment of the market. Floating platforms open up new and possibly better wind resource areas (WRAs), with the potential for more sites adjacent to load. They also offer the possibility for greater standardization in the industry because the floating platforms have limited sensitivity to variability in seabed conditions and water depth (Chapman et al. 2012). Standardization offers the dual benefits of efficiency in fabrication and assembly and increases the possibility for quayside assembly and towing of a complete turbine assembly out to sea (Chapman et al. 2012; Principle

Power 2011).[6] Such changes could offer economies of scale benefits and dramatically simplify the vessel requirements of the industry (Principle Power 2011).

Floating designs are at least initially expected to use standard offshore turbines, but they must also meet an entirely new set of design criteria needed to address the weight and buoyancy requirements as well as the heaving and pitching moments created by wave action. Current floating concepts include the spar buoy, the tension leg platform, and the buoyancy stabilized semi-submersible platform. The spar buoy is perhaps best exemplified by Statoil's Hywind test turbine off the coast of Norway. This full-scale prototype utilizes a 2.3 MW Siemens turbine placed in approximately 220 meters of water and has been in testing since 2009 (Statoil 2011). Principle Power's WindFloat semi-submersible is another technology in testing off the coast of Portugal since October 2011 (Principle Power 2011a). The WindFloat full-scale prototype employs a Vestas V80 2.0 MW turbine (Principle Power 2011a). Various partial-scale prototypes including designs by Sway (REF 2011) and Blue H Technologies (BHT 2012) have also been tested in the past. Acciona, another major turbine OEM, has also announced plans to deploy its 1.5 MW turbine on a floating platform off the coast of Spain within the next year (WPM 2012) and Statoil is actively pursuing the development of a floating demonstration project off the coast of Maine (Turkel 2012). In the meantime, research on floating designs at various universities and other research institutions continues. For example, the Japanese government is supporting an array of floating offshore wind activities including research, development, and a planned demonstration project (Arakawa 2012). More detail on explicit floating offshore designs is included in Section 2.3.3.

2.2.3 Manufacturing

Although much of the innovation and R&D in offshore wind is focused on turbines and foundation equipment, continued evolution in manufacturing and fabrication strategies is also anticipated to facilitate cost reductions. Of significant importance in terms of manufacturing is movement towards commercial and serial production and realization of the economies of scale that can be gained with growing production volumes (Cohen et al. 2008). To some extent, these opportunities have been realized in the land-based market segment, but with the significantly newer turbine designs and more limited industry demand, moving to serial turbine production is a key opportunity for the offshore wind industry. In addition, greater efficiency can likely be achieved with increased automation and optimization in terms of fabrication processes (Cohen et al. 2008). More automation is expected to result in higher component consistency and fewer component defects, helping to drive down the number of potential failure modes in any individual component (Cohen et al. 2008).

Component size and scale are expected to limit land-based transportation for large components such as blades, towers, and nacelles. (The latter are particularly affected by the required castings used in turbines larger than 3-5 MW.) This is anticipated to drive manufacturing to coastal locations, potentially co-located with offshore wind port facilities. At the same time it is anticipated that market size and the required investment to build and operate coastal manufacturing will be a significant factor in determining the level of domestic investment in manufacturing capacity (see also Section 2.4).

[6] Quayside assembly and towing of assembled turbines to the project site is not contingent upon increased standardization but could likely be facilitated by it.

2.3 *Detailed Component-Level Trends and Opportunities*

The future may hold some changes in manufacturing processes and an ability to address extreme conditions such as those created by icing, hurricanes, and deep-water sites. However, much of the technological advancements and cost reductions anticipated by the industry will likely be derived from incremental improvements within the various subsystems of the turbine. Such changes will largely be invisible externally, but will be critical to enable the fundamental scaling trends that can be witnessed externally and that are necessary for the industry to reap the benefits associated with larger machines and increased energy capture. The estimated cost breakdown of a 500 MW reference plant is provided in Table 4-6 in Section 4.4.2. A further breakdown of the turbine cost is provided in our companion report, *U.S. Offshore Wind Manufacturing and Supply Chain Development* (Navigant 2012).

2.3.1 Rotors

Greater energy capture is fundamental to lowering the cost of electricity from offshore wind. Improving aerodynamic efficiency and scaling the rotor are the two primary means of achieving increased energy capture. Aerodynamic efficiency is constrained by the Lanchester-Betz limit and modern turbine rotors are approaching this limit (Chapman et al. 2012; Wiser et al. 2011).[7] As such, scaling the rotor is the primary means for increasing turbine energy capture. When coupled with the right design, material, and control innovations, it can be accomplished with minimal impact on structural loads and installed costs.[8] The effectiveness of scaling to larger rotors to drive down costs is clear given the industry push to move from rotors of 100 meters today to rotors in excess of 150 meters in future generations of offshore wind turbines. To achieve these larger dimensions, innovations in design architecture, materials, and controls are needed to produce rotors that meet the requisite mass restrictions to justify their use while at the same time maintaining equivalent aerodynamic performance and reliability.

Innovations in design architecture, materials, and controls are needed in order to achieve larger dimensions in rotors.

In the future, advanced composites including carbon fiber, new resins and epoxies, and other materials are likely to be increasingly deployed (Ashwill 2009). Carbon fiber in particular may be seen in an increasing number of very long blades in order to provide their required stiffness without adding weight. At the same time, the incremental cost of advanced materials suggests that their use may be limited and the impact of advanced materials alone is unlikely to allow for the scale of rotors the industry intends to develop (UpWind 2011). Changes to blade design architecture such as fore-bending or curved blades (UpWind 2011) as well as the incorporation of passive strategies that utilize bend-twist coupling (Ashwill 2009) to facilitate load shedding are likely to assist in moving towards larger rotors. Active load shedding through the use of individual blade pitch control, partial blade span actuation, or

[7] The Lanchester-Betz limit is based on a simple theoretical model and states that the maximum amount of energy that can be extracted from an unconstrained flow is 59%. Modern rotors today often have a maximum efficiency of 44%–50%.

[8] At a minimum, rotor scaling must result in enough energy capture improvement to offset whatever additional material and installation costs are incurred.

active control surfaces including trailing edge flaps could further enhance the development of larger, lighter rotors (Buhl et al. 2005; Lackner and van Kuik 2009; UpWind 2011). Sensors that support real-time response to loads or even preemptive adaptation to changes in wind speed and turbulence across the rotor disk may also be critical to the large diameter machines of the future; there will be much greater differences in the wind regime across the rotor disk when moving to rotors on the order of 150 meters or more (Andersen et al. 2006; Berg et al. 2009; UpWind 2011). Development and deployment of segmented blades may also occur to facilitate transport, storage, and assembly (UpWind 2011).

2.3.2 Drivetrain and Power Conversion

Limited access to offshore wind power plants has placed a premium on turbine reliability. Widespread and well known failures in gearboxes on the Danish Horns Rev offshore wind plant have focused R&D attention on drivetrain and power conversion designs. Efforts are underway to improve current technologies and to consider the potential offered by alternative design configurations.

Through 2011, the industry as a whole (including land-based and offshore wind) used roughly 80% geared machines (BTM 2012). These conventional designs rely on a two- or three-stage gearbox to convert the low rotational inputs of the turbine rotor (8-15 RPM) to the speed that best matches the efficiency of the generator (1,200 to 1,800 RPM). Although the data on actual failure and replacement rates are extremely limited, it is well known throughout the industry that a common failure point in conventional geared machines is in the gearboxes.

The other 20% of the fleet consists of direct drive turbines (BTM 2012). Direct drive machines eliminate the need for a gearbox by matching the speed of the generator to the speed of the turbine rotor. Direct drive platforms offer the possibility for increased reliability by taking the gearbox out of the equation and reducing the total number of moving parts. In the past, generator size and mass were increased significantly in order to allow direct drive generators to operate efficiently at the rotational speeds of the turbine rotor. Today, direct drive systems employing high-energy density permanent magnets sourced from rare earth elements offer the potential to realize direct drive technologies without the traditional size and mass penalties associated with traditional direct drive concepts. It is notable however, that new direct drive platforms lack an extensive performance record, particularly in marine offshore settings. It is not yet clear that direct drive generators offer superior performance and reliability under the actual working conditions experienced by offshore turbines.

A variety of research efforts have been put in place to better understand internal gearbox dynamics and to assist in developing new designs (e.g., Peeters et al. 2006; Heege et al. 2007). Designs that employ reduced gear loading as well as the incorporation of advanced condition monitoring equipment are thought to reduce wear and facilitate early identification of problem areas where preemptive corrective measures can be taken (Cohen et al. 2008). Winergy's multi-duored gearbox is designed with the explicit purpose of more broadly distributing loads throughout the gearbox (Winergy 2012). Much of the work around direct drive concepts takes advantage of the value of permanent magnets. In the case of Siemens, such efforts have resulted in a direct drive machine that is among the lowest in weight of all designs, geared or direct drive. Analysis conducted in the UpWind (2011) initiative suggested that permanent magnet transversal flux generators were the most promising in terms of drivetrain weight reduction out of ten individual drivetrain configurations.

Chinese export quotas are expected to keep supplies of rare earth elements and subsequently permanent magnets relatively tight in the near term.

Increased reliance on permanent magnets in virtually all new generator designs (and particularly in the direct drive and medium-speed generator designs) and heavy dependence on Chinese sources for rare earth elements (BTM, *Supply Chain Assessment 2012-2015* 2011; Navigant 2012) has raised some concerns in terms of the availability of permanent magnets for the industry. Chinese export quotas are expected to keep supplies of rare earth elements and subsequently permanent magnets relatively tight in the near term (BTM, *Supply Chain Assessment 2012-2015* 2011). However, the wind industry is not alone in its increasing dependence on rare earth derived permanent magnets. With anticipated growth in demand for rare earths among an array of industries, there are a handful of national and international initiatives intended to diversify the global supply base for rare earth elements including those used in wind turbine generator permanent magnets. Significant attention and investment is currently being devoted to the development of new mines outside of China (for example in North America, South America, Malaysia, and Africa, where there are known reserves of rare earth elements). More immediate corporate strategies such as hedging, long-term contracts, strategic joint ventures, and in some cases strategic acquisitions are also being pursued (Navigant 2012). Over the long term, rare earth elements are generally not expected to be a significant bottleneck for the industry (Chapman et al. 2012; Navigant 2012). However, should efforts to develop new supply sources for rare earth elements have limited success, potential shortages and increased costs for rare earth elements could be an issue for specific generator designs moving forward.

Despite the development of permanent magnet direct drive machines, the debate over direct drive versus geared platforms is expected to continue. Among Tier 1 manufacturers, Vestas has selected a medium-speed geared design for its V164-7.0 MW machine, while Siemens continues to expand the capabilities of its direct drive technology and is testing a larger version of its direct drive generator in the Siemens 120-6.0 MW. Farther into the future as machines approach the 10 MW mark, direct drive superconducting generators may also offer the potential for additional mass and size savings along with the potential reliability benefits of direct drive platforms (Abrahamsen et al. 2010). Hydraulic drivetrain designs, in which the mechanical gearbox is replaced with a hydraulic system, are also a possibility.

The continued development of larger and greater turbine capacities will also necessitate higher capacity power electronics. Increasing recognition of the value of grid services including low-voltage ride through and frequency support are expected to result in an increasing number of turbines relying on synchronous generators and full power conversion providing the system operator greater flexibility and individual turbine control. Lower cost power conversion is expected from deployment of higher voltage power electronics despite a loss in efficiency relative to lower voltage semiconductors (UpWind 2011). Multiple paths to the advanced power conversion capabilities of the future could provide the requisite needs and capabilities of the industry (UpWind 2011).

2.3.3 Foundations and Support Structures

At roughly 20% of total project cost, offshore wind foundations represent one of the more costly line items of a project (Tegen et al. 2012; EWEA, *The European Offshore Wind Industry* 2012).[9] The high cost associated with offshore foundations and substructures is a function of the complexity of task they are asked to perform and their substantial material requirements. Today offshore turbines are largely installed on monopile foundations. A monopile foundation consists of a long cylindrical steel tube driven into the seabed, and a transition piece that connects the substructure and the wind turbine tower. Through 2011, monopiles were about 75% of the cumulative European market (EWEA, *The European Offshore Wind Industry* 2012). However, as turbines grow and deeper water depths are pursued, alternatives are likely to be increasingly attractive. Moreover, certain seabed conditions may be more favorable to alternatives such as gravity base structures (GBS) or suction caissons. Through 2011 the cumulative European market was about 21% GBS (EWEA, *The European Offshore Wind Industry* 2012), however, market share of GBS is expected to decline based on currently planned and proposed projects.

Despite long-term trends that suggest declining market share for monopiles, they are expected to continue to be in use for many years. In addition, the monopile's relative simplicity and low labor requirements make it an attractive platform for future innovations that might extend its useful life (EWEA 2011). Alternative designs using a wider tower diameter that would not be possible due to logistics constraints on land could result in monopiles with the necessary stiffness needed for deeper water installations or for larger next generation turbines while also minimizing the required steel content of a given installation (EWEA 2011). Composite towers and foundations might offer other opportunities for low-cost solutions with greater corrosion protection (Musial and Ram 2010). Integrated concrete and steel hybrid structures or entirely concrete structures might also play a role in the future.

Even when considering alternative materials and design architectures, it is likely that the combination of diverse seabed conditions, deeper water, and larger turbines will push the industry away from monopile foundations to alternatives. Alternatives to the monopile include jackets, tripods, GBS, and suction caissons (Figure 2-3).

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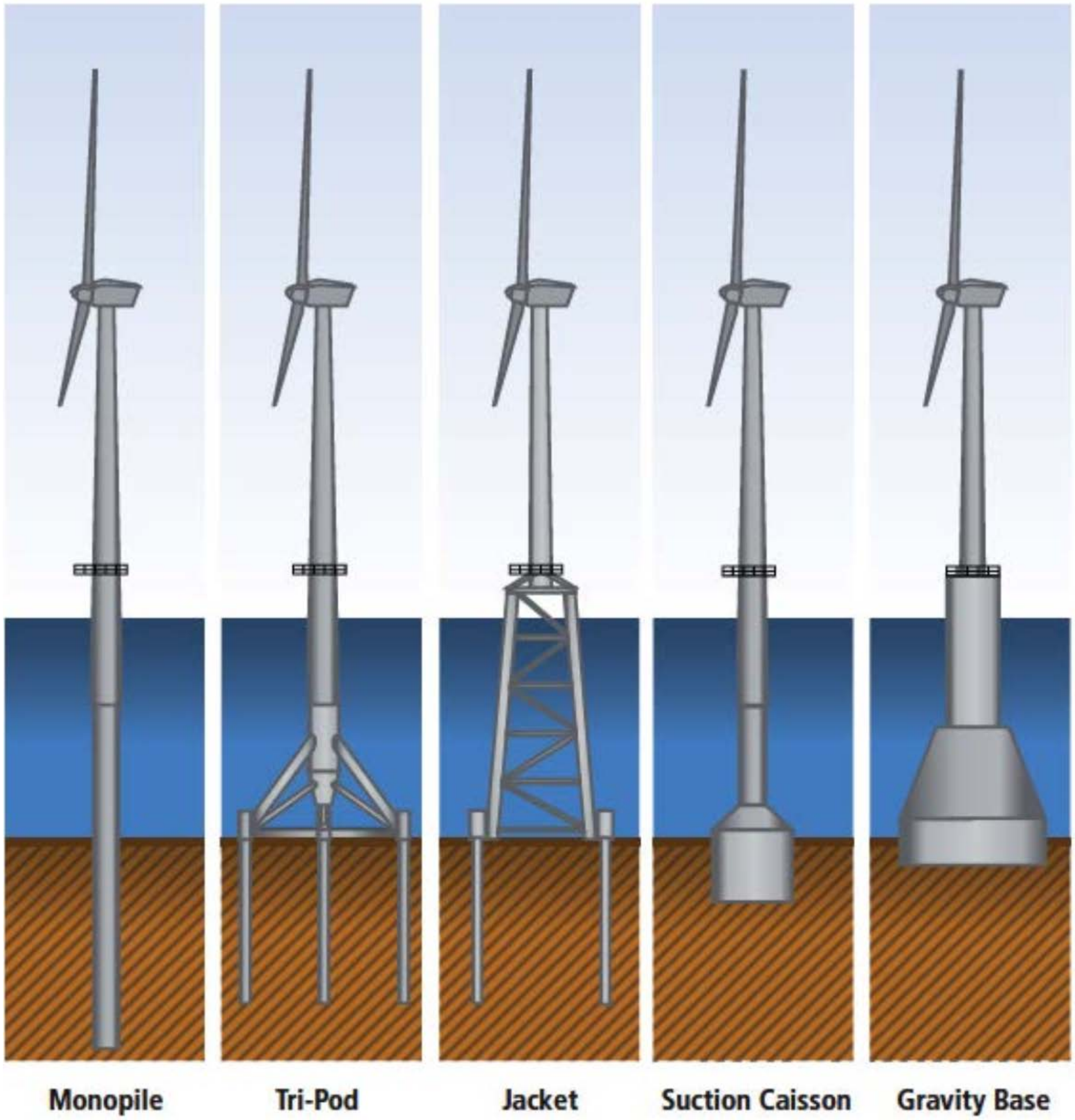
[9] Estimate is based on the foundation and substructure material and assembly cost, but excludes their installation. See also Section 4.

Figure 2-3. Fixed-Bottom Offshore Foundation Concepts



Source: IPCC 2012

Space frame designs (e.g., jackets and tripods) are typically preferred for deepwater sites. Jacket structures are a derivative of the common fixed-bottom offshore oil rig and rely on a four-sided framed structure that is "pinned" to the seabed using four smaller pilings, one in each corner of the structure (EWEA 2011; Chapman et al. 2012). The tripod utilizes a three-legged structure assembled from steel tubing with a central shaft that consists of the transition piece and the turbine tower (EWEA 2011). As in the case of the jackets, the tripod is pinned to the seabed with smaller pilings. Another alternative foundation type (not shown in Figure 2-3) is the tripile, which uses three pilings that are tied together by a central transition piece above the surface of the water (EWEA 2011). Jackets entail significantly more fabrication and assembly but are less material intensive than tripod and tripile designs (EWEA 2011).

GBS or suction caissons may be viable in the shallower more protected locations, particularly those where seabed geology, rocks, or boulders make it challenging to drive pilings. GBS entail a conical or cylindrical casing that is constructed onshore, transported to the project location, placed on the seabed, and then filled with additional ballast in the form of concrete, sand, rock, or iron ore (EWEA 2011). These structures rely exclusively on the mass of the structure and the force of gravity for stability. Suction caissons are similar to GBS in that they do not require pilings. However, suction caissons rely on a large diameter cylindrical structure fixed to the seabed by pumping out the water that would otherwise fill the structure to create a vacuum (Chapman et al. 2012).

The precise distribution of each explicit foundation type is expected to be a function of local geology and bathymetry. More challenging deep-water sites are expected to necessitate the added stiffness offered by the space frame designs. Initial analysis based on the deployment scenarios articulated in the companion DOE Supply Chain study and seabed conditions within those regions suggests that for fixed-bottom technology there will be a roughly even distribution of monopiles, GBS, and space frame structures (Navigant 2012). However, an examination of the current pipeline of proposed projects suggest that at least the initial installations in the United States will rely predominately on monopiles and perhaps jacket foundations.

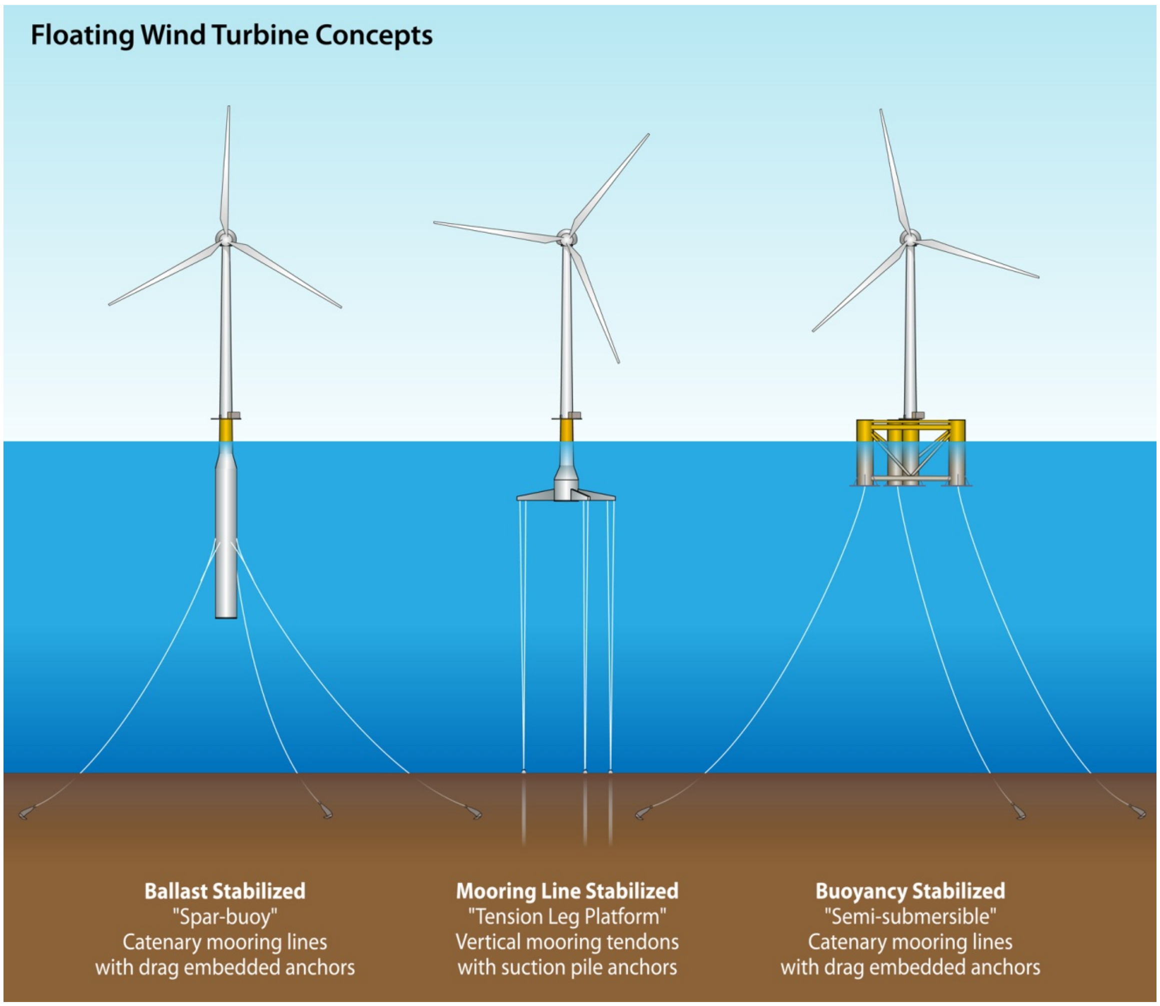
For fixed-bottom technology there will be a roughly even distribution of monopiles, GBS, and space frame structures.

Although there is a sizable offshore wind resource that can be developed with the fixed-bottom foundation technologies noted above, the material requirements and complex and variable installation requirements of these foundations, particularly for the alternatives to the monopile, along with the amount of additional wind resource at water depths exceeding 50 to 60 meters, continue to drive significant interest in floating offshore foundations. While these concepts have been introduced previously, some additional detail on the explicit design features of the various concepts is considered here.

Statoil's spar buoy floating offshore design was the first to enter full-scale testing in 2009 (Statoil 2011). In principle, the spar buoy contains a buoyant structure that is stabilized by a large ballast located on the lower portion of the structure. This structure is maintained in its general position in the water with catenary mooring lines and drag embedded anchors but relies solely on the buoyancy and ballast of the spar structure to withstand the pitch and heave moments exerted by wave action and loading (Figure 2-4) (Chapman et al. 2012; Musial and Ram 2010). The second floating concept to be tested at full-scale is represented by the WindFloat developed by Principle Power. A semi-submersible, the WindFloat is primarily stabilized by a set of three buoyant structures arranged in a triangular form. The WindFloat also relies on a secondary movable ballast system to help maintain stability and withstand wave loads (Principle Power 2011). Semi-submersibles including the WindFloat are held in their general location by catenary mooring lines and drag embedded anchors. Although yet to be tested at full scale, the tension leg platform relies on a buoyant platform-like structure located below the surface of the water that is fixed to the seabed with taut mooring lines. The tensioned mooring lines are the source of stability offered by this design as the primary purpose of the platform is to provide buoyancy (Chapman et al.

2012; Musial and Ram 2010). Another concept, the barge platform which relies on an exceptionally large floating barge for both buoyancy and stability has been considered in the past but faces significant challenges in high seas where the induced motions on the platform can be substantial.

Figure 2-4. Floating Offshore Wind Foundation Concepts



Source: NREL

Little is known about the long-term cost implications of moving to floating offshore platforms. These technologies are only in their infancy and will require years of rigorous design and testing before they are commercially viable. However, floating offshore foundations offer the potential for less foundation material relative to deep-water fixed-bottom foundations and greatly simplified installation and decommissioning. Each of these attributes could support lower costs moving forward. The possibility for reduced material use also helps to incrementally reduce the impact of variability in commodity prices on the industry. Fewer environmental impacts in the form of smaller pilings and significantly reduced seafloor disruption could also be beneficial attributes of floating technology. Although floating technology is generally perceived as a long-term technical innovation, should the existing test prototypes or other concepts continue to show promise and the industry continues to receive significant investment, floating offshore platforms could be viable much sooner as suggested by industry survey data.

2.4 Logistics and Vessels

At roughly 10% of project capital costs, staging, assembly, transport, and installation entails another substantial fraction of offshore wind costs (Tegen et al. 2012). Vessels and logistics strategies associated with each of these project elements are fundamental to the future of the industry and its ability to drive down costs in the future. The types of vessels and supporting logistics infrastructure that will best serve the industry will require significant capital investments outside of the $5,000/kW to $6,000/kW that is estimated to build an individual project. The number and types of vessels as well as the specific logistics strategies of the industry will depend on the evolution and advancement of the industry.

2.4.1 Conceptual Models for Manufacturing, Staging, and Installation

Today there are three primary conceptual models envisioned for producing, staging, and installing equipment – the import-dominated model, the regional hub model, and the dispersed model. The specific model that becomes a reality will be a function of multiple factors, including demand, the ability to generate economies of scale, financing capacity, workforce capacity, industry procurement strategies, and policy. The prevalence of these three models will likely vary as the industry grows and matures over time. State-level net benefits requirements could have a significant influence on the type of manufacturing and installation models that emerge both in the near term and long term.

Import-dominated Model: Although some specialized domestic manufacturers could be serving specific segments of the global offshore wind industry, there is no significant OEM or tier I supplier presence (for offshore wind) in the United States today.[10] The lack of supply chain activity is a function of effectively zero demand at present. Initial projects in the U.S. are expected to import much of their equipment including turbines from sources in Europe or elsewhere, where demand is higher and a more mature offshore wind supply chain is in place. One possible exception to this trend is in foundations, where U.S. oil rig foundation fabrication experience could be transitioned to serve offshore wind, allowing foundations to be manufactured in the U.S. even for the initial projects. Towers and electrical infrastructure including substations, convertor stations, and transformers, might also be sourced from the U.S. but could easily be imported as well. Vessels will likely need to be brought in from outside the U.S. to construct the initial projects. Precedent from the offshore oil and gas industry suggests that in spite of the Jones Act (also known as the *Merchant Marine Act of 1920*), foreign vessels may be utilized for installation purposes so long as they are not moving equipment, but merely offloading and installing the equipment from a fixed location.[11] Presumably, equipment would be required to be brought to the

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[10] Of course, there is a robust and growing supply chain for the onshore segment of the industry (see also Wiser and Bolinger 2012).

[11] This potential opportunity for foreign-flagged installation vessels exploits the fact that the Jones Act applies to the actual transportation of goods. As such, goods could be moved from a U.S. port to a foreign-flagged vessel for the purpose of being installed at an offshore facility so long as that foreign flagged vessel does not transport the equipment. Although there is precedent for such a practice in the offshore oil and gas industry, readers are advised to consult with legal counsel for further guidance.

installation vessel by a U.S. flagged vessel, assuming it was staged at a U.S. port. Staging would likely occur at a temporarily modified U.S. port proximate to the project location. An import-dominated vessels and manufacturing model will likely persist in a low demand environment. Under low demand conditions, the total value of equipment installed by the industry will simply be too low to justify sizable investments in domestic manufacturing and vessel production.

Regional Hub Model: On the opposite end of the spectrum to the import-dominated model is the regional hub model. Assuming demand is high enough to drive local investment in manufacturing, port, and vessel construction, the industry could be served by a series of regional hubs where there are co-located manufacturing, staging, and port facilities. Vessels may be manufactured in any number of locations but under this model could be envisioned to serve a single regional market.

A regional hub model allows for the opportunity to secure very high levels of regional and domestic content as it would only be the very specialized electrical infrastructure equipment that might not be produced in the region where the equipment is installed. The development of offshore wind exclusive berths and integrated development of manufacturing facilities, staging areas, and port berths would also offer the potential for significant efficiency improvements for the industry and noteworthy economies of scale. Many OEMs have suggested similar models for development in Europe; this concept may be best represented by Vestas's recently abandoned Sheerness, U.K. facility (Vestas 2011c) or Siemens' proposed facility in Hull, U.K. (Siemens 2011b). The primary drawback to this model is that it requires an established pipeline of demand that extends over many years. Without a stable market and long-term certainty, it becomes highly difficult to justify the $280 million (Siemens 2011b) to $650 million (NLC 2010) of investment needed to plan and develop any single regional hub.

Dispersed Model: A third model that envisions more dispersed manufacturing and port development may also be viable, particularly with the states' recent legislative push towards net benefits test cases for projects.[12] Although the net benefits analyses take into account an array of factors, a certain level of local manufacturing is anticipated to greatly facilitate the ability for projects to meet the minimum criteria to pass a net benefits test. In the dispersed manufacturing model, production, fabrication, and investment is less centralized and would likely develop more organically as the industry matures and demand grows over time. In this model, existing ports are adapted or retrofitted to accommodate the immediate staging, storage, lift capacity, and air draft needs of the industry without trying to become the exclusive site for all future offshore manufacturing and staging activities. Manufacturing and storage could hypothetically occur at one port while secondary staging and installation may occur out of a separate port that offers closer proximity to the final project site. This

Manufacturing and storage could occur at one port while secondary staging and installation may occur out of a separate port that offers closer proximity to the final project site.

[12] The net benefits test case refers to legislation that has been proposed in several states along the Eastern Seaboard. Broadly speaking, this type of legislation, should it be enacted into law, would require proposed offshore wind facilities to demonstrate a net positive benefit to the state where the project is being built in order to receive the required state or regulatory approvals.

model of development, production, and installation may more closely align with German port and manufacturing investments along the North Sea coast. Investments at Cuxhaven, Emden, Wismar, Brunsbuettel, and other German sites have been more incremental and are designed to resolve specific near-term challenges as opposed to the combined near- and long-term challenges of the industry (Brautigam 2011). This model may not offer the ultimate degree of efficiency and economies of scale provided by the regional hub model; however, to the extent that it matches the levels of investment seen in Germany, it may be realized with far lower initial investments, on the order of $50–$100 million (Brautigam 2011), rather than the multiple hundreds of millions of dollars expected to be needed to complete the regional hub facilities proposed in the U.K.

2.4.2 Equipment Staging and Storage

To date, the offshore wind industry in Europe has utilized existing manufacturing facilities to produce and fabricate turbines. From there, the equipment has been moved to nearby port facilities and then in preparation for construction to temporary storage and staging sites at retrofitted ports. Such an approach has been feasible because it was only recently that offshore wind turbines began to diverge significantly from their land-based counterparts. Moreover, temporary staging facilities were preferred because the industry did not have the sustained or concentrated demand to justify permanent investments in staging and storage facilities in locales proximate to the final project sites. Nevertheless, permanent storage and staging facilities are assumed to be preferable over the long term for the sake of industry efficiency. In addition, co-located manufacturing and staging areas eliminate costly transport of very large offshore wind components, reducing the number of transfers from as high as three (manufacturing facility to port, port to staging area, staging area to project site) to one (staging area to project site). In the future, quayside assembly may also offer the opportunity for greater industry efficiency by reducing costly at-sea construction. However, quayside assembly necessitates port facilities with sufficient air draft and lift capacities as well as vessels that can transport and install full or partially assembled turbines. Quaysides generally need to be 200 to 300 meters long for vessels to be able to load and unload large components such as towers and blades (DECC 2009). Overhead clearances of 100 meters are necessary to enable passage of vertically positioned tower sections (DECC 2009); however, many vessels can accommodate horizontally positioned tower sections in turn reducing vertical clearance requirements. Lateral clearances must accommodate for either star or bunny ear rotor configurations.

As the industry and projects grow in size, storage of high numbers of very large components will likely continue to create logistics challenges. Vestas' Sheerness, U.K. facility—which is no longer being pursued—was anticipated to be on the order of 70 hectares (Vestas 2011c). Temporary storage on barges or distant offshore storage depots along with innovations including segmented or folding blades could facilitate the industry's ability to address its storage challenges. Coordination of production and fabrication of components with industry demand may also assist in reducing storage and staging challenges of the industry.

In the U.K., currently the world's largest offshore wind market, an independent study commissioned by the Department of Energy and Climate Change found that to meet 2020 targets, "significant investment needs to be made in construction ports" (DECC 2009). In stakeholder interviews by Navigant, some manufacturers and project developers expressed frustration at availability of port capacity, size, and/or location. In some instances, non-U.K. ports have been used. There are success stories, however.

Bremerhaven, one of Germany's largest ports, suffered a decline in the 1980s due to a decline in fishing and shipbuilding. In 2002, as it saw the coming growth of the offshore wind sector, the state government of Bremen began investing in upgrades to the port. Since then, Multibrid, now AREVA, and REpower, manufacturers of 5.0+ MW turbines, as well as blade supplier PowerBlades and tower supplier Ambau, have established production facilities at Bremerhaven.

As the offshore wind industry continues to grow, the upgrade of port infrastructure will need to keep up. When ports are in tight supply, the manufacturers and developers who are successful in getting their turbines and projects to market will be the ones who have found access to suitable port facilities.

2.4.3 Transportation

Transportation demands will vary with the practices and strategies of the industry. The various models noted above each have some unique transportation requirements. Transportation demands will also evolve as the life cycle of each project proceeds. During construction, transport vessels, either in the form of dedicated transport vessels or the actual installation vessel itself, are needed to collect the foundation and turbine equipment from a centralized distribution point that can meet the required lift capacity and air draft requirements. Utilizing the installation vessel to transport equipment from the staging port to the project site minimizes the number of required equipment transfers but also consumes highly valuable installation time ferrying equipment between the staging area and the project site. Dedicated transport vessels may allow for more efficient use of the installation vessel but also create the risk for component damage during transfers unless the dedicated transport vessel is capable of carrying out fixed (as opposed to floating) lifts at sea. The trade-off between these two approaches can be expected to be a function of distance between the staging port and the project site. When in closer proximity, the time lost ferrying equipment with the installation vessel is less substantial; sites located farther from port may require dedicated transport vessels. As noted above, the Jones Act will likely require the use of dedicated transport vessels if, or until, U.S. flagged installation vessels can be built. Rapid growth in installations could result in significant vessel shortages, particularly if there is limited long-term market certainty.

During the operations period, distance to the service port is also critical. Unlike the staging port, however, the requirements of the servicing port are far more modest. A servicing port must only have the ability to serve vessels that are capable of transporting a small number of technicians to the project site at reasonable speeds. Servicing ports are anticipated to be much closer to the project site than a staging port or even potentially the onshore point of interconnection with the electrical grid. However, once a project is more than about 15 nautical miles (M) from the nearest possible servicing port, it begins to become prohibitive to transport technicians from land to the site and back in a single shift while still allowing adequate time for work to be completed. Beyond 30 M from a potential servicing port, the need for offshore hotels for technicians starts to become economically viable. For these far offshore facilities, servicing could resemble an offshore drilling rig or even a ship with hoteling facilities such as a modified cruise ship. In either of these cases, staff would be located at sea for a period of weeks at a time and then rotate out with another set of workers who are then located at sea for a similar period. Such a model dramatically increases the offshore wind technician costs by doubling the required workforce and also requiring additional service workers to staff and maintain the hoteling facilities themselves (e.g., cooks). Offshore hoteling models will likely necessitate very large project sizes to ensure the ability to capture economies of scale. Nevertheless, they are expected to be particularly valuable in locations with very limited access opportunities due to weather or very deep water.

The lowest cost point of entry for offshore wind installation vessels is to convert an existing vessel to serve the wind industry.

The significantly greater demands and complexity of equipment installation and transport vessels suggests that much of the attention to vessels is focused on those that will provide these services. In today's industry there are various trade-offs that must be considered with respect to installation and transport vessels. The lowest cost point of entry for offshore wind installation vessels is to convert an existing vessel to serve the wind industry. Useful existing vessels may currently be serving the offshore oil and gas industry. In many cases, these vessels will be more versatile, able to serve a number of roles including transport, foundation installation, and turbine assembly. Versatility reduces mobilization costs but introduces inefficiencies as result of compromise. Moreover, it is not known if the opportunity cost of shifting away from oil and gas development activities even realistically allows for this possibility. However, as a nascent industry, the lower initial investment costs and increased versatility of a converted vessel are likely to be attractive.

Assuming a threshold level of demand and larger project sizes, specialized new build vessels will likely be developed for many of the individual tasks of offshore wind farm construction (e.g., transport, foundation installation, and turbine installation). In principle, specialized vessels may be designed to provide any number of tasks including wet tows (for transport of large monopiles, gravity-based structures, and floating turbines), perpendicular blade transport, assembled rotor transport, monopile gripping and upending, and roll-on lift-off capabilities (for transport between the factory and staging area). Specialization may in the future allow for more "assembly line" style construction processes whereby a series of dedicated vessels installs the foundations, towers, nacelles, hubs, and blades all in turn, one following the next. The ultimate degree of specialization will likely be a function of the overall scale of the industry with the impact on installed costs being a secondary driver. Dedicated new build vessel costs are estimated to be on the order of $100 million (Musial and Ram 2010) but have also been observed to be as much as $300 million and require a long-term design and construction period. The development and construction of a series of dedicated vessels capable of assembly line type construction will likely necessitate significant sustained demand for an extended period.

There are four primary strategies offshore wind farm developers and turbine OEMs have used to date to secure access to installation vessels, the first three involving downstream vertical integration into vessel ownership.

- **Acquiring a vessel company.** The most significant move made by an offshore wind developer to deal with the lack of availability of appropriate jack-up vessels was DONG Energy's 2009 acquisition of A2SEA, which was, at the time, the owner of the world's largest fleet of jack-up vessels for the offshore wind industry. In June 2010, Siemens purchased a 49% share of A2SEA from DONG, in a move that extended Siemens' offshore offering beyond turbines and into installation services.

» **Ordering the construction of new vessels.** In 2009, BARD Engineering, another turbine OEM, took ownership of a new jack-up vessel (4C Offshore Heavy Vessel Lift Database 2011). BARD CEO Anton Baraev indicated that the company would "now be able to install 'BARD Offshore 1' and further wind farms with [its] own construction vessels without having to worry about charter rates and time windows" ("Three Questions to Anton Baraev" 2009). In recent years, other leading offshore wind operators such as RWE Innogy of Germany and Fred Olsen Windcarrier of Norway have ordered their own installation vessels.

» **Building new vessels in-house.** Another approach for gaining access to vessels is to construct them in-house. The shipbuilding divisions of large Korean conglomerates such as Samsung, Daewoo, and STX are well positioned to do this, in addition to U.S. shipbuilders, such as Huntington Ingalls Industries. While these companies are not currently leaders in the offshore wind development business, some are developing offshore-specific wind turbines. Building their own vessels could allow them to enter the market with an integrated offering.

» **Establishing long-term charter agreements.** Some offshore developers have foregone vessel ownership and, instead, have established long-term charter agreements. In 2006, Centrica sealed an agreement with MPI Offshore for a long-term charter of the MPI Resolution jack-up vessel.

The size and scale of specialized vessels can be seen by comparing them to first-generation offshore wind vessels. Two of A2SEA's earlier vessels, the Sea Energy and the Sea Power, measure 91.8 meters in length, have a deck area of 1,020 m2, and have a crane capacity of 450 tons (4C Offshore Heavy Vessel Lift Database 2011). In 2010, DONG Energy ordered a much larger vessel, the Sea Installer, from Chinese shipbuilder COSCO. The vessel will measure 132 meters, have a deck area of 3,350 m2, and a 900-ton crane (4C Offshore Heavy Vessel Lift Database 2011). In 2011, Vattenfall ordered the vessel Pacific Orca from Samsung Heavy Industries. The vessel, to be delivered in 2013, will have a length of 161.9m, a deck area of 4,300m2, and a crane capacity of 1,200 tons (4C Offshore Heavy Vessel Lift Database 2011).

While much attention has been given to the lack of installation vessels, the lack of cable-laying vessels is at least as troubling for the industry. There are only a few fully equipped and highly specialized cable installation vessels for offshore wind power cables. The two leading cable suppliers Prysmian and Nexans own two such vessels. Among the specialized cable installation contractors, Visser & Smit Marine Contracting (VSMC) of the Netherlands, Global Marine Systems of the U.K., and Technip of France are the current market leaders. In 2010, Technip acquired the assets of British company Subocean. VSMC recently took delivery of a new cable-laying vessel and is considering investing more in vessels and equipment while Subocean, at the time of its acquisition, had four specialist vessels for cable-laying. According to comments at the BWEA 2010 offshore conference, the cable-laying fleet needs to grow by more than 500% to satisfy the demands of the offshore wind market.

2.5 *Electrical Infrastructure Trends and Innovations*

Transmission planning has always been an issue for the wind industry. In many parts of the world, load centers are not located near sites with high quality wind resources. Consequently, the most desirable sites for wind farms are frequently away from large population centers and therefore also transmission infrastructure. With land-based wind, there has always been a chicken and egg dilemma when it comes to transmission expansions, often leading to project delays. Wind developers do not want to build wind farms without sufficient transmission. Transmission operators do not want to build new transmission lines without sufficient assurances that they will be able to recover their costs. Cost allocation methodologies are complicated as well. In 2005, in what was once the world's largest land-based wind market, the U.S. state of Texas, the state legislature called for the creation of a Competitive Renewable Energy Zone (CREZ). Transmission lines are now being constructed to five CREZ zones established by the PUC where wind developers have provided collateral-based financial assurances and transmission operators will receive cost recovery from all ratepayers.

The offshore wind industry faces similar transmission planning issues. A study by the German Energy Agency (DENA), released in December 2010 indicated that 1,550 kilometers of marine-based transmission would be needed by 2020 to connect Germany's planned capacity from offshore wind, entailing an annual investment of €340 million. Through the first half of 2011, German offshore wind projects were facing delays due to financial and technical issues. Transmission operator TenneT has indicated that it cannot carry the financial burden alone of connecting all of the country's offshore wind farms to the grid.

The ambitious offshore wind development plans for many countries will necessitate the construction of significant offshore transmission infrastructure as well as onshore network upgrades as some interconnection points could be a significant distance inland. Various initiatives are underway to create shared offshore transmission infrastructure. Some of these efforts are corporate-driven while others are either country- or region-driven. They include the following:

» In the U.S., some companies are trying to address the lack of transmission before it really becomes an issue for the undeveloped U.S. offshore market. In October 2010, Good Energies, Google, and Marubeni announced investment in a $5 billion 350-mile offshore transmission backbone along the Atlantic coast of the U.S." (Malone 2010).

» In 2009, the U.K.'s Department of Energy and Climate Change (DECC) and Office of the Gas and Electricity Markets (Ofgem) established a licensed regulatory regime for offshore transmission similar to the onshore grid. The regime established Offshore Transmission Owners (OFTOs) who will be selected through a competitive tendering process and will receive a steady income stream for a period of 20 years. The regime is expected to generate £15-20 billion in investment in offshore transmission infrastructure between 2010 and 2020.

» In December 2009, nine nations bordering the North Sea signed the declaration for the North Seas Countries' Offshore Grid Initiative. The declaration set the objective of coordinating the technical, market, political, and regulatory components of offshore electricity infrastructure development in the North Seas region.

As with the land-based markets, project developers will need to understand the offshore transmission regime for each country. In many cases, the most attractive projects may be those with easier access to transmission.

Electrical infrastructure is estimated at approximately 15% of total installed project costs (Tegen et al. 2012). As the industry grows and matures, a handful of independent trends are likely to apply upward and downward pressures to the cost of electrical infrastructure. Moving farther from shore requires additional cabling, pushing up the relative share of electrical infrastructure costs as projects are sited farther into the sea. More cabling also puts increasing strains on the already limited supply of cable-laying vessels and suggests that new cable installation vessels might also be required. Increasing electrical infrastructure costs could be offset, at least in part, by reductions in intra-project cabling as turbines scale in size and reliance on higher voltage array cables. Development of high-voltage capability is a strategy being pursued by both Siemens and Vestas that would allow more capacity per turbine array while providing the potential for less equipment in offshore substations.

Despite higher initial costs, distant offshore projects (>50 M offshore) are increasingly exercising a preference for HVDC lines, which offer lower transmission line losses. Reduced line losses offered by HVDC technology are particularly valuable for larger, high production facilities. Continued evolution of HVDC conversion technology and development of the high-voltage cable supply chain are expected to push HVDC costs lower into the future. Improvements in cable-laying vessels, including for example replaceable cable reels, increased marine cable-laying capacity, and innovative trenching equipment might also offer electrical infrastructure cost reductions.

Despite higher initial costs, distant offshore projects are increasingly exercising a preference for HVDC lines, which offer lower transmission line losses.

Growth in the number and size of projects increases the possibility for HVDC trunk lines such as the Atlantic Wind Connection (AWC).[13] In this development model, a high-capacity HVDC trunk line would be used to collect and move power from an array of projects off the Atlantic Coast directly to load centers. Trunk lines such as the AWC offer the potential to reduce individual project costs by reducing the distance to the point of grid interconnection. They might also offer an ability to increase revenues by to delivering power from a broad array of projects throughout the mid-Atlantic to the regions where the power would be most valuable.

Overall, increased standardization in offshore wind electrical equipment including substations and convertor stations is expected with industry maturation. Greater standardization allows for efficiencies both in production and assembly as equipment becomes more modular. The development of self-elevating substations could lower electrical infrastructure costs by reducing the heavy lift requirements associated with today’s offshore substations. Multiple transformer substations offer the possibility for partial power delivery should there be a transformer failure. This approach is expected to reduce production losses in the event of a transformer loss.

[13] http://atlanticwindconnection.com/

2.6 Operations, Maintenance, and Plant Performance

Historically operations expenditures have constituted roughly 20% to 30% of the levelized cost of energy (LCOE) from offshore power plants (Hamilton 2011). Moreover, the limited accessibility of offshore turbines makes it more difficult to service machines that are down, resulting in reduced availability and potentially increased production losses (when periods of low availability are correlated with periods of high wind speeds). Improved siting of wind farms, new operations strategies and technologies, and enhanced access for turbines designed exclusively for the offshore market are anticipated to boost plant production and minimize operations expenditures.

2.6.1 Remote Sensing and Plant Siting

Wind resource assessment is inherently more challenging offshore than onshore. Historical datasets are more limited (Schwartz et al. 2010) and installing a meteorological tower in a marine environment is more complex.[14] However, remote sensing capabilities and meteorological models continue to advance, providing more and better insights into the offshore wind resource (Schwartz et al. 2010). At the micro-scale, improved array modeling and turbine integrated LIDAR technologies are anticipated to enhance our ability to site turbine arrays in the most economically efficient ways and our understanding of the offshore wind resource.

2.6.2 O&M Servicing and Technological Advancement

Approximately two-thirds of annual operations expenditures costs have been for corrective maintenance despite significant annual investments in preventative maintenance including multiple trips to each turbine every year (Hamilton 2011). To drive down operations expenditures, researchers are focused on minimizing unplanned maintenance and replacing corrective maintenance efforts with more regular and more effective preventative maintenance. Increased reliance on preventative maintenance has been a trend for some time, but modern technological advancements in condition monitoring and more experience identifying failure indicators are expected to allow for increased efficiency in diagnosing problematic performance and instituting the appropriate mitigation effort before there is a failure (Wiggelinkhuizen et al. 2008). Advanced condition monitoring techniques might also include self-diagnosing systems, real-time load response, and the ability to manipulate and control individual turbines from an onshore monitoring facility. Coordinating preventative maintenance efforts with improved wind and weather forecasting should allow operators to minimize turbine production losses. Turbine mounted LIDAR will also likely be utilized to inform turbines of changes in wind speed, direction, and turbulence as the wind approaches, allowing for turbines to be optimally positioned for changes in wind conditions as they occur. Such capabilities offer the dual opportunity of enhanced performance and reduced fatigue loads (UpWind 2011). Advanced blades that minimize soiling losses and new engineering and plant management strategies that allow turbines to continue to operate in a more diverse array of wind conditions are also expected to assist in improving plant availability and overall performance.

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[14] Although empirical data is more limited, arguably the uncertainty band is reduced in the marine offshore environment as a result of fewer surface disruptions and less interference from trees, buildings, terrain, and other landscape features that exist onshore.

Offshore-specific turbine designs are anticipated to incorporate new access opportunities, potentially allowing turbine repairs to be conducted in a more diverse set of weather and sea conditions (van Bussel and Bierbooms 2003). Attention to design details that would allow in situ repairs, improved access to components requiring regular maintenance or replacement, and increased system redundancy might offer the potential for lower operations expenditures. As projects move more than 15 M from onshore servicing ports, offshore wind plants will be increasingly serviced by offshore hoteling facilities in the form of ships or fixed platforms. Notably, ships offer the potential for greater lift and equipment storage capacity, as well as mobility, not afforded by fixed hoteling platforms; however, efficiencies may be gained from either type of hoteling facility by allowing technicians to service multiple projects within a general area while reducing transport time and cost. Hoteling facilities are anticipated to increase labor costs due to the need to rotate servicing crews, but early experience suggests that the efficiencies offered by hoteling vessels easily outweigh their additional labor cost. Helicopters may also take on an increasing role in the servicing of the offshore wind industry. They offer significantly increased mobility and transport speeds, potentially allowing for lower mobilization costs and reduced production losses in the event of a need for quick turbine access.

2.7 Summary and Conclusions

Offshore wind in the United States and globally is a nascent industry. Only within the last five years have significant installations (concentrated in Europe, with limited activity in China) and experience began to accrue. With this in mind, offshore wind is at a very different point in the technology development and diffusion process relative to its land-based counterpart and there is a vast array of opportunities to drive down costs into the future. Table 2-1 summarizes the sample of trends and innovations discussed here, including their cost implications and the general timeframe over which these opportunities might be realized given reasonably robust global growth of the industry.[15]

Particularly critical innovations include the emergence of offshore-specific turbine designs, engineered for the marine environment from the bottom up. Moreover, by reducing the logistics constraints, the offshore segment of the industry will likely continue to realize the significant cost of energy reductions that resulted in the past from turbine scaling and are anticipated into the future. Despite the array of opportunities, offshore wind is an industrial-scale, capital-intensive technology. The investment required to realize the cost reductions and industry efficiency potential of the technology is sizable and as such the ultimate success or failure of these innovations will likely be contingent upon the perceived risks and opportunity of the industry moving forward.

[15] Aggressive global demand or a concentrated effort to drive down offshore wind costs could result in more rapid realization of the opportunities discussed here.

Table 2-1. Summary of Offshore Wind Technology Trends and Opportunities

	Cost Implications	Current Global Status	Possible Timing for Large-Scale Acceptance in the U.S.
Alternative Design Concepts			
Downwind Turbines	Softer, Lighter, Blades	None	Unknown
2-Bladed Turbines	Reduced Rotor Material & Mass	R&D	Unknown
Vertical Axis Platforms	Unknown	Conceptual	Unknown
Balance of Plant			
Co-located Manufacturing & Staging	Reduced Transportation & Simplified Logistics	Medium	2020-2030
Offshore Wind Berths	Improved Port Access & Staging	Medium	2015-2020
Modular Production & Storage Capacity	Reduced Transportation & Simplified Logistics	Conceptual	2015-2025
Converted Installation Vessels	Minimal Initial Investment	Medium	2015-2020
New Build Installation Vessels	Higher Efficiency & Productivity	Low	2020-2030
Specialized Assembly Line Vessel Capacity	Higher Efficiency & Productivity	Conceptual	2025-2030
HVDC Interconnections	Reduced Transmission Losses	Low	2015-2030
HVDC Trunk Lines	Reduced Interconnection Costs	Conceptual	2020-2030
HV Array Cables	Less Intra-project Cabling	R&D	2015-2020
Advanced Cable Lay Vessels	Lower Cable Installation Costs	Conceptual	2015-2020
Modular Substations/Convertor Stations	Lower Electrical Infrastructure Costs	R&D	2015-2025
Self-elevating Substations	Lower Electrical Infrastructure Costs	Low	2020-2030
Components			
Large Advanced Rotors	Improved Performance	Prototype	2015-2020
Enhanced Geared Generators	Enhanced Reliability	R&D	2015-2025
Direct Drive Generators	Enhanced Reliability	Low	2015-2020
Superconducting Generators	Reduced Mass & Size	R&D	2020-2030
Advanced HV Power Electronics	Higher Capacity/Enhanced Grid Services	Medium	2012-2017
Advanced Foundations/Substructures	Access to Deeper Water & More Harsh Conditions	Low	2012-2020
Floating Foundations	Standardized Installation & Access to Deepwater Sites	Prototype	2020-2030
Manufacturing			
Commercial/Serial Production	Lower per Unit Costs	Low	2015-2020

	Cost Implications	Current Global Status	Possible Timing for Large-Scale Acceptance in the U.S.
Optimized Automation	Tighter Design Standards/Fewer Defects	Low	2015-2020
Operations, Maintenance, & Plant Performance			
Integrated Access & Maintenance Designs	Reduced Technician Time/ Access in Harsher Conditions	Prototype	2015-2020
Advanced Condition Monitoring	Fewer Component Failures	Low	2015-2030
Real-time Load Response Sensors	Improved Reliability	R&D	2015-2025
Resource Assessment/Array Modeling	Reduced Array Losses/Enhanced Performance	R&D	2015-2020
Offshore Hoteling Facilities	Lower Transportation Costs	Low	2020-2030
Regional Issues			
Hurricane Resiliency	Access to New Resource Areas	Conceptual	2020-2030
Icing (surface & blade)	Access to New Resource Areas	Low*	2020-2030

*There is a single freshwater offshore wind project in Vanern, Sweden; installations in the Baltic Sea have managed light icing conditions.

3. Analysis of Policy Developments

This section provides an analysis of policy developments at the federal and state levels with the potential to affect offshore wind deployment in the U.S. It includes a description of policies for promoting offshore wind and an evaluation of policy examples to close any competitive gaps. The evaluation employs a systematic approach of defining the offshore program objectives (Section 3.1), identifying barriers to meeting the objectives (Section 3.2), and evaluating examples of policies to address the barriers (Sections 3.3 through 3.8). The categories of barriers and policies that are addressed are summarized as follows:

» High cost of offshore wind energy (Section 3.3)
» Infrastructure challenges (Section 3.4)
» Regulatory challenges – site selection and leasing (Section 3.5)
» Regulatory challenges – permitting (Section 3.6)
» Regulatory challenges – operations (Section 3.7)
» Summary of representative policies (Section 3.8)

Summary of Key Findings – Chapter 3

» U.S. offshore wind development faces three significant challenges: (1) relatively high cost; (2) a lack of infrastructure; and (3) uncertain regulatory processes.
» For the U.S. to maximize offshore wind development, the most critical need is for stimulation of demand through addressing high cost. High costs have been addressed through the use of : (a) mandated long-term power contracts; (b) RPS with an offshore wind carveout; (c) investment tax credit; (d) production tax credit; (e) low-interest loans and loan guarantees for developers; (f) accelerated depreciation; and (g) state Feed-in Tariffs.
» Infrastructure policies are generally longer term and could help allow demand to be filled. The following are examples of policies that address transmission infrastructure: (a) establish clear permitting and siting criteria and guidelines; (b) establish consistent cost allocation and cost recovery mechanisms; (c) promote utilization of existing transmission capacity reservations; and (d) designate offshore wind energy resources zones for targeted grid investments.
» Regulatory policies could help to streamline siting and permitting processes. The following are examples of policies that address regulatory challenges: (a) in site selection and leasing, conduct a three-phase process similar to BOEM and U.K. models; (b) in permitting, develop a programmatic EIS for a broad geographic area followed by more limited, detailed EISs or EAs for specific projects; and (c) in operations, allow self-monitoring of environmental and safety compliance.

3.1 *Offshore Program Objectives*

In 2010, the U.S. Department of Energy (DOE) instituted the Offshore Wind Innovation and Demonstration Initiative (OSWInD) to accelerate the development of commercial offshore wind. The

OSWInD Initiative is focused on reducing the cost of offshore wind energy and decreasing the deployment timeline uncertainty. The DOE sees offshore wind as a method to reduce the nation's greenhouse gas emissions, diversify energy supply, deliver cost-competitive electricity to coastal regions, and stimulate the economy. The offshore wind program is specifically aiming to maximize the MW capacity of manufacturing production in the U.S., resulting in more factories and jobs.

The DOE's 2008 report, *20% Wind Energy by 2030*, has determined that it is feasible for wind power to meet 20% of U.S. electricity demand by 2030, which would require wind power capacity to increase to over 300 GW (U.S. DOE 2008). The report projects 54 GW of offshore wind could be installed by 2030 with an average LCOE of 7¢/kWh. While this level may not be achieved, DOE's offshore program has the objective to get as close as possible to this projection by maximizing U.S. offshore wind development and minimizing the LCOE of offshore wind.

3.2 Potential Barriers to Meeting the Objectives

3.2.1 High Cost of Offshore Wind Energy

Capital costs for offshore wind projects are nearly three times that of land-based wind projects. As discussed in Section 4, capital costs for the first generation of U.S. offshore wind projects are expected to be approximately $6,000 per installed kW, compared with approximately $2,100 per installed kW for U.S. land-based wind projects in 2011 (Wiser and Bollinger 2012). Offshore projects have higher capital costs for a number of reasons, including turbine upgrades required for operation at sea, turbine foundations, balance-of-system (BOS) infrastructure, the high cost of building at sea, and O&M warranty risk adjustments. These costs remain high because the offshore wind industry is immature and learning curve effects have not yet been fully realized. There are also a number of one-time costs incurred with the development of an offshore wind project, such as vessels for turbine installation, port and harbor upgrades, manufacturing facilities, and workforce training.

Offshore wind energy also has a higher LCOE than comparable technologies. In addition to higher capital costs, offshore wind has higher O&M costs as a result of its location at sea. Higher permitting, transmission, and grid integration costs contribute to this higher cost of energy, somewhat balanced by an improved wind regime offshore.

Offshore wind has higher financing costs due to the heightened perceived risk. Since it is not yet a mature industry, offshore wind is still perceived by investors as being risky due to regulatory and permitting issues, construction and installation risk, and long-term reliability of energy production. As a result, insurance and warranty premiums remain high. There are also extremely high risks to early stage capital given the uncertainty around the price and availability of future off-take agreements for offshore wind.

The Jones Act

Section 27 of the Merchant Marine Act of 1920, better known as the Jones Act, requires that all goods transported by water between U.S. ports be carried in U.S.-flag ships. Once a wind farm foundation is in place in the ocean, the structure is considered a port. Therefore, U.S. vessels must service it. Currently, the only existing specialist vessels capable of offshore foundation and turbine installation are mostly European-owned, which are in high demand for European projects.

3.2.2 Infrastructure Challenges

Offshore wind turbines are currently not manufactured in the U.S. Domestic manufacturing needs to be in place in the U.S. for the industry to fully develop. The absence of a mature industry results in a lack of experienced labor for manufacturing, construction, and operations. Workforce training must therefore be part of the upfront costs for U.S. projects.

The infrastructure required to install offshore wind farms, such as purpose-built ports and vessels, does not currently exist in the U.S. There is also insufficient capability for domestic operation and maintenance. While turbine installation and maintenance vessels exist in other countries, legislation such as the Jones Act may limit the ability of these foreign vessels to operate in U.S. waters. These issues also apply to transmission infrastructure for offshore wind.

The absence of strong demand for offshore wind in the U.S. makes it difficult to overcome these technical and infrastructure challenges. In order to develop the required infrastructure and technical expertise, there must first be sufficient demand for offshore wind, and that is not expected in the near term due to the high cost of offshore wind and the low cost of competing power generation resources such as natural gas.

3.2.3 Regulatory Challenges

Permitting

Offshore wind projects in the U.S. are facing new and relatively untested permitting processes. After issuing the Final Rule governing offshore wind leasing on the Outer Continental Shelf (OCS) in 2009, Minerals Management Service (MMS)—now the Bureau of Ocean Energy Management (BOEM)—staff estimated that the lease process might require three EISs and may extend seven to nine years. Secretary Salazar announced his *Smart from the Start Program* initiative in 2010. One aspect of the initiative was the concept of preparing an Environmental Assessment which would evaluate the potential environmental impacts of commercial wind lease issuance, associated site characterization surveys, and subsequent site assessment activities (i.e., installation and operation of meteorological towers and buoys) prior to lease issuance, as opposed to preparing an Environmental Impact Statement which would also analyze construction and operation of a wind facility prior to lease issuance. Construction and operations plans proposing the installation of renewable energy generation facilities would be subject to additional project specific environmental reviews. This approach seeks to add some certainty for developers and financiers.

A number of state and federal entities have authority over the siting, permitting, and installation of offshore wind facilities. Cognizant federal agencies include BOEM, U.S. Army Corps of Engineers (USACE), U.S. Environmental Protection Agency (EPA), U.S. Fish and Wildlife Service (FWS), National Oceanic and Atmospheric Administration (NOAA), and others. BOEM is preparing to sign a Memorandum of Understanding (MOU) with USACE to facilitate coordination of federal approvals of offshore wind facilities and is negotiating MOUs with other federal agencies.

In March 2012, a bipartisan federal-state MOU was signed by five Great Lakes states (IL, MI, MN, NY, and PA) and ten federal agencies establishing a Great Lakes Offshore Wind Energy Consortium to support the efficient, expeditious, orderly, and responsible review of proposed offshore wind energy projects in the Great Lakes. The Consortium will help ensure that efforts to meet America's domestic energy demands in an environmentally responsible manner through the use of excellent Great Lakes offshore wind resources occurs in an efficient and effective manner that protects the health and safety of our environment and communities while supporting vital economic growth.

Environmental

Environmental concerns and public resistance present challenges to the industry. Regulatory agencies must consider a range of environmental concerns related to offshore wind, including bird and bat species, marine mammals, and pelagic and benthic species at risk, as well as potential impacts to water quality. At this point in time, the environmental impacts of offshore wind in the U.S. are not well understood. Cultural resources, such as historic preservation sites and tribal resources, must also be considered. In addition, public opposition may arise, especially with offshore wind sites near the shore that could impact viewsheds, environmental resources, and competing human uses such as fishing.

3.3 Examples of Policies for Addressing the High Cost of Offshore Wind Energy

3.3.1 General Discussion of Policy Examples

Support schemes can be divided into "investment support schemes" (MW focused) and "operating support schemes" (MWh focused). The support schemes listed below have been used to address the high cost of offshore wind energy.

Investment support schemes

Renewable energy is a capital-intensive industrial sector. Investment support schemes help reduce the burden for project developers and/or manufacturers, via direct or indirect investment subsidies at the time of construction, which can take the form of the following:

- Cash grants: Part of the investment is paid through public subsidies. This is the simplest and most direct mechanism
- Loans guaranteed by federal or state governments
- Accelerated depreciation of assets: This leads to higher taxable losses in early years – investors with corresponding taxable profits can reduce their tax bills in such years, leading to higher profitability (linked to the tax rate applicable to such underlying taxable profits). Structures can be put in place whereby tax investors (with taxable profits) notionally own the project at the time of investment and share the tax gains from accelerated depreciation with the project's real investors in the form of "tax equity" (i.e., the volume of tax depreciation, multiplied by the tax rate, minus a profit to the remunerator for the use of taxable income)
- Tax breaks, low-interest loans, credits or deductions – various direct or indirect structures through the tax code amounting to some combination of the above two mechanisms. The Business ITC for renewable energy in the U.S. falls into this category. In addition, low-interest

loans or other incentive mechanisms can be provided for manufacturing to help reduce hardware costs

Operating support schemes

Operating support schemes are linked to the actual energy production from renewable energy sources. There are two main philosophies: one whereby the regulator offers a fixed price to renewable energy producers (volume is therefore uncertain), and one where the regulator sets a target volume for renewable energy production (in which case the value of the support will vary). The latter category is typically considered to be more market-oriented.

The following mechanisms are the primary operating support schemes currently in use to support offshore wind:

- Price driven mechanisms
  - Feed-in Tariffs
  - Feed-in Premiums
- Quantity based mechanisms
  - Green certificates
  - Tendering

The use of each of these mechanisms in Europe is summarized in Section 3.3.3. The mechanisms are defined and described more detail in Appendix B.

3.3.2 Current U.S. and State Policies

Figure 3-1 and Table 3-1 provide a summary of policies and related activities to address the high cost of offshore wind energy in selected U.S. states. Additional details of these activities are provided in Appendix A.

Figure 3-1. Summary of Policies to Address High Cost in Selected U.S. States

Policy Options *Barrier: High Cost*	**Jurisdictions where Used**									
	Delaware	**Maine**	**Maryland**	**Massachusetts**	**Michigan**	**New Jersey**	**New York**	**Ohio**	**Rhode Island**	**Texas**
Renewable Portfolio Standard (RPS)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Incorporate PPAs into competitive situations	✓[1]			✓[2]			✓[3]		✓[4]	
RPS with offshore carve out			✓[5]			✓[6]				
Green certificates with premium prices for offshore installations	✓[7]									

(1) Delaware statute directed all-resource competitive bid & Delmarva to negotiate a PPA with Bluewater Wind in 2009 (~14 cents/kwh), but Bluewater Wind withdrew from the PPA in 2011 citing Congressional failure to fund loan guarantees and extension of federal investment and production tax credits.

(2) Massachusetts statute requires PPAs for 7% of load and approved Cape Wind PPA for 18.7 cents/kwh.

(3) Long Island Power Authority conducted competitive bid in 2005 & ended in 2008 for high prices. New York Power Authority conducted competitive bid in Great Lakes in 2009 and ended in 2011 for high prices. NYPA, LIPA, Consolidated Edison, and others issued an RFI for a 350 MW offshore wind project, possibly expandable to fill NY's 700 MW offshore wind target.

(4) Rhode Island issued an RFP for an offshore wind project to produce 15% of the state's electricity demand and subsequently signed a Joint Development Agreement with Deepwater Wind. Approved initial 30MW Pilot PPA for 24.40 cents/kwh.

(5) Governor filed Ocean REC bill based on New Jersey OREC model requiring net economic benefits.

(6) Statute requires 1100 MW Ocean RECs at a cost-effective rate based on a comprehensive net benefits analysis; Board of Public Utilities issuing regulations.

(7) Offshore wind RECs count 3.5 times in meeting Delmarva's renewable energy purchase requirements.

Table 3-1. Policies to Address the High Cost of Offshore Wind in Selected U.S. States

State	RPS	Offshore Wind RPS	Mandatory PPAs	RFPs and Other Activity
Delaware	25% by 2025-2026	350% multiplier for the Renewable Energy Certificate (REC) value of offshore wind facilities sited on or before May 31, 2017.	Delmarva Power was directed to negotiate a long-term PPA with Bluewater Wind. However, NRG-Bluewater Wind failed to make a substantial deposit to maintain the PPA.	Projects receive a subsidy from the grid operator for construction of the export cable.
Maryland	20% by 2022	In January 2012, the governor introduced legislation to create an offshore wind carve-out. The bill failed to be approved by the Senate Finance Committee.		Maryland issued an RFP to conduct initial marine surveys of the offshore Wind Energy Area identified by BOEM. Maryland plans to fund additional surveys with state funds to encourage development of the WEA by private developers after the BOEM competitive auction process.
Massachu-setts	15% by 2020, increasing by 1% each year thereafter with no stated expiration date.	There is no carve-out or REC multiplier for offshore wind.[16] The governor has set a goal of developing 2,000 MW of offshore wind energy to help achieve the RPS requirements.	The Green Communities Act , as amended, requires each electric distribution company to sign PPAs for 7% of its load with renewable energy generators. As a condition of approving the merger between Northeast Utilities and NStar, the DPU required the merged entity to purchase 27.5% of the output of the Cape Wind project.	

[16] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R&re=1&ee=1

State	RPS	Offshore Wind RPS	Mandatory PPAs	RFPs and Other Activity
New Jersey	20.38% Class I and Class II renewables by 2020-2021	The New Jersey RPS contains a carve-out for offshore wind. The state's Board of Public Utilities will define a percentage-based target of 1,100 MW of OSW.		
New York	29% by 2015	There is no carve-out or REC multiplier for offshore wind.		NYPA, LIPA, and Consolidated Edison have filed an unsolicited request for a lease in federal waters off Long Island. NYPA plans to issue an RFP for private project developers to bid to construct the wind farm.
Rhode Island	16% by 2019	There is no carve-out or REC multiplier for offshore wind.		In 2008, Rhode Island issued an RFP for an offshore wind project to produce 15% of the state's electricity demand and subsequently signed a Joint Development Agreement with Deepwater Wind. The Rhode Island Public Utility Commission approved an initial 30 MW Pilot PPA for 24.4 cents/kWh.[17]
Virginia				Virginia is having the local transmission system owner conduct interconnection studies exploring a high-voltage submarine cable that could interconnect to OSW farms.[18]

[17] See http://offshorewind.net/OffshoreProjects/Rhode_Island.html.

[18] See https://www.dom.com/news/2012/pdf/dominion_offshore_public_report_3-13-2012.pdf.

3.3.3 Current Policies in Other Countries

The following sections give an overview of European support schemes for renewable energy and offshore wind. The EU has set the following targets for 2020:

1. Reduce greenhouse gas emissions by 20%
2. Reduce primary energy use by 20%
3. Generate 20% of the electricity with renewable sources

All of the EU member states have committed themselves to these targets and have different support schemes in place to achieve this. This section describes the different support schemes used and evaluates their effectiveness and adverse effects.

Investment support schemes

Table 3-2 lists investment support schemes in various EU countries.

Table 3-2. Renewable Energy Investment Support Schemes by Country

Country	Investment Support Schemes	Comments
Belgium	» Grid subsidy	Projects with a capacity of 216 MW or more receive a subsidy from the grid operator (EUR 25 M) for construction of the export cable. (Smaller projects received a prorated amount.)
Czech Republic	» Cash grant	Up to 40% of investment budget
Finland	» Cash grant	Up to 40% of investment budget
France	» Accelerated depreciation » Research tax credit	
Greece	» Tax break » Cash grant » Leasing subsidies	Total investment incentives up to 40% of investment budget
Italy	» Cash grant	Up to 30% of investment budget
Luxembourg	» Cash grant	Grant of 20% to 25% of investment budget
Netherlands	» Tax break	
Poland	» Tax break » Cash grant	Renewable energy is exempt from tax. Grant from EU structural funds
Spain	» Accelerated depreciation	Free depreciation of new tangible assets used in economic activity

Source: European Renewable Energy Council, 2009 and Taxes and Incentives for Renewable Energy, 2011[19]

Feed-in tariff

FiTs (which feature a guaranteed price per kWh) are the most frequently used support schemes for renewable energy in Europe and have made the continent the pioneer for renewable energy installations. In most countries the FiT scheme has evolved into an "advanced tariff scheme" whereby the number of years when the FiT applies is limited, ensuring a natural phasing out of the support scheme. In order to provide security for the investors, the support scheme normally has a lifespan of between 10 and 15 years. In addition, in some countries the FiT is also limited to a number of full load hours. Price differentiation between the multiple renewable energy sources takes place in most countries.

[19] http://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/Documents/Taxes-Incentives-Renewable-Energy-2011.pdf

> FiTs are the most frequently used support schemes for renewable energy in Europe and have made the continent the pioneer for renewable energy installations.

Solar FiTs have proven to be more difficult to manage than wind FiTs. Set at significantly higher levels, they have a real cost to ratepayers (whereas wind tariffs are close to being cost neutral, taking into account any merit order effect[20])—or to taxpayers if governments choose not to pass on price increases to ratepayers and to instead pay compensation to the utilities. Given the rapid fall in the cost of solar technology, FiT levels have often ended up being higher than necessary, leading to windfall profits, investment booms, and political acrimony when governments slash tariffs. Rapid price adjustments, even if justified by the cost of technology, create an appearance of regulatory uncertainty and can be detrimental to future investment.

Feed-in premium

Very few countries in Europe use Feed-in Premiums (guaranteed premiums per kWh, incremental to the electricity market price). Belgium is probably the main example of its use. A common criticism of the Feed-in Premium is that the regime is susceptible to lobbying, as large industrial power consumers will lobby more aggressively against such a regime that imposes a surcharge on the price of electricity, which is largely independent from the price of power.

Green certificates

Green certificate regimes (where qualifying producers generate tradable certificates which others must purchase) have generally been seen as less stable, more complex, and less favorable to investment. Countries with such regimes have seen investment lag behind countries with FiTs. Further, while green certificate regimes can be made to work for mature technologies like land-based wind, they do not really promote diversification of renewable energy sources without extensive tinkering (which increases complexity and instability).

The risk profile for green certificates is seen as higher due to having twin price risk (in electricity markets as well in the green certificates market). This has been obvious during the banking crisis of 2008, when lending in such countries was reduced much more drastically than in FiT countries.

For this reason, Belgium has set a minimum price for the green certificates (thus creating a de facto Feed-in Premium), Poland imposes the average market price of the previous year, and Romania set a floor-and-cap price. Lithuania has committed to use green certificates beyond 2020.

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[20] The merit order effect is the short-term downward impact on market power prices created by renewable energy when injected into the grid. As a zero-marginal cost source of electricity, renewable energy kWhs always replace more expensive power sources at any point in time, and thus reduce the marginal cost of production and, consequently, the market-clearing price of electricity for that period. As such price reduction applies to the whole market volume, it can become larger than the gross cost imposed by the support regime, which applies only to renewable energy kW.

Tendering

With a tendering regime, regulators set volumes of renewable energy production and provide a specific support regime for that volume over an agreed period – typically via a fixed price or Contracts for Differences (CfD) mechanism. Such volumes are offered to investors on a competitive process.

Renewable energy tenders have a bad track record in various European countries due to the insufficiency of non-compliance penalties, the lack of competition in the bidding process, long project lead times, and complex permitting procedures, which have tended to be separate from the tender process.

Summary of support mechanisms used in Europe

Table 3-3 is a summary of offshore wind operating support mechanisms currently in use across Europe. Table 3-4 shows offshore wind capacity that has been installed under various support schemes. Appendix B shows a summary of advantages, disadvantages, and lessons learned for each of the primary support mechanisms used

Table 3-3. Current Support Mechanisms in Europe

Country	Primary Support Scheme	Notes
Austria	FiT	» 9.7 cEUR/kWh for 13 years
Belgium	Green certificates with floor price (i.e., Feed-in Premium)	» Separate green certificate markets in Brussels, Flanders, and Wallonia plus federal obligations » Offshore wind is supported at the federal level.
Bulgaria	FiT since 2006	» 15-year tariff » FiT for the first 2,250 hours and lower FiT for everything produced above 2,250 hours » Maximum annual digression set at 5%
Cyprus	FiT (since 2006)	» 15-year tariff
Czech Republic	Green Certificates or FiT	» 15-year tariff (from 2013 only for plants <100 kW) » GC: in addition to market price
Denmark	Premium FiT for land-based wind, tender scheme for offshore wind, and fixed FiTs for others	» Premium duration 22,000 peak load hours (nine to ten years)
Estonia	Feed-in premium	» Premium: 5.37 cEUR/kWh for 12 years » Government is considering halving premium level.
Finland	FiT	» 12-year tariff » “Sprinter Bonus” (i.e., additional tariff) for projects built in the first 3 years

Country	Primary Support Scheme	Notes
France	FiT and tender for large projects	» Land-based wind 8.2 cEUR/kWh for ten years and between 2.8 cEUR/kWh and 8.2cEUR/kWh for the next five years depending on the location » Offshore wind 1.9 GW allocated in tenders in April 2012 at tariffs in the 17-20 cEUR/MWh range
Germany	FiT	» Land-based wind 20-year FiTs with annual digression of 1.5% » Offshore wind 20-year FiT with annual digression of 7% starting from 2018 » Land-based wind tariff currently at 8 cEUR/kWh » Offshore tariff at 15cEUR/kWh for 12 years, or 19 cEUR/kWh for 8 years, plus extra period at 15 cEUR/kWh depending on distance and depth
Greece	FiT	» 12 years with the possibility of extension to 20 years
Hungary	FiT	» 10 to 15 years, indexed to inflation
Ireland	FiT	» Offshore wind 0.14 cEUR/kWh - 15 years capped at 1.5 GW
Italy	Tendering with floor price	» Projects of 5 MW and larger based on average lifetime of plants » Not yet approved
Latvia	FiT	» Duration 2 x 10 years » Second term is 60% of the first term and is capped at 3,500 full load hours per year. » Tariff value dependent on factors including size and value of Latvian Lats to the Euro
Lithuania	FiT	» FiT awarded through tender system, valued at 0.087cEUR/kWh, duration 12 years
Luxembourg	FiT	» 10 years (20 years for PV)
Malta	Low VAT rate	» Very little attention to RES support so far
Netherlands	FiT via CfD	» Premium capped at 14.4 cEUR/kWh for offshore wind and 7.6cEUR/kWh for land-based wind » Duration 15 years
Norway	Green Certificates	» Green certificates at 2.16cEUR/kWh in 2011
Poland	FiT and quota obligation	» Minimum price based on formula » 10.4% of all energy produced should be from renewable sources
Portugal	FiT (subject to ongoing review)	» Licensing of all RE projects suspended

Country	Primary Support Scheme	Notes
Romania	Green certificates/quota obligation	» Quota for RE goes from 8.3% in 2010 to 20% in 2020
Slovak Republic	Project-specific FiT	» 12 year » Price linked to project IRR
Slovenia	FiT	» 15 years at 9.538 cEUR/kWh
Spain	FiT (subject to ongoing review)	» Moratorium on subsidies for all RE capacity not already approved
Sweden	Market spot price + green certificates	» Land-based wind GC in place until 2030 » Offshore wind GC + Premium until 2030
U.K.	Green certificates ("ROCs") Under review (EMR)	» Quotas increase until 2037 » 1 ROC for land-based wind, 2 ROCS for offshore » Buyout price set by government (penalty for utilities not reaching quota) with such penalties recycled to producers' pro rata production

Table 3-4. Offshore Wind Capacity Installed Under Support Schemes

Country	Investment Schemes	Operational Schemes	Installed MW	Construction MW	Permitted MW
U.K.	-	Green certificates	1,858	2,359	1,266
Denmark	-	FiT by tender	871	400	36
Germany	-	FiT	140	580	8,877
Belgium	Cash grant	Feed-in Premium	195	296	381
Netherlands	Tax breaks	FiT (to 2007), tender	247	0	3,238
Sweden	-	Green certificates	168	0	1,888
Finland	-	FiT	26	0	703
Ireland	-	FiT	25	0	0
Portugal	-	FiT	2	0	0
France	Accelerated depreciation	Tender	0	0	108[21]
Italy	Cash grant	Tender & floor price	0	0	162

3.3.4 Evaluation of Policy Examples That Address High Cost

The Navigant Consortium has evaluated each policy example in various jurisdictions using two sets of criteria: (1) the relative amount of effort and cost required to implement the policy and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development. The list of criteria, the policies that were evaluated, and the relative rankings for each criterion are provided in Appendix C.

[21] A volume of 2,448 MW has been allocated under the tender in April 2012.

The following examples of policies that address high cost have the most optimal combination of Relative Effort and Relative Results and have shown to be effective based on our analysis:

The following policy examples have shown to be effective in addressing the high cost of offshore wind based on our analysis:
» Mandated long-term power contracts
» RPS with an offshore wind carveout
» ITC or PTC
» Low-interest loans and loan guarantees for developers
» Accelerated depreciation

» *Long-term contracts for power*. Mandated buy programs that require utilities to enter into 15-20- year PPAs, similar to Massachusetts' Green Communities Act. In July 2012, six New England states approved a plan for a coordinated competitive renewable energy procurement process at the end of 2013 for thousands of MW of renewable energy with an offshore wind target of over 1,000 MW, which could result in long-term contracts for offshore wind and spread the costs broadly over the region.[22] Another major new report assessing the benefits and approaches to collaborative procurement of offshore wind was issued in September 2012 by the Offshore Wind Accelerator Project of the Clean Energy States Alliance. "Collaborative Procurement of Offshore Wind Energy" concludes that aggregated procurement could reduce the levelized cost of electricity by $35/MWh, and together with low-cost debt financing and the ITC could result in an estimated total LCOE for offshore wind of $95/MWh.[23]

» *ORECs.* Mandatory credits for offshore wind energy production to meet state RPSs or a federal Clean Energy Standard. OREC programs with longer terms and more stable prices have shown to be effective. New Jersey has issued initial regulations to implement its OREC program with a target of 1,100 MW of offshore wind energy.

» *Investment Tax Credit (ITC) for developers.* Similar to the current ITC of 30% of initial capital cost. The policy is in place generally for at least six years, given the current time required to develop and build offshore wind projects. The ITC can leverage project financing before construction and operation, unlike the PTC.

» *Production Tax Credit (PTC) for developers.* Similar to the current PTC of $22/MWh, with a premium for offshore wind. The policy is generally in place for at least six years. Developers typically have the option of using the ITC or the PTC, but not both.

» *Low-interest loans and loan guarantees to developers.* Similar to the recently expired Section 1704 DOE loan guarantee program.

» *Accelerated depreciation for developers.* Allow depreciation of initial capital in less than the five-year depreciation that is currently in place (e.g., the two-year bonus depreciation schedule that is due to expire for wind plants at the end of 2012).

» *State FiTs*. Major utilities or grid operators in participating states would be required to pay a defined $/kWh rate for offshore wind energy. Payments would continue at a guaranteed rate for 15-20 years for any given project. Payments to future offshore wind plants would be lower,

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22 See http://nescoe.com/uploads/ED_Coord_Procure.pdf.

23 See http://www.cleanenergystates.org/resource-library/resource/collaborative-procurement-of-offshore-wind-energy-a-buyers-network-assessment-of-merits-and-approaches.

based on the growth of the offshore wind market. The level of the FiT would be roughly equal to the LCOE of offshore wind less the LCOE of conventional energy. The policy would be in place for at least six years.

Only one or two of these policies are typically used if they include sufficient levels of support and duration, although low-interest loans and loan guarantees and accelerated depreciation are often implemented in addition to any of the other policies.

Timing and other considerations for these policy examples are discussed in Section 3.8. It is worth noting that "non-incentive" policies such as commercial demonstration programs and manufacturing R&D are found to have less effective results in addressing high costs. However, based on our analysis they will be useful in maintaining a competitive industry in the medium to long term after demand begins to increase.

3.4 Examples of Policies for Addressing Infrastructure Challenges

3.4.1 General Discussion of Policy Examples

The primary infrastructure policies for offshore wind are related to transmission and port upgrades as well as providing incentives for local manufacturing.

Transmission

Current transmission-related policies for offshore wind focus on the following:

- Direct connect design (land-based or offshore collector/converter) and system upgrades
- Who will plan, build, operate, and maintain the offshore transmission system
- Who will hold responsibility for funding offshore grid investments (i.e., cost allocation and cost recovery for system upgrades)
- Siting/permitting of transmission

Ratepayers eventually pay for all transmission and generation costs, whether their electric bills are bundled or each cost is itemized and added to the local distribution cost. Under the current policy in some parts of the country, including the Atlantic coast, any new generator must pay for the cost of the new interconnection to the grid and any transmission system upgrades required to accommodate the new generation reliably. These interconnection and grid upgrade costs must then be incorporated into the cost of the energy produced by that generator to become part of the wholesale cost of that energy that is ultimately passed through to the ratepayers. However, significant interconnection and grid upgrade costs deter construction of new offshore wind generation, because developers must have an assurance of cost recovery in order to obtain financing to build new transmission lines. Thus arises a “chicken and egg” dilemma for the offshore wind industry. The following policies have been proposed to help address this dilemma.

Based on research of effective policies in various jurisdictions, the first policy examined is more comprehensive transmission system planning to optimize grid investments necessary to interconnect offshore wind farms.

- » Policy Description
  - o BOEM, state offshore wind task forces, and/or developers identify priority offshore wind areas with a favorable wind resource, based on positive results from a wind resource assessment and other factors, such as available land (or water/ocean space).
  - o Transmission system planners identify transmission upgrades or new transmission required to develop an offshore wind project area (i.e., conceptual transmission expansion plans).
  - o Developers and transmission system planners evaluate direct single interconnections to each wind farm or joint interconnections to multiple wind farms (such as the proposed AWC submarine cable off the mid-Atlantic coast).
- » Policy Rationale
  - o Optimizing the transmission infrastructure for consolidated wind farms reduces costs to the customer and environmental impacts.
  - o Federal Energy Regulatory Commission (FERC) Order 1000[24] directs Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to consider state and federal energy policies, which includes RPSs, when planning expansion of their respective transmission systems. More specifically, Order 1000 requires that each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
  - o A single environmental review and permitting process can be conducted, which reduces costs and timelines.

Therefore, transmission providers should comply with FERC's encouragement in Order 1000 by planning transmission upgrades to accommodate offshore wind. Alternatively, individual states can require the planning of transmission upgrades to accommodate offshore wind within their jurisdictions (similar to how Texas plans for transmission to remote land-based wind development areas, as discussed below).

Texas could provide an example with its legislation to spread the costs of new grid upgrades to all ratepayers.

Based on research of effective policies in various jurisdictions, a second policy example is to allocate the costs of offshore

[24] See FERC website for summary and further information: http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

transmission system upgrades to all regional transmission system customers. RTOs or ISOs could implement this recommendation by planning and allocating costs to ratepayers for grid upgrades to accept wind power from offshore projects (as encouraged by FERC Order 1000). Texas could provide an example with its legislation to spread the costs of such new grid upgrades to all ratepayers.

In nearly all jurisdictions nationwide, the generator must fund its direct interconnection to the grid as well as all associated transmission system upgrades. In some regions, the cost of upgrades to the existing backbone grid required to allow the new renewable generator to operate and deliver energy into the grid is broadly allocated to consumers across the region, while in most regions those costs are assigned in part or in full to the interconnecting generator.

Currently, offshore wind generators off all East Coast states must fund and oversee the construction of the offshore interconnection cable plus grid upgrades. The generator must then add the costs of interconnection and grid upgrades to the cost of offshore generation to compile the wholesale price of the offshore wind energy. The energy and transmission costs are then passed on to only the customers who purchase the offshore wind energy.

The Texas legislature in 2005 decided to establish CREZs that would host new wind farms - mostly in windy west Texas. Per long-standing ERCOT policy, all ratepayers would pay for the new transmission lines to carry that power to the demand centers. Thousands of miles of CREZ lines are now under development. In New York, NYPA, LIPA, and Consolidated Edison have now proposed a joint offshore wind farm south of Long Island and decided to pay for the costs of the interconnection and necessary grid upgrades.

In other cases, the transmission system developer/owner initially funds the transmission expansion for repayment later by generators from their production revenues. When this occurs, the wind farm owner (i.e., the generator) typically needs to demonstrate an initial commitment. This commitment is generally in the form of a financial deposit mechanism (as in the California Tehachapi Wind Resource Area). The California ISO's (CAISO's) proposed financing mechanism was developed to connect multiple location-constrained renewable resources to the CAISO grid and to roll in the costs of these facilities through the transmission owner's transmission revenue requirement and subsequent transmission access charges (TACs) to new generation developers. The generators that interconnect to the grid are responsible for paying a pro rata share of the going-forward costs of the line (through the TAC) until the line is fully subscribed and the transmission owner is repaid for its initial investment.

In most transmission territories outside of Texas and California, all ratepayers are currently assessed only for new transmission demonstrated necessary to maintain system reliability. Offshore wind generation can strengthen grid reliability and implement RPSs by providing an additional generation resource to an existing transmission grid. Therefore, even though offshore wind is a variable energy resource which may ramp up or down, the availability of an additional resource to the existing generation portfolio should enhance system reliability – provided that appropriate interconnection equipment and practices are implemented to address the variable input, such as those currently being implemented for terrestrial wind farms.

FERC has begun expanding authorization for ratepayer allocation of costs beyond just reliability improvements to grid upgrades for reduced overall transmission costs and to support new public policies. FERC Order 1000[25] directs transmission providers such as RTOs and ISOs to consider state and federal energy policies when planning expansion of their respective transmission systems, and to consider cost allocation to all transmission customers of new transmission to support public policies such as renewable energy generation. While Order 1000 encourages but does not require any transmission provider to spread the cost to regional ratepayers of new transmission for offshore wind, decisions to do so would substantially reduce the generation component cost to be borne by the purchasers of that wind.

The Midwest ISO (MISO) has now agreed to spread to all grid customers the transmission costs for "multi-value projects" which include economic and public policy benefits. Other RTOs such as the Southwest Power Pool and PJM already allocate the costs of high-voltage transmission into ratepayers' costs.

Developers of the AWC offshore submarine cable system in the mid-Atlantic are seeking regional cost allocation for their proposed transmission project. The developers will ask PJM to evaluate (and FERC to approve) AWC as a multi-driver transmission project that provides a combination of reliability, market efficiency, and public policy benefits. If it qualifies, PJM has proposed allocating the costs of multi-driver projects to all beneficiaries from a line through the PJM tariff, not generators. Permitting certain backbone offshore transmission projects to qualify for regional cost assignment, as opposed to requiring an interconnecting generator to pay for them, promises to reduce the capital costs and operating costs that wind farm developers would incur by having to construct individual radial lines to shore.

Appropriate fees for use of new offshore transmission by offshore generators (transmission tariffs) can be determined after the final construction and O&M costs are known using ratemaking policies currently in effect. RTOs, ISOs, and groups of regional planning authorities, such as the Eastern Interconnection Planning Collaborative, could continue to model the impact on the grid of various policies of interest to state, provincial, and federal policymakers and other stakeholders.

Furthermore, while RTOs, ISOs, and transmission providers consider planning for and allocating costs to ratepayers for offshore wind transmission upgrades, individual states and utilities may choose to implement the innovative models of Texas CREZ, CAISO, and the NYPA Collaborative to promote offshore wind for their customers more quickly.

In addition to the policy examples mentioned above, which have been implemented in either Europe or the U.S., there are additional examples mentioned in the Great Lakes Wind Collaborative's 2011 study *Transmission-Related Policy Options to Facilitate Offshore Wind in the Great Lakes* (Great Lakes Wind Collaborative 2011).

[25] See FERC website for summary and further information: http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

- Establish clear permitting criteria/guidelines in each state for transmission project siting and installation.
    - Model guidelines for consideration by individual states could be developed by regional organizations such as RTO Stakeholder Committees and the New England Conference of Public Utility Commissioners.

- Establish a basis for inter-RTO and international cost allocation and transmission siting and planning.
    - Enabling developers to send power to multiple load centers can improve project economics and enable larger offshore wind farms, thereby minimizing the transmission footprint per MW ratio. At the same time, load centers can hedge against wind variability by linking to wind farms in diverse locations.
    - Participating in the development of DOE's congestion study and National Interest Electric Transmission Corridor report can encourage the designation of certain regions attractive for offshore development as National Interest Electric Transmission Corridors. This would provide federal assistance for interstate siting that would augment transmission planners working through existing institutions like RTOs but would not override state siting authorities that deny construction authority.

- Promote utilization of existing transmission capacity reservations to integrate offshore wind.
    - Some conventional generation facilities that are aging and often operate consistently below full capacity may be utilizing less than their full transmission capacity reservations. Many of these facilities are located in close proximity to the shoreline and could serve as injection points for new offshore wind facilities if a substantial portion of corresponding transmission is not being used. Transferring consistently unused transmission capacity to new offshore wind facilities may preclude the need for substantial onshore transmission upgrades. Ultimately, this pattern of development could allow offshore wind to be scaled up to utilize the full transmission capacity for conventional generating units, replacing those units as they are run at lower capacities and ultimately retired.

- Establish policies supporting the development and implementation of Integrated Resource Planning.
    - State public utility commissions could engage interested parties in identifying additional transmission resources needed to meet state renewable energy obligations. Utilities could be required to objectively analyze the potential of all available resources. The Eastern Interconnection State Planning Council has the potential to be a forum for state discussions on this topic.

Ports

Maritime ports were not originally designed with the offshore wind sector in mind. In many cases, quaysides, laydown areas, and clearances must be upgraded to accommodate ever larger turbines and foundations, as well as an increasing volume of offshore projects.

The primary offshore wind policies related to port infrastructure focus on the following:

- » Overall port strategy and planning at the country level
- » Upgrades to ports (when ports are held by the state)
- » Incentives encouraging port upgrades (when ports are privately held)

The Navigant Consortium identified two policy examples, used in countries such as Germany, U.K., and Denmark, and discussed in detail in Section 3.4.3, related to improving the port infrastructure to better accommodate offshore wind:

Ports Policy Example 1: Upgrade state-held ports or provide incentives for private port upgrades.

- » If a country's ports are held by the state, the national government may identify and perform upgrades needed by strategically positioned ports.
- » If a country's ports are held by the private sector, the government may provide incentives to encourage the port upgrades. The government may have a vested interest in supporting the private sector (e.g., meeting national renewable energy targets).

Ports Policy Example 2: Develop a country-wide strategy focusing on a select number of locations spread around the coast. A government agency may commission a study to assess the following:

- » Specific requirements of the offshore wind industry for ports
- » Current capabilities of the country's ports
- » Potential port expansion or development to meet the needs of the offshore wind sector

Based on the study's findings, the government agency may develop a policy for long-term port development.

Manufacturing

Manufacturing-related policies for offshore wind include the following categories based on our research:

- » Government support for offshore wind manufacturing at port sites
- » Favorable customs duties, export credit assistance, or quality certification

The first policy category, government support for offshore wind manufacturing at port sites, includes the following factors:

- » Expedited permitting for prototype turbines (e.g., Bremerhaven – Multibrid)
- » Creation of wind-related training/degree programs at local universities
- » Tax credits
- » Loans

The second policy category is composed of favorable customs duties, export credit assistance, or quality certification. A country's export credit agency may provide loans or loan guarantees for the sale of domestically manufactured turbine or turbine components to customers in other countries. By assuming part of the risk, the export credit agency increases the likelihood that companies obtain financing from private banks and investors. Frequently, obtaining financing for a project is a key to winning orders.

3.4.2 Current U.S. and State Policies

While specification of offshore wind energy resource zones for targeted grid investments has not occurred in the U.S., it has been done for the land-based wind market. California, Michigan, and Texas have designated specific areas for land-based wind development to provide a level of certainty for transmission development to avoid a "if we build it, they will come" situation.

California

California started its Renewable Energy Transmission Initiative (RETI) in 2007. The purpose of RETI is to engage the state's renewable energy generation and transmission to participate in a collaborative process to facilitate the designation of transmission corridors, and the siting and permitting for renewable energy generation and transmission projects.

The main components of RETI are as follows:

1. Identifying CREZ with sufficient energy resource densities to justify building transmission lines to them
2. Ranking CREZ on the basis of environmental impacts, the certainty and schedule of project development, and the cost and value to California consumers
3. Developing conceptual transmission plans to the highest-ranking CREZ
4. Supporting the California Independent System Operator (California ISO), Investor-Owned Utilities (IOUs), and Publicly Owned Utilities (POUs) in developing detailed plans of service for commercially viable transmission projects
5. Providing detailed costs and benefit analyses to help establish the basis for regulatory approvals of specific transmission projects[26]

In California, developers pay an initial deposit for ratepayer-subsidized transmission development and then later pay the balance of the total transmission interconnection cost through long-term operating revenues.

Michigan

State legislation passed in 2008 (PA 295, Part 4) requires the Michigan Public Service Commission to designate a primary wind energy resource zone and provides authority for the designation of additional zones. On January 27, 2010, the Michigan Public Service Commission (MPSC) issued a final order designating two Michigan regions as wind energy resource zones. The primary wind energy resource zone is an area known as "Region 4", which includes parts of Bay, Huron, Saginaw, Sanilac, and Tuscola

[26] http://www.energy.ca.gov/reti/RETI_FAQ.PDF

counties. A second area, known as "Region 1" has been identified by the MPSC as an additional wind energy resource zone. Region 1 includes parts of Allegan County, Michigan.

The MPSC based its decision on the findings of the Wind Energy Resource Zone Board, which submitted its final report in 2009. Wind Energy Resource Zones are intended to expedite siting of the transmission projects needed to move the wind energy onto the electric grid. The designation means that the MPSC will facilitate the planning, siting, and construction of electricity transmission lines in order to facilitate wind energy development in the area. Affected parties within the WREZ are given 21 days to reach agreement on a voluntary cost allocation methodology for the transmission upgrade projects needed to develop wind generation. If an agreement is reached, then the necessary actions will be taken by the parties at the Midwest Independent Transmission System Operator, Inc. (MISO). If the parties are unable to reach a cost allocation treatment amongst themselves, the MPSC will pursue another process to resolve the matter.[27]

Texas

In 2008, in response to legislative action, the Texas Public Utilities Commission established five CREZ to be connected to load centers. Each of the five CREZ sites is to be funded by all ratepayers. The PUC called for $4.93 billion of CREZ transmission projects to be constructed by seven transmission and distribution utilities and independent transmission development companies. The initiative will eventually facilitate the transmission of more than 18 GW of wind power from west Texas and the Panhandle to the state's highly populated areas.[28]

3.4.3 Current Policies in Other Countries

Denmark

Transmission

Offshore wind sites in Denmark are granted through the Danish Energy Agency's (DEA) competitive tender process. The Danish transmission system operator (TSO), Energinet.dk, is responsible for funding and connecting the wind farms to the onshore grid. The TSO recovers the costs through the transmission tariff collected from all electricity customers. The offshore wind farm and the offshore transmission system development timelines set out in a call for tender are very challenging. However, project termination or delays after tender award are subject to substantial penalties. This is one of the reasons for there being only one bidder during the recent tendering process of the Anholt wind farm. Due to the design of the tendering process, all projects are connected individually (i.e., point-to-point connections) and there are no plans for inter-project transmission.

Ports

[27] http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-230708--,00.html)
[28] http://www.texascrezprojects.com/

Ports in Denmark are owned by their respective municipalities. Any upgrades made to them are approved by the municipality.

Denmark's primary offshore wind port is the Port of Esbjerg. The port was once one of Denmark's largest fishing ports but had faced a decline in recent decades. It was largely revitalized with the installation of the Horns Rev 2 offshore wind project. Now, 65% of wind turbine exports pass through the port.[29] The Port of Esbjerg's board of directors has developed a strategic plan through 2019 that includes DKK 1 billion (US$183 million) of investment for new infrastructure and reconfiguring the port's facilities to create additional space for wind turbines in a new south harbor.[30] Esbjerg is home to the Offshore Center Danmark, the country's official competence and innovation center for the offshore industry. Through more than 240 member companies and institutions, the Center works to develop the areas of oil and gas and offshore wind.[31]

> "I believe we've only seen the tip of the iceberg. Only around a fraction of the planned wind farms in the North Sea have been established so far, so there's still a great potential. That's why we're making an investment in Esbjerg Harbour of well more than €100 million, and we're aiming to achieve an even more optimum infrastructure." – Esbjerg mayor Johnny Søtrup [32]

Germany

Transmission

In 2006, the German government deemed two German TSOs, TenneT and 50Hertz, legally responsible, in their respective areas, for planning, consenting, designing, building, and operating offshore transmission connections for all offshore wind projects whose construction has begun prior to 2015. Investments in offshore transmission assets are incurred by the TSOs and recovered through transmission tariffs from the customers of all four German TSOs.

The tendering process for a developer's project to be connected to the transmission system is designed to provide the TSO with the opportunity to coordinate offshore transmission system development where it is more efficient to do so. TenneT is, in fact, clustering wind farms and providing shared connections. For example, the 800 MW BorWin2 HVDC line will connect the Global Tech I and Veja Mate projects, each with a capacity of 400 MW.[33] The tendering process also enables the TSO to consider future transmission system requirements due to further offshore wind farm development in the area. A system operator may choose, for example, to oversize the transmission system in anticipation of future

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[29] http://www.esbjergkommune.dk/Admin/Public/DWSDownload.aspx?File=Files/Filer/Engelsk/New_Energy_Esbjerg.pdf
[30] http://www.investindk.com/News-and-events/News/2009/Offshore-wind-farms-mean-big-business-for-the-Port-of-Esbjerg
[31] http://www.offshorecenter.dk/
[32] http://www.offshorecenter.dk/artikel.asp?id=456&name=Abundance_of_new_jobs_in_Esbjerg
[33] http://www.tennettso.de/site/en/Tasks/offshore/our-projects/borwin2

generation assets. An example of this is TenneT's proposed construction of the 900 MW DolWin2 HVDC line. This line will connect the Gode Wind II project as well as other yet-to-be-named projects.[34]

Ports

Bremerhaven

The Federal State of Bremen has stated a goal of making Bremerhaven and Bremen into the leading competence center and production area for offshore wind energy in northwest Germany.[35] In 2002, having recognized the emerging potential of offshore wind, the state government of Bremen decided to invest €20 million on infrastructure upgrades and other incentives to help the port of Bremerhaven benefit from the significant wind development already approved for in the German North Sea.[36] The state of Bremen was the first in northern Germany to implement such a policy for offshore wind.[37] Policy actions have included R&D and investment support schemes, as well as support for networks and offshore-oriented infrastructure. The state's policy reserved certain areas for offshore activities and invested in port upgrades to accommodate these activities. Regional policymakers in Bremen strongly recruited companies to relocate or set up their offshore activities in the state. In subsequent years, AREVA (Multibrid), Repower, Powerblade, and Weser Wind established manufacturing facilities at the port of Bremerhaven.

The Wind Energy Agency Bremerhaven/Bremen (WAB), formed in 2002, represents Germany's offshore wind industry and the wind energy network in the northwest region. Most offshore wind companies operating in or near the port of Bremerhaven are part of the WAB. The state of Bremen will continue to partially finance WAB until 2013.[38]

The state of Bremen and the municipality of Bremerhaven fund the Bremerhaven Economic Development Company (BIS), founded in 2001. The BIS is the key point of contact for companies wishing to conduct business in the area and has provided incentives for manufacturers to establish operations at the port and funded many projects that have upgraded the port of Bremerhaven.

The State of Bremen will provide startup financing for the Fraunhofer Institute for Wind Energy and Energy System Technology (IWES), which will be established in the next five years.

In January 2010, the Bremen Senate decided to commission a new heavy load, assembly, and transshipment facility for the offshore industry at Bremerhaven beginning in 2014. The €200 million facility will be called Offshore Terminal Bremerhaven (OTB). Government officials in Bremen have

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[34] http://www.tennettso.de/site/en/Tasks/offshore/our-projects/dolwin2

[35] http://www.power-cluster.net/AboutPOWERcluster/ProjectPartners/BremerhavenEconomicDevelopmentCompany/tabid/624/Default.aspx

[36] http://www.ewea.org/fileadmin/ewea_documents/documents/publications/WD/2009_september/Mini_Focus_September_2009.pdf

[37] http://druid8.sit.aau.dk/acc_papers/16vikj17dhdajdhyxsi7vymf446q.pdf

[38] http://www.wab.net/index.php?option=com_content&view=article&id=328&Itemid=74&lang=en

stated the goal of developing Bremerhaven into the European center for offshore wind energy. The construction, financing, and operation of the OTB will be conducted through a concession model. The state government has selected Bremenports, which has managed the port infrastructure in Bremen and Bremerhaven since 2002, to conduct a European-wide public tender for the project. The Bremen government will grant the concession to the private investor who will recover its costs through user fees. The investor will receive no government startup financing.[39]

Cuxhaven

The government of Lower Saxony, having identified the port and logistics needs of the offshore wind energy in the region, is investing to upgrade the North Sea ports of Cuxhaven, Emden, and Brake.[40] This is in contrast to Bremen's concession model that provides no public funds. To shift its focus to offshore wind power, the port of Cuxhaven is investing €450 million to construct two new offshore terminals.[41] This is in addition to storage and laydown areas already completed. Cuxport, the port operator in Cuxhaven, has designed a heavy load berth to accommodate the extreme stresses from foundation sections and generators. In addition, it is planning a new berth for ships of up to 290 meters in length.[42]

The Netherlands

Transmission

In 2010, the Dutch government approved a proposal to make TenneT, the Dutch TSO, responsible for the construction and management of the country's offshore transmission grid.[43]

Currently, offshore wind developers in the Netherlands are responsible for incurring offshore transmission system costs. Reinforcements to the onshore transmission system are borne by the TSO and recovered through transmission tariffs collected from all electricity customers. Due to growth in the Dutch offshore market, however, there are calls to change this in the near future.

In early 2011, the EIB announced that it would provide €450m in loans to TenneT to complete the 380kV Randstad transmission ring between The Hague and Rotterdam.[44] The transmission cable would enable the connection of offshore wind farms.

TenneT and the Danish TSO, Energinet.dk, are developing an undersea HVDC interconnector between the two countries' electricity grids. The project is called the COBRAcable. The proposed connection

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[39] http://www.bremenports.de/misc/filePush.php?id=571&name=Offshore_Broschuere_eng.pdf

[40] http://www.pes.eu.com/assets/misc_new/pp52-55seaportspdf-202124705931.pdf

[41] http://renewables.seenews.com/news/germanys-ports-in-cuxhaven-bremerhaven-bet-on-offshore-wind-power-23354

[42] http://www.cuxport.de/en/rhenus-cuxport/services/offshorebase-cuxhaven/

[43] http://www.tennet.org/english/images/100552%20TEN%20Offshorebroch%20%20EN_tcm43-19468.pdf

[44] http://www.eib.org/projects/press/2011/2011-013-eib-supports-key-dutch-grid-project-to-connect-offshore-wind-farms.htm

would have a capacity of approximately 700 MW and would be around 275 kilometers in length. The project incorporates the possibility of interconnecting offshore wind farms.[45]

United Kingdom

Transmission

The U.K. government's offshore electricity transmission regulatory regime separates the generation from the transmission. The Office of Gas and Electricity Markets (Ofgem) regulates offshore transmission in the U.K. In the country's offshore wind market, qualifying companies bid through a competitive tender process to become an OFTO. The OFTOs will receive, via the TSO, National Grid, a 20-year stream of revenue payments. These payments are determined according to the OFTO's bid during the tender process. Under this regime, offshore wind farm operators can choose to construct their own transmission connections or opt for the OFTO to do so. This approach is unique as most other European countries have directly tasked their TSOs with construction and maintenance of offshore wind grid connections.

Ports

In 2007, the U.K. government conducted a review of national port policy. The government recommended that the country's major ports, most of which are privately owned and operated, produce master plans.

The Planning Act 2008 was enacted to speed up the approval process for new nationally significant infrastructure projects (NSIPs) in various economic sectors. National Policy Statements (NPS) were developed for 12 infrastructure sectors, one of which was ports.

In 2008, the DECC commissioned an independent study by BVG Associates entitled *U.K. Ports for the Offshore Wind Industry: Time to Act*.[46] The findings of the report contributed to the Department for Transport's NPS for ports. The NPS on ports was published in October 2011 and presents the government's conclusions regarding the need for new port infrastructure.[47] The statement considers the current role of ports in the country's economy, the ports' forecasted future demand, and the options for meeting future needs. The NPS provides decision-makers with the approach they should use to evaluate port development proposals.

In October 2010, the U.K. launched its first National Infrastructure Plan (NIP).[48] Whereas the NPSs focus more on infrastructure planning, the NIP focuses on investment in infrastructure. The scope of the sectors covered in the NIP is also greater than that of the NPSs.

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[45] http://www.tennet.org/english/projects/Internationaalenoffshore/index.aspx
[46] www.berr.gov.uk/files/file49871.pdf
[47] http://assets.dft.gov.uk/publications/national-policy-statement-for-ports/111018-ports-nps-for-das.pdf
[48] http://www.hm-treasury.gov.uk/d/nationalinfrastructureplan251010.pdf

In October 2010, to support the achievement of its renewable energy targets for 2020, the U.K.'s DECC and The Crown Estate announced a £60 million investment to establish world-class offshore wind manufacturing at ports sites.[49] On publication of its country's first NIP, the Prime Minister said, "We need thousands of offshore turbines in the next decade and beyond yet neither the factories nor these large port sites currently exist. And that, understandably, is putting off private investors. So we're stepping in." [50]

The following policies have shown to be effective in addressing transmission infrastructure:

- *Establish clear permitting and siting criteria and guidelines*
- *Establish consistent cost allocation and cost recovery mechanisms*
- *Promote utilization of existing transmission capacity reservations*
- *Designate offshore wind energy resources zones for targeted grid investments.*

The government has stated that it will accept applications from manufacturers, or joint applications from manufacturers and ports. The funding, however, is not available for port-only applications. Applicants apply for support under the Grants for Business Investment scheme, the U.K.'s national business support scheme that supports sustainable investment and job creation in the Assisted Areas of England. Assisted Areas are locations where regional economic development aid may be granted under EU legislation. Funding commenced in April 2011 and is available through March 2015.

Shortly upon the announcement of this funding, turbine manufacturers Siemens, Gamesa, and Vestas committed to building portside manufacturing facilities in the U.K. Siemens has committed to produce its 6 MW offshore turbines at the Port of Hull in East Yorkshire[51] and Gamesa has chosen to manufacture offshore turbines at the Port of Leith near Edinburgh.[52] Assuming that a solid pipeline of projects exists, Vestas will build its V164-7.0 MW turbines at the Port of Sheerness in Kent.[53]

3.4.4 Evaluation of Infrastructure Policies

Similar to Section 3.3.4, we have evaluated each infrastructure policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results). A list of criteria, the policy examples that were evaluated, and the relative rankings for each criterion are provided in Appendix C.

[49] http://www.decc.gov.uk/en/content/cms/news/pn10_111/pn10_111.aspx
[50] http://www.decc.gov.uk/en/content/cms/news/pn10_111/pn10_111.aspx
[51] http://www.bbc.co.uk/news/uk-england-humber-17993593
[52] http://www.guardian.co.uk/environment/2012/mar/23/gamesa-offshore-windfarm
[53] http://www.vestas.com/en/media/news/news-display.aspx?action=3&NewsID=2662

The following infrastructure policy examples have the most optimal combination of Relative Effort and Relative Results:

- *Establish clear permitting criteria and guidelines for transmission planning and siting*. Examples include efforts by States governments and the U.S. government to "one-stop" permitting process similar to state siting boards in Massachusetts, Connecticut, New York, and New Hampshire and the Great Lakes MOU for Offshore Wind.
- *Establish clear and consistent cost allocation and cost recovery mechanisms for transmission interconnections and upgrades*. FERC Order 1000[54] directs RTOs to consider state and federal energy policies when planning to expand their respective transmission systems, and to consider cost allocation to all transmission customers of new transmission for renewable generation, as was done by the Texas Public Utilities Commission in 2008.
- *Promote utilization of existing transmission capacity reservations to integrate offshore wind*. State governments (i.e., public utility commissions and energy facility siting boards) and groups of regional planning authorities could consider using transmission capacity reservations of aging conventional shoreline generation facilities that are being operated below full capacity. The sites could serve as injection points for new offshore wind facilities.
- *Offshore transmission planning could target BOEM Wind Energy Areas (and similarly identified areas in other regions of the country) and consider public policy mandates, such as RPS, as required by FERC*. State governments (i.e., public utility commissions and energy facility siting boards) and groups of regional planning authorities, such as the Eastern Interconnection Planning Collaborative, could identify transmission needs driven by public policy requirements and evaluate potential solutions to those needs that include joint interconnections for multiple wind farms, such as the AWC. Transmission planning could target the Wind Energy Areas identified by BOEM and/or state/regional offshore wind task forces.

Timing and other considerations for these policy examples are discussed in Section 3.8.

3.5 Policies That Address Regulatory Challenges – Site Selection and Leasing

3.5.1 General Discussion of Policy Examples

The following policy examples that affect offshore wind site selection and leasing have been implemented or proposed:

<u>General</u>

- *Global planning approach that includes offshore*
  - In 2010, DOI established its "Smart from the Start" Initiative for Atlantic Ocean wind to (1) identify priority Wind Energy Areas for potential development, (2) improve BOEM

[54] See FERC website for summary and further information: http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

coordination with local, state, and federal partners, and (3) accelerate the leasing process.
    - BOEM has established task forces with several Atlantic states, including ME, MA, RI, NY, NJ, DE, MD, VA, NC, and SC, to engage intergovernmental partners and help inform BOEM's planning and leasing processes.
- *Federal/state policy coordination*
    - In June 2010, the Atlantic Offshore Wind Energy Consortium was created to facilitate federal/state offshore wind development coordination by an MOU signed by the U.S. Department of the Interior and the states of ME, NH, MA, RI, NY, NJ, DE, MD, VA, and NC.
    - In February 2012, an MOU was signed among five Great Lakes states and ten federal agencies that created the Great Lakes Offshore Wind Energy Consortium (GLOWEC) to promote the efficient, expeditious, orderly, and responsible evaluation of offshore wind power projects in the Great Lakes.

<u>Leasing</u>

- *Regulatory framework for marine spatial planning*
- *Dedicated offshore wind areas*. Identification of wind energy areas is led by state regulators who identify environmental constraints and engage in discussions with stakeholders with competing offshore uses. This policy is the first phase of BOEM's Smart from the Start initiative
- *Phased access*, where developers have a short-term right to evaluate a wind resource with a longer term right to develop
- *Selection of sites by regulators, followed by competitive bidding by developers*. This process is used in Texas, New York, and Denmark
- *BOEM call for lease nominations*

3.5.2 Current U.S. and State Policies

U.S. states are taking a variety of approaches to offshore wind site selection and leasing. Common themes are to form panels or task forces to engage local stakeholders and to coordinate state efforts with with BOEM and various regional consortia. Figure 3-2 provides a high-level summary of state-level policies that are being employed, and further details are provided in Appendix A.

Figure 3-2. Site Selection and Leasing Policies in U.S. States

Policy Options ***Barrier: Regulatory***	**Jurisdictions where Used**												
	Delaware	**Illinois**	**Maine**	**Maryland**	**Massachusetts**	**Michigan**	**Ohio**	**New Jersey**	**New York**	**North Carolina**	**Rhode Island**	**Texas**	**Virginia**
General: Panels or task forces in place to engage local stakeholders to identify constraints and sites for offshore wind	✓	✓	✓	✓	✓	✓ 1	✓ 2	✓	✓	✓	✓	✓	✓
Federal/state policy coordination (3)(4)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Leasing: Regulatory framework for marine spatial planning			✓		✓	✓		✓			✓	✓ 5	
State selects sites &conducts competition												✓ 5	
BOEM call for lease nominations				✓	✓			✓			✓		✓

(1) Report of the Michigan Great Lakes Wind Council, October 2010, identifies 13,339 square miles which are considered to be most favorable to the sustainable development of offshore wind energy. Five priority areas were identified, known as wind resource areas (WRAs). GLOW Council expired under new Governor who is re-evaluating offshore wind development as in Ohio & Wisconsin.
(2) Ohio's Offshore Wind Turbine Placement Favorability Interactive Map Viewer tool can be used to evaluate sites.
(3) In June 2010, the Atlantic Offshore Wind Energy Consortium was created to facilitate Federal-state offshore wind development coordination by an MOU signed by the U.S. Department of the Interior and the states of ME, NH, MA, RI, NY, NJ, DE, MD, VA, and NC.
(4) In February 2012, an MOU was signed among 5 Great Lakes states and 10 federal agencies that creates an Offshore Wind Energy Consortium to promote the efficient, expeditious orderly and responsible evaluation of offshore wind power projects in the Great Lakes.
(5) The TX General Land Office stipulates which areas are available for lease, the minimum MW size, and the minimum royalty rates. Winning bidders are granted phased access, first given research rights and then construction and operation rights.

3.5.3 Current Policies in Other Countries

Denmark

<u>Planning</u>

In 1997, the Danish government published Denmark's Action Plan for Offshore Wind. This plan recognized the difficulty in finding sufficient suitable land-based sites for wind power to reach the government's long-term wind targets. The action plan identified five potential large-scale offshore demonstration projects to be funded by a Public Service Obligation and built by public utilities. Subsequently, the government opted to use a tender process for the development of two 160+ MW projects. The wind farms Horns Rev and Nysted were eventually constructed, the former in 2002 and the latter in 2003. In the 1997 Action Plan, the government also outlined a centralized spatial planning procedure for offshore wind in Denmark, identifying appropriate sites for development while taking into account the potential environmental impacts.

In 2004, the Danish Energy Authority called for tenders for two 200 MW offshore wind farms, one at Horns Rev II and one at Rødsand. The former was completed in 2009 while the latter was completed in 2010. In 2007, the action plan was updated to reassess selected sites for offshore wind development. The updated plan identified areas with favorable wind resources totaling 4,600 MW of potential capacity, corresponding to 50% of Danish electricity consumption.[55]

Concessions

The Danish Government controls economic activity within territorial waters, the Contiguous Zone, and the Exclusive Economic Zone. It can award offshore wind farm concessions based on the Electricity Supply Act.

The Danish government has a centralized offshore wind spatial planning procedure and awards all offshore wind concessions.

Developers can apply for an offshore license in two ways:

1. Based on the Danish Government's action plan for offshore wind development, the DEA invites developers to bid on tenders for pre-specified sites.
2. Through the "open-door principle," developers, at any time, can apply to develop a site. The DEA assesses the site and, if it approves the project, grants development rights on a "first come, first served" basis.[56]

Under the first procedure, the transmission connection to shore is performed and funded by the TSO. In the second procedure, the grid connection must be performed by the developer. Cost recovery in this case is based on the onshore rules. Projects following the "open-door principle" must also offer 20% ownership to the local population, as is the case with land-based wind. Due to the lack of financial incentives, no major commercial offshore project has been developed through the open-door route.

Germany

Planning

Given the lack of a standardized permitting process, the first few proposed offshore wind farms in Germany had to define their own site investigations plan. More recently, however, the German government has sought to develop a more government-led spatial planning system and regulatory process for offshore wind. Still, the government has not yet implemented a centralized tender or bidding process like those used in the U.K. and Denmark.[57] In 2004, Germany's Federal Spatial Planning Act was expanded to the Exclusive Economic Zone (EEZ), which extends 200 nautical miles from the German shore.[58] This enabled the development of a spatial plan for offshore wind led by the permitting agency, the Federal Maritime and Hydrographic Authority (BSH). The first draft of this spatial plan, released in

[55] http://ec.europa.eu/ourcoast/download.cfm?fileID=983
[56] http://www.ens.dk/en-US/supply/Renewable-energy/WindPower/offshore-Wind-Power/Procedures-and-permits-for-offshore-wind-parks/Sider/Forside.aspx
[57] http://www.northsearegion.eu/files/repository/20120320110429_PC-StateoftheOffshoreWindIndustryinNorthernEurope-Lessonslearntinthefirstdecade.pdf
[58] http://www.nve.no/Global/Energi/Havvind/Vedlegg/Offshore%20wind%20experiences%20-%20A%20bottom-up%20review%20of%2016%20projects%20(Ocean%20Wind).pdf

2008, identified five priority areas (1,100 km^2) for offshore wind energy in the Germany North and Baltic Seas. The draft plan was subsequently revised multiple times based on industry feedback. Offshore wind farm development outside the priority areas is allowed, but is subject to the results of comprehensive environmental impact assessments.

Concessions

In Germany, permits for offshore wind farms are allocated through an open-door procedure. The first candidate to submit a proposal for a project that meets all of the BSH's stated criteria is given priority to develop the site. The principal component of the German regulatory procedure for offshore wind is obtaining the permit from the BSH. The permit provides a developer with exclusive rights to a site. Once the project is fully consented, the developer can submit an application for grid connection. Under German law, an offer for grid connection and the purchase of the electricity generated from the wind farm are mandatory. This last step is the source of many delays; financial responsibility for these delays has not yet been allocated clearly.

The Netherlands

Similarly, the OWEZ project in the Netherlands required consent from numerous authorities, but the process is now managed by a single ministry. A clear procedure is critical to increase developments, as it reduces the developer's risks at an early stage in the project.

An Integrated Management Plan for the Netherlands Economic Zone in the North Sea in 2015 introduces an integrated assessment framework for all activities requiring a permit. One of the key motivators for this plan is the need to plan for offshore wind energy. Specific zones have been identified where future offshore wind development should be concentrated. Specific site locations and delivery schedules are determined by developers in their consent applications.

In the Netherlands, the spatial planning for offshore wind for Round 3 is currently in reorganization. The so-called Round 2 in 2005 was a "first come, first served" system under the Wet Beheer Rijkswaterstaatwerken (WBR), a law for spatial planning of waterworks at sea. This led to an unexpectedly large number of 70 project initiatives by nine consortia in 2005, prompting the organizing Ministry of Transport and Waterworks to install a moratorium to stop further initiatives. Finally, at the end of 2009, 12 projects developed by six consortia were awarded the right to tender for subsidy in 2010. The organizing Ministry of Economical Affairs has earmarked a budget for 950 MW of subsidies in this Round 2.

Neither government nor industry is satisfied with the planning and organization of the Dutch Round 2, and final decisions on how to organize Round 3 have not been made. Current plans are that the Ministry of Transport and Waterworks may reserve four large areas totaling about 1,000 km^2 for offshore wind. Consortia may then be asked to tender for wind concessions in those areas, together with earmarked financial support. Selection should then be based upon financial strength of the consortium, their plans, and their track record, as in the U.K. system.

The Netherlands has demonstrated how ineffective government policies, shifting financial support schemes, and an unstable judicial framework constrain development and increase investment risk. Two Round 1 projects have progressed in Dutch waters: Egmond aan Zee and Prinses Amalia; however, Prinses Amalia was developed outside governmental planning and obtained a permit during the project implementation. Such political and regulatory risk threatens industry engagement. Equally, the Dutch Round 2 program has been criticized by project developers for an alleged hands-off and slapdash nature, lacking upfront government spatial planning. As mentioned previously, more than 70 projects were submitted to the Dutch government, forcing the moratorium on any new proposals in 2007, while the government eventually whittled the list down to 12 realistic contenders.

Concessions

The rights for development are granted through a competitive tendering process. To take part in this tendering process, the developer has to obtain a planning consent for the site. The winning bidders receive the Stimulation of Sustainable Energy Production (SDE) tariff. To date, two tendering rounds have been held. The third and most significant round was planned, but did not commence due to political uncertainty and changes recently introduced to the FiT structure. Developers would have looked to obtain consent in anticipation of the third tendering round, thus accounting for the number of projects in the 'approved' stage in the Netherlands.

In July 2011, the FiT system was changed and the first call to tender was launched for renewable energy generation under this new tariff SDE+. The SDE+ scheme is expected to be consumed by other renewable technologies. This is because the tariff is not deemed to provide sufficient returns compared to the high capital costs of offshore wind power. The economic crisis and the unsatisfactory tender results for the previous OWF tender rounds, including several objections and procedures in court, have reduced interest in offshore wind development and have resulted in new strategies by the government to reach the 2020 renewables targets.

In December 2008, the Dutch cabinet announced two locations in the North Sea where future offshore wind farms can be developed, a 344-square-kilometer area located some 35 km off the coast of Walcheren and a 1,170-square-kilometer area approximately 90 km off the coast of Noord-Holland province. In addition, two search areas were defined, one just off the coast of Noord-Holland province, and a second area to the north of the Wadden Sea Islands. It is TenneT's responsibility to prepare its transmission grid in due time to accommodate these new offshore wind farms.

United Kingdom

The U.K. has had three rounds of offshore wind concessions.

Round 1

In 2001, developers seeking sites for offshore wind projects initiated Round 1. The relatively quick consenting process for some of the projects in this round, such as North Hoyle and Scroby Sands, reflects the well-established consenting regime for electricity projects in place at the time. This demonstrated the value and importance of a strong permitting framework for offshore wind. The incremental approach used in Round 1, namely smaller projects that were relatively close to shore, delivered viable projects while also providing significant experience and lessons learned for all stakeholders (i.e., developers, contractors, and government).

Round 2

Whereas Round 1 was developer-led, Round 2, launched in 2003, was led by government. The U.K. government recognized the importance of spatial planning and the need to streamline the consenting process. A "one-stop shop" approach was created for permitting. For Round 2, the government commissioned Strategic Environmental Assessments (SEAs) for three regions deemed attractive for offshore wind development, the Thames Estuary, the Greater Wash, and the North West. In July 2003, The Crown Estate (TCE) issued a formal Invitation to Tender. Round 2 was designed to be significantly more ambitious than Round 1. No limit was placed on size and no restriction to territorial waters was made. Fifteen of the 70 proposed projects were granted leases.

The U.K. government recognized the need to streamline the consenting process and created a "one-stop shop" approach for permitting.

In Round 2, TCE charged successful applicants a one-time fee based on the spatial area of their respective sites. This ranged from £25,000 to £0.5M. Once operational, owners of Round 2 projects will be required to make lease payments on the order of £0.88/MWh (indexed to inflation). The lease payments are projected to be approximately 1% of gross power sales, including incentives. In July 2009, TCE announced an offer to operators of Round 1 and Round 2 wind farms to extend their site leases to 50 years, affording developers greater certainty when considering life-extension and re-powering of their projects. This move was also designed to instill greater confidence in the supply chain, addressing a perceived gap in the project pipeline between Rounds 2 and 3.

Round 3

For Round 3, initiated in 2008, TCE, the seabed owner and manager, established a strategic spatial planning process and identified nine Round 3 Zones in U.K. waters prior to running an extensive tender process to identify credibility and financial robustness. Additionally, the U.K. government has implemented a new Infrastructure Planning process for the permitting of offshore projects, providing an improved, more efficient, and timelier consenting regime.

U.K. Round 3 exemplifies the importance and benefits of "zonation," SEAs, and proactive spatial planning. This framework approach, commencing in 2007 with a national Strategic Environmental Assessment, concluded with an extensive marine spatial planning constraint mapping process undertaken by TCE, with extensive consultation with stakeholders.

In U.K. Round 3, the advantages of zonation have been further extended by providing a collaborative framework with TCE to develop the zones to maximize capacities. The principle of proactive spatial planning has been taken a stage further in Round 3 through the ongoing technical and environmental zone appraisal within the zone by the developer and TCE to utilize regional environmental assessment tools to best locate projects according to environmental and permitting constraints. For Round 3, Crown

Estate has granted exclusive development rights for nine zones. New Infrastructure Planning Commission will be a one-stop permitting shop. Permits from local authorities will still have to be obtained.

In December 2007, the Department for Business, Enterprise and Regulatory Reform (BERR) announced the commencement of an SEA, aimed at facilitating significant further expansion for offshore wind. A target of 25 GW of additional capacity by 2020 was also announced. In January 2009, the U.K. Offshore Energy SEA Environmental Report was issued for public consultation. The SEA indicates that the preferred approach of DECC is to apply spatial and operational limitations to offshore wind development zones, where required, to mitigate unacceptable environmental impacts, while supporting the overall use of the U.K. marine environment for achievement of the U.K. government's energy policy objectives.

A generic version of a Round 3 pro forma leasing agreement has been published by TCE; however, the specifics of individual agreements are negotiated on a project-by-project basis. The pro forma states that leases are offered on an 80-year basis (as opposed to 50-year leases for Round One and Round Two projects). Once awarded a site, developers pay a non-refundable Lease Premium of an amount agreed upon with the TCE. Rent from date of lease agreement to commissioning is a notional £500 per annum per leasing agreement. Following wind farm commissioning, the rent payable is a factor of generated electricity.

The 2009 Marine and Coastal Access Act, together with the 2010 Marine (Scotland) Act and upcoming Northern Ireland Marine Bill, have set up a maritime planning system for all U.K. waters. Suitable areas for offshore wind development have been identified through SEAs.

3.5.4 Evaluation of Site Selection and Leasing Policies

Similar to Section 3.3.4, the Navigant Consortium evaluated each site selection and leasing policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy example, as determined by the expected impact on offshore wind development (Relative Results). A list of criteria, the policies that were evaluated, and the relative rankings for each criterion are provided in Appendix C.

The following policy examples have shown to be effective in addressing regulatory challenges:

- *Leasing: conduct a 4 stage process similar to the BOEM model*
- *Permitting: Develop a programmatic EIS for a broad geographic area followed by more limited, detailed EISs or EAs for specific projects*
- *Operations: Self-monitoring of environmental and safety compliance*

The following site selection and leasing policy examples have the most optimal combination of Relative Effort and Relative Results:

» *BOEM model*. Conduct a 4 stage authorization process: (1) planning & analysis; (2) leasing; (3) site characterization & assessment; and (4) commercial development). This is the primary model now being implemented in the U.S. and

U.K. There is general support for the overall structure, yet there is no substantial support for any legislative revisions despite ongoing efforts to streamline the existing model through implementation practices.

» *Texas and Denmark model*. A utility collaborative selects sites and initiates the lease process. It then holds a competitive bid process to select a wind farm developer to construct a wind farm while the utility permits and constructs the interconnection to the onshore grid and negotiates a PPA. This model is effective where implemented because it includes the PPA and interconnection support to facilitate financing the projects.

Timing and other considerations for these two policy examples are discussed in Section 3.8. Although both of these policies have shown to be effective in the U.S., the BOEM model has more universal acceptance, allows for unsolicited applications, and is less costly to implement.

3.6 Policies That Address Regulatory Challenges – Permitting

3.6.1 General Discussion of Policy Examples

The main policy examples for offshore wind farm permitting differ primarily in the level of centralization in producing environmental impact statements (EISs).

» *Require site-specific EISs for every offshore wind project*: Under this policy, developers produce individual EISs for each wind farm regardless of whether adjacent projects have addressed similar issues.

» *Conduct a programmatic EIS (PEIS) over broad geographic areas to determine categorical exclusions, followed by less detailed environmental assessments for individual projects*: The objective of this policy is to gain economies of scale and scope in conducting EISs, addressing common issues across multiple projects in a common area, and saving time and expense. Issues that are unique to a certain project are addressed in a less detailed, site-specific EIS.

» *Develop a programmatic EIS (PEIS) for a broad geographic area followed by detailed EISs for selected individual projects*: This example is similar to the previous example, with the exception that the project-specific EISs are more detailed. A PEIS evaluates the impacts and identifies appropriate mitigation for a range of standard technologies to be installed in a relatively uniform environment. The completed PEIS provides guidance to developers and regulators for subsequent specific development proposals. In the U.S., if the same technologies are proposed with the mitigation recommended by the PEIS, the subsequent NEPA review can focus only on unique aspects of the specific technologies or environment at the proposed wind farm site and cable route, which may significantly reduce the NEPA review period. A PEIS will generally take a couple of years to complete, but if initiated early, for example, during the initial Wind Energy Area identification and competitive auction processes, it can significantly expedite final review of the winning leaseholder's project. This is especially true if programmatic EISs or EAs are conducted for Wind Energy Areas simultaneously with the lengthy process to determine the winning bidders in areas where competitive interest exists.

3.6.2 Current U.S. and State Policies

U.S. policy

Instead of waiting for the Site Assessment Plan (SAP) to be filed to trigger the SAP NEPA review, BOEM initiated a Programmatic Environmental Assessment (PEA) for four mid-Atlantic states (NJ, DE, MD, and VA) simultaneously. By covering all major site assessment and characterization technologies and their impacts, this PEA is expected to enable more expeditious review of site assessment proposals by developers in these four states. The PEA was conducted during the nomination of lease sites in Maryland and Virginia and did not delay those Calls for Information and Leases. Winning bidders in Maryland and Virginia may seek expedited EAs and departures from certain SAP requirements if they use one of the standard technologies already determined by the PEA not to cause significant impacts with appropriate mitigation. Even if one or two issues must be addressed that were not covered in the PEA, then only those issues need be addressed and the EA can be reviewed and issued more promptly than an EA covering all the site assessment issues.

Council on Environmental Quality (CEQ) NEPA regulations specifically encourage tiering NEPA reviews off prior NEPA reviews:

> "Agencies are encouraged to tier their environmental impact statements to eliminate repetitive discussions of the same issues and to focus on the actual issues ripe for decision at each level of environmental review." Sec. 1508.28

> "Whenever a broad environmental impact statement has been prepared (such as a program or policy statement) and a subsequent statement or environmental assessment is then prepared on an action included within the entire program or policy (such as a site-specific action) the subsequent statement or environmental assessment need only summarize the issues discussed in the broader statement and incorporate discussions from the broader statement by reference and shall concentrate on the issues specific to the subsequent action. The subsequent document shall state where the earlier document is available. Tiering may also be appropriate for different stages of actions." Section 1502.20

Tiering is thus authorized to make NEPA reviews more efficient, reducing the analysis and time needed to complete subsequent reviews. As the same technologies are constructed and operated in similar environments, EISs can be gradually replaced by Environmental Assessments and eventually in some cases by Categorical Exclusions.

EISs can be gradually replaced by Environmental Assessments and eventually in some cases by Categorical Exclusions.

BOEM issued a Programmatic EIS for offshore energy development in 2007, prior to issuance of the Final Rule. When issuing the Final Rule, BOEM (then the Minerals Management Service, or MMS) stated:

> "We will ensure that environmental analysis for OCS renewable energy proposals is proportional to the scope and scale of each proposal, is effectively tiered to programmatic NEPA documents, and efficiently incorporates other publicly available information by

> reference. The MMS will ensure timely and efficient coordination of the development and review of environmental documents with all agencies that have jurisdiction or special expertise to provide the decision-makers. We will ensure that mitigation and monitoring information informs future decision-making processes." 74 FR 19638, 19643 (April 29, 2009)

In 2011, CEQ released final guidance on the "Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact" (FONSI). This guidance explains that an EIS can be avoided by issuance of an EA with mitigating conditions sufficient to warrant a Finding of No Significant Impacts. The guidance requires any agency issuing a mitigating FONSI to follow up and confirm that all such conditions are implemented.

As part of the Secretary's Smart from the Start initiative, BOEM conducted a Regional EA that analyzed the impacts associated with offshore wind lease issuance and site characterization and assessment activities that may take place in the areas identified by BOEM offshore New Jersey, Delaware, Maryland, and Virginia. Provided that the activities proposed by New Jersey, Maryland, and Virginia lessees fall within the scope of the activities analyzed in the Regional EA, additional NEPA review prior to the approval of Site Assessment Plans may not be necessary. In the event that a particular lease is issued, and the lessee submits a SAP, BOEM will determine whether the EA adequately considers the environmental impacts of the activities proposed in the lessee's SAP. If the analysis in the EA adequately addresses these impacts, such as by using technologies already addressed in the Regional EA, then no further NEPA analysis would be required before the SAP is approved. If the EA analysis is inadequate, additional NEPA analysis would be conducted before the SAP could be approved.

Similarly, routine activities could eventually be determined "categorical excluded" by BOEM, meaning they do not individually or cumulatively have a significant effect on the human environment and would require no EA or EIS. CEQ issued new guidance in 2011 on establishing and maintaining categorical exclusions for routine activities. Many oil and gas exploration activities have been granted categorical exclusions. Over time, site assessment activities, such as installing a meteorological tower, should become routine and warrant a categorical exclusion instead of an EA.

Additionally, it is important to note that any offshore wind project to be constructed in state waters, including any cables that would be necessary to transmit power back to shore, is subject to state regulation or permitting requirements.

State policy

States have a regulatory role when a wind energy project is proposed for construction in federal or state waters. Under the Submerged Lands Act, states have authority generally over the first three nautical miles of a state's coastal submerged lands, and states have passed coastal management laws and developed permitting and leasing programs for activities in state submerged lands. Offshore wind energy projects proposed in state waters could be subject to a comprehensive regulation that is managed by a single state agency or be subject to permitting authorities managed by multiple state and local agencies (Massachusetts, Rhode Island and New York have state siting boards that coordinate other state agencies and provide one-stop permitting for instate generation and the interconnection cables offshore and onshore).

States will have a regulatory role for projects in federal waters if a portion of the federal project (e.g., a cable) is constructed in state submerged lands. Furthermore, the Coastal Zone Management Act (CZMA) gives states the authority to require that projects in federal waters will not result in a violation of a state's federally-approved coastal zone management program. This review process by the state is frequently referred to as a CZMA "consistency review."

3.6.3 Current Policies in Other Countries

Denmark

In Denmark, Chapter 3 of the Promotion of Renewable Energy Act indicates that the right to exploit energy from water and wind within the territorial waters and the EEZ (up to 200 nautical miles) around Denmark belongs to the Danish State. To establish an offshore wind project in Denmark, a developer must obtain three licenses from the DEA. In terms of permitting, this agency serves as a "one-stop shop." It streamlines the project developer's relationship with all of the offshore wind power stakeholders. The three mentioned licenses are:

- License to carry out preliminary investigations
- License to establish the offshore wind turbines (only given if preliminary investigations show that the project is compatible with the relevant interests at sea)
- License to exploit wind power for a given number of years and – in the case of wind farms of more than 25 MW – an approval for electricity production (given if conditions in license to establish project are kept)

The Danish Energy Agency serves as a "one stop shop" for permitting.

The DEA grants the three licenses for a specific project. If a given project can be expected to have an environmental impact, the developer must perform an Environmental Impact Assessment (EIA). The specific regulations regarding EIAs for offshore wind farms are described in Executive Order no. 815 of August 28, 2000.

Germany

As mentioned in Section 3.5.3, in 2004, Germany's Federal Spatial Planning Act was expanded to the EEZ, which extends 200 nautical miles from the German shore.[59] This enabled the development of a spatial plan for offshore wind led by the permitting agency, the Federal Maritime and Hydrographic Authority (BSH). The first draft of this spatial plan, released in 2008, identified five priority areas (1,100 km^2) for offshore wind energy in the Germany North and Baltic Seas. The draft plan was subsequently revised multiple times based on industry feedback. Offshore wind farm development outside the priority areas is allowed but is subject to the results of comprehensive EIAs.

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[59] http://www.nve.no/Global/Energi/Havvind/Vedlegg/Offshore%20wind%20experiences%20-%20A%20bottom-up%20review%20of%2016%20projects%20(Ocean%20Wind).pdf

In Germany, permits for offshore wind farms are allocated through an open-door procedure. The first candidate to submit a proposal for a project that meets all of the BSH's stated criteria is given priority to develop the site. The principal component of the German regulatory procedure for offshore wind is obtaining the permit from the BSH. The permit provides a developer with exclusive rights to a site.

The Netherlands

As mentioned in Section 3.5.3, the OWEZ project in the Netherlands required consents from numerous authorities, but the process is now managed by a single ministry. A clear procedure is critical to increase developments, as it reduces the developer's risks at an early stage in the project.

An Integrated Management Plan for the Netherlands Economic Zone in the North Sea in 2015 introduces an integrated assessment framework for all activities requiring a permit. One of the key motivators for this plan is the need to plan for offshore wind energy. Specific zones have been identified where future offshore wind development should be concentrated.

United Kingdom

As mentioned in Section 3.5.3, whereas the U.K.'s Round 1 was developer-led, Round 2, launched in 2003, was led by government. The U.K. government recognized the importance of spatial planning and the need to streamline the consenting process. A "one-stop shop" approach was created for permitting. For Round 2, the government commissioned SEAs for three regions deemed attractive for offshore wind development: the Thames Estuary; the Greater Wash; and the North West.

For Round 3 initiated in 2008, TCE, the seabed owner and manager, established a strategic spatial planning process and identified nine Round 3 Zones in U.K. waters, prior to running an extensive tender process to identify credibility and financial robustness. Additionally, the U.K. government has implemented a new Infrastructure Planning process for the permitting of offshore projects, providing an improved, more efficient, and timelier consenting regime.

U.K. Round 3 exemplifies the importance and benefits of "zonation," SEAs, and proactive spatial planning. This framework approach, commencing in 2007 with a national Strategic Environmental Assessment, concluded with an extensive marine spatial planning constraint mapping process undertaken by TCE, with extensive consultation with stakeholders.

In U.K. Round 3, the advantages of zonation have been further extended by providing a collaborative framework with TCE to develop the zones to maximize capacities. The principle of proactive spatial planning has been taken a stage further in Round 3 through the ongoing technical and environmental zone appraisal within the zone by the developer and TCE to utilize regional environmental assessment tools to best locate projects according to environmental and permitting constraints. For Round 3, TCE has granted exclusive development rights for nine zones. New Infrastructure Planning Commission will be a one-stop permitting shop. Permits from local authorities will still have to be obtained.

In December 2007, BERR announced the commencement of a SEA aimed at facilitating significant further expansion for offshore wind. A target of 25GW of additional capacity by 2020 was also announced. In January 2009, the U.K. Offshore Energy SEA Environmental Report was issued for public consultation. The SEA indicates that the preferred approach of DECC is to apply spatial and operational limitations to offshore wind development zones, where required, to mitigate unacceptable environmental impacts, while supporting the overall use of the U.K. marine environment for achievement of the U.K. government's energy policy objectives.

The 2009 Marine and Coastal Access Act, together with the 2010 Marine (Scotland) Act and upcoming Northern Ireland Marine Bill, have set up a maritime planning system for all U.K. waters. Suitable areas for offshore wind development have been identified through SEAs.

3.6.4 Evaluation of Permitting Policies

Similar to Section 3.3.4, the Navigant Consortium evaluated each permitting policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results). A list of criteria, the policies that were evaluated, and the relative rankings for each criterion are provided in Appendix C.

The following permitting policy example has the most optimal combination of Relative Effort and Relative Results :

» *Develop a programmatic EIS for a broad geographic area followed by detailed EISs for selected individual projects*.

Timing and other considerations for this policy example are discussed in Section 3.8.

3.7 Policies That Address Regulatory Challenges – Operations

3.7.1 General Discussion of Policy Examples

There are multiple examples for the environmental and safety compliance monitoring of offshore wind plants. These examples differ primarily in the party responsible for conducting monitoring activities.

» *Environmental and safety compliance monitoring by the government*: A government agency is responsible for conducting monitoring activities prior to, during, and after construction of an offshore wind farm to assess a baseline characterization of the local environment and any subsequent changes.
» *Self-monitoring by developers/operators*: The developer or operator of a wind farm monitors the impact of its offshore wind farm on the environment and submits the monitoring data to a government agency for verification.
» *Monitoring by third parties*: A certified, independent third party monitors the impact of an offshore wind farm on the environment and submits the monitoring data to a government agency for verification.

3.7.2 Current U.S. and State Policies

Current approvals for energy facilities by federal and state authorities having jurisdiction include conditions on construction and operation to protect the public and the environment from new facilities. For offshore wind farms, such conditions may include the following:

» Restrictions on public access to the facility for public safety
» Restrictions on operation during extremely high winds that could cause catastrophic failure and loss of the blades
» Post-construction environmental monitoring surveys of birds, bats, and marine mammals
» Seabed scouring around the foundations to ensure ongoing protection of the environment and mitigation of any significant effects that may arise

The U.S. Fish & Wildlife Service (USFWS) negotiates the survey protocols for avian and bat studies, which include post-construction monitoring through their jurisdiction under the Endangered Species Act and the Migratory Bird Treaty Act. The USFWS has issued new guidelines for avian and bat surveys for terrestrial wind farms and is beginning to look at guidelines for surveys for offshore wind farms. Earlier studies identified flashing red lights as providing a deterrent effect unlike flashing white lights, which attract some species. Government-sponsored studies may help identify additional technologies that may deter birds from flying through offshore wind farms.

Cape Wind has agreed to conduct three years of post-construction avian and bat aerial and boat-based surveys as a condition of their BOEM lease. The cost of these post-construction surveys will exceed one million dollars per year.

While more limited post-construction monitoring of mammals is also required for the Cape Wind project, the biggest concern about marine mammals is contact or "allision" with vessels. The construction period requires the use of many large vessels and therefore requires mitigation measures to protect marine mammals, such as the following:

» Reduced vessel operating speeds
» Trained, independent protected species observers
» Hydro-acoustic monitoring
» Construction delays and shutdowns when mammals are within exclusion zones

O&M visits by small vessels to offshore turbines are usually only a couple of times per year and thus much less threatening to marine mammals.

Further government studies of the mating and calving grounds and migratory routes of endangered whales may help to site wind farms safe distances from the whales and provide more protection during construction and operation of wind farms.

3.7.3 Current Policies in Other Countries

European governments have sponsored and conducted post-construction surveys in addition to, and independent from, the surveys conducted by the wind farm operators and reported to regulatory agencies.

Denmark

In granting the building permits for Horns Rev and Nysted, Denmark's first two large-scale (100+ MW) wind farms, the DEA included an obligation for the project developers to carry out comprehensive environmental monitoring programs. It was specified that these programs should include detailed measurements of the environmental conditions before, during, and after construction. Between 2001 and 2006, the program had a budget of DKK 84 million (approximately €11 million). The program was financed as a public service obligation by electricity consumers. The monitoring work has been coordinated by a group consisting of the Danish Forest and Nature Agency, the Danish Energy Authority, and the projects' developers, Vattenfall and DONG Energy. The results of the monitoring programs have been evaluated by the International Advisory Panel of Experts on Marine Ecology (IAPEME).[60]

Germany

In February 2007, the BSH published the third edition of the "Standard for Investigation of the Impacts of Offshore Wind Turbines on the Marine Environment (StUK3)."[61]

In Germany, the approval holder for an offshore wind farm is responsible for conducting the baseline assessment, as well as assessments during the construction and operational phase. Monitoring data must be submitted annually to the approval authority. The monitoring data must include the status prior to construction, as well as any change during and subsequent to construction.

As part of Alpha Ventus (RAVE), Germany's first offshore wind farm, the Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety (BMU) initiated and financed the research at RAVE project. The BMU has allocated €50 million for the initiative. The initiative encompasses approximately 25 research projects, some of which are focused on the interdependency of environmental and technological impacts of offshore wind energy generation. The initiative is coordinated by Fraunhofer IWES.[62]

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[60] http://193.88.185.141/Graphics/Publikationer/Havvindmoeller/Offshore_wind_farms_nov06/pdf/havvindm_korr_16nov_UK.pdf

[61] http://www.bsh.de/en/Products/Books/Standard/7003eng.pdf

[62] http://www.iwes.fraunhofer.de/en/press_media/overview/2012/alpha-ventus--research-and-industry-present-common-achievements.html

The Netherlands

In 2001, the Dutch government decided to support the OWEZ offshore wind energy farm demonstration project. Prior to the project's construction, the Dutch government called for baseline studies on ecology and environmental factors. From 2002-2004, several consultancies conducted the baseline studies. After the wind farm began operation in late 2006, the project developer, NoordzeeWind, as required in the tender agreement, continued to monitor the project's impact on the environment. NoordzeeWind conducted this NSW-MEP Monitoring and Evaluation Programme in cooperation with leading research institutes. The research program began in 2006 and continued until 2012.[63] The Dutch government designated NL Agency, Energy and Climate Change as the responsible party for overseeing the monitoring program on behalf of the Dutch Ministry of Economic Affairs. NL Agency received the data and verified the consistency, integrity, validity, and plausibility of the data. Moreover, the Agency was instructed to store and distribute the data to third parties.[64]

United Kingdom

In the U.K., offshore wind farm license holders are responsible for monitoring the environmental impacts of their facilities.

In the U.K., offshore wind farm license holders are responsible for monitoring the environmental impacts of their facilities. Licenses under the Food and Environment Protection Act 1985 (FEPA) are required for any construction activity within the marine environment. The FEPA licensing process includes a thorough assessment of the likely impacts of the offshore wind farm on the marine environment and the need for measures to mitigate impacts and/or plans for marine environmental monitoring.

In 2010, the Centre for Environment, Fisheries & Aquaculture Science (Cefas), with support from FEPA and the Sea Mammal Research Unit (SMRU), conducted a study entitled "Strategic Review of Offshore Wind Farm Monitoring Data Associated with FEPA Licence Conditions."[65] The report concluded:

» It is vital to have clearer objectives within license conditions to ensure the developer knows why and what monitoring is required.
» It is important to incorporate datasets from national or even international monitoring programs to utilize all available data.
» There is a need to develop novel techniques to assess the issues identified in the Environmental Statements.
» Few conditions can be removed from licenses.
» License conditions need to better reflect current scientific understanding and need to be more explicit in their wording to aid enforcement.

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[63] http://www.agentschapnl.nl/programmas-regelingen/ecology-and-environment

[64] http://www.agentschapnl.nl/programmas-regelingen/monitoring-and-evaluation-windpark-egmond-aan-zee

[65] http://cefas.defra.gov.uk/media/393490/strategic-review-of-offshore-wind-farm-monitoring-version-final-19-august-2010-sir.pdf

» More work is required within monitoring reports to assess interactions between different receptors.
» All topic areas stressed the need to have a standardization of survey and analytical methodologies wherever possible to aid in future comparison and assessment.

3.7.4 Evaluation of Operations Policies

Similar to Section 3.3.4, the Navigant Consortium evaluated each operations policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results). A list of criteria, the policies that were evaluated, and the relative rankings for each criterion are provided in Appendix C.

The following operations policy has the most optimal combination of Relative Effort and Relative Results:

» *Self-monitoring by developers/operators*. This example scores well in all categories, with the exception of possible conflicts of interest. This concern could be balanced with government oversight in critical areas. For example, governments could fund generic studies that provide more protection to birds and bats, and help identify whale mating, calving, and migratory areas to minimize exposure to construction and O&M vessels supporting offshore wind farms. Developers would continue to fund and execute their own post-construction surveys for review by regulators.

Timing and other considerations for this policy example are discussed in Section 3.8.

3.8 Summary of Effective Policy Examples

The policy examples that the Navigant Consortium has identified as effective in Sections 3.3 to 3.7 are summarized in Table 3-5. A short-term policy is defined as being implemented within the next two years, although the terms of the policies will generally be much longer.

Table 3-5. Examples of Effective Offshore Wind Policies

Barrier		Short Term	Medium to Long Term
High Cost		» Long-term contracts for power » ORECs » ITC for developers » PTC for developers » Low-interest loans and guarantees » Accelerated depreciation » State FiTs	» Technology development credits to reduce capital costs » Applied research to decrease O&M costs » Turbine innovation subsidies to increase energy capture
Infrastructure		» Promote utilization of existing transmission capacity reservations to integrate offshore wind » Target BOEM Wind Energy Areas and consider public policy mandates, such as RPS, as required by FERC	» Establish clear permitting criteria for transmission planning & siting » Establish consistent cost allocation and recovery mechanisms for transmission interconnection and upgrades » R&D investment support » Manufacturing tax credits
Regulatory	**Leasing**	» Similar to BOEM's "Smart from the Start" model - 4 stage authorization process: (1) planning & analysis; (2) leasing; (3) site characterization & assessment; and (4) commercial development	
	Permitting	» Expedite lease auction process and set efficient schedule for NEPA review of leasing and permitting process in accordance with CEQ NEPA regulations	» Conduct a new programmatic EIS for offshore wind construction, then require only site-specific EISs for limited site-specific issues
	Opns.	» Self-monitoring of environmental and safety compliance by developers/ operators	

Although many policy examples are shown as short term, the most critical needs are addressed by those designed to stimulate demand (i.e., policies that address high cost). A portfolio approach that incorporates multiple policy elements could be effective, similar to the U.S. land-based wind market, which has been stimulated through a mix of PPAs with PTCs, ITCs, and renewable portfolio standards (RPSs). Other examples such as the FiT have proven to be effective in stimulating offshore wind demand in many European countries.

Infrastructure policies have shown to be effective in ensuring the demand can be filled. These policies can help to streamline siting and permitting processes, and put critical infrastructure components in place, such as transmission and ports. Mid- to long-term policies may help to instill confidence in the market. Manufacturers are unlikely to build new U.S.-based manufacturing capacity without confidence in U.S. long-term, stable demand. Only after the U.K. and Germany signaled that long-term demand would exist did manufacturers begin to build portside manufacturing capacity in those countries. After the U.S. offshore market takes off, manufacturing incentives such as tax credits could be appropriate.

Finally, governments have used R&D investment support as an effective long-term policy. R&D support can help to drive down the total installed system cost and the LCOE, which is critical to the longer term success of offshore wind market development. However, it is uncertain to significantly contribute to the development of a burgeoning U.S. market in the near or medium term.

4. Economic Impacts

4.1 Summary

The following sections review our work to date developing models and data sets to project the economic impacts of U.S. offshore wind development through 2030. Estimated employment, earnings, and output are gross impacts only accounting for economic impacts that result from new investment in offshore wind plants. They do not consider implications to the broader economy in terms of displacement of alternative generation sources, impacts to electricity rates, or impacts from incentive schemes that may support offshore wind development. The Navigant Consortium created a complete set of assumptions on capital and O&M costs for the near term (2015 to 2018), with high-level projections on how they will evolve to 2030. We have projected domestic and local content out to 2030 as well.

Summary of Key Findings – Chapter 4

- A 500 MW reference plant installed in the mid-Atlantic in 2018 is estimated to have capital costs of $3,040 million or $6,080/kW.
- Total operations and maintenance (O&M) costs for the reference plant are assumed to be approximately $68 million/year or $136/kW-year.
- The JEDI model shows that the 500 MW reference plant would support approximately 3,000 job-years over the construction period and drive $584 million in local spending over the same period.
- During operation, the plant (and the resulting local impacts) would support 313 jobs each year in the local economy and $21 million/year in local spending.
- In the high-growth scenario, the U.S. offshore wind industry could support ~350,000 FTEs by 2030, but in the low-growth scenario, it would be ~50,000.
- In the high-growth scenario, the U.S. offshore wind industry could drive $70 billion (in 2011 dollars) per year by 2030 but in the low-growth scenario it would be ~$10 billion.

4.2 Existing Studies

The Navigant Consortium began assessing the economic impacts of offshore wind power plants by collecting information on similar studies that have been conducted in the U.S. and internationally. Studies used economic impact models that could be leveraged or contained data that could be used in this study. The following section summarizes each study and any relevant data, in alphabetical order by title.

4.2.1 Literature Review

A Closer Look at the Development of Wind, Wave & Tidal Energy in the U.K, 2008
Author: Bain & Company
Region and Period of Study: United Kingdom to 2020
Intent of Study: Examine employment opportunities and challenges in the context of rapid industry growth
Models Used: The authors developed their own proprietary model to analyze employment impacts.

Solar and Wind Sectors on Course to Employ 2 Million People Worldwide by 2020, 2012
Author: Bloomberg New Energy Finance
Region and Period Study: Global Wind Power Industry 2011 and 2020
Intent of Study: Estimate direct and indirect global employment in the wind (and solar) power industry
Models Used: None. The analysis relies on reported industry data and employment at OEMs and their primary suppliers.

Offshore Wind Green Growth Paper, 2010
Author: Carbon Trust
Region and Period of Study: United Kingdom to 2020 and beyond
Intent of Study: Calculate investment and employment impacts of the offshore wind industry
Models Used: Unknown

Offshore Wind Power: Big Challenge, Big Opportunity, 2008
Author: Carbon Trust
Region and Period Study: United Kingdom, 2020
Intent of Study: Analyze the potential role and impact of offshore wind to the U.K. including reporting of potential direct and indirect employment from offshore wind in 2020
Models Used: Unknown

Employment and Economic Impacts of Ontario's Future Offshore Wind Power Industry, 2010
Author: The Conference Board of Canada
Region and Period of Study: Ontario, Canada to 2026
Intent of Study: Calculate the contribution that offshore wind generation might make to electricity supply, employment, and economic activity
Models Used: Statistics Canada's input-output models

Wind At Work, 2009
Author: European Wind Energy Association
Region and Period of Study: European Union 2008 - 2030
Intent of Study: Quantify and project the direct and indirect employment of the wind power industry in the EU including identification of workforce shortages
Models Used: Proprietary Input-Output Analysis and direct workforce surveys

Green Growth: The Impact of Wind Energy on Jobs and the Economy, 2012
Author: European Wind Energy Association
Region and Period Study: European Union 2012 - 2030
Intent of Study: Quantify the direct and indirect impact of the wind power industry on employment, GDP, exports and imports, tax balance, and fuel expenditures
Models Used: Proprietary Input-Output Model supplemented by data collected from company financial statements and direct industry surveys

Economic Impact Analysis of the Cape Wind Off-Shore Renewable Energy Project, 2003
Author: Global Insight
Region and Period Study: Massachusetts
Intent of Study: Estimate the economic and fiscal impacts from the proposed Cape Wind offshore wind projects to Massachusetts and selected counties within the state
Models Used: IMPLAN

Global Wind Energy Outlook 2008
Author: Global Wind Energy Council and Greenpeace International
Region and Period Study: Worldwide 2008 - 2030
Intent of Study: Analyze the worldwide markets for windpower through 2030 including employment
Models Used: Unknown

Economic Valuation of the Visual Externalities of Off-shore Wind Farms
Author: Jacob Ladenburg, Alex Dubgaard, Louise Martensen, Jesper Tranberg
Region and Period Study: Denmark, 2005
Intent of Study: Evaluate the visual externalities associated with offshore wind in Denmark, including an analysis of employment impacts
Models Used: Statistics Denmark Input-Output Multipliers

Could Extended Operating Life Help Reduce Offshore Wind Cost of Energy?, 2011
Author: Michael Drunsic, DNV
Intent of Study: Provide insights into how extending turbine operating life is a potential means for reducing the cost of energy for offshore wind power

Mapping Renewables Skills: "Green Collar" Jobs in the Power Sector
Author: The National Skills Academy for Power and The Energy Technologies Institute
Region and Period Study: United Kingdom 2009 - 2020
Intent of Study: Analyze the labor demand and skills needed to serve the growing renewables industries
Models Used: None: Labor per MW was estimated based on direct industry interviews.

Offshore Technology, 2001
Author: Offshore Wind Energy in Europe, Project: Concerted Action on Offshore Wind Energy in Europe
Region and Period of Study: The complete EU coastline with potential for offshore wind energy (except Portugal) and the Baltic Sea, circa 2001
Intent of Study: Support the realization of offshore wind energy by mobilizing available but scattered knowledge from previous/ongoing national and EU efforts

Review of the Generation Costs and Deployment Potential of Renewable Electricity Technologies in the U.K., 2011
Author: Ove Arup & Partners, Ltd. for the Department of Energy and Climate Change
Region and Period of Study: United Kingdom to 2030
Intent of Study: Review the deployment potential and generation costs of renewable electricity technologies

Analysis of the Employment Effects of the Operation and Maintenance of Offshore Wind Parks in the U.K, A Report for Vestas Offshore, 2010
Author: Oxford Economics
Region and Period of Study: United Kingdom to 2020
Intent of Study: Provide an assessment of the employment impact of the operation and maintenance of offshore wind farms
Models Used: Employment data supplied by Vestas

Working for a Green Britain: Vol 2, 2011
Author: Renewable U.K. and Energy & Utility Skills
Region and Period of Study: United Kingdom to 2021
Intent of Study: Estimate future employment and skill needs in the U.K. wind and marine industries
Models Used: The authors developed their own proprietary model for employment modeling.

The Potential Economic Impact of an Off-Shore Wind Farm to the State of South Carolina
Author: Roger Flynn and Robert Carey
Region and Period Study: South Carolina with no time period specified
Intent of Study: Estimate the economic and fiscal impacts to South Carolina from manufacturing, installation, and operation of a 480 MW wind farm off the coast of South Carolina
Models Used: REDYN

Today's Investment – Tomorrow's Asset: Skills and Employment in the Wind, Wave and Tidal sectors. Report to the British Wind Energy Association, 2008
Author: SQWenergy
Region and Period of Study: United Kingdom to 2020
Intent of Study: Identify skill gaps needed to meet 2020 renewable energy goals
Models Used: The authors developed their own proprietary model for employment impacts analysis.

Maximizing Employment and Skills in the Offshore Wind Supply Chain, 2011
Author: SQW Energy
Region and Period of Study: United Kingdom, through Round 3 of their offshore wind program
Intent of Study: Research the employment and skills opportunities associated with the offshore wind energy sector and its supply chain
Models Used: Cited work by others

4.2.2 Findings

No existing work met the needs of our study, so we created our own models.

In all of the studies the Navigant Consortium reviewed, the authors used in-house tools that were applied to other countries. Thus, there were no models available to use in lieu of creating our own model because the studies reviewed did not provide public information and were done in other countries with different supply chains and economies not indicative of the U.S. However, several of the studies reported their findings on employment impacts as a function of installations, so the Navigant Consortium will be able to use that information to benchmark results.

4.3 Data Collection

4.3.1 Overview

Local employment and economic impacts are a function of the amount of spending and labor sourced from the local economy. Before looking at local impacts, the Navigant Consortium collected information on project-level costs at a higher level of detail than is typically reported in literature or project press releases. Thus, the Navigant Consortium's internal knowledge, expert interviews, and vendor quotes were relied upon as sources of cost data. The remainder of Section 4.3 reviews data sources and findings for each cost category.

4.3.2 Typical Project

Many project-specific variables such as water depth, foundation type, distance to shore, and turbine size significantly impact costs for offshore wind farms. Thus, rather than collecting cost information for a generic plant, the Navigant Consortium developed a reference project, summarized in Table 4-1, and then collected cost data for this plant.

Table 4-1. Reference Project

Project Parameter	Value	Rationale
Project Location	North Atlantic of the U.S.	This region has many plants proposed and represents a mid-point in labor costs compared to other regions of offshore wind project development
Year of Construction	2018	Wanted plant costs that were not the first one built (which could be in the middle of this decade), or during a period with a high volume of installations. According to market forecasts, 2018 will likely be such a period. We assume a two year construction period
Project Size	500 MW	Common size for plants proposed in the area
Turbine Size	3 to 5 MW	
Water Depth	20 to 30 m	Common depth for project proposed in the North Atlantic
Distance to Staging Port	100 miles	Common distance for plants proposed in the North Atlantic relative to suitable ports
Distance to Interconnection	50 miles	Common distance for plants proposed in the NorthAtlantic
Distance to Servicing Port	< 30 miles	Assumed that a port closer than the staging port could be used for servicing
Foundation Type	Jacket	Most common design for proposed U.S. plants in 20-30 m water depths

4.3.3 Turbine

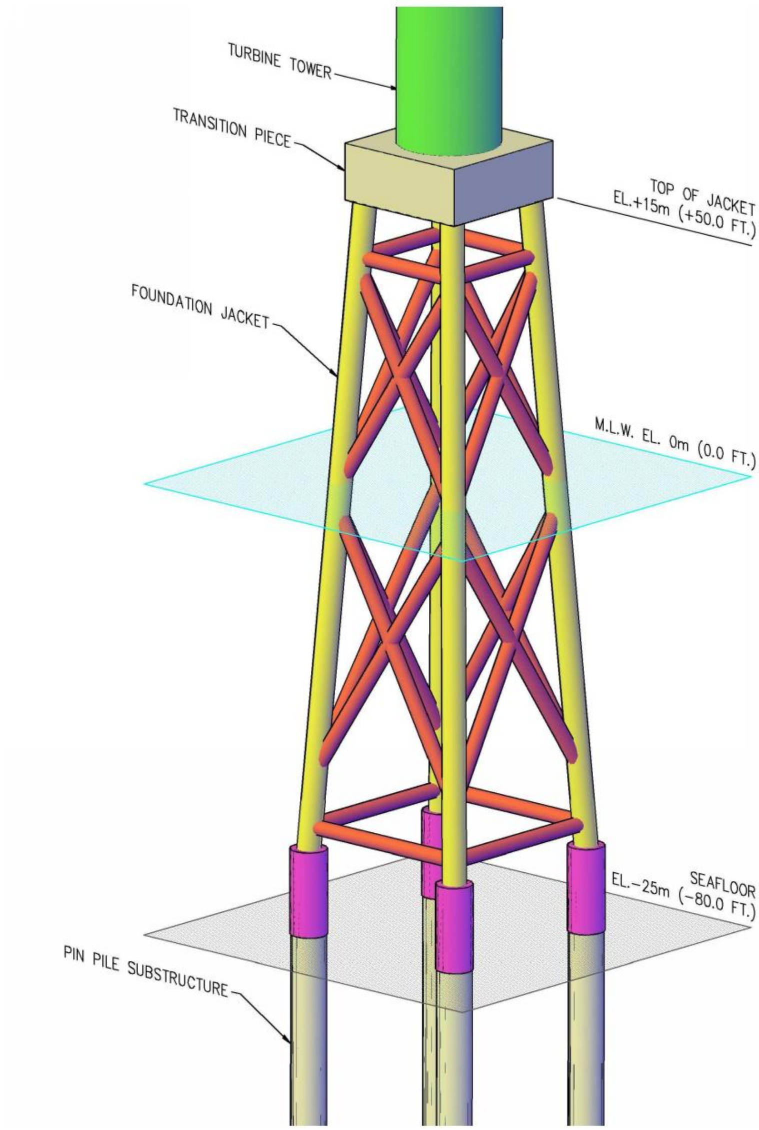
Turbine costs and their distribution among the nacelle, blades, and towers were derived from two primary sources. Total turbine costs were sourced from NREL's recent *2010 Cost of Wind Energy Review* (Tegen et al. 2012) that included offshore wind data. Data reported there suggest a representative turbine cost of approximately $1,800/kW for a 500 MW project (using 3.6 MW turbines) with a total installed capital cost of $5,600/kW. This cost also includes financing costs. Data reported by Tegen et al. (2012) were noted to have been sourced from "recent publications (Douglas-Westwood 2010; BVG 2011; Deloitte 2011) and conversations with offshore wind project developers in the United States."

NREL's *Wind Turbine Cost and Scaling Model* (Fingersh et al. 2006) was utilized to determine the requisite allocation of costs among the three primary turbine components (i.e., the tower, blades, and nacelle) in an land-based plant. This model suggested a general breakdown across an array of turbine sizes, both for machines in production today as well as in prototype testing, of approximately 55% of turbine cost in the nacelle/drivetrain, 25% in the blades, and 20% in the tower. It is recognized that these percentages could vary based on significant differences in tower height, rotor diameter, or drivetrain design; however, in the absence of a large sample of empirical data they were determined to be sufficient.

4.3.4 Foundation and Substructure

Initial input from a turbine manufacturer yielded jacket foundations as the preferred foundation type for early offshore wind development in the U.S. Therefore, this analysis focuses primarily on jacket foundations. Based on the turbine size and water depth, COWI selected a conceptual jacket foundation design, as seen in Figure 4-1, similar to a design proposed for a European wind farm.

Figure 4-1. Conceptual Jacket Foundation Example



Source: OCC. The representative jacket foundation was prepared from observations of typical member sizes of European jacket designs for similar site conditions.

The dimensions and material weights identified in the conceptual jacket design were used in interviews with material providers, component fabricators, and offshore installation contractors as an example to better determine costs, rates of production, personnel hours, and equipment required during fabrication and installation of the foundation and substructure.

Model and cost inputs assume that the steel required to construct the jacket and associated pin pile substructure would be sourced within the U.S. Fabrication production rates are consistent with rates observed in the existing Gulf of Mexico oil and gas fabrication industry. These rates are likely consistent with a semi-mature U.S. offshore wind (OSW) fabrication industry as newly developed North Atlantic (the location of our typical project) fabrication yards will have gained some experience from the first OSW projects, but not likely to have invested fully in automated machinery, which will reduce the labor hours required and associated costs. Labor rates were determined using a combination of Davis-Bacon prevailing wage rates and construction labor rates published by the R.S. Means series for the state of Maryland, consistent with the Mid-Atlantic project location. Open-shop (e.g., non-union) fabrication yards will cause a lowering of costs. Therefore, the assumed labor costs are conservative.

Costs input to the JEDI model assume that fabrication and installation are two separate contracts. Though it is possible to issue one RFP for the fabrication and installation of the foundation, the work tasks are fundamentally different and costs are anticipated to be more competitive if bid independently in order to prevent a supply chain bottleneck of qualified companies.

Because jackets are assumed to be fabricated in the North Atlantic, it is reasonable to assume that the fabrication yard will also serve as the foundation installation port; foundation and substructure components will be shipped directly offshore on material barges.

Future projects will consider alternative foundation types, including monopile and gravity base foundations. These two will be selected based on their proven track record in Europe for shallow and transitional water (up to 40m - 130 ft.) depths.

4.3.5 Electrical System

Project collection system

Our analysis assumes that a representative 3 or 5 MW turbine would be used. We used the 3 MW design for costing - therefore, cost estimates plan for the material and installation of 167 (e.g., a 500 MW array with 3 MW turbines) medium-voltage alternating current (MVAC) inter-array cables. These cables would be laid on the seafloor, pulled into each respective turbine foundation and post-lay buried by a tracked Remotely Operated Vehicle (ROV). Following best practices as recently evidenced in the European market, the model treats inter-array cabling and export cabling as separate contracts. Costs were compiled based on installation rates and costs observed in Europe.

Transformer station

The JEDI model assumes one transformer station will be included with the project to step up the inter-array collection voltage (33kV MVAC) to a higher export voltage (115kV or 230kV HVAC) for export from the transformer station to the converter station. The transformer station will be contracted as a turnkey project for an electrical OEM (Siemens, Alstom, ABB or equivalent).

Converter station

The JEDI model assumes that a single HVDC converter station will be shared between two projects. An HVDC export cable allows for greater energy to be carried further distances with less energy loss than an equivalent HVAC system. Interviews with offshore electrical equipment manufacturers suggest that HVDC will be capable of carrying 800-1,000MW of power by 2018. To allow for redundancy two HVDC export cables will run from the converter station to the landside substation, each project providing funding for one HVDC line. The converter will be contracted as a turnkey project for an electrical OEM (Siemens, Alstom, ABB or equivalent).

Export cable

Current cost projections for the representative project provide for a single HVDC cable to export power from the converter station to shore as well as an HVAC cable to export the power from the offshore transformer station, to the DC converter station. Unlike the inter-array cables, long-distance export cables will be laid and buried in place simultaneously by a plow towed behind the export cable vessel. Following best practices, as recently evidenced in the European market, the model treats inter-array cabling and export cabling as separate contracts, though HVAC and HVDC cables may be installed by a single contractor. Costs were extrapolated from contractors' cost estimates for a U.S. project with similar export cable design parameters.

Equipment, cost, and staffing data for the electrical system was collected from interviews with existing cable manufacturers and installation contractors, proposal data from projects in the United States, and from other in-house data. Projected costs were compared to numbers published by reports commissioned by the U.S. Department of the Interior and Bureau of Offshore Energy Management and case studies from European projects.

4.3.6 Development Services

Engineering (project and interconnection facility design)

Engineering costs were compiled based on an average of engineering costs observed for recently completed projects in Europe. We assume the European experience will translate to US projects. Costs were converted to U.S. currency using an approximate exchange rate as observed on July 1, 2011.

Ports and staging

Costs provided for ports and staging were evaluated from publicly reported development costs for ports in Europe and one port in the U.S. that have been specifically developed for the OSW industry. Costs for each port were divided by the number of immediate projects they were anticipated to serve. In practice, a significant amount of the port development costs may be borne by the initial projects. Once ports have been developed, use costs to future projects may be expected to decrease. Investment in ports and waterways is one way that public investment could greatly support offshore wind development, as well as other industries relying on water-based transportation. Therefore, investment in port and navigation projects will have a compounding effect and the cost/benefit ratio will be very favorable.

Air transportation (personnel or materials)

Air transportation for construction was based on 30 months of a quoted rate for a monthly charter of an offshore-certified helicopter, capable of transporting up to six personnel or 1,000 lbs of equipment per transit. The helicopter provider was located in the North Atlantic region and the quoted price is based on establishing a temporary base of operations adjacent to the installation port.

Marine transportation (personnel or materials, including vessel mobilization)

Installation of the jackets is assumed to be completed by a jack-up barge (though in the post-2020 time frame, a Self-Propelled Installation Vehicle [SPIV] could be used). For this model, the jack-up barge remains at the offshore installation site. Jacket foundations and substructures are transported from the fabrication yard to the installation site by offshore classed material barges. Two sets of tugs and barges are required. One set will supply the jack-up barge on-site while the other tug/barge returns to port to be reloaded and transit back to site. Upon using all of the transported components, the barge roles alternate. The steel frame structures are more robust than the turbine superstructure components, so it is possible to lift foundation components from floating construction plant, though only during certain sea states. Marine transportation costs were obtained from U.S. offshore contractors as well as reports prepared for BOEM.

Erection/installation (equipment services only, excludes labor)

For the JEDI model, the turbines will be installed by an independent turbine installation contract. The model assumes that turbines will be installed by an SPIV. In this case, the U.S. is assumed to benefit from European vessel experience and will have current "next generation" turbine installation vessels available. Primary characteristics of the SPIV selected for this model include:

- Cargo capacity: six complete turbines per trip
- Steaming speed (when not restricted by navigation concerns): 10-14 knots
- Installation rate: 3 days per turbine (inclusive of load, travel times, and weather delay)
- Operating hours: (2) 12 hour shifts per day, work schedule 24/7/365
- Workers are housed on vessel
- Vessel support spread: two crew vessels, full time

Despite the relative complexity of the SPIV type vessels, they are likely to be available in a semi-mature U.S. market due to the turbine OEMs' prohibition of transferring sensitive turbine equipment between floating vessels at sea. Though jack-up barges are another technically viable solution to transport and install turbines, the faster steaming speed of the SPIV vessels relative to the jack-up barges is a strong advantage given the anticipated 100-nautical-mile steaming distance for the representative project.

For this JEDI model, wind farm foundations and substructures are assumed to be installed by a jack-up barge. Alternatively, the foundation installation contractor may elect to use floating equipment to install jacket and pin piles, as has been done in some offshore oil and gas projects. After being transported offshore, jacket foundations are lowered in place. The substructure pin piles may be preinstalled in the seafloor, or driven through driving sleeves in the jacket frame. Primary parameters of the jack-up barge installation affecting the JEDI model include:

- Jackets and pin piles are transported by offshore classed barge.
- Transport barge is able to carry four complete foundations and substructures per trip.
- Two sets of transport barges with tug are required to keep the jack-up barge in continuous operation.
- Average install time is 3 days per foundation, includes load, travel times, and weather delay.
- (2) 12-hour shifts per day, work schedule 24/7/365.
- Workers are housed on the offshore vessel.
- Requires support from two crew vessels, full time.

For both the turbine and foundation installation, the large installation vessels may be chartered with or without installation crew. There has been a trend in Europe for installation vessel charter durations to span multiple seasons and for vessels to work on multiple projects for one developer, reducing mobilization costs to the developer. The long-term contracting arrangements are also preferred by developers and vessel operators because the pipeline of projects allows the vessel standby times (and therefore costs) to be reduced. The JEDI model input considers a vessel mobilization cost for each vessel plus a monthly charter rate over the anticipated installation duration of the project. The smaller support /crew vessel day rates typically include the vessel master and crew.

4.3.7 Financing

Financing costs for an offshore wind farm include bank fees, insurance, due diligence costs, interest payments during construction, and several other items. See the Appendix for a thorough discussion of each of these items. The total cost for the typical project comes to $520M.

4.3.8 Summary of Capital Costs

Adding these items together yields installed costs of $3.04B for a 500 MW project or $6,080/kW. This value is slightly higher than those reported in the literature, but this example assumes jacket foundations and a farther distance from shore in terms of site location as well as distance to staging port. Most other studies assume monopole foundations, which are typically less expensive.

Near term capital costs for a 500 MW offshore wind farm came to $6,080/kW

4.3.9 Operation and Maintenance

O&M direct labor costs for a 500 MW offshore wind plant are assumed to be $5.6 million per year, with a breakdown as shown in Table 4-2.

Table 4-2. O&M Labor Costs by Employee Type

	Employees	$/hour	M$/year
Technicians	30	43	2.7
Administrative	10	24	0.5
Management/supervision	20	58	2.4
Total	60		5.6

Key labor assumptions are primarily from the Oxford Economics study (2010) and are summarized as follows:

- Approximately 0.28 employees per MW are required for smaller plants (in the 100 MW range), if they are close enough to shore so the crew can be transported daily.
- Management and support staff employment levels do not move proportionally to capacity, but operate on a threshold basis. For example, once a wind farm reaches a certain size, additional office-based staff are required. (The threshold differs depending on the role, with those employed in central support roles able to manage the largest capacity.)
- One exception to the previous assumption is employment of technicians, which is assumed to increase at 50 percent of the increase of capacity (i.e., if capacity doubles, the number of technicians increases by half).
- Based on the above, the resulting labor ratio for a 500 MW plant is 0.12 employees per MW for project-level staffing.
- The high level of skills required is reflected in the average annual income paid to technicians. Salaries of £40,000/year place offshore technicians in the top 20 percent of U.K. workforce incomes.
- Long-distance wind farms (not yet included in this analysis) lead to a different approach to O&M employment in these sites. Instead of being land-based, non-central O&M employment at these sites is based offshore and therefore operated with a 14-day shift pattern similar to oil rigs. Consequently, all non-central employment at these wind farms is doubled. These plants are likely to operate with an accommodation platform similar to that at the Horns Rev 2 site in Denmark. These platforms require additional support employment (for example catering), which is estimated to be equal to 20 percent of the number of offshore staff.

O&M materials and services costs for a 500 MW offshore wind plant are estimated as shown in Table 4-3.

Table 4-3. O&M Materials and Services Costs

	$/MW-year	M$/year
Water Transport	28,000	14.0
Site Facilities	14,000	7.0
Machinery and Equipment	6,000	3.0
Subcontractors	9,000	4.5
Corrective Maintenance Parts	65,000	32.5

Key assumptions and sources for these estimates are as follows:

- Total O&M costs for a 500 MW offshore wind plant in the mid-Atlantic will range from $100 to $230/kW-year, depending primarily on the year of operation (DNV).
- Total O&M costs for an offshore wind plant >100 MW will range from £117K to £196K/year in 2010, decreasing to from £100K to £167K/year in 2030 (all in 2010£), depending primarily on site characteristics and the cost of steel and commodity prices (Ove Arup & Partners).
- Excluding direct labor and corrective maintenance parts, the cost breakdown for offshore wind O&M expenditures will be as follows: 46% for water transport, 23% for site facilities, 10% for machinery and equipment, and 14% for subcontractors (Oxford Economics).

The above assumptions result in estimated total O&M costs for a 500 MW offshore wind plant in the mid-Atlantic equal to $133/MW-year or $66.6 million/year.

Near term O&M costs for a 500 MW offshore wind farm came to $133/MW-year.

4.3.10 Local Content Assumptions

We have projected local and domestic content for each scenario and year of analysis through 2030. We leveraged our companion supply chain study, interviews with our project partners, and data on existing suppliers that could serve the offshore wind market. These assumptions for each component are shown in Appendix D with the caveat that these are very high-level assumptions and are very dependent upon things beyond the scope of this study such as changes in financial markets, evolution in international trade agreements, and overall economic health of different countries. In this section, we discuss near-term (pre-2020) assumptions for our typical project.

We assumed a near term domestic content of 40%.

Given relatively low demand in all three scenarios over this time period, very little new supply chain investment is anticipated. The estimates included in Table 4-4 are reflective of the existing labor force and its ability move into the offshore wind space. Generally, for goods and services where there is significant overlap with existing U.S. industries, it is expected that a substantial portion of the projected demand will be provided locally or domestically. Where there is little or no direct overlap, goods and services will need to be imported. For example, the Gulf region of the U.S. has significant offshore foundation production and fabrication expertise developed to serve the offshore oil industry. The industry could easily transition into offshore wind, even for only a handful of projects. This high transferability is reflected in the domestic content estimates for foundation and substructure materials and labor, both of which exceed 50%. In contrast, the primary manufacturing facilities for offshore wind turbines are in Europe and will likely remain there if demand is low in North America. Only modest amounts of turbine equipment–most of which would likely come from the central plains or surrounding states since that is where the existing land-based production capacity is concentrated–are expected to be sourced domestically.

Table 4-4. Near-Term Local Content and Domestic Sourcing Assumptions for Our Typical Project[66]

	North Atlantic Region	National (e.g. Domestic Content)	Discussion
Turbine Equipment Costs			
Nacelle/Drivetrain	0%	25%	Some manufacturing exists in the U.S. that could provide offshore components, but pre-2020, most components will likely be sourced from Europe.
Blades	0%	10%	
Towers	0%	10%	
Materials & Other Equipment			
Basic Construction (e.g., concrete, rebar, gravel)	100%	100%	These items are produced locally throughout the U.S. and will likely be sourced locally.
Foundation	5%	60%	These materials will likely come from the Gulf or overseas as that is where most of the expertise is for offshore oil platforms.
Substructure	0%	60%	
Project Collection System	0%	15%	Many high-voltage systems, wiring, and components – and the associated designers – are currently made in Europe and in the 2020 timeframe, the demand of the U.S. offshore wind industry will likely not be large enough to draw manufacturing to the U.S.
HV Cable (project site to point of grid interconnection)	0%	10%	
Converter Stations (for DC line to land)	5%	5%	
Substation (including transportation)	5%	5%	
Labor Costs			
Foundation Assembly	0%	90%	The Gulf region has an existing skill base from the offshore oil and gas industry that can supply labor for the offshore wind industry.
Substructure Assembly	0%	90%	
Management/Supervision	95%	95%	The deals we are familiar with which would leverage local management and supervision.
Insurance During Construction			
CAR/Third-Party Liability/business Interruption, etc.	0%	0%	Pre-2020, only European companies with offshore wind projects experience will likely provide insurance during construction.
Development Services/Other Costs			
Engineering (Project and interconnection facility design)	100%	100%	This requires local knowledge and each of the regions of study has engineering firms that can help with this.

[66] See Appendix D for a full discussion of % local content assumptions and how they evolve over time.

	North Atlantic Region	National (e.g. Domestic Content)	Discussion
Legal Services	100%	100%	This requires local knowledge for many items, and for general legal support, many of the law firms that work in this area have offices located near areas of offshore wind development.
Public Relations	100%	100%	This is typically done by local firms that have relationships with local media and decision-makers.
Ports and Staging	100%	100%	It was assumed that wind farms will be built out of the nearest suitable port, which should be in the region.
Site Certificate/Permitting	100%	100%	This requires local knowledge of laws, regulations, and agencies, so we assumed all local sourcing.
Air Transportation (personnel or materials)	100%	100%	These services can most cost effectively be provided by local companies.
Marine Transportation (personnel or materials, includes vessel mobilization)	100%	100%	
Erection/Installation	50%	75%	Some of this work can be done by local contractors, but some specialized skills or vessels are likely to come from Europe in the near term.
Decommissioning Bonding	0%	0%	It was assumed that firms offering these services in Europe will offer them in the U.S. in the pre-2020 time frame.
Construction Financing	0%	0%	In the pre-2020 time frame, most debt financing will come from European banks that are familiar with offshore wind transactions.
Interest During Construction	0%	0%	
Due Diligence Costs	0%	50%	European banks will likely want to use due diligence firms they are familiar with, but some items (e.g., transmission or structural) will require firms with U.S. experience.
Reserve Accounts: MRA/DSRA	0%	100%	Because most project developers are domestic, they will most likely use domestic banks for holding reserve accounts.
Bank Fees	0%	0%	In the pre-2020 time frame, most debt financing will come from European banks that are familiar with offshore wind transactions.

	North Atlantic Region	National (e.g. Domestic Content)	Discussion
Other Miscellaneous	0%	0%	
Operation and Maintenance			
Labor			
Technician Salaries	95%	95%	The O&M plan analyzed – discussed in Section 4.3.9 – assumes land-based staff service the facility.
Monitoring & Daily Operations Staff & Other Craft Labor	95%	95%	
Administrative	95%	95%	
Management/Supervision	0%	95%	Similar to U.S. land-based wind plants, it was assumed that management staff will be located at a central location and manage several wind farms.
Materials and Services			
Water Transport	95%	95%	These services will primarily be provided from the servicing port and surrounding area.
Site Facilities	95%	95%	
Machinery and Equipment	95%	95%	
Subcontractors	95%	95%	
Corrective Maintenance Parts	0%	25%	These are primarily related to the nacelle and drivetrain, so the same domestic content as above was assumed.
Financing			
Debt Financing	0%	0%	Most debt financing will likely come from European banks in the near term.
Equity Financing/Repayment			
Individual Investors	0%	0%	N/A – All equity is likely to come from corporations.
Corporate Investors	0%	50%	Assuming the production tax credit is available, U.S. entities will need to provide equity because a tax liability is required. However, it is uncertain as to how the interest (e.g., profit) will be reinvested. The Navigant Consortium assumed only 50% stays in the U.S. economy.
Tax Parameters			
Property Tax	100%	100%	By definition, these are local taxes.
Sales Tax	100%	100%	By definition, these are local taxes.

	North Atlantic Region	National (e.g. Domestic Content)	Discussion
Other Local Taxes	100%	100%	By definition, these are local taxes.

4.3.11 Cost Projections

Based on existing literature, we assume installed costs decrease 30% by 2030.

To project how offshore wind costs will evolve over time, the Navigant Consortium used information from NREL's recent *Renewable Electricity Future's Study* (NREL 2012) as well as data from Tegen et al. (2012). The latter NREL study completed a comprehensive literature review of offshore wind cost projections. NREL normalized other study's results to a consistent starting year and LCOE and compared all the studies. For this study, the median cost projection was chosen, with annual cost declines shown in Table 4-5. The cost declines were applied to both capital and O&M costs for plants built in that year.

Table 4-5. Projected Capital and O&M Cost Declines for New Plants

Year	Cost Reduction Over Prior Year
2016	-3.7%
2017	-3.7%
2018	-2.8%
2019	-2.8%
2020	-2.8%
2021	-2.8%
2022	-2.8%
2023	-2.1%
2024	-2.1%
2025	-2.1%
2026	-2.1%
2027	-2.1%
2028	-1.5%

4.4 *Modeling*

4.4.1 Background on JEDI Models

NREL has developed a set of input/output models known as the Jobs and Economic Development Impacts (JEDI) models. These models rely on the widely recognized and well known I/O multiplier data provided by the Minnesota IMPLAN Group. Offshore wind is the latest addition to this suite, which already includes biofuels, coal, concentrating solar power, natural gas, solar photovoltaics, wind, and marine/hydrokinetic power.[67] As part of this project, we created an offshore wind specific model. Please refer to 1.4.7Appendix D**Error! Reference source not found.** for more information on the JEDI models.

4.4.2 Offshore JEDI Model

JEDI requires detailed estimates of project expenditures and the share of each individual expenditure line item that is procured locally. These data must be developed for both the construction and operations period of the plant life cycle. As offshore wind is only a nascent industry in the U.S. and no projects have been completed in the U.S., the Offshore Wind JEDI model relies on projected costs for individual project elements.

Specific line item expenditures were developed internally by the Navigant Consortium and based on the available public literature, historical experience in Europe, supplier bids for specific project tasks, and informal discussions with various industry players. To our knowledge, the cost estimates employed here represent the best available estimate of current costs for the specific project outlined in Section 4.3.2. Nevertheless, they are projections based on a hypothetical project. Cost inputs are intended to be representative of a project built in the 2018 timeframe; however, to a large extent they are informed by today's prices (e.g., current commodity prices and vessel day rates). Actual projects will have varying costs (and subsequently varying results) depending on a wide variety of factors including project commercial operation date, project location, seabed conditions, water depth, available local labor, available local goods and services, future wind turbine prices, and commodity prices at the time of construction among other factors.

Table 4-6 summarizes the current construction period cost inputs. At nearly 30% of total capital cost, the turbine represents the single largest line item during the construction period. Other significant line items include the foundation and substructure (labor alone represents 16%, material is an additional 5%),[68] the HV cable and electrical infrastructure required to move the power from the project to the grid (15%), and erection and installation (6%). Constituting roughly 3-5% of capital costs each, miscellaneous line items including interest during construction, due diligence, decommissioning bonding, and the required reserve accounts are also non-trivial.

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[67] NREL's JEDI models are publicly available spreadsheet tools that apply state-specific IMPLAN year 2010 multipliers. The JEDI analysis tools were developed by NREL in conjunction with MRG & Associates. For more information on the JEDI tools, see http://www.nrel.gov/analysis/jedi/.

[68] This hypothetical project relies on jacket structures that are particularly labor intensive relative to other potential foundation and substructure systems; however, their space frame design uses significantly less material. Labor costs here assume a one-off project rather than a mature, rationalized production and fabrication process.

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Table 4-6. JEDI Modeling Construction Period Cost Inputs

	Cost	Cost Per KW	Percent Of Total Cost
Equipment Costs			
Turbine Costs	$917,500,000	$1,835	29.8%
Foundation & Substructure	$149,500,000	$299	4.9%
Collection System	$78,490,000	$157	2.6%
HV Cable, Converter, & Substations	$465,250,000	$931	15.1%
Labor Costs[1]			
Foundation & Substructure Installation Labor	$510,964,750	$1,022	16.6%
Project Management (Developer/owners management costs)	$8,547,760	$17	0.3%
Development Costs			
Insurance During Construction	$67,000,000	$134	2.2%
Development Services (Engineering, Legal, PR, Permitting)	$28,900,000	$58	0.9%
Ports & Staging	$125,000,000	$250	4.1%
Erection/Installation (equipment services only)	$189,231,600	$378	6.2%
Air & Marine Transportation	$29,755,250	$60	1.0%
Other Costs			
Decommissioning Bonding	$100,000,000	$200	3.3%
Interest During Construction	$162,695,880	$325	5.3%
Due diligence, Reserve Accounts, Bank Fees	$160,636,060	$321	5.2%
Miscellaneous	$17,394,000	$35	0.6%
Total Construction Cost[2]	**$3,010,865,300**	**$6,022**	**97.9%**

[1]Labor costs reported independently only for those line items for which labor could be isolated; for other expenditures involving significant labor such as substation installation, it was assumed that 30% would be a direct labor expenditure.

[2]Total does not equal 100% due to the exclusion of sales tax, which is likely to be assessed against capital goods and materials and is estimated at approximately 2% of total project capital cost.

Table 4-7 summarizes annual expenditures during the operations period. During operations the predominant line item expense is the estimated average expenditure on replacement parts and equipment. In reality such costs may not dominate in any individual year; however, replacement costs could be substantial (i.e., well in excess of 50%) during years in which major equipment replacements are necessary. As this project is assumed to be serviced from a land-based port approximately 25 miles away, transportation to and from the facility is also a significant annual operations period expenditure, making up about 20%. Utilities and maintenance of the land-based infrastructure including the interconnection substation as well as an operations facility represent about 10% of annual expenses. Total labor costs are also about 10% of average annual expenditures.

Table 4-7. JEDI Modeling Operations Period Cost Inputs

	Cost (Annual)	Cost Per KW (Annual)	Percent of Total
Labor			
Technician Salaries	$2,700,000	$5.40	4.0%
Administrative	$500,000	$1.00	0.7%
Management/Supervision	$2,400,000	$4.80	3.5%
Materials and Services			
Water Transport	$14,000,000	$28.00	20.6%
Site Facilities	$7,000,000	$14.00	10.3%
Machinery and Equipment	$3,000,000	$6.00	4.4%
Subcontractors	$4,500,000	$9.00	6.6%
Corrective Maintenance Parts	$32,500,000	$65.00	47.8%
Sales Tax (Materials & Equipment Purchases)	$1,420,000	$2.84	2.1%
Total Operations Expenditures	**$68,020,000**	**$136**	**100.0%**

4.4.3 Benchmarking

Initial JEDI estimates suggest that the hypothetical 500 MW facility described above and completed in 2018 would support about 3,000 FTE in the North Atlantic region during the project construction period and about 315 FTE in the North Atlantic region during operations. This equates to an average of about 6 FTE per installed MW (during the construction period) and about 0.6 FTE per operating MW (during the operations period). Based on the regional content estimates detailed in Section 4.3.10, about 40% of construction period effects are in the supply chain and more than 50% of operation period effects are a result of supply chain activity and local government revenues. Examining this same project's effect on the national economy using the higher domestic content estimates shown in Table 4-2 and national I/O multipliers estimates suggests that nationally the project could support nearly 34 jobs per MW during construction and more than one job per MW during operations. These two sets of numbers can be compared with a series of prior studies using various methodologies and analytical approaches.

In 2009, EWEA compiled an extensive dataset of employment in the wind industry. EWEA relied on direct industry surveys as well as I/O data to determine the total direct and indirect wind industry employment throughout the EU. These data were predominantly representative of land-based industry as there were less than 2 GW of offshore wind capacity (as compared with 55 GW of land-based capacity) during the period in which EWEA collected their data. However, as Europe had a highly mature wind industry supply chain, they provide a comprehensive view of the industry with effectively 100% local (EU) content. The results of this study are shown in Table 4-8 and illustrate that development and construction supported approximately 15 FTE per MW of completed capacity. The bulk of employment from construction- related activities was in direct and indirect manufacturing. Approximately 0.33 FTE were supported by direct O&M activity while a total of 0.40 FTE direct and indirect workers were supported by all operations period expenditures. More recently, EWEA has asserted that offshore wind is “between 2.5 and three times more labor intensive than land-based wind energy,” suggesting that offshore wind could support even more FTE during both construction and operations (EWEA, *Green Growth* 2012).

Table 4-8. EWEA Estimated European Wind Energy Jobs

Employment Category	Jobs/Annual MW	Jobs/Cumulative MW	Basis
Wind Turbine Manufacturing – Direct	7.5		Annual
Wind Turbine Manufacturing – Indirect	5.0		Annual
Installation/Construction	1.2		Annual
Operations and Maintenance		0.33	Cumulative
Other Direct Employment[69]	1.3	0.07	75% Annual, 25% Cumulative
Total Employment	15.1	0.40	

Source: EWEA, *The Wind at Work* 2009

In March 2012, Bloomberg New Energy Finance (BNEF) released its updated wind and solar industry employment estimates with data specific to the offshore industry. BNEF estimates are somewhat atypical in that they rely not on models but on project-specific labor requirements and employment levels at OEMs, potential suppliers, and industry service providers. In this sense, they are robust estimates of the industry as narrowly defined by BNEF (see Table 4-9) but miss significant portions of the supply chain impact and other indirect effects and completely exclude induced impacts. For example, operations jobs are limited to on-site technicians only and foundation production employment is calculated from labor estimates at primary steel producers such as Tata Steel, rather than from companies who may be fabricating and assembling jacket structures. Nevertheless, as a point of reference BNEF’s offshore wind results are shown in Table 4-9. From this assessment, development and construction activities are

[69] Including IPP/utilities, consultants, research institutions, universities, financial services, other

estimated to support approximately 17 FTE per installed MW, again with the significant majority of these jobs being in manufacturing. Operations activities are estimated to support 0.17 FTE per MW of operating capacity. Notably, these estimates are 55% and 70% higher than the BNEF estimates for land-based wind.

Table 4-9. BNEF Estimated Offshore Wind Energy Jobs in 2011

Employment Category	Jobs/MW
Manufacturing Turbines	11.7
Construction	2.4
Manufacturing Materials	1.2
Cables and OHVS	1
Project Development	0.65
Operation	0.17
Financial Services	0.1

Source: Bloomberg New Energy Finance (2012)

Although not directly comparable to estimates from JEDI, these two data sources are noteworthy in that they represent total potential direct and, to some extent, indirect employment in the wind industry as a whole. Accordingly, these estimates likely represent a lower bound on what might reasonably be expected given very high (e.g., 100%) levels of local content. In addition, they illustrate the general distribution of labor requirements. From these data, one can observe that if only construction is assumed to be local then wind industry employment would be between 1.2 and 2.4 jobs per MW. Simply adding in manufacturing would make this number jump to 13.7 and 15.3 jobs per MW, respectively. Were a comprehensive evaluation of the supply chain included in these two datasets, adding in manufacturing would result in an even more sizable jump in impact per installed MW.

Along with these two datasets, a handful of additional studies have been evaluated for the sake of comparing with our initial JEDI results. The construction period results from four additional studies are shown in Table 4-10. The operations period impacts from eight additional studies are shown in Table 4-11. These data suggest the possibility for very broad-ranging impacts during construction and variable but more consistent impacts during operations.

Table 4-10. Construction Period Employment from Prior Input-Output Analyses

Study	Estimated Total Construction Period FTE/MW
Global Insight (2003)	1.4 – 2.4
Ladenburg et al. 2005 (Horns Rev)[1]	12.7
Ladenburg et al. 2005 (Nysted)[1]	12.3
Flynn and Carey (2007)	2.0 – 3.7
Conference Board of Canada (2010)	25 – 29

[1]Includes estimated direct and indirect effect only.

Table 4-11. Operations Period Employment from Prior Input-Output Analyses

Study	Estimated Total Operations Period FTE/MW
Global Insight 2003	0.37
Flynn and Carey 2007	0.20 - 0.33
Ladenburg et al. 2005 (Horns Rev)[1]	0.54
Ladenburg et al. 2005 (Nysted)[2]	0.11
Bain & Co (2008)	0.34
The Carbon Trust (2008)	0.27 - 0.36
Conference Board of Canada (2010)	0.3
Oxford Economics (2010)	0.28 - 0.43
Renewable U.K. (2011)	0.34 - 0.38

[1]Includes estimated direct and indirect effects
[2]Includes estimated direct on-site effects only

The range of impacts observed during construction varies from just over 1 FTE to nearly 30 FTE per installed MW. Impacts during operations are estimated to range from 0.11 FTE per MW to 0.54 FTE per MW. The wide range of impacts can, in part, be explained by differences in analysis design; for example, reporting only direct and indirect impacts as opposed to direct, indirect, and induced impacts. After controlling for changes in analysis design and reporting, the variability of the results is largely a function of different assumptions around key variables such as time period, level of economic analysis (e.g., direct, indirect, and induced) and local sourcing assumptions.

As suggested by both the EWEA (*The Wind at Work* 2009) and BNEF (2012) data above, the location of the manufacturing is the single most critical variable in explaining differences in the results that occur during the construction period. If manufacturing occurs within the region of interest, the total (direct, indirect, and induced) impacts increase substantially. Initial JEDI analysis focused on the construction period and examined regional content levels ranging from 7% to 45% and found that they resulted in an increase in construction period impacts from 3 FTE to 14 FTE. Such an increase was observed largely as a result of simply increasing the share of turbine towers and foundations that were sourced from within the region.

Total costs are also important. In *Global Insight's* (2003) study of the impacts of the Cape Wind project, the installed cost was estimated at $1,670 per kW, nearly one-quarter of the estimated costs for projects today (Table 6, Tegen et al. 2012; BNEF 2012). All else equal, this alone would result in a substantially lower employment impact than would be expected for today's projects. Moreover, Global Insight assumed that many of the major components could not be sourced in the United States; only 25% of the manufacturing jobs would accrue in-state. In this instance, it was a combination of extremely low installation costs (although not completely out of line with expectations at the time the study was completed) and limited local manufacturing that resulted in estimates of only 1.4 to 2.4 FTE per installed MW during construction. The 2007 study by Flynn and Carey, which examined impacts to the state of South Carolina from a 500 MW facility across an array of local content levels, came to similar conclusions for the same reasons. Flynn and Carey assumed total installed costs of only $1,460 per kW; however, they considered sensitivities with up to 100% local content, which largely explains why their results at the upper end of their range are as much as 50% greater than those of Global Insight.

More recent research — such as that of the Conference Board of Canada (CBOC), which relies on relatively comparable installed costs ($4,300/kW) and generous local content assumptions of 55% to 63%, the latter of which are a result of Ontario's local content requirements—found results roughly an order of magnitude greater than anticipated in the earlier work by Global Insight and Flynn and Carey. By adjusting the inputs in the JEDI model to align with the more optimistic assumptions considered by the CBOC, the JEDI model estimated approximately 27 FTE per MW. This result is quite consistent given likely differences in underlying multiplier data and other less significant assumptions. With a state/regional range of estimated construction period impact from 3 FTE per MW up to 27 FTE per MW, the JEDI model appears capable of generally replicating the range of construction period results projected by past work. JEDI's national estimate of approximately 34 FTE per MW is somewhat higher even than the CBOC estimate, but is also likely affected by slightly higher installed costs applied in JEDI, relatively high local content estimates for the national scenario given the full U.S. economy to draw from, and relatively large national multipliers, which reflect a slower rate of leakage in the U.S. economy as a whole when compared to individual states or regions.

As the total operations period annual investment is substantially lower than what occurs during the construction period, the total impacts are lower and there is less potential for variability in the assumptions employed across the various analyses. O&M cost estimates have increased over time, but their growth has been much slower than total installed costs. The result is that even across time there is greater consistency in the estimated operations period employment impacts. The majority of studies completed to date suggest ongoing direct O&M labor impacts are approximately 0.1 FTE to 0.3 FTE per

MW of operating capacity. When examining the total impacts the range in the literature is estimated at 0.27 FTE to 0.54 FTE per MW.

Initial JEDI results are actually slightly higher than this range with a regional estimate of just over 0.6 FTE per MW; JEDI's national estimate is even greater, in excess of 1 FTE per MW. The most likely explanation for the relatively high impact estimated by JEDI is higher O&M costs than have been applied in the past. JEDI justifies its assumed higher operations expenditures in two ways: 1) historical estimates for O&M expenditures have been proven to be optimistic both for land-based and offshore installations and 2) offshore facilities in the U.S. will likely be further from shore than the European projects that have been analyzed to date, suggesting higher logistics and transportation costs. An additional factor is that JEDI captures the impacts of local government revenues in the form of property tax and sales tax, which would also boost total JEDI operations period employment relative to those studies that look exclusively at the impacts within the industry itself. National estimates of operations period impacts are again boosted by higher domestic content relative to regional content and slower leakage overall from the national economy, but are also increased as a result of the capture of a portion of project-related revenues in the form of payments to domestic equity shareholders.

In summary, JEDI results are expected to be greater than early studies such as Global Insight (2003) and Flynn and Carey (2007) due primarily to significant differences in installed cost inputs and more modest differences in O&M cost inputs. JEDI results are also expected to be greater than EWEA (*The Wind at Work* 2009) and BNEF (2012) in cases where there is high domestic content because of the fact that JEDI captures impacts in the wind industry, in the full supply chain, and in induced impacts. However, for individual regions JEDI is expected to be somewhat more conservative than the estimates generated by the CBOC (2010) due largely to different assumptions about what can be locally sourced. Estimated national impacts will likely be higher than most other analyses due to the larger economy from which to draw from for project-level resources, as well as the larger national multipliers that reflect slower rates of economic leakage from the domestic economy as a whole.

Our results compare well with other work, given our higher assumed costs.

Although there are some key differences between initial JEDI results and the literature, the ability of the JEDI model to generally replicate the range of impacts shown in the literature during the construction period, and to be comparable to the upper end of the reported range for O&M impacts, indicates that the model is broadly consistent with prior work. This suggests that JEDI offers a robust starting point for both regional and national employment impacts analysis from offshore wind. Into the future, continued refinement of both the cost inputs and local content estimates will increase the ability of the model to reflect what occurs in the industry as it evolves and matures.

4.5 Projected Economic Impacts

4.5.1 Methodology

The Navigant Consortium used the JEDI model and the information discussed above to project the economic impacts of offshore wind development out to 2030 for the North Atlantic region and the U.S.

as a whole. For each year of analysis, projected costs and the percentage local assumptions discussed above were inputted and the JEDI model reported local employment and investment impacts.

4.5.2 Market Forecast

In order to project the employment impacts of offshore wind deployment over time, the Navigant Consortium needed an estimate of annual installations going forward. As part of Navigant's other DOE offshore work (Navigant 2012), the team developed three scenarios for offshore wind growth. The high-growth scenario was based on total offshore capacity expected under DOE's 20% Wind Energy by 2030 report (54-GW aggregate demand by 2030). Moderate and low-growth targets were selected to help isolate effects of aggregate demand changes. The team formulated annual capacity addition assumptions for each of four regions, relying on several inputs:

- Regions' reliance on enabling technologies (e.g., floating foundations, de-icing)
- Currently planned projects in each region
- Historical growth trends in the European offshore and U.S. land-based markets
- Supply chain ramp-up expectations

The Navigant Consortium selected five regions to analyze: North Atlantic Coast, South Atlantic Coast, Great Lakes, Gulf Coast, and Pacific Coast, with the results shown in Table 4-12.

Table 4-12. Annual Installation Scenarios

Scenario Name	54GW by 2030 High-Growth-High-Tech Scenario		28GW by 2030 Moderate Growth with High-Technology Adoption		10GW by 2030 – Low-Growth – Low-Tech Scenario	
	2020	**2030**	**2020**	**2030**	**2020**	**2030**
Total Capacity Deployed by Milestone Date (GW)	**7.0**	**54.0**	**3.5**	**28.0**	**1.0**	**10.0**
Regional Distribution						
North Atlantic	2.5	18.0	1.6	9.8	0.8	6.3
South Atlantic	1.5	10.0	0.4	2.2	0.2	1.7
Great Lakes	1.0	6.0	0.5	4.0	0.0	1.0
Gulf Coast	1.0	5.0	0.5	4.0	0.0	1.0
Pacific Coast	1.0	15.0	0.5	8.0	0.0	0.0

4.5.3 Results

Individual project

Local impacts of the reference project described in Section 4.3.2 were first reviewed with the local sourcing assumptions outlined in Table 4-4. Table 4-13 shows the results and the plant would support ~3,500 job-years over the construction period and drive $652M in local spending over the same period. During operation, the plant (and the resulting local impacts) would support 284 jobs each year in the local economy and $50M in local spending. However, these numbers are strongly dependent upon the percentage local assumptions and would increase by three to fourfold if all components and services were sourced from the region.

Our reference project would support 3,500 job-years and drive $652M in local spending.

Table 4-13. JEDI Outputs for a 500 MW Plant in the North Atlantic, Completed in 2018

Output	Jobs[FTE]	Investment [$2011M]
During Construction		
Project Development and On-site Labor Impacts	854	$246
Construction and Interconnection Labor	405	
Construction-Related Services	450	
Turbine and Supply Chain Impacts	1,454	$248
Induced Impact	1,182	$158
Total	3,490	$652
During Operation (Annual)		
On-site Labor Impacts	28	$3
Local Revenue and Supply Chain Impacts	174	$37
Induced Impacts	79	$1
Total	284	$50

Employment impacts

Figure 4-2 shows the national employment that could be supported each year by the U.S. offshore wind industry under each market scenario from Table 4-12 and the domestic and local content assumptions discussed in the appendix. Employment impacts are not seen until 2015 in all scenarios because that is when construction is expected to start. In the high-growth scenario, the U.S. offshore wind industry could support ~350,000 FTEs by 2030 (or ~70,000 FTEs by 2020), but in the low-growth scenario, it would be ~50,000 by 2030 (or ~7,000 by 2020). Given the supply chain and industry dynamics of the offshore wind industry, most jobs are in indirect and induced industries, shown in Figure 4-3. These results are strongly dependent on the domestic sourcing assumptions shown in Table 4-4 and discussed in Appendix D. If more components and services were sourced domestically, these results would be higher.

Figure 4-2. Annual U.S. Employment Supported by the U.S. Offshore Wind Industry

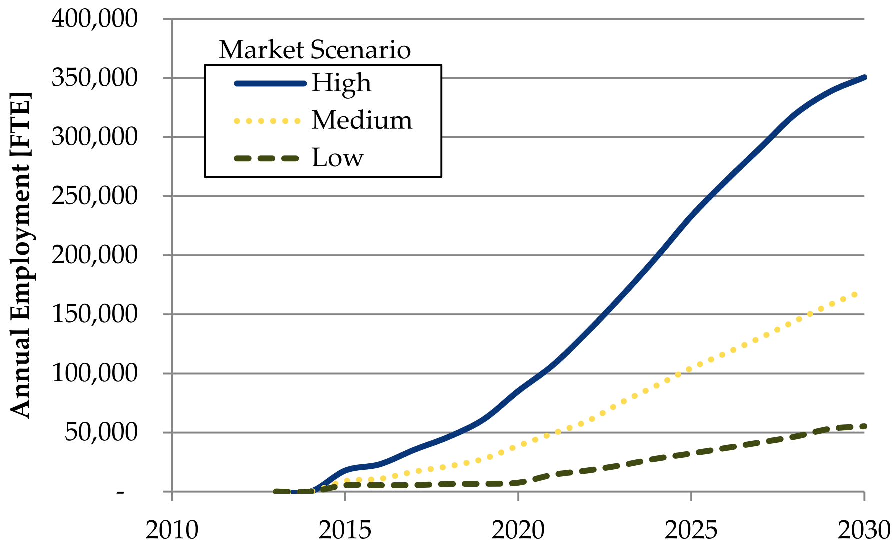


Figure 4-3. Distribution of Job Type for the High- Growth Scenario

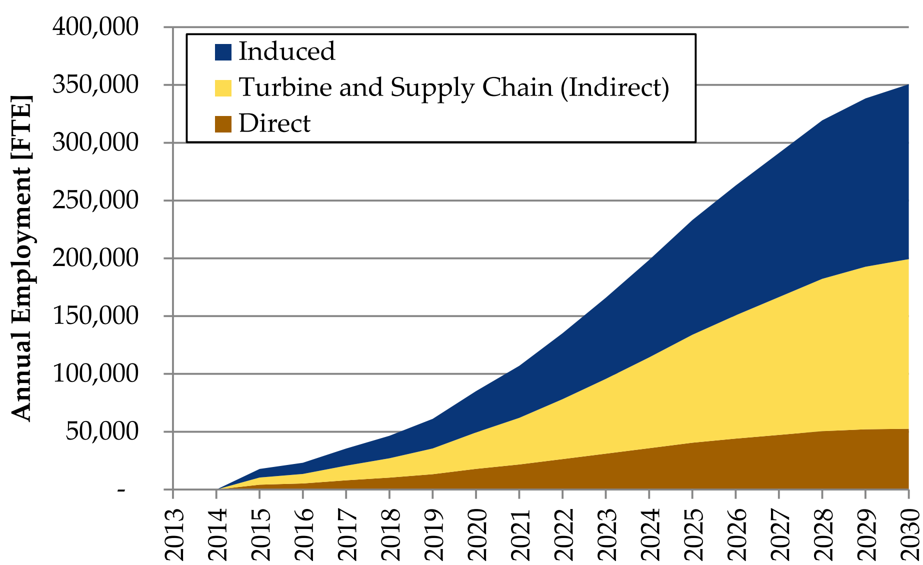
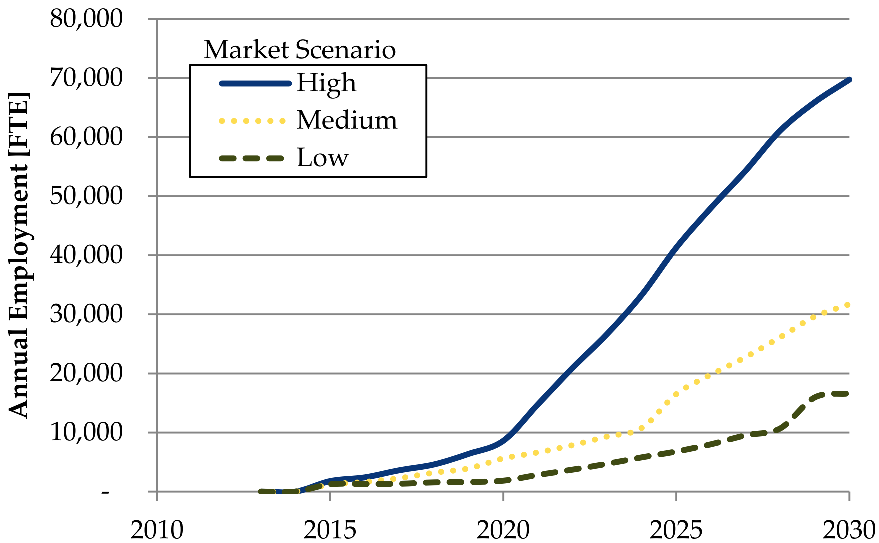


Figure 4-4 shows results for the North Atlantic region over the same time period. By 2030, construction and operation of offshore wind plants in the region could support ~70,000 FTE's in the high case and ~17,000 FTE's in the low case. These results are strongly dependent on the local sourcing assumptions shown in Table 4-4. If more components and services were sourced locally, the numbers could increase by three to fourfold based upon extra modeling we conducted.

Figure 4-4. Annual Regional Employment Supported by Offshore Wind Activity in the North Atlantic Region



Economic activity impacts

Figure 4-5 shows the national economic activity—meaning expenditures on components and services—that could be supported each year by the U.S. offshore wind industry under each market scenario from Table 4-12. Economic impacts are not seen until 2015 for all scenarios because that is when we expect construction to start. In the high-growth scenario, the U.S. offshore wind industry could drive $70B (in 2011 dollars) a year by 2030 but in the low-growth scenario it would be ~$10B. Given the supply chains and industry dynamics of the offshore wind industry, most of the economic activity is in indirect and induced industries, shown in Figure 4-6. These results are strongly dependent on the domestic sourcing assumptions shown in Table 4-4. If more components and services were sourced domestically, these results would be higher.

Figure 4-5. Annual U.S. Economic Activity Supported by the U.S. Offshore Wind Industry

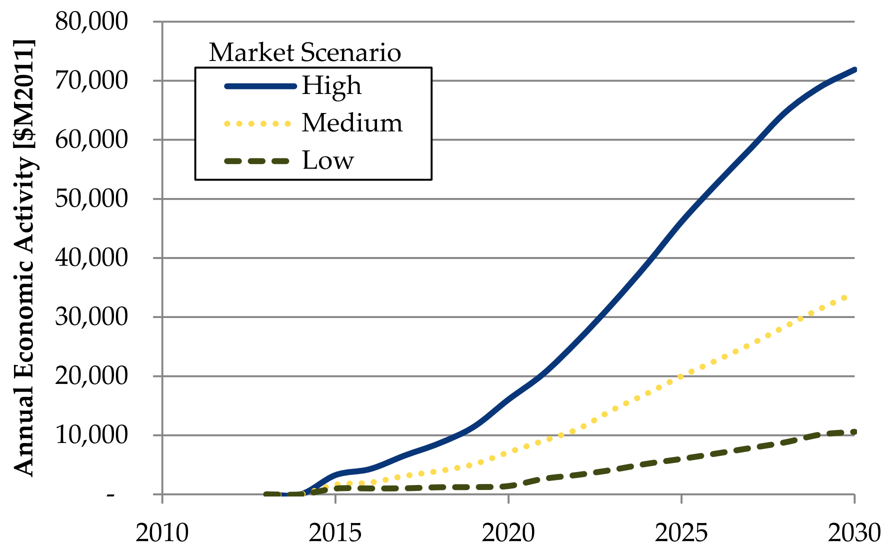


Figure 4-6. Annual Economic Activity by Supply Chain Area for the High- Growth Scenario

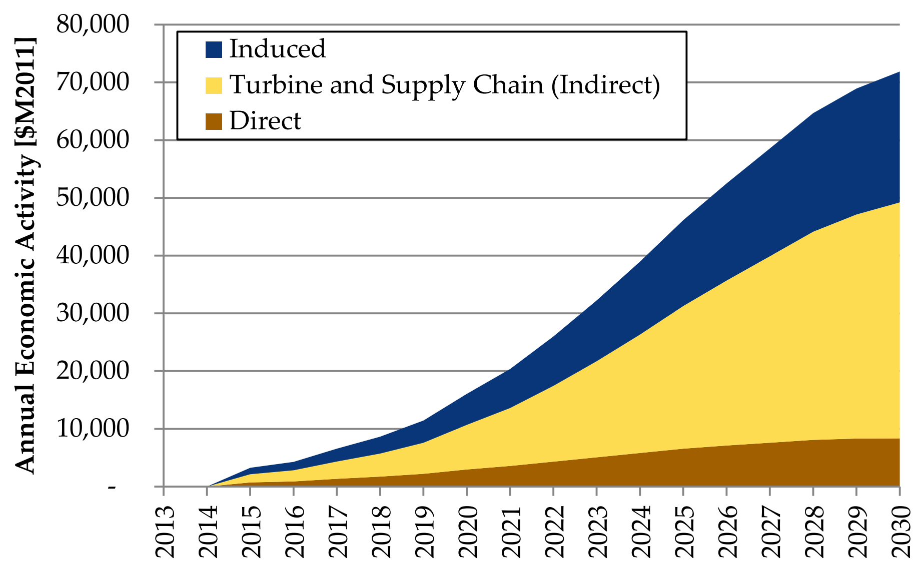
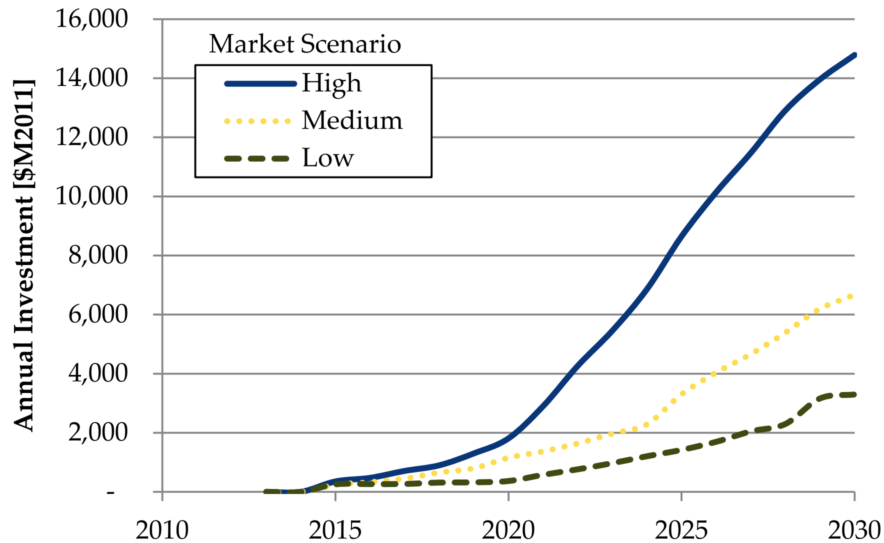


Figure 4-7 shows results for the North Atlantic region over the same time period. By 2030, construction and operation of offshore wind plants in the region could drive $14B/Year in the high case and $3.5B/Year in the low case. These results are strongly dependent on the local sourcing assumptions shown in Table 4-4. If more components and services were sourced locally, the numbers could increase by three to fourfold.

Figure 4-7. Annual Regional Economic Activity Supported by Offshore Wind Activity in the North Atlantic Region



4.6 *Next Steps*

We will survey the industry next year to see if growth is happening relative to our projections. This is dependent upon construction moving forward on any projects.

5. Developments in Relevant Sectors of the Economy

5.1 Introduction

The development of an offshore wind industry in the U.S. will depend on the evolution of other sectors in the economy. This section identifies and evaluates the related economic sectors and their potential impact on an offshore wind industry.

Summary of Key Findings – Chapter 5

- The development of an offshore wind industry in the U.S. will depend on the evolution of other sectors in the economy.
- Two factors in the power sector will have the largest impact: (1) the change in the price of natural gas, and (2) the change in coal-based generation capacity.

We categorize two types of potential impact: demand for offshore projects and the price of those projects. Table 5-1 summarizes the related economic sectors and their potential impact on offshore wind.

Table 5-1. Factors That Impact Offshore Wind

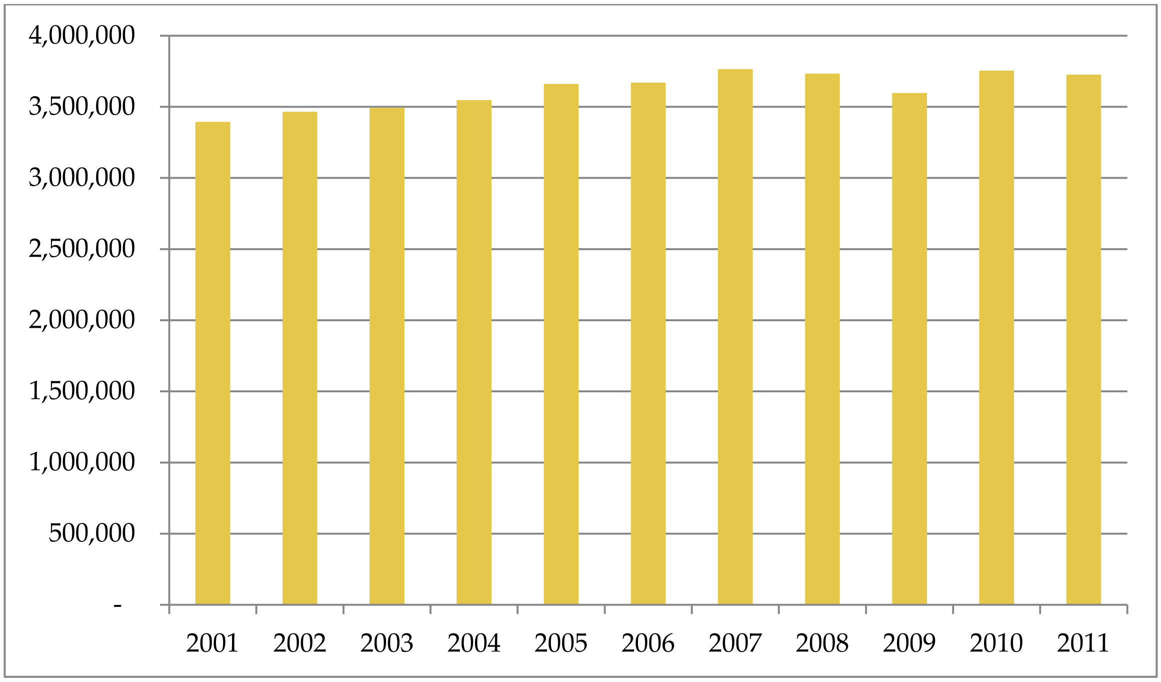
Economic Sector	Factor	Potential Impact on Offshore Wind: Change in Demand	Potential Impact on Offshore Wind: Change in Price	Relative Importance of Factor
Power sector	» Change in overall demand for electricity.	X		Low
	» Change in the country's nuclear power generation capacity.	X		Medium
	» Change in natural gas prices.	X		High
	» Change in the country's coal-based generation capacity.	X		High
Oil and gas	» Change in level of offshore oil and gas development.		X	Medium
Construction	» Change in level of construction activity using similar types of equipment and/or raw materials as offshore wind.		X	Low
Manufacturing	» Change in manufacturing of products that utilize similar types of raw materials as offshore wind.		X	Low
Telecommunications	» Change in demand for subsea cable-laying vessels.		X	Low
Financial	» Change in the cost of capital.		X	Medium

5.2 *Power Sector*

5.2.1 Change in Overall Demand for Electricity

Factors such as population growth, changes in the level of economic activity, adoption of energy efficiency and demand response measures, and changes in climate could change the overall demand for electricity in the U.S. This, in turn, could impact the demand for offshore wind projects in the U.S. That said, electricity consumption in the U.S. has increased, on average, less than 1% per year over the last decade (see Figure 5-1). Significant increases in electricity consumption are unlikely in the foreseeable future due to moderate levels of economic growth and population growth as well as increasing levels of energy efficiency.

Figure 5-1. U.S. Retail Electricity Sales: 2001-2011 (million kWh)



Source: EIA

5.2.2 Change in the Country's Nuclear Power Generation Capacity

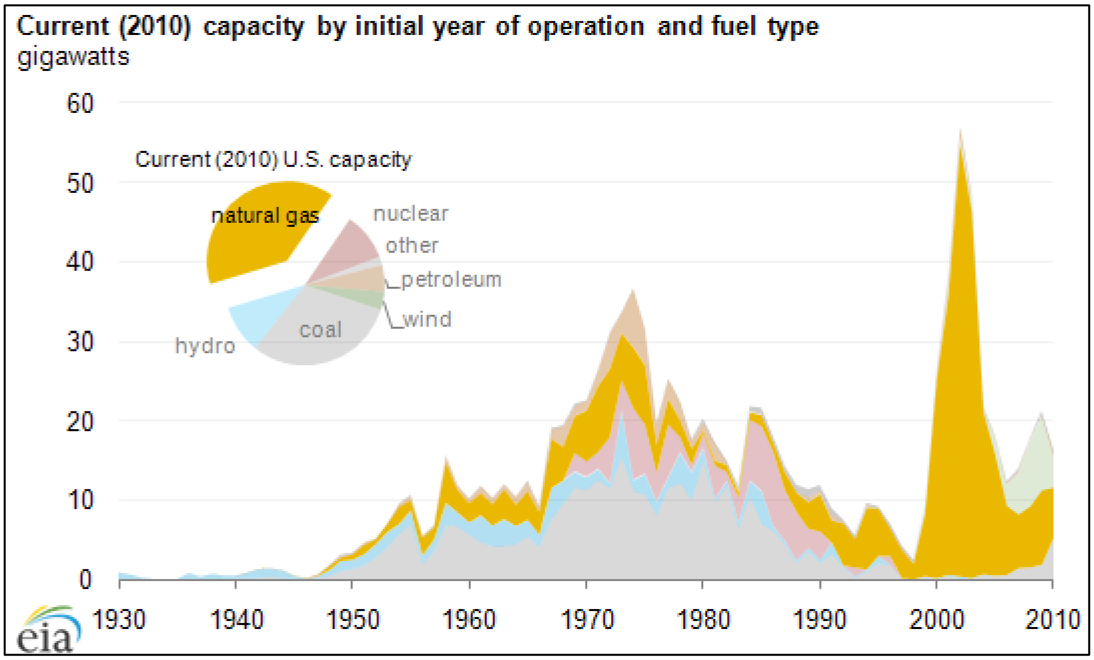
After the Fukushima nuclear accident in Japan, Germany decided to abandon over 20 GW of nuclear power, closing eight plants immediately with the remaining nine plants set to close by 2022. Realizing the additional power generation capacity needed to avoid a supply shortfall, the country has developed and begun to execute plans to install a significant number of large offshore wind farms in the North and Baltic Seas. If another Fukushima-like incident were to occur somewhere in the world, it is at least feasible that the U.S. could contemplate a similar retreat from nuclear power. The subsequent push to make up for the shortfall could increase offshore wind development in the U.S.

Similarly, an increased pro-nuclear attitude in the U.S., potentially as a way to meet CO_2-reduction targets, could reduce offshore wind activity in the U.S. if the levelized cost of new nuclear plants were to be more attractive than that of offshore wind. In early 2012, the United States Nuclear Regulatory Commission approved the construction license for four new nuclear reactors, two in South Carolina and two in Georgia. These would be the first nuclear reactors built from scratch in the last 30 years. If these reactors are successfully completed and become operational, their impact on the future of offshore wind in the U.S. is unclear. There is also uncertainty around the expected LCOE from these new nuclear plants as the nuclear industry has not had a strong track record of meeting projected costs and schedules.

5.2.3 Change in Natural Gas Prices

Since 2000, most new power generation capacity in the U.S. has come from natural gas and wind (see Figure 5-2), partly in response to the environmental impacts of coal-fired electricity generation,

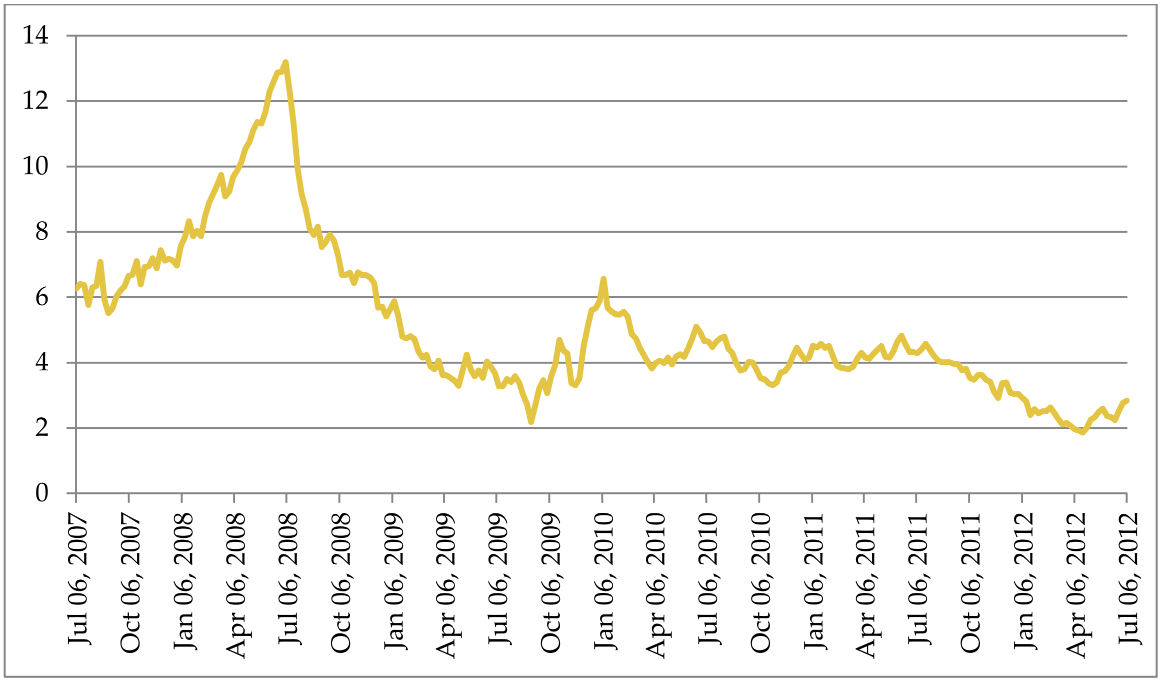
Figure 5-2. U.S. Power Generation Capacity Additions by Fuel Type



Source: EIA

As such, natural gas-fired generation is wind's primary competitor in the U.S. Natural gas prices declined from above $4/MMBtu in August 2011 to below $2/MMbtu in April 2012, in large part due to the supply of low-cost gas from the Marcellus Shale (see Figure 5-3).

Figure 5-3. Henry Hub Natural Gas Spot Price ($/MMBtu): 2007-2012



Source: EIA

This decline has reduced wholesale electricity prices as well as made natural gas-fired generation sources even more attractive than wind in many cases. Continued low natural gas prices could greatly constrain demand for offshore wind farms in the U.S. If natural gas prices were to rise significantly, however, the attractiveness of offshore wind as an electricity generation source in the U.S. could increase.

5.2.4 Change in the Country's Coal-Based Generation Capacity

In recent years, some electric utilities in the U.S. have announced plans to retire coal-fired power plants or to convert them to natural gas. According to Cleantechnica, between January 2010 and March 2012, 106 coal plant retirements had either been planned or executed.[70] This represents 319 units, with a combined capacity of 42,895 MW (13% of coal fleet) and output of 150 million MWh per year (8% of coal fleet). There are multiple factors involved in these retirement decisions. Many of the U.S.'s coal-fired power plants are over 50 years old and expensive to continue to operate and maintain. Complying with environmental requirements such as the EPA's mercury and air toxics standards can also be costly. In addition, according to the Energy Information Administration, "Delivered coal prices to the electric power sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of $2.40 per MMBtu (5.8 percent increase from 2010)" (EIA 2012). Continued coal plant retirements could increase the demand for offshore wind plants in the U.S.

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[70] http://cleantechnica.com/2012/03/05/106-u-s-coal-plant-retirements-since-2010/

5.3 Oil and Gas

5.3.1 Change in Level of Offshore Oil and Gas Development

Many of the initial installation vessels used in the offshore wind sector were retrofitted from the offshore oil and gas sector. While certain shipbuilders are designing and building custom vessels for offshore wind development, it can still be economical in some markets to upgrade vessels from the oil and gas sector. An increase in offshore oil and gas activity could limit the availability and/or increase the cost of these vessels for use in wind applications, as they may be returned to service in the oil and gas sector. Indeed, Seajacks, a vessel operator, indicates on its website that its "self-propelled vessels are suitable for installation and maintenance of offshore wind turbines, and are also able to perform maintenance work on offshore oil and gas platforms."[71] Another potential issue is that the availability of laydown area and cranes at key maritime ports could be constrained by offshore oil and gas activity. This issue, however, is not expected to be as significant in the north and mid-Atlantic as it is in the North Sea.

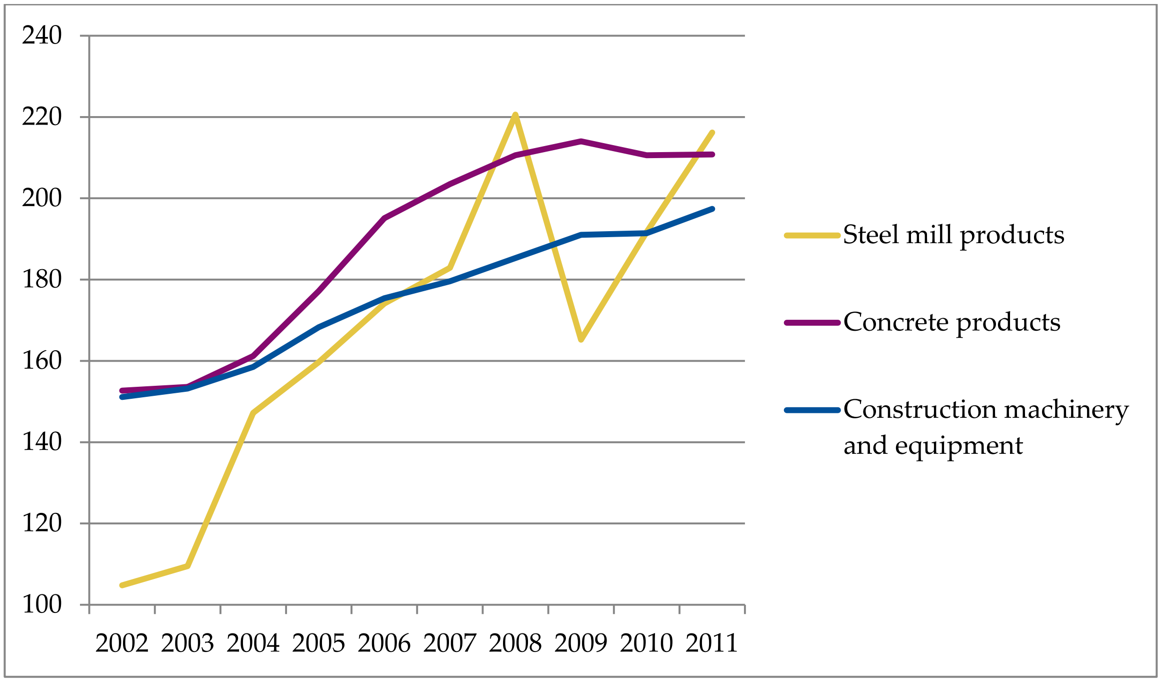
5.4 Construction

5.4.1 Change in Level of Construction Activity Using Similar Types of Equipment and/or Raw Materials as Offshore Wind

The construction sector and the offshore wind sector use many of the same types of equipment and raw materials. Construction projects such as roads, bridges, buildings, and sports stadiums require equipment such as tall cranes and materials such as concrete and steel. Cranes are needed to lift wind turbine tower segments, foundations, and to preassemble rotors onshore. Wind turbine towers require significant quantities of steel, while foundations may require concrete and/or steel. Since towers represent 7-8% of the cost of an offshore wind farm and the foundations and substructures represent 22-25% (Navigant 2012), the level of construction activity in the U.S. outside of the offshore wind sector could impact the price of offshore wind power. Figure 5-4 shows the evolution of commodity prices since 2002.

[71] http://www.seajacks.com/who_we_are.php

Figure 5-4. Producer Price Index for Selected Commodities (2002-2011)



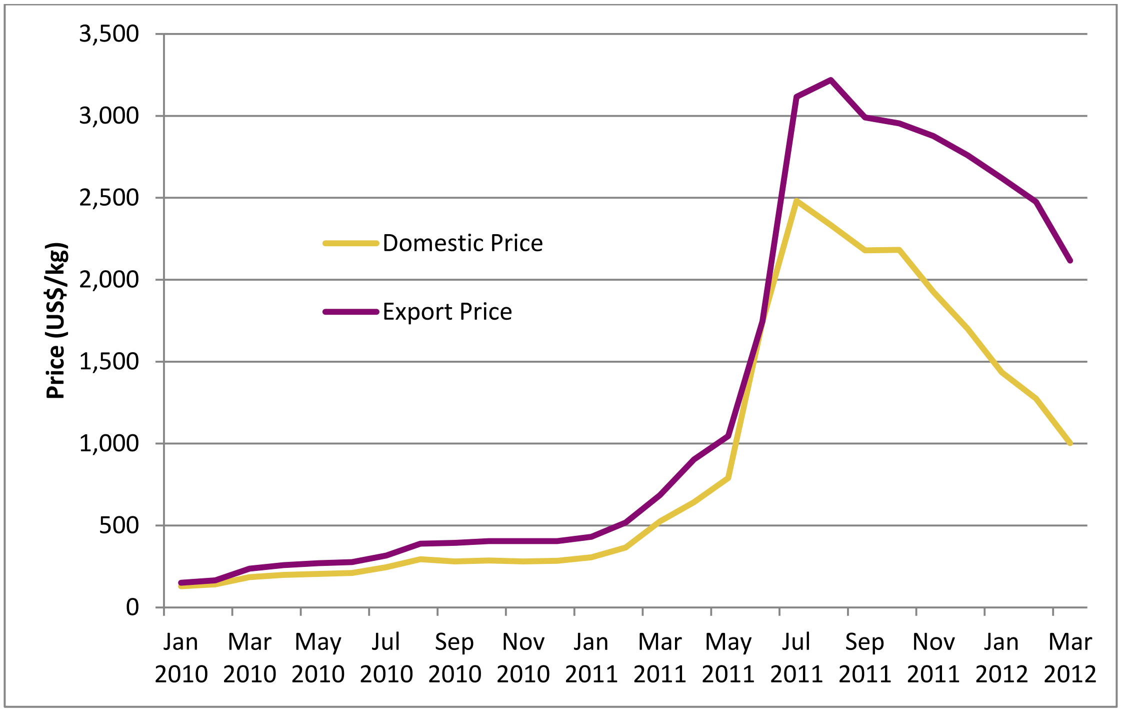
Source: United States Department of Labor, Bureau of Labor Statistics
Base Year (100) = 1982

5.5 *Manufacturing*

5.5.1 Change in Manufacturing of Products That Utilize Similar Types of Raw Materials as Offshore Wind

The manufacturing sector similarly uses many of the same raw materials as offshore wind. The manufacture of automobiles, heavy equipment, and appliances, for example, requires significant amounts of steel, a material used in wind turbine towers and offshore foundations. Manufacturing sectors such as aerospace, automotive, and marine vessels use composite materials similar to those used in wind turbine blades. Finally, rare earth materials such as Neodymium are used in applications such as the permanent magnets that are used in certain types of electric motors and electrical generators, including those in many direct drive wind turbine generators. In recent years, the price of rare earth metals such as Dysprosium has spiked dramatically (see Figure 5-5). The increase in activity in any of the mentioned manufacturing sectors could increase the demand and therefore the cost of certain raw materials needed for wind turbine production.

Figure 5-5. Domestic vs. Export Prices of Dysprosium in China



Source: Technology Metals Research

5.6 Telecommunications

5.6.1 Change in Demand for Subsea Cable-Laying Vessels

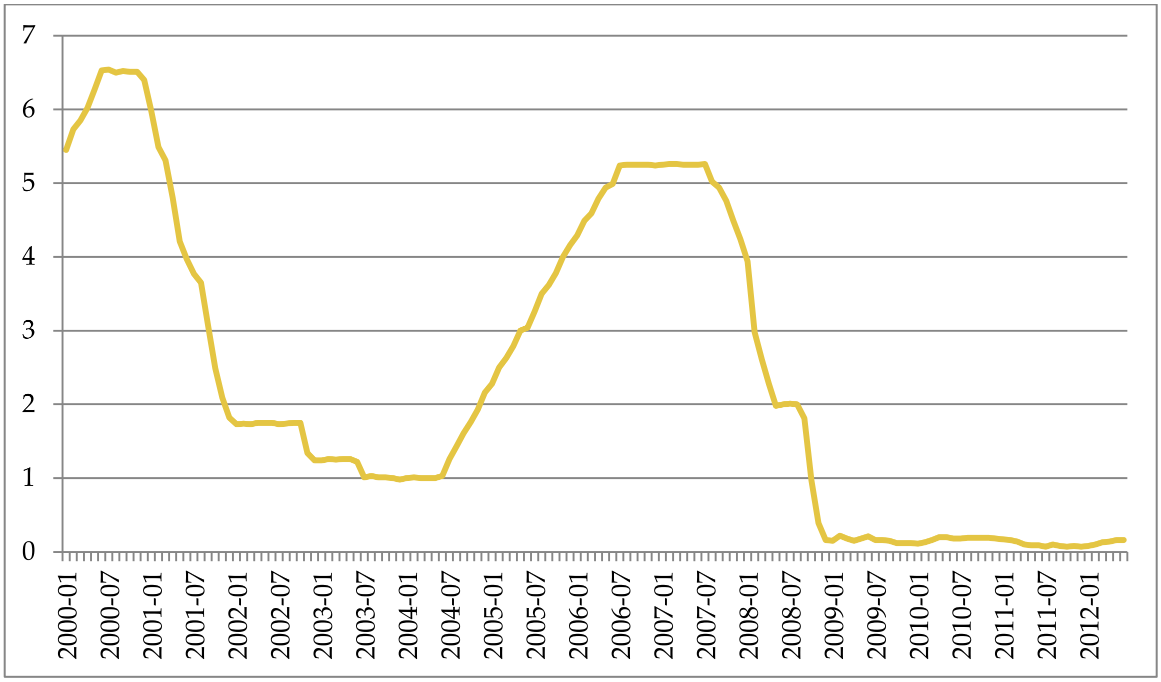
The specialized vessels that are appropriate for subsea cable-laying are relatively few in supply and high in demand (BTM 2011). Not only are these vessels high in demand in Europe for offshore wind projects, many of them are also used to lay subsea cable for the telecommunications industry. An increase in deployment of subsea cables by global telecommunications companies could increase the development costs of offshore wind farms.

5.7 Financial

5.7.1 Change in the Cost of Capital

The authors estimate that construction financing costs could represent up to 12% of the total capital costs of a 500-MW offshore wind farm in the U.S. (Navigant 2012). As a result, changes in the cost of capital can have a significant impact on the cost and price of offshore wind power. An increase in overall economic activity in the country would increase the demand for and therefore the cost of capital. Offshore wind projects would have to compete with other infrastructure projects to secure the capital necessary for development. While interest rates have been very low in recent years, the Federal Funds Rate was above 5% as recently as 2007 (see Figure 5-6).

Figure 5-6. Federal Funds Effective Rate (%): Jan. 2000 – July 2012



Source: U.S. Federal Reserve

6. Conclusion

The development of a comprehensive annual market report is an important step for the U.S. offshore wind industry for two reasons. First, market assessments, especially those produced for government agencies, provide stakeholders with a trusted data source. Second, the production of a comprehensive assessment covering technical, regulatory, financial, economic development, and workforce issues will annually inform the creation of policy to remove barriers facing the U.S. offshore wind industry.

This report provides readers with a foundation of information to help set appropriate policies to guide U.S. offshore wind energy development. As discussed in this report, significant technological advances are already unfolding within the offshore wind industry, but more could be done to direct needed improvements to further reduce offshore wind costs and to stimulate needed infrastructure development. Policy examples from other countries have shown that proper policy designs can stimulate offshore wind markets. The analysis in this report demonstrates that offshore wind markets can have a significant impact on economic development throughout the U.S. The analysis showed that in the high-growth scenario, the U.S. offshore wind industry could support ~350,000 FTEs in 2030, and 50,000 FTE in the low-growth scenario. As this report is updated and published annually for the next two more years, the Navigant Consortium team hopes that the information provided will prove to be a valuable resource for manufacturers, policy makers, developers, and regulatory agencies to move the market toward a high-growth scenario for the offshore wind industry.

The survey, interviews, and workshops that provided important inputs to this report content will be repeated each year as part of the annual data collection and dissemination process. The Navigant Consortium appreciates the input and cooperation that participants have provided and look forward to similar involvement in future installments of this report.

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Appendix A. Offshore Wind Policies in Selected U.S. States

This appendix includes details on offshore wind policies and related activities in selected U.S. states. The categories of policies to address high cost and site selection and leasing are included. A summary of policies that address high cost is provided in tabular form in Section 3.3.2.

A.1 Delaware

A.1.1 Policies to Address High Cost

In 2005, Delaware Senate Bill (S.B.) 74 established a renewable portfolio standard (RPSs) of 10% by 2019-2020. Two years later, S.B. 19 increased the target to 20%. In July 2010, the target was revised again by S.S. 1 for S.B. 119 to 25% by 2025-2026.[72]

While Delaware does not have a carve-out for offshore wind, in 2008, S.B. 328 set a 350% multiplier for the Renewable Energy Certificate (REC) value of offshore wind facilities sited on or before May 31, 2017.[73]

In 2007, an all-resource competitive bidding process was conducted in Delaware. Four state agencies including the Delaware Public Services Commission, the Office of Management and Budget, the State Controller, and the Department of Natural Resources & Environmental Control directed Delmarva Power to negotiate a long-term PPA with then Bluewater Wind. The company, which became a subsidiary of NRG Energy and was later known as NRG-Bluewater Wind, proposed to build a 450 MW offshore wind farm approximately 12 miles from the coast.[74]

In December 2011, NRG-Bluewater Wind failed to make a substantial deposit to maintain the PPA. NRG continues its efforts to obtain a lease for the site from BOEM after BOEM determined that there was no competitive interest in the site. Whoever pursues development of the site will now have to obtain a new PPA. See http://www.nrgenergy.com/nrgbluewaterwind/index.html for more details.

A.1.2 Site Selection and Leasing Policies

BOEM issued a Call for Information for Delaware projects and received two lease nominations. BOEM subsequently determined that only one bidder was qualified and thus issued a Determination of No Competitive Interest to NRG-Bluewater Wind on April 12, 2011. NRG Energy is currently negotiating lease terms with BOEM.[75]

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[72] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE06R&re=1&ee=1
[73] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE06R&re=1&ee=1
[74] http://www.usowc.org/states/de.html
[75] See http://boem.gov/Renewable-Energy-Program/State-Activities/Delaware.aspx.

A.2 Maryland

A.2.1 Policies to Address High Cost

Maryland has an RPS of 20% by 2022. In January 2012, Governor O'Malley introduced legislation to create an offshore carve-out based on offshore renewable energy credits (ORECs), similar to the system used in New Jersey. The bill, however, failed by one vote to be approved by the Senate Finance Committee this year.

Maryland issued an RFP in July to conduct initial marine surveys with state funds of the offshore Wind Energy Area identified by BOEM. Maryland plans to fund additional surveys with state funds to encourage development of the WEA by private developers after the BOEM competitive auction process.

A.2.2 Site Selection and Leasing Policies

BOEM convened a Task Force and, in November 2010, issued a Request for Interest in offshore development off the coast of Maryland. BOEM received several favorable responses and numerous comments on environmental concerns. In February 2012, BOEM issued a Call for Information for a reduced Wind Energy Area of just a few lease blocks and received ten lease nominations.[76]

A.3 Massachusetts

A.3.1 Policies to Address High Cost

The Massachusetts Department of Energy Resources (DOER) has set an RPS for new renewables of 15% by 2020. The RPS increases by 1% each year thereafter with no stated expiration date. There is no carve-out or REC multiplier for offshore wind.[77] Governor Deval Patrick has set a separate goal of developing 2,000 MW of offshore wind energy to help achieve the RPS requirements.

In 2008, the governor signed the Green Communities Act, which authorized distribution utilities to sign PPAs with renewable energy developers. The Act, as amended, requires each electric distribution company to conduct two solicitations within five years and sign PPAs for 7% of its load with renewable energy generators.

The Massachusetts Department of Public Utilities (DPU) has approved a 15-year PPA between the developers of the Cape Wind project and National Grid for half of the project's output. The PPA would start in 2013 (or later, since the project is delayed) at $0.187/kWh, with a 3.5% annual increase. The DPU concluded that the contract is cost-effective because its benefits well exceed its costs. It also found that approving the PPA is in the public interest, because no other renewable resource in the region matches Cape Wind in terms of size, proximity to large electricity load, capacity factor, and advanced stage of permitting, and because its bill impacts are in the range of only 1 to 2%.

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[76] See http://boem.gov/Renewable-Energy-Program/State-Activities/Maryland.aspx.

[77] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R&re=1&ee=1

The contract allows for upward and downward price adjustments based on a variety of contingencies. If Cape Wind is unable to tap certain federal subsidies, the price would go up, but under other circumstances the prices could go down, to the benefit of ratepayers. Specifically, should debt financing costs be reduced as a result of a DOE loan guarantee, 75% of the savings would be passed along to customers in lower rates. Similarly, if actual project costs, as verified by an independent audit, fall to such an extent that the developer's rate of return on debt and equity exceeds 10.75%, the contract price of electricity will be reduced to give ratepayers 60% of the benefit of the lower costs; if actual project costs are higher than anticipated and reduce this rate of return, the developer absorbs those losses without impact on rates paid by consumers. This mechanism in the contract assures that the developers of the project will not reap windfall profits.

The order concluded that the contract met the DPU's standard for long-term contracts under Section 83 of the Green Communities Act, as well as the Department's standard for the public interest. In terms of cost-effectiveness, the Department concluded that the costs would be outweighed by the benefits provided by the contract, namely assisting National Grid and the Commonwealth to comply with the state's renewable energy and greenhouse gas emissions reduction requirements; providing National Grid the option to extend the contract beyond 15 years at a price that covers the remaining costs of operating the facility plus a reasonable rate of return; enhancing electricity reliability in the state; moderating system peak load; and creating additional employment. The DPU observed that wind data show that Cape Wind's capacity factor would have averaged an impressive 76 percent during the region's top ten historic peak hours. It concluded further that the project will create an average of 162 jobs per year for the 15 years of the contract—but many more than that during the two-plus-year construction period.

In terms of the public interest, the DPU found that the Cape Wind project offers "unique benefits relative to the other renewable resources available." In addition, the DPU found that the contract price was reasonable for offshore wind, which the Department determined to be needed to meet state renewable energy and greenhouse gas requirements. The bill impacts that could occur as a result of the contract "are small relative to the volatility that electric customers regularly experience due to the fluctuations in wholesale electricity prices, and the contract will mitigate that volatility."[78]

The Massachusetts Supreme Judicial Court has upheld this contract on appeal, ruling that the DPU reasonably determined the PPA was cost-effective, based on the administrative record based on non-quantitative benefits of offshore wind moderating peak demand, suppressing wholesale generation prices and the proximity of such large renewable generation to load centers.

As a condition of approving the merger between Northeast Utilities and NStar, the DPU required the merged entity to purchase 27.5% of the output of the Cape Wind project. This PPA is currently under review by the DPU.

[78] The 300-plus-page DPU order is located at: http://www.env.state.ma.us/dpu/docs/electric/10-54/112210dpufnord.pdf.

Some additional lawsuits challenging environmental approvals of the project have been consolidated and remain outstanding, but Cape Wind is currently initiating final geophysical and geotechnical surveys, negotiating construction contracts, and planning to proceed with construction over the next couple of years.

A.3.2 Site Selection and Leasing Policies

BOEM convened a Task Force and in March 2011 issued a Request for Interest in a 2,000 square mile area south of Nantucket and Martha's Vineyard. After extensive negotiations with commercial fishermen, Massachusetts requested, and BOEM agreed, to cut the Wind Energy Area approximately in half. On February 6, 2012, BOEM issued a Call for Information and received ten lease nominations. On the same date, BOEM issued a Notice of Intent to Prepare an Environmental Assessment with another opportunity for public comment.[79]

A.4 Michigan

A.4.1 Site Selection and Leasing Policies

An October 2010 report of the Michigan Great Lakes Wind (GLOW) Council identified 13,339 square miles that are considered most favorable to the sustainable development of offshore wind energy. Five priority areas, known as wind resource areas (WRAs), were identified. The GLOW Council completed its tasks and disbanded in 2010. The current governor is re-evaluating offshore wind development. Similar re-evaluation scenarios are taking place in Ohio and Wisconsin, where political leadership and associated renewable energy policy shifts occurred in 2010.

A.5 New Jersey

A.5.1 Policies to Address High Cost

New Jersey has an RPS of 20.38% Class I and Class II renewables (which includes wind) by compliance year 2020-2021. The standard also includes an additional 5,316 GWh of solar-electric energy by compliance year 2025-2026. New Jersey has established a carve-out in its RPS for offshore wind based on offshore wind ORECs. However, a timeline has not been established for the OREC targets. The state's Board of Public Utilities (BPU) must define a percentage-based target to reach 1,100 MW of offshore wind capacity. Projects seeking ORECs must present a price proposal for the credits as well as a comprehensive net benefits analysis. The BPU plans to issue rules in 2012.

A.5.2 Site Selection and Leasing Policies

BOEM issued a Call for Information for New Jersey projects on April 20, 2011, and received 11 lease nominations and 16 comments on environmental issues and competing uses.[80]

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[79] See http://boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.

[80] See http://boem.gov/Renewable-Energy-Program/State-Activities/New-Jersey.aspx.

A.6 New York

A.6.1 Policies to Address High Cost

The New York Public Service Commission (PSC) has adopted an RPS of 29% by 2015. New York's RPS does not have a carve-out nor a REC multiplier for offshore wind.

In 2005, the Long Island Power Authority (LIPA) conducted a competitive bid for offshore wind but canceled the process in 2008 due to high costs projected to reach 29 cents/kWh.

In 2009, the New York Power Authority (NYPA) conducted a competitive bid for offshore wind in the Great Lakes but ended the process in 2011 due to high costs.

NYPA, LIPA, and Consolidated Edison (NYPA Collaborative) have filed an unsolicited request for a lease in federal waters off Long Island for a 350 MW offshore wind project, possibly expandable to 700 MW. BOEM plans to issue later this year a Request for Competitive Interest inviting other developers for this site to indicate their interest and inviting public comments on environmental concerns. NYPA has issued an RFP to hire consultants to prepare a Site Assessment Plan to file after a Determination of No Competitive Interest by BOEM. NYPA then plans to issue an RFP for private project developers to bid to construct the wind farm. The NYPA Collaborative has conducted the interconnection studies and plans to fund the interconnection and purchase the power from the wind farm, which will provide the basis for the project financing.

A.6.2 Site Selection and Leasing Policies

In 2010, the State of New York requested that BOEM establish a task force to facilitate intergovernmental communications regarding OCS renewable energy activities and development. This task force is planning to identify a Wind Energy Area for lease by private developers.

A.7 Ohio

A.7.1 Site Selection and Leasing Policies

Ohio developed an Offshore Wind Turbine Placement Favorability Interactive Map Viewer to be used to evaluate sites. This tool is no longer publicly available, although some individual maps are available online.

A.8 Rhode Island

A.8.1 Policies to Address High Cost

In 2004, Rhode Island established an RPS of 16% by 2019. There is no carve-out or REC multiplier for offshore wind.

In 2008, Rhode Island issued an RFP for an offshore wind project to produce 15% of the state's electricity demand and subsequently signed a Joint Development Agreement with Deepwater Wind. The Rhode Island Public Utility Commission approved an initial 30 MW Pilot PPA for 24.4 cents/kWh, which was eventually upheld by the Rhode Island Supreme Court. Rhode Island legislative advocates hope that lessons learned from construction and operation of the pilot project will help reduce the cost of constructing and operating a much larger wind farm of 500 to 1,000 MW with the same 6 MW wind turbines.[81]

A.8.2 Site Selection and Leasing Policies

Rhode Island held a competitive bid process in 2008 to select a preferred developer for an offshore wind farm off the coast of Rhode Island. Deepwater Wind LLC was selected as the winner and first negotiated the contract to sell 30 MW of wind energy from a pilot wind farm in state waters off Block Island, RI. BOEM issued a Request for Competitive Interest for the transmission route through 6 miles of federal waters and then issued a Determination of No Competitive Interest. Deepwater has initiated marine surveys, bird and bat surveys, with project permitting taking place in 2012 and construction projected for 2015.

On August 18, 2011, BOEM issued a Call for Information and received nine lease nominations for a larger offshore wind farm or farms on the OCS. On July 2, BOEM issued a Notice of Availability of a draft Environmental Assessment (EA) for the Wind Energy Area off Rhode Island and Massachusetts, and scheduled two public hearings during the public comment period. This EA process has been initiated, while final plans for a competitive auction process are developed and circulated within the Rhode Island Renewable Energy Task Force before being presented to the public for comment in a Pre-Sale Notice of Lease Sale.[82]

A.9 Texas

A.9.1 Site Selection and Leasing Policies

The Texas General Land Office stipulates which areas are available for lease, the minimum MW size, and the minimum royalty rates. Winning bidders are granted phased access, first given research rights, and then construction and operation rights.

A.10 Virginia

A.10.1 Policies to Address High Cost

Virginia is seeking to reduce the cost of offshore wind by having the local transmission system owner, Dominion, conduct interconnection studies exploring a high-voltage offshore submarine cable that could interconnect to a few wind farms.[83]

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[81] See http://offshorewind.net/OffshoreProjects/Rhode_Island.html.
[82] See http://boem.gov/Renewable-Energy-Program/State-Activities/Rhode-Island.aspx.
[83] See https://www.dom.com/news/2012/pdf/dominion_offshore_public_report_3-13-2012.pdf.

A.10.2 Site Selection and Leasing Policies

In February 2012, BOEM convened a Renewable Energy Task Force and issued a Call for Information and Nominations, and received several nominations and comments. BOEM has announced that it will issue a Pre-Sale Notice of Lease Sale during Fall 2012.[84]

[84] See http://boem.gov/Renewable-Energy-Program/State-Activities/Virginia.aspx

Appendix B. Characteristics of Operating Support Mechanisms

Operating support schemes are linked to the actual energy production from renewable energy sources. There are two main philosophies: one whereby the regulator offers a fixed price to renewable energy producers (volume is therefore uncertain), and one where the regulator sets a target volume for renewable energy production (in which case the value of the support will vary). The latter category is typically considered to be more market-oriented.

<u>Price-driven support schemes</u>

Under such schemes, governments put in place mechanisms that allow qualifying producers (as defined by the regulator) to benefit from a specific price regime for their production. These can be divided into Feed-in Tariffs (FiTs) and Feed-in Premiums.

» **Feed-in Tariff**: a guaranteed price per kWh produced by renewable energy sources

The FiT provides qualifying power producers with a guaranteed price per kWh. Different technologies can receive different price levels.

Such a mechanism is typically accompanied by priority dispatch (i.e., every kWh produced by the power producer is automatically granted access to the grid). The power is purchased either by the local utility or by the grid operator and is managed by such buyer under the normal power market rules. (Under normal market mechanisms, that power is fed into the market clearing system at a price of zero.)

The combination of guaranteed dispatch and fixed price per kWh provides investors with a high level of certainty as to future revenues (they bear operational risk, but no volume or price risk) and thus very stable returns.

FiTs can sometimes take the form of Contracts for Differences (CfD), whereby the regulator sets up an agency that pays to producers (which sell their power on the market) the difference between such market price and a pre-agreed level (which corresponds to the FiT).

» **Feed-in Premiums**: a guaranteed premium per kWh produced by renewable energy sources, incremental to the electricity market price

The Feed-in Premium provides qualifying power producers with a guaranteed price per kWh in addition to the electricity market price for such kWh, once fed into the grid. Different technologies can receive different premiums, allowing for differentiated support. This can take the form of tax credits (as the PTC in the U.S.) or payments made by specific public bodies, allowing the gross cost of the mechanism to be immediately visible.

Feed-in Premiums provide an additional revenue stream to renewable energy producers, but lets them bear full price and volume risk on their production. Unless specific arrangements are put in place by the regulator, renewable energy producers also bear balancing cost risk into the system. Such mechanisms, if set at the right level, are usually sufficient to ensure the economics of renewable energy projects. They provide more volatile earnings, unless projects enter into long-term PPAs with buyers to eliminate the volume and/or the price risk.

Quantity-based support schemes

Under such schemes, governments set a target volume for renewable energy production (typically over a period of a number of years) and put in place incentives and mechanisms to reach these at the lowest cost possible.

» **Green Certificates**: tradable certificates which qualifying producers generate and others must purchase

The government imposes an obligation on the entire market to have a minimum percentage of the electricity to be produced by renewable sources. The authorities issue certificates to qualifying producers of renewable energy, and impose an obligation on other market players to purchase certificates pro rata their volume of non-qualifying production (or their consumption). Certificates can be traded, and the sale of these certificates provides an additional revenue stream to qualifying producers in addition to the sale of electricity. The quota obligation ensures there is a demand for certificates as non-qualifying suppliers will need to buy certificates to fulfil their quotas. Such quotas will typically increase over time. Different technologies can benefit from different numbers of certificates. The regulator can impose minimum or maximum prices for green certificates by setting artificially high or low quota levels (compared to qualifying production capacity), as well as penalties for non-compliance by non-qualifying producers or guaranteed purchase prices by a public body (which makes the mechanism similar to the Feed-in Premium).

Such mechanisms, if there is enough visibility and predictability on future quota levels, are usually sufficient to ensure the economics of renewable energy projects. They provide more volatile earnings, unless projects enter into long-term PPAs with buyers to eliminate the volume and/or the price risk on both the electricity itself and on the green certificates.

» **Tendering**: A certain quantity of renewable energy production is tendered.

The regulators offer a guaranteed price level for a predefined period (either in the form of a FiT or a Feed-in Premium) for a given production volume, to be paid under a long-term PPA, and calls for qualifying producers to bid for the lowest price for such volume.

Table B-1 is a summary of advantages, disadvantages, lessons learned, and countries that currently employ operating support mechanisms to promote offshore wind in Europe.

Table B-1. Characteristics of Support Mechanisms in Europe

	Advantages	Disadvantages	Lessons Learned	Countries
Feed-in Tariff	» Applies to actually produced electricity, avoiding windfall effects, generally favoring the most productive sites. » Encourages owners to conduct long-term O&M of their facilities to keep them running. » Reduces the cost of capital invested in the sector, and thus the cost per kWh produced. » Ultimately paid by electricity consumers and not by taxpayers, ensuring a logical allocation of the burden. » Can provide the public with a long-term hedge against increasing power prices. » Least expensive and most effective way to build up renewable energy capacity if the program is designed and implemented well.	» Can encourage over-investment if prices are set at too generous levels, leading to windfall effects. » Can be hard to determine the right level of a FiT to obtain the maximum amount of green electricity with a minimum amount of subsidies.	» Tariffs should be guaranteed for a long enough duration to allow upfront costs to be spread over a large enough volume of production. » Tariffs offered to new projects should reduce over time (price digression) to encourage and enforce technological improvement. » Projects should not be allowed to switch to market prices during the FiT period, in order for the public to keep the full benefit of the price hedge against increased fuel prices. » Programs should focus on market-responsive and price-lowering program designs—triggers, caps, and tender processes—that are likely to prove more sustainable. » Administrative burdens need to be considered.	» Austria » Bulgaria » Cyprus » Finland » France » Germany » Greece » Hungary » Ireland » Latvia » Lithuania » Luxem-bourg » Nether-lands » Portugal » Slovenia » Spain

	Advantages	Disadvantages	Lessons Learned	Countries
Feed-in Premium	» Only applies to actually produced electricity, avoiding windfall effects and favoring the most productive sites. » Encourages owners to conduct long- term O&M of their facilities to keep them running. » By creating an additional dedicated revenue stream for renewable energy sources, it has shown to be effective at spurring investment. » The gross costs of the support mechanism are fully transparent, as the volume produced and the price paid to such volumes are easily identified. » Allows the system to benefit from the merit order effect as renewable energy volumes are injected directly into the power market.	» Can encourage over-investment if premiums are set at too generous levels, leading to windfall effects. » Cash flows are less stable than with a FiT as the revenues are still largely dependent on the market price of electricity. » There is no long-term price hedge like with FiTs—producers will benefit from higher underlying power prices and will also receive the premium. In other words, the gross cost of the mechanism does not vary inversely with power prices like it does for FiTs. This can create political tension at times of high power prices.	» Tariffs should be guaranteed for a long enough duration to allow upfront costs to be spread over a large enough volume of production. » Tariffs offered to new projects should reduce over time (price digression) to encourage—and enforce—technological improvement. » Measures should be built into the policy to contain the total cost, in particular at times of high power prices.	» Belgium » Estonia

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	Advantages	Disadvantages	Lessons Learned	Countries
Green Certificates	» Is market-based and thus means to be "technology neutral." It allows competition between different renewable energy technologies through the price for the green certificates and should in theory lead to the least expensive technologies being put in service to reach the desired quota. » Quotas can be adjusted over time, giving policymakers a more direct tool to control the level of investment in renewable energy.	» Prices of green certificates can be highly volatile due to uncertainty in future obligations and supply. Investors will require long-term PPAs with price floors, which favor the incumbent utilities. » Makes investors carry significant volume risk, which is hard to manage on a project-by-project basis. This discourages investment, or generates windfall revenues for utilities. » When projects are delayed, prices of green certificates can become high as quotas are not reached. » It is difficult for new and unproven technologies to penetrate the market.	» The penalty for not reaching the obligation quota should be higher than the difference between the price for renewable energy and conventional energy. » A minimum price for the green certificates appears to be necessary in immature markets to insure investment security. » The obligation quota should be set with a long time horizon in order to stimulate investment in the supply chain. » Generally, green certificate regimes lead to higher costs for consumers, confusion amongst investors, politicians, and the public, and less political support.	» Norway » Poland » Romania » Sweden » U.K.
Tendering	» Visibility on renewable energy investment volumes and future production » Visibility on cost for the regulator » Competition between bidders that should ensure the lower cost options are developed	» Depending on the level of competition, prices may or may not be aligned with the regulator's expectations. » Once the regime is allocated to an investor or set of investors, the government has no certainty that the investment will actually take place; investors can change their minds or meet adverse circumstances.	» A penalty for non-compliance to the contracted tender should be implemented to avoid low bids that are not feasible in the end. » It is important to have a balanced volume allocated in each tendering round. When the total volumes tendered are too high, there will be limited competition and high prices. When volumes are too low, many investors will be frustrated.	» U.K. » Nether-lands » France » Italy » Denmark » Portugal » Ireland

Appendix C. Evaluation of Policy Examples

C.1 Evaluation of Policy Examples That Address High Cost

The Navigant Consortium has evaluated each policy example using two sets of criteria: (1) the relative amount of effort and cost required to implement the policy and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development.

Effort criteria (cost)

- *Cost to taxpayers.* Policies with lower costs to U.S. or state governments received higher scores.
- *Cost to ratepayers.* Policies that have lower or more limited financial impact on ratepayers received higher scores.
- *Administrative and transaction costs.* Policies that require little or no administrative effort after their initial implementation received higher scores than policies that require complex or expensive administrative effort.
- *Mechanism to reduce costs as the offshore wind market grows.* Policies that contain a mechanism to reduce incentive costs as the offshore wind market grows received higher scores than policies that contain no such mechanism.
- *Political feasibility*. A policy received a low effort score if it is estimated to be difficult to implement due to political concerns.

Results criteria (effectiveness)

- *Used in the U.S.* A policy will have a greater chance of success if it has been previously used to promote land-based wind by the U.S. federal government or by one or more U.S. states.
- *Used in other countries*. Policies that have been used by other countries to promote offshore wind will generally be more effective.
- *Leverages private capital*. A policy will be more effective if it results in the investment of more private capital.
- *Basis for incentive*. An incentive will be more effective if it is based on MWh production instead of MW capacity.
- *Length of time incentive is in place*. An incentive will be more effective if it is a long-term policy, which will give investors more certainty.
- *Provides a reliable revenue stream*. A policy that results in a guaranteed income stream for developers will be more effective than one that results in an uncertain income stream.
- *Recommended in the Navigant survey or in published policy documents*. Policies that are recommended by multiple industry stakeholders will generally be more effective.

We used the above effectiveness and effort criteria to evaluate the following policies:

- *Long-term contracts for power*. Mandated buy programs that require utilities to enter into 15-20 year PPAs, similar to Massachusetts' Green Communities Act.

- *ORECs.* Mandatory credits for offshore wind energy production to meet state RPSs or a federal Clean Energy Standard. The most effective programs will have longer terms and more stable prices.
- *ORECs with a price floor.* Utilities or grid operators would be required to pay a minimum $/MWh value for ORECs. There should also be a limit on the maximum annual rate hike due to offshore wind, with utilities or grid operators assuming the costs of qualified excess incentives.
- *Investment Tax Credit (ITC) for developers.* Similar to the current ITC of 30% of initial capital cost. The policy should be in place for at least six years, given the current time required to develop and build offshore wind projects.
- *Production Tax Credit (PTC) for developers.* Similar to the current PTC of $22/MWh, with a premium for offshore wind. The policy should be in place for at least six years. Developers should have the option of using the ITC or the PTC, but not both.
- *Cash grants for developers.* Similar to the current Section 1603 cash grant program. The policy should be in place for at least three years.
- *Low interest loans and loan guarantees to developers.* Similar to the recently expired Section 1704 DOE loan guarantee program.
- *Commercial demonstration programs.*
- *Accelerated depreciation for developers.* Long-term or permanent change in the U.S. tax code to allow depreciation of initial capital in less than the five-year depreciation that is currently in place (e.g., the two-year bonus depreciation schedule that is due to expire for wind plants at the end of 2012).
- *ITC for manufacturers*.
- *Sponsored R&D on manufacturing*.
- *Communications and marketing programs.*
- *State FiTs*. Major utilities or grid operators in participating states would be required to pay a defined $/kWh rate for offshore wind energy. Payments should continue at a guaranteed rate for 15-20 years for any given project. Payments to future offshore wind plants should be lower, based on the growth of the offshore wind market. The level of the FiT should be roughly equal to the LCOE of offshore wind less the LCOE of conventional energy. The policy should be in place for at least six years.
- *Federal FiT*. Same as state FiTs, except for the entire U.S.

The results of the evaluation are shown in Table C-1. The Navigant Consortium assigned qualitative scores for each criterion to each policy example. Using the weight factors shown in Table C-1, we combined the scores to produce a Relative Effort score and a Relative Results score for each example. All scores range between 0 (unfavorable) and 1 (favorable).

Table C-1. Evaluation of Policies That Address High Cost

Policy Examples *Barrier: High Cost*	Effort					Results						
	Cost to Taxpayers	Cost to Ratepayers	Administrativ e costs	Mechanism to reduce costs	Political Feasibility	Effective in U.S. Onshore Market	Effective in non-U.S. Offshore Markets	Leverages private capital	Based on MWh production	Long term policy	Reliable revenue stream	Recommended in Navigant Survey
Weight factor	*20%*	*20%*	*20%*	*20%*	*20%*	*13%*	*13%*	*25%*	*13%*	*13%*	*13%*	*13%*
Long term contracts for MWh	●	◐	◐	○	◐	◐	●	●	●	●	●	◐
ORECs	●	○	○	●	◐	◐	◐	●	◐	●	○	●
ORECs with price floor	●	◐	○	●	○	○	○	●	◐	●	◐	○
ITC for developers	○	●	●	○	●	●	◐	●	○	◐	●	◐
PTC for developers	○	●	◐	○	●	●	◐	●	●	◐	●	●
Cash grants for developers	○	●	●	○	◐	●	●	●	○	○	●	◐
Low interest loans and guarantees	◐	●	○	○	●	●	●	●	○	◐	●	●
Commercial demonstration programs	◐	●	◐	○	◐	○	○	◐	○	◐	○	○
Accelerated depreciation	◐	●	◐	○	●	●	●	●	○	●	●	○
ITC for manufacturers	◐	●	●	○	●	●	◐	◐	○	●	○	◐
Sponsored R&D for manufacturing	●	●	◐	○	●	●	◐	○	○	○	○	◐
Communications programs	●	●	●	○	●	◐	◐	○	○	○	○	○
State FiTs	○	●	◐	◐	◐	◐	●	●	●	◐	●	●
Federal FiT	○	●	◐	◐	○	○	●	●	●	◐	●	●

● = favorable ◐ = neutral ○ = unfavorable

The Relative Effort and Relative Results scores are summarized and shown graphically in Figure C-1. The following policies that address high cost have the highest combination of Relative Effort and Relative Results:

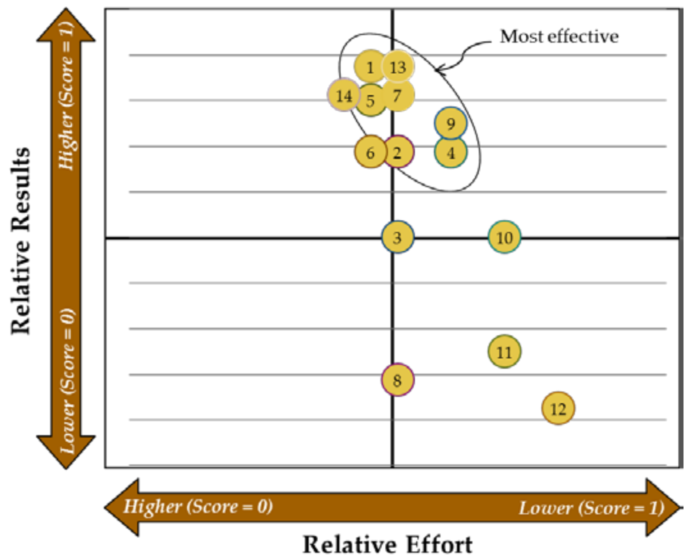
» Long-term contracts for MWh
» ORECs
» ITC for developers
» PTC for developers
» Low interest loans and guarantees
» Accelerated depreciation
» State FiTs

Timing and other considerations for these policy examples are discussed in Section 3.8. It is worth noting that "non-incentive" policies such as commercial demonstration programs and manufacturing R&D are found to deliver "lower" results in addressing high costs. However, they will be useful in maintaining a competitive industry in the medium to long term after demand begins to increase.

Figure C-1. Evaluation of Policies That Address High Cost

	Policy Examples *Barrier: High Cost*	Effort	Results
1	Long term contracts for MWh	0.50	0.88
2	ORECs	0.50	0.69
3	ORECs with price floor	0.50	0.50
4	ITC for developers	0.60	0.69
5	PTC for developers	0.50	0.88
6	Cash grants for developers	0.50	0.69
7	Low interest loans and guarantees	0.50	0.81
8	Commercial demonstration programs	0.50	0.19
9	Accelerated depreciation	0.60	0.75
10	ITC for manufacturers	0.70	0.50
11	Sponsored R&D for manufacturing	0.70	0.25
12	Communications programs	0.80	0.13
13	State FiTs	0.50	0.88
14	Federal FiT	0.40	0.81

1 = favorable 0.5 = neutral 0 = unfavorable



C.2 Evaluation of Infrastructure Policies

Similar to Section C.1, we have evaluated each infrastructure policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results).

<u>Effort criteria (cost)</u>

- *Cost to taxpayers.* Policies with lower costs to U.S. or state governments received higher scores.
- *Cost to ratepayers.* Policies that have lower or more limited financial impact on ratepayers received higher scores.
- *Necessary lead time*. Policies that have shorter lead times received higher scores.

<u>Results criteria (effectiveness)</u>

- *Used in the U.S.* A policy will have a greater chance of success if it has been previously used to promote land-based wind by the U.S. federal government or by one or more U.S. states.
- *Used in other countries*. Policies that have been used by other countries to promote offshore wind will generally be more effective and received higher scores.

» *Recommended in the Navigant survey or in published policy documents*. Policies that are recommended by multiple industry stakeholders will generally be more effective and received higher scores.

We used the above effort and results criteria to evaluate the following infrastructure policies:

» *Establish clear permitting criteria and guidelines for transmission planning and siting*. State governments (i.e., public utility commissions and energy facility siting boards) and the U.S. government (i.e., BOEM, the Army Corps of Engineers, and FERC) should work together to create a "one-stop shop," similar to state siting boards in Massachusetts, Connecticut, New York, and New Hampshire and the Great Lakes MOU for Offshore Wind.

» *Establish clear and consistent cost allocation and cost recovery mechanisms for transmission interconnections and upgrades*. FERC Order 1000[85] directs RTOs to consider state and federal energy policies when planning to expand their respective transmission systems, and to consider cost allocation to all transmission customers of new transmission for renewable generation, as was done by the Texas Public Utilities Commission in 2008.

» *Promote utilization of existing transmission capacity reservations to integrate offshore wind*. State governments (i.e., public utility commissions and energy facility siting boards) and groups of regional planning authorities should consider using transmission capacity reservations of aging conventional shoreline generation facilities that are being operated below full capacity. The sites could serve as injection points for new offshore wind facilities.

» *Offshore transmission planning should target BOEM Wind Energy Areas (and similarly identified areas in other regions of the country) and consider public policy mandates, such as RPS, as required by FERC*. State governments (i.e., public utility commissions and energy facility siting boards) and groups of regional planning authorities, such as the Eastern Interconnection Planning Collaborative, should identify transmission needs driven by public policy requirements and evaluate potential solutions to those needs that include joint interconnections for multiple wind farms, such as the AWC. Transmission planning should target the Wind Energy Areas identified by BOEM and/or state/regional offshore wind task forces.

» *Establish policies supporting the development and implementation of Integrated Resource Planning*. State public utility commissions should engage interested parties in identifying additional transmission resources needed to meet state renewable energy obligations. Utilities would be required to objectively analyze the potential of all available resources. The Eastern Interconnection State Planning Council has the potential to be a forum for state discussions on this topic.

[85] See FERC website for summary and further information: http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

The results of our evaluation are shown in Table C-2. The Navigant Consortium assigned qualitative scores for each criterion to each policy example. Using the weight factors shown in Table C-2, we combined the scores to produce a Relative Effort score and a Relative Results score for each example. All scores range between 0 (unfavorable) and 1 (favorable).

Table C-2. Evaluation of Infrastructure Policies

Policy Examples ***Barrier: Infrastructure (Transmission)***	Effort			Results		
	Cost to Government	Cost to Ratepayers	Necessary Lead Time	Effective in U.S. Onshore Market	Effective in Non-U.S. Offshore Markets	Recommended in Navigant Survey
Weight factor	*40%*	*40%*	*20%*	*40%*	*40%*	*20%*
Establish clear permitting criteria and guidelines for transmission planning and siting	●	●	◐	◐	●	◐
Establish clear and consistent cost allocation and cost recovery mechanisms for transmission development	●	●	◐	●	◐	◐
Promote utilization of existing transmission capacity reservations to integrate offshore wind	●	◐	●	●	◐	◐
Target established wind energy zones and consider public policy mandates	○	●	●	●	●	◐
Establish policies supporting the development and implementation of Integrated Resource Planning	●	◐	◐	◐	◐	◐

● = favorable ◐ = neutral ○ = unfavorable

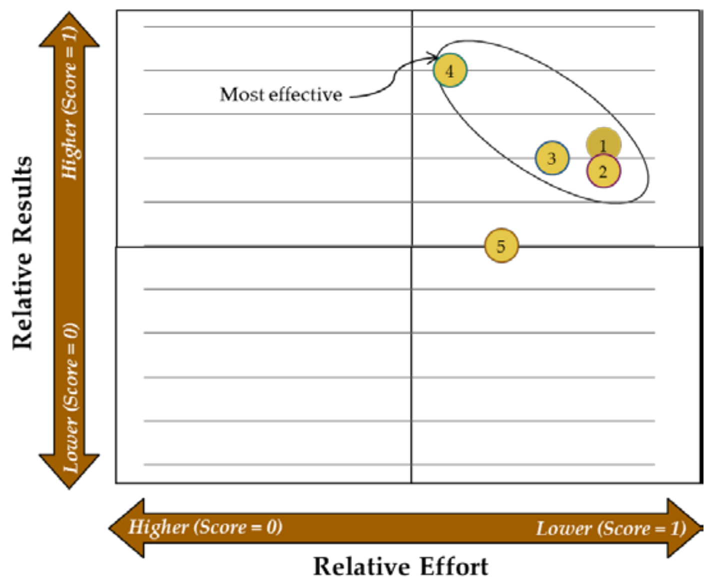
The Relative Effort and Relative Results scores are summarized and shown graphically in Figure C-2. The following policies have the highest combination of relative effort and relative results:

» Establish clear permitting criteria and guidelines for transmission planning and siting
» Establish clear and consistent cost allocation and cost recovery mechanisms for transmission interconnection and upgrades
» Promote utilization of existing transmission capacity reservations to integrate offshore wind
» Target BOEM Wind Energy Areas (and similarly identified areas in other regions of the country) and consider public policy mandates, such as RPS, as required by FERC

Timing and other considerations for these policy examples are discussed in Section 3.8. Although a high percentage of the evaluated policies are determined to be effective, the initial list of five policies had already been scrutinized by other organizations and they are all relatively inexpensive. If the list needs to be narrowed down further, establishing clear permitting criteria and establishing clear cost allocation mechanisms (Examples 1 and 2 in Figure C-2) would be the most effective for the least effort.

Figure C-2. Evaluation of Infrastructure Policies

	Policy Examples *Barrier: Infrastructure*	Effort	Results
1	Establish clear permitting criteria and guidelines	0.90	0.70
2	Establish clear cost allocation and re-covery mechanisms	0.90	0.70
3	Use existing capacity reservations	0.80	0.70
4	Target established wind energy zones and consider public policy mandates	0.60	0.90
5	Establish policies supporting IRPs	0.70	0.50



1 = favorable 0.5 = neutral 0 = unfavorable

C.3 *Evaluation of Site Selection and Leasing Policies*

Similar to Section C.1, the Navigant Consortium evaluated each site selection and leasing policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results).

Effort criteria (cost)

- *Cost to taxpayers.* Policies with lower costs to U.S. or state governments received higher scores.
- *Cost to ratepayers.* Policies that have lower or more limited financial impact on ratepayers received higher scores.
- *Necessary lead time*. Policies with shorter lead times received higher scores.

Results criteria (effectiveness)

- *Used in the U.S.* A policy will have a greater chance of success if it has been previously used to promote land-based wind by the U.S. federal government or by one or more U.S. states.
- *Used in other countries*. Policies that have been used by other countries to promote offshore wind will generally be more effective and received higher scores.
- *Recommended in the Navigant survey or in published policy documents*. Policies that are recommended by multiple industry stakeholders will generally be more effective and received higher scores.

The Navigant Consortium used the above effort and results criteria to evaluate the following site selection and leasing policies:

Smart from Start Model. BOEM has established a new lease process for offshore energy facilities, including wind farm sites, that is based on the BOEM lease process for oil and gas development. To summarize, the Smart from the Start process is conducted in four major phases: (1) planning and analysis, (2) leasing, (3) site characterization and assessment, and (4) commercial development.

The planning and analysis phase includes establishing an Intergovernmental Task Force to engage stakeholders; publishing a Call for Information and Nominations and Notice of Intent to Prepare an Environmental Assessment (EA); announce Area Identification (Area ID); and conduct environmental compliance reviews. Identification of wind energy areas is led by state regulators who identify environmental constraints and engage in discussions with stakeholders with competing offshore uses. Rhode Island and Massachusetts initiated their own offshore management planning processes before Smart from the Start but the results were plugged into the BOEM process. BOEM also incorporated the results of early offshore studies by New Jersey, Delaware, and Virginia into the identification of Wind Energy Areas in those states. In effect, BOEM has accepted virtually all Wind Energy Area boundary requests submitted by the state task forces for their respective states. Identification of all significant constraints and competing uses upfront reduces the likelihood that a major constraint or competing use will arise later in the leasing and permitting process and result in potentially lengthy delays.

Initiating earlier environmental reviews expedites the lease and permit process because NEPA reviews are the most time-consuming aspects of the approval process. Instead of waiting for the Site Assessment Plan (SAP) to be filed to trigger the SAP NEPA review, BOEM initiated a Regional EA for four Mid-Atlantic states simultaneously. By covering all major site assessment and characterization technologies and their impacts, this Regional EA will enable more expeditious review of site assessment proposals by developers in these four states. If a developer proposes the same technology as already assessed in the Regional EA with a Finding of No Significant Impact, the developer may then submit a request for a SAP departure and no additional time is required at this stage for NEPA review. Even if one or two issues must be addressed that were not covered in the Regional EA, then only those issues need be addressed and the EA can be reviewed and issued more promptly than an EA covering all the site assessment issues.

As an example, in July 2012, BOEM issued a Notice of Availability of a draft EA for the Wind Energy Area off Rhode Island and Massachusetts and scheduled two public hearings during the public comment period. This EA process has been initiated while final plans for a competitive auction process are developed and circulated within the Rhode Island Renewable Energy Task Force before presented to the public for comment in a Pre-Sale Notice of Lease Sale.

The leasing phase consists of publishing leasing notices and issuing leases. Leases can be issued either after negotiating with a single developer (after BOEM determines no competitive interest in that site) or by holding a lease sale (competitive auction process). The lease conveys the right to submit plans for BOEM's approval after environmental reviews are complete.

In the site characterization and assessment phase, the lessee will conduct surveys in the lease area (site characterization), and if the lessee intends to install data collection facility (meteorological tower or buoy) it must submit a SAP to BOEM (site assessment). BOEM conducts environmental and technical reviews of the lessee's SAP and approves, disapproves, or approves with modifications. The lessee has 5 years to conduct these activities which produce the information required to submit a Construction and Operations Plan (COP).

In the commercial development phase, the COP provides details of the proposed project (turbine layout, size, cable routes, etc.) and the construction methodology and proposed mitigation measures. BOEM must approve the COP before the lessee may construct and operate. The operations term is typically 25 years.

Coordination of federal and state permitting in the last two phases is critical to an expedited approval process. Some state agencies have jurisdiction over the same issues as some federal agencies, such as threatened and endangered species and coastal wetland impacts. Coordination to review and approve proposed survey protocols is important to prevent one agency from asking for additional surveys on the same topic. Coordination is also essential when negotiating conditions to mitigate unavoidable impacts and prevent inconsistent mitigation conditions for state and federal permits. Finally, coordination of required public meetings and hearings can facilitate an expedited approval process for all state and federal approvals.

» *BLM model*. Under this model, developers select sites and submit their own plans for the land to be leased. BLM has developed a streamlined process from which the Smart from the Start Program was inspired. However, developer-selected sites offshore are considered unsolicited and must undergo a competitive review process as required by the Energy Policy Act of 2005

(EPACT). Also, BOEM regulations prohibit an unsolicited lease request after a state task force has been established to identify a Wind Energy Area in a specific state.

» *Texas and Denmark model*. Under this model, the government or utility selects sites and holds a competitive process among developers. This model contains the same constraints identified for the BLM model above. However, one site is being developed in state waters in Texas, outside BOEM jurisdiction to speed the approval process. In New York, three utilities, NYPA, LIPA, and Consolidated Edison have joined into a collaborative (NYPA Collaborative) to select an offshore site and have submitted an unsolicited lease request to BOEM. The NYPA Collaborative plans to obtain a lease for site assessment and then conduct a competitive bid to select a project developer. This model has two significant benefits over other models: (1) the NYPA Collaborative will negotiate a power purchase contract with the winning bidder for the energy from the wind farm, which will provide the basis for the financing of the wind farm; and (2) the NYPA Collaborative will provide the interconnection to the onshore grid, retaining their eminent domain authority as New York utilities in case it is necessary to procure the rights of way for the interconnection.

The evaluation results are shown in Table C-3. The Navigant Consortium assigned qualitative scores for each criterion to each policy example. Using the weight factors shown in Table C-3, the scores were combined to produce a Relative Effort score and a Relative Results score for each example. All scores range between 0 (unfavorable) and 1 (favorable).

Table C-3. Evaluation of Site Selection and Leasing Policies

Policy Options ***Barrier: Regulatory (Site Selection and Leasing)***	**Effort**			**Results**		
	Cost to Government	**Cost to Ratepayers**	**Necessary Lead Time**	**Effective in U.S. Onshore Market**	**Effective in non-U.S. Offshore Markets**	**Recommended in Navigant Survey**
Weight factor	*40%*	*40%*	*20%*	*40%*	*40%*	*20%*
(BOEM model) 4 stage authorization process: (1) planning & analysis; (2) leasing; (3) site characterization & assessment; and (4) commercial development	●	●	●	◐	●	◐
(BLM model) Developers select sites and submit their own plans for the land to be leased (1)	●	◐	●	◐	◐	◐
(Texas and Denmark model) The government or utility selects sites and holds a competitive process among developers	◐	●	◐	●	●	◐

(1) BLM accepts applications (for land-based wind projects) on a first-come, first-served basis, although competitive leasing may occur if deemed appropriate in specific areas.

● = favorable ◐ = neutral ○ = unfavorable

The Relative Effort and Relative Results scores are summarized and shown graphically in Figure C-3. The following site selection and leasing policies have the highest combination of Relative Effort and Relative Results:

- *BOEM model*. Four stage authorization process: (1) planning and analysis, (2) leasing, (3) site characterization and assessment, and (4) commercial development. . This is the primary model now being implemented in the U.S. and U.K. There is general support for the overall structure, but there is no substantial support for any legislative revisions despite ongoing efforts to streamline the existing model through implementation practices.

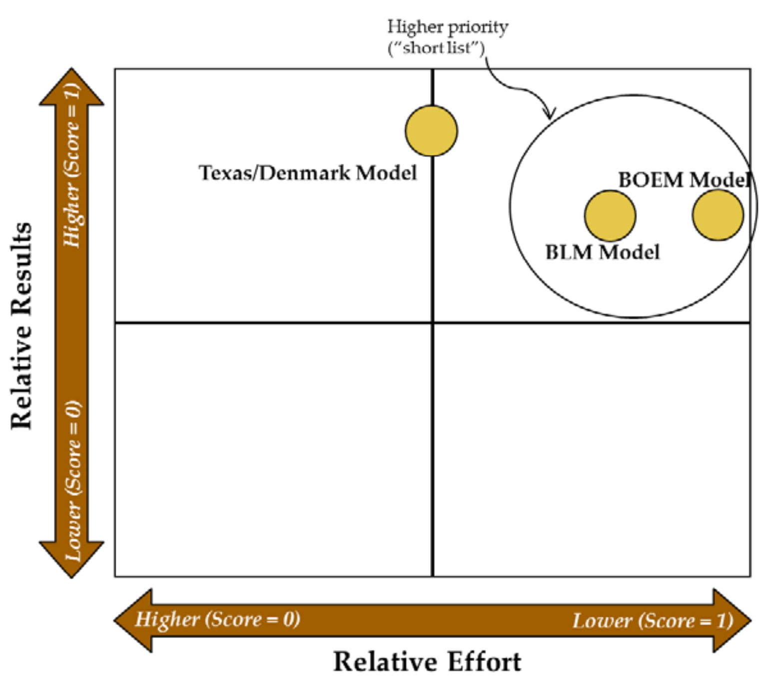
- *Texas and Denmark model*. The utility collaborative selects the site and initiates the BOEM lease process, and then holds a competitive bid to select the wind farm developer to construct the wind farm. Utilities permit and construct the interconnection to the onshore grid and negotiate a PPA for the power. This model is effective where implemented because it includes the PPA and interconnection support to facilitate financing the projects.

The BLM model is efficient for land-based wind and is the basis of the BOEM model and Smart from the Start Program, but it would be very difficult to enact through new legislation.

Timing and other considerations for these two policy examples are discussed in Section 3.8. Although both of these policies are shown to be effective in the U.S., the BOEM model has more universal acceptance and is less costly to implement.

Figure C-3. Evaluation of Site Selection and Leasing Policies

Policy Options *Barrier: Regulatory (Site Selection and Leasing)*	Effort	Results
(BOEM model) 4 stage authorization process: (1) planning & analysis; (2) leasing; (3) site characterization & assessment; and (4) commercial development	1.00	0.70
(BLM model) Developers select sites and submit their own plans for the land to be leased	0.80	0.70
(Texas and Denmark model) The government selects sites and holds a competitive process among developers	0.50	0.90



1 = favorable 0.5 = neutral 0 = unfavorable

C.4 Evaluation of Permitting Policies

Similar to Section C.1, the Navigant Consortium evaluated each permitting policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results).

Effort criteria (cost)

- » *Cost to taxpayers.* Policies with lower costs to U.S. or state governments received higher scores.
- » *Necessary lead time*. Policies with shorter lead times received higher scores.

Results criteria (effectiveness)

- » *Used in the U.S.* A policy will have a greater chance of success if it has been previously used to promote land-based wind by the U.S. federal government or by one or more U.S. states.
- » *Used in other countries*. Policies that have been used by other countries to promote offshore wind will generally be more effective and received higher scores.
- » *Recommended in the Navigant survey or in published policy documents*. Policies that are recommended by multiple industry stakeholders will generally be more effective and received higher scores.

The Navigant Consortium used the above effort and results criteria to evaluate the permitting policies discussed below. Each of these examples could apply within the context of federal or state permitting authorities.

- » *Require site-specific EISs for every offshore wind project*. The initial draft regulations issued by MMS/BOEM proposed three full EISs for each offshore wind project: one to begin the lease process, one to authorize site assessment and characterization activities, and one to authorize the Construction and Operations Plan (COP). However, the NEPA statute and regulations requires only that level of environmental review commensurate to the potential impacts of the proposed federal action.[86] BOEM has since agreed that NEPA does not require a full EIS prior to initiating the lease process or prior to the site assessment process.[87] Therefore, BOEM now agrees that EAs are appropriate to address the limited environmental impacts of those initial lease process

[86] 42 USC 4321 et seq. See, for example, Sierra Club v. Watkins, 808 F.Supp. 852 (D.D.C. 1991)(the level of analysis should be commensurate with the severity of impacts).

[87] When issuing its final lease rule, MMS/BOEM stated: " the level of NEPA analysis for such leases will have to be commensurate with the type and scope of potential activities entailed with the lease rights conveyed. 74 FR 19638, 19658 (April 29, 2009). MMS/BOEM further stated “the SAP will undergo the appropriate NEPA reviews and may require either an Environmental Impact Statement (EIS) or an EA. …. Like the SAP, the COP will undergo the appropriate NEPA reviews and may require either an EIS or an EA.” 74 FR at 19652 (April 29, 2009).

steps.[88] A full EIS for the COP can be expected to take about two years, according to public statements by BOEM staff, due in part to evaluating the impacts from a new technology in an area of the environment not well-studied in the past. As more and more EISs are issued for subsequent offshore wind farms, agency staff can be expected to issue EISs in shorter periods of time, unless significant impacts arise at specific new sites.

» *Conduct a programmatic EIS over broad geographic areas to determine categorical exclusions, followed by less detailed EAs for individual projects*. CEQ NEPA regulations specifically encourage tiering NEPA reviews off prior NEPA reviews. Tiering is thus authorized to make NEPA reviews more efficient, reducing the analysis and time to complete subsequent reviews. As the same technologies are constructed and operated in similar environments, EISs can be gradually replaced by EAs and eventually by categorical exclusions.

» *Develop a programmatic EIS for a broad geographic area followed by detailed EISs for selected individual projects*. Site-specific EISs following a Programmatic EIS defeat the purpose of the EIS, requiring excessive effort and time not required by NEPA for all the reasons presented above explaining why reduced environmental review is appropriate following a PEIS.

The results of the evaluation are shown in Table C-4. The Navigant Consortium assigned qualitative scores for each criterion to each policy example. Using the weight factors shown in Table C-4, the scores were used to produce a Relative Effort score and a Relative Results score for each example. All scores range between 0 (unfavorable) and 1 (favorable).

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[88] See, for example, "Notice of Intent to Prepare Environmental Assessment for Commercial Lease and Site Assessment Activities Off Massachusetts: http://boem.gov/uploadedFiles/BOEM/Renewable_Energy_Program/State_Activities/MA%20Notice%20of%20Intent_Federal%20Register.pdf

Table C-4. Evaluation of Permitting Policies

Policy Examples *Barrier: Regulatory (Permitting)*	Effort		Results		
	Cost to Government	Necessary Lead Time	Effective in U.S. Onshore Market.	Effective in Non-U.S. Offshore Markets	Recommended in Navigant Survey
Weight factor	*70%*	*30%*	*40%*	*40%*	*20%*
Require site specific Environmental Impact Statements (EISs) for every offshore wind project	○	○	◐	●	○
Conduct a programmatic EIS over broad geographic areas to determine categorical exclusions, followed by less detailed environmental assessments for individual projects	●	●	●	○	◐
Develop a programmatic EIS for a broad geographic area followed by detailed EISs for selected individual projects	◐	●	●	◐	◐

● = favorable ◐ = neutral ○ = unfavorable

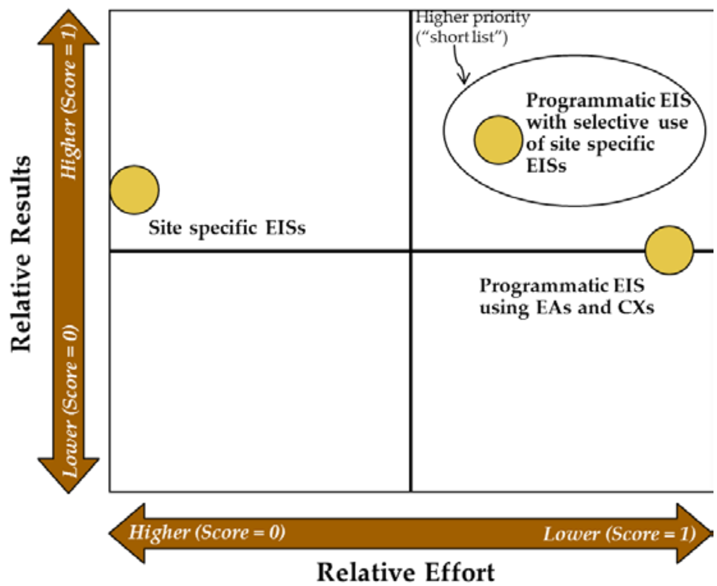
The Relative Effort and Relative Results scores are summarized and shown graphically in Figure C-4. The following policy has the highest combination of Relative Effort and Relative Results:

» *Develop a programmatic EIS for a broad geographic area followed by detailed EISs for selected individual projects.*

Timing and other considerations for this policy example are discussed in Section 3.8. Note that this policy would interface with state permitting authorities, as the states still have some regulatory authority even in federal waters (beyond three nautical miles for all states except Texas). In the Great Lakes, the states have primary authority for all permitting, although a federal EIS or EA would likely be triggered.

Figure C-4. Evaluation of Permitting Policies

Policy Examples *Barrier: Regulatory (Permitting)*	Effort	Results
Require site specific Environmental Impact Statements (EISs) for every offshore wind project	0.00	0.60
Conduct a programmatic EIS for offshore wind, using Environmental Assessments (EAs) and Categorical Exclusions (CXs)	1.00	0.50
Develop a programmatic EIS and allow site specific EISs to be used selectively	0.65	0.70



1 = favorable 0.5 = neutral 0 = unfavorable

C.5 Evaluation of Operations Policies

Similar to Section C.1, the Navigant Consortium evaluated each operations policy example using two sets of criteria: (1) the relative effort and cost required to implement the policy (Relative Effort) and (2) the relative effectiveness of the policy, as determined by the expected impact on offshore wind development (Relative Results).

<u>Effort criteria (cost)</u>

» *Ease of* implementation. Policies that are less complex and easier to implement received higher scores.

» Cost *to taxpayers.* Policies with lower costs to U.S. or state governments received higher scores.
» *Necessary lead time*. Policies with shorter lead times received higher scores.

Results criteria (effectiveness)

» *Used in the U.S.* A policy will have a greater chance of success if it has been previously used to promote land-based wind by the U.S. federal government or by one or more U.S. states.
» *Used in other countries*. Policies that have been used by other countries to promote offshore wind will generally be more effective and received higher scores.
» *Conflicts of interest*. Policies with no conflicts of interest received higher scores.

The Navigant Consortium used the above effort and results criteria to evaluate the following operations policies:

» Environmental and safety compliance monitoring by the government
» Self monitoring by developers/operators
» Monitoring by third parties

The results of our evaluation are shown in Table C-5. We have assigned qualitative scores for each criterion to each policy example. Using the weight factors shown in Table C-5, the scores were combined to produce a Relative Effort score and a Relative Results score for each example. All scores range between 0 (unfavorable) and 1 (favorable).

Table C-5. Evaluation of Operations Policies

Policy Examples *Barrier: Regulatory (Operations)*	Effort			Results		
	Ease of Implementation	Cost to Government	Necessary Lead Time	Effective in U.S. Onshore Market.	Effective in Non-U.S. Offshore Markets	Conflicts of Interest
Weight factor	*25%*	*50%*	*25%*	*33%*	*33%*	*33%*
Environmental and safety compliance monitoring by the government	○	○	◐	◐	◐	●
Self monitoring by developers/operators	●	●	◐	●	●	○
Monitoring by third parties	◐	○	◐	◐	◐	●

● = favorable ◐ = neutral ○ = unfavorable

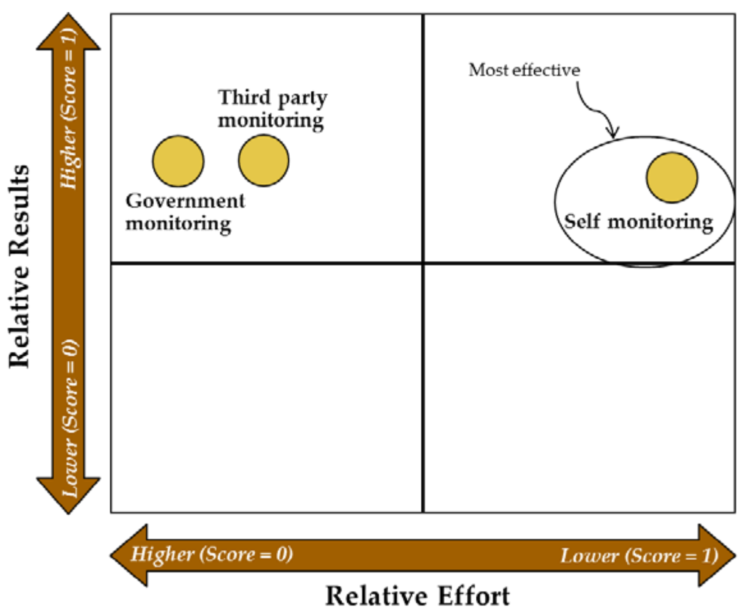
The Relative Effort and Relative Results scores are summarized and shown graphically in Figure C-5. The following operations policy has the highest combination of Relative Effort and Relative Results:

» *Self monitoring by developers/operators*. As shown in Figure C-5, this example scores well in all categories, with the exception of possible conflicts of interest. This concern could be balanced with government oversight in critical areas. For example, governments could fund generic studies that provide more protection to birds and bats, and help identify whale mating, calving, and migratory areas to minimize exposure to construction and O&M vessels supporting offshore wind farms. Developers would continue to fund and execute their own post-construction surveys for review by regulators.

Timing and other considerations for this policy example are discussed in Section 3.8.

Figure C-5. Evaluation of Operations Policies

Policy Examples *Barrier: Regulatory (Operations)*	Effort	Results
Environmental and safety compliance monitoring by the government	0.13	0.67
Self monitoring by developers/operators	0.88	0.67
Monitoring by third parties	0.25	0.67



1 = favorable   0.5 = neutral   0 = unfavorable

Appendix D. Content and Financing Assumptions

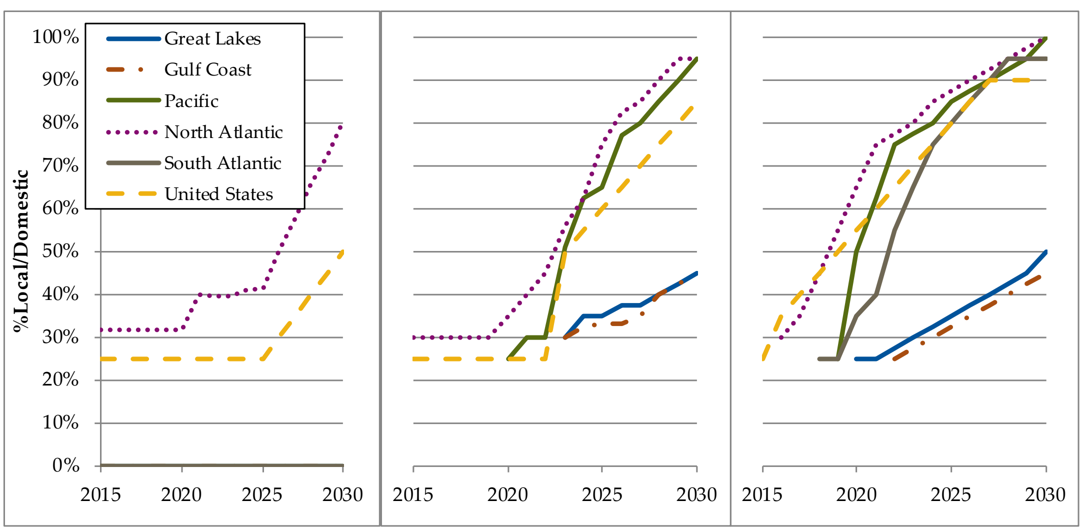
D.1 Local and Domestic Content Assumptions

This section presents our local (i.e., regional) and domestic content assumptions for each scenario and year of analysis. For the domestic content analysis, we only present the results here. Please refer to our companion supply chain study for a discussion of how we arrived at our domestic content assumptions.

Nacelle/Drivetrain, Blades, and Towers

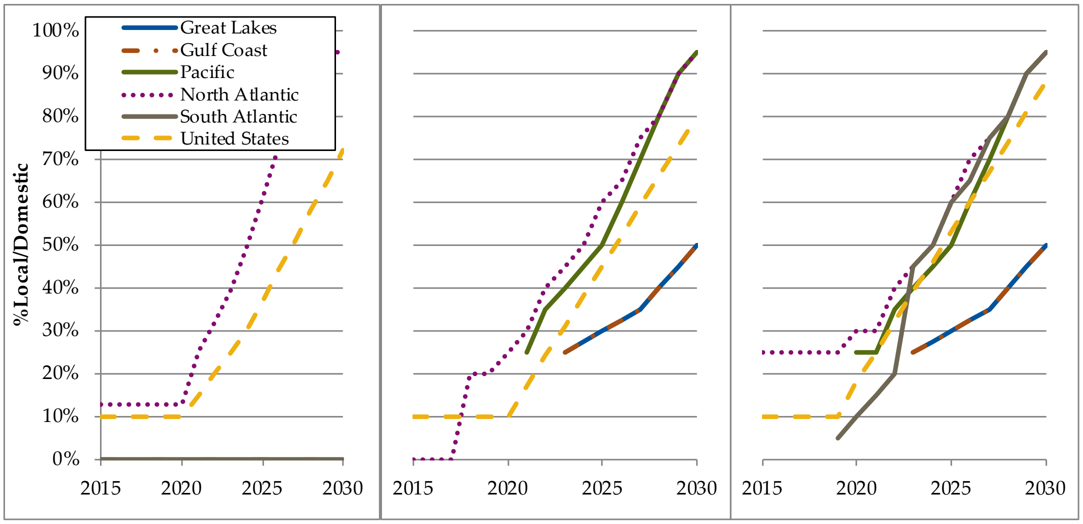
From our research, we have found that turbine component suppliers look at two market sizes—300 MW and 800 MW—when making decisions on where to locate a manufacturing facility. At 300 MW/year, a manufacturer that gets 1/3 market share and can sell 100 MW per year and 800 MW/year is a big enough market to locate an entire production line in the region. We used the MW forecasts discussed in Section 4.5.2 and looked when a region reached 300 and 800 MW/year and scaled percentage local content accordingly. Since most of corrective maintenance parts are associated with these components, we applied these assumptions to corrective maintenance parts as well.

Figure D-1. Local and Domestic Content Assumptions for Nacelle/Drivetrain



	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	35%	45%	25%	35%	50%
Gulf Coast	0%	0%	0%	0%	33%	45%	0%	33%	45%
Pacific	0%	0%	0%	25%	65%	95%	50%	85%	100%
North Atlantic	32%	41%	80%	35%	75%	95%	65%	88%	100%
South Atlantic	0%	0%	0%	0%	0%	25%	35%	80%	95%
United States	25%	25%	50%	25%	60%	85%	55%	80%	90%

Figure D-2. Local and Domestic Content Assumptions for Blades and Towers

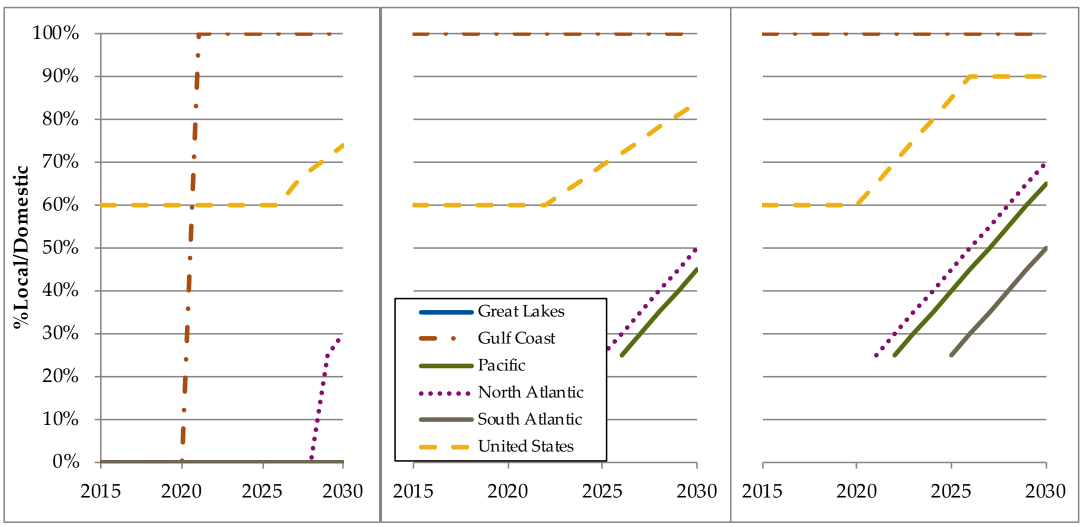


	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	30%	50%	0%	30%	50%
Gulf Coast	0%	0%	0%	0%	30%	50%	0%	30%	50%
Pacific	0%	0%	0%	0%	50%	95%	25%	50%	95%
North Atlantic	13%	61%	95%	25%	60%	95%	30%	60%	95%
South Atlantic	0%	0%	0%	0%	0%	25%	10%	60%	95%
United States	10%	37%	72%	10%	45%	80%	18%	53%	88%

Substructure and Foundations

Currently, the Gulf Region of the U.S. has significant offshore foundation production and fabrication expertise developed to serve the offshore oil industry. Initially, we assumed that any equipment that is sourced domestically will come from the Gulf Region. As the industry grows, some portion of the manufacturing or assembly could be located in regions of high demand; however, since the equipment required for manufacturing is specialized and expensive, we assumed that regional production does not start until demand is ~800 to 1 GW/year.

Figure D-3. Local and Domestic Supply Assumptions for Foundations and Substructures

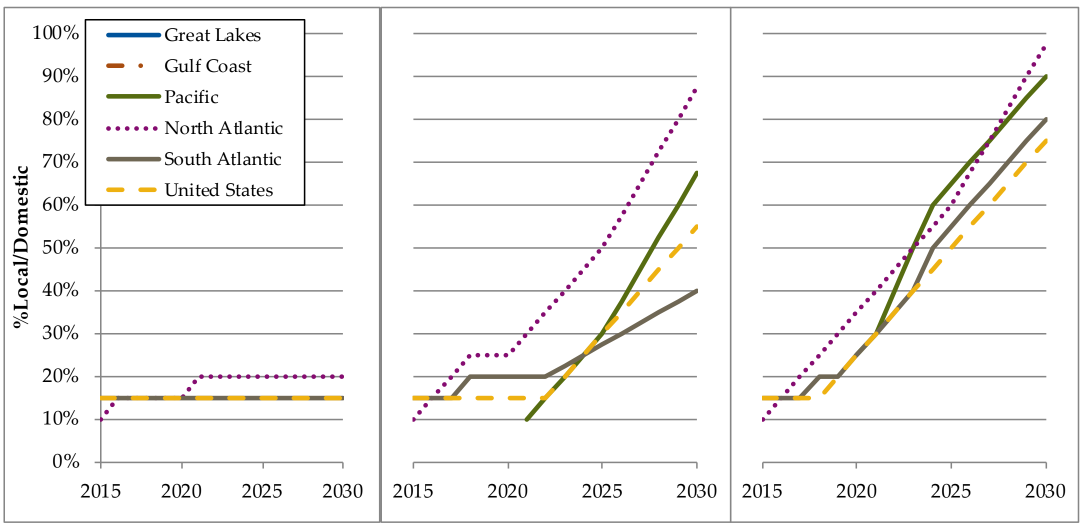


	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gulf Coast	0%	100%	100%	100%	100%	100%	100%	100%	100%
Pacific	0%	0%	0%	0%	0%	45%	0%	40%	65%
North Atlantic	0%	0%	30%	0%	25%	50%	0%	45%	70%
South Atlantic	0%	0%	0%	0%	0%	0%	0%	25%	50%
United States	60%	60%	74%	60%	69%	84%	60%	85%	90%

Project Collection and HV Cable

The largest producers of this equipment – ABB, Prysmian, Nexans and NKT – are not U.S.-based, so most equipment will not likely come from the U.S. early on. As the offshore wind industry grows, some equipment may come domestically. To estimate what regions equipment may come from, we looked at U.S. locations of the aforementioned companies. Most of their current U.S. locations are on the East Coast (e.g., the North and South Atlantic regions). As the industry grows, we assumed current suppliers or new suppliers would build manufacturing close to the largest demand. In all scenarios, this was the Atlantic and Pacific coasts.

Figure D-4. Local and Domestic Supply Assumptions for Project Collections Systems and High-Voltage Cabling

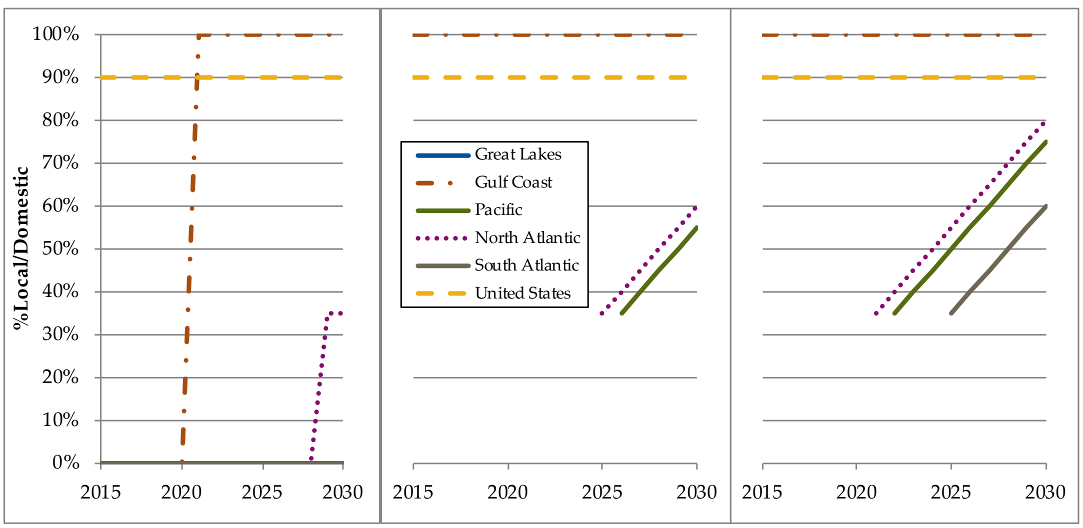


	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gulf Coast	0%	0%	0%	0%	0%	0%	0%	0%	0%
Pacific	0%	0%	0%	0%	30%	68%	25%	65%	90%
North Atlantic	15%	20%	20%	25%	50%	88%	35%	60%	98%
South Atlantic	15%	15%	15%	20%	28%	40%	25%	55%	80%
United States	15%	15%	15%	15%	30%	55%	25%	50%	75%

Substructure and Foundation Labor

As discussed above, substructure and foundation equipment is currently produced in the Gulf Region for the offshore oil and gas industries. As a result, the Gulf Region has an existing skill base from the offshore oil and gas industry that can supply labor for the offshore wind industry. We assumed that until a region reaches a large demand (~800MW to 1 GW/Year), most labor will come from the Gulf Region. As regional demand grows, we assume that local training providers (e.g., community colleges and trade schools) will start to offer courses with the necessary skills.

Figure D-5. Local and Domestic Supply Assumptions

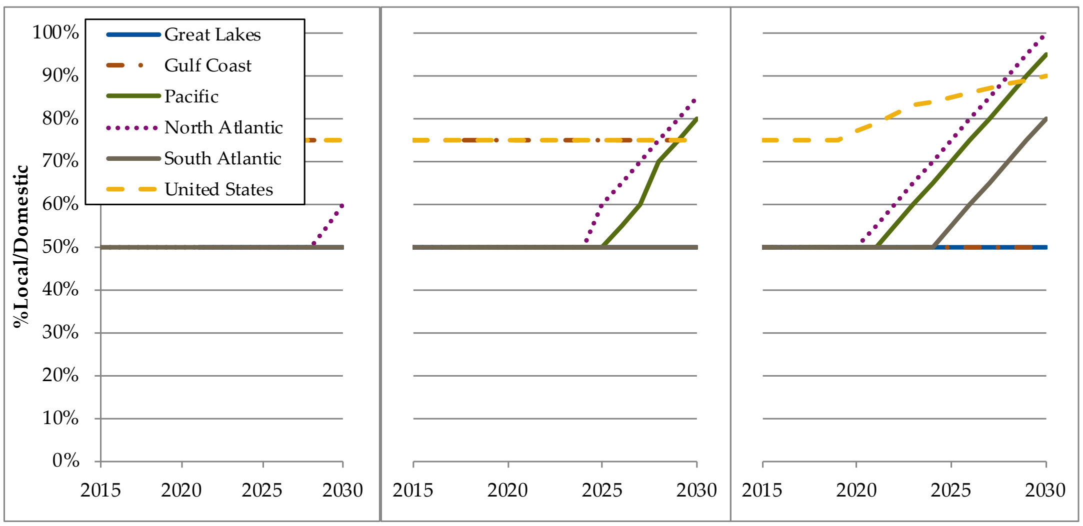


	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gulf Coast	0%	100%	100%	100%	100%	100%	100%	100%	100%
Pacific	0%	0%	0%	0%	0%	55%	0%	50%	75%
North Atlantic	0%	0%	35%	0%	35%	60%	0%	55%	80%
South Atlantic	0%	0%	0%	0%	0%	0%	0%	35%	60%
United States	90%	90%	90%	90%	90%	90%	90%	90%	90%

Erection and Installation Services (including labor and equipment)

Some of this work can be done by local contractors, but some specialized skills or vessels are likely to come from Europe in the near term. For the equipment and services that do come domestically, some of it will have to come from the Gulf Region because that region has the necessary infrastructure to support offshore oil and gas. As regional demand becomes large (~800MW to 1 GW/Year), we assumed regional expertise will develop and local contractors will purchase the necessary equipment.

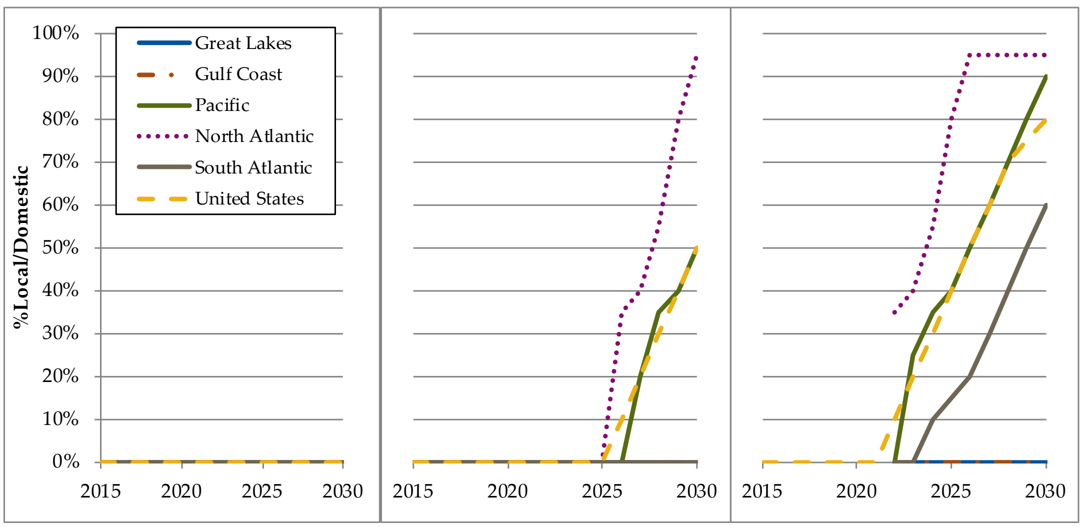
Figure D-6. Local and Domestic Supply Assumptions for Erection and Installation Services



	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	50%	50%	50%	50%	50%	50%	50%	50%
Gulf Coast	0%	75%	75%	75%	75%	75%	50%	50%	50%
Pacific	0%	0%	0%	50%	50%	80%	50%	70%	95%
North Atlantic	50%	50%	60%	50%	60%	85%	50%	75%	100%
South Atlantic	50%	50%	50%	50%	50%	50%	50%	55%	80%
United States	75%	75%	75%	75%	75%	75%	77%	85%	90%

Construction Financing (including bank fees), Project Debt, and Insurance
Early on, we expect most debt will come from European banks and insurance companies as they are familiar with the offshore wind industry. As the U.S. offshore market grows, some U.S. banks will likely get involved. However, most banks and insurance firms are headquartered in New York, so most of the economic impact will be there. But we assume at some point, banks and insurance firms with headquarters outside New York (such as Wells Fargo and Northern Trust) will start lending and providing insurance.

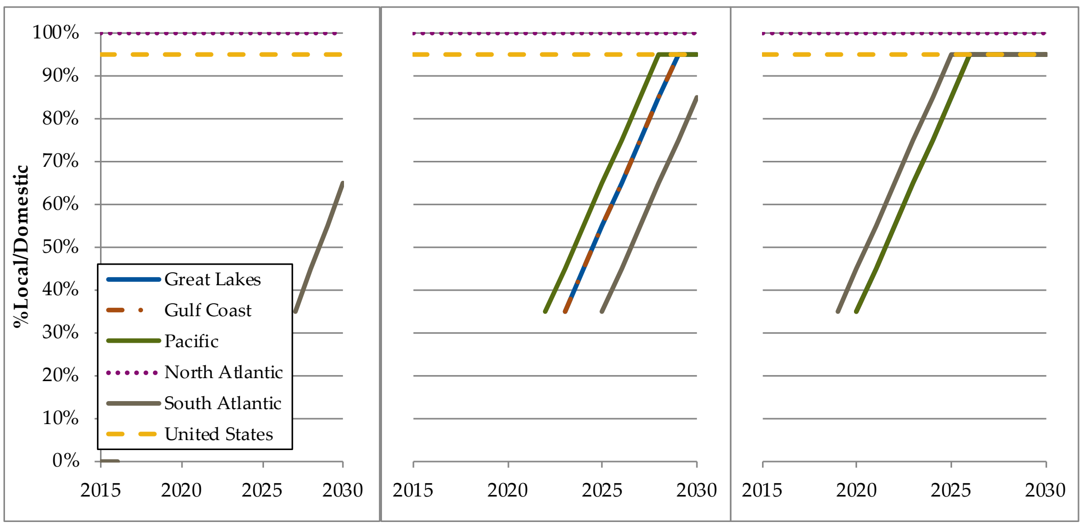
Figure D-7. Local and Domestic Supply Assumptions for Construction Financing and Project Debt



	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gulf Coast	0%	0%	0%	0%	0%	0%	0%	0%	0%
Pacific	0%	0%	0%	0%	0%	50%	0%	40%	90%
North Atlantic	0%	0%	0%	0%	0%	95%	0%	80%	95%
South Atlantic	0%	0%	0%	0%	0%	0%	0%	15%	60%
United States	0%	0%	0%	0%	0%	50%	0%	40%	80%

Management of Operating Plants
Currently in the land-based wind industry, staff in a central facility manages several wind plants across the country. We assumed that in the near and mid-term, most of these staff will be in the North Atlantic region because that is where the most near-term project development activity is. As a region's installed base gets large enough (defined as 1 GW of installations), we assumed staff would start to be located to that region.

Figure D-8. Local and Domestic Ongoing Project Management Staff



	Low			Medium			High		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Great Lakes	0%	0%	35%	0%	55%	95%	35%	85%	95%
Gulf Coast	0%	0%	35%	0%	55%	95%	35%	85%	95%
Pacific	0%	0%	0%	0%	65%	95%	35%	85%	95%
North Atlantic	100%	100%	100%	100%	100%	100%	100%	100%	100%
South Atlantic	0%	0%	65%	0%	35%	85%	45%	95%	95%
United States	95%	95%	95%	95%	95%	95%	95%	95%	95%

Other Categories

For all other inputs to JEDI, we assumed static percentage local and domestic sourcing, per the discussion in Section 4.

Table D-1. Static Regional and Domestic Sourcing Assumptions

	Regional	National	Discussion
Materials & Other Equipment			
Basic Construction (e.g., concrete, rebar, gravel)	100%	100%	These items are produced locally throughout the U.S. and will likely be sourced locally.
Labor costs			
Management/Supervision	95%	95%	The deals we are familiar with which would leverage local management and supervision.
Insurance During Construction			
Development Services/Other Costs			
Engineering (Project and interconnection facility design)	100%	100%	This requires local knowledge and each of our regions of study has engineering firms that can help with this.
Legal Services	100%	100%	This requires local knowledge for many items, and for general legal support, many of the law firms that work in this area have offices located near areas of offshore wind development.
Public Relations	100%	100%	This is typically done by local firms that have relationships with local media and decision-makers.
Ports and Staging	100%	100%	We assume that wind farms will be built out of the nearest suitable port, which should be in the region.
Site Certificate/Permitting	100%	100%	This requires local knowledge of laws, regulations, and agencies, so we assumed all local sourcing.
Air Transportation (personnel or materials)	100%	100%	In our research, we have found that these services can most cost effectively be provided by local companies.
Marine Transportation (personnel or materials, includes vessel mobilization)	100%	100%	
Reserve Accounts: MRA/DSRA	0%	100%	We assume that because most project developers are domestic, they will use domestic banks for holding reserve accounts.
Operation and Maintenance			

	Regional	National	Discussion
Labor			
Technician Salaries	95%	95%	The O&M plan we analyzed – discussed in Section 4.3.9 – assumes land-based staff service the facility.
Monitoring & Daily Operations Staff & Other Craft Labor	95%	95%	
Administrative	95%	95%	
Materials and Services			
Water Transport	95%	95%	These services will primarily be provided from the servicing port and the surrounding area.
Site Facilities	95%	95%	
Machinery and Equipment	95%	95%	
Subcontractors	95%	95%	
Financing			
Equity Financing/Repayment			
Individual Investors	0%	0%	N/A – We expect all equity to come from corporations.
Corporate Investors	0%	50%	Assuming the production tax credit is available, U.S. entities will need to provide equity because a tax liability is required. However, we are uncertain as to how the interest (e.g., profit) will be reinvested. So, we are assuming only 50% stays in the U.S. economy.
Tax Parameters			
Property Tax	100%	100%	By definition, these are local taxes.
Sales Tax	100%	100%	By definition, these are local taxes.
Other Local Taxes	100%	100%	By definition, these are local taxes.

D.2 Detailed Financing Assumptions

Introduction

We have chosen to calculate financing costs using the project finance approach for the following reasons:

» Costs of funding for utilities are not always public and less public information on these deals is available.

» Costs of funding for the individual wind farm for balance sheet deals are not public or difficult to assess from total funding costs of the utility.

» Difference in risk allocation between the project and the sponsors (and thus pricing) between individual balance sheet financed deals is more diverse when compared to project finance deals.

- In our opinion, the project finance deals give the best estimate of the integral financing costs of an individual project.
- We expect most of the U.S. deals to be structured as leveraged, project finance deals.

Project Finance (PF) has been used for the financing of offshore wind projects only in Europe to date, and it has only been applied for a relatively small number of projects. The parameters discussed below are therefore based on what remains a small sample and represent the Navigant Consortium's best estimates of how these would translate to the U.S. market. The general assumption is that banks likely to participate in U.S. offshore projects will be those European banks which have built offshore PF experience in Europe. They will likely assess U.S. projects the same way; however, pricing and other market conditions may be subject to the terms of the U.S. wind PF market, which at times have deviated from European ones. Financing conditions have therefore been indicated in relative terms (i.e., by reference to standard land-based terms). In addition, it is difficult to predict what the financial market situation will be like in 2018, and therefore what the financing conditions will be for offshore wind.

Existing Precedents

Financing parameters for 10 recent OSW projects are shown in Table D-2. The first pioneer transactions took place prior to the financial crisis (Princess Amalia), 120 MW in 2006 and C-Power, 30 MW in 2007, demonstrating that it was possible for banks to accept construction risk in an offshore environment under multi-contracting frameworks. Two transactions (Belwind, 165 MW, and Boreas, 194 MW) then closed in the second half of 2009, suggesting that banks were willing to support this relatively new and untested sector even in post-crisis conditions provided that the projects were properly structured. In 2010, C-Power and Borkum West closed followed by Meerwind and Global Tech I in 2011.

Table D-2. Key Past Project Financing Parameters

	Q7 2006	C- Power 2007	Belwind 2009	Boreas 2009	C-Power 2010	Borkum West 2010	Meerwind 2011	Globaltech I 2011	Baltic 1 2011	Lincs 2012
Base Budget *(in MEUR/MW)*	383 M *3.200*	153 M *5.100*	619 M *3.750*	ca. 600 M *ca. 3.050*	1,289 M *3.950*	780 M *3.900*	1,175 M *4.050*	1,600 M *4.000*	196 M *4.050*	ca. 1,100 M *ca. 4,050*
Senior Debt *(% base budget)*	188 M *49%*	95 M *62%*	426 M *69%*	GBP 340 M 67%	869 M *67%*	470 M *60%*	822 M *70%*	960 M *60%*	138 M *70%*	GBP 425 M *42%*
Base Equity excl. contingency	50 M *13%*	26 M *17%*	104 M *17%*	GBP 166 M**33%*	25 M *19%*	260 M *33%*	350 M *30%*	640 M *40%*	58 M *30%*	GBP 575 M *58%***
Contingency (*debt: equity*) *(% base budget)*	60 M *(50/50)* *16%*	16 M *(70/30)* *11%*	80 M *(70/30)* *13%*	Not required (project operational)	63 M *(70/30)* *5%*	80 M *(50/50)* *10%*	90 M *(70/30)* *8%*	135 M *(50/50)* *9%*	Not required (project operational)	GBP 150 M (50/50) 15%
Debt Sizing (base scenario)	1.35 DSCR @p90	1.30 DSCR @p90	1.50 DSCR @p50	Blended DSCR	1.30 DSCR @p90	1.35 DSCR @p90	1.30 DSCR @p90	1.35 DSCR @p90	1.35 DSCR @p90	Blended DSCR
Debt: Equity	53:47	63:37	69:31	67:33	68:32	59:41	70:30	60:40	70:30	45:55
Maturity	1.5y+9.5y	1.5y+15y	1.5y+15y	15y	3y+15y	2y+15y	2.5y+15y	2y+10y	14y	15y
Margin (avg – est.)	<200 bp	<150 bp	<300 bp	>300 bp	<250 bp	>300 bp	<300 bp	>300 bp	ca 300 bp	ca 250 bp

Source: Company press releases; "Finding bank debt for offshore wind farms: what's possible ", Dexia, EOW 2009, Stockholm; "Largest ever offshore wind financing closes", IJOnline, 26/11/2010; "Trianel closes on Borkum West", *Project Finance Magazine*, 20/12/2010; "Borkum West II closes", pfi, 13/1/2011; "Syndication closed for Global Tech 1", inspiratia, 13 July 2011; "Details emerge of Blackstone's offshore wind financing", SparkSpread, 8 August 2011;

“288MW Meerwind IPP”, IJOnline, 24 August 2011; “Landmark Global Tech I reaches FC”, inspiratia, 1 September 2011; “Baltic 1 Offshore Wind Farm”, inspiratia, 13 December 2011; “Centrica set to sign £500m offshore financing”, SparkSpread, 22 February 2012; “CENTRICA, SIEMENS RECEIVE $660 MILLION FOR U.K. WIND PROJECT”, BNEF, 13 June 2012, “The strongest Lincs”, inspiratia, 14 June 2012; GGEB estimates

Debt-Sizing Process

Senior Debt

The debt level for offshore wind projects in Europe is constrained by two factors:

1. The net cash flows generated by the project (see Figure D-9)
2. An overall cap expressed as a percentage of the total investment amount (see Figure D-10)

Figure D-9. Revenue Side Constraint

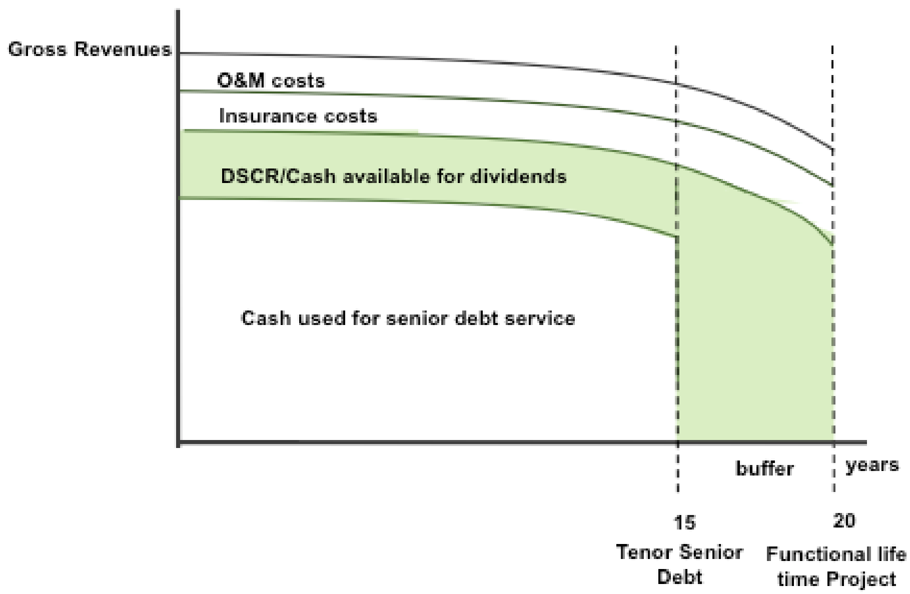
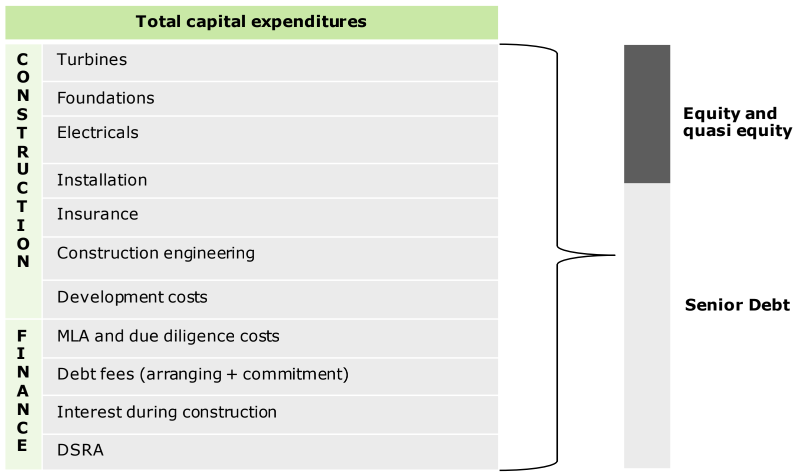


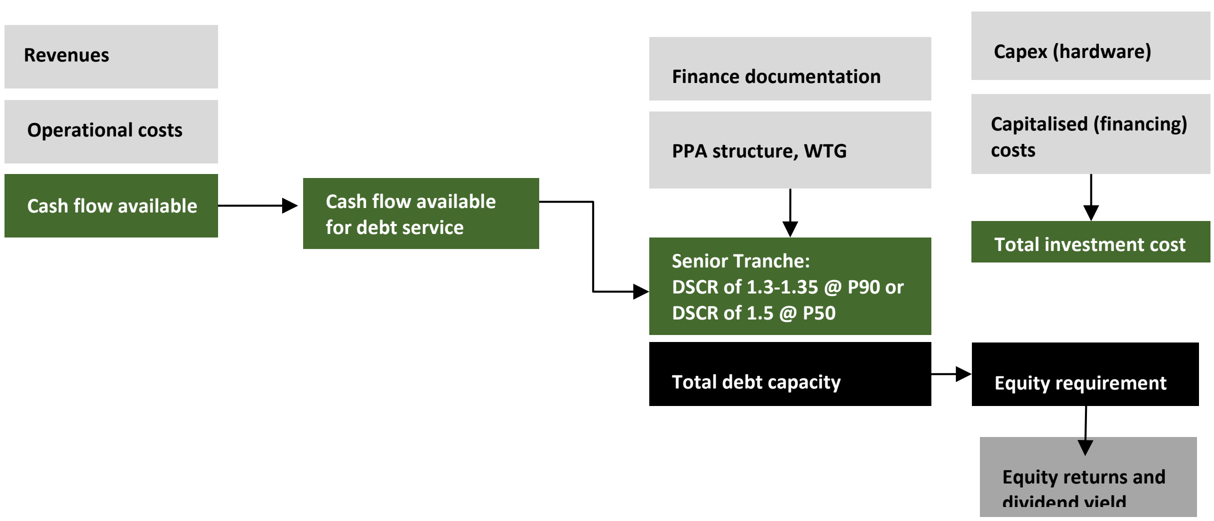
Figure D-10. Capital Expenditure Constraint



Cash Flows

The banks determine the debt capacity on the basis of revenues actually available for debt service (i.e., after operating costs) and assume a safety margin. This safety margin is expressed through the Debt Service Coverage Ratio (DSCR). The cash flow available for debt service is divided by the DSCR to determine the (semi)annual debt service the project can bear. This is called the "sculpted modeling method". It enables the project to optimize its debt capacity and is outlined in Figure D-11.

Figure D-11. Debt-Sizing Process



The DSCR value used depends on the wind resource assumptions that banks are willing to accept in their base case. The wind data acceptability will depend on the reliability of the data. P90 and P50 wind assumptions have been accepted for European projects. For P50 a DSCR level of 1.5 and for P90 a DSCR level of 1.3-1.35 are the minimum levels required for offshore projects under current market conditions. We foresee that the same DSCR levels will be required for U.S. offshore wind projects.

Cap on Leverage

The total debt level is capped at a certain percentage of the total base case investment amount to ensure that, irrespective of project cash flows, equity parties have "skin in the game" and provide a minimum fraction of the investment budget to demonstrate their commitment to and trust in the long-term prospects of the project. In the current European market, a 70% cap on the debt portion has become the standard for well-structured deals. Banks will likely require the same cap on leverage in the U.S. if a project is to be considered bankable.

An interesting point to note is that there is no specific requirement that "hard" equity constitutes the remaining 30%: quasi-equity such as mezzanine debt, tax equity, pre-completion revenues, vendor finance or other subordinated forms of debt may be taken into account towards that requirement, subject to more or less stringent conditions, but in all cases including full subordination to senior debt.

Contingent Debt

Banks have accepted construction risk for offshore projects with multi-contracting on the basis of well-defined contingency plans allowing the project to withstand pre-agreed "worst case" delay or cost overrun scenarios. Such contingency plans need to be financed beforehand, by way of a combination of contingent equity and contingent debt committed on financial close. Subject to the financial strength of the equity parties, equity drawdown might be required at financial close.

The required level of the contingency budget is subject to the perceived risk level of the project and is ultimately determined by the lender's technical advisor. The proportion of contingent debt and contingent equity is typically similar to the proportion agreed for in the base budget (i.e., in current market conditions contingent debt would be up to 70% of the agreed contingency budget).

Financing Costs

Typical OSW financing parameters are summarized in Table D-3 and described in more detail below.

Senior Debt

Margins for all PF debt have significantly increased across all sectors following the financial crisis, and the same is true for offshore wind, as the small sample of transactions demonstrates, with prices moving from 150-200 bp to 300-400 bp. This reflects both the increased cost for banks of accessing long-term liquidity and a more conservative approach to risk by the institutions still willing to lend. (Many dropped out of the market altogether.)

For a well-structured deal in the offshore sector in Europe with no unusual features, the margin can be expected to be in a range of 300-400 bp for the repayment period, with typically a 25-50 bp additional premium during the construction period. In line with the persistent difference noted in the land-based wind market, transactions in the U.S. market are likely to be priced a bit higher than in the European market, for comparable risk structures.

There will be additional fees imposed for arranging the financing and fulfilling other roles. The arranging role can be performed by a commercial bank or a separate financial advisor managing the financing process. Upfront fees are for European projects not very different from those prevailing in the land-based wind debt market (around 275 bp). We expect a somewhat higher upfront fee will be charged for U.S. projects.

Contingent Debt

The margin for the contingent debt is typically 50 bp above the margin of the senior debt.

Tenor and Repayment Terms

Senior Debt

The tenor of the loan was to date subject to the expected operational life of the project and the duration of the guaranteed gross revenues (e.g., subsidies, PPAs). Banks usually prefer to see a tail (e.g., a PPA term beyond the debt term) to ensure total debt is repaid with some buffer to spare. In Europe, the maximum tenor to date is 15 years plus construction and this maturity is unlikely to be breached for a number of years. The global financial crisis and the new regulations (Basel Committee on Banking Supervision's revised capital, liquidity and leverage requirements published in September 2010 ("Basel III")) have forced banks to ask for stricter financing conditions, or in some cases, not do business. Banks have signaled that providing a 15-year legal loan maturity (the period in which the loan must be repaid in full) post-construction for offshore wind projects is currently not feasible anymore. Legal loan maturities are being reduced from 15 years post-construction to 7-10 years post-construction (imposing a refinancing risk on the borrower) with additional cash sweeps to incentivize the borrower to refinance prior to the legal loan maturity date.

A 10-year tenor can be considered as a reasonable legal loan maturity for this project.

The sculpted repayment schedule in Europe is based on semi-annual repayments. This is in line with wind seasonality and typical O&M payment terms and it is highly likely that the same will be applied for projects in the U.S.

Contingent Debt

The tenor for contingent debt is usually relatively short: 5-7 years. The repayment schedule is semi-annual, with repayments typically by means of a cash sweep or a fixed repayment schedule (linear).

Table D-3. Financing Parameters Summary

Debt-Sizing Parameters	
Debt/Equity ratio	70/30
DSCR based on P50 and P90 wind statistics	1.5 for P50 and 1.30-1.35 for P90
Financing Costs	
Upfront fee	300 bp – 350 bp
Mandated Lead Arranger (MLA) fee	275 bp
Construction margin senior debt	350 bp – 350 bp
Operational margin senior debt year 1-5	325 bp – 375 bp
Operational margin senior debt year 6-10	350 bp – 400 bp
Operational margin senior debt year 11-15	375 bp – 425 bp
Margin contingent debt	50 bp above senior debt margin
Loan Characteristics	
Tenor senior debt	Construction + 10 years
Tenor contingent debt	5-7 years
Repayment schedule	Semi-annual

Working Capital

A cash reserve might need to be funded at financial close to cover any shortfalls in the cash flow. The amount required is, however, dependent on the time lag between accounts payable and receivable. A detailed assessment is required in order to assess whether the project has sufficient cash to pay its invoices on time.

Due Diligence Costs

As part of the due diligence process, a bank will require its legal, insurance, technical, and tax advisors to review the project contracts and documents and provide a detailed due diligence report providing their findings. Satisfactory conclusions and no major issues outstanding is one of the conditions for financial close. The due diligence costs for this project have been set to USD 15.6 M on the basis of the advisory cost typically expected for the development of an offshore wind project in Europe when it involves PF.

Insurance

Offshore wind faces significant risks, whereby costs increase exponentially when unexpected events arise (as the projects are capital intensive and incidents also result in loss of revenue due to delay). The non-recourse character of a project-financed project requires all the risks to be managed by the project. A strong insurance package is therefore very important to ensure its bankability. A bankable insurance package will need to include:

» Sufficient protection of the project’s assets
» Coverage for project’s debt service and fixed operating costs (at a minimum)
» Funding for any potential liability incurred to a third party

The insurance package should cover both the construction phase and the operations phase with preferably the same insurance providers to ensure that there can be no ambiguity in the coverage at takeover/completion of the project.

The standard insurance package during construction covers:

» Construction All Risks (CAR): This insurance covers all material damage to and/or loss or destruction of the work insured, however caused, during the insurance period. Main exclusions include normal wear and tear or deterioration, business interruption, betterments, war and kindred risks and atomic/nuclear reactions. Current market standards in Europe are deductibles around $ 300,000 to $ 600,000. Underwriters will fear high-frequency damages if these levels are lowered, resulting in large cash flows and high handling costs. Substantially lower deductibles are therefore not possible. Higher deductible levels can lead to lower premiums, but they are usually not acceptable for the contractors.
» Delay in Startup (DSU): This insurance covers delay based on a material damage to and/or loss or destruction under the construction policy or a loss of scheduled vessels for installation. This report covers an offshore wind farm project that is project financed. Lenders require this insurance as delays in interest payments will generally not be tolerated. A party developing on a balance-sheet-based finance might be able to await revenues and still meet payment obligations. Therefore, a delay in startup insurance might be a needless expense, provided the developer is well aware that any delay weighs directly on the equity capital.
» Third-Party Liability (TPL): Covers for damages or injuries of third parties caused by the Project Works. Limit subject to discussion with the employer and contractors. Its main exclusions are typically damages caused by contractor's material or floating material, motorized vehicles, Employers liability, damages covered under CAR, and gradual environmental damage (asbestos). Note however that the TPL is difficult to assess as the "claim culture" is somewhat more aggressive in the U.S. as in Europe. For now, the Navigant Consortium assumed similar TPL rates as in Europe.

The standard insurance package during the operational period covers:

» Physical Damage (PD): This insurance covers on an all risks basis damage to and/or loss of the wind farm or any part thereof.
» Business Interruption (BI): This insurance covers losses resulting from interruption of business caused by a physical damage covered under the Operational All Risks Insurance.

The insurance period is typically 12 months, which is tacitly renewed each year. Main exclusions are deliberate action, normal wear and tear, fines and guarantees, war and kindred risks, and atomic and nuclear reactions. Current market standards in Europe are deductibles around $300,000 to $600,000 for the PD coverage and 45 to 90 days for the BI coverage. Underwriters will fear high-frequency damages if these levels are lowered, resulting in large cash flows and high handling costs. Substantially lower deductibles are therefore not possible. Higher deductible levels can lead to low premiums, but the underlying balance sheet should be examined to ensure sufficient financial strength.

» Third-Party Liability: Damages or injuries of third parties caused by the Project Works. Main exclusions are gradual environmental damage (asbestos), war, terrorism, and willful act. Note, however, that the TPL is difficult to assess as the "claim culture" is somewhat more aggressive in the U.S. than in Europe. For now, the Navigant Consortium assumed similar third TPL rates as in Europe.

The insurance quotes shown in Table D-4 are based on insurance quotes seen in the European market and provide an indication of what the rates in the U.S. can be.

Table D-4. Insurance Premium Overview

Insurance during construction	
Construction All Risks during construction (% of ECV*)	1.25 %
Delay in Startup (% of total revenue 18 months)	3.5 %
Third-Party Liability (% of ECV*)	0.015 %
Insurance during operation	
Physical Damage (% of ECV)	0.5 %
Business Interruption (% total revenue 18 months)	1.75 %
Third-Party Liability (% of ECV)	0.015 %

* ECV = Estimated Contract Value

D.3 Background on JEDI Models

Economic development occurs when a specific area or region of interest is able to secure new sources of investment and when at least a portion of those investments is captured by local businesses and individuals. Economic development analysis seeks to track new investments in a specific location, distinguish different types of expenditures in those regions, and then examine the impact of those investments in the given locality. For those expenditures that are local, the impacts entail the initial investment plus potential downstream effects in the supply chain and in the consumer and retail sectors of the economy. If an expenditure associated with a given project is not captured locally, it is treated as economic leakage and has no economic development value for the region of interest.

Economic development activity is typically estimated using input-output (I/O) models. I/O models apply historical relationships between demand (i.e., specific expenditures within a given sector of the economy) and the resulting economic activity to estimate how new expenditures will affect economic development metrics, including jobs, earnings (wages and employer paid benefits), and output, a general measure of economic activity.[89] Although some I/O models incorporate dynamic elements, many are static—they measure inter-industry relationships for a given time period—and linear—they assume that any change in demand, regardless of magnitude, has the same proportional result. However, the

[89] Output is defined more broadly than other metrics of economic activity, including value added or GDP; output is the sum value of all goods and services at all stages of production (i.e., as a raw material and as a finished product). Value added refers only to the market value of the final product.

inter-industry relationships utilized in I/O modeling tend to change only gradually over a long period of time, and I/O modeling is a widely used methodology for measuring economic development activity.

NREL has developed a set of I/O models known as the Jobs and Economic Development Impacts (JEDI) models. These models rely on the widely recognized and well known I/O multiplier data provided by the Minnesota IMPLAN Group. Offshore wind is the latest addition to this suite, which already includes biofuels, coal, concentrating solar power, natural gas, solar photovoltaics, wind, and marine/hydrokinetic power.[90]

NREL's JEDI models classify results into three categories: direct, indirect, and induced. Within JEDI, direct results are defined as on-site labor and professional services. These are the impacts from dollars spent on labor by companies engaged in development and on-site construction and operation of power generation and transmission. These results do not include materials—only labor. With its exclusive emphasis on labor, JEDI's first tier of impacts is narrower than typical direct economic impacts. Companies or businesses that fall into this category include project developers, environmental and permitting consultants, road builders, concrete-pouring companies, construction companies, tower erection crews, crane operators, and O&M personnel.

Indirect effects are reported in JEDI as local revenues, equipment, and supply chain results. These results are driven by the increase in demand for goods and services from direct on-site project spending. Businesses and companies included in the second tier of economic activity include construction material and component suppliers, analysts and attorneys who assess project feasibility and negotiate contract agreements, banks financing the projects, all equipment manufacturers (i.e., blade manufacturers), and manufacturers of replacement and repair parts.

Induced effects are the third and final category and are driven by the local expenditures of those receiving payments within the first two categories. These are often associated with increased business at local restaurants, entertainment, and retail establishments, as well as child care providers or any other entity affected by the increased economic activity and spending occurring in the first two tiers.

JEDI model results are displayed in two different time periods: construction and operations. Construction period results are inherently short-term. Jobs are defined as full-time equivalents (FTE), or 2,080-hour units of labor. (One construction period job equates to one full-time job for one year.) Equipment manufacturing jobs, such as tower manufacturing, are included in construction period jobs as it is ultimately new construction that drives equipment manufacturing. All employment related to the construction of the project is reported in FTE. Operations period results are long-term, for the life of the project, and are reported as annual FTE jobs and economic activity. Operation period impacts continue to accrue throughout the operating life of the facility.

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[90] NREL's JEDI models are publicly available spreadsheet tools that apply state-specific IMPLAN year 2010 multipliers. The JEDI analysis tools were developed by NREL in conjunction with MRG & Associates. For more information on the JEDI tools, see http://www.nrel.gov/analysis/jedi/.

JEDI results are not intended to be a precise forecast; they are an estimate of potential activity resulting from a specific set of projects or scenarios. In addition, JEDI results presuppose that projects are financially viable and can be justified independent of their economic development value. Importantly, results generated by the JEDI models are gross (not net) results. They do not consider potential increases or decreases in electricity rates resulting from investments in new infrastructure, nor do they consider whether the respective projects displace economic activity elsewhere.