# The Impact of Wind Generation on Wholesale Electricity Prices in the Midcontinent Market

## An Empirical Investigation

Dov Quint, Colorado School of Mines
Steve Dahlke, Great Plains Institute

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# 1. ABSTRACT

The Midcontinent Independent System Operator, known as MISO, is the second largest organized competitive wholesale electricity market in the U.S., serving 14 states with over 180 gigawatts of generation capacity, encompassing 6,427 generating units, and 65,800 miles of transmission lines. (FERC, 2017) Wholesale electricity prices in MISO have decreased over the past several years, as both natural gas prices have fallen and as large amounts of wind generation capacity have been added. We identify the impact of increased wind generation on wholesale electricity prices in MISO using an empirical econometric approach studying historical hourly electricity prices, demand, natural gas prices, and other MISO market data over the years 2008-2016. The results show a statistically significant impact of wind generation on real-time hourly MISO system prices, ranging from an estimated decrease of $0.14 to $0.34 per mega-watt hour for each 100 mega-watt hours of additional wind generation, depending on the time period considered. We - observe this effect declining over time: the $0.34/MWh effect is observed during 2008-2011, and the $0.14/MWh effect is observed during 2013-2016. The decreasing marginal impact of wind generation over time may be attributable to the long-term shifts in the supply and demand dynamics experienced in the MISO energy market, as well as to changes made to the MISO market structure to better accommodate variable generation. Finally, implications of our findings with respect to forecasting effects of future increased wind penetration on electricity markets are discussed.

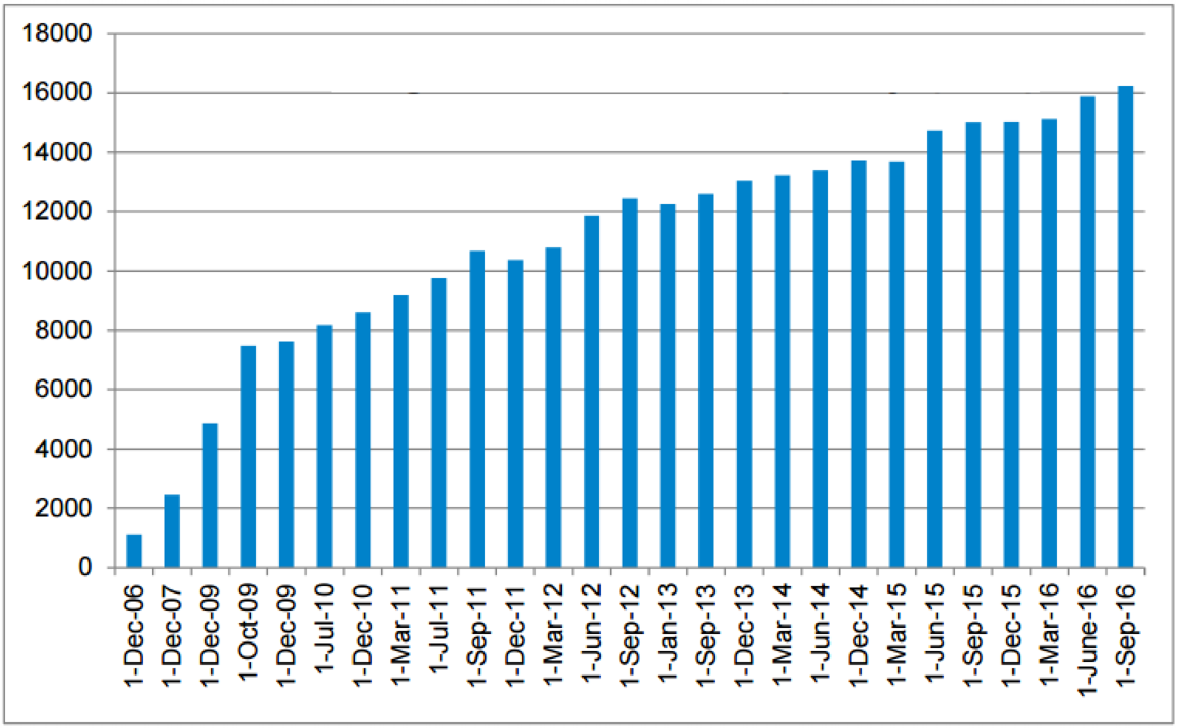
# 2. INTRODUCTION

The main goals of a power system are to provide energy that is reliable and affordable. Over the past several years, there has been a new focus on clean energy as a third goal among system operators, utilities, consumers, and state and federal regulators. Driven mainly by policy and improvements in technology, renewable energy sources have experienced tremendous investment and growth in the past decade in the United States.

Much debate has occurred on the effects of renewable energy such as wind and solar power on both reliability and affordability, given their costs and the variable weather dependent nature of their generation. Improved renewable generation and grid integration technology, combined with improved forecasting methods and changes to wholesale market rules and other subsidies and mandates have fostered tremendous growth in the amount of wind and solar power utilized in the U.S. (NREL, 2016). The integration of large amounts of renewable energy onto the electricity grid however has posed many technological and economic challenges to grid operators, utilities, and market participants.

The combination of state-level renewable portfolio standards, federal production tax credits, cost reductions and improvements in wind turbine technology, more accommodative ISO level market rules for variable generation, and the tremendous endowment of natural wind resources in the Midwest region has led to large growth in wind capacity and generation within the MISO footprint. Wind capacity in MISO has grown from less than 2000 mega-watts in 2006 to over 16,000 mega-watts as of September 2016, as shown in Figure 1. (MISO MTEP Report, 2016). Wind generation as a percentage of total MISO load has gone from approximately 1% to 7% from 2008 to 2016. (MISO Data Library)

**Figure 1: MISO Wind Capacity (MW) 2006- 2016 (Source: MISO MTEP 15 Report)**




## Research Motivation

The main purpose of this research is to provide a detailed empirical study of the impact of wind generation on electricity prices in a large competitive wholesale market. Most previous research in this area has been conducted through forward looking simulations, as opposed to measuring from actual historical data as we have in this study.

Simulation studies model the structural aspects of wholesale electricity markets, and focus on predicting price dynamics by reconstructing the supply and demand curves present within these markets, and then simulating the price effects brought on by changes in levels of renewable generation. Empirical studies focus on looking at actual historical data, and employ statistical models to identify the effect of renewable generation, while controlling for other conditions that affect prices.

Now that the U.S. has significantly higher levels of renewable generation compared with several years ago. This allows empirical studies using historical data to be both possible and appropriate, whereas simulation studies were probably the most appropriate method several years ago for studying the potential impact of high levels of renewable generation on the grid. The MISO region is an ideal place to conduct an empirical investigation to try to quantify the impact of wind generation on wholesale electricity prices, as the system has experienced a large build-out in wind capacity, and will likely continue this trend.

A limited amount of empirical studies in this area have been conducted in European electricity markets, and on other ISO markets in the U.S., include the Texas ERCOT market. To our knowledge, there have been no in-depth empirical studies of the impacts of increased wind generation on wholesale electricity prices in MISO. This study also adds to the research in this area by using additional control variables such as congestion, and by attempting to assess the changing impact of wind generation on prices over several distinct time periods. We believe this study should be particularly relevant given the recent trends in wind capacity, and electricity and natural gas prices since the launch of the MISO market in 2005. Our findings of a statistically significant reduction of wholesale electricity prices in MISO due to wind generation matches with the results of previous studies done on other wholesale electricity markets in the U.S and Europe.

The remainder of this research paper is structured as follows: Section 3 summarizes the previous research on this subject, and provides a more detailed description of the contrast between empirical and simulation methods in the study of energy markets. Section 4 provides a detailed description of the data set and summary of the MISO market. Section 5 describes the methodology and econometric models used to analyze the data. Section 6 provides a detailed analysis of the model results. Section 7 goes into further depth interpreting the model results, providing possible explanations in some of the patterns and trends, and potential applications to forecasting. Section 8 concludes the paper and offers suggestions on future extensions for research in this area.

# 3. LITERATURE REVIEW

Research on the effect of wind generation on wholesale electricity markets generally falls into one of two categories: simulation or empirical studies. In general simulation studies are forward looking, and empirical studies focus on analysis of historical data.

Simulation studies are appropriate for testing large changes or shocks to a system for which there is little historical precedence or relevant data. In the case of studies of power prices, simulation studies model the structural aspects of wholesale electricity markets, and focus on predicting price dynamics by reconstructing the supply and demand curves present within these markets, and then simulating large changes to supply to demand. The cumulative supply curve generally represents the marginal costs of energy generation, and the demand curve represents load. Since wind power produces electricity at a lower marginal cost of generation compared to other sources, the supply curve is pushed out during times of high renewable generation, leading to lower prices. This occurrence is referred to as the merit-order effect, and an illustration of this impact on supply curves on prices in discussed further in Section 7 of this paper.

“The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region” report by Synapse Energy Economics, published in 2012, provides an in-depth study of the potential impacts of increased wind generation in MISO using these simulation-based methods. Their results show significant wholesale market price impacts to increased levels of wind generation, and the magnitude of these impacts are dependent on simulated changes in coal retirements, peak demand, gas capacity build-out, and the completion of certain transmission expansion projects. Comparison between the results of an historical empirical investigation and simulation results such as ones presented by Synapse are difficult, as the specific levels of the variables selected in the simulation would need to be calibrated closely to the actual observed occurrences.

Empirical studies focus on investigating relationships in historical data, and building models to identify these relationships and measure causal inference. One challenge in studying markets in which prices are determined by supply and demand is the simultaneity issue, in which sloped supply and demand curves cannot effectively be described in a linear model. However, since the short term hourly demand is generally inelastic in wholesale electricity markets, (i.e. a vertical demand curve) the simultaneity issue should not impact a multivariate regression representation of the relationship between prices and the variables shifting the supply and demand curves.

Another study, “Renewable Generation and Electricity Prices: Taking Stock and New Evidence for Germany and Austria”, by Klaas Würzburg, Xavier Labandeira, Pedro Linares, provides a comprehensive literature review through the year 2013 of empirical studies of the impact of wind generation on wholesale electricity prices. Most studies on the subject have been conducted on European electricity markets, specifically Spain and Germany, which are two large markets that have had significant renewable capacity additions over the last twenty years. Since many European countries began their development of renewable generation earlier than the U.S., more empirical studies have been done in that region. The authors of this paper also conduct their own empirical analysis of the German and Austrian market by building a multivariate regression model to test the impact of renewable generation on wholesale prices in that market, and find that an increase of 1 GW of wind generation reduces the day-ahead electricity price by an average of about 1 Euro / MWh using data from 2010 -2012. These results are in a similar range to our findings for the MISO market.

“The Impact of Wind Generation on the Electricity Spot-Market Price Level and Variance: the Texas experience” by Woo, Horowitz, Moore and Pacheco (2012) provides an analysis of the 15-minute spot electricity price in four zones in the Texas ERCOT market from 2007 to 2010, showing significant impacts of wind generation on prices, ranging from decrease of $0.32 / MWh to $1.53 / MWh for a 100 MWh increase in wind generation, depending on the geographical zone. This Texas study is particularly relevant for our analysis of the MISO market during the time-frame in the study in this paper, as the ERCOT market experienced large capacity additions in wind generation and has a comparable wind resource potential. The structure, generation stack, and price formation economics of the MISO market is also more easily comparable to the ERCOT market than it is to European markets where most of the previous research in this area has been conducted.

Another study on U.S. markets is “The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest” by Woo, Zarnikau, Kadish, Horowitz, and Wang (2013). This study is specific to the northwest U.S which is not under an organized wholesale ISO market and has unique generation supply dynamics driven by the large seasonal swings in the massive federally managed hydro-electric resources in the region. That paper estimates the short-run daytime price reduction from a 100 MWh increase in wind generation to be approximately $.096 / MWh.

Both the ERCOT and North-West studies previously mentioned use multi-variate regressions and different specifications for lagged prices and error terms, a general methodology which we will also apply in our study of MISO prices in this paper. Our MISO study adds other control variables such as system binding constraints, which measure overall congestion on the system. We also test for quadratic relationships in the system by testing a model using polynomial specifications for the independent variables.

“Wind Power and Electricity Prices in the PJM Market” by Gil and Lin uses a robust weighted least squares regression non-parametric method to estimate the total impact of wind generation on the

PJM market, finding a negative impact of wind on prices, but does not focus on marginal effects or control for exogenous variables such as fuel costs. These are important components that should be taken into account in studies like ours.

# 4. DATA AND SUMMARY STATISTICS

Three reports sourced directly from the MISO data library comprise the core of the data set for this study. (https://www.misoenergy.org/Library/Pages/Library.aspx) The Real-Time Pricing Report provides hourly level summaries of pricing results for the Real-Time market for all pricing hubs in MISO as well as the MISO System Price. The Real-Time Expanded report includes data on Real-Time Load, Outages, and Binding Constraints for the entire MISO system, all at the hourly level. The Real-Time Pricing and Real-Time expanded report were published as daily files, which were aggregated into a single database containing 78,888 hourly observations over the years 2008 - 2016. The real-time market was chosen for analysis in this research, as opposed to the day-ahead market, as we are interested in testing the impact of actual real time wind generation, as opposed to the forecast, on the real-time economic dispatch of MISO resources and thus real-time wholesale hourly prices.

It is important to consider the structural changes which occurred in the MISO market during the 9 years of our data set. To make level comparisons of the load, outage, and constraint variables, the data was separated into three distinct slices, which we will refer to as periods one, two and three. Period one starts from the beginning of the data set, January 1st, 2008, and goes through the end of May, 2011, which is the point at which First Energy exited the MISO system. Period two extends from the start of June 2011, through December 18th, 2013, which represents the period before the MISO South zone was added onto the system. Period 3 begins on December 19th, 2013, and extends through the end of the data set at December 30th, 2016. Table 1 below shows a compete summary of the main variables of interest in the data set for the three different time periods. The changes in Real-Time load reflect the structural changes in the MISO market participants across the three periods.

The following subsections describe in further detail our dependent variable of interest in this study, the MISO System Price, as well as the independent control variables. Wind generation, load, outages, binding constraints, and gas prices, are the primary independent variables in our model that determine price formation in the MISO market. By controlling for them in the multivariate regression models we can isolate and measure the impact of wind generation on prices.

**Table 1: Summary Statistics**

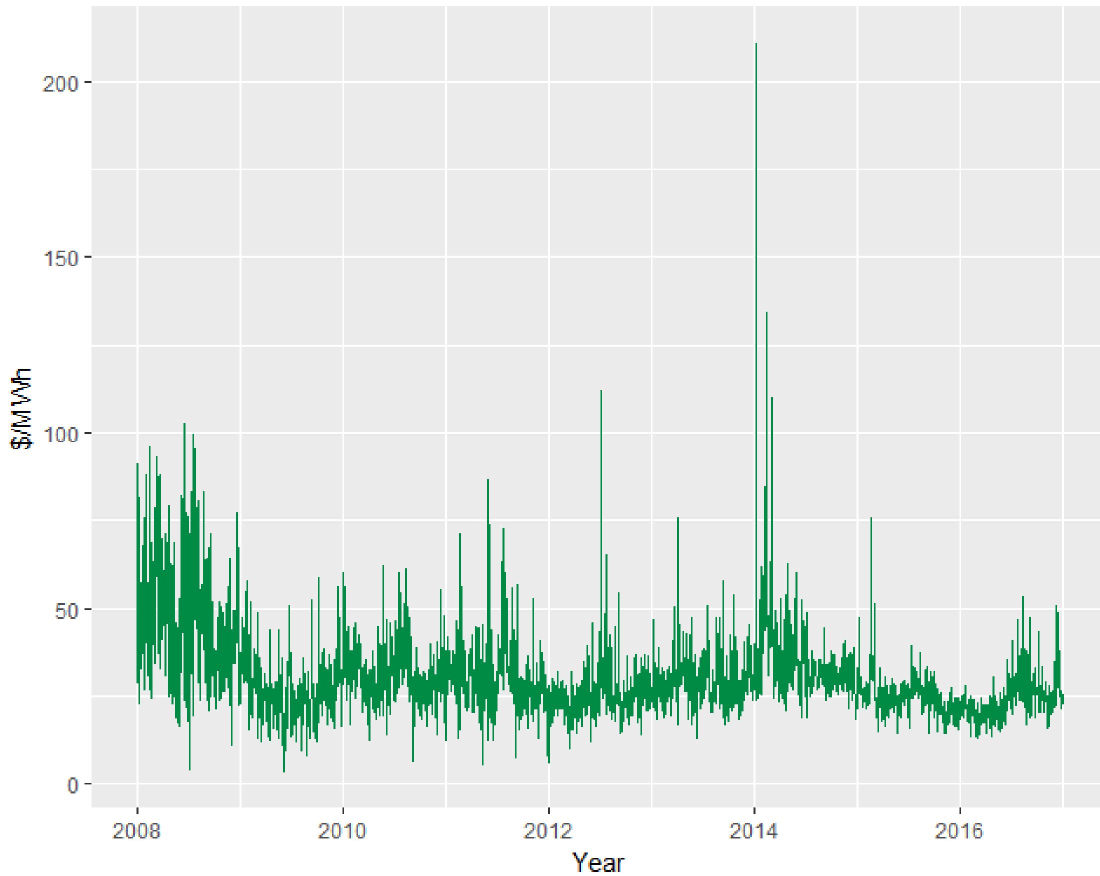
| | Mean | Median | Std Dev | Minimum | Maximum |
|---|---|---|---|---|---|
| **Period 1 (Jan 2008 - May 2011)** | | | | | |
| MISO System Price ($/ MWh) | 34.75 | 27.00 | 26.90 | -240.02 | 674.62 |
| Wind Generation (MWh) | 1845.80 | 1481.01 | 1404.30 | 0.00 | 6893.47 |
| Henry Hub Gas Price ($/mmbtu) | 5.53 | 4.42 | 2.50 | 1.83 | 13.31 |
| Real-Time Load (GW) | 65.30 | 65.07 | 10.59 | 39.53 | 108.81 |
| Real-Time Outages (GW) | 16.40 | 16.24 | 6.75 | 3.41 | 37.26 |
| Binding Constraints (Number) | 2.40 | 2.00 | 1.91 | 0.00 | 22.00 |
| **Period 2 (June 2011 - Dec 2013[d])** | | | | | |
| MISO System Price ($/ MWh) | 28.16 | 24.31 | 21.21 | -112.84 | 1042.63 |
| Wind Generation (MWh) | 3581.19 | 3249.34 | 2191.27 | 6.75 | 9885.20 |
| Henry Hub Gas Price ($/mmbtu) | 3.36 | 3.44 | 0.66 | 1.82 | 4.92 |
| Real-Time Load (GW) | 59.30 | 58.27 | 10.20 | 38.35 | 103.73 |
| Real-Time Outages (GW) | 15.42 | 14.48 | 5.58 | 5.24 | 30.21 |
| Binding Constraints (Number) | 4.51 | 4.00 | 3.23 | 0.00 | 22.00 |
| **Period 3 (Dec 2013[d] - Dec 2016)** | | | | | |
| MISO System Price ($/ MWh) | 28.38 | 24.76 | 21.10 | -26.42 | 1750.83 |
| Wind Generation (MWh) | 4838.84 | 4469.86 | 2815.50 | 0.00 | 13599.28 |
| Henry Hub Gas Price ($/mmbtu) | 3.18 | 2.88 | 1.02 | 1.49 | 8.15 |
| Real-Time Load (GW) | 77.44 | 76.00 | 12.18 | 51.17 | 120.76 |
| Real-Time Outages (GW) | 25.07 | 23.97 | 9.22 | 8.04 | 46.16 |
| Binding Constraints (Number) | 6.42 | 6.00 | 4.15 | 0.00 | 30.00 |

*d: Periods 2 and 3 separation marked when MISO South Zone was added on December 19th, 2013*

## MISO System Prices

The MISO market is characterized by a locational marginal pricing system that represents the cost of dispatching additional resources to meet the marginal load demanded at each location. The MISO system price represents an aggregation of all locational marginal prices on the system, and thus is the best single measurement of the economic condition of the MISO energy market. System wide prices do experience large spikes, which can be due to increases in demand, fuel prices, system congestion, outages, or other factors which impact the real-time dispatch of resources on the MISO system. Figure 2 shows the daily average of the hourly MISO system price. Even though the analysis in this paper is performed on the observations of the individual hourly real-time prices, the daily average gives a better overview of the long-term trends and ranges in prices, which are not easily seen when looking at long term charts of hourly prices. The large price spikes in January 2014 as seen on the graph occurred during the period known as the "polar vortex" when extremely cold temperatures combined with higher than normal winter load conditions, higher natural gas prices, and high levels of congestion causing large spikes in real-time prices.

**Figure 2: MISO System Daily Average Real-Time Prices, 2008 - 2016 (Source: MISO Data Library)**




### Wind Generation

MISO provides historical hourly wind generation data aggregated across the entire system. Wind generation is measured in megawatt hours. The wind generation figure is not a capacity measurement; it is the actual energy generated from wind resources within MISO on a real-time basis. Figure 3 below shows the wind generation in MISO from 2008 - 2016, measured as a daily average of the hourly real-time generation. Figure 4 shows the monthly average of the real-time hourly wind generation in MISO from 2014 - 2016, and highlights the seasonal pattern of wind generation, which tends to be highest in November, December, and April, and lowest during the mid-summer months of July and August.

**Figure 3: Hourly real-time wind generation - Daily Average, MISO system, 2008 - 2016 (Source: MISO Data Library)**

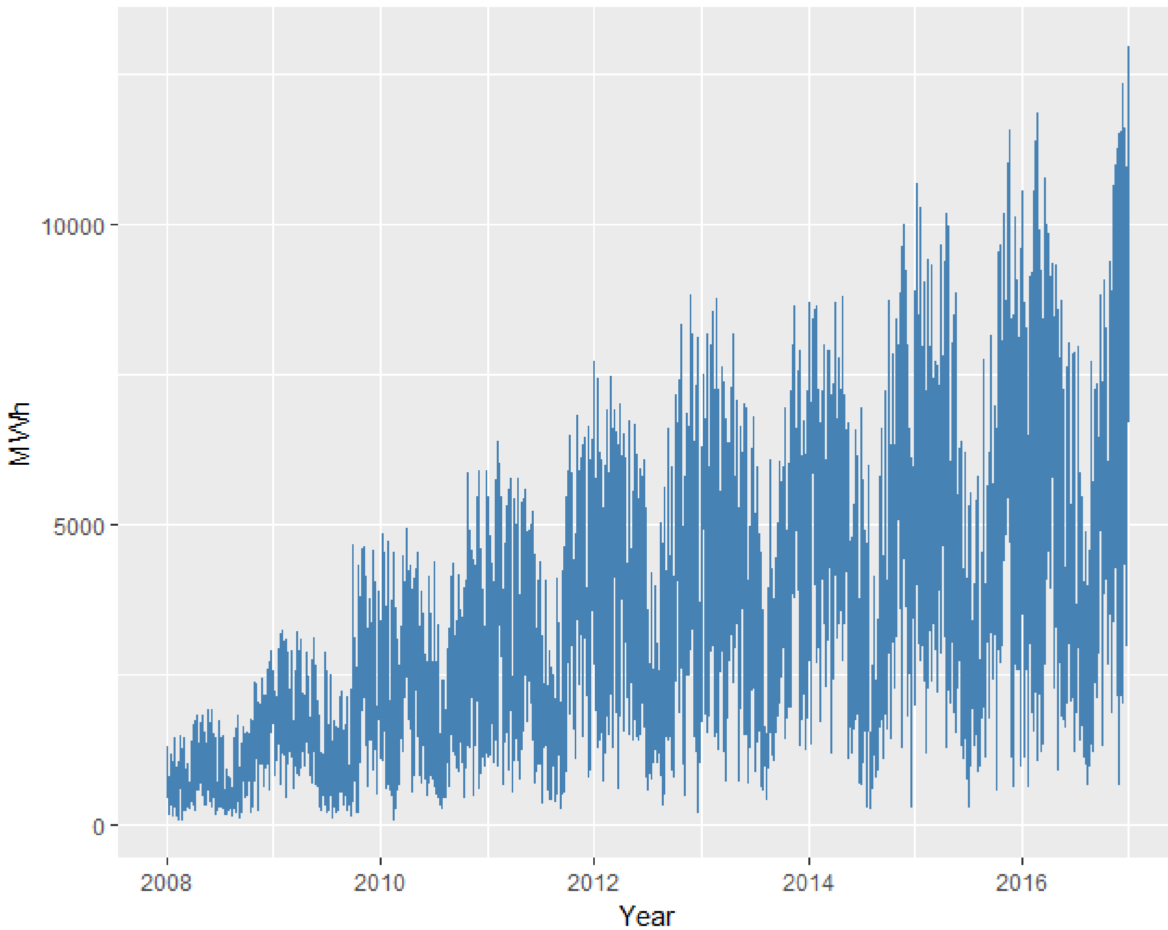
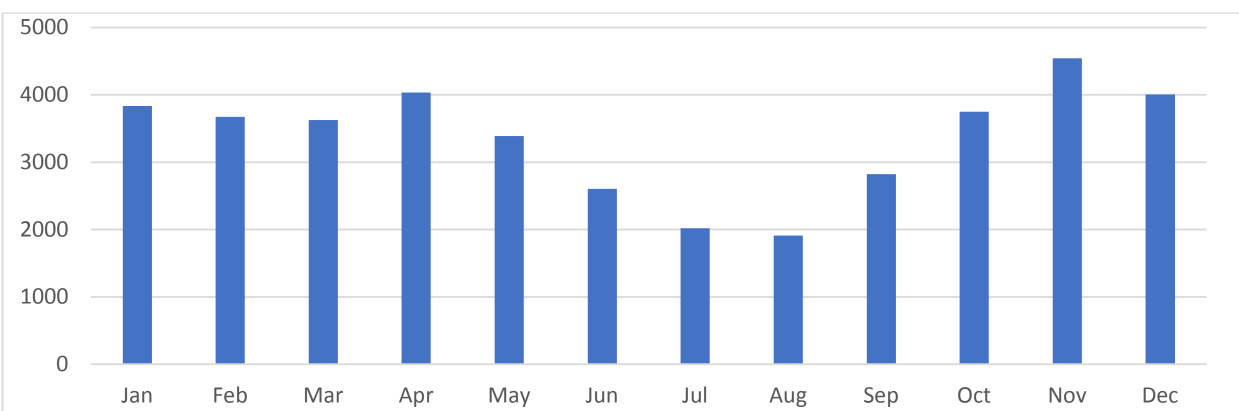


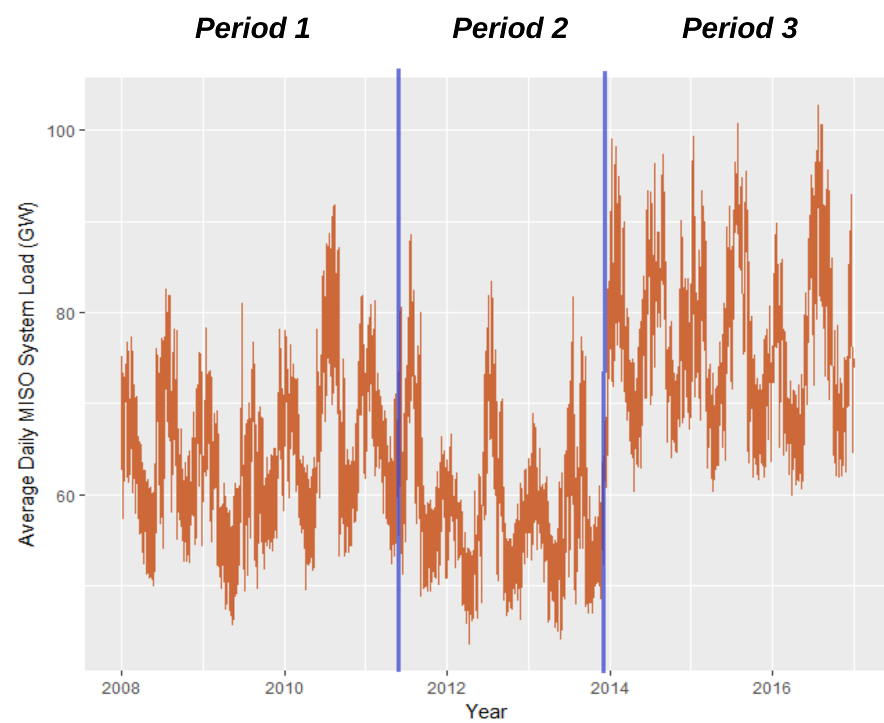

**Figure 4: Average hourly wind generation by month (MWh), MISO system, 2014 - 2016 (Source: MISO Data Library)**



### Load

Figure 5 shows the hourly real time load data by daily average over the entire data set. The breaks between the periods are highlighted with the vertical blue lines. The largest structural change in terms of system wide load occurs between periods two and three in December 2013, when the MISO South zone was added to the system, which incorporates utility footprints in Louisiana, Arkansas, Texas, and Mississippi.

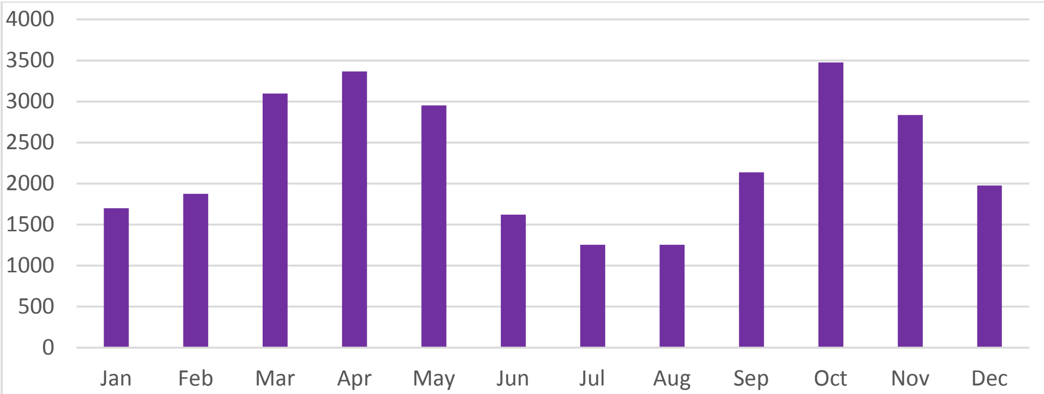
**Figure 5: MISO system hourly real-time load - Daily Average, 2008 - 2016 (Source: MISO Data Library)**




### Outages

The Real-Time Outages figure measures the planned and unplanned outages at each hour in the Real-Time market, and includes all nuclear outages, as well as all other plant outages. Scheduled seasonal nuclear outages for maintenance and refueling, which are typically during the spring and fall, represent the largest value of outages on the system. Figure 6 shows real-time hourly outages, measured in MW, averaged over each month of the year.

**Figure 6: MISO System Wide Hourly Real-Time Outages by Month (MW) -Daily Average, 2014 -2016 (Source: MISO Data Library)**



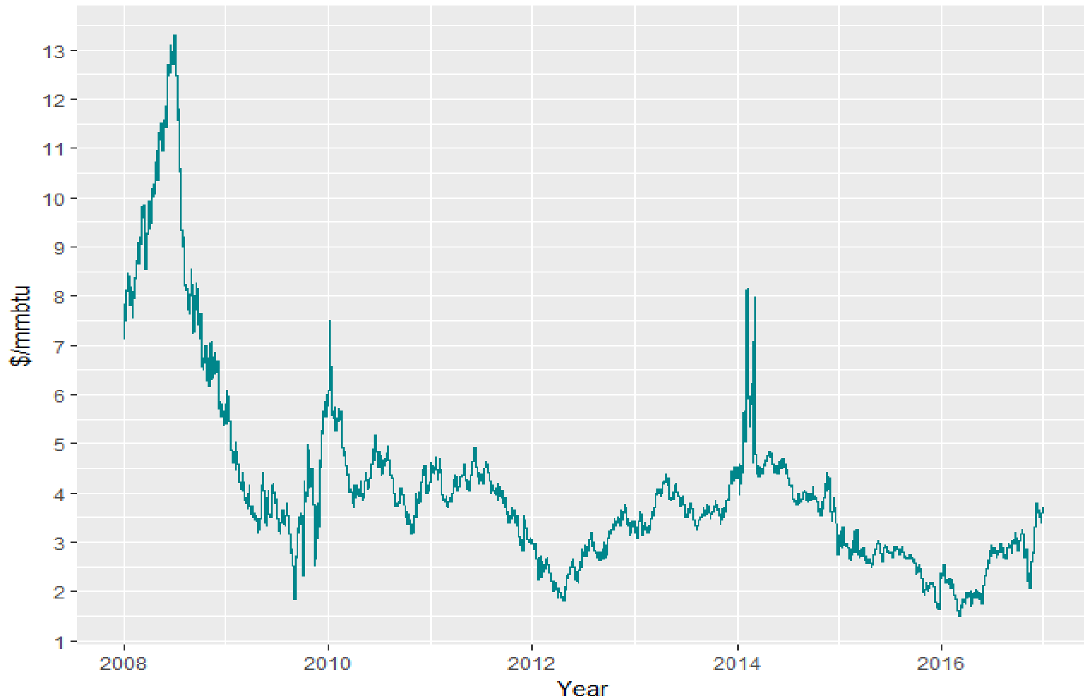

## Binding Constraints

Real-Time binding constraints measure the integer count of binding constraints in the Real-Time MISO market for each hour. A constraint on the transmission system becomes binding once a generation unit is dispatched out of merit order and sets the locational marginal price (MISO Data Library). The way in which transmission congestion impacts specific locational marginal prices is a result of the unit commitment and security constrain economic dispatch solution. The total level of binding constraints on the MISO system in every hour should give a general indication of the level of transmission congestion on the system, with higher levels of congestion leading to higher locational marginal prices within constrained nodes in the system, and this leading to a higher overall average MISO wide system price.

## Natural Gas Prices

Henry Hub spot natural gas prices are used in the data set as a measurement of gas fuel costs, which explain a significant portion of the variation in the system wide electricity price. Prices for natural gas for individual generators will vary by specific location and company contract considerations. Figure 7 shows daily Henry Hub natural gas prices from 2008 - 2016, which were sourced from the EIA.

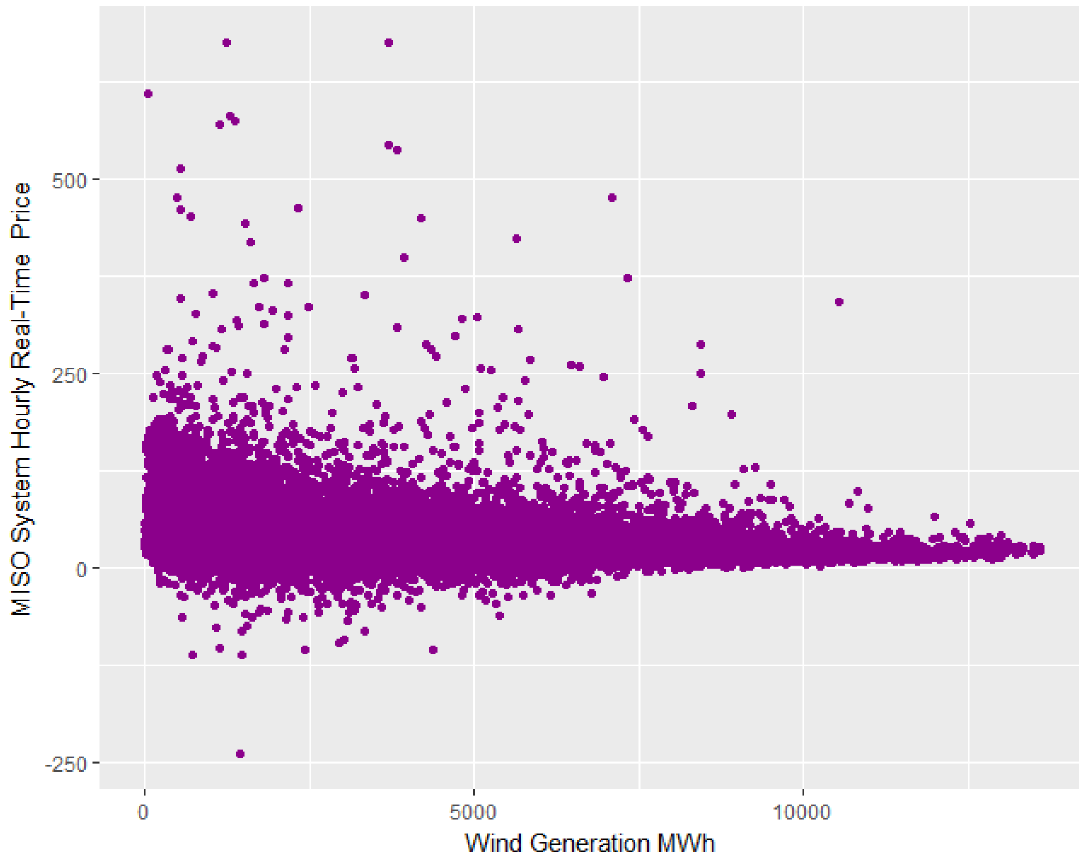
**Figure 7: Henry Hub Spot Natural Gas Prices ($/mmbtu) 2008 - 2016 (Source: EIA)**




## MISO System Prices and Wind Generation

Figure 8 is a scatterplot of observations of hourly wind generation in the MISO system in MWh, and hourly MISO system real-time prices (filtering out three price observations above $750). The chart visually shows a mild negative correlation between increased wind generation and prices, but does not account for any other factors such as demand or fuel prices. The goal of the econometric modeling methodology detailed in the next section will be to mathematically identify the impact of wind generation on the hourly real-time price, while controlling for the previously mentioned variables and seasonal patterns.

**Figure 8: Scatterplot of MISO system hourly real-time prices and hourly wind generation 2008-2016 (Source: MISO Data Library)**




# 5. METHODOLOGY AND ECONOMETRIC MODELS

The empirical approach in this paper follows the work of the previous research discussed in the literature review (Woo et al, Würzburg et al) with some modifications and inclusion of additional control variables. The four individual models described below use a multi-variate regression approach estimated using ordinary least squares. This approach produces individual estimates for the impact of the independent variables, such as wind generation and fuel prices, on the MISO system hourly real-time price.

A comprehensive review of electricity price modeling methods by Weron (2014) explores the many approaches to electricity price modeling, including computational intelligence methods, agent based simulation models, and a multitude of statistical models. The main challenge of statistical modeling of electricity prices is the existence of spikes, which the linear regression models tend to do a poor job of predicting. The main goal of this research is the identification of casual inference between variables in our data set, and not the forecasting of future prices, and the focus thus is building econometric models which incorporate the main determinants of supply and demand, and will allow us to reliably estimate the impact of wind generation on the hourly system wide wholesale price in MISO.

Some important noted limitations of this study are that we do not measure the impact of wind generation on specific nodal, hub or regional prices; the only dependent variable is the MISO System Hourly Real-Time Price. Additionally, we do not account for regional differences in wind generation, as the only wind generation variable is the total hourly generation on the whole MISO system. This study also does not explicitly account for changes in rules or bidding behavior of wind generators, and does not explicitly account for the impact of transmission build-out in the MISO system.

## Working with Time Series Data

Working with our time-series data presents certain challenges that often require transformation of the data or qualifications of conclusions, as correlations of variables over time may invalidate some of the assumptions inherent in multivariate regression models. (Kennedy, 2008). One common issue is when a variable is non-stationary, meaning that it's mean and variance change over time, such as when a variable has a strong up or down trend through the entire time period of a data set. For our data set, the Augmented Dickey-Fuller test for non-stationarity was run on all of the variables, and all were found to be stationary, negating the need to conduct first-difference transformation.

## Econometric Models

Four distinct econometric models are applied to the data set in order to test and measure the impact of wind generation on electricity prices. Model 1 is a basic cross sectional multivariate regression, which does not include any lagged price variables or error terms. Model 2 uses the Prais-Winsten estimation methods, which adds a lagged error term. Model 3 uses a variant of the ARIMA family of models, known as a SARMAX model. Models 2 and 3 are used to capture the auto-regressive and auto-correlated characteristics of electricity prices. Model 4 goes back to the same cross-sectional multivariate method as used in Model 1, but substitutes squared terms for the exogenous variables, which tries to capture the potentially non-linear structure of supply and demand in electricity price formation. The four models are described in further detail below.

### Model 1: Cross-Sectional Multivariate Regression

$$\mathbf{MISOprice_t = \alpha + \beta_1\, Wind_t + \beta_2\, GasPrice_t + \beta_3\, Load_t + \beta_4\, Outages_t + \beta_5\, BindingConstraints_t}$$

$$\mathbf{+ \sum_H \beta_H Hourly_{Ht} + \sum_D \beta_D\, Daily_{Dt} + \sum_M \beta_M\, Monthly_{Mt} + \varepsilon_t}$$

The MISOprice is the MISO system wide price at hour t, Wind is the total megawatt hours of wind generation during hour t, GasPrice is the Henry Hub daily price as reported by the EIA projected over the entire 24-hour period for that day, Outages are the real-time outages as reported by MISO in hour t, and Binding Constraints represents the total absolute integer number of binding constraints on the MISO system at hour t. The next three terms are the time dummies which measure 1 or 0, for every hour of the day, every day of the week, and every moth of the year. (One hour, day, and month each excluded due to singularity issue in regression modeling)

Although changes in load, which are exogenously driven by weather should pick up most of the impact of shifts in demand, the individual time dummies should absorb any unobservable seasonal time effects on price that are not absorbed by the load variable. These unobservable seasonal variations on the hourly, daily, and monthly level may include market participant and generator behavior.

In the cross-sectional multivariate regression model, the real-time electricity price is assumed to be determined independently in each time period through the interaction of supply and demand. Demand is the load in each period, which follows daily, weekly, and monthly patterns based on customer behavior. Shifts around these multiple seasonal patterns are driven exogenously in the short term by changes in weather. The shape of the supply curve is generally assumed to be determined by generators bidding at their marginal costs. Marginal costs for wind generators are at or close to zero, and are sometimes negative due to the production tax credit subsidy. For gas generators, marginal costs are determined by individual unit heat rates and by fuel prices. Since gas generators are on the margin for the majority of hours in the real-time MISO market (76% in 2015, MISO), the reliable estimation of the supply curve can be made by including gas prices, which shift the curve upward and downward, and outages and wind generation, which will shift the curve inward and outward depending on their levels in a given hour. A visual representation of the supply and demand curves in the MISO market are described further later in this report, represented as the top panel of Figure 10. The binding constraints variable should be able to pick up some of the impacts of congestion, which will impact specific locational marginal prices and thus the system wide price, but which are not easily modeled in the context of the structure of the supply curve.

**Model 2: Prais-Winsten Model**

$$\mathbf{MISOprice_t = \alpha + \beta_1\, Wind_t + \beta_2\, GasPrice_t + \beta_3\, Load_t + \beta_4\, Outages_t + \beta_5\, BindingConstraints_t}$$

$$\mathbf{+ \sum_H \beta_H Hourly_{Ht} + \sum_D \beta_D\, Daily_{Dt} + \sum_M \beta_M\, Monthly_{Mt} + \varepsilon_t + \rho\varepsilon_{t-1}}$$

Models 2 and 3 relax the assumption of intertemporal independence of prices, and add variables to account for autocorrelated and autoregressive behavior. Model 2 is a Prais-Winsten estimation, which accounts for possible serial correlation in the error term. This model has the same structure as the multivariate linear regression in Model 1, also using ordinary least squares estimation. The Prais-Winsten model accounts for serial correlation in the error term by adding as a variable the error term from the previous period (hour), denoted as $\boldsymbol{\varepsilon_{t-1}}$, and estimates a coefficient for this term, denoted as $\boldsymbol{\rho}$ (Bailey, 2017) Serial correlation in the error term can produce a bias in the standard errors if not accounted for, but will generally not produce a bias in the coefficient estimates.

**Model 3: SARMAX Model**

$$\mathbf{MISOprice_t = \alpha + \beta_1\, Wind_t + \beta_2\, GasPrice_t + \beta_3\, Load_t + \beta_4\, Outages_t + \beta_5\, BindingConstraints_t}$$

$$\mathbf{+ \sum_H \beta_H Hourly_{Ht} + \sum_D \beta_D\, Daily_{Dt} + \sum_M \beta_M\, Monthly_{Mt} + \varepsilon_t + \phi MISOprice_{t-1} + \mu\varepsilon_{t-1}}$$

ARIMA models, which stands for Auto-Regressive Integrated Moving Average, are widely applied Time-Series models, particularly in market and price data. (Kennedy, 2008) ARIMA models are normally univariate, and our modifications turn it into what is generally known as SARMAX model, which stands for Seasonal Auto-Regressive Moving Average with Exogenous Variables. The Seasonal component is accounted for by the inclusion of the seasonal dummy variables in the model. The Auto-regressive component is accounted for by the inclusion of the one-period lagged price in the model. The Moving Average component is accounted for by inclusion of the one-period lagged error term in the model. The Exogenous component accounts for the external variables in the model (Gas Prices, Load, Outages, Binding Constraints. The letter I, which stands for Integrated, is excluded from this model, as this implies that the data has been first differenced, which it has not been in our model. The SARMAX (1,0,1) notation of our model implies the use of one lagged price variable, zero differencing in the data, and one lagged error term.

**Model 4: Cross - Sectional Multivariate Regression with Quadratic Terms**

$$\mathbf{MISOprice_t = \alpha + \beta_1\, Wind_t + \beta_2\, GasPrice^2{}_t + \beta_3 Load^2{}_t + \beta_4\, Outages_t + B_5 BindingConstraints^2{}_t + \sum_H \beta_H Hourly_{Ht} + \sum_D \beta_D\, Daily_{Dt} + \sum_M \beta_M Monthly_{Mt} + \varepsilon_t}$$

The fourth and final model uses the same variables as the cross-sectional multivariate regression in Model 1, except that it uses squared terms for the gas price, load, and binding constraints. The squared terms on the gas price and load should help better specify the convex and quadratic shape of the generation supply curve. The squared term on the binding constraint variable may also help better measure the non-linear relationship between grid congestion and locational marginal prices on the MISO system.

The main hypothesis in this research is that the estimated $\boldsymbol{\beta_1}$ coefficients on wind generation will be negative and statistically significant. The magnitude of the estimates and any differences across the models or patterns over time are not assumed, and the actual results are analyzed and interpreted in the next section. We also expect positive and statistically significant estimates for coefficient, $\boldsymbol{\beta_2}$, natural gas prices, $\boldsymbol{\beta_3}$, load, $\boldsymbol{\beta_4}$, outages, and $\boldsymbol{\beta_5}$, binding constraints, based on the structural market specification described by the four models.

Due to the addition of variables accounting for the auto-regressive and auto-correlation in models 2 and 3, any conclusions on the estimated impacts of wind generation on prices is conditional on the lagged error or price terms.

# 6. RESULTS

Table 2 below shows the results of four different models run over three different time periods, for a total of twelve different summaries. The coefficients on Hourly Wind Generation show the impact on the MISO system wide price of a 1 MWh increase in hourly wind generation. Multiplying these numbers by 100, or 1000, yields the estimated single period price impact of a 100 MWh or 1 GWh hourly increase in wind generation, respectively. For example, in the first column in Table 2 for Model 1, the impact of a 100 MWh increase in wind generation would be 100 * -.0031, or - $0.31. A one thousand MWh increase (one GWh), would lead to an estimated price reduction of $3.10 in the same period.

Figure 9 provides a graphical representation of the coefficient estimates for wind generation for the four different models across the three time period segments. The first noticeable pattern is that the coefficients on wind generation are extremely close within each time period across the different models. This shows that adding the auto-correlated lagged error term, auto-regressive lagged price term, or changing variables to squared terms does not have a large impact on the measurement of the single period coefficient on wind generation.

The second noticeable pattern is the decreasing marginal effect of wind generation over time. The major structural changes in the MISO market have been accounted for by slicing the time periods appropriately. The major trends in the MISO market over this time frame are the decreases in natural gas prices, and the large build-out in wind capacity and increases in wind generation. An explanation of this decreasing marginal impact of wind generation on MISO prices is explained in further detail in the next section.

The positive coefficients on both the level and squared terms for the Henry Hub natural gas price confirm the hypothesis that increases in natural gas prices lead to a higher MISO system price. The positive and statistically significant coefficients on the level and squared terms for the real-time load and outage levels confirm the supply and demand model structure being measured in the models. The positive and statistically significant coefficients on the level and squared terms for the binding constraints also confirm the hypothesis of the impact of increased levels of system wide congestion on the MISO system price.

Turning to Models 2 and 3, which contain inter-temporal variables, the rho coefficient ($\rho$) in the Prais-Winsten model estimates the impact of the lagged error term from the model on current hourly prices. This positive and statistically significant coefficient shows that when the MISO system wide price is higher than the expected value as predicted by the model in a given hour, the price in the next period is also expected to be higher than would be predicted solely by the exogenous variables in that period. This result is known as positive first-order autocorrelation, and describes the lingering impact of higher than expected prices, due to a spike or a shock to the system. Model 3, the SARMAX model, uses both a lagged price variable and the lagged error term. The positive and statistically significant coefficients on the lagged price variable show positive auto-regressive behavior in prices, something that is common in energy markets, especially when looking on an intra-day scale. The coefficient on the lagged error terms however is now negative in contrast to the results in the Prais-Winsten model. This result is in line with the findings by Woo et al, in their research on the Texas ERCOT market, and shows that when controlling for the lagged prices and the lagged error term, the estimates on the lagged error term show negative first order auto-correlation, meaning that a shock in the system leading to a spike in prices has a dampening effect on current prices.

One aspect of Including the lagged price in Model 3, is the ability to ascertain the multi-period impact of an increase in wind generation on prices. In this SARMAX model, the multi-period effect of an increase in wind generation in a can be calculated as **$[\beta_1 / (1 - \phi)]$**, which would reflect the impact on prices in the current period as well as the impact on prices in the next period, which occur through the current period. The comparisons between models and time periods, and the interpretation and analysis of results in the following sections will focus only on the single period impact of wind generation on prices.

Other variables within the data set that were tested in the models but did not show statistical significance or have an impact on the wind generation estimate included coal prices, power imports, committed generation, and the differences between the day ahead and real-time figures for load and outages. These variables were not included in the models. Several interaction terms were also tested, included combinations of interactions between wind, load, and gas prices, and were not shown to be statistically significant or have any impact on the single wind generation estimated coefficient. For the sake of conciseness, the coefficient estimates for the time dummies are not included in this table 2. The models were also tested with the exclusion of outliers of large price spikes, but this did not have a significant impact on the results, and therefore all of the data points were included in the models.

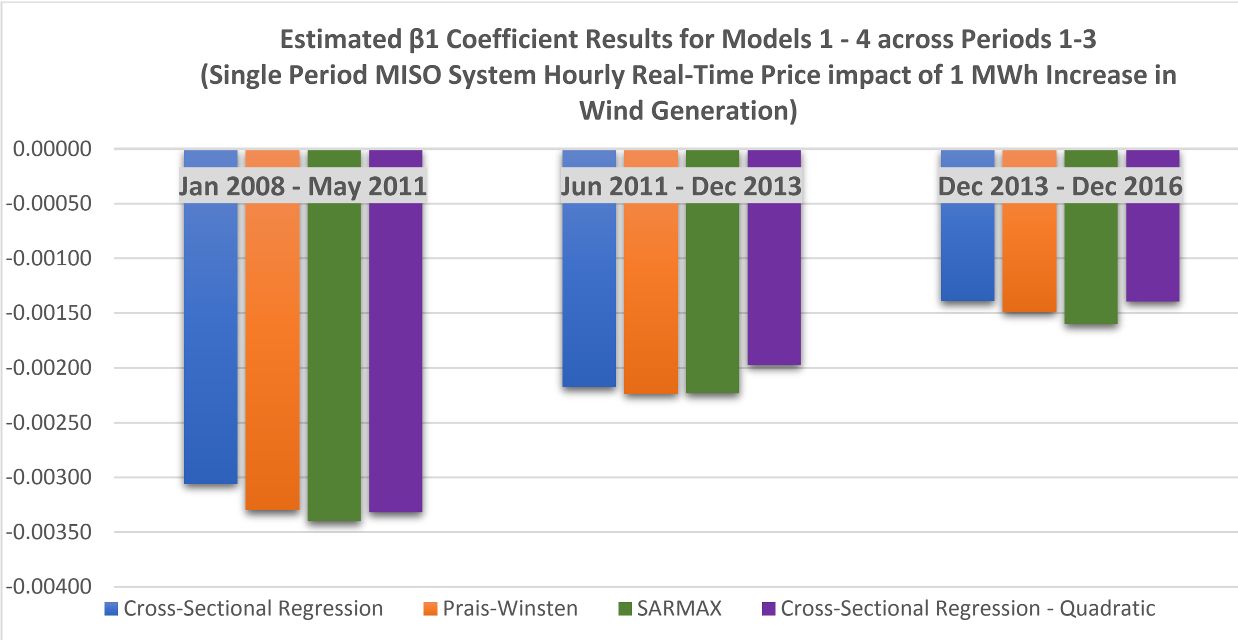
### Table 2: Model Results

| Dependent Variable = Hourly MISO System Real-Time Price | | | | | | |
|---|---|---|---|---|---|---|
| | | | TIME PERIODS | | | |
| MODELS | Jan 2008 – May 2011 | | Jun 2011 – Dec 2013[d] | | Dec 2013[d] – Dec 2016 | |
| **Model 1: CS Regression** | | | | | | |
| **Hourly Wind Generation (MWh) β1** | **-0.0031** | *** | **-0.0022** | *** | **-0.0014** | *** |
| Henry Hub Natural Gas Price β2 | 2.9830 | *** | 2.9381 | *** | 5.3569 | *** |
| Real - Time Load (GWh) β3 | 1.5335 | *** | 1.0319 | *** | 0.7759 | *** |
| Real - Time Outages (GWh) β4 | 0.0312 | | 0.4657 | *** | 0.3885 | *** |
| Binding Constraints β5 | 0.1384 | ** | 0.7094 | *** | 0.5213 | *** |
| $R^2$ | 0.4320 | | 0.2565 | | 0.2993 | |
| **Model 2: Prais-Winsten** | | | | | | |
| **Hourly Wind Generation (MWh) β1** | **-0.0033** | *** | **-0.0022** | *** | **-0.0015** | *** |
| Henry Hub Natural Gas Price β2 | 2.9753 | *** | 2.9008 | *** | 5.2243 | *** |
| Real - Time Load (GWh) β3 | 1.6097 | *** | 1.0494 | *** | 0.7867 | *** |
| Real - Time Outages (GWh) β4 | 0.0407 | | 0.4645 | *** | 0.3898 | *** |
| Binding Constraints β5 | 0.4599 | *** | 0.7431 | *** | 0.6228 | *** |
| $\varepsilon_{t-1}$ ρ | 0.4159 | *** | 0.2703 | *** | 0.3094 | *** |
| $R^2$ | 0.6097 | | 0.6110 | | 0.6158 | |
| **Model 3: SARMAX (1,0,1)** | | | | | | |
| **Hourly Wind Generation (MWh) β1** | **-0.0034** | *** | **-0.0022** | *** | **-0.0016** | *** |
| Henry Hub Natural Gas Price β2 | 2.9091 | *** | 2.9008 | *** | 5.1056 | *** |
| Real - Time Load (GWh) β3 | 1.9096 | *** | 1.0494 | *** | 0.8073 | *** |
| Real - Time Outages (GWh) β4 | -0.0125 | | 0.4645 | *** | 0.3923 | *** |
| Binding Constraints β5 | 0.5511 | *** | 0.7431 | *** | 0.6993 | *** |
| $MISOprice_{t-1}$ ф | 0.8037 | *** | 0.5595 | *** | 0.6719 | *** |
| $\varepsilon_{t-1}$ μ | -0.4926 | *** | -0.3197 | *** | -0.4135 | *** |
| **Model 4: CS Regression - Quadratic** | | | | | | |
| **Hourly Wind Generation (MWh) β1** | **-0.0033** | *** | **-0.0020** | *** | **-0.0014** | *** |
| Henry Hub Natural Gas Price$^2$ β2 | 0.2057 | *** | 0.4335 | *** | 0.7602 | *** |
| Real - Time Load $^2$ (GWh) β3 | 0.0106 | *** | 0.0078 | *** | 0.0045 | *** |
| Real - Time Outages (GWh) β4 | 0.0595 | * | 0.4527 | *** | 0.3806 | *** |
| Binding Constraints$^2$ β5 | 0.0701 | *** | 0.0408 | *** | 0.0323 | *** |
| $R^2$ | 0.4287 | | 0.2585 | | 0.3090 | |

***** = Significant at 99% confidence level, ** = Significant at 95% confidence level, * = Significant at 90% confidence level*

*d: Periods 2 and 3 separation marked when MISO South Zone added December 19th, 2013*

**Figure 9: Comparison of Model Results Across Time Periods**




# 7. INTERPRETATION AND APPLICATIONS

This section provides a more detailed explanation of the model outputs and interpretation of some of the patterns in the results. It also includes a discussion of potential applications of this study to electricity market forecasting and assessing future impacts of renewable generation.

## Supply Curve Shape and Merit-Order Effect Interpretation

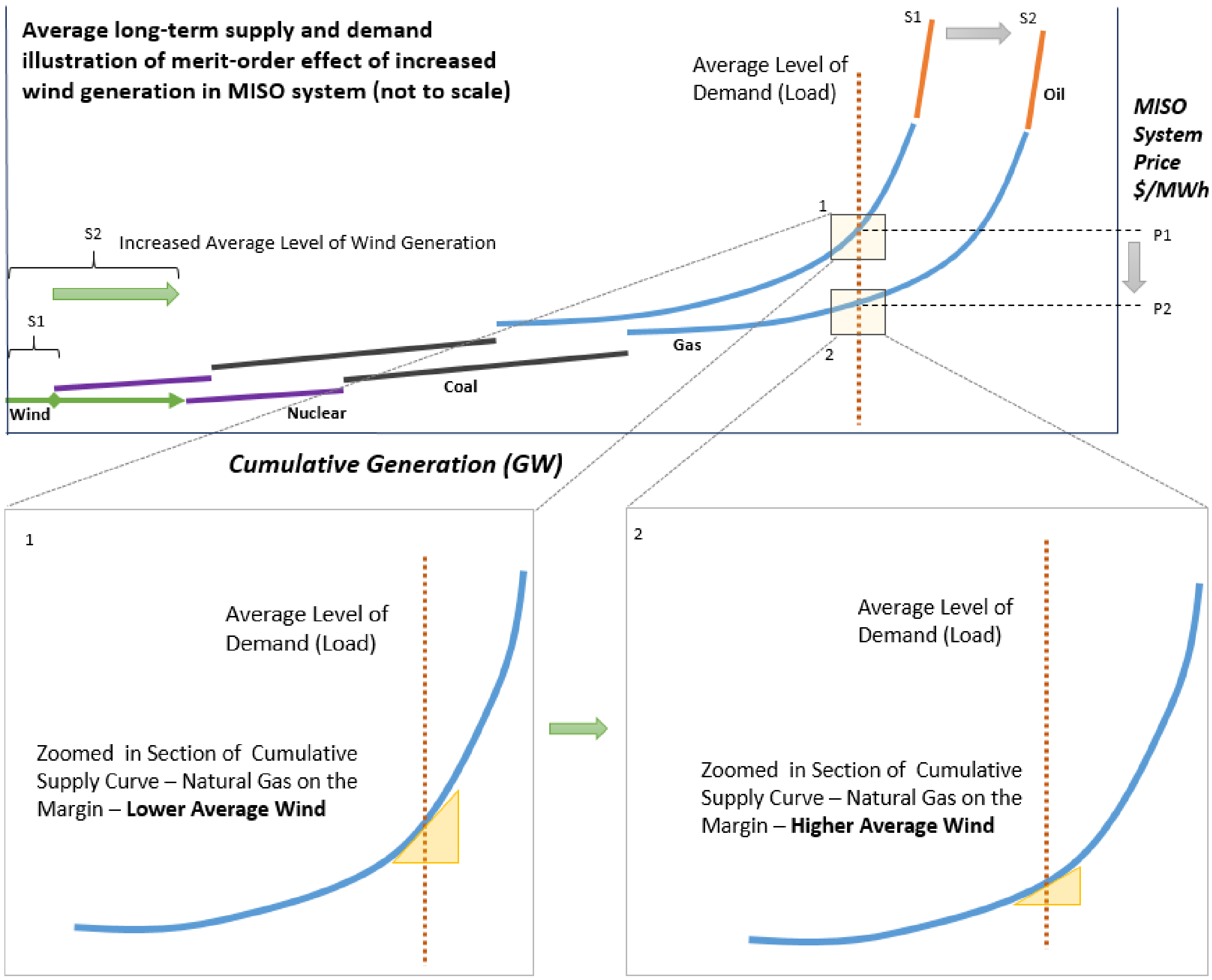
Table 2 shows that the marginal effect of an incremental rise in wind generation on electricity price is decreasing over time. This is shown in the decreasing coefficient estimates of the impact of wind generation resulting from the models in Figure 9, and may be due to the convex shape of the cumulative generation supply curve. Here we describe one likely explanation of this effect: As levels of wind generation increase the electricity supply curve shifts outward over time. When the long-term supply curve is pushed out further by increased wind capacity, the slope of the curve at equilibrium is less steep, and the marginal impact of hourly increases in wind generation decreases over time as more wind capacity is added.

This phenomenon is illustrated in Figure 10. The cumulative supply curve is broken down by resource in order of increasing marginal cost of generation. Although this figure is not drawn to scale, the merit order of each generation source is a fair representation of the long-term average supply dynamic across the MISO system. Since gas generation sets the price in the MISO system most the time, we can draw an average demand curve crossing the supply curve where gas is the marginal generation source. Given a long-term increase in wind capacity, and thus a higher average level of wind generation, the supply curve shifts out from position S1 to S2 as shown in the figure, resulting in average equilibrium prices moving down from P1 to P2.

Expanding on this long-term change in the average supply curve, and diving into analysis of short-term changes around the long-term average, the shaded boxes numbered one and two are zoomed in to help show how incremental changes in the supply curve may impact prices. The marginal effect of short term increases in hourly wind generation would be manifested as small shifts around the current equilibrium. The negative of the slope of the hypotenuses of the shaded triangles in boxes 1 and 2 could then be interpreted as the coefficient on wind generation from the regression equations in the econometric models in the previous section, as this coefficient is measuring the ratio of the decrease in price (vertical rise of the triangle) from an incremental exogenous increase in wind generation (horizontal length of the triangle). The quadratic representation of the gas price and load level in Model 4 represent the convex shape of the portion of the supply curve where the demand curve crosses on average. Comparing the slope of the hypotenuses in the shaded triangle areas in boxes 1 and 2 provides a visual illustration of the difference in the marginal effect of an incremental short-term shift outward in the supply curve due to a rise in wind generation on the hourly level, when the long -term average supply curve is at an outward shifted level on average due to an increase in wind capacity.

This phenomenon has already been identified and explored in further depth by Oliver and Johnson (2016), which they have aptly named the “stochastic merit order effect”. The decreasing marginal impact of wind generation over time as wind capacity is added, as measured by the regression models in the previous section, should offer a further statistical example of this “stochastic merit order effect”. This phenomenon may be particularly relevant when considering the impact of wind generation in the real-time market during high load events, such as the polar vortex of 2014. This extreme cold weather event caused demand to shift to extremely high levels, producing price spikes as equilibrium occurred on the steep sloped, nearly vertical portion, on the far right of the supply curve. An outward shift in the curve due to higher levels of wind generation may make it less likely that large outward shifts in demand would lead to these extreme price spikes.

**Figure 10: The Merit Order Effect and Decreasing Marginal Impact of Wind Generation: Hypothetical MISO supply and Demand Curve**




## Applications to Electricity Market Forecasting

The results of the models could potentially be used as a tool to forecast electricity prices in the MISO system based on marginal increases in wind capacity. For example, if there was an estimated one gigawatt of additional wind capacity that was planned to come online over the next two years, and these wind turbines were estimated to have an average annual capacity factor of 38%, we would expect on average 380 MWh of additional wind generation in every hour, not considering the build-out timeline of the generation. Using the average estimate of the four models in the most recent period (-.0015), we might expect this marginal additional wind generation to reduce the MISO system hourly real-time price by $0.57 (380* -.0015), holding constant the average levels of all of the other variables from the most recent period. This marginal impact of increased wind generation could be a useful component for MISO market participants when forecasting future market prices and trends.

We note that users should be careful when using these results to compare estimated prices with zero wind generation to estimated prices with current levels of wind generation. The data set used in this research was generated through certain occurrences of all of the variables, and thus there is no non-treatment data set or counterfactual to compare the results to. The build-out of wind generation capacity has impacts on the behavior of other participants in the market, including on investment decisions for other type of generation. The current generation supply stack is a function of the existence of the wind capacity and generation levels, and thus it would be inappropriate to make an extrapolation of the results comparing the price impacts of the current average levels of wind generation to a potential price outcome with zero or very low wind generation.

With this limitation in consideration, an estimate could be formulated of the wholesale price impact of increased wind generation capacity for several years in the future, given an average capacity factor, and assuming similar levels of the other exogenous variables. Though future levels of load, outages, and binding constraints could be estimated based on historical averages, the MISO system price is heavily dependent on natural gas prices, and therefore any projection of this wholesale electricity price would be sensitive to the assumption made on gas prices.

### Wind Forecasting and Market Structure

The flattening over time of the average real-time supply curve at the point of average load could also be caused by changes to the way wind generation participates in the MISO market, particularly in the dispatchability of wind in the day-ahead market and the application of improved forecasting techniques. A 2015 NREL report “Review and Status of Wind Integration and Transmission in the United States” synthesizes the recent research on the integration of wind power into wholesale power markets. This comprehensive report highlights the important characteristics of electricity market structure which facilitate accommodation of wind generation, including shorter dispatch intervals, improved forecasting, geographical dispersion of wind resources, and flexibility of the other generation resources within the market.

A recent Great Plains Institute Report “Competitive Markets and Renewables” (Dahlke, Quint 2016) summarizes some of the benefits that competitive wholesale markets may have for improved utilization of renewable resources, and conducts an empirical study of wind integration in MISO and neighboring regions.

Finally, a recent evaluation by the MISO market monitor, Potomac Economics, in November 2016 notes a pattern of wind unit managers over-forecasting their generation in the day ahead market, causing large deviations between their day ahead commitments and actual real-time generation. Potomac notes that due to the different payments and settlement rules that effect wind generators, they may have an incentive to over-forecast their output in the day-ahead market. This over-forecasting may be leading to inefficient dispatch of energy in the real-time market. This phenomenon highlights the increasing importance of renewable generation participant behavior in price formation in electricity markets, and the potential challenge of integrating predictions or assumption about this behavior into market models. The overall impact of this particular market behavior by wind generators on MISO system-wide real time prices has not been studied, and suggestions on market structure changes to mitigate this issue are currently being evaluated by MISO.

### Transmission and Wind Generation

One shortcoming of the analysis is that we have not included the potential impact of transmission capacity build-outs into the model. Because we are looking at MISO system wide prices, and the overall impact of system wide wind generation on these prices, transmission capacity built specifically to connect high wind area and wind farms to load centers may have an impact on real-time hourly price behavior which is not accounted for in our models. MTEP (MISO Transmission Expansion Planning) provides detailed analysis of the costs and benefits of transmission projects across the MISO footprint, including the MVP (Multi-Value-Project) portfolio, which is designed in part to better connect wind generation resources to load centers. Transmission capacity has and may continue to have impacts on congestion and locational marginal prices patterns, and the impacts of wind generation on LMP's and congestion levels will flow into the MISO system wide price. Including variables to account for transmission capacity additions in our models may help us better estimate the impact of wind generation and these transmission projects on MISO system prices, and could provide an exciting avenue for future research on the MISO market and beyond.

# 8. CONCLUSION

This research provides thorough empirical investigation of the impact of wind generation on the hourly real-time MISO system wide electricity price. Using nine years of hourly price, generation, load, outage, fuel cost, and congestion data, and applying four different econometric models, the results showed a statistically significant impact of increased wind generation across all models and time periods on hourly real-time MISO system prices, which ranged from a decrease of $1.39 / MWh to $3.40 / MWh for each additional GWh of wind generation.

A decreasing marginal impact of wind generation over time displayed in the results may be explained by the long term outward shift in the average generation supply curve, and may also be due to alterations in market rules that are accommodative to intermittent generation, and improved wind forecasting techniques. Future research on the impact of transmission capacity, market structure, and participant behavior in combination with increased levels of wind generation should be an important area of future study. Additionally, the methods and models presented in this research could be applied to other electricity markets outside of MISO.

Energy prices in the MISO market have a significant economic impact in the Mid-West region of the U.S. The rapid build-out of wind generation capacity in this wind resource-rich region has had and will continue to affect the economics, reliability, and environmental impact of the electric grid. Understanding and quantifying the impact of wind generation in the MISO market should provide useful data for policy makers, power system planners, market participants, renewable energy developers, and all MISO stakeholders.

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