Final Technical Report

Mid-Atlantic Offshore Wind Interconnection and Transmission (MAOWIT)

DOE Award Number: DE-EE0005366

Project Period: October 2011 – September 2015

Principal Investigator(s):
Willett Kempton, 302-831-0049, willett@udel.edu,
University of Delaware, College of Earth, Ocean & Environment; Research Director, Center for Carbon-free Power Integration
Cristina L. Archer – 302-831-6640, carcher@udel.edu,
University of Delaware

Warren B. Powell – 609-258-5272, powell@princeton.edu,
Princeton University
Hugo P. Simao – 609-258-6809, hpsimao@princeton.edu,
Princeton University

Name and addresses of recipient organizations:
University of Delaware
Newark, DE 19716

Names of other project team member organizations:
Atlantic Grid Developers
PJM Interconnection
Princeton University
Sailor's Energy (Michael Dvorak)
TransElect (Paul McCoy)

Date of Report
5 April 2016

Acknowledgement: This report is based upon work supported by the U.S. Department of Energy under Award No. DE-EE0005366.

Disclaimer: Any findings, opinions, and conclusions or recommendations expressed in this report are those of the author(s) and do not necessarily reflect the views of the Department of Energy.

Table of Contents

List of Acronyms

ARMA	Autoregressive Moving Average
AWC	American Wind Connection
A/S	Ancillary Services
BOEM	Bureau of Ocean Energy Management
DOD	Department of Defense
DOE	Department of Energy
GW	Giga-watt
GWa	Average Capacity
HVDC	High Voltage Direct Current
ISO	Independent Service Operator
MAOWITS	Mid-Atlantic Offshore Wind Interconnection and Transmission
MW	Megawatt
NASA	National Aeronautics and Space Administration
NDBC	National Data Buoy Center
PJM	Pennsylvania-New Jersey-Maryland Interconnection
POI	Point of Interconnection
RTO	Regional Transmission Organization
WEA	Wind Energy Area
WRF	Weather Forecasting Model

Executive Summary

Introduction

This project has carried out a detailed analysis to evaluate the pros and cons of offshore transmission, a possible method to decrease balance-of-system costs and permitting time identified in the DOE Office Wind Strategic Plan (DOE, 2011). It also addresses questions regarding the adequacy of existing transmission infrastructure and the ability of existing generating resources to provide the necessary Ancillary Services (A/S) support (spinning and contingency reserves) in the ISO territory.

This project has completed the tasks identified in the proposal:

1. Evaluation of the offshore wind resource off PJM, then examination of offshore wind penetrations consistent with U.S. Department of Energy's (DOE) targets and with their assumed resource size (DOE, 2011).

2. Comparison of piecemeal radial connections to the Independent System Operator (ISO) with connections via a high-voltage direct current (HVDC) offshore network similar to a team partner.

3. High-resolution examination of power fluctuations at each node due to wind energy variability

4. Analysis of wind power production profiles over the Eastern offshore region of the regional ISO to assess the effectiveness of long-distance, North-South transmission for leveling offshore wind energy output

5. Analysis of how the third and fourth items affect the need for ISO grid upgrades, congestion management, and demand for Ancillary Services (A/S)

6. Analysis of actual historic 36-hr and 24-hr forecasts to solve the unit commitment problem and determine the optimal mix of generators given the need to respond to both wind variability and wind forecasting uncertainties.

The project is separated into seven tasks, each which aim at achieving the above six objectives:

> Task 1: Analysis of offshore transmission nodes at various levels of wind capacity build-out
>
> Task 2: Bathymetric and use conflict mapping
>
> Task 3: Weather Forecasting Model (WRF) output
>
> Task 4: Power Flow Model
>
> Task 5: Analysis of offshore wind leveling

Task 6: Unit Commitment Model

Task 7: Dissemination

Task 1

In looking at the various levels of offshore wind capacity build-out, five build-out scenarios are assumed, and are summarized in Table 1. (Figures have been revised based on subsequent analysis, and are now in the for-publication Archer et al 2016 manuscript.)

Table 1: The five build-out levels of offshore wind considered in the MAOWIT study. Level 1 is the current PJM WEAs, levels 2-5 are increasing fractions of PJM load.

Build-out level	Blocks included (Figure 1)	N. of wind turbines	Installed capacity (GW)	Average output (GW_a)	Percent of average PJM load
1	1.1-1.4	1,638	7.3	3.3	4.4%
2	2.1-2.8	5,637	25.3	11.2	15.0%
3	3.1-3.4	7,990	35.8	16.0	21.4%
4	4.1-4.6	10,906	48.9	21.9	29.1%
5	5.1-5.7	15,556	69.7	31.5	42.0%

The rated capacity is calculated from the total available area given a spacing factor of 10 by 10 rotor diameters for build level 1 and 8 by 8 rotor diameters for subsequent build levels, and a 126-m rotor diameter for a 5MW offshore wind turbine. To calculate the average capacity (GWa), the rated capacity is multiplied by the assumed capacity factor of 35%. The percentage of the average PJM load is calculated by dividing the average capacity by the 2010 average PJM load of 79.6 GW.

The offshore wind energy will be transported to shore via offshore HVDC transmission similar to the Atlantic Wind Connection (AWC), and that will be compared with integration via piecemeal radial ties.

The AWC transmission system consists of a converter station offshore to convert AC power from the turbines to DC, 1300 km of HVDC cabling (both onshore and offshore), and a converter station onshore to convert back to AC for the grid. Thus, for a 1000 MW wind project 150 km from shore (assuming on average, some lateral travel plus the run to the shore converter station), the losses from the wind farm to onshore grid via HVDC would be 2.6-2.9% (Negra et al., 2006). That calculation done for this project corresponds with the internal assessment of the maximum AWC losses of 2.79% during full-load for a 1000 MW wind project with two converter stations and 1300 km of 320 kV-dc lines (D. Ozkan, personal communication, June 24, 2012).

For radial AC ties from a 1000 MW project 50 km from shore using 230 kV cables the total line losses would be 1.96%. The total line loss is composed of the submarine loss of 0.0718 MW per km at 50 km and 4 required cables plus the land loss of 0.0653 MW per km at 20 km and 4 required cables. If 138 kV cables are used instead, the total line losses would be 2.86%. The total loss is composed of the submarine loss of 0.07 MW per km at 50 km and 6 required cables
(21 MW) plus the land loss of 0.0630 MW per km at 20 km and 6 required cables (7.56 MW).

The combined 28.6 MW loss divided by 1000 MW project yields a 2.86% loss.

Task 2

Conflict areas are defined, as zones that we believe are less likely for offshore wind development. The following studies and databases were reviewed to determine potential conflict areas: Based on our assessment of the several published articles, reports and databases, the following factors creating conflict areas were included:

- Designated Shipping Lanes
- Military Conflict for North Carolina, Virginia & Delaware Coast
- Fish Havens
- Visual Conflict
- Outer Continental Shelf Shipping Conflict
- Harbor Restricted Areas
- Dump Sites
- Explosives

Additionally, the NASA conflict area surrounding Wallop's Island was considered but not excluded because we believe that it will be a developer's decision whether they wish to take the risk of possible falling projectiles, and it seems plausible that they would take as much risk with equipment as do skippers with manned vessels, the latter of which traverse this zone today. As near-shore, shallow ocean area becomes scare, developers may be willing to study and undertake this risk in exchange for cost savings. Finally, military exclusion zones for Maryland and New Jersey were not provided by the Department of Defense in time for the final analysis, and are therefore not included.

To analyze the impact of full build-out of the WEAs, GIS work was performed to explicitly add these regions. Up-to-date BOEM WEA definitions were obtained from the BOEM GIS data website (BOEM, 2013) and incorporated into build-block definitions, shown in Figure 2. For clarity, we reorganized and renamed all sub-blocks in a logical order of X.Y, where X is the build order and Y is the serial number of the farms in that build, labeled from north-to-south.

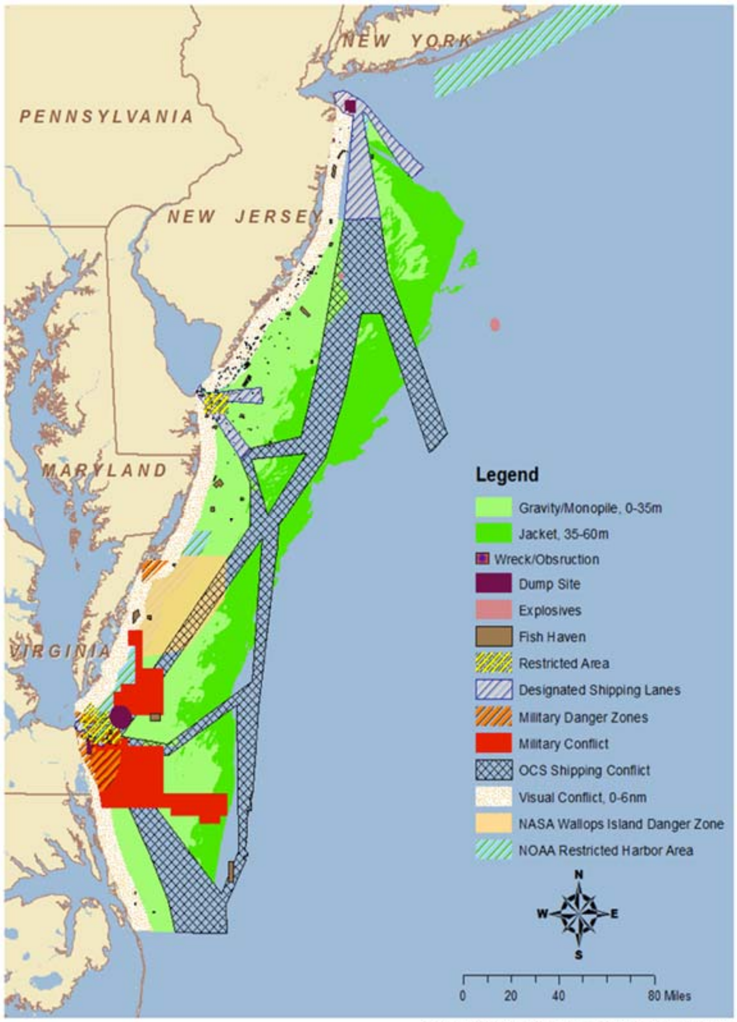


Figure 1: *The environmental and social conflict areas considered in this study, distinguished by color and hatching. In remaining areas, the bathymetry is displayed in light and dark green, designating appropriate foundation type.*

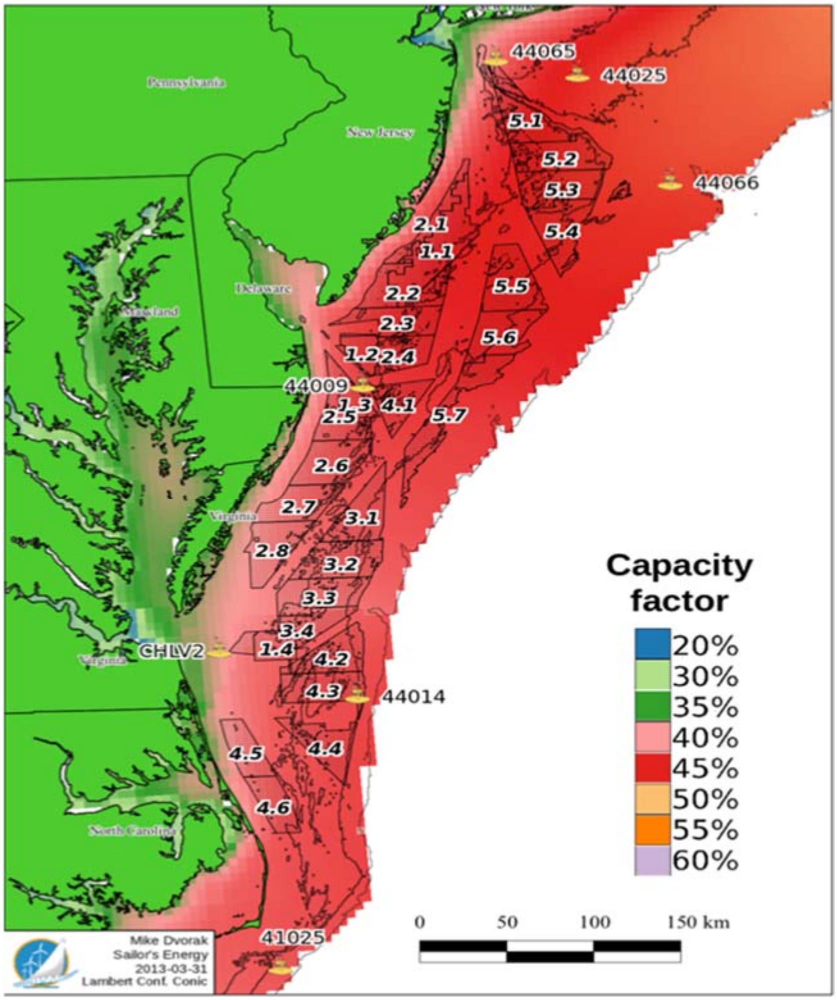


Figure 2: Turbine hub-height (90 m) wind resource data derived from Dvorak, et al. (2012) using WRF high-resolution (5.0 km) hourly wind fields for the 5-year period of 2005-2010. Capacity factor was calculated using a REpower 5M 5.0 MW turbine power curve. The sunblock numbering scheme corresponds to the build-out order, using the new numbering described in Table 4. Isodepth contours are plotted at 30, 50, and 200 m water depth.

Task 3

The performance of WRF for the maximum build-out scenarios is summarized by lease block (summing over all sub-blocks within each block). Main findings are as follows:

1. The overall performance is satisfactory: bias amplitudes are ~10% of the mean, RMSE ~50% of the mean, and correlations are often >0.7.

2. WRF has a positive bias in general (all blocks except block 4).

3. Although the bias in generally lower for the 24-48 hr forecasts, the RMSE and the correlation are both better for the 0-24 hr forecasts.

4. Overall, the standard deviations of the forecast and actual power are similar. This means that the variability of the synthesized forecast and validation system would match the real world variability of the

offshore resource. This passes the modeling skill test #1 as defined by Pielke, et al. (2002, p. 464).

5. Overall, the RMSE<standard deviation of the observations, which passes the model skill test #2 in Pielke, et al. (2002, p. 464).

6. The WRF performance is better in the winter than in the summer because the turbine power curve at high wind speeds acts as a low-pass filter for forecasting error at winds over 15 ms^{-1}. That is, severe over-estimates of wind speeds >15 ms^{-1} do not show up as error because the turbine is already outputting full power regardless of the over-estimate in wind speed.

Task4:

Per agreement, Task 4 has been bundled in as part of Task 6.

Task 5

The wind output profile of the entire studied offshore region (by build-out level) can be observed in Figures 28 through 31. These figures show the total energy (in MW) that could be produced from wind in the Mid-Atlantic offshore region in certain weeks of the months of January, April, July and October of 2010.

The figures show that the wind energy levels generated by the 5 build-out levels are highly correlated with each other. Consequently, even after the aggregation of the production over the whole Mid-Atlantic offshore region there is still significant variability in the total level of energy generated. The observed leveling effect is much less than what was indicated in an earlier work by Kempton *et al* (2010). .

Task 6

One result of this project was added effort on developing the SMART-ISO model under the direction of CO-PI Warren Powell at Princeton University. SMART - ISO is a simulator of the market operations of PJM that aims to strike a balance between detailed representation of the system and computational performance. It comprises three optimization models embedded within a simulation model that captures the nested decision-making process:

1. Day-ahead unit commitment (DA-UC) model
2. Intermediate-term unit commitment (IT-UC) model
3. Real-time dispatch

Accurate modeling of the nesting of these three models is a central tool used by Independent Service Operators (ISOs) to adapt to uncertainty. In SMART - ISO all three optimizations include a DC approximation of the power flow, and an AC power flow model is run after both the intermediate-term UC and the real-time economic dispatch model to verify the electrical stability of the grid.

The simulator takes as inputs:

1. The list of generators available for scheduling in the PJM area (including all relevant operational and iconic parameters)
2. The transmission grid (buses and line), including relevant transmission parameters
3. Historical (and/or simulated) time series of loads (both active and reactive) at the bus level over the simulation horizon
4. Rolling time series forecasts of non-dispatchable generation (e.g wind) over the same horizon
5. Historical (and/or simulated) time series of non-dispatchable generation.

Table 2 shows the results of adding increasingly higher levels of offshore wind into the unconstrained PJM grid. The percentage of offshore wind participation in the total generation at build-out level 1 ranged from 2.2% in the peak load month of July to 4.3% in the winter month of January, whereas at build-out level 5 (the highest) it ranged from 16.7% to 30%. The percentage of wind used, with respect to what was actually available, was as high as 94.8% at build-out level 1 in January, and as low as 56.4% at build-out level 5 in October. The most noteworthy results in Table 5, though, are the estimates of the likelihood of load shedding at some time during the simulated week, due to the unexpected variation in the wind energy generation. From build-out level 2 and up, in any season, it is practically certain that the PJM system as currently operated will face load shedding at least once a week. At build-out level 1 it is possible to operate the system without any load shedding on a week, but at different degrees, depending on the season (it is more likely to observe some load shedding in July and January, when the loads are higher, than in the shoulder months of April and October). The more energy generated from wind, the larger are the errors in the forecasts used in the commitment planning, and consequently the higher is the likelihood that the dispatchable generation committed beforehand will be unable to handle unexpected variations in the wind energy.

There are different ways in which the PJM market operation can be modified to try to cope with the uncertainty in the wind energy forecasts. We tested two of them: (1) the addition of ramp-up and ramp-down reserves from dispatchable (fast) generation; and (2) a radical improvement in the day-ahead and intermediate-term wind forecasts. “Radical” in this context means assuming that we have perfect forecasts, that is, they are equal to the actual observed values. This is obviously an idealized situation that will serve as a boundary case for any improvements that might be made in forecasting wind energy in the future. We will henceforth refer to (1) as the imperfect forecast case and (2) as the perfect forecast one.

The runs concluded that installing offshore wind capacity of 25.3GW (level 2) or more, without upgrading the PJM transmission grid, would be inadvisable.

Table 2: Adding offshore wind energy to the unconstrained PJM grid

Build-out Level	Installed Capacity (GW)	Month-Year	Generation from Offshore Wind (%)	Used Wind (%)	Likelihood There Will Be Load Shedding at Some Time During the Week (%)	Average Peak Load Shedding (GW), When There Is Any Shedding
1	7.3	Jan-10	4.3	94.8	38.1	0.6
		Apr-10	4.0	78.3	9.5	0.3
		Jul-10	2.2	92.1	81.0	2.3
		Oct-10	4.0	78.2	9.5	0.6
2	25.3	Jan-10	14.5	93.4	100.0	3.1
		Apr-10	15.1	87.7	100.0	3.8
		Jul-10	7.1	86.9	100.0	6.4
		Oct-10	15.8	90.0	100.0	2.3
3	35.8	Jan-10	20.8	93.4	100.0	5.2
		Apr-10	20.4	83.9	100.0	4.3
		Jul-10	10.3	85.6	100.0	7.7
		Oct-10	20.8	83.9	100.0	3.2
4	48.9	Jan-10	25.6	84.2	100.0	5.4
		Apr-10	24.2	74.0	100.0	4.4
		Jul-10	14.1	80.5	100.0	9.8
		Oct-10	24.1	72.1	100.0	3.9
5	69.7	Jan-10	30.0	68.7	100.0	7.4
		Apr-10	29.9	62.9	100.0	5.4
		Jul-10	16.7	68.1	100.0	12.5
		Oct-10	27.5	56.4	100.0	3.1

Introduction

This project will provide a detailed analysis to evaluate the pros and cons of offshore transmission, which is outlined as possible method to decrease balance-of-system costs and permitting time in the DOE Office Wind Strategic Plan (DOE, 2011). It will also address related and pressing questions regarding the adequacy of existing transmission infrastructure and the ability of existing generating resources to provide the necessary Ancillary Services (A/S) support (spinning and contingency reserves) in the ISO territory.

Through this project we will achieve six objectives:

1. Examination of offshore wind penetrations consistent with U.S. Department of Energy's (DOE) targets and with their assumed resource size (DOE, 2011)

2. Comparison of piecemeal radial connections to the Independent System Operator (ISO) with connections via an high-voltage direct current (HVDC) offshore network similar to a team partner.

3. High-resolution examination of power fluctuations at each node due to wind energy variability

4. Analysis of wind power production profiles over the Eastern offshore region of the regional ISO to assess the effectiveness of long-distance, North-South transmission for leveling offshore wind energy output

5. Analysis of how the third and fourth items affect the need for ISO grid upgrades, congestion management, and demand for Ancillary Services (A/S)

6. Analysis of actual historic 36-hr and 24-hr forecasts to solve the unit commitment problem and determine the optimal mix of generators given the need to respond to both wind variability and wind forecasting uncertainties.

Task 1 – Analysis of Offshore Transmission Nodes at Various Levels of Wind Capacity Build-out

Subtask 1.1 - Determine Modeling Scenarios

This goal was reached through several group meetings and phone calls, in conjunction with review of peer-reviewed literature plus unpublished industry analyses, to insure that the build-out scenarios can be scientifically justified, make sense to the subgroups and require reasonable effort on the part of each group. Through this process, we decided that the project will analyze the PJM Interconnection grid impact of five different offshore wind build-outs.

1. For the lowest build-out, we use the Bureau of Ocean Energy Management (BOEM) revised Wind Energy Areas (WEA) off the states of New Jersey, Delaware, Maryland and Virginia. Developers have submit bids for leases of these ocean blocks and therefore it represents a near-term, already-planned build-out level

2. The second offshore wind build-out satisfies around 15% of the PJM average load.

3. The third build-out satisfies 25% of the PJM average load

4. The fourth build-out satisfies 35% of the PJM average load

5. As a maximum level of wind build-out, we delineated the available ocean adjacent to the ISO up to 60-m depth after excluding areas for environmental and conflicting use exclusion zones. This is the maximum build-out assuming bottom-mounted turbines filling un-conflicted space up to 60 m depth. The method for determining un-conflicted space is described in Task 2 below.

Table 1 displays the sizes of the relative build-out levels1.
The rated capacity is calculated from the total available area given a spacing factor of 10 by 10 rotor diameters for build level 1 and 8 by 8 rotor diameters for subsequent build levels, and a 126-m rotor diameter for a 5 MW offshore wind turbine. To calculate the average capacity (GWa), the rated capacity is multiplied by the assumed capacity factor of 35%. The percentage of the average PJM load is calculated by dividing the average capacity by the 2010 average PJM load of 79.6 GW.

Table 1: The five build-out levels of offshore wind considered in the MAOWIT study. Level 1 is the current PJM WEAs, level 2-3 are increasing fractions of PJM load.

Build-out level	Blocks included (Figure 1)	N. of wind turbines	Installed capacity (GW)	Average output (GW_a)	Percent of average PJM load
1	1.1-1.4	1,638	7.3	3.3	4.4%
2	2.1-2.8	5,637	25.3	11.2	15.0%
3	3.1-3.4	7,990	35.8	16.0	21.4%
4	4.1-4.6	10,906	48.9	21.9	29.1%
5	5.1-5.7	15,556	69.7	31.5	42.0%

Subtask 1.2 - First-Cut Transmission Constraints

The offshore wind energy will be transported to shore via offshore HVDC transmission similar to the Atlantic Wind Connection (AWC), and that will be compared with integration via piecemeal radial ties. Both options will be modeled in Task 4 and Task 6. The preliminary POIs, offshore conversation stations and HVDC lines which will subsequently be modeled are displayed below in Figure 1. Note that the HVDC transmission and converter stations correspond to current AWC plans, thus they do not connect all the wind areas in our higher build levels. The delineation of the ocean areas at each build will be used in the WRF wind modeling to predict power output from each subarea. The power output is modeled as arriving onshore to PJM grid at the POI, and becomes the input to the power flow model.

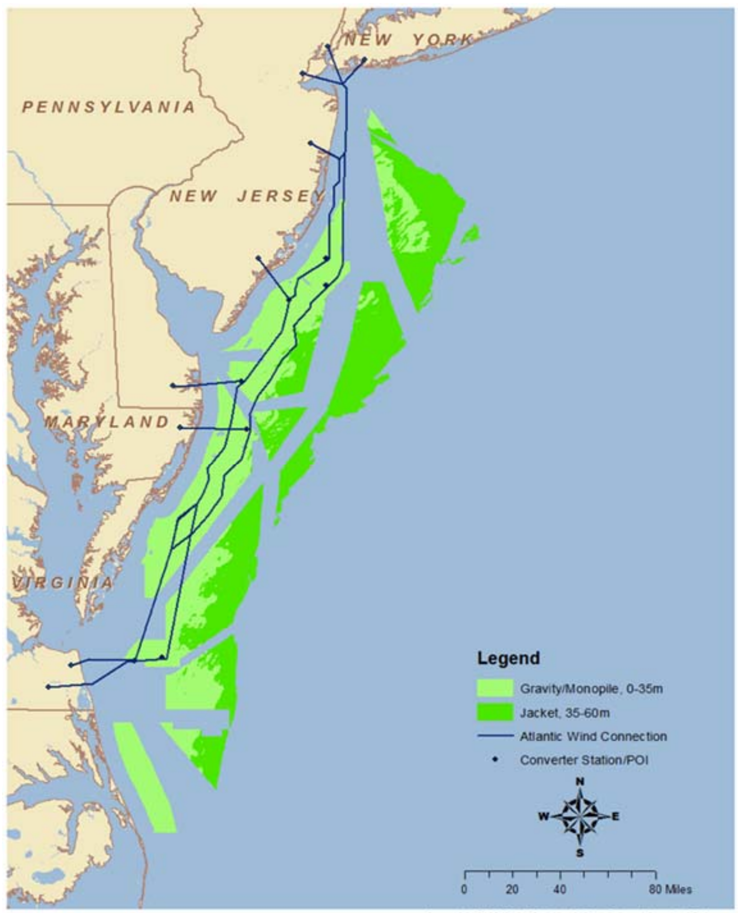


Figure 1: The location of the POIs, HVDC offshore transmission and offshore converter stations for the first build level overlaid on the study area, less conflict areas and delineated by bathymetry and corresponding foundation technology.

Subtask 1.3

The estimated tr[illegible] are about 3%.

According to Negra et al. (2006) the losses of an offshore converter station are between 0.11% and 0.7% depending on the load. The line losses per mile range from 0.007% per km for long distances to 0.02% for shorter distances, depending on the length of the cabling (data from Negra et al., 2006). The AWC transmission system consists of a converter station offshore to convert AC power from the turbines to DC, 1300 km of HVDC cabling (both onshore and offshore), and a converter station onshore to convert back to AC for the grid. Thus, for a 1000 MW wind project 150 km from shore (assuming on average, some lateral travel plus the run to the shore converter station), the losses from the wind farm to onshore grid via HVDC would be 2.6-2.9% (Negra et al., 2006). That calculation done for this project corresponds with the internal assessment of the maximum AWC losses of 2.79% during full-load for a 1000 MW wind project with two converter stations and 1300 km of 320 kV-dc lines (D. Ozkan, personal communication, June 24, 2012).

For radial AC ties from a 1000 MW project 50 km from shore using 230 kV cables the total line losses would be 1.96%. The total line loss is composed of the submarine loss of 0.0718 MW per km at 50 km and 4 required cables plus the land loss of 0.0653 MW per km at 20 km and 4 required cables. If 138 kV cables are used instead, the total line losses would be 2.86%. The total loss is composed of the submarine loss of 0.07 MW per km at 50 km and 6 required cables (21 MW) plus the land loss of 0.0630 MW per km at 20 km and 6 required cables (7.56 MW).

The combined 28.6 MW loss divided by 1000 MW project yields a 2.86% loss.

Task 1 Key Results & Outcomes:

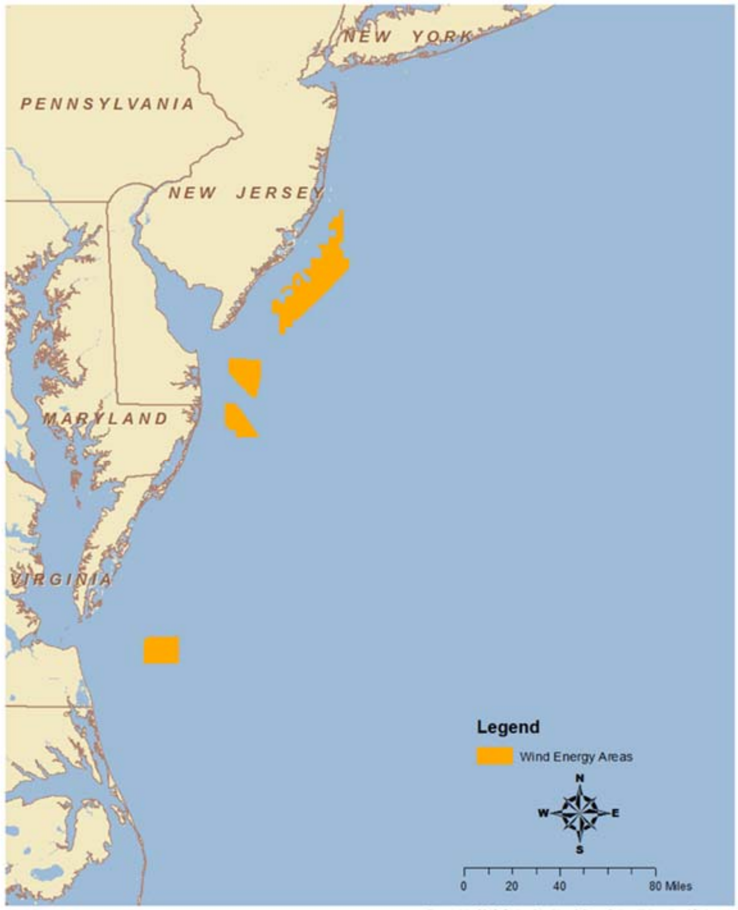
- Determined the five offshore wind build-out levels to be modeled
- Determined the offshore wind POIs
- Assessed the line losses calculations and parameters

Task 2 – Bathymetric and Use Conflict Maps

Deliverable: Build-out Area Maps. The task objective is to identify the areas where offshore wind projects could likely be constructed off the coast of the PJM ISO region and to determine how much wind capacity would be injected into each of the POIs.

Build Level 1: Wind Energy Areas
For the first build level we model wind projects constructed only in the four BOEM designated Wind Energy Areas (WEA) within the study area. In response to comments to BOEM, there have been several iterations of the WEAs, last revised June 2012. In order to begin analysis, and because we expect any subsequent revisions to be small, we will use the June 2012 version even if there are subsequent adjustments. In total, the WEAs can hold 8.3 GW of offshore wind capacity (see subsequent turbine spacing discussion). From that capacity, we make an approximation of power output,

subject to the more precise wind modeling to be conducted in subsequent quarters of the project. To that end, our initial delimitation of blocks assumed an approximate capacity factor of 35%, for which the WEAs would correspondingly constitute 3.6% of the average PJM load. The first build-out map is displayed below in Figure 2, with only the WEAs. (The capacity factor is subsequently computed precisely using WRF.)



After the BOEM WEA build out, subsequent build-out levels are determined by assessing less precise factors from the literature (Dhanju et al., 2008; Sheridan et al., 2012). These factors include: bathymetry, foundation technologies, distance from shore, and social and environmental conflict areas. This study only assesses the commercially available technologies of gravity based, monopile, or jacket structures. Based on European experience gravity

Figure 2: Build Level 1, the BOEM WEAs

es of 35-meters at which ... Jacket structures can in turn be installed to depths of 60-meters.

Conflict Areas

Conflict areas are defined, as zones that we believe are less likely for offshore wind development. The following studies and databases were reviewed to determine potential conflict areas:

1. Prior peer-reviewed, published articles defining and delineating potentially incompatible social or environmental ocean uses such as designated fish havens, shipping lanes, military areas or obstruction of beach views (see Dhanju et al., 2008; Sheridan et al., 2012; Firestone, Kempton & Krueger 2009, Firestone et al 2012; Lilley et al 2010)

2. A published Masters' Thesis, "The offshore wind power potential in PJM: A regional resource assessment," research performed by Scott Baker. The thesis includes an assessment of environmental and human-use conflict areas within PJM and delineates regions by offshore wind bottom-mounting technology (Baker, 2011).

3. A privately commissioned study by Atlantic Grid Development (AGD) required to assess where to plan and install the AWC.

4. Consultation with Frederick Engle of the Department of Defense regarding military exclusion zones (personal communication, June 1, 2012).

5. *The Delaware Marine Spatial Planning Project* performed by the Center of Carbon-free Power Integration at the University of Delaware which includes a careful analysis of marine mammal, sea turtle and avian activity, geological paleochannels, and human-use conditions (e.g. fishing and shipping) off the Mid-Atlantic (Bates et al., 2012). Some data sets do not extend across the entire PJM region.

Based on our assessment of the aforementioned published articles, reports and databases, the following factors creating conflict areas were included:

- Designated Shipping Lanes
- Military Conflict for North Carolina, Virginia & Delaware Coast
- Fish Havens
- Visual Conflict
- Outer Continental Shelf Shipping Conflict
- Harbor Restricted Areas

- Dump Sites
- Explosives

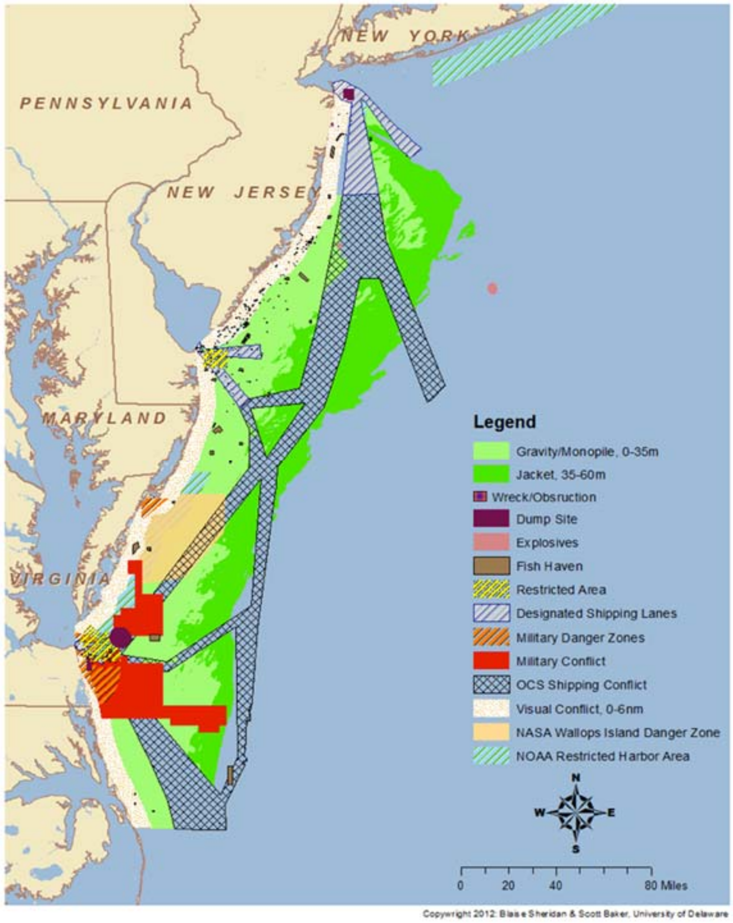


Figure 3: The environmental and social conflict areas considered in this study, distinguished by color and hatching. In remaining areas, the bathymetry is displayed in light and dark green, designating appropriate foundation type

... allop's Island was co[...] will be a developer's d[...] falling projectiles, an[...] with equipment as do skippers with manned vessels, the latter of which traverse this zone today. As near-shore, shallow ocean area becomes scare, developers may be willing to study and undertake this risk in exchange for cost savings. Finally, military exclusion zones for Maryland and New Jersey were not provided by the Department of Defense (DOD) in time for the final analysis, and are therefore not included.

The complete conflict areas and foundation types delineated by bathymetry (as per Sheridan et al., 2012) are displayed in Figure 3.

Build-out Blocks

After removing the conflict areas the remaining areas were delineated as nine individual build blocks (Figure 4), which are then designated to specific build-out levels. We chose offshore wind build blocks to correspond with build levels based on distance from shore, bathymetry and whether development had previously commenced in this block during a prior build level—for instance, the blocks which contain the WEA were selected first.

The blocks are then subdivided—using the spacing factors discussed below—into areas, which contain a maximum of roughly 5000 MW of offshore wind capacity.

Of course 5 GW of capacity is larger than any individual wind project and would require several separate converter stations.

But this size yields a manageable number of sub-blocks (25 total) for the meteorological modeling and power output analysis of each sub-block, and serves as the maximum possible integration size for individual radial ties. These sub-block areas are assigned to specific POIs for future power flow and unit commitment modeling purposes. In the radial, AC ties scenario, the offshore wind build blocks are linked with POIs based on geographical proximity. With the HVDC line, the switchgear can be controlled to direct electricity from the line into any POI selected by the operator.

Turbine Array Spacing

To assess the wind capacity, which can be produced in each of the blocks, it is necessary to determine the spacing between turbines in an array. The spacing between turbines in a wind project is an economic decision; a tradeoff between the cost of land (or rent of ocean area), versus the cost of the turbine, cabling, and lost revenue from the wake effect. If turbines are placed too close together then the wake-effect and turbulence from the upstream turbines can affect the power generation of the downstream turbines. However, increasing the distance between turbines increases the length and cost of the required inter-array cabling as well as the required space and therefore costs for that space.

Since the first US offshore projects have substantial amount of ocean available but are expected to have high capital costs (Levitt et al., 2011), based on AWC conversations with offshore wind developers and the Offshore Wind Development Coalition, we believe that the first projects will use a wind project spacing of 10 rotor diameters by 10 rotor diameters if there is no prevailing wind direction. In the case of a strong prevailing wind direction the projects could use a spacing of 10 rotor diameters downwind by 5-rotor diameters crosswind (as recommended by, for example, Manwell et al., 2002).

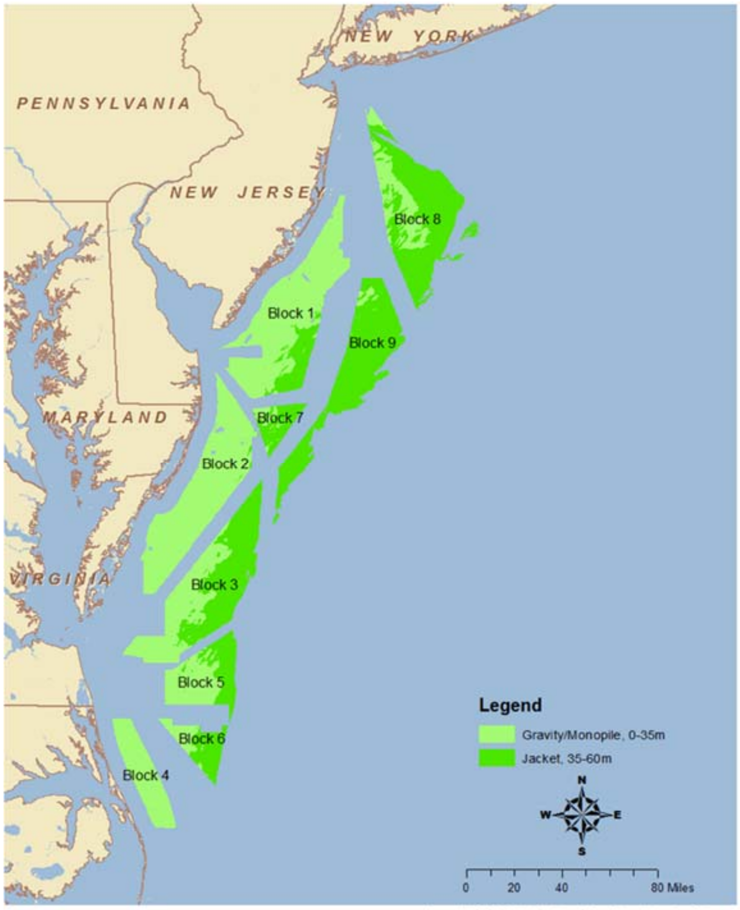


Figure 4: The nine build areas remaining, after removing environmental and social conflict areas. The bathymetry is displayed in light and dark green, corresponding to foundation type. The block numbers shown on this map have been superseded, so numbers here should be ignored.

A wind rose displays the directional component of the wind vector. These were produced at the centroid of each block in Figure 4 from the WRF wind modeling of 5 years of wind velocity data as part of Task 3 (Dvorak et al., 2012). The following pages show wind roses from each of Blocks 1 through 9.

From the wind roses it can be seen that for some blocks the prevailing wind directions are from the SW and NW—for Blocks 1, 2, 7 & 9 (Figures 5, 6, 11 & 13). For … at is, there is no pr… 7-10 & 12).

Figure 5: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 1.

Figure 6: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 2.

Figure 7: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 3.

Figure 8: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 4

Figure 9: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 5.

Figure 10: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 6.

Figure 11: Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 7.

Figure 12: *Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 8.*

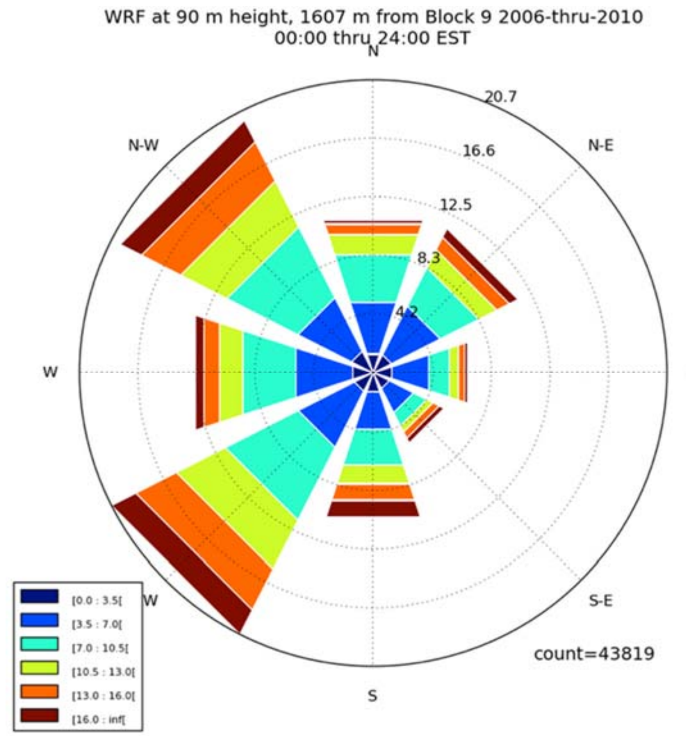


Figure 13: *Wind rose from 5 years of WRF wind velocity from the centroid of build-out block 9.*

In the lack of a strong prevailing wind direction, as in the case of blocks 3-6 and 8, we believe it makes the most sense to align the turbines in a square formation to minimize the wake effect. However, when the wind roses display a strong bi-directionality about 45° apart, as is the case in Blocks 1, 2, 7 and 9, it may make sense to use an equilateral triangular or hexagonal spacing pattern as displayed below in Figure 14. By using equilateral triangle spacing the wake effect on the downstream turbines is lessened because most of the time the wake would miss the downstream turbines due to the 15° offset between the prevailing wind and the turbine.

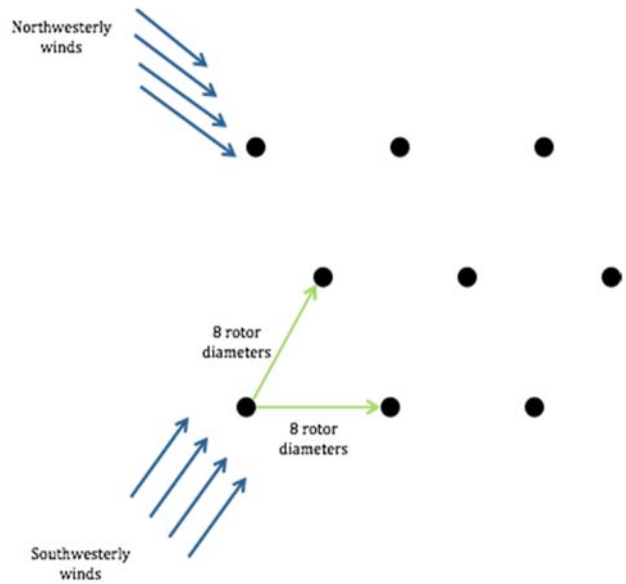


Figure 14: Potential turbine array spacing for bi-directional prevailing winds 45% degrees apart.

Ultimately, the spacing between turbines in an array is an economic decision which will be made on a case by case basis after weighing wake losses against cost of ocean space and desire to produce electricity at certain times of day or year (if such meteorological trends exist). We believe that early projects will face different economic conditions than later projects. Thus, for the purpose of this study we use a 10 by 10 rotor diameter for the Wind Energy Area build-out, which yields a capacity per area of 3.1 MW/km^2. We believe that future projects will face more space constraints and that after the creation of a US supply chain will see lower offshore wind prices, as in Europe (Levitt et al 2011). Therefore, we project that future projects will use a similar capacity per area as Europe—between 5-8 MW/km^2 (data from 4C Offshore Wind, 2012). For the post-Wind Energy Area build-outs, the spacing factor will be 8 rotor diameters by 8 rotor diameters yielding, by European standards a rather conservative—that is, a low—wind capacity per area of nearly 5 MW/km^2.

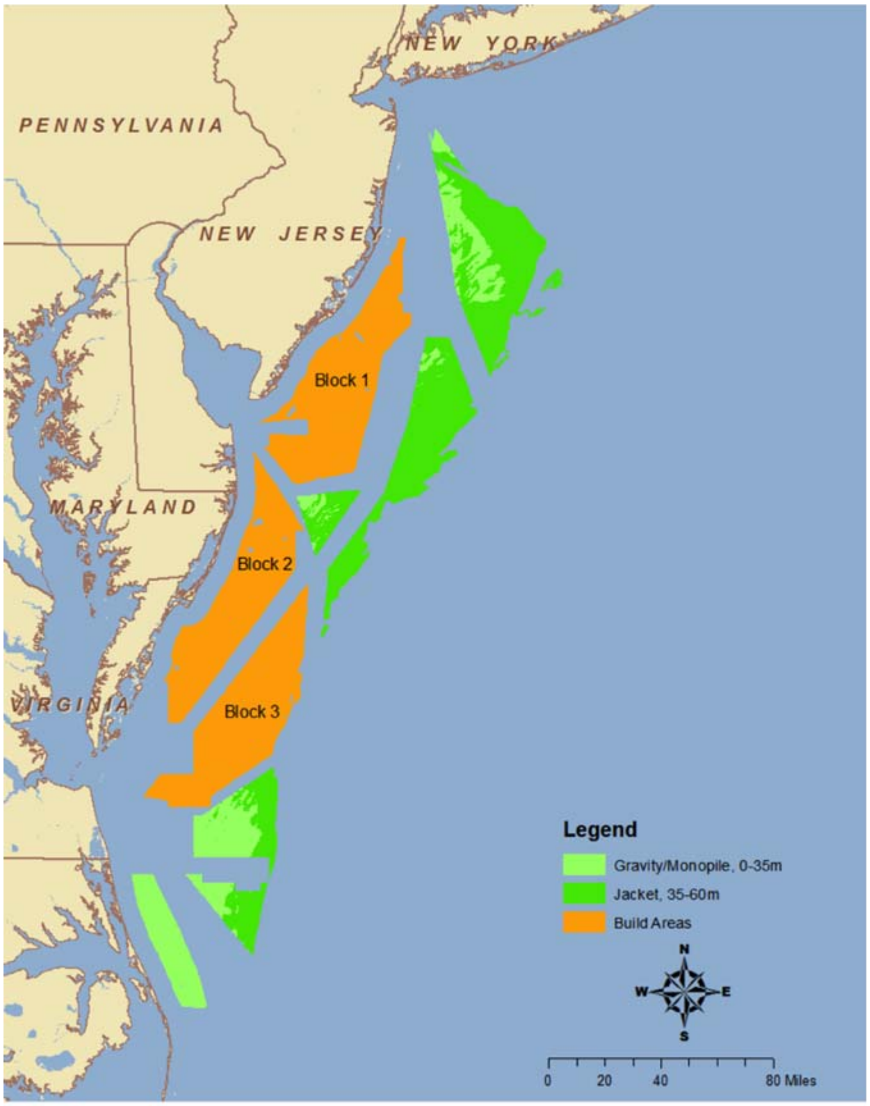


Figure 15: Build Level 3, which, on average, satisfies 25% of the average PJM load.

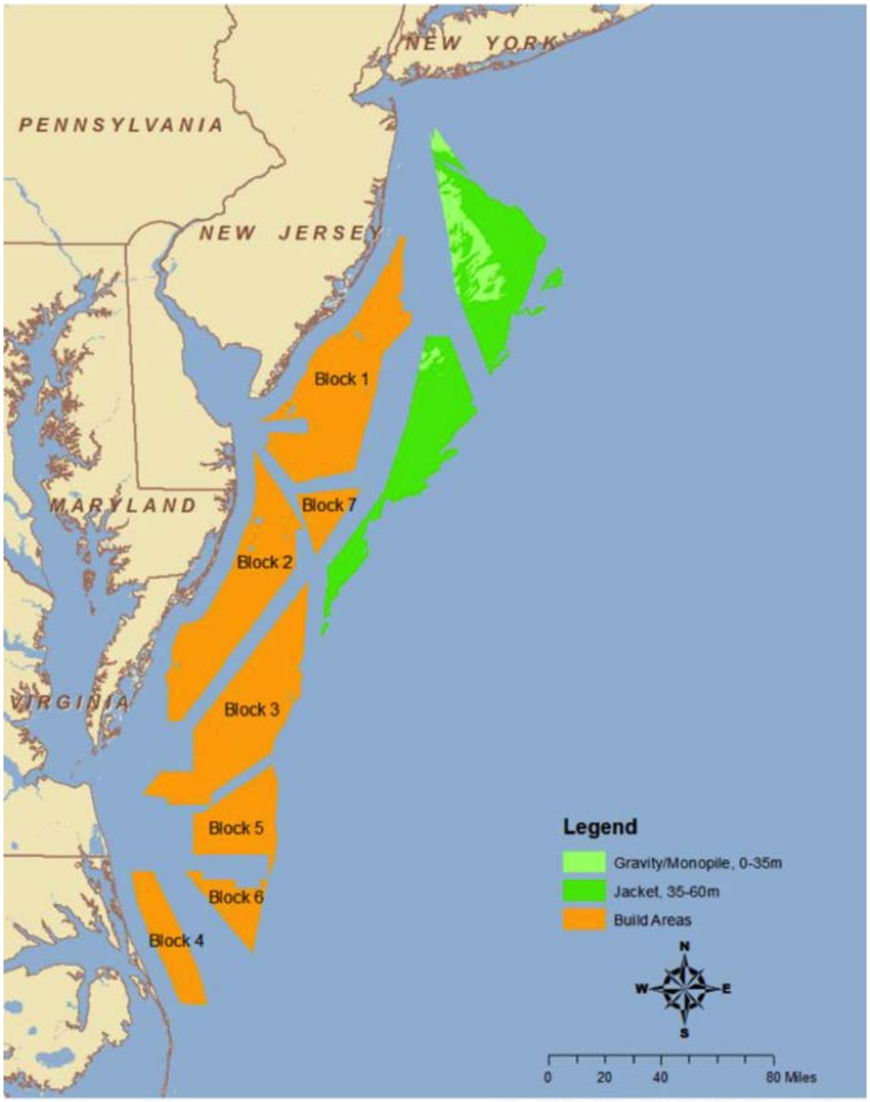


Figure 16: Build Level 4, which, on average, satisfies 35% of the average PJM load.

Task 3 – Weather Forecasting Model (WRF) Output
Deliverable: Resource Map

Subtask 3.1 - Run WRF & Develop Wind Maps
We created these seasonal maps, and they are shown are in Figure 20. We also updated the original resource map of the MAOWIT build-out scenario. This phase, Task 3 was also used to update capacity factors and percentage of PJM load, as shown in our final Table 1 above--the initial quarterly report table like this was based on a static assumption of 35% capacity factor.

In previous versions of the MAOWIT build-out, the WEAs were not explicitly included in the wind resource maps as separate sub-regions. To analyze the impact of full build-out of the WEAs, GIS work was performed to explicitly add these regions. Up-to-date BOEM WEA definitions were obtained from the BOEM GIS data website (BOEM, 2013) and incorporated into build-block definitions, shown in Figure 15 and 16. During the development of data maps and tables, we reorganized and renamed all sub-blocks in a logical order of X.Y, where X is the build order and Y is the serial number of the farms in that build, labeled from north-to-south. (One map above uses the old block numbering.) All WEAs are in the first build out level (that is, WEAs are numbered 1.*).

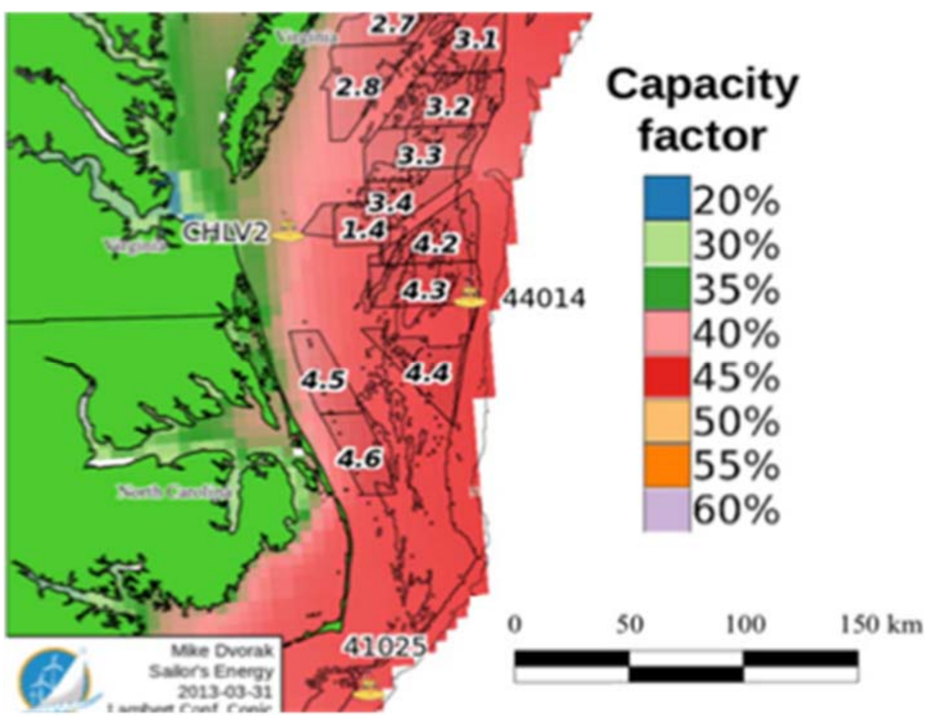


Figure 17: Turbine hub-height (90 m) wind resource data derived from Dvorak, et al. (2012) using WRF high-resolution (5.0 km) hourly wind fields for the 5-year period of 2005-2010. Capacity factor was calculated using a REpower 5M 5.0 MW turbine power curve. The sunblock numbering scheme corresponds to the build-out order, using the new numbering described in Table 4. Isodepth contours are plotted at 30, 50, and 200 m water depth.

Table 2: Original (middle column) and new, logical naming scheme (right column) for MAOWIT sub-blocks. New sub-blocks are labeled X.Y, where X is the build order and Y is the serial number of farms in that build, labeled from north-to-south.

Build-out Level	Original Sub-block Lease	New Sub-block Lease		Build-out Level	Original Sub-block Lease	New Sub-block Lease
1	BOEM areas to be defined	1.1 (NJ)		**4**	7.1	4.1
1	...	1.2 (DE)		**4**	5.1	4.2
1	...	1.3 (MD)		**4**	5.2	4.3
1	...	1.4 (VA)		**4**	6.1	4.4
2	1.1	2.1		**4**	4.1	4.5
2	1.2	2.2		**4**	4.2	4.6
2	1.3	2.3		**5**	8.1	5.1
2	1.4	2.4		**5**	8.2	5.2
2	2.1	2.5		**5**	8.3	5.3
2	2.2	2.6		**5**	8.4	5.4
2	2.3	2.7		**5**	9.1	5.5
2	2.4	2.8		**5**	9.2	5.6
3	3.1	3.1		**5**	9.3	5.7
3	3.2	3.2				
3	3.3	3.2				
3	3.4	3.4				

Seasonal wind maps of peak-time wind resource were created from a previous US East Coast wind resource assessment study (Dvorak, et al., 2012). That study defined the peak electricity usage period as being from 08:00-21:00 EST, based on analysis of electric load data on the eastern seaboard. Maps of seasonal capacity factor during peak-electricity time for Winter (Jan-Mar), Spring (Apr-Jun), Summer (Jul-Sep), and Fall (Oct-Dec) were created with five years (2006-2010) of hourly, high-resolution (5 km) WRF simulations. Capacity factor was calculated using hourly 90-m wind power output from a REPower 5.0 MW wind turbine curve.
Additionally, the mean 90-m wind speed map shown in the Y2Q1 report (as opposed to the capacity factor maps shown in this report) was updated with the new sub-block definitions. The MAOWIT website was updated to incorporate all of these new changes and updates, serving as an internal and external documentation (http://sailorsenergy.com/maowit-build-blocks).

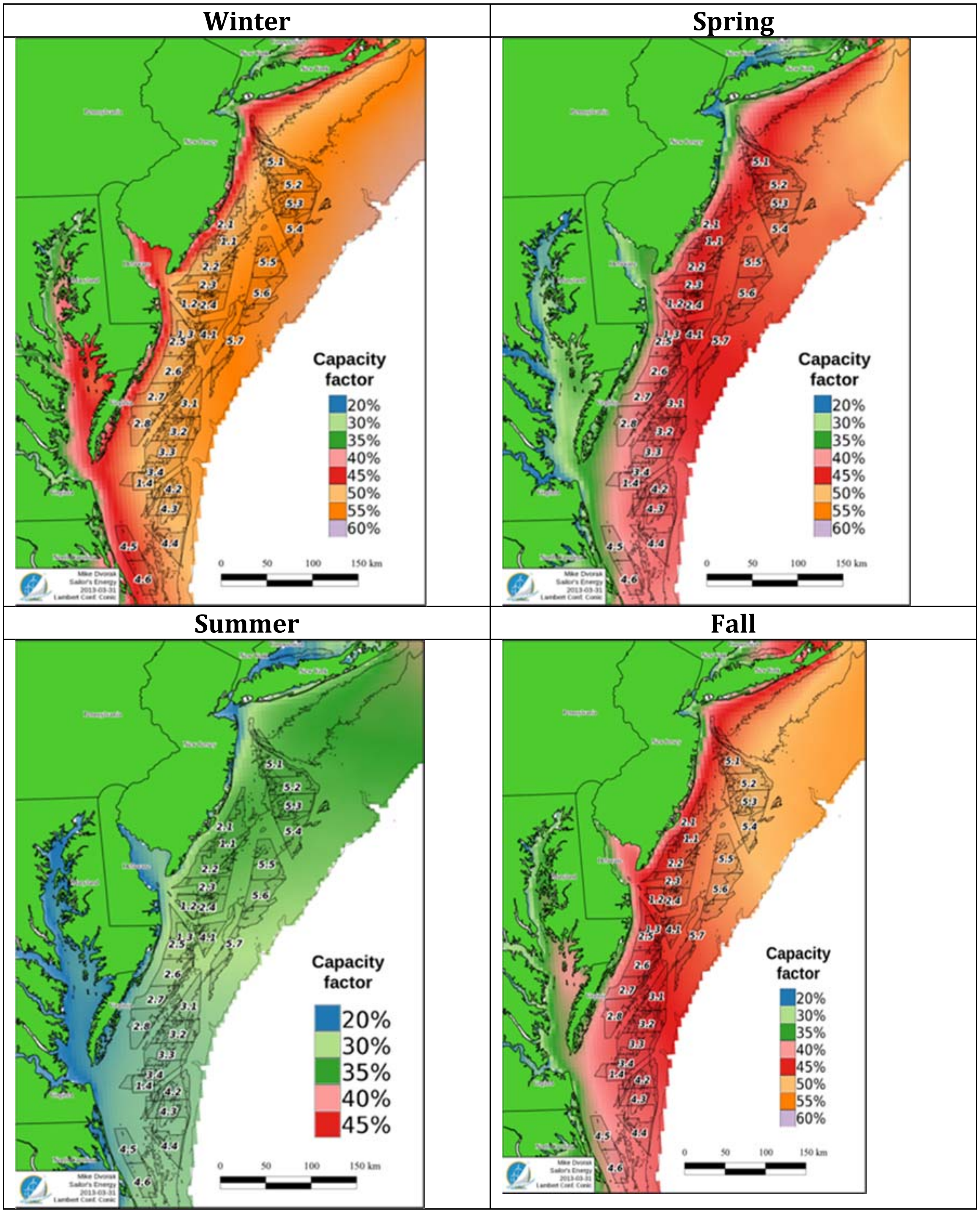


Figure 18: Similar to Figure 17 but for each season, and considering only the winds during daily peak-time electricity usage (08:00-21:00 EST) using data for the MAOWIT region (data from Dvorak, et al., 2012). Capacity factor derived from hourly WRF-ARW wind data using a REpower 5M 5.0 MW turbine power curve at the 90-m height.

Subtask 3.2 – Error Analysis of the Cape Wind data

Analysis of the error at Cape Wind and at the buoys near Cape Wind and near the tie points has highlighted the following two unexpected issues:

A) The wind speed patterns near Cape Wind are different and uncorrelated with those observed further south (tested for the month of May 2009 near buoy 44014, close to an AWC tie point).

> To conclude this, we looked at the cross-correlation between the buoy nearest to Cape Wind (44018) and that near Maryland (44014) with respect to 5-m wind speeds (measured, not simulated). There is little cross-correlation between the two, even when time lags are taken into account. The distribution is actually a dual-peak distribution, with maxima at -12 and +12 (Figure 19). This could be due to the month of May being a transitional month between winter and summer, thus with both storms from the north and from the south. But the main point is that the cross-correlation is near zero and at most it is 8%. This finding makes it hard to justify using Cape Wind errors at locations that are too far south from Cape Wind. If the two buoys are so un-correlated to one another, we have no reason to believe that the WRF's error and performance should be the same at the two. The two buoys experience different weather regimes and the WRF can have, at least in principle, completely different performances in the two regimes, and therefore potentially completely different error types and distributions.

B) The WRF buoy error at 5 m is not a good predictor of the WRF error at the Cape Wind tower (at 90 m).

We examined the correlation between the WRF wind speed errors at 90 m and at 5 m at Cape Wind (using buoy 44018 as a proxy for the 5-m observation at Cape Wind). The two have little correlation with one another (correlations are 0.18 and 0.25 for the 0-24 and 24-48 forecasts respectively). Figure 2 shows that, when the WRF over-predicts at 5 m, it can just as likely over-predict, under-predict, or even have no error at 90 m. Given this small correlation, we cannot justify developing a predictor for the 90-m error that is based only on the error at 5 m unfortunately.

Given these results, we consider alternative methods to determine the 90-m wind speed error near the AWC tie points. We have explored several possible methods, including a least-square fitting of combinations of 5-m wind speed errors and 90-m wind speed forecasts and shear ratios, with little success. Based on this analysis, we have determined that using 5-m buoy observations extrapolated to a higher elevation is a better predictor of actual wind power prediction errors at the turbine hub height than tall-tower observations taken at a distant location. Therefore, we will use nearby, near-surface buoy (and not Cape Wind tower observations) for validation of our WRF forecast in future work.

The WRF model was run with our new initialization technique for four months of the year 2010 (January, April, July, and October, representative of the four seasons). Four months in 2010 were selected, rather than the whole year, as agreed upon by all partners at the last MAOWIT meeting on October 22, 2012. Each day of the four months, WRF was started at noon local time (16 UTC during daylight savings and 17 UTC otherwise) and run for 48 hours with output every 10 minutes. As such, two WRF forecasts were generated each day: a 0-24 hr and a 24-48 hr forecast time series for each point of the wind areas with a 24-hr forecast overlap. A total of 123 48-hr simulations were run, which generated over 50 TB of output data. Relevant output fields were post-processed and stored in the PostgreSQL database, also run on the UD Mills cluster. In total, the WRF simulations used 35,000 CPU hours.

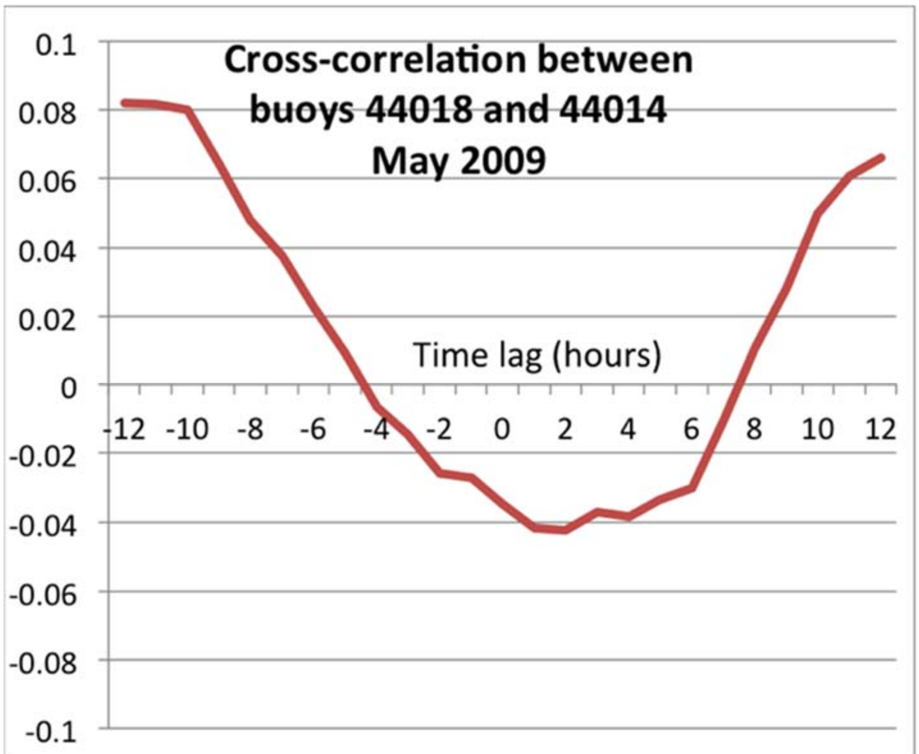


Figure 19: Cross-correlation between the 5-m winds observed at the buoy nearest to Cape Wind (44018) and at a second buoy (44014) located further south, near one of the AWC tie points offshore of Maryland. The correlation is very low (note expanded vertical scale) for any lags, with the highest correlation only 0.08, for time lags of -12 and +12 hours

To obtain the "actual," or observed, wind power time series for the wind areas, we use the following simple method to obtain "actual" wind speed at hub height at all offshore grid points. For each offshore grid point, we use the nearest National Data Buoy Center (NDBC) buoy or tower observation winds extrapolated to 90 m using the log-law. All of the buoy observations shown in Figure 1 are at 5-m height with the exception of the CHLV2 tower, which is 43-m height. With the log-law, wind speed V(z) at height z (z=90) at a given buoy is calculated as a function of the buoy's wind speed at the reference height z_{REF} (z_{REF}=5 m) as follows:

Equation 1

$$V(z) = V(z_{REF})\frac{\log(\frac{z}{z_0})}{\log(\frac{z_{REF}}{z_0})}$$

where z_0 is the surface roughness (z_0=2x10^{-4} m). Then the "actual" 90-m wind speed at each offshore grid point i,j was set to be equal to that of the nearest buoy.

This method has the advantage that it preserves more geographical variability than using only the single-point Cape Wind, while being simple and conservative. The observation network also captures the synoptic-scale variability (e.g. Nor'easters and the Bermuda High) that can dominate the offshore wind resource over 1000 km. Also, the WRF performance for wind power forecasts is satisfactory, as discussed next in sub-task 3.3. There are two additional reasons why we are satisfied with our simple method to obtain "actual" time series of 90-m wind.

First, the developed method to assess our wind power forecasting error highlights a fundamental challenge of offshore wind forecasting: few observations exist offshore to validate forecasts and calibrate models. Given that no actual 90-m wind measurements are available offshore along the entire East Coast, the task of "creating" such observations required a creative scheme that preserved the inherent spatio-temporal variability of the resource. Although we explored several possible more complicated spatial, height-to-height, and temporal correlation methods, we found that more complicated schemes only added a layer of complexity to our analysis and understanding of the forecasting errors.

Second, the approach taken to achieve this subtask has shifted as the met team and power modeling team have better understood the needs and capabilities of each other's models. Whereas initially the WRF simulations were going to be treated as "actual," and therefore calibrating the model was essential to obtain realistic wind power values, now the redefined met task is to generate a realistic time series of the errors. For the unit commitment model, what is essential is a realistic measure of how far off early unit dispatch will be. As such, it is not as important that the WRF forecasts be absolutely accurate, but rather representative of forecast errors that would be observed in future offshore wind power forecasting. Given uncertainty in actual data, we error toward being "conservative," that is, a difference between forecast and actual that is no less than would appear with better actual data; this means that we will not underestimate the difficulty of integrating offshore wind into PJM. With our above-described validation method, we know we are generating conservative error estimates because:

- We only use 9 NDBC observation locations (8 buoys plus the Chesapeake Light House). All the offshore grid points that are near one of these 9 observations are assigned the same 90-m wind speed. We believe that the actual 90-m wind speeds will have more geographical variability and closer to the variability simulated by WRF. Therefore the real errors are more likely to be lower and more in-phase than the ones we are generating here.
- The ramp rates experienced at one of the 9 observations, for example during a front passage, are immediately spread to all the nearby points, thus causing a possible overestimate of the actual ramp rates. In fact, ramps would be slower because the front would move through wind turbine fields a row at a time, not all at once.
- As more measurements are made offshore, forecasting models like WRF will be tuned to more accurately predict wind farm power output. In-situ measurements made at offshore wind farms, if made publicly available, would be incorporated into initial conditions for forecasting models, further increasing their accuracy.

Since both errors and ramp rates are likely to be overestimated with our method, our approach is conservative, which increases our confidence that the true minimum offshore wind penetration that can safely be introduced into the PJM system is likely to be higher than the predictions we will develop from this project. We consider the forecast model validation technique described above to be scientifically reasonable and to accurately reproduce the variability of the offshore resource, given limited in-situ observations.

Subtask 3.3 - Calculate Scenarios' Maximum Power Output

For this subtask we used the 23 lease sub-blocks and 9 blocks identified in the previous reports, shown in Figure 4. These were tabulated for both the actual and WRF forecast energy output as shown in Table 2 below.

We first calculated wind power from 90-m wind speeds ("actual" and 0-24 hr and 24-48 hr forecasts) at all offshore grid points that were inside the 23 lease sub-blocks using the power curve of the REPower 5 MW wind turbine, fitted with polynomial curves as follows:

Equation 2

$$P = \begin{cases} 0 & V < 3.5 or V > 30 \\ a_L V^3 + b_L V^2 + c_L V + d_L & 3.5 \leq V < 11 \\ a_U V^3 + b_U V^2 + c_U V + d_L & 11 \leq V < 15 \\ 5000 & 15 \leq V < 30 \end{cases}$$

where P is the power in kW, V the 90-m wind speed in m/s, and the coefficients for the lower (L) and upper (U) polynomials are shown in Figure 20.

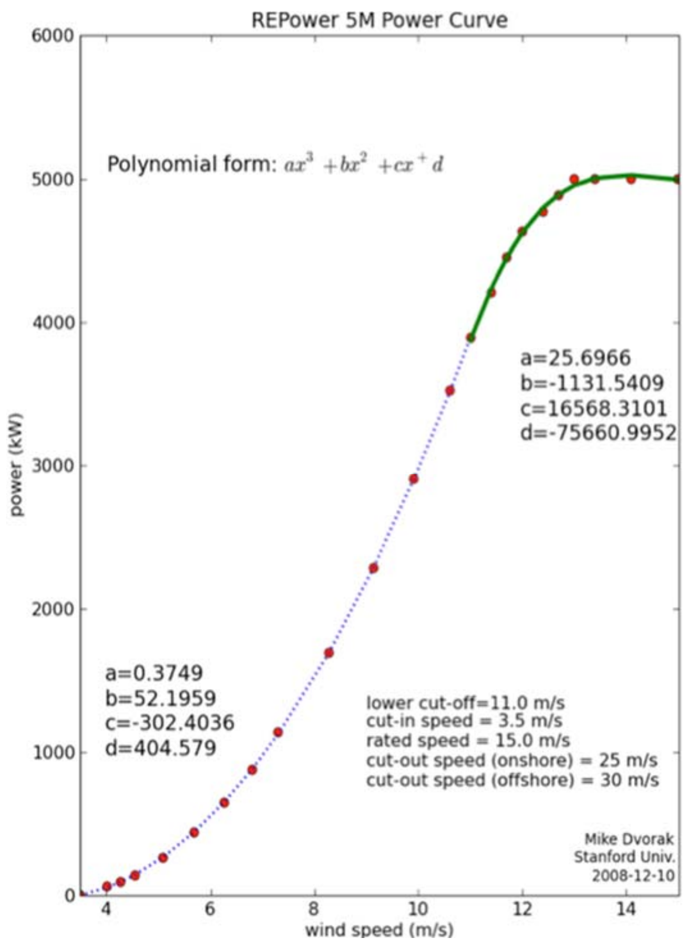


Figure 20: Power curve of the REPower 5 MW wind turbine with fitting polynomial and coefficients

The total power P_k at sub-block k ("actual" and 0-24 and 24-48 hr forecast) is the sum of the power output of all the grid points within the sub-block for each 10-minute period, assuming a spacing of 10Dx10D (where D=126 m is the diameter of the turbine rotor, and accounting for array losses of 10% (thus array efficiency h=0.90) as follows:

Equation 3

$$P_k = \eta N_k \frac{\sum_{(i,j)\in k} P_{i,j}}{n_k}$$

where N_k is the number of turbines installed in sub-block k and n_k is the number of WRF grid points i,j within sub-block k. In the maximum build-out scenario, the entire area A_k of sub-block k is covered with turbines and therefore the maximum number of turbines is:

Equation 4

$$N_k^{MAX} = \frac{A_k}{10D \times 10D}$$

Replacing N_k in Eq. (3) with Eq. (4), we obtained the desired time series of maximum build-out power ("actual" and 0-24 and 24-48 hr forecasts).

Further details about the setup of the database and the GIS work that was conducted on the sub-block areas is available on this preliminary webpage: http://www.sailorsenergy.com/maowit-build-blocks.

The performance of WRF for the maximum build-out scenarios is summarized in the table in Quarterly report of January 2013, by lease block (summing over all sub-blocks within each block). Main findings are as follows:

1. The overall performance is satisfactory: bias amplitudes are ~10% of the mean, RMSE ~50% of the mean, and correlations are often >0.7.
2. WRF has a positive bias in general (all blocks except block 4).
3. Although the bias in generally lower for the 24-48 hr forecasts, the RMSE and the correlation are both better for the 0-24 hr forecasts.
4. Overall, the standard deviations of the forecast and actual power are similar. This means that the variability of the synthesized forecast and validation system would match the real world variability of the offshore resource. This passes the modeling skill test #1 as defined by Pielke, et al. (2002, p. 464).
5. Overall, the RMSE<standard deviation of the observations, which passes the model skill test #2 in Pielke, et al. (2002, p. 464).
6. The WRF performance is better in the winter than in the summer because the turbine power curve at high wind speeds acts as a low-pass filter for forecasting error at winds over 15 ms^{-1}. That is, severe over-estimates of wind speeds >15 ms^{-1} do not show up as error because the turbine is already outputting full power regardless of the over-estimate in wind speed.

The time series of "actual", 0-24 hr, and 24-48 hr wind power forecasts by sub-block for the maximum build-out scenario were delivered to the Princeton team as comma separated value (CSV) files. The only missing deliverable is the same time series for the BOEM areas, which will be generated by Y2Q2. The reason for the delay in generating the BOEM area maximum build-out power is that we do not yet have the shapefiles for such areas.

During a review of the data, discrepancies were discovered in the raw data that we received from our contractor. In a normal model, artificial spikes occur every 24 hours when the model resets. However, the data that was used for the WRF model had an error with these spikes occurring every twelve hours instead (Figure 21). Note that the ramp rates are measured, on this plot, as fractions of absolute power change over the power at the previous 10-minute interval (blue line) and in actual power change (GW) with the red line. Thus a spike with a value of 2 in the blue line represents a power change of 200% (either a drop or an increase).

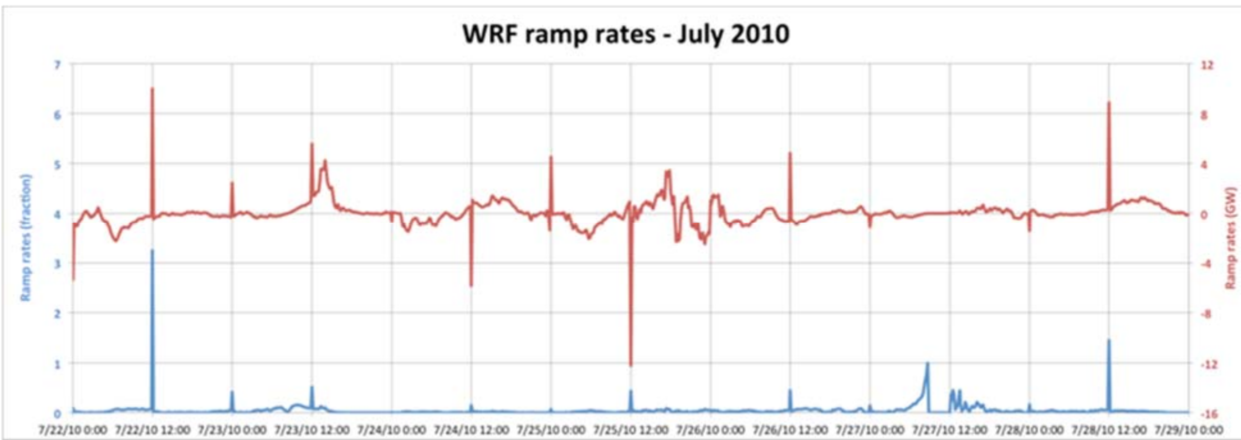


Figure 21: WRF ramp rates for July 2010 with data error.

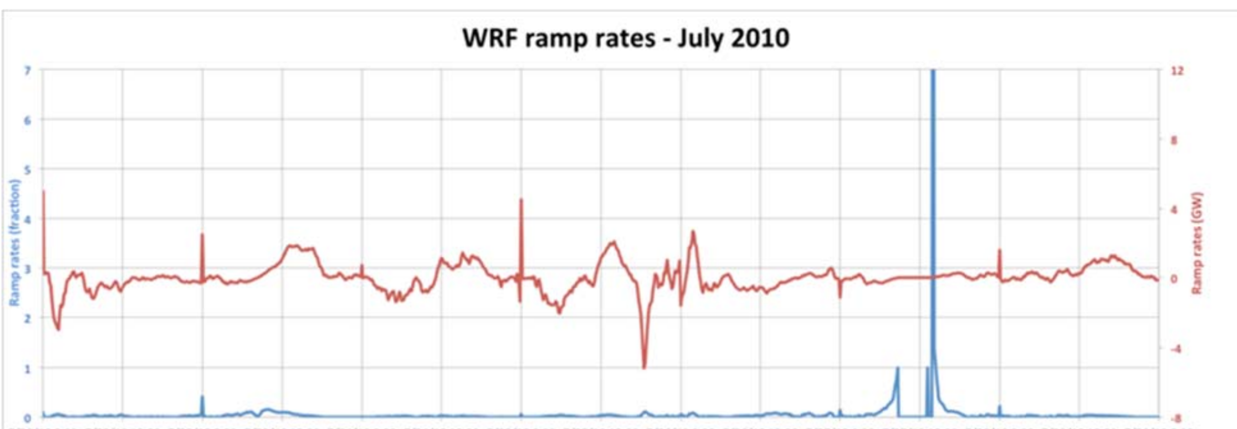


Figure 22: WRF ramp rates for July 2010 with no-error. Fixing the error in the spikes in the ramp rates had a large effect on the Smart-ISO simulations because the removal of the artificial spikes at noon made it possible to clear completely Build-out level 3, as opposed to only level 2 that we determined in previous quarterly reports. Note that the spikes at midnight do not affect our results because the Smart-ISO model is restarted every day with forecasts from midnight to midnight. As such, at the beginning of the simulation at midnight, there is no spike because there is no previous 10-minute interval to determine the ramp rate from.

Task 5 – Analysis of Offshore Wind Leveling
Deliverable: Offshore Wind Output Profile and Map of non Coincident Wind Resources. Full report is contained in the quarterly report of July 30, 2013.

The wind output profile of the entire studied offshore region (by build-out level) can be observed in Figures 28 through 31. These figures show the total energy (in MW) that could be produced from wind in the Mid-Atlantic offshore region in certain weeks of the months of January, April, July and October of 2010. These months were chosen as representative of the four seasons of the year. The graphs also depict the amount of energy produced in each of the 5 build-out levels envisioned for the region. The peak amount of energy that can be generated from the build-out levels is about 69 GW, with all losses already subtracted (array and transmission losses inside each farm). The transmission losses were calculated in the written report "Transmission Loss Estimation," attached at the end of this quarterly report. This transmission report is an updated version of the report in the previous Y2Q2 quarterly report.

The graphs show the total energy produced by hour for one week, hours 1 through 168. Most of these graphs show that wind generation fluctuates every few hours, but the week in October demonstrates a different pattern. There is an extended period of time in October 2010 (Figure 26) (approximately 48 hours, between hours 19 and 67) in which offshore generation would be sustained at or near peak level across the whole region. Cross examination with weather data shows that this period does correspond to a significant weather event in the region. Similarly, another weather event between hours 105 and 133 in January 2010 (Figure 23) would have yielded generation levels near peak, if the specified offshore wind farms were in place.

The deliverables for this Subtask show that the wind energy levels generated by the 5 build-out levels are highly correlated with each other. Consequently, even after the aggregation of the production over the whole Mid-Atlantic offshore region there is still significant variability in the total level of energy generated. The observed leveling effect is much less than what was indicated in an earlier work by Kempton *et al* (2010). It should be noted, however, that the study completed by Kempton encompassed offshore wind covering the whole Eastern seaboard, from Maine to Florida, as opposed to specifically the New Jersey to Virginia coast that the present study investigates.

Although generalized offshore wind leveling across the Mid-Atlantic region is not observed, the sub-blocks included in the build-out block 5 (light blue in Figures 23-26) offer some complementarity to the other build-outs. An example of this can be observed between hours 67 through 85 in January 2010 (Figure 23), hours 67 through 73 in April 2010 (Figure 24), and hours 111 through 121 in October 2010 (Figure 26). This observation suggests that the order of implementation of wind projects after build-out level 1 should be re-examined.

Key Results & Outcomes:

- Subtask 5.2, “Reports on Wind Leveling” has been completed. The results are shown in Figures 23-26.
- Generalized offshore wind leveling is not observed across the build-outs, but build-out 5 offers complementarity to the other build-outs during periods of several hours.
- A period of approximately 48 hours in October provided energy output sustained at or near peak level. This high energy event coincided with a weather event in the region. A similar situation also occurred in January.
- A report “Transmission Loss Estimation” written to aid in the completion of Subtask 5.2 has been completed estimating the percentage transmission losses for the sub-blocks.

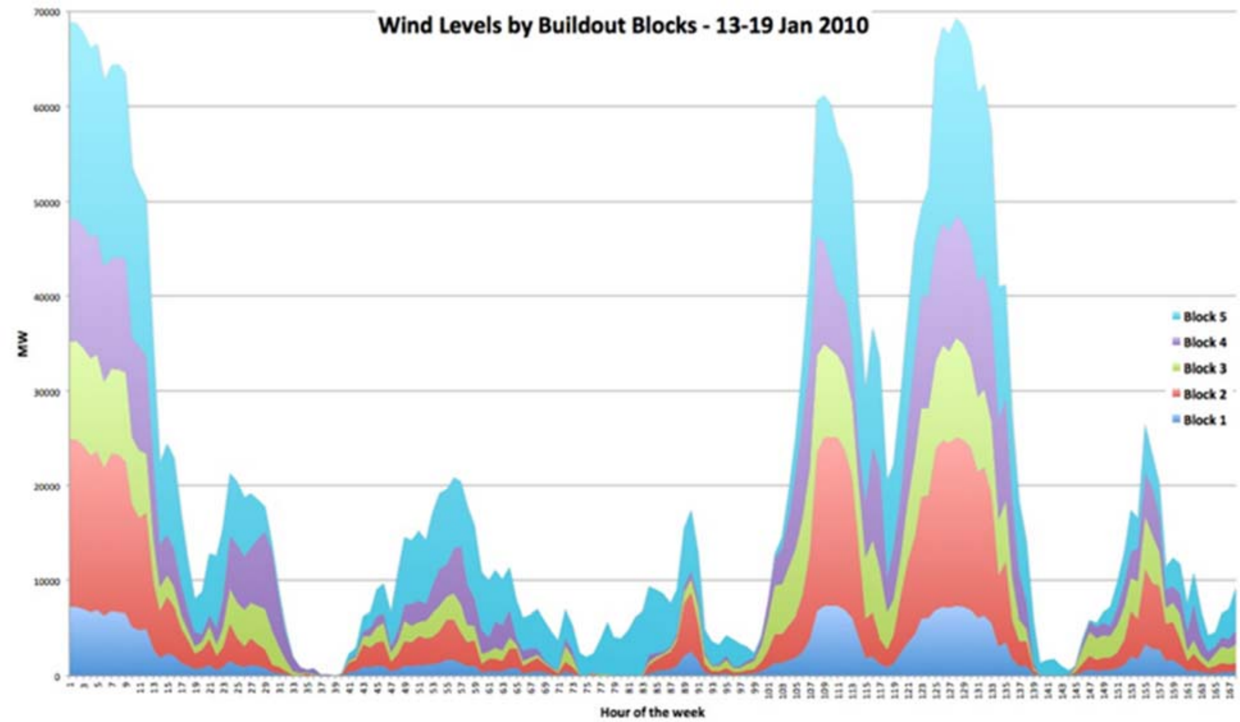


Figure 23: Total wind energy output (in MW) by build-out blocks. The wind output was calculated hourly over the course of the week for a total of 168 hours.

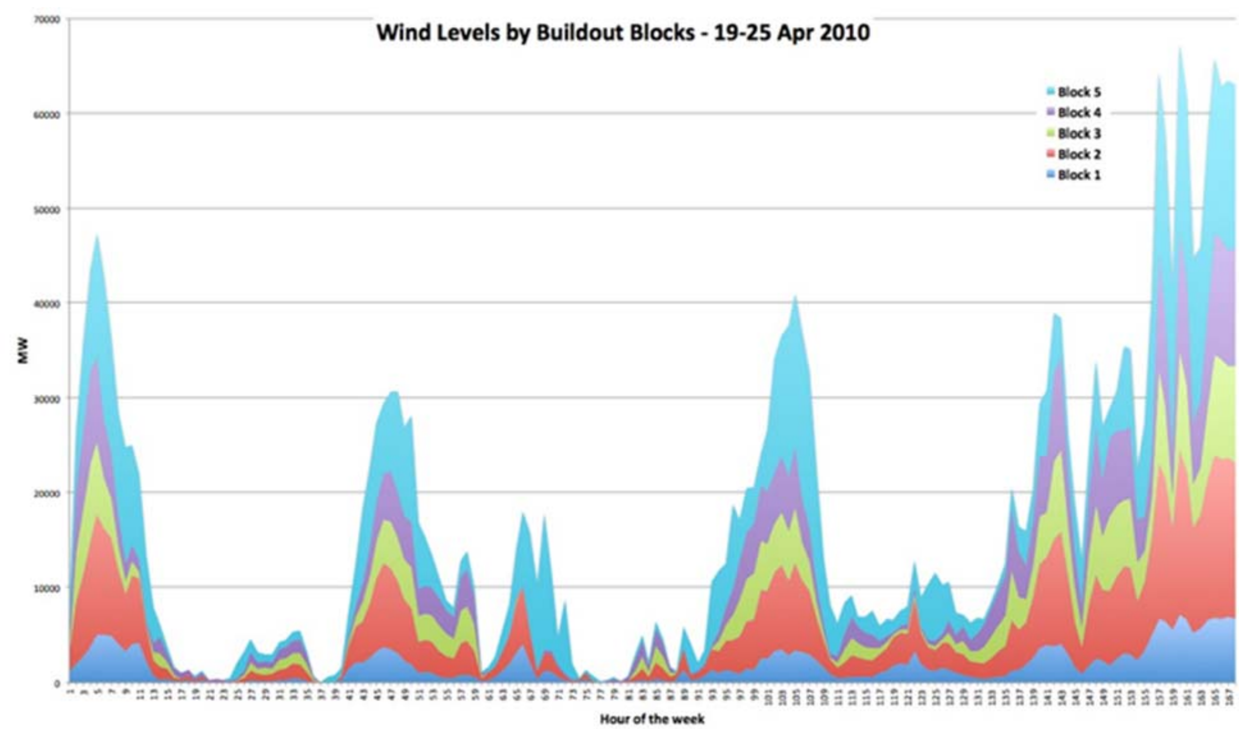


Figure 24: Total wind energy output (in MW) in 19-25 April by build-out blocks. The wind output was calculated over the course of the week for a total of 168 hours.

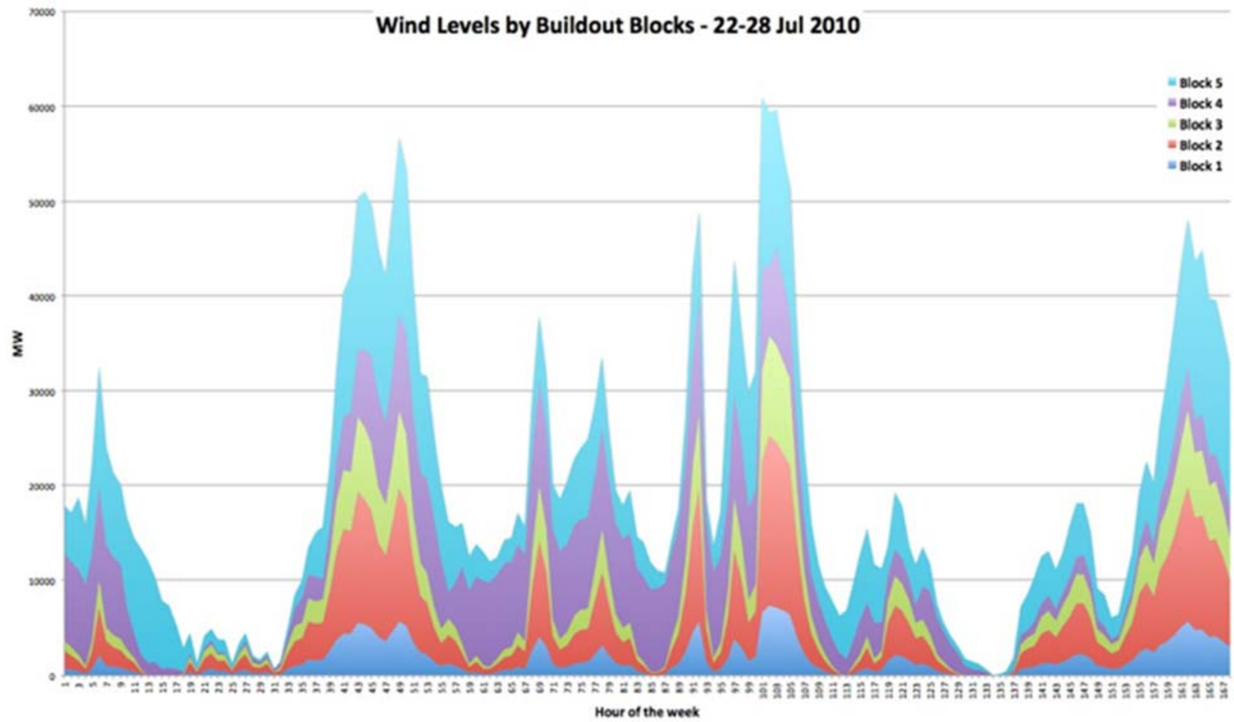


Figure 25: Total wind energy output (in MW) in 22-28 July 2010 by build-out blocks. The wind output was calculated hourly over the course of the week for a total of 168 hours.

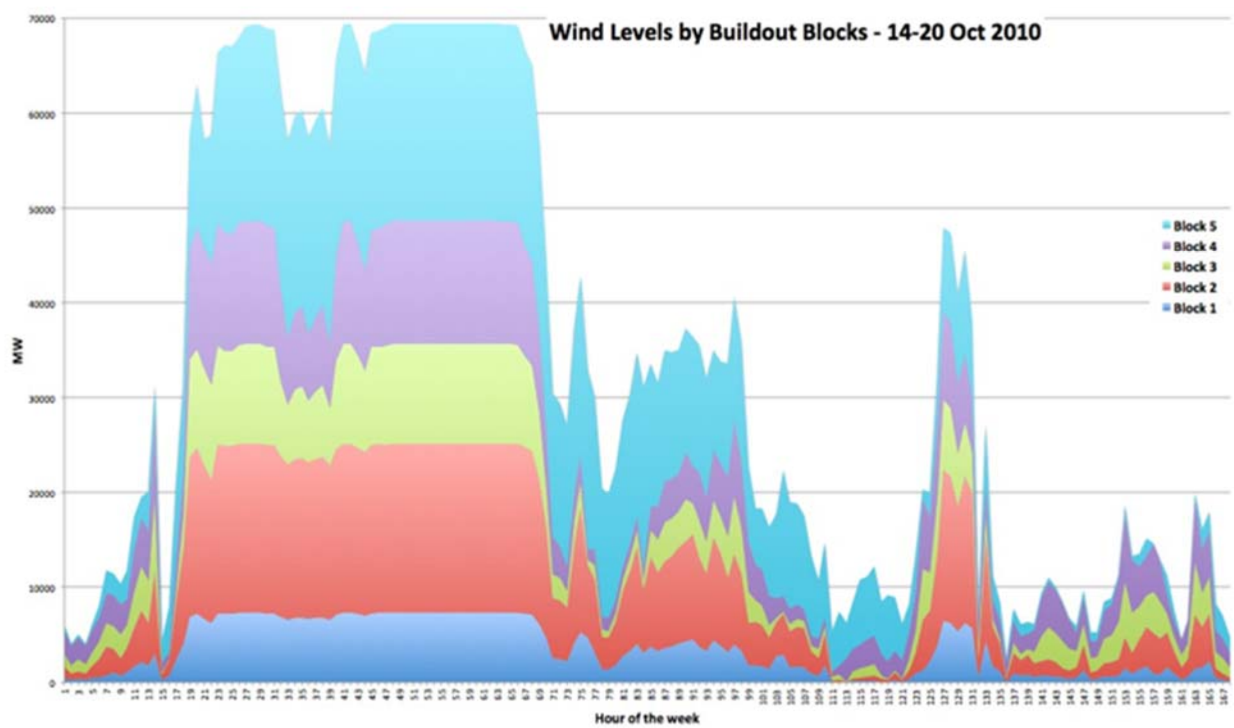


Figure 26: Total wind energy output (in MW) in 14-20 October 2010. by build-out blocks. The wind output was calculated hourly over the course of the week for a total of 168 hours.

Task 6 – Unit Commitment Model

Deliverables: Report on Unit Commitment Results
Report on High Frequency Impacts

The full report is contained in the publication by Warren et al, referenced in the "Accomplishments" section of this report.

The SMART-ISO simulator was run for one week in each of the four months that
represented a season (January, April, July, and October), first without any offshore wind (the "current" situation, also called build-out level 0) and then with each one of the five build-out levels of offshore wind. For each level of build-out and each month, we picked three different weeks and seven sample paths of offshore wind for each week, thus totaling twenty-one sample paths. The results presented henceforth were compiled from simulations using these sample paths.

SMART-ISO: Unconstrained grid, no ramp-up or down reserves added.
Table 5 shows the results of adding increasingly higher levels of offshore wind into the unconstrained PJM grid. The percentage of offshore wind participation in the total generation at build-out level 1 ranged from 2.2% in the peak load month of July to 4.3% in the winter month of January, whereas at build-out level 5 (the highest) it ranged from 16.7% to 30%. The percentage of wind used, with respect to what was actually available, was as high as 94.8% at build-out level 1 in January, and as low as 56.4% at build-out level 5 in October. The most noteworthy results in Table 5, though, are the estimates of the likelihood of load shedding at some time during the simulated week, due to the unexpected variation in the wind energy generation. From build-out level 2 and up, in any season, it is practically certain that the PJM system as currently operated will face load shedding at least once a week. At build-out level 1 it is possible to operate the system without any load shedding on a week, but at different degrees, depending on the season (it is more likely to observe some load shedding in July and January, when the loads are higher, than in the shoulder months of April and October). The more energy generated from wind, the larger are the errors in the forecasts used in the commitment planning, and consequently the higher is the likelihood that the dispatchable generation committed beforehand will be unable to handle unexpected variations in the wind energy.

Table 3: Adding offshore wind energy to the unconstrained PJM grid

Build-out Level	Installed Capacity (GW)	Month-Year	Generation from Offshore Wind (%)	Used Wind (%)	Likelihood There Will Be Load Shedding at Some Time During the Week (%)	Average Peak Load Shedding (GW), When There Is Any Shedding
1	7.3	Jan-10	4.3	94.8	38.1	0.6
		Apr-10	4.0	78.3	9.5	0.3
		Jul-10	2.2	92.1	81.0	2.3
		Oct-10	4.0	78.2	9.5	0.6
2	25.3	Jan-10	14.5	93.4	100.0	3.1
		Apr-10	15.1	87.7	100.0	3.8
		Jul-10	7.1	86.9	100.0	6.4
		Oct-10	15.8	90.0	100.0	2.3
3	35.8	Jan-10	20.8	93.4	100.0	5.2
		Apr-10	20.4	83.9	100.0	4.3
		Jul-10	10.3	85.6	100.0	7.7
		Oct-10	20.8	83.9	100.0	3.2
4	48.9	Jan-10	25.6	84.2	100.0	5.4
		Apr-10	24.2	74.0	100.0	4.4
		Jul-10	14.1	80.5	100.0	9.8
		Oct-10	24.1	72.1	100.0	3.9
5	69.7	Jan-10	30.0	68.7	100.0	7.4
		Apr-10	29.9	62.9	100.0	5.4
		Jul-10	16.7	68.1	100.0	12.5
		Oct-10	27.5	56.4	100.0	3.1

There are different ways in which the PJM market operation can be modified to try to cope with the uncertainty in the wind energy forecasts. We tested two of them: (1) the addition of ramp-up and ramp-down reserves from dispatchable (fast) generation; and (2) a radical improvement in the day-ahead and intermediate-term wind forecasts. "Radical" in this context means assuming that we have perfect forecasts, that is, they are equal to the actual observed values. This is obviously an idealized situation that will serve as a boundary case for any improvements that might be made in forecasting wind energy in the future. We will henceforth refer to (1) as the imperfect forecast case and (2) as the perfect forecast one.

The SMART-ISO model was used to complete different scenarios of the PJM grid and offshore wind energy. Runs were used assuming an unconstrained grid, and no ramp up or down reserves added. Through our analysis of the unconstrained grid, and no ramp up or down reserves added, it was determined that the more energy that is generated from offshore wind, the higher the forecast error is. Therefore dispatchable generation committed beforehand will be unable to handle variations in the wind. In order to account for uncertainty, ramp-up and ramp down services can be added "fast" or day-ahead forecasts can be improved radically. These were called imperfect and perfect forecasts, respectively. Although there is no such thing as a perfect wind forecast, a combination of forecast improvements with synchronized reserves could potentially allow PJM to operate with no load shedding up to 70 GW. Using the results of the generation mix as the levels of wind energy in the system increase, we were also able to estimate the impact on the network average settlement price and the impact on emissions of air pollutants. These were estimated assuming both perfect and imperfect forecasts. Runs were also completed assuming a constrained grid with no ramp-up or down reserves added in order to evaluate the capacity of the PJM system to integrate various build-out levels with the transmission grid constrained by its current thermal capacities. The runs concluded that, therefore, installing offshore wind capacity of 25.3GW (level 2) or more, without upgrading the PJM transmission grid, would be inadvisable.

Task 7 - Dissemination & Deliverables

For list of publications and conference presentations, see the section "Accomplishments." This section gives detail on the Public Workshop, which was a task on the work plan.

Public Workshop

Attendees: Willett Kempton (PI-UD), Cristina Archer (UD), Warren Powell (Princeton University), Hugo Simeo (Princeton), Elpiniki Apostolaki (UD), Deniz Ozkam (Atlantic Grid Developers), Daniel Ancona (Princeton Energy Partners), Aranya Venkatesh (ExxonMobil), Christopher Clack (NOAA), Daniel Kirk-Davidoff, (MDA Information Systems), Markian Melnyk (Atlantic Grid Developers), Richard Bowers (UD), Joseph Brodie (UD), Jeremy Firestone (UD), Stephanie McClellen (UD).

Purpose
The purpose of this workshop was to discuss methods and results for transmission and integration of large penetrations of offshore wind into a Regional Transmission
Organization (RTO) using realistic wind power forecast errors and a detailed model of the RTO's unit commitment, economic dispatch, and power flow.

Workshop Agenda:
9:00 Convene, coffee, introductions
9:30 Transmission for the offshore wind resource adjacent to PJM.
10:15 Wind forecast error and the integration of wind power to the grid
11:00 Simulation of electricity market operations and integration of wind power into the grid
11:45 Critique and discussion by panel of external experts (D. Anacona, C. Clack, & M. Melnyk)
12:45 Lunch and continuation of discussion
1:30-2:30 Open discussion of lessons learned and next steps

Summary of project
Supported by DOE funding, the "Mid-Atlantic Offshore Wind Integration and

Transmission" (MAOWIT, DOE award #DE-EE0005366) study is a collaboration among the University of Delaware, Princeton University, and Atlantic Grid Developers. The area studied was PJM Interconnection, one of the largest U.S. electricity grid operators with a generation capacity of 186 Gigawatts (GW). We estimated the exploitable offshore wind resource along the U.S. East Coast adjacent to PJM, considering exclusion zones and conflicting water uses, and divided the total resource into five build-out levels, from 7 to 70 GW of total installed capacity. Then this resource is injected into PJM under differing assumptions, using "Smart-ISO", a model of the entire PJM grid.

This workshop discussed modeling realistic wind power forecast errors. The project used the Weather Research and Forecasting Model (WRF), initialized every day at local noon and run for 48 hours to provide midnight-to-midnight forecasts for one month per season with a stochastic forecast error model for offshore winds constructed based on forecast errors at inland wind farms in PJM. Using the auto-regressive moving-average (ARMA) model, 21 equally plausible sample paths of synthetic actual winds are generated for each seasonal WRF forecast to provide realistic wind power forecast errors for the RTO.

Each path is then input into Smart-ISO, to simulate PJM's sequencing of decisions and information, inclusive of day-ahead, hour-ahead, and real-time commitments to energy generators. The workshop will discuss how Smart-ISO can compensate for wind forecast errors. While PJM is used as a case study for this workshop methods for adopting the processes of the study to other RTOs will be discussed.

Papers were prepared by the DOE-funded team: Warren Powell, Hugo Simão (Princeton University), Cristina Archer, Willett Kempton, Elpiniki Apostolaki, (University of Delaware), Deniz Ozkan, Paul McCoy (Atlantic Grid Developers), Mike Dvorak (Sailor's Energy).

Workshop Feedback

During the critique and discussion with the expert panel several comments, suggestions, and concerns were addressed to the research team. Overall, the panel and other expert attendees felt that the results were new and advanced the field, and could be of significant commercial consequence. Comments, suggestions, and critiques can be broken up into three key topics: source data for models, policy implications, and future research ideas. The research team provides response to the major comments, suggestions, and critiques below, in this report.

<u>Source Data for Models</u>

A number of comments received during the expert panel discussion involved the data utilized to obtain the research team's results. Among key concerns regarded the methodology of modeling the wind estimates utilized for the analysis, namely are the measurements extrapolated in WRF from onshore data accurate representation of the offshore wind. Critics suggested that the critical assumptions of WRF in extrapolating out the offshore wind estimates from onshore data and consider what the marginal improvement (error) derived from the study and look at European experience and difference in onshore verse offshore data as a comparison to the difference we should expect to see. One panel member suggested abandoning WRF and consider utilizing short range ensemble system to forecast wind speeds offshore and compare those results to the results obtained in WRF. These concerns will be considered and address in post-hoc analyses and future research.

Policy Implications

The research team received several comments regarding the ability of the produced research to inform policy decisions and policy changes. One member of the expert panel suggested that PJM should be considering other things besides reliability and economics in its decisions and the Smart ISO produced by this research could benefit PJM in moving to concerns beyond the required principle concerns of reliability and economics. Another point was that the analysis does not take into consideration the Environmental Protection Agency's (EPA) Clean Power Plan which will likely result in more natural gas coming online suggesting that more fast-ramp time generation could be available, making wind integration easier than with the current generation mix. This was not considered in the model used, which is today's PJM grid.

A need for better wind resource and wind prediction data were cited by all members of the expert panel and several others. One option for policy suggested by the panel would be a requirement that when a lease is granted for offshore wind development, that the developer be required to make the data available either publicly or at a minimum to academic institutions engaging in wind power related research. Denmark, for example, has such a requirement. One panel member also suggested that Bureau of Ocean Energy Management (BOEM) should consider funding of meteorological tower installation offshore.

Future Research Ideas

Future research topics suggested by the panel included expanding the analysis out to other Regional Transmission Organizations (RTOs) beyond PJM, with Alberta and Ontario RTOs suggested as possible alternatives. In discussions regarding the limitations of the forecast data of PJM, one member of the expert panel suggested the research team look to the Electric Reliability Council of Texas (ERCOT), which provides public 1-hour ahead forecasts.

Accomplishments

Peer-Reviewed Publications submitted:
Archer, C. L., H. P. Simão, W. Kempton, W. B. Powell, and M. J. Dvorak, 2015, "The challenge of integrating offshore wind power in the U.S. electric grid. Part I: Wind forecast error." Revised and re-submitted to *Renewable Energy*.

Simão, H. P., W. B. Powell, C. L. Archer, and W. Kempton, 2015, "The challenge of intergrating offshore wind power in the U.S. electric grid. Part II: Simulation of electricity market operations." Revised and resubmitted to *Renewable Energy*.

Apostolaki-Iosififou, Elpiniki, Regina McCormack, Willett Kempton, Paul McCoy, and Deniz Ozkan, "Transmission for Large-Scale Offshore Wind Energy Development," 2016, to be submitted to IEEE Transaction on Power Systems.

Jonathan J. Buonocore, Patrick Luckow, Jeremy Fisher, Willett Kempton, Jonathan I. Levy, "Health and Climate Benefits of Offshore Wind Facilities in the Mid-Atlantic United States", submitted to *Environmental Research Letters*, Feb 2016 (ERL-102334). [Uses MAOWIT data of offshore wind production off NJ and MD.]

Reports

2015 "New York Offshore Wind Cost Reduction Study" Prepared for: New York State Energy Research and Development Authority, Albany, NY. (Stephanie McClellan, Deniz Ozkan, Willett Kempton, Andrew Levitt, Heather Thomson. Report distributed by NY ERDA and SIOW. 15 Feb 2015. 71+15 pp http://www.ceoe.udel.edu/File%20Library/About/SIOW/New-York-Offshore-Wind-Cost-Reduction-Study-ff8-2.pdf [Uses offshore wind data produced in MAOWIT project.]

Conference presentations and posters:

2016 "Climate, Air Quality, and Health Benefits of Offshore Wind Facilities in the Mid-Atlantic United States" Poster, with Jonathan Buonocore, Patrick Luckow, Jeremy Fisher, Willett Kempton, Jonathan Levy, Presented at Air Quality in Milan. Milan, Italy, 14-18 March 2016. [Used data from MAOWIT]

2016 Integration of large-scale wind with transmission and inherent storage." Invited presentation at Risø National Laboratory, Roskilde, Denmark, 17 Feb 2016

2015 Kempton, W., S. McClellan, D. Oscan, H. Tompson, 2015 "Reducing Costs for Offshore Wind". Poster at EWEA Offshore Wind Conference, Copenhagen, DK. 10 March 2015

2013 Mike Dvorak and Cristina Archer, "Model Forecasting Accuracy Along an East Coast Offshore Grid Corridor" Presented at UD symposium, "The Importance of Meteorology to Wind Energy: Research Needs for the Next 10 Years", University of Delaware, 2013-02-27. This described the forecasting system for the MAOWIT corridor. The talk slides are posted on http://sailorsenergy.com/us-east-coast-offshore-wind.

The MAOWIT team has submitted, and had accepted, several posters at the American Wind Energy Association (AWEA) conference in October 2013.

Additional outreach:

A meeting was held with PJM to demonstrate the SMART-ISO model to gain feedback on the model's capabilities.

A meeting was held on May 2nd 2014 at Princeton University to discuss workshops to disseminate the results from this project. At the meeting, it was determined that at least three additional workshops, should be held: one with PJM, one at the University of Delaware which would be open to a general audience, as well as Grid operators and wind manufacturer, and finally, presenting a panel on these results at the AWEA Offshore Wind Conference in October 2014.

On May 15th, 2014, a presentation was held at the Department of Energy in Washington, D.C. to disseminate results of the project so far.

A small workshop was held with PJM on June 3rd, in which the updated SMART-ISO model was presented. This effort is of interest to PJM, but this workshop also helped us to understand PJM's dispatch process. A final workshop with PJM will be planned to present the final results to a larger PJM audience.

Two presentations on the MAOWIT project were presented for the AWEA Offshore Conference in Atlantic City on October 7th, 2014. Two of the seven peer-reviewed papers will be presented: one on the SMART-ISO model and the other on Wind Modeling and the WRF model.

A talk was presented to the International Conference Energy & Meteorology to present research on the MAOWIT project. This discussed the importance of wind forecast errors for integrating offshore wind power into the electric grid. This conference was held in Boulder, Colorado in June 2015.

References Cited

Baker, Scott, 2011, The Atlantic Offshore Wind Power Potential in PJM: A Regional Offshore Wind Power Resource Assessment. Thesis, Master of Marine Policy, University

Bates, Alison, Kateryna Samoteskul, John Callahan, and Jeremy Firestone, 2012, Delaware Marine Spatial Planning: Offshore Wind Context. Final Report, 9 April 2012. Delaware, Newark, Delaware, USA. available April 2016 at: http://www.ceoe.udel.edu/File%20Library/Research/Carbon%20Free/CCPI-DE-MSP-OSW-Context-2012.pdf

DOE, 2011. A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Wind & Water Power Program.

Dhanju, Amardeep, Phillip Whitaker, Willett Kempton (2008), Assessing offshore wind resources: An accessible methodology, Renewable Energy, 33(1): 55- 64. Published doi:10.1016/j.renene.2007.03.006

Firestone, Jermey, Willett Kempton, Andrew Krueger. 2009. Public Acceptance of Offshore Wind Power Projects in the USA. *Wind Energy*. 12:2, 183-202.

Firestone, Jeremy, Willett Kempton, Meredith Blaydes Lilley, and Kateryna Samoteskul, Public acceptance of offshore wind power across regions and through time, 2012, Journal of Environmental Planning and Management, 55:10, 1369-1386. Published doi:10.1080/09640568.2012.682782

Kempton, Willett, Felipe M. Pimenta, Dana E. Veron, and Brian A. Colle, 2010, Electric power from offshore wind via synoptic-scale interconnection, Proceedings of the National Academy of Sciences 107 (16): 7240-7245, April 20, 2010. Published doi: 10.1073/pnas.0909075107

Levitt Andrew C.; Kempton Willett; Smith Aaron P.; Walt Musial; and Jeremy Firestone, 2011, Pricing offshore wind power. Energy Policy 39 (10): 6408-6421. Published doi:10.1016/j.enpol.2011.07.044

Lilley, Meredith Blaydes, Jeremy Firestone and Willett Kempton, 2010, The effect of wind power installations on coastal tourism, Energies 3(1), 1-22; (special issue on Wind Energy). Published doi:10.3390/en3010001

J.F. Manwell, J.G. McGowan, A.L. Rogers, 2002, Wind Energy Explained: Theory, Design and Application. Wiley.

Sheridan, B., S. D. Baker, N. S. Pearre, J. Firestone, and W. Kempton, 2012: Calculating the offshore wind power resource: Robust assessment methods applied to the U.S. Atlantic Coast. *Renewable Energy*, **43**, 224-233. doi:10.1016/j.renene.2011.11.029.