ENERGY TECHNOLOGIES AREA

LAWRENCE BERKELEY NATIONAL LABORATORY

Estimating the Value of Offshore Wind Along the United States' Eastern Coast

Detailed Summary of Results

Andrew D. Mills, Dev Millstein, Seongeun Jeong, Luke Lavin, Ryan Wiser, Mark Bolinger

April 2018

ENERGY TECHNOLOGIES AREA

BERKELEY LAB

OVERVIEW

Development of offshore wind in the United States has been limited to date despite a recent acceleration in global deployments and indications of steep cost reductions in European tenders for offshore wind energy. In part, this is due to an unclear understanding of the economic value that offshore wind provides within local or regional electricity markets.

We develop a rigorous method to estimate the marginal value provided by offshore wind projects (whether fixed-bottom or floating-platform), focusing on economic but also including environmental impacts. Seasonal and diurnal profiles of wind resources vary by location, including whether plants are onshore or offshore. These location-specific profiles impact the value of wind in terms of the types of other generation it displaces, its contribution to meeting peak demand, its ability to reduce emissions, and the local price of electricity and renewable energy credits (RECs).

This project explores these various aspects of value along the East Coast using real historical weather patterns at thousands of potential offshore wind sites and wholesale and REC market outcomes. In effect, the work asks: What would have been the marginal economic value of offshore wind projects along the East Coast over the 2007 to 2016 timeframe? We then also highlight factors that might drive these values up or down in the future for potential offshore wind projects.

The work builds on recent and ongoing research by NREL, and is informed by a comprehensive review of the available U.S. offshore wind energy valuation literature. Knowing the primary drivers for the value of offshore wind, and how that value varies geographically and over time, can inform wind developers, purchasers and energy system decision-makers, and may help inform DOE on its offshore wind technology cost targets as well as the early-stage R&D investments necessary to reach them.

ORGANIZATION OF BRIEFING

- Key Findings
- Summary of Methods
- Primary Results
- Supplemental Results
- Assessment of Future Trends
- Appendix: Methodological Details

See also a narrative summary of the key findings of this work and a journal article pre-print:

https://emp.lbl.gov/publications/estimating-value-offshore-wind-along

Note that NREL is conducting a parallel effort to assess the potential future wholesale market impacts of offshore wind in New York and New England, focusing on performance metrics such as reliability, capacity value, transmission needs, production cost savings, wholesale price suppression, curtailment levels, and system ramping needs. That future-looking modeling work is complementary to our data-driven historical work. The NREL results will be available later in the year.

KEY FINDINGS (1)

- The marginal total market value of offshore wind—considering energy, capacity, and RECs—varies significantly by project location, and is highest for sites off of New York, Connecticut, Rhode Island, and Massachusetts. The median, 2007 – 2016, market value is highest in ISO-NE (~$110/MWh), in part due to higher REC prices. The energy and capacity value is higher for NYISO, particularly for the Long Island region. The median, 2007 – 2016, value is lower (~$55/MWh) in the Non-ISO region south of PJM.
- Comparing LCOE estimates with value estimates, we find that the most attractive sites from this perspective are located near southeastern Massachusetts and Rhode Island, while the least attractive are far offshore of Florida and Georgia.
- The total market value of offshore wind can be approximated (to within ±5%) by the value of a flat block of power. Locational variations are driven primarily by differences in average energy (and REC) prices, and not by differences in diurnal and seasonal wind generation profiles.
- Diurnal and seasonal generation profiles do matter, but mostly for capacity value, which is a small component of overall value. The capacity value can be up to 50% different than the capacity value calculated based on a flat block of power. The capacity credit of offshore wind in the NYISO and ISO-NE markets is significantly higher in winter than in summer; offshore wind in these regions benefits from having capacity credit assessed in both seasons.
- The market value of offshore wind also varies significantly from year to year, driven primarily by changes to energy and REC prices. The market value of offshore wind is lowest in the most recent year evaluated, 2016, falling roughly 50% from 2007.
- The energy and capacity value of offshore wind in the three ISO regions exceeds the value of onshore wind, by $6/MWh – $20/MWh in 2016. This difference in value between onshore and offshore wind is due to differences in location and differences in hourly output profiles. The estimated summer and winter capacity credit for offshore wind in the three ISOs is roughly double that for onshore wind.

KEY FINDINGS (2)

- Offshore wind reduces air emissions that are harmful to human health and the environment, yet the avoided emissions rate for pollutants like SO_2 has declined over time (e.g., declining from 4.5 kg-avoided to 1.0 kg-avoided per MWh-wind from 2007 to 2015, in the Mid-Atlantic region). Avoided emissions attributable to offshore wind vary by region—highest in the Mid-Atlantic, lower in the Southeast, and lowest in the Northeast.
- Wholesale electricity and natural gas price reductions attributable to offshore wind can be substantial, though these price reductions represent a transfer from producers to consumers and would be anticipated to decline over time, as supply adjusts to the new demand conditions. If the natural gas price reduction benefits are calculated nationally, consumer savings equal $30-$80/MWh-wind; if the savings are considered only for the region in which the wind is deployed, consumer savings are found to be up to $6/MWh. The wholesale price 'merit order' effect is estimated to deliver more than $25/MWh-wind consumer savings in the three ISO regions, with much lower savings outside those regions.
- Interconnecting to a more-distant but higher-priced node can increase the value of offshore wind by as much as $25/MWh-wind, particularly when switching from PJM or ISO-NE nodes to NYISO nodes around Long Island. Having more than one interconnection point and arbitraging between them can boost value even further (by $40/MWh-wind in some cases). Selling RECs into a different state than the one in which the project interconnects can also add up to $20/MWh-wind of value, depending on the location. Adding battery storage (in MWh terms) sized at roughly one quarter of the offshore wind project capacity can boost value by up to $3/MWh-wind, with still-greater incremental value as battery size increases. Finally, wind turbine design is found to have a minor effect on market value, at least for the first offshore wind projects installed in a region.
- Though the historical perspective taken in this study is instructive in terms of identifying key value drivers for offshore wind, the decision to build offshore wind going forward will depend on expectations of future benefits, which may differ from recent historical experience.

SUMMARY OF METHODS

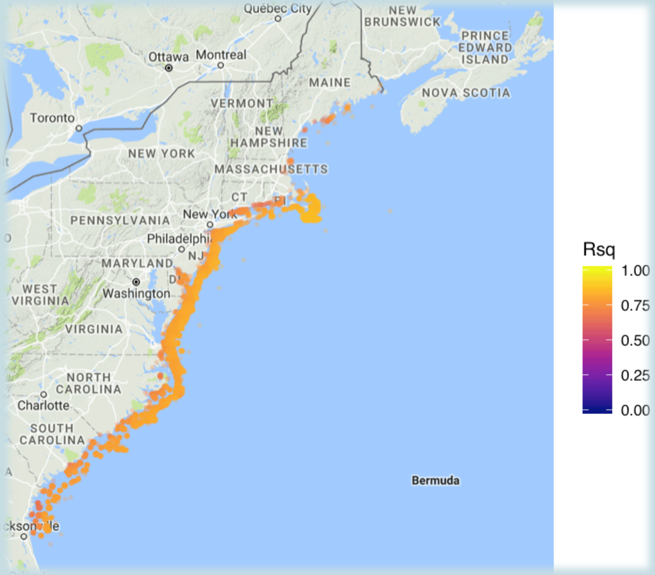
WIND SPEED

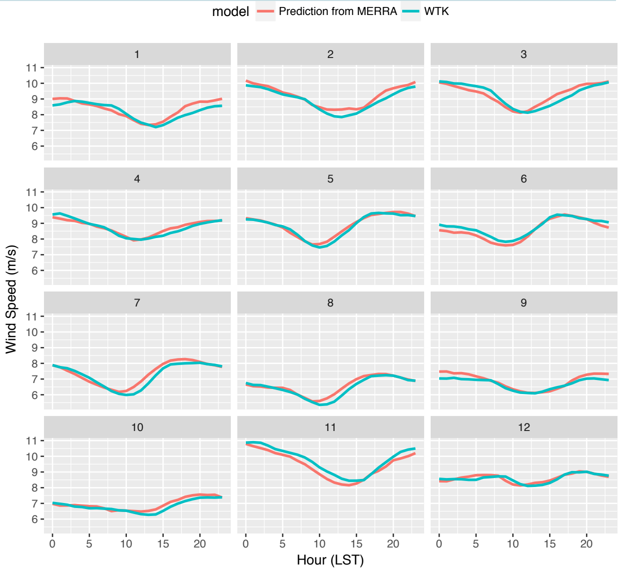
Used NREL Wind Tool Kit (WTK) to identify sites (whether fixed-bottom or floating). Further screened sites for technical potential: >7 m/s average wind speed at 100m, <1000m water depth, within U.S. Exclusive Economic Zone.

Used WTK data for hourly wind speeds at each site between 2007-2013.

Wind speeds for 2014-2016 estimated using reanalysis (MERRA) data available at coarse geographic resolution.

Downscaled coarse MERRA data to the WTK sites with a site-by-site linear regression to describe the relationship between MERRA and WTK wind speed.



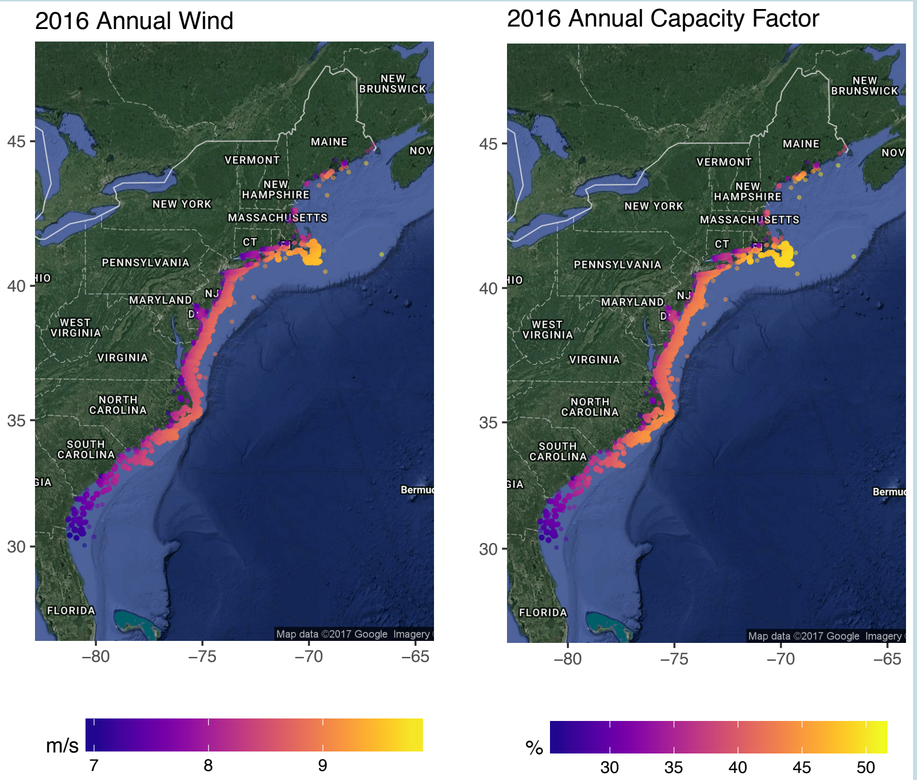


- Cross validation of downscaled MERRA and WTK wind speeds showed that the approach can effectively recreate the WTK diurnal and seasonal cycles for 2013 based on 2007 – 2012 data (~6,700 sites).
- Average R^2 value: 0.8 for 2007 – 2013 cross validation (~6,700 sites)

WIND POWER

Converted wind speed to hourly gross wind power output based on an offshore turbine power curve from NREL (Musial et al 2016). The 6 MW, 100m hub height turbine has large blades suited to North American applications (318 W/m^2). Net hourly wind power output accounts for four sources of losses:

- *Wake losses:* assumed turbines in 10 X 10 grid with 7D spacing; wake loss rate is a function of wind speed (but losses insensitive to atmospheric stability and wind direction).
- *Electrical losses:* average losses vary with distance to shore and water depth. Instantaneous loss rate increases with increases in wind power.
- *Availability:* assume 96% across all hours.
- *Other losses:* assume 2% losses across all hours.
- *Other assumptions:* For simplicity, air density was treated as constant across time.

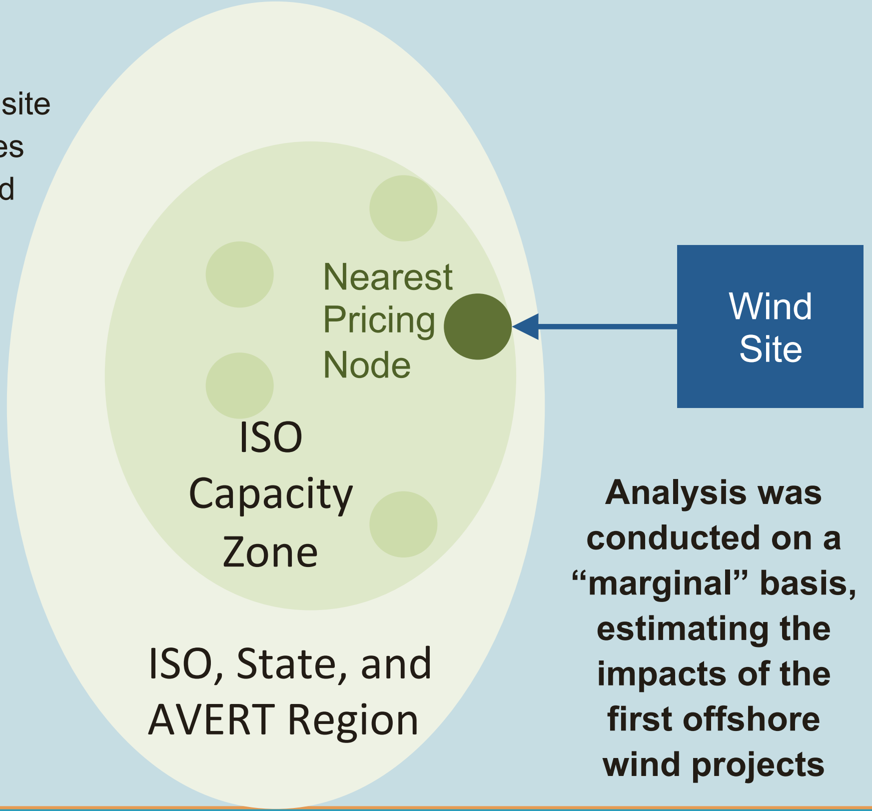


2016 annual average hourly wind speed (left) and energy generation (right) for all sites (~6,700)

VALUE CALCULATIONS

Marginal impacts were estimated using recent historical prices and emissions rates for 2007-2016.* Benefits and impacts for each wind site are based on associating it with the *nearest* large pricing node. Nodes are mapped to an ISO, ISO capacity zone, state (for REC value), and AVERT region (for emissions and wholesale and gas price impacts).

- *Energy value:* hourly nodal real-time energy prices (referred to as locational marginal prices, or, LMPs)
- *Capacity value:* ISO capacity zone prices and capacity credits estimated using each ISO's practices
- *REC value:* monthly Tier 1/Class 1 REC prices for each state and monthly wind power
- *Avoided emissions:* EPA's AVERT model for each year
- *Wholesale price effect:* reduction in wholesale energy prices from historical relationship of price and demand
- *Natural gas price effect:* reduction in gas from AVERT, with price elasticity from EIA



Analysis was conducted on a "marginal" basis, estimating the impacts of the first offshore wind projects

*Additional information on the methods used for each category are detailed in the appendix

MATCHING WIND TO NEAREST NODE

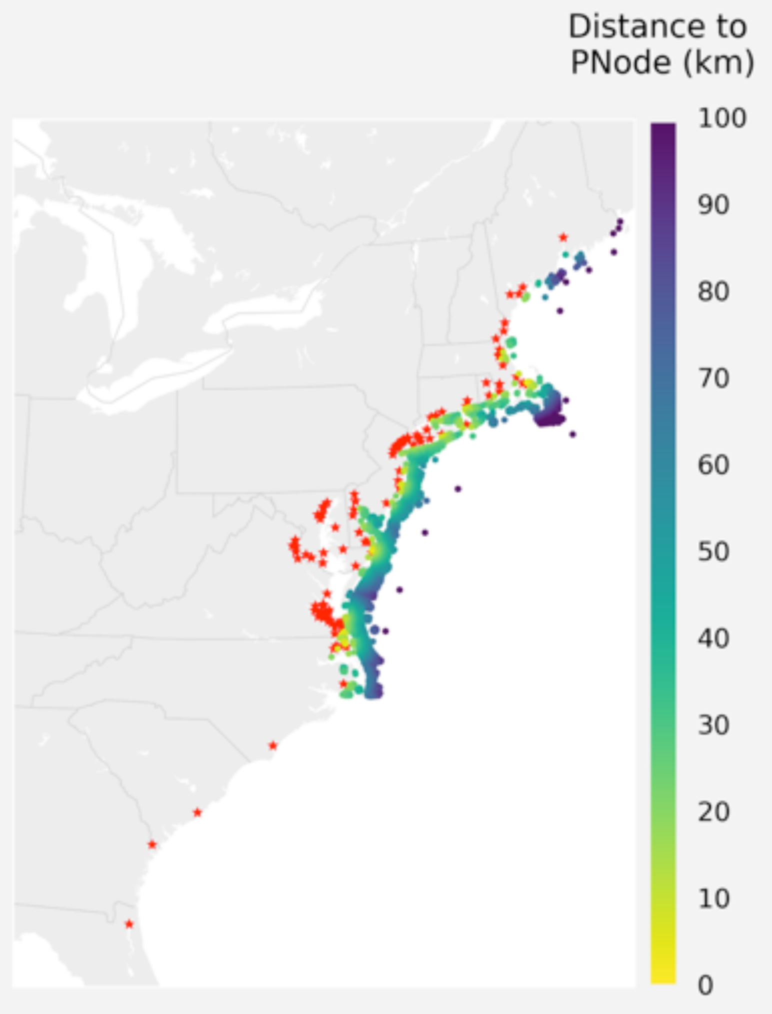
Large pricing nodes (red stars) were identified as nodes with substations having voltages higher than 138 kV or with more than 200 MW of generation.

The distance from each wind site to the nearest large pricing node is often less than 50 km.

Wind sites outside of ISO-NE, NYISO, and PJM are associated with a balancing area based on state boundaries, rather than particular nodes. Distances in the Non-ISO region are not shown.

- Non-PJM North Carolina: Duke Energy Progress
- South Carolina: South Carolina Power Service Authority
- Georgia: Southern Company
- Florida: JEA

State boundaries offshore are from U.S. BOEM.



CAPACITY MARKET RULES VARY BY ISO

For each ISO, the capacity value is based on the revenue that an offshore wind plant would have earned had it participated in the capacity market between 2007-2016.

The capacity revenue depends on the market price of capacity for each ISO capacity zone and the capacity credit of the offshore wind plants.

Each ISO has different rules for estimating the capacity credit, shown in the table. In general, the capacity credit depends on generation during a defined peak period. ISO-NE and NYISO define peak periods for the summer and winter. PJM only uses a summer peak period.

We assume that the capacity value in Non-ISO regions is based on the capacity prices from the southernmost capacity zone in PJM (DOM) and the capacity credit rules for PJM.

	ISO-NE	NYISO	PJM
Seasons	Summer and Winter	Summer and Winter	Summer
Summer Peak Period	June-Sept 1-6pm	June-Aug 2-6pm	June-Aug 2-6pm
Winter Peak Period	Oct-May 5-7pm	Dec-Feb 4-8pm	N/A
Basis of Measurement	Median during peak	Average during peak	Average during peak
Average over which years?	Rolling average over previous 5 years	Previous year	Rolling average over previous 3 years

ELEMENTS NOT ADDRESSED IN THIS ANALYSIS

Short-term variability and forecast error: We do not account for any costs associated with the short-term variability (sub-hourly) and forecast error of offshore wind.

- Eastern Wind Integration and Transmission Study (EWITS) estimated these costs to be \$3-6/MWh (\$2016) in scenarios with more than 20% energy from wind.

No price suppression effect for wind value: Wind value is calculated on the margin, without accounting for effects of wind on its own revenues. In contrast, we do estimate a wholesale price effect for consumers since even small price impacts lead to large changes in consumer costs.

Local price suppression: The wholesale price effect does not account for any local price suppression associated with congestion and losses. It also does not account for any potential reduction in forward capacity market prices.

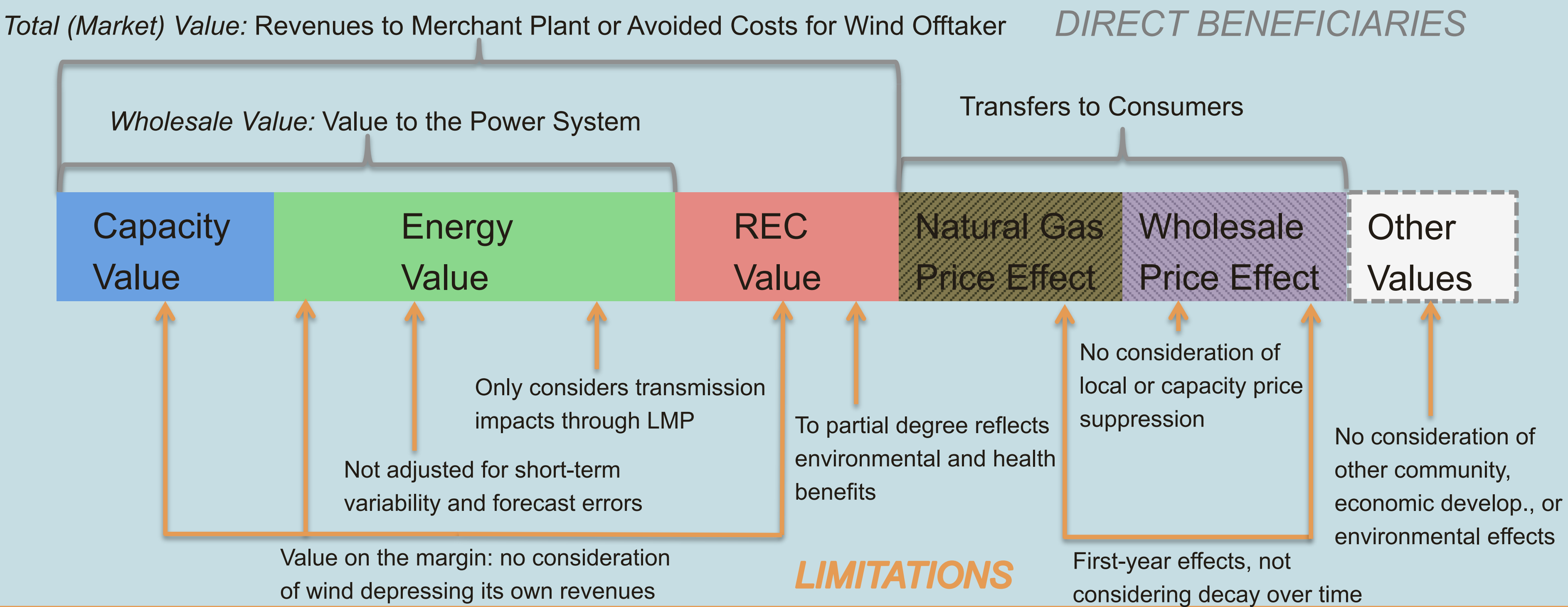
Environmental valuation: To some extent, avoided air emissions are valued through RECs and through pollution permit prices embedded in LMPs (e.g., permits for SO_2, NO_x, or CO_2 in the RGGI program).

- If instead valued based on environmental and health benefits, recent values could range from \$26/MWh to >\$100/MWh depending on the region within the East Coast and methods used (Millstein et al. 2017).

Transmission avoidance: Avoided transmission costs are only addressed through the congestion component of the LMP prices. We do not directly estimate avoided transmission costs of offshore wind relative to other options.

Other values and costs: Our analysis does not estimate the economic value or cost of other community and environmental effects (e.g., job creation, economic development, water use, tourism, property values, fishing impacts, etc.).

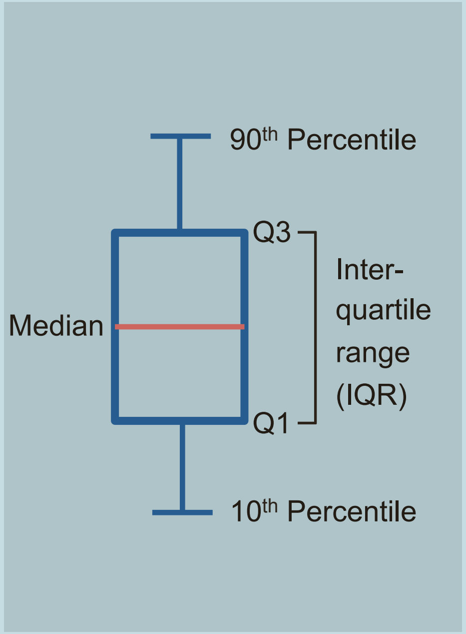
SUMMARY OF VALUE STREAMS CONSIDERED OR EXCLUDED FROM ANALYSIS



PRIMARY RESULTS

- Energy, capacity, and REC value, by location and over time
- Impact of high- and low-value periods for energy value
- Normalized value relative to flat baseload block
- Offshore capacity credit: summer and winter
- Evidence of a sea-breeze effect
- Value comparisons with onshore (land-based) wind
- Avoided air pollution emissions
- Wholesale price "merit-order" effect
- Natural gas price suppression effect

Guide to reading the box and whisker plots



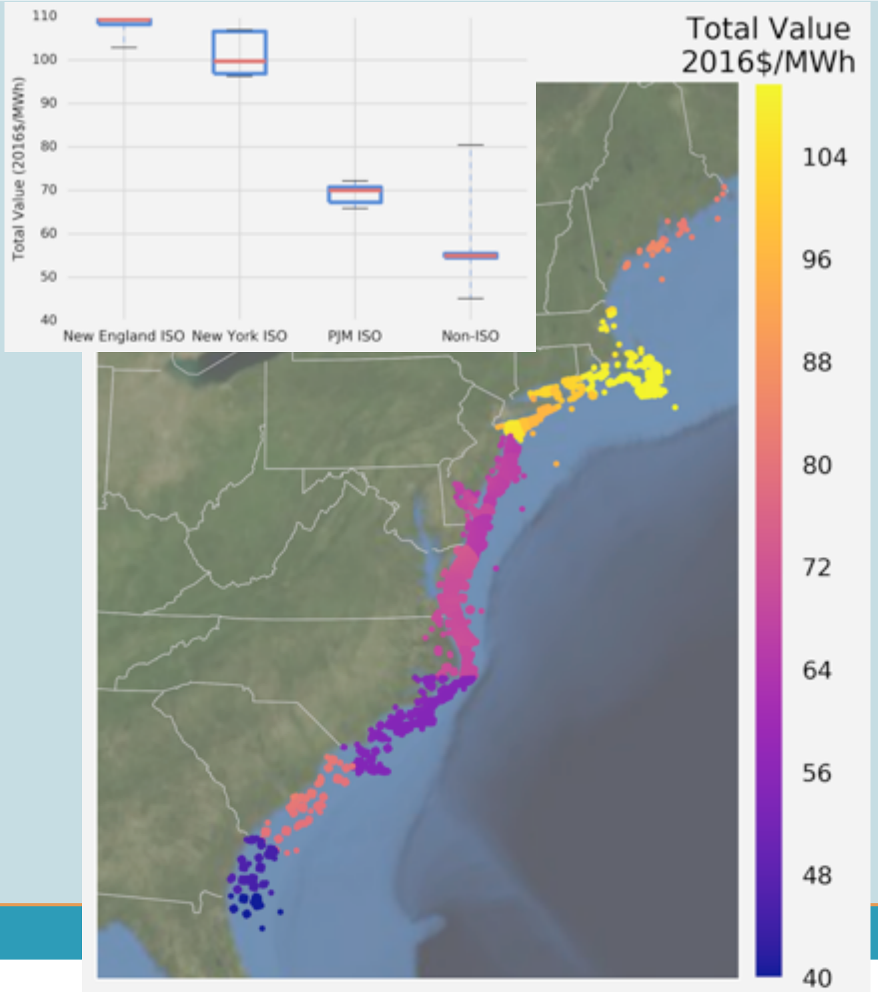
ENERGY, CAPACITY, AND REC VALUE

Total average energy, capacity, and REC* value over 2007-2016 is highest near New York, Connecticut, Rhode Island, and Massachusetts. The median value for sites in ISO-NE is nearly $110/MWh across 2007-2016, and for NYISO is $100/MWh.

The median value of sites in PJM is $70/MWh, while it is closer to $55/MWh for sites in the Non-ISO region south of PJM.

South Carolina Power Service Authority reports high marginal costs (system lambdas) compared to neighboring balancing areas in 2009-2010 and 2012-2013, resulting in higher value.

Variation in total value across sites is primarily driven by variation in electricity and REC prices rather than in wind power profiles *(see later slides)*.



*Tier 1/Class 1 RECs, used here, do not provide any incremental value to offshore RECs. Offshore REC programs did not exist with transparent prices over 2007-16.

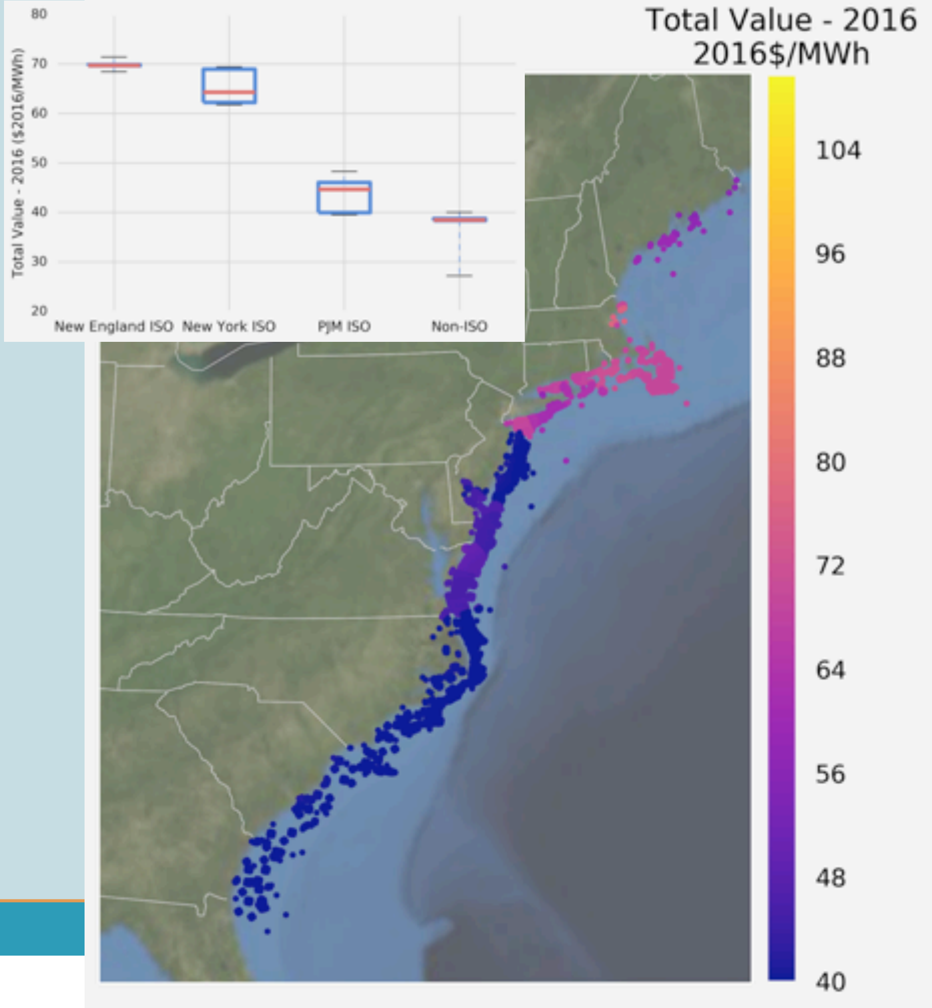
TOTAL VALUE IS LOWEST IN 2016

Total energy, capacity, and REC value is the lowest in 2016.

The geographic variation in value is similar in 2016 to the variation over 2007-2016. The median value for sites in ISO-NE is $70/MWh in 2016, and for NYISO is nearly $65/MWh. The median value of sites in PJM is $45/MWh, while it is less than $40/MWh for sites in the Non-ISO region south of PJM.

South Carolina Power Service Authority's 2016 system lambdas are more in line with neighboring balancing authorities.

Lower value in 2016 than in earlier years is driven primarily by the lower LMPs, and hence lower energy value, and by somewhat lower REC prices.

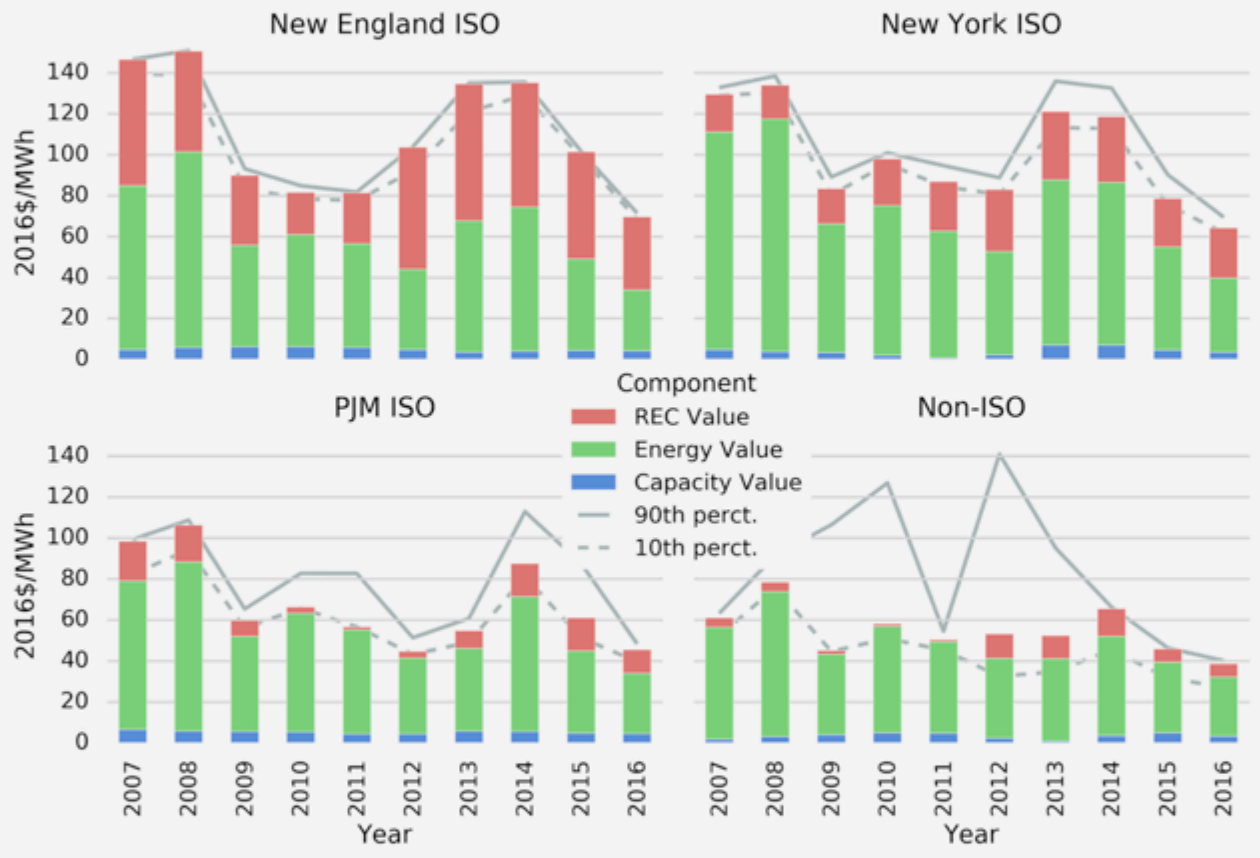


VALUE COMPONENTS

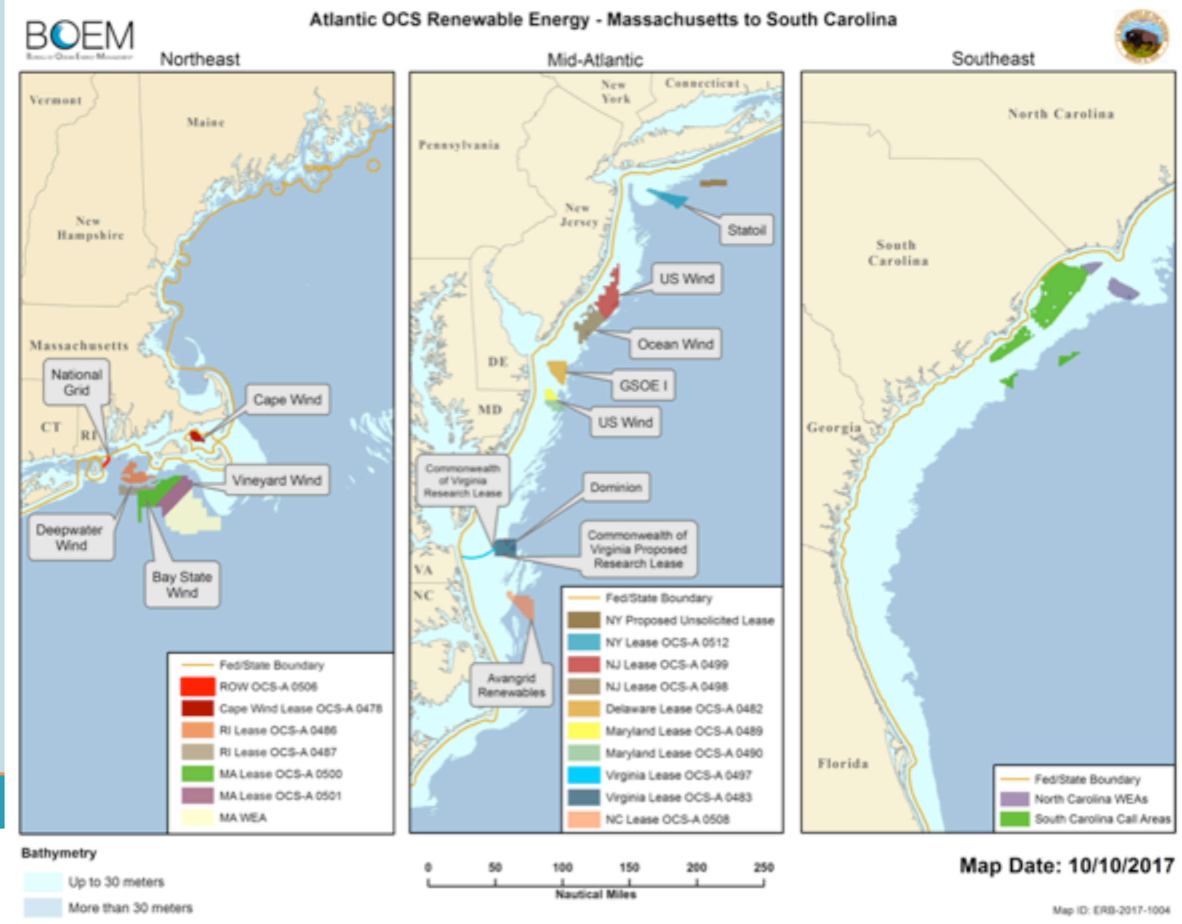
Figure shows the median value of each component across all sites in each region, with background lines showing the 10-90th percentile of the total value across all sites in each region.

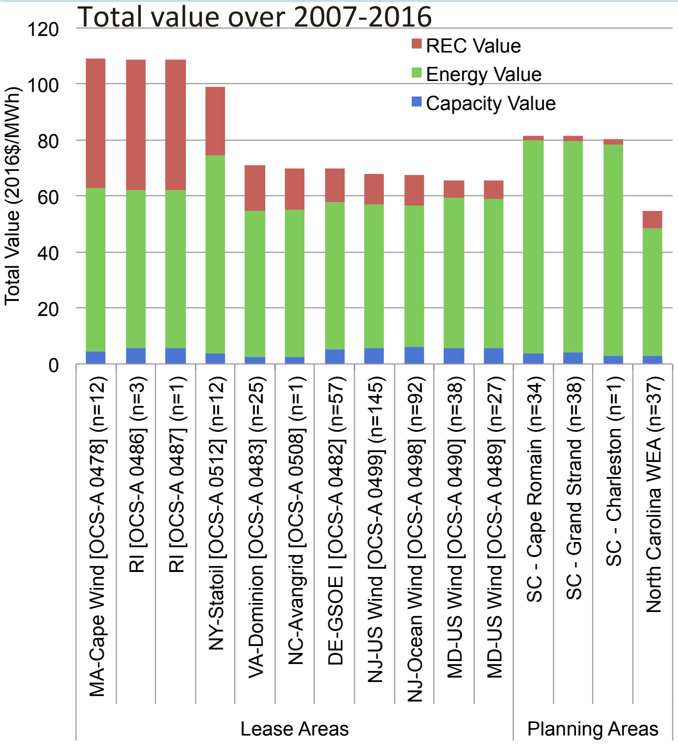
The total value is highest in New England ISO, in part due to higher REC prices. The energy and capacity value is higher for New York ISO, particularly for the Long Island region (Zone K).

Capacity value is a minor contributor to the value of offshore wind across all years and regions.



MEDIAN ENERGY, CAPACITY, AND REC VALUE BY BOEM AREA





n is the number of WTK sites in a BOEM area. Note that not all NREL WTK sites are in BOEM areas, and some BOEM areas have no WTK sites.

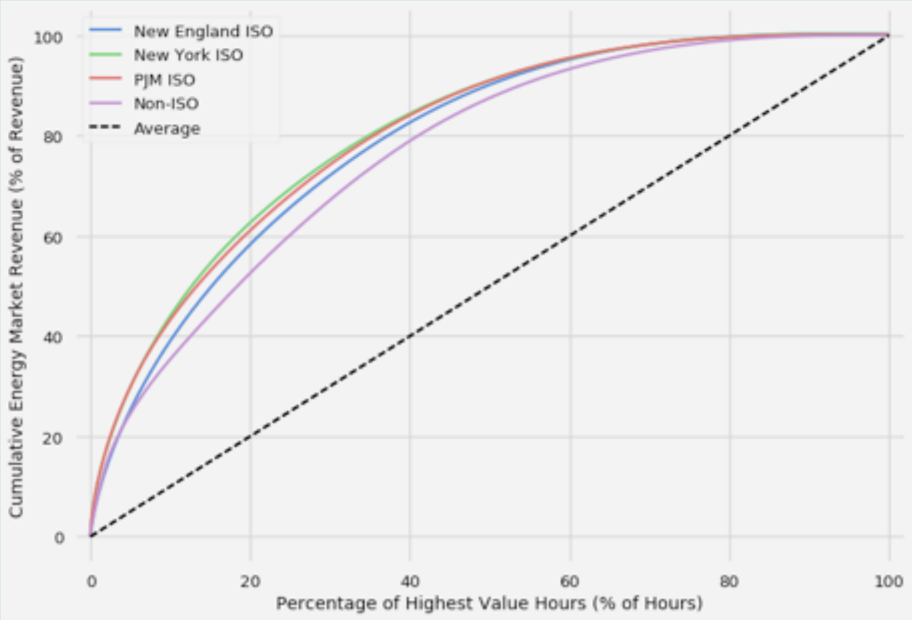
SHARE OF ENERGY REVENUE FROM HIGH VALUE PERIODS

LMPs vary dramatically over time due to various constraints in the power system including available generating capacity, transmission, fuel delivery, or demand for electricity. Additionally, wind output varies over time. As a result, high value periods that are coincident with wind output have a disproportionate impact on the energy value of offshore wind.

The figure shows the share of energy market revenue derived from the highest value hours for the median value site in each of the four regions. The “Average” line illustrates what this curve would look like if the revenue in each hour was the same.

The top 5% of hours contribute about 20% of total energy market revenue, while the bottom 40% of hours contribute less than 5% of energy market revenue.

The median site in NYISO is the most sensitive to high value hours, while the Non-ISO site is the least sensitive.



VALUE OF A FLAT BLOCK OF POWER

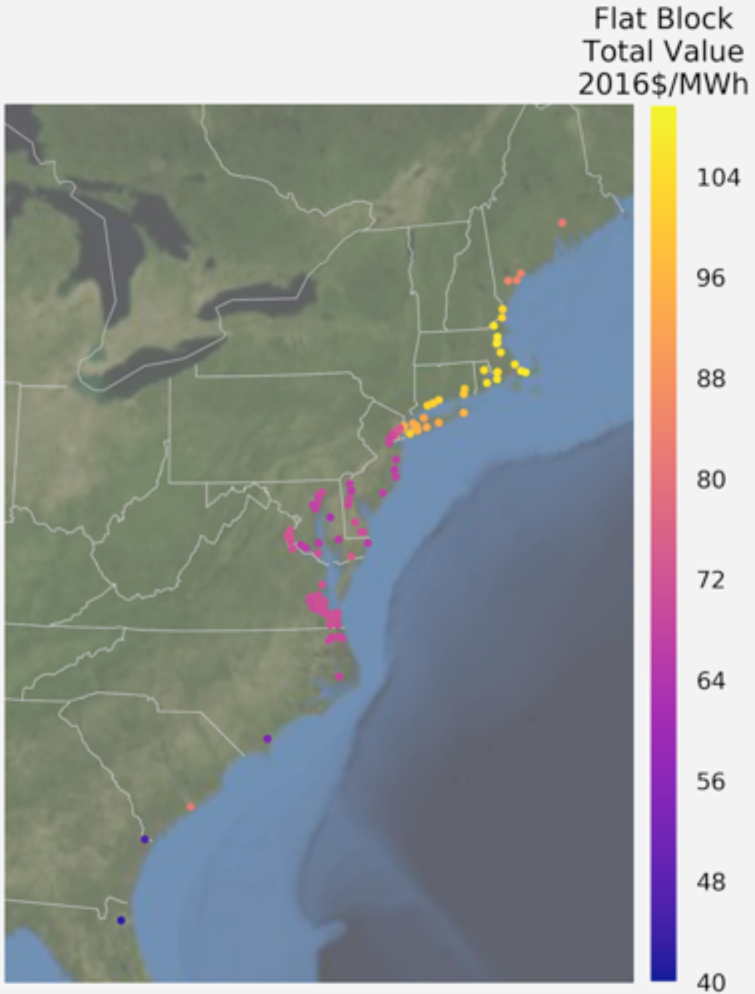
Variation in the value of offshore wind across sites is due to two main sources of variation:

(1) The temporal wind generation profile across sites

(2) The price of energy, capacity, and RECs across nodes

To isolate these two sources of variation, we can normalize the results by the value of a flat block of power (i.e., a source of energy with constant output in all hours). The figure shows this value of a flat block of power for each node.

Wind sites whose output is better correlated with times of high value will have a value that exceeds a flat block while wind sites negatively correlated with times of high value will have a value below that of a flat block.



NORMALIZED TOTAL VALUE

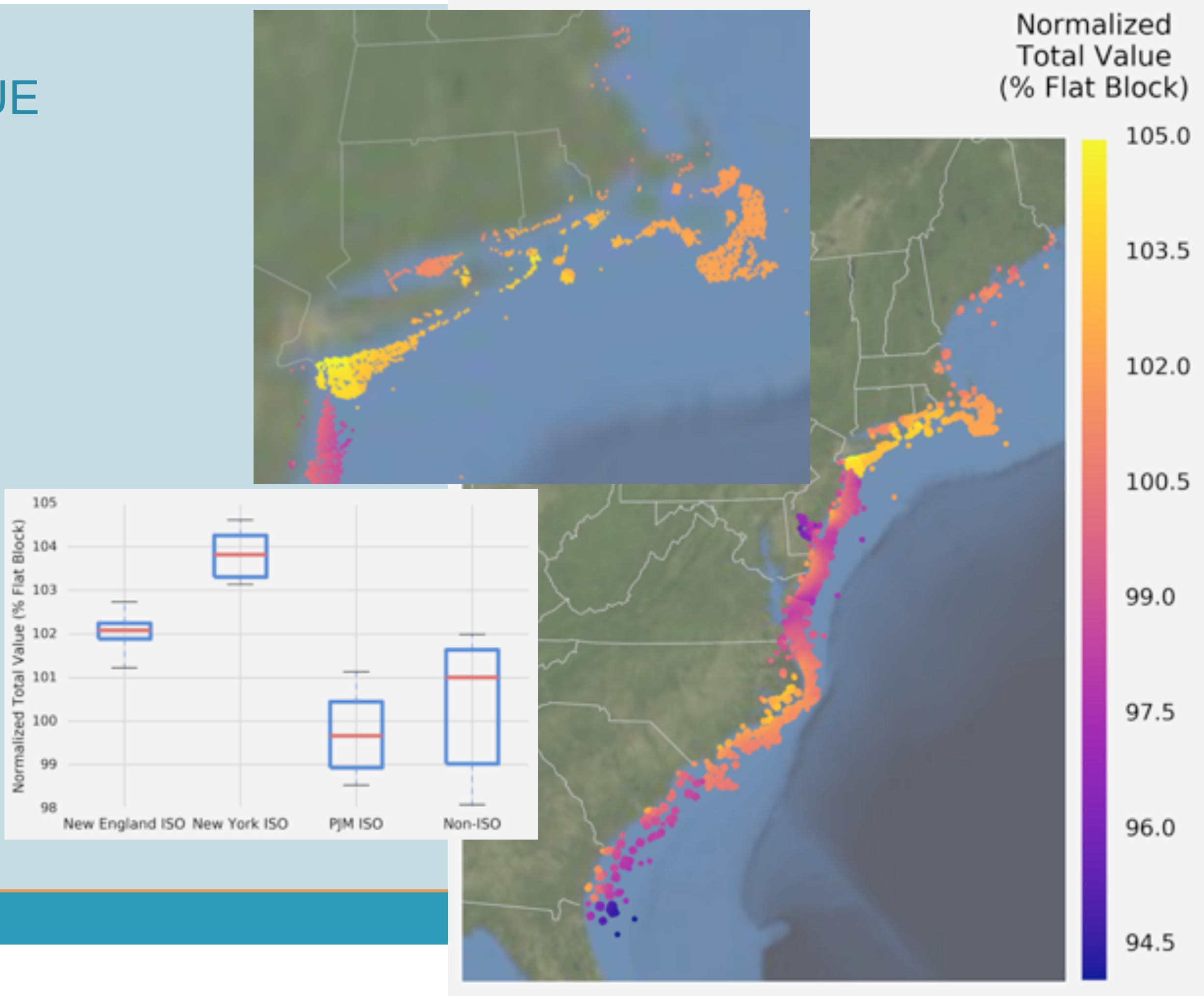
Normalizing the total value at each wind site by the value that would be generated if the wind were constant across all hours (a flat block) highlights the effect of wind variability.

For most sites, the value of offshore wind with its actual historical profile is very close to that of a flat block (within 98-105%).

The highest correlation occurs for sites in New York ISO (103-105% of a flat block), near New York City and Long Island.

The lowest correlation occurs for sites outside of the ISOs, near Florida.

Reminder: value estimates are 'marginal', for the first offshore wind deployments

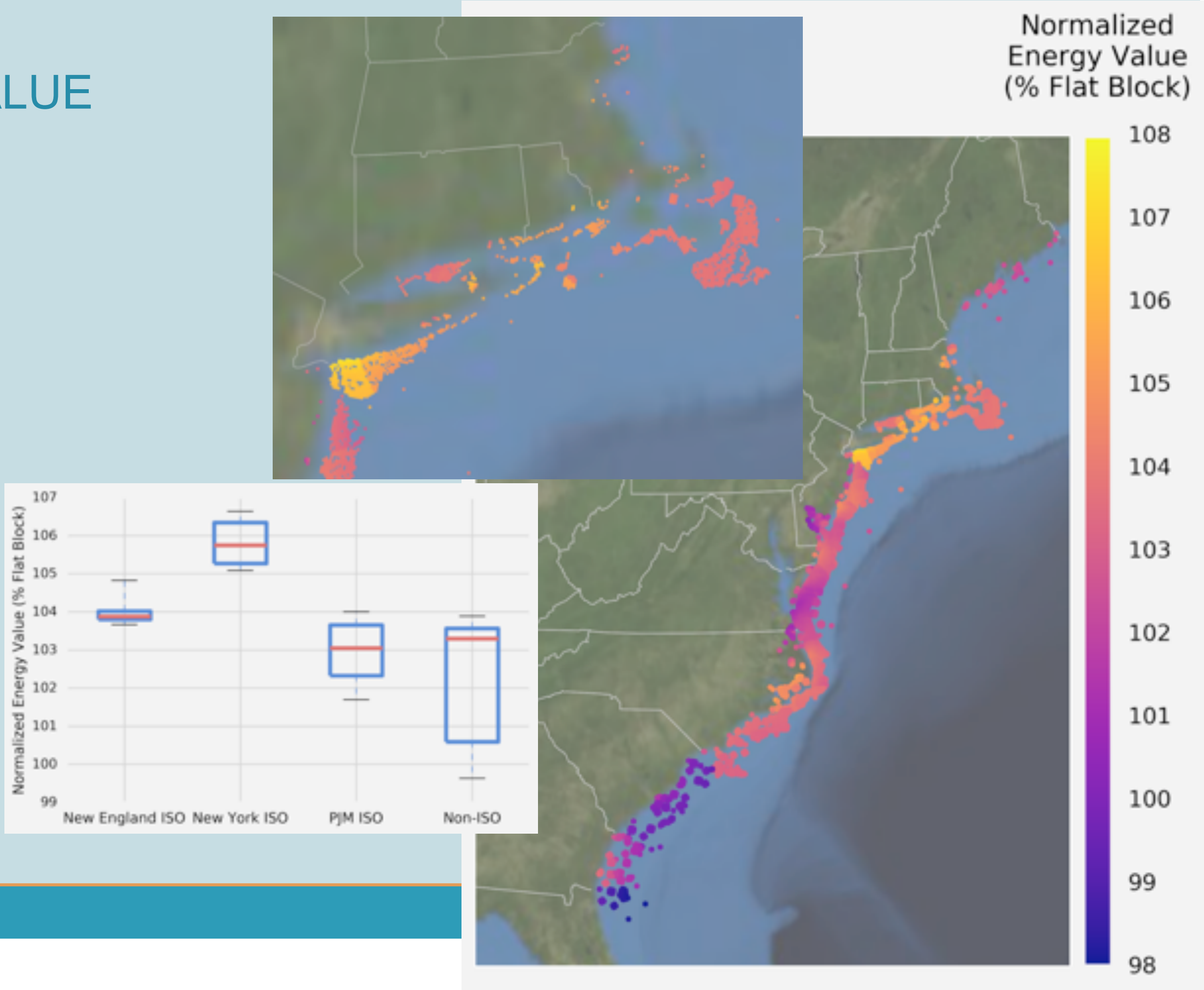


NORMALIZED ENERGY VALUE

Wind generation from many offshore sites tends to be slightly positively correlated with higher wholesale energy prices (LMPs).

The highest correlation occurs for sites in New York ISO (105-107% of a flat block), near New York City and Long Island.

The lowest correlation occurs for sites outside of the ISOs, near Florida, Georgia, and South Carolina.

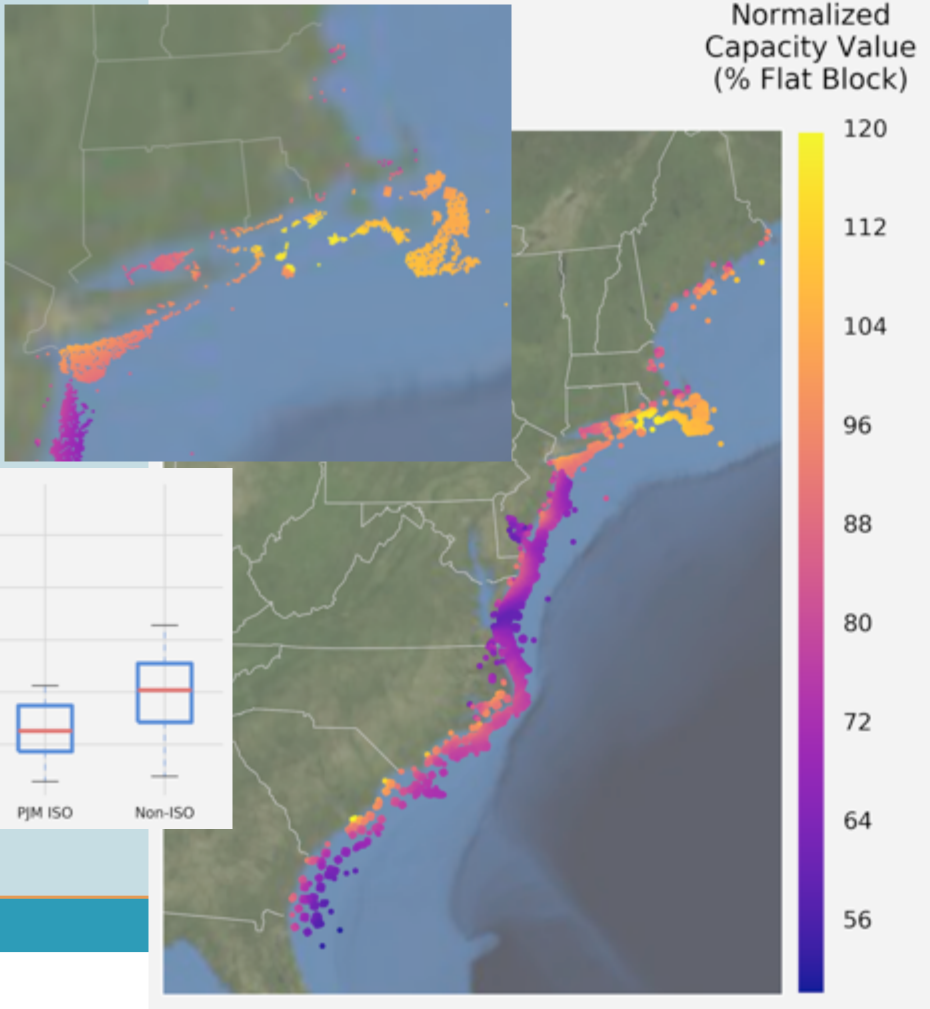


NORMALIZED CAPACITY VALUE

Most sites in ISO-NE have a capacity value that exceeds the capacity value of a flat block of power. This is in part due to the high capacity credit of offshore wind in the winter months (shown on later slide).

The capacity value of offshore wind in PJM and the non-ISO region, where the peak period only includes summer, is typically less than a flat block of power.

A trend is noticeable on some parts of the coast where the capacity value tends to be higher near the shore than far from shore.



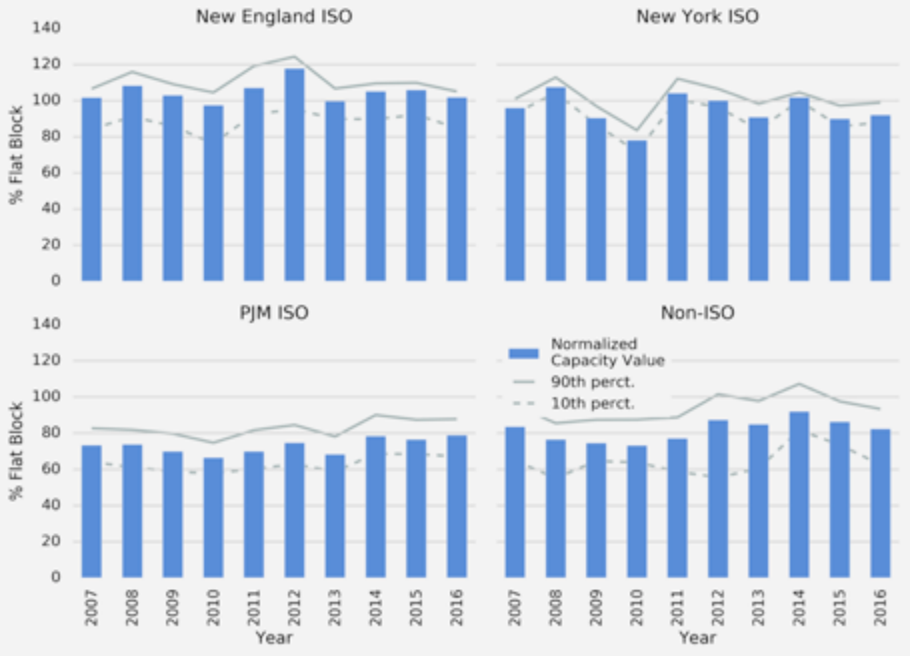
NORMALIZED VALUE OVER TIME

ENERGY VALUE

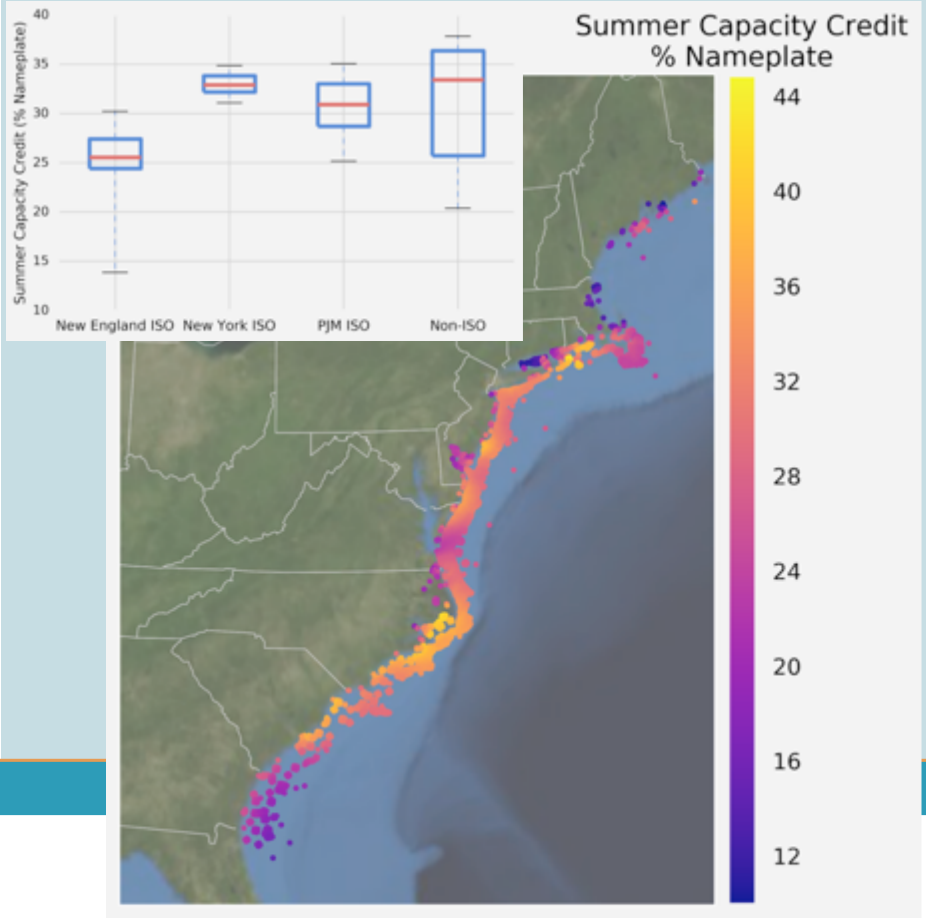
Normalized energy value is consistent over time, though somewhat higher in 2014 for the ISOs: 2014 had high energy prices in the winter due to the "Polar Vortex."

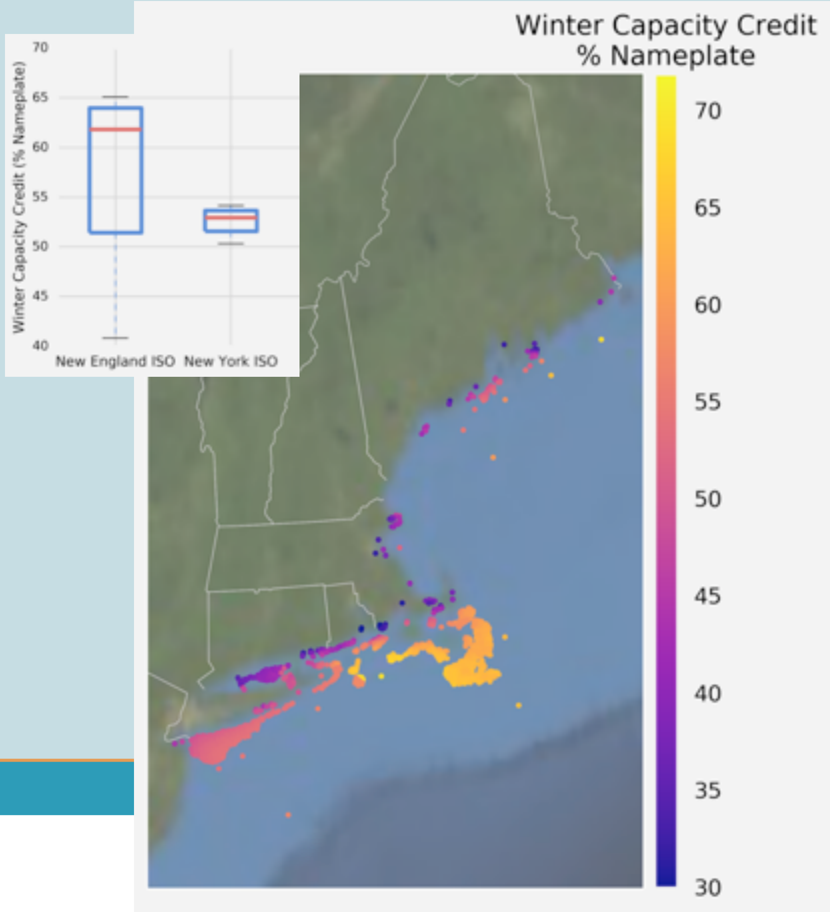
CAPACITY VALUE

Normalized capacity value varies most from year to year in NYISO, where the capacity credit depends on production in the previous year. PJM and ISO-NE use average of 3 and 5 years.



SUMMER AND WINTER CAPACITY CREDIT





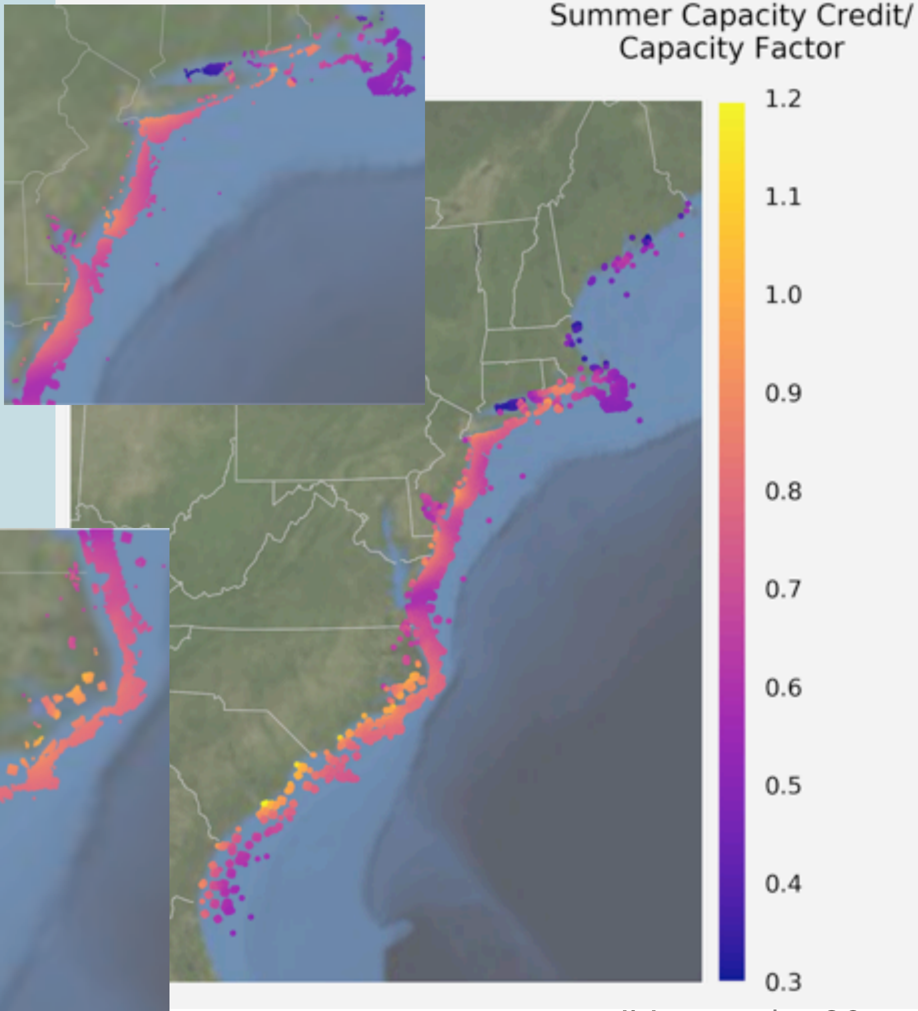
EVIDENCE OF A SEA-BREEZE EFFECT

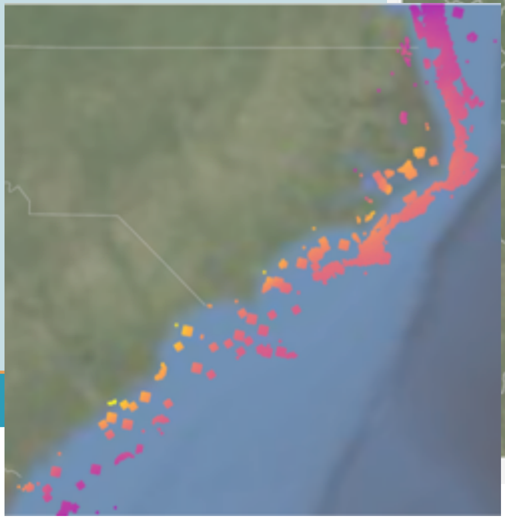
A ‘sea-breeze’ effect suggests that sites near the shore should produce more of their annual energy during the summer peak period relative to sites more distant from shore.

We can isolate this potential sea-breeze effect by measuring the ratio of the energy produced in the summer peak period (the summer capacity credit) to the energy produced over the full year (the capacity factor).

The higher the ratio, the greater the relative share of production in the peak period.

The sea-breeze effect appears strongest near the Carolinas and is also somewhat evident in areas around MD, southern NJ, NY, and RI.

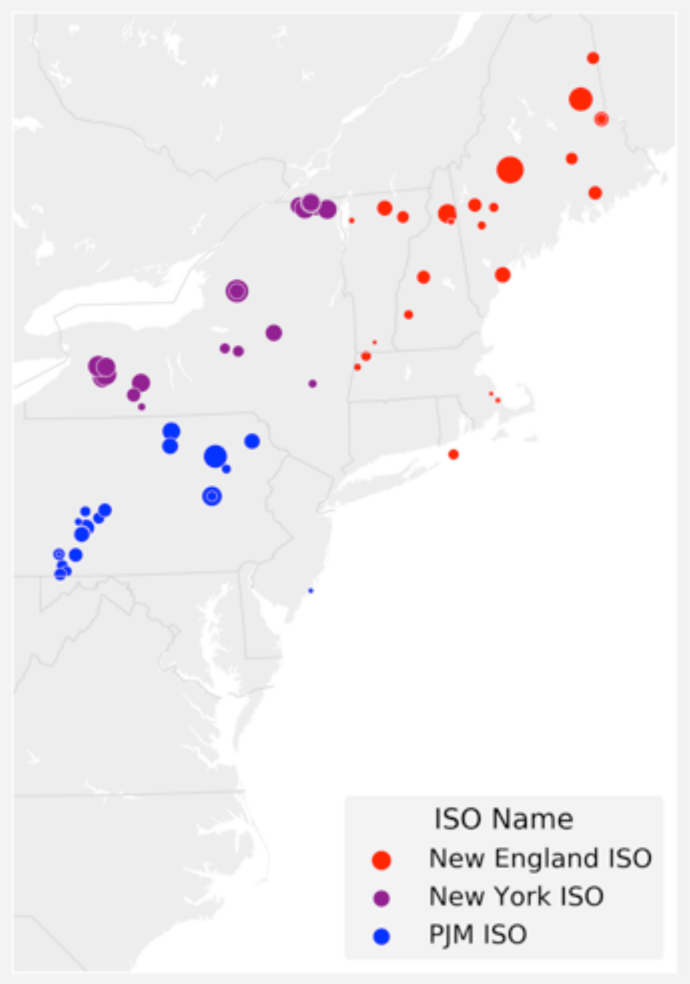




ONSHORE WIND ALTERNATIVES

Electricity buyers have various alternatives for meeting needs. These alternatives interconnect at different locations and have different generating profiles than offshore wind. Here we compare the energy and capacity value of offshore wind to onshore wind for the three ISO regions. The figure shows the location and relative size of currently operating wind plants (as of the end of 2016).

The offshore wind value is based on the median value site in each ISO. The onshore wind value is based on the aggregate hourly wind profile in ISO-NE, NYISO, and the Mid-Atlantic region of PJM.* The energy value is based on the capacity-weighted average hourly LMP price and the aggregate wind profile, for each ISO. The capacity value is based on the capacity-weighted average zonal capacity price and the capacity credit of the average wind profile, for each ISO. The node where each onshore wind plant has interconnected is provided by ABB Velocity Suite.

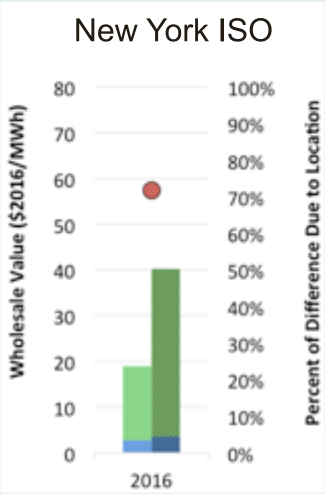


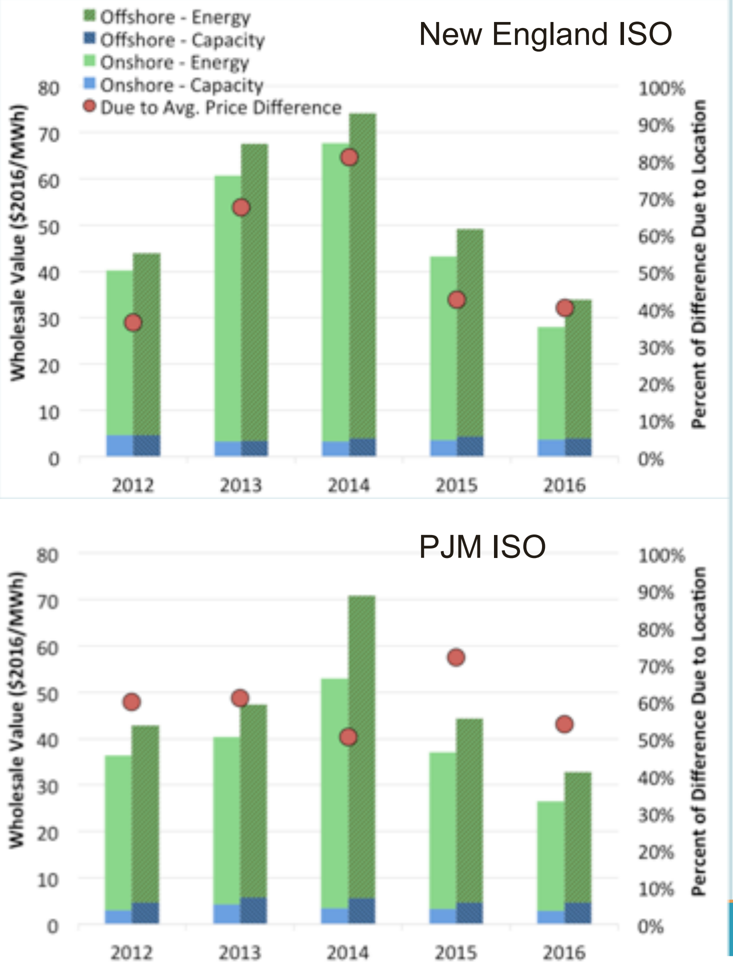
*Aggregate onshore wind hourly output profiles are only available for a limited set of years. The comparison to offshore focuses only on the overlapping subset of years.

ONSHORE WIND ALTERNATIVES

Across all ISOs and years of available onshore wind generation data, the wholesale value of offshore wind exceeds the value of onshore wind. The value of offshore wind is particularly higher than onshore wind in the New York ISO region, where offshore plants would interconnect in transmission constrained regions with higher prices.

The difference in wholesale value between onshore and offshore wind is due to differences in location and differences in hourly output profiles. The share of the difference due to locations is highlighted in the charts—it is estimated based on comparing the difference in value for onshore and offshore wind to the difference in value for a flat block of power at the same locations. Location appears to play a somewhat larger role than output profile, in most cases.





ONSHORE WIND ALTERNATIVES

Though capacity value is only a small fraction of the wholesale value of wind, the capacity credit of offshore wind is substantially greater than the capacity credit of onshore wind across all ISOs.

In the table, for New England ISO and PJM ISO, the capacity credit is the average across 2012-2016 for both onshore and offshore wind. For New York ISO, the capacity credit is based only on wind output in 2016.

One caveat for this comparison is that we are comparing the capacity credit of a single offshore site to the capacity credit of the aggregate wind profile for the onshore sites. Furthermore, the nameplate capacity of onshore wind is an estimate: we used the capacity and commercial online date of wind plants reported in ABB's Velocity Suite.

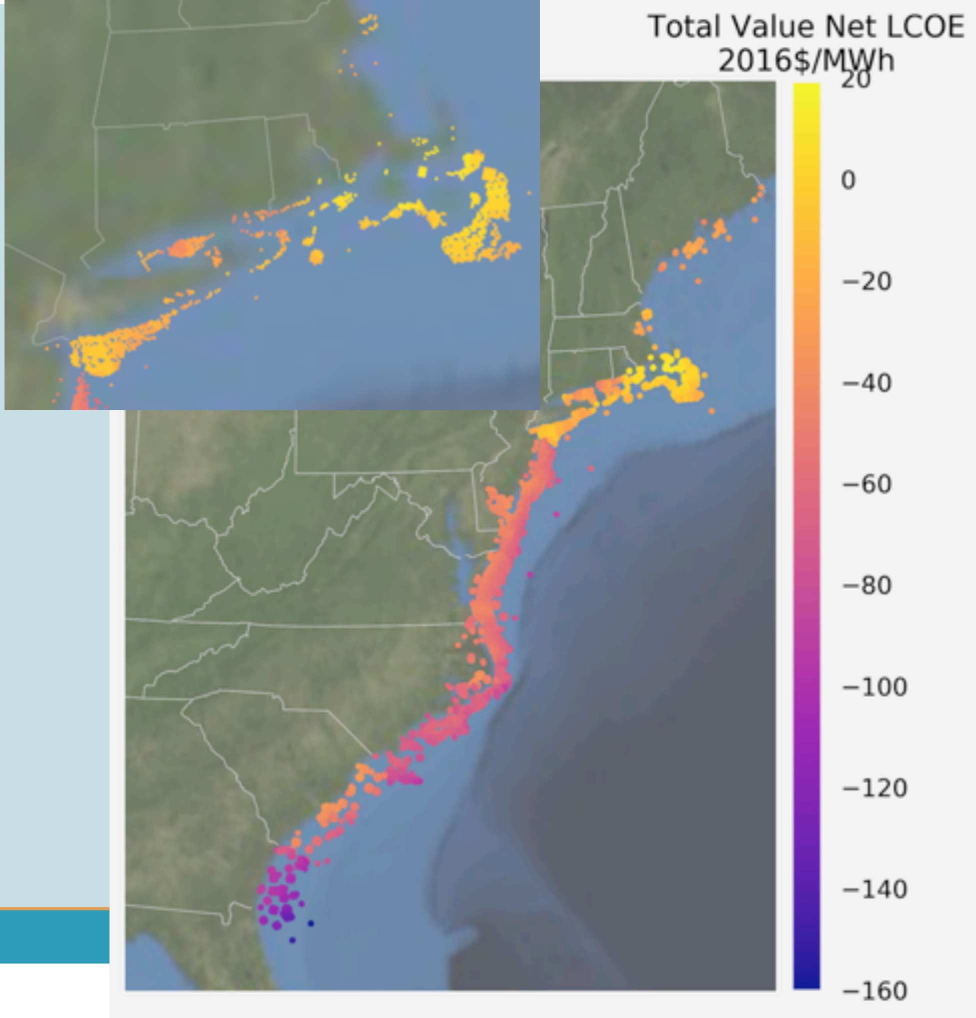
ISO Name	Capacity Credit (% Nameplate)			
	Summer		Winter	
	Onshore	Offshore	Onshore	Offshore
New England ISO	15%	24%	30%	63%
New York ISO	19%	39%	37%	61%
PJM ISO	14%	31%	n/a	n/a

HIGHEST VALUE NET OF COSTS

The most attractive offshore wind sites will have the highest value net of the cost of offshore wind. To develop a relative ranking of sites, we subtract the levelized cost of energy from the total energy, capacity, and REC value at each site. The levelized cost is based on an estimate from NREL for offshore wind plants with 6 MW turbines in 2022.

It is important to note that the purpose of this calculation is only to develop a relative ranking of sites, not to determine the magnitude of the net cost. Estimating the magnitude of the net cost would compare the future levelized value of offshore wind to the future levelized costs, rather than comparing the historical average value to the future levelized cost.

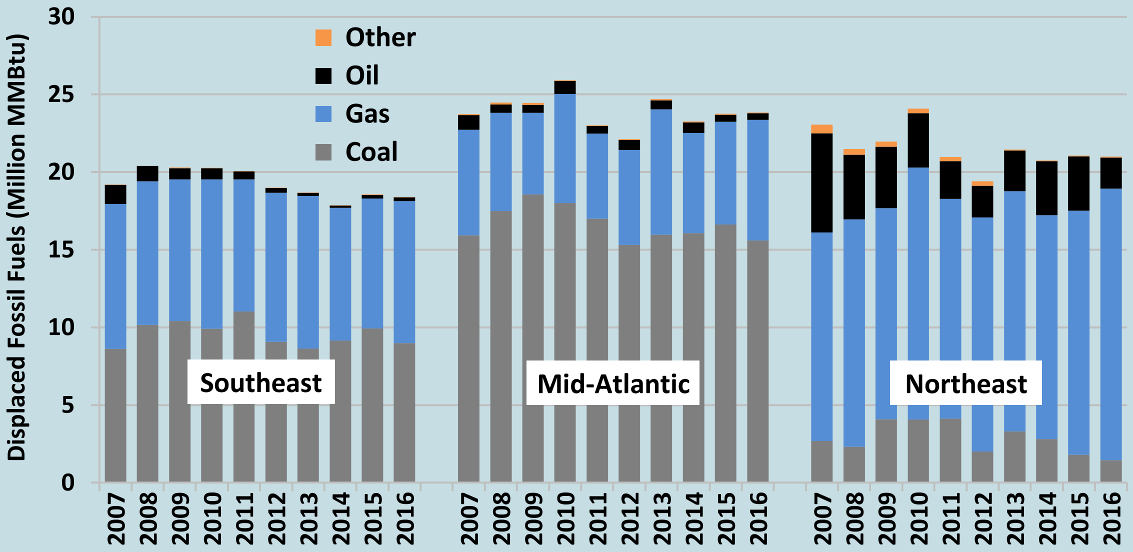
The most attractive sites are near southeastern Massachusetts and Rhode Island. The least attractive sites are far offshore of Florida and Georgia.



DISPLACED FOSSIL GENERATION

As a low-marginal-cost resource, offshore wind displaces the marginal generator—typically coal-, gas-, and/or oil-fired generation, depending on the region—from the bid stack in each hour. We use the EPA's AVERT model to estimate which generators would have been displaced, as well as the resulting avoided emissions (next slide) and avoided fossil fuel burn (see graph to the right). In all three AVERT regions along the East Coast, we calculate this displacement using an average wind profile for each region (i.e., averaged over all offshore sites in each region.*)

Offshore wind displaces primarily natural gas in the Northeast, primarily coal in the Mid-Atlantic, and a roughly equal mix of gas and coal in the Southeast.



*Additional analysis, summarized in the Appendix, found that displacement and avoided emissions from AVERT are not sensitive to the averaging across sites.

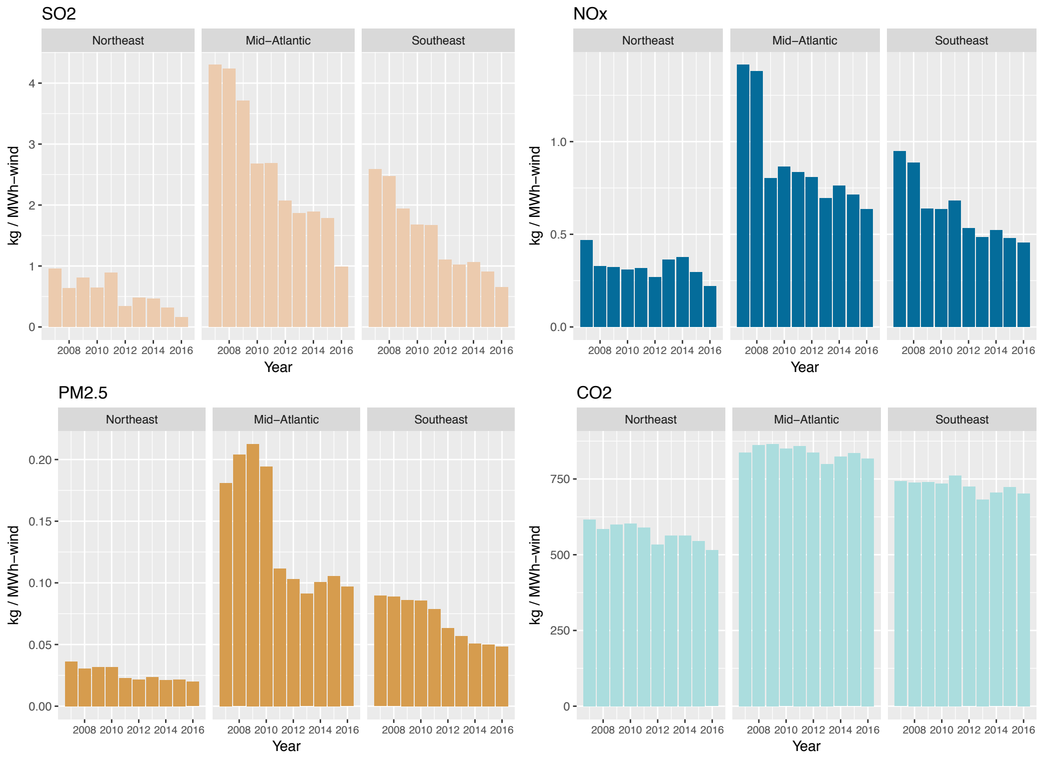
AVOIDED AIR EMISSIONS

Avoided emissions depend on the emissions rate of marginal generation in each hour. Avoided emissions were calculated for three AVERT regions using the wind profile averaged over all offshore sites in each region.*

The avoided emissions vary by region: highest for offshore wind in the Mid-Atlantic, lowest for offshore wind in the Northeast.

The avoided SO_2, NO_x, and $PM_{2.5}$ rates decline with time as coal plants comply with increasingly stringent emission requirements.

To some degree, the economic value of avoided emissions is already embedded in energy value since pollution permit prices are included in LMPs. REC value similarly reflects avoided emissions benefits. That being said, studies have found recent air quality benefits from wind power in these regions ranges from \$26/MWh to >\$100/MWh, depending on the location of the wind project.



*Additional analysis, summarized in the Appendix, found that avoided emissions from AVERT are not sensitive to the averaging across sites.

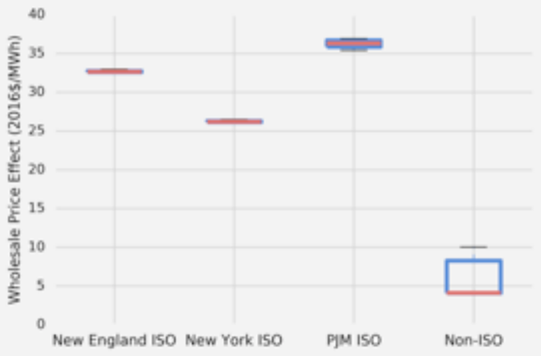
WHOLESALE ELECTRICITY PRICE EFFECT

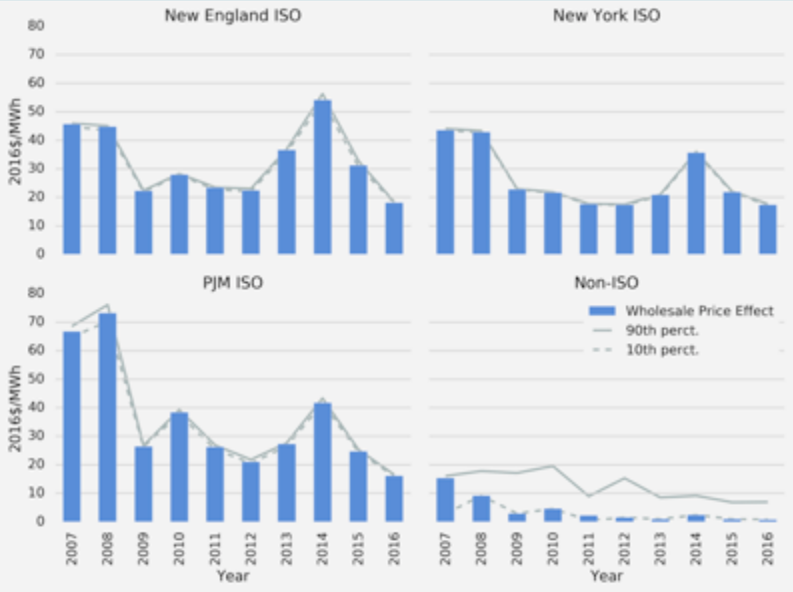
The wholesale “merit order” price effect of wind depends primarily on the slope of the supply curve and the amount of load that purchases wholesale power at spot market prices. There is very little variation in the wholesale price effect between sites in the same ISO. Significant variation occurs from year to year as changes in natural gas prices change the slope of the supply curve.

The slope of the supply curve is highest in ISO-NE but the load in PJM is much larger, leading to the highest wholesale price effect in PJM.

The loads in the Non-ISO region are much smaller, leading to a smaller effect. The vertically integrated utilities in the Non-ISO region were also assumed to have less than 20% of their load purchased at spot prices.

Note that the wholesale price effect represents a transfer of wealth from producers to consumers; moreover, any low marginal cost generator would have a directionally-similar impact on wholesale market prices. Some jurisdictions consider price effects, while others do not.



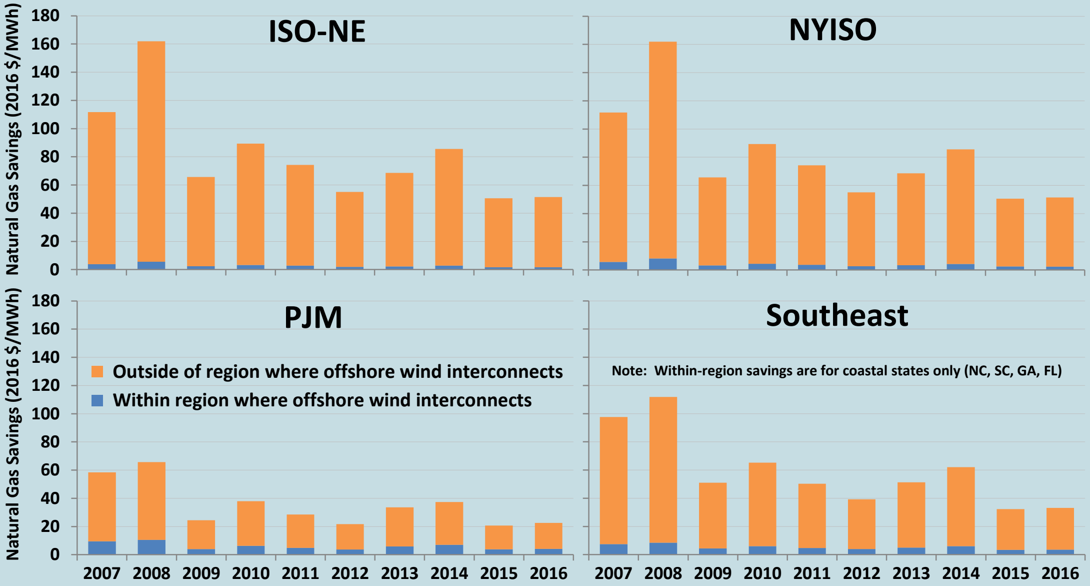


NATURAL GAS PRICE EFFECT

The impact of wind on natural gas prices* depends on how much gas-fired generation wind displaces in each AVERT region, the assumed inverse price elasticity of natural gas supply (held constant across regions at 3.0), and the level of natural gas prices (also constant across regions -- a national average wellhead price). Results on this slide are based on an average wind generation profile for each region.

Offshore wind displaces the most gas in the Northeast, which is the region most reliant on gas-fired generation (and which includes both ISO-NE and NYISO in AVERT), resulting in the largest gas price reduction, and hence dollar savings, on a national basis (orange bars). But the two northeastern regions' share of national savings is the smallest of the four regions, due to lower *total* gas consumption (blue bars).

Again, the gas price reduction represents a transfer of wealth from gas producers to gas consumers, and may not be considered a net societal benefit in some jurisdictions.



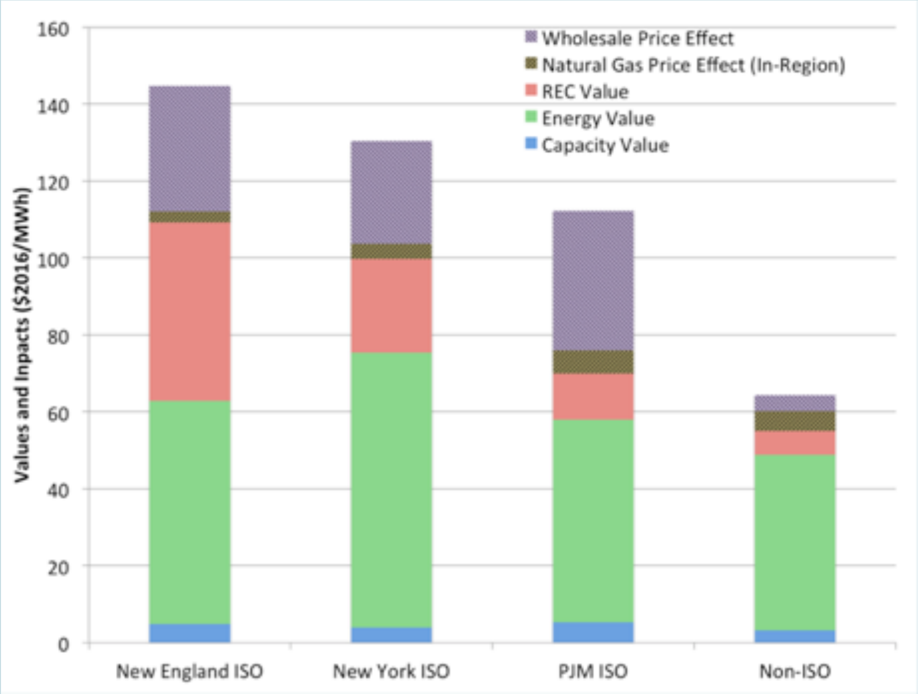
*The same effect could occur with coal and other fuels displaced by offshore wind generation, but likely at a much smaller magnitude given prices that are generally less-responsive than natural gas prices to changes in demand, coupled with the fact that coal and other fuels (e.g., nuclear) are not as widely used as natural gas in other sectors of the economy outside of the power sector.

SUMMARY

This figure reports the average market value and other effects over 2007-2016 for the median value site in each region. The market value of offshore wind varies significantly by project location, and is highest for sites off of New York, Connecticut, Rhode Island, and Massachusetts. The total market value is highest in ISO-NE, in part due to higher REC prices. The energy and capacity value is higher for NYISO, particularly for the Long Island region.

In addition, we quantified the avoided CO_2, SO_2, NO_x, and $PM_{2.5}$ emissions of offshore wind (see slide 32).

Whether offshore wind is economically attractive will depend on tradeoffs between value and cost. Cost reductions that approximate those witnessed recently in Europe may be needed for offshore wind to offer a credible economic value proposition on a widespread basis in the United States.



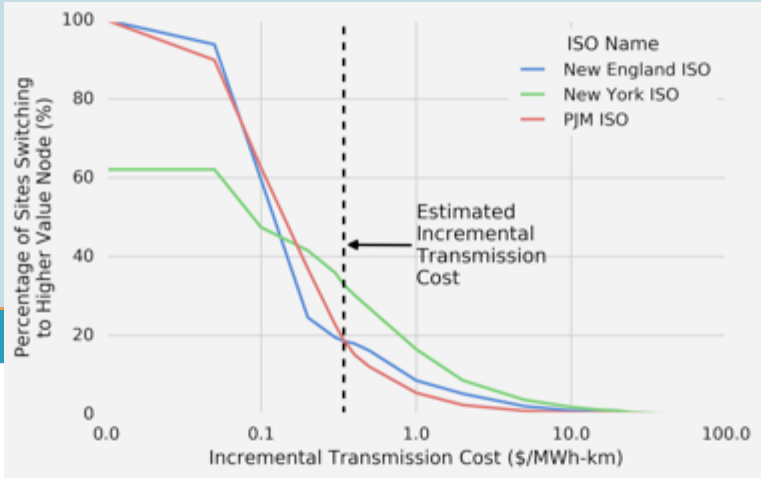
SUPPLEMENTAL RESULTS

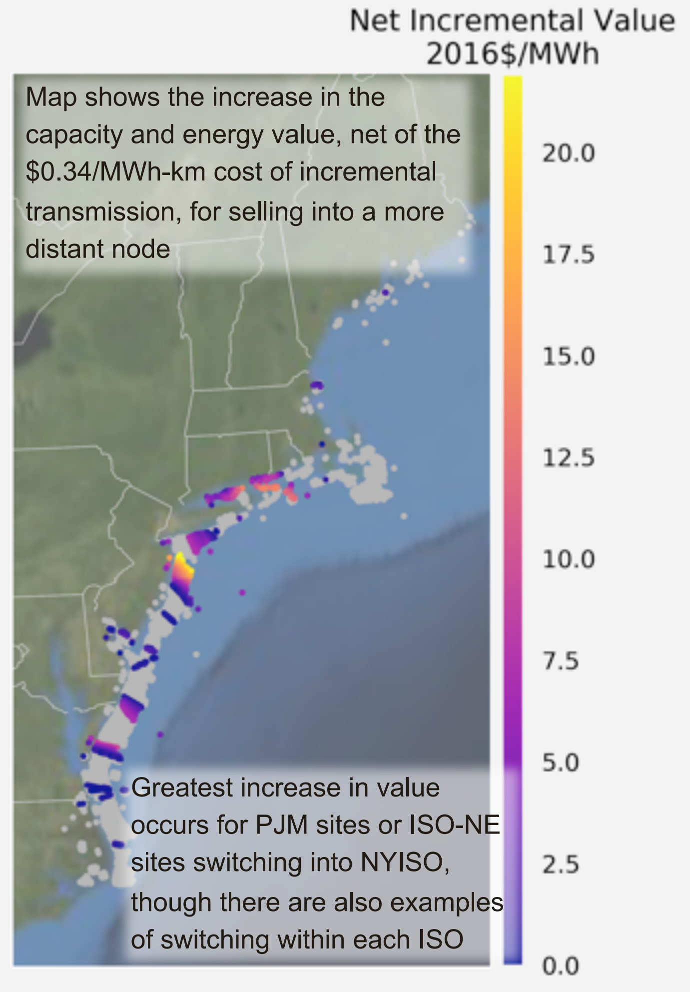
- Value of selling at more-distant interconnection pricing node
- Value of ability to arbitrage among multiple interconnection pricing points
- Value of storage for offshore wind
- Value of selling into highest-value regional REC markets
- Impact of larger rotors and taller towers on offshore wind value
- Impact of refined treatment of wake losses

VALUE OF SELLING AT DISTANT NODE (1)

In some locations, offshore wind plants may be willing to pay more in transmission to interconnect to a more distant, but higher value node.

At an incremental transmission cost of about $0.34/MWh-km, estimated from previous NREL cost studies, about a third of the sites in NYISO would get a higher energy and capacity value from selling to a more distant node. Roughly 20% of sites in PJM and ISO-NE would switch nodes at that incremental transmission cost. This analysis does not consider REC value impacts or permitting and other restrictions that might arise during the interconnection process.





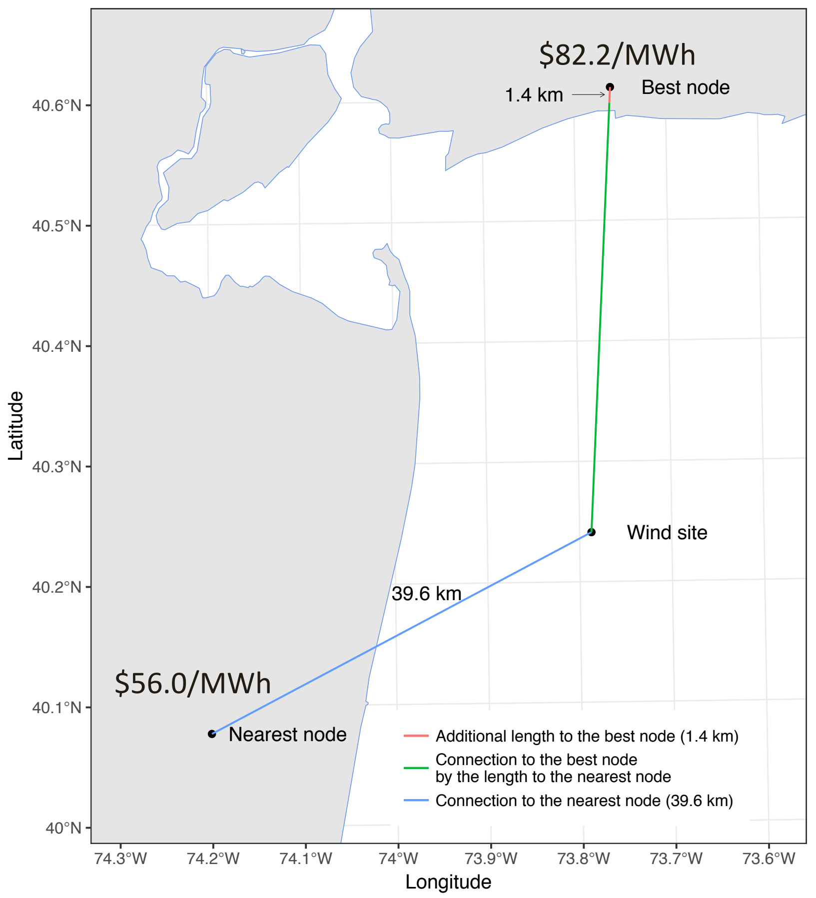
VALUE OF SELLING AT DISTANT NODE (2)

The offshore wind site with the highest net incremental value from connecting to a more distant node is shown here.

In the base analysis, the wind site is assumed to connect to the nearest node in PJM, about 40 km from the offshore wind site. The wholesale energy and capacity value of wind at the closest node in PJM is $56.0/MWh over 2007-2016.

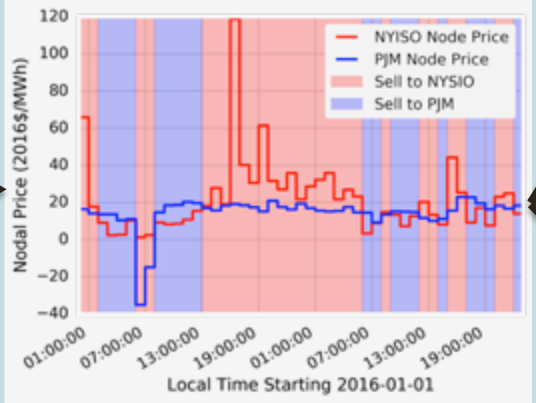
Alternatively, the offshore wind site could connect to a more distant node in NYISO. The additional distance to get to the NYISO node is 1.4 km. The wholesale energy and capacity value of wind at this node is $82.2/MWh over 2007-2016.

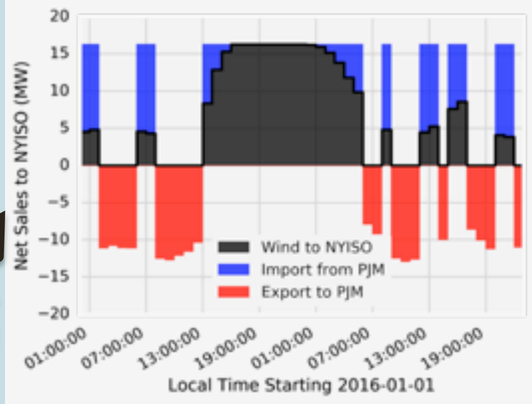
Assuming an incremental transmission cost of $0.34/MWh-km means that getting to the node in NYISO would add about $0.5/MWh of additional costs. The net incremental of value is then $25.7/MWh over 2007-2016. Again, this analysis excludes any REC value implications.

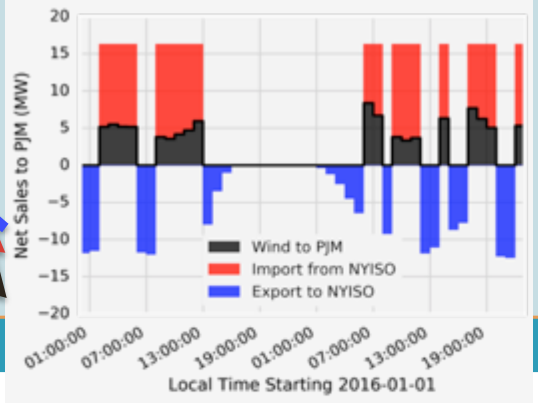


MULTIPLE INTERCONNECTION POINTS (1)

When offshore wind is near multiple nodes with very different prices, it may be cost-effective to interconnect at multiple locations rather than just one. Here we examine a potential offshore wind plant nearest to a node in Northern New Jersey (PJM), but also near the most valuable node in Long Island near New York City (NYISO). We assume the wind plant sells power to the node with the highest price for each hour and that the remaining capacity of the line is used to import power from the lower priced node to sell at the higher priced node. REC value is not considered.

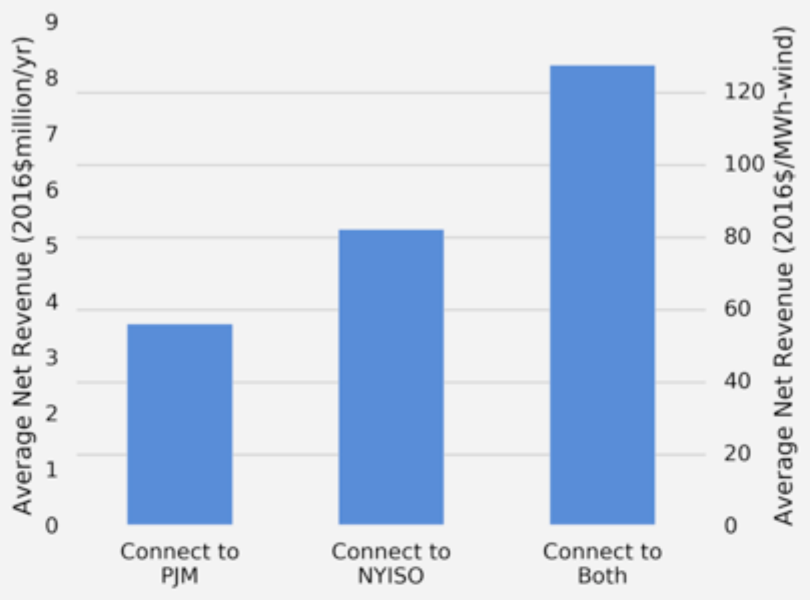






MULTIPLE INTERCONNECTION POINTS (2)

For this particular offshore wind location, we find a considerable increase in wholesale revenue from interconnecting to both nodes and using the spare capacity to import power from the low priced node to the high priced node (over 2007-2016). Importing power across the spare capacity is responsible for 30% of the net revenue earned when connecting to both.



In this particular case, we assume that the offshore wind plant earns capacity revenue commensurate with the actual wind profile delivered to each market. The majority of the wind power (72%) is sold to NYISO.* No REC revenue is considered in this example.

Adding an additional 40km of offshore cable would add about $14/MWh-wind to the cost. The additional revenue from connecting to both exceeds this cost due the the additional opportunity to import power over the spare capacity. The cost of the additional interconnection could be higher though as we did not consider the cost of additional equipment at the interconnection point. Note: this analysis is a hypothetical exercise that does not consider actual market rules and practices that may restrict delivery to multiple points.

*We also examined whether there is an arbitrage opportunity for buying capacity from the PJM market and selling it over the line into NYISO market, but found that PJM capacity prices exceeded NYISO market prices in Long Island.

VALUE OF STORAGE (1)

What is the break-even cost of storage? How much more valuable would wind have been with storage?

Answering these questions is complicated by the myriad ways storage could be sized and operated. As a rough approximation, we estimated the capacity and energy value of 4 hours of storage at the median value offshore wind site in each ISO region with the following assumptions:

- Storage earns nameplate capacity in the capacity market
- Storage can arbitrage between high and low price hours within a day, assuming perfect foresight and 90% round-trip efficiency
- Storage does not participate in ancillary service market
- Configured as 1.25MW / 5MWh of storage for 18MW wind
- Storage not constrained in operations by presence of offshore plant
- Assume a 15% capital recovery factor

Storage with these conditions was found to increase the value of offshore wind by up to ~$3/MWh

Break-even Cost of Storage* ($/kWh-storage)

ISO Name	Capacity + Value	Energy Value =	Break-even Cost
New England ISO	$70/kWh	$100/kWh	$170/kWh
New York ISO	$60/kWh	$190/kWh	$250/kWh
PJM ISO	$110/kWh	$130/kWh	$240/kWh
Non-ISO	$60/kWh	$30/kWh	$90/kWh

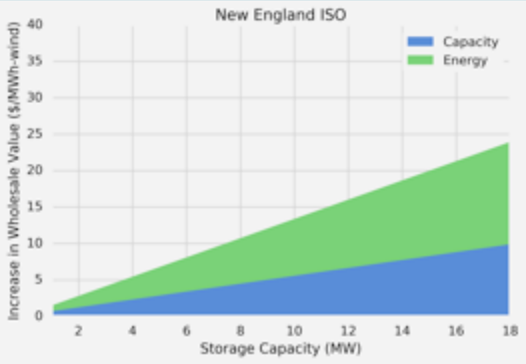
Increase in Value of Wind ($/MWh-wind)

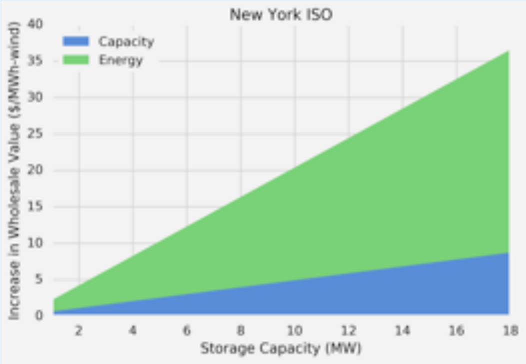
ISO Name	Capacity + Value	Energy Value =	Increase in Wind Value
New England ISO	$0.7/MWh	$1.0/MWh	$1.7/MWh
New York ISO	$0.6/MWh	$1.9/MWh	$2.5/MWh
PJM ISO	$1.2/MWh	$1.5/MWh	$2.7/MWh
Non-ISO	$0.6/MWh	$0.3/MWh	$0.9/MWh

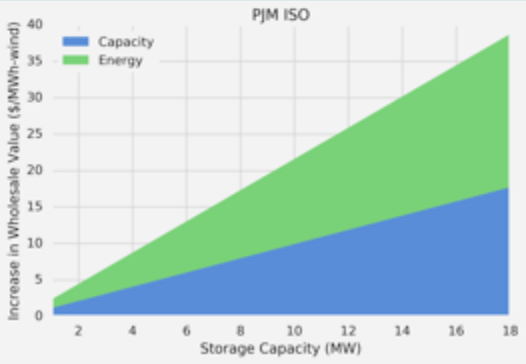
*Current storage costs are estimated to be ~$500/kWh and are projected to continue to decline (Cole et al. 2016, Lazard 2017).

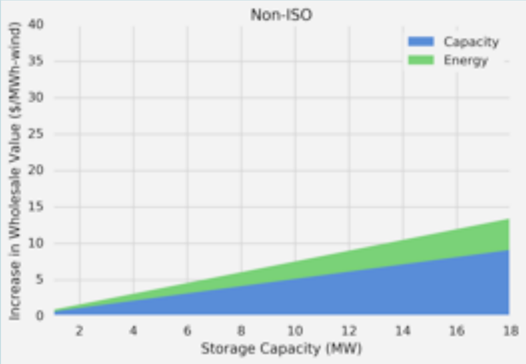
VALUE OF STORAGE (2)

The previous result was based on a 1.25 MW, 4 hour battery for 18 MW of offshore wind. However, the larger the battery, the greater the amount of energy that can be arbitraged, potentially increasing the value of wind further. The maximum battery size explored here (1:1 power with the wind source) could store 4 hours of wind power during low value times to sell during high value times. One limitation would be if the storage and wind share equipment, in which case the additional value would taper off as the battery size grows given the operational limitations imposed on the battery due to wind power output. The larger size would of course also have a higher equipment cost, which is not included here.







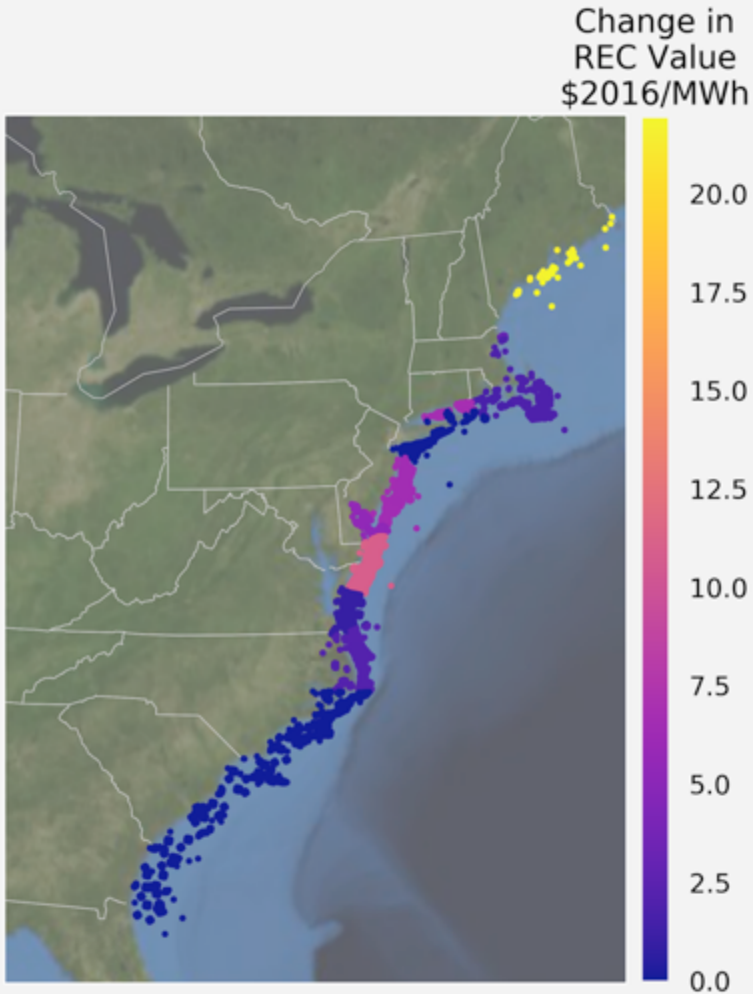


REGIONAL REC VALUE

When a state has an RPS, we assume that offshore wind RECs would be valued at that state's REC price. For states in PJM and ISO-NE, however, offshore wind could sell its RECs in states other than the state where it interconnects. We compare the value of RECs assuming they could be sold in any state within an ISO to the value if sold to the interconnecting state.

The largest increase in the value of RECs is apparent in Maine, where offshore wind could sell RECs to meet the RPS in other ISO-NE states rather than Maine. Selling RECs within ISO-NE would have increased the value of RECs for offshore wind plants in Maine by more than $20/MWh over 2007-2016 (or $12/MWh in 2016).

States in PJM see a smaller increase in the REC value by selling RECs at the highest price in PJM rather than to the interconnecting state.



ALTERNATIVE WIND TURBINES

Alternative turbine designs alter the annual energy production and cost of offshore wind, but they can also impact the value. Here we compare the energy and capacity value of offshore wind at the median site for each ISO using our base assumption of a 100m hub height and specific power of 318 W/m^2 to two alternative turbines:

- Larger rotors & taller tower: 250 W/m^2 specific power, 150m hub height
- Smaller rotors: 384 W/m^2 and 100m hub height

Turbine design is found to have a very small impact on value over 2007-2016 (less than 1% difference from the base results).

For the site in ISO-NE, a turbine with a larger rotor and taller tower increases the value. For other sites the value increases with smaller rotors.

These results are partly driven by the “marginal” approach to estimates; at higher offshore wind penetrations, we expect that larger rotors and taller towers would slow the rate of value decline.

Larger Rotors (250W/m^2) and Taller Tower

ISO Name	Increase in Value Relative to Base	
	$2016/MWh	% Base
New England ISO	$0.1/MWh	0.2%
New York ISO	-$0.6/MWh	-0.8%
PJM ISO	-$0.1/MWh	-0.1%
Non-ISO	-$0.2/MWh	-0.4%

Smaller Rotors (384 W/m^2)

ISO Name	Increase in Value Relative to Base	
	$2016/MWh	% Base
New England ISO	-$0.4/MWh	-0.6%
New York ISO	$0.6/MWh	0.7%
PJM ISO	$0.2/MWh	0.4%
Non-ISO	$0.2/MWh	0.4%

REFINED WAKE LOSSES

A stable atmosphere increases wake losses. If stability is correlated with high prices then including stability in wake loss calculations could change the value of wind. Our earlier calculations do not account for the potential temporal correlation of stability and prices.

We estimate the potential magnitude of the error over 2007-2016 by testing an extreme case where we assume:

- The atmosphere is stable half of each year*
- Stable periods (and high wake losses) occur when prices are below the median price for the year
- Unstable periods (and low wake losses) occur when prices are above the median price for the year
- Wake losses are about 25% higher during stable periods than unstable periods (estimated from Hansen et al. 2012)

Increase in Value of Wind

ISO Name	Increase With Correlated Stability	
	$2016/MWh	**% Base**
New England ISO	$0.27/MWh	0.43%
New York ISO	$0.35/MWh	0.46%
PJM ISO	$0.28/MWh	0.50%
Non-ISO	$0.13/MWh	0.27%

In this extreme case where atmospheric stability is directly linked to wholesale prices, the wholesale value of wind (capacity and energy value) increases by at most 0.5% at the median value sites. These estimates demonstrate that value estimates are unlikely to be notably different with refined estimates of wake losses.

*Analysis of stability for the median value site in ISO-NE shows this is a good approximation. PJM and NYISO median sites are unstable 70% of the year and the Non-ISO is almost always unstable, which lessens the effect of stability on wind value.

ASSESSMENT OF FUTURE TRENDS

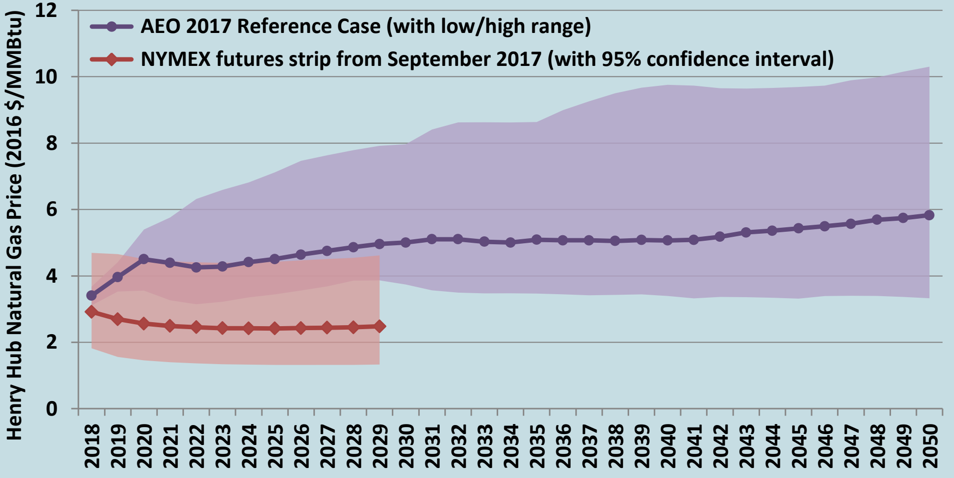
- Energy value
- Capacity value
- REC value
- Air emissions
- Electric and gas price effects

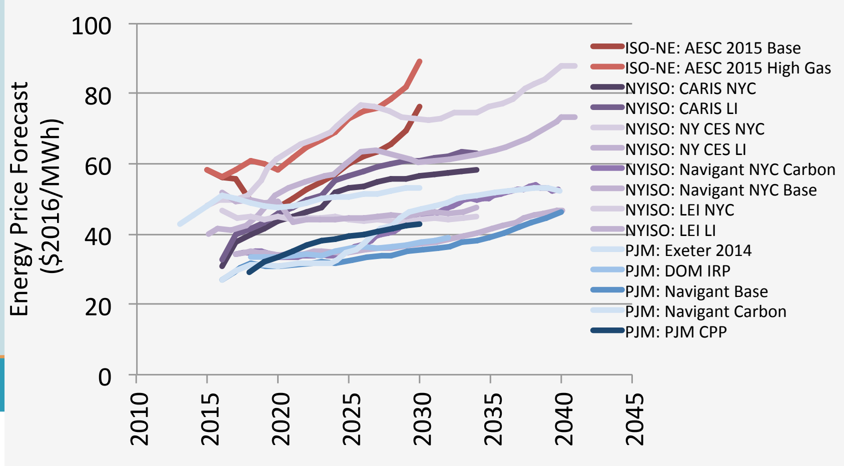
OUTLOOK FOR ENERGY VALUE

The outlook for the future energy value of offshore wind depends in large part on the direction of natural gas prices, which is uncertain: EIA projects an increase whereas nearer-term NYMEX futures are flat.

Several projections of electricity prices in the ISO-NE, NYISO, and PJM areas show significant variation across forecasts, but a general upward trend. Energy price forecasts are higher with assumptions of higher gas prices or higher carbon prices.

Over 2007-2016, the energy value for most wind sites was between 99-107% of the time-weighted average energy price. Growth in the share of wind energy could drive this ratio lower as supply increases during windy hours; such "value factor decline" has been observed for onshore wind in various locations, and estimated in numerous modeling studies.



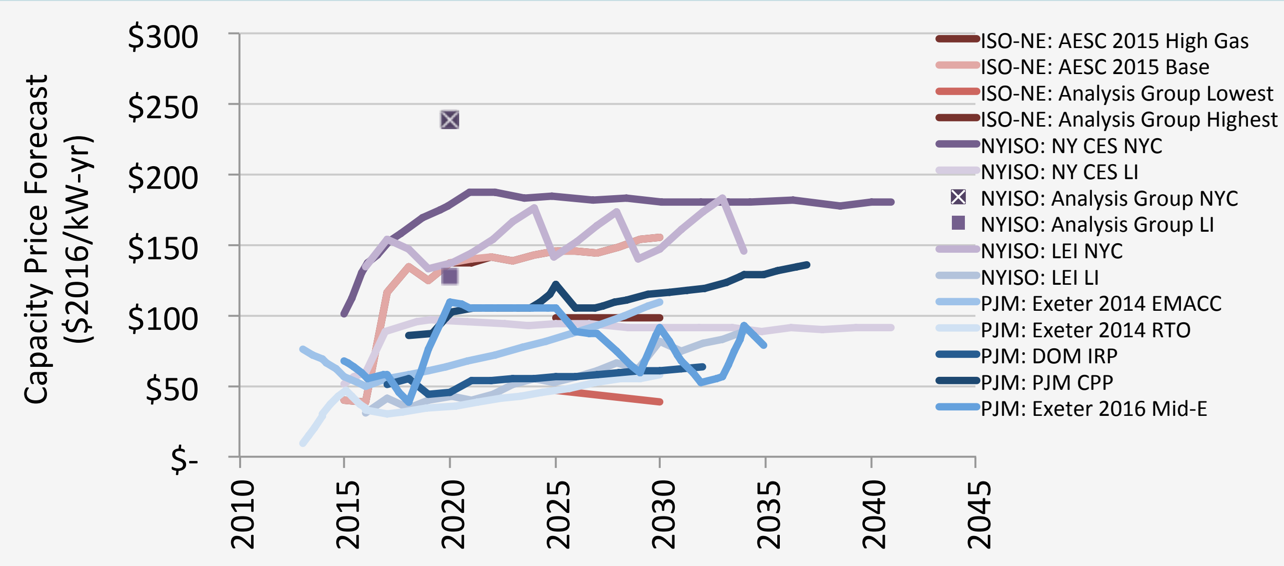


OUTLOOK FOR CAPACITY VALUE

Capacity market prices are expected to increase based on multiple forecasts, as presented in figure.

There are, however, several reforms that are proposed or have been implemented in recent auctions that may reduce capacity market revenues for wind.

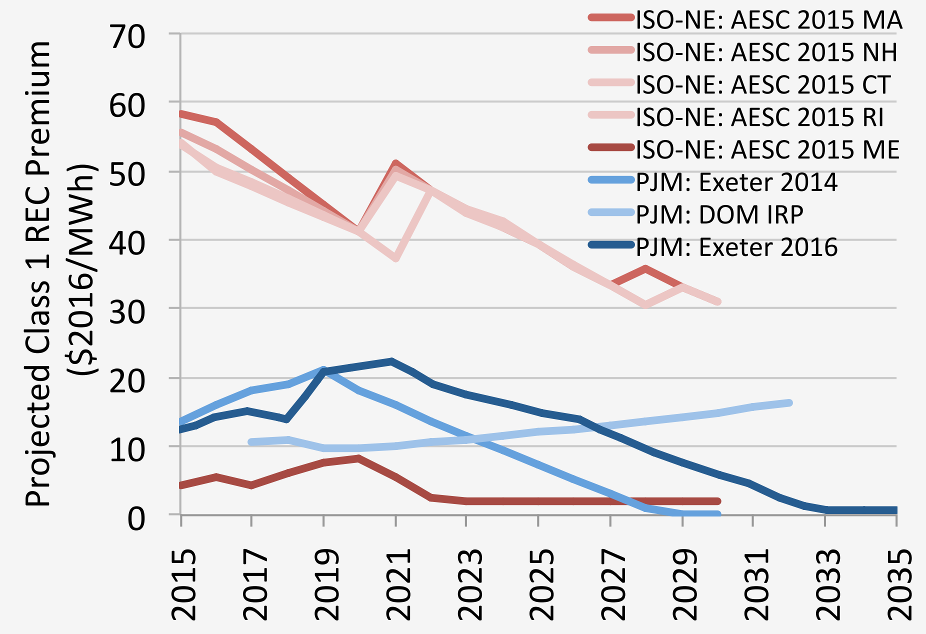
PJM, for example, is implementing a capacity performance requirement and ISO-NE has a minimum offer rule for resources that earn out-of-market revenues.



OUTLOOK FOR REC VALUE

Three recent forecasts of REC prices on the East Coast project declines over time as the cost of renewable technologies declines and energy market prices increase. In the short term, REC prices are very sensitive to the balance between REC supply and demand. In the long-term, prices are sensitive to the direction of renewable energy costs and energy market prices: increases in the energy market prices lower the price of RECs, all else being constant. A fourth study forecasts a gradual increase in REC prices in PJM.

Some states have policies that have or may create offshore specific REC prices that are higher than the ones used for the historical analysis (MD, NJ, MA, NY, etc.).



OUTLOOK FOR AIR EMISSIONS

Power sector air emission rates (and thus avoided emission rates) have dropped dramatically between 2007 and 2016.

Emission reductions are primarily due to:

- MATS requirements for SO_2 control technology at all power plants
- Low natural gas prices and the associated switch from coal to gas power
- This price reduction also affects the loading order, meaning coal may be avoided prior to gas given new wind generation

Future avoided emissions will likely remain at this reduced level unless MATS air quality requirements are removed.

Avoided emissions may also be impacted by future regulatory changes related to CSAPR or to RGGI.

It is not easy to predict the impacts of increases to natural gas prices on avoided emissions:

- Higher natural gas prices might encourage more coal and higher power sector emissions overall
- But in that case wind power might more likely lead to avoided natural gas use (due to higher gas prices) and avoided emissions could thus be lower

OUTLOOK FOR ELECTRIC AND GAS PRICE EFFECTS

Wholesale power price and gas price suppression results presented earlier should be considered single-year/first-year effects. These effects will tend to decay over longer time periods, as supply has time to adjust to lower demand. Hence, the electric and gas price reductions resulting from the *hypothetical historical* offshore wind that we've modeled here should moderate/decay over time.

Meanwhile, the outlook for electric and gas price reductions in the future will depend on a variety of factors, including the responsiveness (or elasticity) of prices to reductions in demand, which in turn depends on the slope of the supply curve. For example, if shale gas continues to flatten the supply curve, the price response to demand changes will be less.

The natural gas price effect may also depend on future natural gas price levels in two ways:

- Higher gas prices might shift the dispatch order, potentially altering how much gas-fired generation wind displaces
- Inverse elasticity measures a % change in price in response to a % change in demand; at higher (lower) gas prices, that % change in price leads to larger (smaller) dollar savings

The wholesale power price suppression lowers prices in the energy market. Lower revenues in the energy market for generators may eventually lead to higher capacity prices if affected units are required to meet planning reserve margins.

APPENDIX: METHODOLOGICAL DETAILS

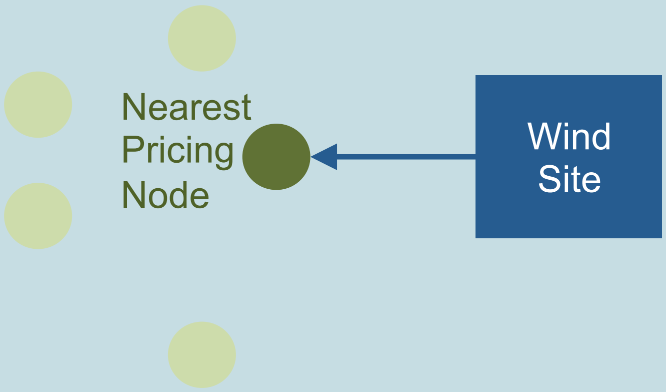
ENERGY VALUE METHODOLOGY

Energy value is calculated as the revenue an offshore wind plant would earn in the energy market by selling its power at the nodal LMP, per unit of wind energy generated. The revenue for each hour is the hourly wind generation multiplied by the hourly real-time LMP.

The hourly LMP accounts for the timing of when energy is cheap or expensive and it embeds the cost of congestion, transmission-level losses and, depending on the region, the compliance cost of various emissions regulations.

For the Non-ISO regions we use the hourly marginal costs reported by the balancing authority (the “system lambda”). Each balancing authority is responsible for determining its method for calculating hourly marginal costs.

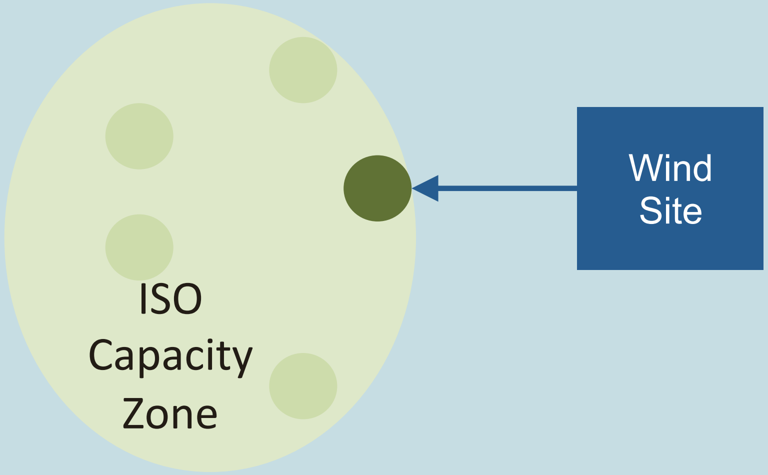
This approach does not account for any costs associated with wind forecast errors or increases in ancillary services. Also, analysis was conducted on a “marginal” basis, estimating the impacts of the first offshore wind projects.



CAPACITY VALUE METHODOLOGY

Capacity value is calculated as the revenue an offshore wind plant would earn in the capacity market by selling its power at the zonal capacity price, per unit of wind energy generated. The amount of capacity that a wind plant can sell is a fraction of its nameplate capacity based on the capacity credit. The rules for calculating the capacity credit of wind plants varies between the ISOs (as described earlier).

Each ISO bases the capacity credit on historical wind production during peak periods. For example, to calculate the 2016 capacity credit for a wind plant in PJM, which uses a rolling average over the past three years, we used wind generation data during the peak for 2013-2015. When there is no historical data available (e.g., we do not have 2006 wind data for the capacity value in 2009), we substitute the average capacity credit over the full 10 years of data.



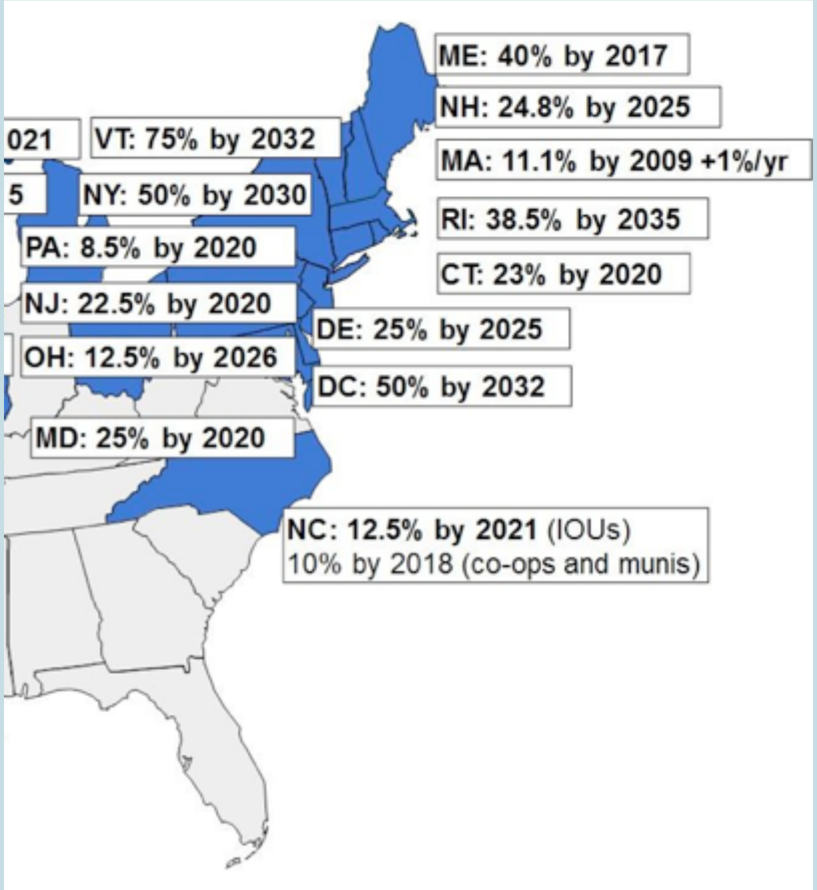
REC VALUE METHODOLOGY

REC value is calculated as the revenue an offshore wind plant would earn by selling Tier 1/Class 1 RECs at monthly REC prices, per unit of wind energy generated.

For states with an RPS, we use the REC prices for the state to which the offshore wind plant interconnects. Spot REC prices are not available for NY or NC, even though these states have an RPS. For NY, we instead use long-term REC prices published by NYSERDA. For NC, we use estimates of RPS compliance costs.

For states whose RPS began after 2007 (DE, RI, ME), we use the highest REC price within the ISO until that state's RPS began.

For VA, which does not have an RPS but is located in PJM, we use the highest REC price available in PJM. For non-ISO states without an RPS (SC, GA, FL), we use national voluntary REC prices.



AVOIDED EMISSIONS METHODOLOGY

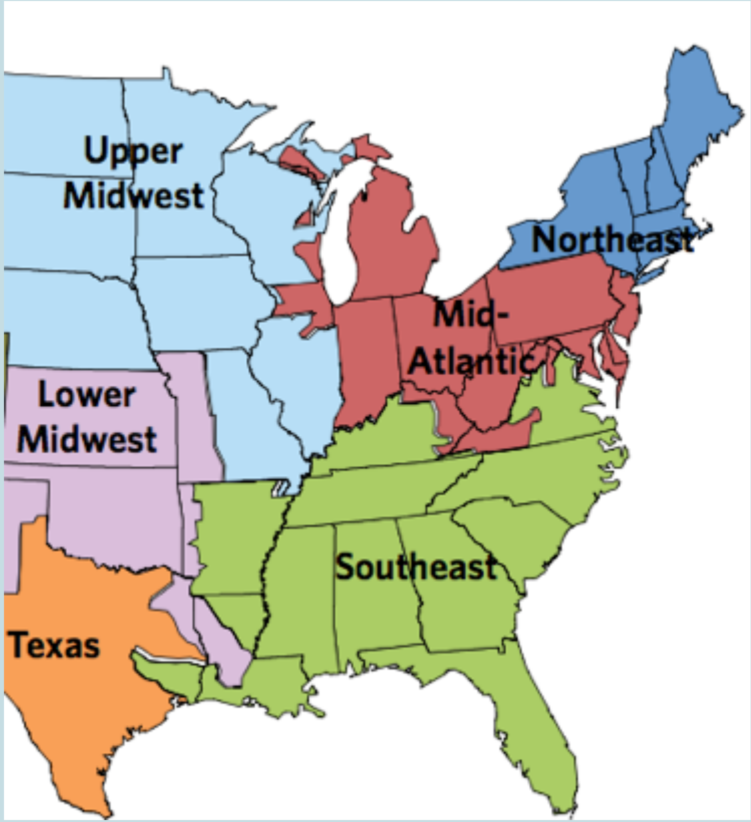
Avoided emissions are calculated based on the emissions rate of the generators that are estimated to be on the margin in each hour. The estimates are based on EPA's AVERT tool, which develops statistical relationships between hourly generator output and net demand.

Unique AVERT models were released by EPA for each year between 2007-2016.

AVERT is used to estimate the emissions (SO_2, NO_x, $PM_{2.5}$, CO_2) that would have been avoided based on an hourly offshore wind power profile developed from all offshore wind sites in each region.

AVERT has three analysis regions along the eastern seaboard:

- AVERT assumes no transfers between regions – only generators within a region are affected by the addition of offshore wind
- AVERT treats all locations within each region as equal



ELECTRICITY PRICE EFFECT METHODOLOGY

Adding a new generator with low marginal costs leads to a near-term reduction in wholesale electricity prices. The wholesale price effect of wind is the difference in the cost to load of purchasing power at spot market prices with and without a wind plant due to these lower wholesale prices.

Studies that use production cost models to simulate power markets with and without wind generally estimate the cost to load as the product of the hourly LMP and the hourly load. Since we do not use such a tool, we estimate the change in prices with a change in supply for each hour using statistical relationships between wholesale prices and demand.

In particular, we estimate the change in the energy component of the LMP as a function of demand and natural gas prices for each year in each ISO. In the Non-ISO region we use the system lambdas instead of the energy component of the LMP.

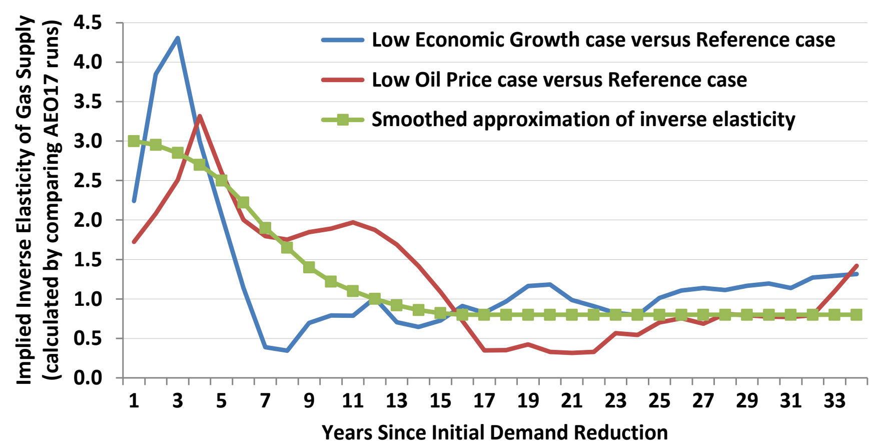
The overall methodology for estimating the relationship between hourly prices and demand is similar to a cost-benefit analysis of a real-time pricing program by Navigant (2011). In contrast to Navigant, we only focus on the energy component of LMPs and do not estimate local congestion components.

Furthermore, we assume that loads in the ISO region use contracts to hedge 60% of their load and vertically integrated utilities in the Non-ISO region hedge 80% of their load. These assumptions are similar to assumptions from other studies (Chernick and Neme 2015), though it is important to note that there is wide variation in assumptions used by different analysts.

NATURAL GAS PRICE EFFECT METHODOLOGY

Using an average hourly offshore wind generation profile from each of its three regions along the eastern seaboard, AVERT estimates the annual reduction in natural gas burn from adding 600 MW of offshore wind to each region. We then translate that MMBtu reduction into a % reduction in national gas demand in the year in question, and apply a first-year (i.e., no decay) inverse elasticity of supply of 3.0 (see figure) to arrive at the corresponding % reduction in national average wellhead prices. We apply the % wellhead price reduction to average wellhead prices in the year in question to arrive at the corresponding $/MMBtu price reduction. Total dollar savings nationally are the product of the $/MMBtu price reduction and total national gas consumption post-wind. Dividing total dollar savings by the annual MWh of offshore wind yields national $/MWh-wind savings.

In-region dollar savings are the product of the national $/MMBtu price reduction and total in-region gas consumption post-wind. Dividing in-region dollar savings by the annual MWh of offshore wind yields in-region $/MWh-wind savings.



ATMOSPHERIC STABILITY AND WAKE LOSSES

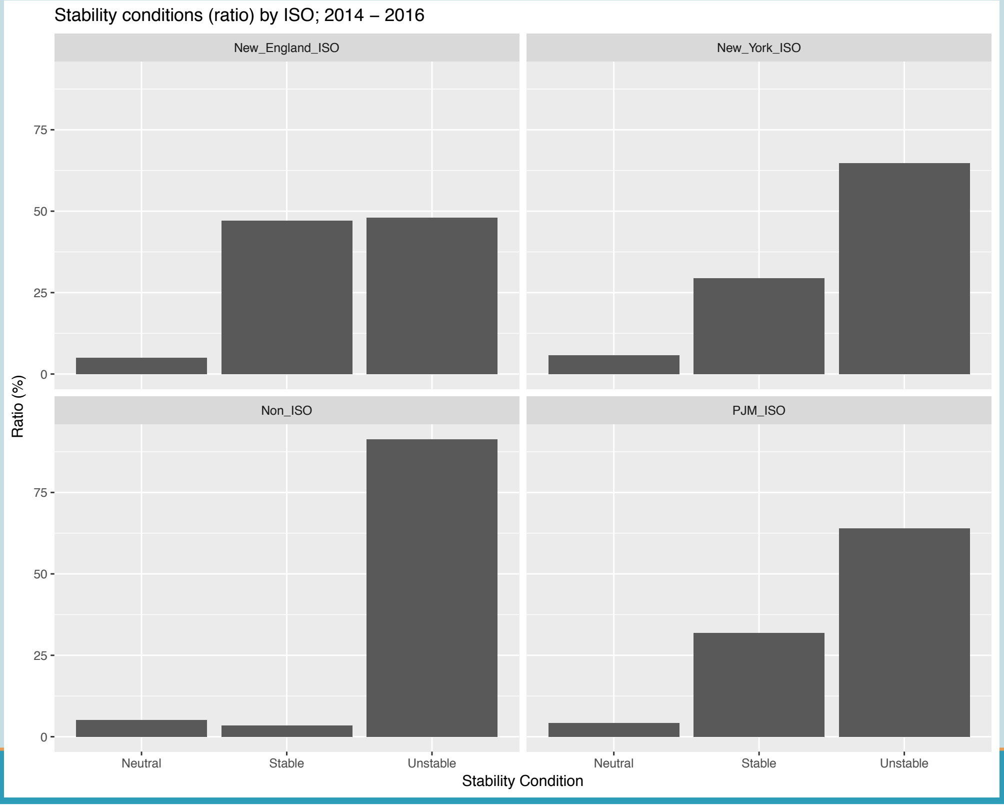
The supplemental results on wake losses examines the potential impact on the value of offshore wind if unstable conditions (when wake losses are lower) are correlated with times of high value.

Here we show the percentage of time that the atmosphere is considered Neutral, Stable, or Unstable based on the Monin−Obukhov Length for the median value site in each region.

The assumption that the atmosphere is stable half of the year is reasonable for New England ISO.

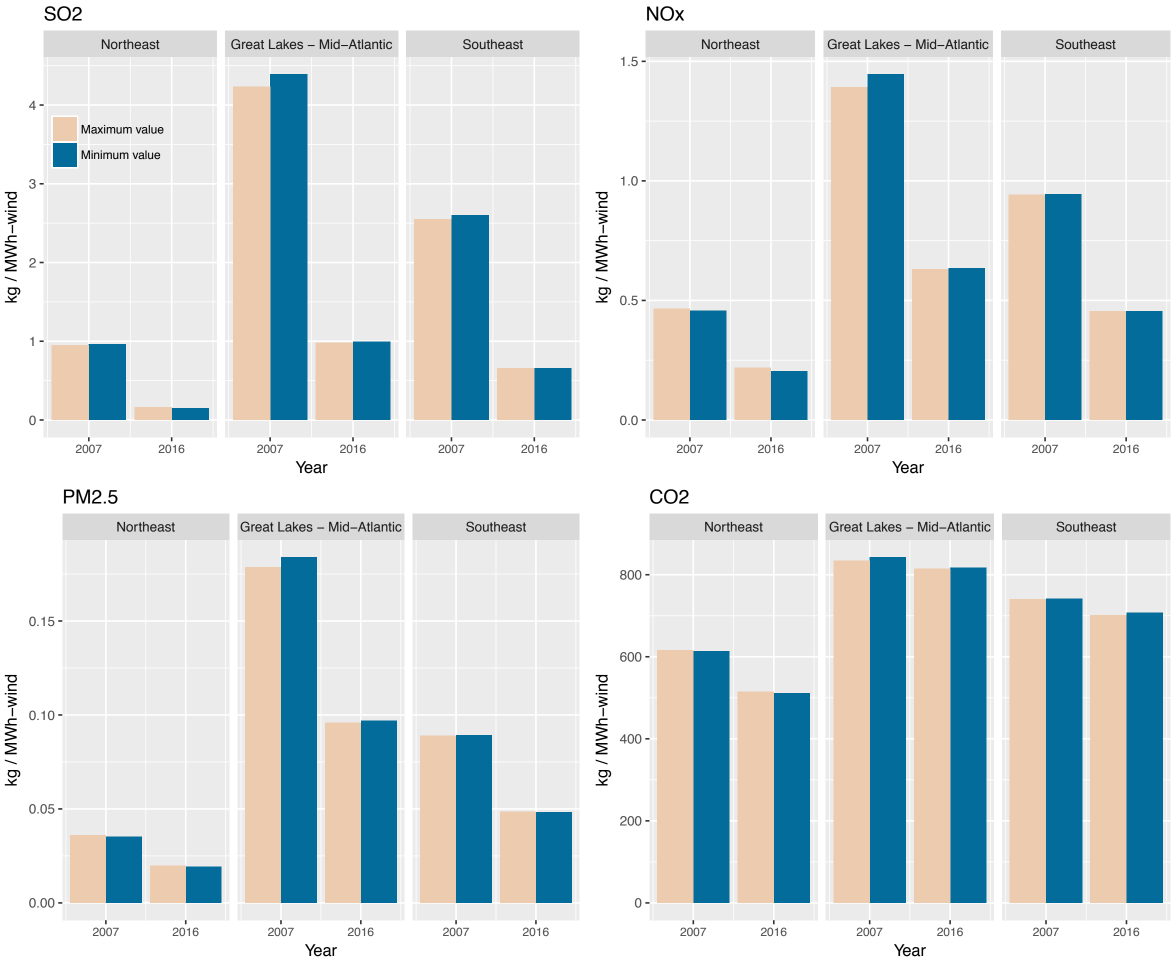
Regions further to the south have unstable conditions more frequently.

These trends across regions are corroborated by a second measure of atmospheric stability, the Boundary Layer Height.



AVOIDED EMISSIONS ARE INSENSITIVE TO OFFSHORE WIND PROFILES

We calculated the avoided emissions of offshore wind using the wind generation profile for the site in each region that had the highest and lowest normalized total value. The figure demonstrates that the avoided emissions are not sensitive to the choice of wind generation profile. We therefore use the average wind profile in each region, rather than the wind profile at each individual site, when calculating the avoided emissions of offshore wind.



ACKNOWLEDGEMENTS AND CONTACT INFORMATION

Contact the Authors

Andrew Mills: ADMill@lbl.gov; 510-486-4059

Ryan Wiser: RHWiser@lbl.gov; 510-486-5474

Acknowledgments

For their support of this research at the U.S. Department of Energy, we especially thank Patrick Gilman, Alana Duerr, Gary Norton, Rich Tusing, and Daniel Beals. Additionally, for reviewing elements of this report or providing useful feedback during its execution, we also acknowledge: Fredric Beck (U.S. DOE), Philipp Beiter (NREL), Ben Cohen and Gary Davidson (NYISO), Lucas Feinberg (U.S. BOEM), Jeremy Firestone (U. Delaware), Jamil Khan (Deepwater Wind), and Walt Musial (NREL). Lawrence Berkeley National Laboratory's contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the DOE under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.