Synapse
Energy Economics, Inc.

The Net Benefits of Increased Wind Power in PJM

Final Report
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1. Summary

By the end of 2012, wind power accounted for roughly 3.4% of PJM's installed capacity supply (6,300 MW[1] of approximately 185,000 MW total, excluding demand side resources). It provided 12,634 GWh of annual energy, about 1.5%% of PJM's total[2]. Over the next 13 years, the presence of renewable portfolio standards (RPS) in the PJM states will result in significant increases in supplied renewable energy, with most of the increase coming from wind power. PJM States[3] have RPS goals for renewable resources totaling roughly 14% of all energy consumed by 2026. PJM estimates that about 11 of the 14%, or 108,539 GWh total, will be from wind in 2026.[4]

In this analysis, we examine the effects of roughly doubling the level of currently projected wind power in PJM by 2026, with much of the increase in wind installations beyond that of the "RPS case" or base case coming in the last five years of the 2013-2026 horizon analyzed. Increased transmission required to enable the base case will likely be in place by the turn of the decade or in the early part of the following decade, and additional transmission infrastructure coupled with the RPS case transmission overlays will allow for continuing integration of an increased amount of wind. Improved overall "flexibility"[5] of the PJM system – arising from coal-fired power plant retirement and increasing installations of newer, flexible gas-fired combined cycle and combustion turbine resources coupled with key transmission improvements - will balance energy needs and allow the system to operate reliably even with a relatively high level of variable energy output from wind resources. Continuing declining costs and improving performance of wind power will lead to beneficial economic and emission results for consumers in PJM.

In this analysis we find that consumers will see a significant net benefit from such wind increases, with net savings (compared to the base case) on the order of $6.9 billion per year by 2026. These net savings arise from total production cost savings of $14.5 - $14.9 billion/year by 2026, and incremental revenue requirements for new investment of $7.6 to $8.0 billion/year by 2026. We find emissions reductions of 14% for carbon dioxide, 10% for NOx, and 6% for SO2, compared to the base case.[6] These findings, based on the modeled year 2026, validate an economic preference for an energy future with greater levels of wind power than current renewable portfolio standards suggest. It is a future where wind-powered resources displace a significant portion of energy that would otherwise be obtained from traditional fossil fuels, all the while retaining sufficient resource adequacy to ensure reliable grid operation.

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[1] PJM Wind Power Statistics, December 2012, http://www.pjm.com/~/media/committees-groups/task-forces/irtf/20121217/20121217-item-11-wind-power-statistics.ashx.

[2] PJM projected 2012 net energy for the entire RTO is 821,786 GWh. 2012 PJM Load Forecast Report, Table E-1.

[3] PJM states include all or parts of Pennsylvania, New Jersey, Maryland, Delaware, Washington DC, Virginia, Ohio, Illinois, Indiana, Michigan, West Virginia and Kentucky.

[4] GE Energy Consulting, "Final Report: Task 2 Scenario Development and Analysis", Prepared for PJM Interconnection LLC, January 26, 2012, Table 3, page 8.

[5] In short, flexibility refers to the underlying dispatchability or maneuverability of the aggregate of resources available to balance system energy needs with available supply.

[6] We note that the base case already presumes the retirement of roughly 58 GW of coal (vs. 2012 PJM coal in service), which provides a considerable reduction of all three of these pollutants, in advance of the emissions reductions seen in these wind increase scenarios.

Increased wind power displaces fossil-fueled generation, primarily gas and coal-fired production. It lowers emissions and exerts downward price pressure on wholesale energy markets. While not analyzed in this report, it creates jobs in installation and manufacturing across both the PJM region and other parts of the country, and its lowering of emissions reduces health costs. Even adding in the cost of wind-enabling transmission and recognizing that ongoing installations of gas-fired resources will be required to offset the retirement of coal plants and add balancing capacity to the system, a doubling of wind power by 2026 relative to what would otherwise be in place with current RPS standards will allow consumers to reap economic and emission benefits.

Purpose of Study

Synapse conducted this analysis to assess the overall economic and emissions effect on PJM ratepayers of alternative electricity futures that include higher levels of wind than will be seen under current renewable standards. By testing the effects of different combinations of increased renewable energy supply, increased transmission infrastructure, reductions in the use of fossil-fueled resources, and increases in the overall flexibility of the thermal resource base in PJM, we are able to draw broad conclusions about the relative benefits and costs to consumers of pursuing a clean energy future in the PJM region that roughly doubles the amount of wind power that would otherwise be in place by 2026 under current standards.

Methodology and Key Assumptions

Synapse modeled the economic and emissions effects of a PJM electricity future in 2026 that includes significantly higher levels of renewable energy (primarily wind) than a reference case tied to current state renewable portfolio standards (RPS). The reference case achieves an aggregate 14% RPS by 2026 across the PJM States, with most of that (11%) sourced from wind. The two wind cases developed for this analysis roughly double that level of supplied renewable energy, with increased wind power. One wind case distributes the wind around the PJM region; a second wind case allows for a portion of the total wind to be sourced from higher-performing wind regions (the Midwest) and then imported into PJM via high voltage DC lines.[7] The reference case includes transmission increases projected from PJM information on a planned RPS Overlay[8], and the wind cases include incremental transmission beyond the planned RPS overlays to allow even higher levels of wind power to be integrated onto the grid. All cases include coal plant retirement and gas plant additions to ensure resource adequacy, and all cases presume that at least part of the cost of carbon emissions will be internalized; we use a $30/ton emissions adder for CO2 in 2026 to estimate this internalization. We ran one sensitivity without this adder for base and wind cases.

Synapse used the ProSym production cost modeling tool[9] to gauge energy impacts in year 2026 for each case. ProSym is an hourly dispatch and unit commitment production cost model that provides a detailed picture of the operation of the electric power sector over the course of a year. It uses a 10-zone configuration for the PJM system, and it performs a unit commitment and

[7] In this way, our methodological approach is similar to PJM's study in that one of the wind cases tested includes wind sourced from the Midwest region and delivered via HVDC lines.
[8] Information available at http://www.pjm.com/~/media/committees-groups/committees/teac/20121213/20121213-2012-rps-study-transmission-overlay-list-of-facilities.ashx.
[9] Ventyx, Market Analytics ProSym model.

economic dispatch for 168-hour “typical weeks” over the course of the year, respecting variations in wind output and outages of conventional generation. It is based on an extensive assumption set, including load, resource mix, transmission system configuration, fuel prices, and operational constraints. The model output includes generation by resource type, marginal prices, and transmission flows for hourly periods of the year 2026.

Synapse used a capital investment spreadsheet tool to track projected overall costs associated with generation, transmission, and demand response (DR) in each of the cases. It also tracked additional offshore wind capital costs for a sensitivity case. The tool tracked the year-by-year capital investment requirements, and used benchmark financial assumptions including a proxy for weighted average cost of capital, and depreciation periods to estimate annual revenue requirements associated with all new capital investment for each of the base and wind cases.

Using the production cost modeling and capital investment accounting tool, Synapse computed production cost and energy market impacts from the wind cases, relative to the base case; and determined the incremental revenue requirements needed to pay for the increased capital investment of the wind cases. We then estimated the net impacts in 2026 of the alternative wind cases, relative to a base case using less wind (and more natural gas).

An additional production cost simulation run was executed to test the sensitivity of the results to increased levels of offshore wind. Additional model runs were also conducted to help determine how the power system responds to different sets of resource addition or transmission addition assumptions. The results of those model runs provided important insights into the economics of power system operation under different resource assumptions, and helped to shape the final sets of resource assumptions used in the wind scenarios.

The study did not build up overall rate impact effects on PJM consumers, but rather focused on the difference in aggregate impacts that would be seen from a base case when greater levels of wind are integrated onto the system. We note that net benefits accrue beyond the PJM region in this study, as the sizable increases in wind additions effect transfers at the PJM borders and the economic dispatch in adjacent Eastern Interconnection regions. The study added resource capacity to maintain planning reserve margins, with slightly higher margins for the wind cases in the out years (2020-2026) to address the increased operating reserve requirement that may be needed to integrate large levels of wind power. The study did not attempt to model any effects of the PJM RPM capacity market, which is a near-term, three-year forward construct. Our interest was long-term outcomes under clean energy scenarios; the annual revenue requirement construct was used to estimate the relative long-term investment outcomes.

Synapse presumes that at least a portion of the societal costs of carbon emissions will be internalized across the PJM system by 2026, and to support a consistent comparative framework, we assumed the same carbon emission cost in all three scenarios. To test the broad cost/benefit outcomes in the absence of a carbon emission cost, we ran the production cost model without the carbon cost adder for the base and PJM wind case, but leaving coal retirement assumptions unchanged. In those model runs, we found the broad results still show net benefit: the production cost savings exceeded the capital investment for a net benefit of roughly $2.6 billion/year in 2026.

Our key resource assumptions, listed in detail in Chapter 2, include the following:

Table 1: Key PJM Resource Assumptions

	Base	Wind –PJM Only	Wind – PJM + MISO
Total installed wind, GW	32.1	65.4	65.4*
Total installed gas, GW	123.0	122.9	122.9
Total installed coal, GW	17.5	16.7	16.7
Total retired coal, GW (from 2012 base year)	57.9	58.7	58.7
Gross peak load, 2026, GW**	190.9	190.9	190.9
Base transmission additions	PJM RPS Overlay	PJM RPS Overlay	PJM RPS Overlay
Estimated aggregate transmission path increase over RPS overlay, wind cases, MW***	-	5,750	5,750

Notes:

*Total installed wind in PJM+MISO case equal to total installed wind in PJM case, but average capacity factor of the wind is greater in the MISO+PJM wind case, and thus it provides a greater amount of annual energy. See Appendix Table 1.
**Sum of non-coincident peaks for each of ten PJM zones as modeled in ProSym.
***Based on sum of zone-to-zone additions between ProSym PJM zones.

Key Findings

Our key findings are listed in the summary table below.

Table 2: 2026 Production Costs and Emissions, Revenue Requirement Impacts, and PJM Energy Prices for Base and Wind Cases

	Reference Case	High Wind – sourced from PJM Only	High Wind – sourced from PJM and MISO
One-year 2026 Production Costs, Eastern Interconnection, $ Billions [$2026]	$198.3	$183.8	$183.4
One-year 2026 Production Cost Savings from Reference Case, $ Billions [$2026]		$14.5	$14.9
Annualized Capital Investment Requirements, 2026, PJM – Wind, Gas, DR, Incremental Transmission, $ Billions/year [$2026]	$17.4	$25.0	$25.4
Increased Investment from Reference Case, $ Billions/year [$2026]		$7.6	$8.0
Overall net annual savings – 2026 – Wind cases vs. Reference case, $ Billions [$2026]		$6.9	$6.9
PJM 2026 Market Energy Price – Load-weighted Average Annual Price, $/MWh [$2026]	$80.27	$78.53	$78.53

PJM Resource Emissions, CO2 eq. (000 tons)	320,231	269,987	276,490
PJM Resource Emissions, SO2 (000 tons)	272	257	257
PJM Resource Emissions, NOx (000 tons	105	95	95

Based on our findings, we conclude the following:

1. The cost to increase wind installations and wind output across the PJM region up to 2 times beyond what current renewable portfolio standards call for by 2026 (including the costs associated with increased transmission, and gas generation investment needed to maintain resource adequacy margins) is more than offset by production efficiency gains seen across the broader PJM and interconnected regions. Wind output displaces coal, gas and oil-fired generation; this displacement is the source of the production cost (and corresponding reduced emissions) benefits we observe in the modeling results.
2. We draw this conclusion based on the results of year 2026 ProSym production cost model runs, and our capacity/investment cost accounting model that includes the costs of all wind, transmission and gas resource supply requirements associated with the base and high wind scenarios. It estimates the annual investment cost requirements associated with each of the base and high wind cases, accounting for the timing of resource need and projections of investment or capital costs for the supply resources. The incremental investment costs for the high wind scenarios (compared to the base case) can be compared to the decreased production costs (compared to the base case) seen in the high wind cases.
3. By 2026, our modeled wind scenarios (total PJM wind = 65.4 GW) lead to a production cost savings on the order of $14.5 to $14.9 billion dollars per year ($2026) compared to the base scenario (total PJM wind = 32.1 GW) that includes roughly half that level of installed wind.
4. We computed annual revenue requirements for the incremental investment associated with the base and wind cases. The annual revenue requirement increase above the base case for the wind case ranges from $7.6 to $8.0 billion per year ($2026). Thus, net production cost efficiency gains from the increased wind scenarios are on the order of $6.9 billion per year by 2026, when the higher levels of wind are in place.
5. Production cost efficiency gains from improved average wind resource performance (from a portion of wind resources sourced from the higher-performing MISO region) are roughly offset by the increased transmission costs to deliver those resources to PJM.
6. PJM carbon emissions in the wind scenarios are 14% lower than base case emissions. SO2 emissions are 6% lower and NOx emissions are 10% lower than base case levels. Base case levels include the effect associated with retiring roughly 58 GW of coal-fired plants in PJM.
7. Load-weighted average annual energy market prices in the PJM zones are lower under the wind cases. Average annual energy prices differences for the PJM zones in aggregate are roughly $1.74/MWh lower for the wind cases, relative to base case prices. This is generally expected given that wind output reduces, or displaces, the use of fossil-fueled resources that set the market clearing price in PJM. The price differences are

greatest in the non-summer months, when wind output is highest, load is lowest and supply margins are greatest.

Notably for this study, peak load summer months see market prices higher in the wind cases relative to the base cases, reflecting the more difficult balancing act required in the high wind cases, the greater variation in wind output during those times, and the presence of a steep marginal cost of supply during those periods that renders clearing prices more sensitive to these factors than during less resource-tight months. In simpler terms: the wind cases see more summer peak period energy from "peaking" fossil resources, and less summer peak period energy from base-loaded and intermediate-loaded fossil resources, relative to the base case. This is a consequence of using economically optimal unit commitment and dispatch while respecting fossil-fuel plant operating constraints and the time profiles of wind output. It is also arises from increased exports from or reduced imports to the PJM zone, relative to the base case.

Prices in regions adjacent to PJM are also lower, as the interconnected nature of the grid results in greater flows from PJM to those neighboring regions than is seen in the base case. This illustrates that some of the production cost efficiency benefits seen in the study could flow outside the PJM region, depending on how individual resource and load contractual arrangements are structured throughout the areas.

8. If all production cost efficiency gains flow to consumers based on consumers paying the annual revenue requirements for incremental wind installed in the PJM region, then consumers are clearly much better off economically with increased wind resources, relative to a base case with less wind and more gas. In a market environment however, consumers would not pay the "annual revenue requirements" associated with the increases in wind power. Instead, they pay spot prices for power, and merchant investment would cover the costs of incremental wind – and receive spot market revenue streams. In this analysis, we assume that consumers both pay for the increased wind plant, and retain the production cost efficiencies that result.
9. Increasing the amount of "PJM wind" that is sourced from further west regions, in this analysis modeled as MISO-sourced wind, leads to incrementally greater wind performance and higher production cost efficiencies. These savings are roughly offset by increased transmission costs associated with delivering more of this wind to PJM via HVDC lines, the proxy delivery method used in this analysis.

2. Methodology and Key Assumptions

A. Methodology

The methodology used to complete this study consisted of three components. First, we researched current PJM system RPS requirements and the status of transmission infrastructure plans to determine key parameters for our reference case. Next, we licensed and used the ProSym production cost simulation modeling tool to estimate the detailed energy effects of base and alternative scenarios of clean energy in PJM. Last, we developed a capital investment accounting framework to track and monetize the investment costs necessary to implement each of the base and wind scenarios.

The ProSym production cost tool modeled the PJM wholesale market and determined overall production costs for an eastern interconnection representation, computed zonal-based marginal prices, and estimated emissions output for 2026. This was performed for an “existing RPS” or base case, and two wind cases. One wind case sourced all wind from within PJM; the other included a portion of wind sourced from wind-rich MISO regions and delivered via new HVDC transmission infrastructure. Synapse’s capital investment accounting tool modeled the time profile of required capital investments in generation, transmission and demand response for these three scenarios (and incremental solar, energy efficiency and offshore wind investments in sensitivity cases). Based on the results of the ProSym model runs and our capital investment accounting tool, we estimate the net impacts of high wind scenarios to PJM customers, at an aggregate level for the year 2026. These net impacts are in terms of changes in the overall cost of electricity and changes in overall emissions, under the assumptions used for the wind scenarios.

A number of key assumptions underpin our analysis, and are explained in the “Assumptions” section below.

B. The Modeling Framework

Synapse ran base and wind scenarios for the year 2026 using the ProSym production cost modeling system. We developed a capital investment accounting tool to track required annual investments in supply, demand and transmission investments. We used resource book life and a proxy for weighted average cost of capital to determine the annual revenue requirements associated with the required investments. We compared the overall incremental costs of wind scenarios over the base case, and the overall production benefits (and corresponding market-based benefits, under a wholesale market model formulation) of wind cases compared to the base case.

PROSYM Production Cost Model

For this analysis, we use Market Analytics, under license from Ventyx, to estimate system production cost and market value of energy by simulating the operation of the wholesale electric energy market in the Eastern Interconnect. Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. The simulation engine used is PROSYM. The modeling system and the default data are provided by the model vendor Ventyx. Synapse has updated some of the default data used by Ventyx, such as transmission path capacity across PJM zones (to account for planned RPS transmission overlays) and the underlying flexibility of new natural gas resource installations.

The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. However, the model does require assumptions about the quantity and type of existing and new capacity over the study horizon.

The Market Analytics model uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed results for hourly electricity prices and market operations. Based on hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e. the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions.

PROSYM also models randomly occurring forced (i.e. random) outages of generating probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo-type random number draw. Many other models simulate the effect of forced outages by "de-rating" the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While such de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the results for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM models generating units with a much higher level of detail including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail. Few other electric system models simulate dispatch in this kind of detail.

The model's fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

The input assumptions to the Market Analytics locational-price-forecasting model include market rules and topology, hourly load profiles, forecasted annual peak demand and total energy, thermal unit characteristics, conventional hydro and pumped storage unit characteristics, fuel prices, renewable unit characteristics, transmission system paths and upgrades, generation retirements, additions and uprates, outages, environmental regulations, and demand response resources.

Transmission

The smallest location in Market Analytics is a Location (typically representing a utility service territory) which for modeling purposes is mapped into a Transmission Area (TA). A TA may represent one or more Locations. Transmission areas represent sub regions of Control Areas such as PJM. Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission liens involved. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny. The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those that comprise the planned PJM RPS Overlay[10], and the reference Market Analytics database. We also consider any congestion identified during our modeling.

Transmission-path assumptions were based on those developed by Market Analytics based on the transmission paths represented in PJM. We have modified those based on RTO data and proposed projects to represent future additions.

The transmission system within Market Analytics is represented by links between transmission areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables: “From” location; “To” location; transmission capability in each direction; line losses in each direction; and wheeling charges.

Unit Information

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the US Energy Information Administration (EIA), US Environmental Protection Agency (EPA), North American Electric Reliability Corporation (NERC), and Federal Energy Regulatory Commission (FERC), and various trade press announcements as well as Ventyx’s own professional assessment.

For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. For smaller units (e.g. combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings.

[10] Synapse estimated rough path increases between PJM zones based on PJM’s “List of Upgrades Comprising the 2012 PJM RPS Overlay” and common transfer capabilities associated with major line and transformer additions (as sourced from the EIPC document “Phase 2 Report: Part 5, Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios”, transmission line cost estimate matrix tables). As PJM and Ventyx produce more information on the path transfer capacity ratings associated with the RPS Overlay, the underlying model used in this analysis could be updated to more accurately characterize those increases.

New generic non-renewable resources were added to meet any residual installed capacity requirements after adding planned and RPS additions. Based on the mix of resources in the interconnection queue, and the constraints on the construction of new coal or nuclear units in the foreseeable future, we assume generic additions comprising gas-fired 490-MW combined cycle (CC) units and 180-MW combustion turbines (CT). These additions are dispersed throughout the Eastern Interconnect based on zonal need and historical zonal capacity surplus-deficit patterns. We also assume that these new units in general will exhibit flexible operational characteristics, and we model relatively low minimum operating limits in our model runs.

Retirements

Specifically, we assume retirement of roughly 58 GW of PJM coal in the base and wind cases in this study. In general, this study assumes that plants that have been operating since the implementation of restructured markets will continue to operate in the absence of any major changes in market and regulatory conditions. We assume that retirements of existing plants will be driven by requirements for environmental retrofits due to regulatory changes currently proposed or under consideration by the EPA. These rules include: the Cross-States Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), the Coal Combustion Residuals (CCR) Rule, the 316(b) rule governing impingement and entrainment of aquatic life in power plant cooling systems, effluent limitation guidelines, and any updates to the National Ambient Air Quality Standards (NAAQS). Many of these retirements have already been announced, and this is reflected in the unit database. Plants that continue to operate with environmental retrofits are assumed to be retired at the end of their regulatory life, which is anywhere from 60 to 75 years, depending on the unit.

Demand Response and Energy Efficiency Resources

Synapse estimated base case availability of demand response and energy efficiency resources based on the current (2013) PJM load forecast report. Synapse included additional demand response resources in both base and wind cases to help bridge the capacity gap arising from our modeled retirement of coal plants.

Emissions

Market Analytics has the ability to model, and apply unit costs of compliance for multiple emissions. For this analysis, we modeled the costs of complying with regulations governing the emissions of SO2, NOx and estimated a proxy compliance cost for CO2 in 2026. The model includes the unit costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions. In this way, we project market prices which reflect, or internalize, the unit-compliance costs for each emission, except mercury. The assumptions for SO2 and NOx allowances are based on the Market Analytics default data and consistent with the current futures prices. CO2 prices are based on assumed prices under federal regulation according to the October 2012 Synapse 2012 Carbon Dioxide Price Forecast.

Capital Investment Cost Model

Synapse developed a spreadsheet-based model to calculate the capital costs associated with investments in power generation, demand response and transmission for the base and each wind scenario. The model does not capture all capital costs that will be incurred across the interconnection, but it does capture the primary cost differences associated with the foundations for the base and wind scenarios. The model accounts for the time profile of investment, and thus we were able to calculate the overall annual revenue requirements associated with the primary investments. By comparing between base and wind cases, and respecting the time profile of the capital investments, we obtain a key high level measure of the total costs of a clean energy scenario – an annual revenue requirement. The incremental annual revenue requirement associated with the wind cases can be compared to the production cost benefit seen in the wind scenarios (i.e., base case production costs minus wind case production costs) to obtain an overall assessment of the value of a clean energy future.

To determine the annual capital investment requirements for each of the cases, a time series profile of resource additions and transmission additions is computed between 2013 and 2026.

The resource addition profile for the base case is determined based on the required pace of wind additions to reach 2026 RPM goals, an estimated pace of near-term retirement of coal fired units, projected retirements of additional coal-fired units under a carbon cost assumption, near-term demand response additions, and gas-fired resource additions necessary to maintain resource adequacy based on meeting a planning reserve margin. Base case transmission additions projected from the PJM RPS Overlay are presumed added as capital investments over the years 2017-2022, and are equal for all of the scenarios.

The wind scenario investment additions build off of the base case scenario additions. Incremental wind, transmission, and demand response resources are added, and a revised set of gas-fired additions was determined based on a planning reserve margin. Gas fired additions in the wind case are roughly the same as in the base scenarios, even though wind resources contribute to capacity reserve requirements. However, recognizing the need for increased flexibility on a high wind system, the planning reserve requirement used to determine the "residual" gas-fired resource additions is higher in the wind scenarios than in the base case.

To obtain a stream of annual revenue requirements associated with the capital investments the capital investment model amortizes the infrastructure needs over a presumed book lifetime, and assumes a nominal annual financing rate of 8% to account for inflation and real rate of return requirements.

C. Assumptions

Synapse developed common assumptions for the base and wind cases for PJM peak load and annual energy, 2026 fuel prices, coal plant retirement levels, all other supply resources except wind and natural-gas-fired supply, and a carbon price. Assumptions for wind supply, transmission infrastructure, and natural gas plant additions vary by scenario. The assumptions are listed in the table below.

Table of Key Assumptions

Table 3. Detailed Assumptions

2026 Assumptions	Base Case	High Wind, PJM	High Wind, PJM + MISO
Total installed onshore wind, MW	28,056	61,433	55,433
Total installed offshore wind, MW	4,000	4,000	4,000
Installed external wind, MW	0	0	6,000
External wind delivered via HVDC to PJM zones:	-	-	3,000 APS 3,000 South
Total installed wind, MW	32,056	65,433	65,433
Transmission additions	PJM RPS Overlay	Overlay + Additional intra-zone path increases	Overlay + Additional intra-zone path increases + HVDC to PJM
Incremental transmission path increases, PJM zone-to-zone, total MW *MISO-Gateway to PJM AEP *PJM-AEP to PJM-S *PJM-CE to WI-UPMI *PJM-APS to PJM-S *MISO-IA to PJM-CE *PJM-APS to PJM-EPA	-	5,750	5,750 + HVDC
Estimated cost of PJM path incremental additions, $ Billions $2012	-	$1.8	$1.8
Estimated cost, HVDC to deliver MISO wind to PJM, $ Billions $2012	-	-	$4.0
Projected peak load,2026, MW, excl. EE and DR, NCP of 10 zones	190,871		
Energy efficiency peak load reduction, MW	923		
Demand response, "supply side" modeling, MW	18,212		
Annual PJM load, GWh, excluding losses and net imports/exports	986,549		
Annual PJM energy, GWh, from PJM resources	947,164	988,113	986,434
Natural Gas price, $/mmBTU, 2026 nominal, Henry Hub	$6.67	$6.67	$6.67
Carbon price, $/ton CO2eq	30	30	30
Coal retirement, GW	57.9	58.7	58.7
Total Natural Gas Capacity, MW	122,998	122,929	122,929
Cost of New Combustion Turbine ($2012/kW)	$936/kW		
Cost of New Combined Cycle ($2012/kW)	$1,144/kW		
Wind Capital Costs – Onshore – 2013 ($2012)	$1,999/kW		
Wind Capital Costs – Onshore – 2026 ($2012)	$1,872/kW		
Wind Capital Costs – Offshore – 2013 ($2012)	$5,658/kW		
Wind Capital Costs – Offshore – 2026 ($2012)	$4,160/kW		
Wind Performance – Average Annual Capacity Factor – All PJM Zones including Offshore – 2026 Aggregate wind	38.0%	38.0%	39.6%
Wind Performance – Average Annual Capacity Factor –PJM ComEd – 2026 Aggregate wind	39.0%	38.9%	40.7%
Wind Performance – Average Annual Capacity Factor – PJM AEP – 2026 Aggregate wind	36.3%	37.4%	37.4%
Wind Performance – Average Annual Capacity Factor – Offshore Wind– 2026 Aggregate wind	45.0%		
Wind Performance – Average Annual Capacity Factor – MISO External Wind Imported to PJM – 2026 Aggregate wind	-	-	41.5%
Planning reserve margin - 2026	22.8%	26.4%	26.4%

Note: The wind performance values shown are based on the results of the production cost runs. Performance potential for wind was slightly greater than shown here; a small amount of wind curtailment resulted from the model runs.

Discussion

The analysis we conducted hinges on the sets of assumptions made. We discuss some of the choices below, for the critical assumptions that impact the modeling results.

- Transmission. We modeled an increase in transmission path capacity between a number of ProSym PJM zone paths to represent the presumed presence of the PJM RPS Overlay. These increases were in place for base and wind cases, and as such there is no differential cost impact across the cases due to the Overlay. We used PJM's information on the specific facilities that comprise the planned RPS Overlay, along with industry standard information on the capacity of transmission line and transformer equipment to estimate increases in zone-to-zone transmission path capacity as configured by the Ventyx model.[11] We also estimated incremental transmission reinforcement needs between PJM zones (and in two cases, between PJM zones and external zones) in order to approximate a future with additional transmission beyond that of the Overlay. As part of our estimate of reinforcement needs to help support more wind, we iterated multiple runs of the ProSym production cost model and reviewed wind curtailment output data to help determine critical paths where transmission increases were required to lower curtailment, for both base and wind cases. The table below summarizes the increases we assumed:

Table 4. PJM Path Transmission Increase Assumptions

Intra-PJM Zonal Path	Assumed Overlay Increase – Base and Wind Cases, MW	Incremental Increase – Wind Case Only, MW
PJM-AEP.PJM-APS	500	
PJM-AEP.PJM-CE	1500	
PJM-AEP.PJM-S	300	
PJM-CE.PJM-MISO-IN	500	
PJM-S.PJM-AEP	300	
PJM-CE.PJM-AEP	1500	
PJM-EPA.PJM-SW	200	
PJM-SW.PJM-EPA	200	
PJM-MidE.PJM-SW	1000	
PJM-SW.PJM-MidE	1000	
PJM-SW.PJM-S	1000	
MISO-Gat.PJM-AEP		1200
PJM-CE.WI-UPMI		1733
PJM-APS.PJM-S		900
MISO-IA.PJM-CE		1227
PJM-APS.PJM-EPA		324

- Carbon price. We included a carbon price in base and wind cases primarily because we anticipate that by 2026 carbon pricing will likely be part of the regulatory regime. One of the more significant effects of including a carbon price is the impact it would have on coal plant retirement decisions. As of early 2013, roughly 20,000 MW of PJM coal plants have

[11] As information is made available from PJM, or through Ventyx, any necessary adjustments to these assumptions could be made. Our estimates are necessarily rough; no full-scale transmission planning assessment was conducted.

either announced retirement or are at risk of retirement, based on the Ventyx default data projecting retirements, and based on PJM documentation of "at risk" coal plants.[12] We note that under the EIPC "national carbon case"[13], which used a $30/ton carbon price (by 2020), almost all coal fired power plants were retired in the modeling. Here we assume that 58-59 GW of coal plant retirement (inclusive of formally announced PJM coal retirements) will occur. Our modeling leaves in the highest performing (highest capacity factor) coal plants.

To gauge the sensitivity of the economics to a case where carbon was not explicitly priced in the electric power sector, we ran sensitivities of the base case and one of the wind cases excluding the carbon price adder. The results continued to show net benefits, on the order of $2.6 billion/year in 2026, for that scenario. We note that the presence or absence of a carbon adder could influence retirement decisions for coal plants nationwide, not just in PJM. In our analysis, we did not model the economic dynamics of resource expansion / retirement decisions under the influence of a carbon price. We presumed a certain level of coal plant retirement, and kept those resource decisions fixed for all subsequent runs.

- Natural gas plant additions to meet planning reserve margins. Our modeling environment did not include an optimal capacity expansion process although we attempted to specify a reasonable mix. We note that generally a mix of combined cycle and combustion turbine resources are the current gas-fired expansion choices. Both types of units provide flexible, dispatchable capacity that helps to integrate wind resources onto the grid. During our modeling process, we ran several executions of the wind case runs with varying amounts of natural gas resources and transmission increases in place, primarily with an aim to minimize the level of wind curtailments seen in our model results. We adjusted minimum operating level parameters for new gas resources downward from the Ventyx default values, as a mechanism to approximate a more flexible fleet going forward.
- Natural gas prices. We used default Ventyx data for natural gas price projections for 2026. Those projections are roughly in line with current EIA AEO projections of natural gas prices.
- Wind cost assumptions. We used NREL/LBL presentation data and wind technology reports to guide our projections of slightly decreasing real costs for wind turbine technology, and increasing performance trends for wind power.[14]

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[12] See, e.g., PJM TEAC Reliability Analysis, March 15, 2012, and January 10, 2013, at-risk slides.
[13] See for example, EIPC Phase I Report and related summary results of carbon cases, available at http://www.eipconline.com/Modeling_Results.html.

[14] See e.g., Lawrence Berkeley Laboratory, "2011 Wind Technologies Market Report", http://eetd.lbl.gov/ea/emp/reports/lbnl-5559e.pdf and Wiser, Ryan, Lawrence Berkeley National Laboratory, Eric Lantz, National Renewable Energy Laboratory, Mark Bolinger, Lawrence Berkeley National Laboratory, Maureen Hand, National Renewable Energy Laboratory, "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects", February 2012, available at http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf.

3. Results of Modeling

Table 5 lists the key results of our production cost modeling process, and our use of the capital investment accounting tool. As explained in our summary section, increased wind power displaces generation on the margin (gas, coal, or and/or oil). This displacement gives rise to lower costs of production, since fuel costs for wind are zero. Simultaneously, in an energy market environment such as PJM, marginal prices are lower for much of the year to reflect the infra-marginal nature of the wind resource, leading to requirements to use less-expensive marginal supply to balance the electric power system.

Table 5: 2026 Production Costs and Emissions, Revenue Requirement Impacts, and PJM Energy Prices for Base and Wind Cases

	Reference Case	High Wind – sourced from PJM Only	High Wind – sourced from PJM and MISO
One-year 2026 Production Costs, Eastern Interconnection, $ Billions [$2026]	$198.3	$183.8	$183.4
One-year 2026 Production Cost Savings from Reference Case, $ Billions [$2026]		$14.5	$14.9
Annualized Capital Investment Requirements, 2026, – Wind, Gas, DR, Incremental Transmission, $ Billions/year [$2026]	$16.8	$24.4	$24.9
Increased Investment from Reference Case, $ Billions/year [$2026]		$7.6	$8.0
Overall net annual savings – 2026 – Wind cases vs. Reference case, $ Billions [$2026]		$6.9	$6.9
PJM 2026 Energy Price – Load-weighted Average Annual Price, $/MWh [$2026]	$80.27	$78.53	$78.53
Emissions, CO2 eq. (000 tons)	320,231	269,987	276,490
Emissions, SO2 (000 tons)	868	257	257
Emissions, NOx (000 tons)	190	95	95
Capital Investment – Additional Wind Supply - $ Billions, nominal	85.4	154.6	154.6
Capital Investment – Additional Gas Supply - $ Billions, nominal	82.6	86.2	86.2
Capital Investment – Demand Response - $ Billions, nominal	3.3	3.3	3.3
Capital Investment – Assumed RPS Overlay Investment, $ Billions, nominal	5.6	5.6	5.6
Capital Investment – Incremental Transmission Investment, $ Billions, nominal	-	2.2	7.2

This study finds that the increased wind cases provide overall benefits to consumers due to the presence of additional wind resources, transmission, and sufficient gas-fired resources to support integration of the wind into the system.

The base and wind cases contain identical resource profiles for nuclear, oil (#2 and #6), petroleum (pet coke), hydro, wood, biomass and solar resources and as such no incremental revenue requirements are assumed between the base and wind cases for those resource groups. The only differences between the base and wind scenarios are wind installation quantities, gas-fired resource additions (and thus total gas-fired resource base), transmission system investment, and a small difference in coal-fired resources. This simplification – i.e., minimizing the number of variables that differ between the cases - allows us to focus on the incremental differences between a base case and the high wind cases arising from just a few factors.

Tables 6 through 8 below show the required pattern of resource investments for the base and wind scenarios, and the annual revenue requirements for those investments.

Table 9 below shows the pattern of PJM prices across months and across PJM zones for the base case and the wind case (PJM sourced wind). It illustrates the disparity in market prices between summer and non-summer months. The table shows prices for the PJM-sourced wind case; minimal differences exist between prices for that wind case, and the PJM+MISO sourced-wind case.

Table 6. Capital Investment Model – Resource Additions – Base Case

	Base Case Additions MW			Base Case Investment Costs $ Millions nominal			Base Case Annual Capital Recovery Requirements $ Millions nominal			
Year	Total Wind	Total Gas	DR	Total Wind	Total Gas	DR	Total Wind	Total Gas	DR	Total - All Resources
2013	1,451	0	0	$2,959	$0	$0	$301	$0	$0	$301
2014	2,419	0	0	$5,000	$0	$0	$811	$0	$0	$811
2015	2,903	8,940	1000	$6,087	$9,856	$637	$1,431	$934	$159	$2,524
2016	2,903	8,170	2000	$6,176	$8,951	$1,299	$2,060	$1,797	$485	$4,342
2017	2,419	9,150	2000	$5,221	$10,253	$1,325	$2,591	$2,785	$817	$6,193
2018	3,386	11,510	0	$9,402	$13,180	$0	$3,549	$4,052	$817	$8,418
2019	2,419	11,940	0	$5,375	$14,257	$0	$4,096	$5,402	$817	$10,315
2020	2,903	6,060	0	$8,401	$7,416	$0	$4,952	$6,102	$817	$11,871
2021	2,903	2,140	0	$6,638	$2,881	$0	$5,628	$6,361	$817	$12,806
2022	2,903	2,730	0	$8,452	$3,488	$0	$6,489	$6,690	$817	$13,995
2023	1,451	2,600	0	$5,058	$3,279	$0	$7,004	$7,005	$817	$14,826
2024	1,451	2,960	0	$5,028	$3,772	$0	$7,516	$7,371	$817	$15,704
2025	1,435	2,960	0	$4,955	$3,848	$0	$8,021	$7,744	$817	$16,582
2026	1,468	1,030	0	$6,644	$1,407	$0	$8,698	$7,878	$817	$17,392
Total	32,412	70,190	5,000	$85,395	$82,586	$3,261	Annual recovery continues in later years			

Table 7. Capital Investment Model – Resource Additions – Wind (PJM source) Case

windre v7	Wind Case Additions MW				Wind Case Investment Costs $ Millions nominal				Wind Case Annual Capital Recovery Requirements $ Millions nominal				
Year	Total Wind	Total Gas	DR	Incre-mental Trans-mission	Total Wind	Total Gas	DR	Incre-mental Trans-mission	Total Wind	Total Gas	DR	Incremental Trans-mission	Total - All Resources
2013	1,451	0	0		$2,959	$0	$0	$0	$301	$0	$0	$0	$301
2014	2,419	0	0		$5,000	$0	$0	$0	$811	$0	$0	$0	$811
2015	2,903	8,940	1000		$6,087	$9,856	$637	$0	$1,431	$934	$159	$0	$2,524
2016	2,903	8,170	2000		$6,176	$8,951	$1,299	$0	$2,060	$1,797	$485	$0	$4,342
2017	2,419	9,150	2000		$5,221	$10,253	$1,325	$0	$2,591	$2,785	$817	$0	$6,193
2018	3,386	11,510	0		$9,402	$13,180	$0	$0	$3,549	$4,052	$817	$0	$8,418
2019	2,419	11,940	0		$5,375	$14,257	$0	$0	$4,096	$5,402	$817	$0	$10,315
2020	2,903	6,060	0		$8,401	$7,294	$0	$351	$4,952	$6,099	$817	$31	$11,899
2021	4,120	2,140	0		$9,423	$2,881	$0	$359	$5,912	$6,357	$817	$63	$13,149
2022	5,744	2,730	0		$15,044	$3,488	$0	$366	$7,444	$6,686	$817	$96	$15,042
2023	6,493	2,600	0		$16,923	$3,279	$0	$373	$9,168	$7,002	$817	$129	$17,115
2024	7,242	2,960	0		$18,852	$3,772	$0	$380	$11,088	$7,367	$817	$162	$19,434
2025	7,617	3,960	0		$19,925	$5,328	$0	$388	$13,117	$7,872	$817	$197	$22,003
2026	9,240	2,530	0		$25,843	$3,671	$0	$0	$15,749	$8,207	$817	$197	$24,970
Total	61,258	72,690	5,000		$154,631	$86,208	$3,261	$2,217	Annual recovery continues in later years				

Table 8. Capital Investment Model – Resource Additions – Wind (PJM + MISO source) Case

windrev8 altwind	PJM+MISO Wind Case Additions MW				PJM+MISO Wind Case Investment Costs $ Millions nominal				PJM+MISO Wind Case Annual Capital Recovery Requirements $ Millions nominal				
Year	Total Wind	Total Gas	DR	Incremental Transmission	Total Wind	Total Gas	DR	Incre-mental Trans-mission	Total Wind	Total Gas	DR	Incremental Trans-mission	Total - All Resources
2013	1,451	0	0		$2,959	$0	$0	$0	$301	$0	$0	$0	$301
2014	2,419	0	0		$5,000	$0	$0	$0	$811	$0	$0	$0	$811
2015	2,903	8,940	1000		$6,087	$9,856	$637	$0	$1,431	$934	$159	$0	$2,524
2016	2,903	8,170	2000		$6,176	$8,951	$1,299	$0	$2,060	$1,797	$485	$0	$4,342
2017	2,419	9,150	2000		$5,221	$10,253	$1,325	$0	$2,591	$2,785	$817	$0	$6,193
2018	3,386	11,510	0		$9,402	$13,180	$0	$0	$3,549	$4,052	$817	$0	$8,418
2019	2,419	11,940	0		$5,375	$14,257	$0	$0	$4,096	$5,402	$817	$0	$10,315
2020	2,903	6,060	0		$8,401	$7,294	$0	$351	$4,952	$6,099	$817	$31	$11,899
2021	4,120	2,140	0		$9,423	$2,881	$0	$359	$5,912	$6,357	$817	$63	$13,149
2022	5,744	2,730	0		$15,044	$3,488	$0	$1,585	$7,444	$6,686	$817	$204	$15,150
2023	6,493	2,600	0		$16,923	$3,279	$0	$1,616	$9,168	$7,002	$817	$347	$17,333
2024	7,242	2,960	0		$18,852	$3,772	$0	$1,649	$11,088	$7,367	$817	$494	$19,766
2025	7,617	3,960	0		$19,925	$5,328	$0	$1,682	$13,117	$7,872	$817	$643	$22,449
2026	9,240	2,530	0		$25,843	$3,671	$0	$0	$15,749	$8,207	$817	$643	$25,416
Total	61,258	72,690	5,000		$154,631	$86,208	$3,261	$7,242	Annual recovery continues in later years				

Table 9. PJM Load-Weighted Average Monthly Prices by ProSym Transmission Zone, Base and Wind (PJM source) Cases

PJM Wind Case Prices by PJM Zone, by Month - 2026 - Load-Weighted $/MWh													
PJM Zone	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
PJM - AEP	73.0	72.9	70.1	65.7	67.5	83.2	128.3	117.1	73.6	66.6	68.3	71.2	81.3
PJM - APS	72.5	71.7	68.5	64.4	65.9	81.6	127.6	116.2	71.9	65.3	67.0	70.7	79.7
PJM - ATSI	73.4	73.0	70.6	66.4	67.9	84.0	131.4	119.8	74.1	66.9	69.1	71.6	82.4
PJM - COMED	49.7	59.5	55.4	45.9	54.3	75.5	102.6	100.9	62.8	46.5	55.4	48.0	65.3
PJM - DEOK	74.8	74.8	71.9	67.4	69.3	86.1	131.8	121.1	75.6	68.3	70.1	73.0	84.1
PJM - South	73.2	72.4	69.0	64.9	66.8	83.7	129.3	118.5	73.0	66.1	67.6	71.5	82.4
PJM MidAtlantic - E	73.5	71.5	65.3	61.7	63.2	78.1	124.4	114.4	69.9	64.0	64.7	70.8	79.7
PJM MidAtlantic - East PA	72.3	70.5	65.9	62.4	63.0	76.5	119.1	109.7	68.9	63.5	64.7	69.8	76.6
PJM MidAtlantic - SW	72.6	71.3	67.4	63.0	64.8	81.7	129.3	117.5	71.2	64.0	65.8	70.2	81.1
PJM MidAtlantic - West PA	71.1	70.1	66.4	63.0	63.8	76.3	114.7	106.3	69.1	64.0	65.3	69.1	75.4
Total All Zones	70.0	70.5	66.5	61.7	64.2	80.6	123.5	114.1	70.7	62.8	65.3	67.9	78.5

Base Case Prices by PJM Zone, by Month - 2026 - Load-Weighted $/MWh													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
PJM - AEP	77.5	77.1	73.9	68.3	69.7	84.4	124.4	118.1	77.0	69.1	73.2	75.9	83.8
PJM - APS	76.0	75.1	70.8	65.4	67.0	82.0	122.4	116.0	74.1	66.2	69.8	74.1	81.0
PJM - ATSI	77.4	76.9	74.0	68.4	69.8	84.7	127.1	120.5	77.1	69.0	73.3	75.8	84.4
PJM - COMED	73.9	75.3	72.8	68.0	68.7	82.1	116.3	112.5	75.9	67.8	72.8	73.5	81.9
PJM - DEOK	79.5	79.2	75.8	70.0	71.6	87.1	128.1	122.3	79.1	70.9	75.2	77.9	86.7
PJM - South	76.2	75.3	70.5	65.1	67.4	83.5	123.3	117.5	74.8	66.1	69.6	74.2	82.9
PJM MidAtlantic - E	72.3	69.8	63.1	60.4	61.2	67.6	110.4	98.6	66.3	62.6	63.1	69.6	74.3
PJM MidAtlantic - East PA	71.6	69.1	63.8	61.0	60.7	66.2	105.2	94.3	65.1	62.0	63.2	69.0	71.8
PJM MidAtlantic - SW	74.6	73.5	68.7	62.8	64.9	80.6	121.6	115.1	71.3	63.5	66.7	72.3	80.6
PJM MidAtlantic - West PA	72.7	70.7	65.9	62.6	62.2	68.3	103.4	94.0	66.3	63.3	65.4	70.4	72.5
Total All Zones	75.1	74.2	70.0	65.2	66.5	78.8	118.6	111.4	72.9	66.2	69.4	73.3	80.3

Offshore Wind Sensitivity Run

We conducted a sensitivity analysis on the PJM wind case to gauge the overall effect under increased offshore wind levels. Table 10 below presents the key alternative assumptions and results of those analyses.

Table 10. Sensitivity Run Assumptions and Results

	Reference Case	Offshore Wind Sensitivity
Input Change		
Wind Case – PJM Wind		5 GW additional offshore wind, PJM Mid-East and PJM-South locations; 6 GW less onshore wind buildout; 1 GW less CT resource buildout; small change in timing of CT and CC additions in later years (2020+).
Modeling Results		
One-year 2026 Production Costs, Eastern Interconnection, $ Billions [$2026]	$198.3	$183.6
One-year 2026 Production Cost Savings from Reference Case, $ Billions [$2026]		$14.7
Annualized Capital Investment Requirements, 2026, PJM – Wind, Gas, DR, Incremental Transmission, $ Billions/year [$2026]	$17.4	$26.2
Increased Investment from Reference Case, $ Billions/year [$2026]		$8.8
Overall net annual savings – 2026 – Wind case vs. Reference case, $ Billions [$2026]		$5.9

The results of the sensitivity run illustrate that significant net benefits still accrue to a scenario with more offshore wind, but the overall net benefits are not as great as seen in the onshore wind scenario. This is driven primarily by the higher capital costs of the offshore wind. We do note though that there are synergies between the level of offshore wind development, and the level of increased transmission need beyond the RPS overlay that we have not captured in this sensitivity run that could have the effect of making the higher offshore wind case closer in net benefits to the onshore wind case. To gauge the level of required transmission in a reduced onshore/increased offshore case, additional model iterations would be required to assess if lower transmission investment (onshore) would result in acceptable levels of congestion and/or curtailment of onshore wind. Further analyses are required to test this. Also, while 5 GW of offshore wind is a sizable increment above the base case level of 4 GW of offshore wind, we understand that PJM is analyzing “high offshore wind” cases with much higher levels of offshore wind. Such increases could lead to significantly lower onshore transmission buildout requirements.

4. Observations, Conclusions, and Next Steps

Observations and Conclusions

While analyzing the PJM system under different wind and gas resource addition assumptions, the modeling results clearly indicated that large, annual, net benefits from production cost efficiency gains exist for high wind scenarios. Displacing fossil-generated electricity with wind power leads to lower overall production costs. In most months, our modeling also indicates that PJM market prices are also lower in the wind cases. Tellingly, summer month periods with low levels of wind power output can still lead to higher market prices (compared to the base case) for those months in the high wind scenarios. This occurs because of the different mix of generation used, arising from the more complex operational solutions required (in the wind cases) when responding to large variations in wind energy output during those months. It is also influenced by the pattern of PJM to neighboring region imports and exports under the different scenarios.

We summarize our observations and conclusions below.

1. Increased installation of wind power resources in the PJM region at roughly double the levels specified by existing RPS statutes lead to annual production cost reductions that range from $14.5 to $14.9 billion per year. This result, arising from the use of the ProSym production cost modeling tool, is based on a set of reasonable assumptions concerning future carbon costs in the electric sector, load, coal retirement levels, natural gas resource additions, improved transmission system infrastructure, and natural gas prices.
2. Consumers see significantly improved emission profiles in the wind scenarios. Carbon, SO2 and NOx emissions are all reduced.
3. The incremental costs to achieve these production cost gains ranges from $7.6 to $8.0 billion per year by 2026. This indicates that in general a planned expansion of wind power in the region will lead to net benefits for consumers.
4. The energy market price impact of a high wind case is seen to be relative high in non-summer months, and market prices in the summer period are high in the wind cases. PJM consumers could be exposed to these market prices, but to the extent that PJM consumers pay for the incremental wind power assumed for the wind scenarios, consumers are hedged against those market prices. We assume that all production cost efficiency gains seen in this analysis flow to consumers, and all required investments are borne by consumers. We also note that the Eastern interconnection-wide nature of the energy modeling leads to a relative increase in exports from PJM in the wind cases, compared to the base case (with PJM net imports).

Next Steps

Additional analysis is required to determine the relative effects of varying any number of critical assumptions. To further test the robustness of the results seen in this analysis, Synapse recommends the following additional scenarios, or sensitivities, be analyzed using the production cost modeling and capital investment recovery model:

1. Assume large scale retirements of coal plant resources throughout the Eastern Interconnection, not just in the PJM region. A rebalancing of capacity requirements in each major area would be necessary to ensure resource adequacy.
2. Conduct iterative runs of the production cost modeling by incrementally stepping up transmission system transfer capacities, and simultaneously reducing the overall planning reserve margin, to optimize the tradeoffs between building more transmission and building sufficient balancing capacity with new gas-fired resources.
3. Continue to test production cost effects on different combinations of increased demand-side resources, including energy efficiency and demand response. Given the relatively high summer period prices and transmission congestion during those periods, it appears that non-wind related constraints can lead to increasing production costs, since summer wind output is relatively low in the model.
4. Test the effects of multiple combinations of increasing wind, solar and energy efficiency resources.
5. Test varying potential cost profiles for offshore wind and solar resources.
6. Examine PJM boundary interactions, and assess the extent to which different import/export flow patterns are influenced by resource decisions within and outside of PJM.

Appendix – Supporting Tables

Key ProSym Model Run Inputs and Results – All Cases

Table A.1 Installed Capacity (MW), Annual Generation (GWh), by Resource Type, Total PJM Region

	Base	share	High Wind - PJM	share	High Wind - PJM+MISO	share
PJM Resource Installed Capacity, MW						
Wind	32,056	12.7%	65,433	23.0%	65,433	23.0%
Gas	122,998	48.8%	122,929	43.2%	122,929	43.2%
Coal	17,528	7.0%	16,748	5.9%	16,748	5.9%
Nuclear	34,068	13.5%	34,068	12.0%	34,068	12.0%
Hydro	2,602	1.0%	2,602	0.9%	2,602	0.9%
DR	20,088	8.0%	20,088	7.1%	20,088	7.1%
Other (PS, Solar, Oil, Biomass)	22,458	8.9%	22,458	7.9%	22,458	7.9%
Total	251,798	100.0%	284,326	100.0%	284,326	100.0%
PJM Resource Annual Energy, GWh						
Wind	106,742	11.3%	217,862	22.0%	226,884	23.0%
Gas	403,796	42.6%	343,556	34.8%	333,026	33.8%
Coal	127,226	13.4%	116,679	11.8%	116,351	11.8%
Nuclear	261,219	27.6%	261,211	26.4%	261,211	26.5%
Hydro	8,175	0.9%	8,175	0.8%	8,175	0.8%
DR	2,387	0.3%	2,555	0.3%	2,542	0.3%
Other (PS, Solar, Oil, Biomass)	37,620	4.0%	38,075	3.9%	38,243	3.9%
Total	947,164	100.0%	988,113	100.0%	986,434	100.0%

Table A.2 Annual Capacity Factor of Installed Resources, Total PJM Region

Capacity Factors	Base	High Wind - PJM	High Wind - PJM+MISO
Wind	38.0%	38.0%	39.6%
Gas	37.5%	31.9%	30.9%
Coal	82.9%	79.5%	79.3%
Nuclear	87.5%	87.5%	87.5%
Hydro	35.9%	35.9%	35.9%
DR	1.4%	1.5%	1.4%
Other (PS, Solar, Oil, Bio)	19.1%	19.4%	19.4%

Table A.3 Wind Generation Installed Capacity (MW), Annual Generation (GWh) and Average Annual Capacity Factor, by PJM Transmission Area, Base and Wind Cases

	Total Installed Wind, MW	Annual Energy, GWh	Annual Ave CF
Base Case			
AEP	10,288	32,711	36.3%
APS	2,597	8,129	35.7%
ATSI	1,069	3,277	35.0%
CE	10,838	37,062	39.0%
DEOK	-	-	-
EPA	1,241	3,763	34.6%
MidE	3,034	11,913	44.8%
S	1,564	5,503	40.2%
SW	186	589	36.1%
WPA	1,240	3,796	34.9%
Total	32,056	106,742	38.0%

	Total Installed Wind, MW	Annual Energy, GWh	Annual Ave CF
High Wind - PJM			
AEP	20,999	68,858	37.4%
APS	6,000	19,389	36.9%
ATSI	3,000	9,471	36.0%
CE	24,000	81,719	38.9%
DEOK	-	-	-
EPA	2,000	6,221	35.5%
MidE	3,034	11,913	44.8%
S	3,000	9,737	37.1%
SW	400	1,302	37.2%
WPA	3,001	9,252	35.2%
Total	65,433	217,862	38.0%

	Total Installed Wind, MW	Annual Energy, GWh	Annual Ave CF
High Wind - PJM+MISO			
AEP	19,999	65,552	37.4%
APS	9,000	33,057	41.9%
ATSI	3,000	9,471	36.0%
CE	19,000	67,696	40.7%
DEOK	-	-	-
EPA	2,000	6,221	35.5%
MidE	3,034	11,913	44.8%
S	6,000	22,421	42.7%
SW	400	1,302	37.2%
WPA	3,001	9,252	35.2%
Total	65,433	226,884	39.6%

Table A.4 Coal Retirements

Coal Retirements from 2012 (MW)

Base	57,912
Wind Case - PJM	58,692
Wind Case – PJM + MISO	58,692