# The Evolution of the Market for Wholesale Power*

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## Abstract

The authors investigate the dispersion of wholesale electricity day-ahead spot prices over the period following the open access of transmission by FERC order 2000; specifically 2001–2010. By implementing principal component analysis, Granger causality as well as Engel and Rogers (1996) type regressions, the authors conclude that the regional wholesale markets have begun to converge to a national market. Despite this pattern of convergence, there does still appear to be constraints that segment the market along interconnections.

**JEL Code**: C31, C32, L94, N72, Q4

**Keywords**: electricity spot markets, market integration, PCA

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# 1 Introduction

There is considerable debate over whether or not there exists a national market for wholesale electric power in the US.[1] This question has extensive implications for a wide range of public policies regarding mergers, production and imports of energy resources, electric power generation, electric power transmission, and retail electricity service. There are three major regions in the lower 48 states that have interconnected transmission grids: the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect, see Figure (1).[2] Based on an analysis of electricity pricing data, we find that there is significant economic integration within the three regional wholesale power markets. In addition, we find that despite the absence of transmission interconnections between the three regions, the regional markets are becoming economically integrated with each other. We conclude that a national market for wholesale electric power is emerging.

To test the hypothesis that there is an emerging national wholesale power market, we examine monthly averages of day-ahead wholesale price data at fourteen trading hubs and compare prices both within and between the three regions. We employ monthly averages to take into account the effects of market forces of duration longer than one day and shorter than one month. These long-term market forces include bilateral contractual agreements and trades among buyers and sellers, demand adjustments by industrial and commercial buyers

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[1] For example, The U.S. Energy Information Administration (EIA) devotes an entire section of their current Electricity Monthly Update to "[the U.S. many] regional wholesale electricity markets." The Electric Energy Market Competition Task Force (2005) asks "whether competition in wholesale markets has resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that is generally associated with competitive markets." The American Public Power Association (APPA) (2008) argues that: "the structural features of the electric utility industry [has made] it difficult for true competition to develop or flourish."

[2] The physical movement of electrons across interconnects due to engineering limitations is practically non-existent. The EIA recently characterized the status of the eastern and western interconnects as being: "the Eastern and Western interconnections (and a third interconnection covering most of Texas) are for most purposes electrically isolated from each other. Each interconnection is operated independently, and trade between the interconnections across the direct current ties is minimal." (EIA, 2011)

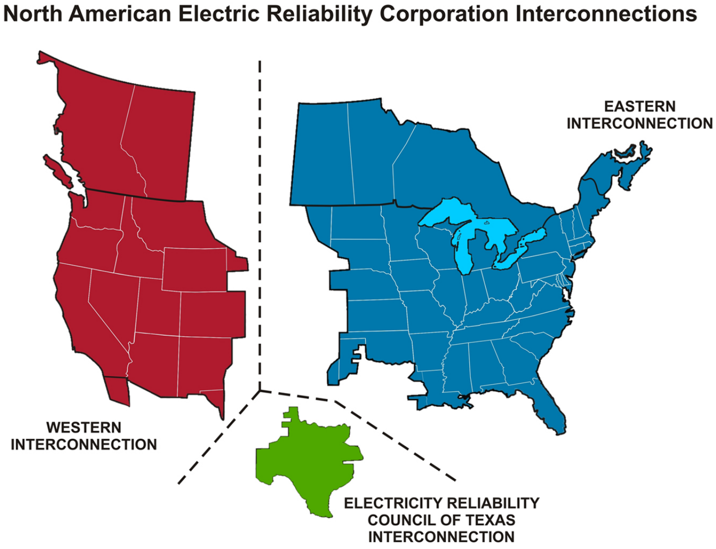

Figure 1: Map of the three interconnects throughout the United States
Source: Department of Energy

with multiple facilities, supply adjustments by electricity suppliers with multiple facilities, and factor price equalization in energy sources. Monthly averages reflect both direct arbitrage of electric power within regions and indirect economic arbitrage within and between regions. Thus, we examine whether a national market is emerging with an adjustment period that is less than one month.

The main results of the analysis are as follows. First, we find strong evidence of the emergence of a national market for wholesale power by looking at the cross-sectional dispersion of prices both within and between the three interconnect regions. All measures of cross-sectional dispersion have been trending downward in the decade following open access to transmission. Using principal component analysis we find that the overall variance explained by the first principal component has been growing over time, explaining as much as 88 percent in the latter half of the sample up from 60 percent in the first half. Next, we find evidence of the price series interdependence using Granger causality tests. All of our results are robust to adjustment for the common influence of natural gas prices, as well as seasonality.

Next, we consider the transaction costs that are associated with economic arbitrage between the three regions. Economic arbitrage exists between the three regions despite the absence of transmission connecting the regions with each other. We introduce methods used to estimate border effects in the international trade literature to determine the impact of the absence of transmission interconnections.[3] Using the volatility of relative prices within the same interconnect as a control for the effect of distance on the volatility of prices, we estimate the effect of being separated by a transmission interconnect on the volatility of relative prices between the two locations. We find that trading hubs across transmission interconnects experience price volatility border effects equivalent to trading hubs separated by a distance of only 300 miles in the latter half of the sample, down from as much as 800 miles in the prior half of the decade.

Finally, we consider the possibility of estimating transaction costs per-unit of electric power within and between regions using pairwise price differences between the fourteen trading hubs in our data set. Using the Jarque-Bera and Lilliefor statistical tests for normality, we fail to reject the null hypothesis that the distribution of price differences between trading hubs within regions is normal for 23 and 31, of the 91 pairs, respectively. Accordingly, it is not possible to estimate the per-unit transaction costs between trading hubs as in Spiller and Huang (1986), Spiller and Wood (1988a), Spiller and Wood (1988b), and Kleit (1998), Kleit (2001) due to identification issues common in mixture models.[4] In order to estimate transaction costs, additional data or information about trade flows or other factors would be

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[3] On estimation of border effects in the literature on international trade, see Anderson and van Wincoop (2004) for a survey, and Coe et al. (2007), Engel and Rogers (1996).

[4] The question of whether there is a unified market for electric power tends to differ from antitrust market definition under the Department of Justice's (DOJ) horizontal merger guidelines. Werden and Froeb (1993) argue that the economic market definition differs from the antitrust definition of the "relevant market" that is used to identify market power effects of mergers. Werden and Froeb (1993) and Coe and Krause (2008) caution against using price correlation and co-integration tests for economic market definition to determine market power in merger analysis.

necessary. Absent such additional information, it is possible that transaction costs within regions are negligible or even zero.

Our discussion builds on the classic work of Stigler and Sherwin (1985) who argue that high correlations between prices implies that goods reside within the same market, controlling for serial correlation and common influences. We extend the analysis of Doane and Spulber (1994) that examines the development of a national wholesale market for natural gas. King and Cuc (1996) utilize the Kalman filter to allow for time variation in the level of cointegration among the series, see also DeVany and Walls (1993). Evans et al. (2006) and Zachmann (2008) use principal component analysis to address the level of integration in the New Zealand and the European Union electricity context, respectively. We extend the series of multivariate techniques that statistically identity the level of integration among an arbitrary amount of series; specifically by looking at the cross sectional dispersion over time.

We consider the emergence of a national market in wholesale electric power in the context of the restructuring of the U.S. electric markets both at the wholesale and retail level.[5] Accordingly, our data begin in 2001 with national restructuring of the industry and the introduction of hubs for wholesale electric power. Park et al. (2006) use directed graph techniques in order to motivate a particular Cholesky decomposition and explore the resulting impulse response functions and forecast error decomposition, inferring the different roles hubs play in the price transmission mechanism. Our results are consistent with those of Park et al. (2006), which find that the integration of trading hubs seems strong especially amongst hubs within the same transmission interconnect. Mjelde and Bessler (2009) look at the integration of the PJM and Mid-Columbia trading hubs (both at on-peak and off-peak hours) as it pertains to the prices of their major fuel sources. Earlier studies by DeVany and Walls (1999) and Woo et al. (1997) address the issue of market integration within the Western

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[5] See Holburn and Spiller (2002) and Kwoka (2006). Jamasb and Pollitt (2005) provides a review of the European experience.

Interconnect and find evidence that the region has developed into an integrated wholesale market using pairwise cointegration tests.

## 1.1 History of the Wholesale Electricity Market

This section examines the development of the wholesale power market. The section considers the effects of deregulation and industry restructuring and economic forces driving market convergence.

The market for electricity in the United States exhibits steadily increasing geographic scope from a few city blocks to a nation-wide scale with international connections to Canada. Electricity transmission dramatically increased the distance for electric power supply, allowing electric utilities to expand their service territories. In 1882, Thomas Edison's Pearl Street Power Station served 85 customers in lower Manhattan and service was limited to one square mile. In 1895, George Westinghouse opened a hydroelectric power plant at Niagara Falls and, with the application of alternating current (AC), transported electricity for 25 miles.[6] By 1920, Samuel L. Insull's Commonwealth Edison served 500,000 customers in Chicago.[7] In the 1920s, interconnection and long-distance transmission of electric power expanded considerably.[8] During the 20th century, major electric utilities expanded their service territories to include millions of customers. Today, what is called the "world's largest machine," the U.S. electric transmission grid, has over 200,000 miles of high-voltage transmission lines.[9] Despite ever-increasing distances in electricity transmission and distribution, however, the U.S. electricity market remained fragmented at the start of the 21st century.[10] Electricity

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[6] Berton (1992).

[7] http://www.encyclopedia.chicagohistory.org/pages/2622.html

[8] Hughes (1983).

[9] See www.eei.org/ourissues/ElectricityTransmission/Pages/default.aspx, www.theenergylibrary.com/node/647, and Biello (2008).

[10] For much of U.S. history the electrical power market resembled a patchwork quilt of localized monopoly utilities responsible for generation, transmission, and distribution serving consumers at regulated prices. See

markets were limited to the local or regional service territories of incumbent electric utilities. The opening of access to transmission by the Federal Energy Regulatory Commission (FERC) under order 2000 in December 1999 was a watershed moment in the development of the national market for wholesale electric power.[11] The development of the wholesale markets also has dependence on differences in regulatory policies at the state level.[12] As of late 2012, seventeen states allowed retail customers to purchase electricity directly from competitive suppliers. Most of these states are found in the northeast with the exception of Illinois, Texas, and California. Even though residential participation in the competitive market place has been low across most of the states, a sizeable amount of commercial and industrial customers have begun to purchase their power from competitive suppliers.

The FERC actions led to the development of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that manage transmission systems covering regional markets in over two-thirds of the US. The RTOs/ISOs for the US and Canada deliver 2.2 million gigawatt-hours of electricity annually and monitor more than 270,000 miles of high-voltage power lines.[13] The seven major RTOs/ISOs are the California ISO, the Southwest Power Pool, the Electric Reliability Council of Texas (ERCOT), PJM Interconnection, Midwest ISO (MISO), New York ISO (NYISO), and ISO New England.[14] The PJM Intercon-

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Fagan (2006) who first used the illustrative metaphor of the electricity market resembling a "patchwork quilt" in his review of the restructuring of the electrical markets.

[11] The Federal Energy Regulatory Commission (FERC) instituted open access regulation of transmission in 1996 to help establish wholesale power markets. Then, several years later, the FERC required public utilities that owned or operated transmission facilities to participate in Regional Transmission Organizations (RTOs) and guarantee open access to all third party providers. This order came at the heels of independent power producers complaining that vertically integrated utilities were discriminating against third party energy producers in providing access to transmission. Since this initial order, FERC has continued with this agenda of opening up electricity generation, transmission, and distribution by way of orders 2000 and 2006.

[12] The California episode in the early 2000s have given some states pause in restructuring their wholesale/retail markets; see Borenstein and Bushnell (1999), Borenstein and Bushnell (2002). Other states, most notably Texas, have experienced greater success in their restructuring efforts.

[13] http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/Opening-access.aspx

[14] MISO also covers part of Canada. Canada also has the Alberta Electric System Operator, New Brunswick System Operator, and the Ontario Independent Electric System Operator.

nection is an RTO that "coordinates the movement of wholesale electricity and manages the high-voltage electric grid and the wholesale electricity market" in 13 states and the District of Colombia.[15] An Independent System Operator (ISO) is an organization that manages transmission systems and power flows on the grid. MISO, an example of an ISO serves as an "independent platform for transparent regional energy markets" that "encourages wholesale electric competition in the region, and cultivates greater system reliability as well as coordinated, value-based regional planning.[16]"

Following the FERCs actions, the number of power marketers and independent generation developers increased dramatically. Trade in wholesale power markets rose significantly transforming the usage of the nation's transmission grid.[17] The development of the wholesale market accompanied expansion in the size of firms through mergers and acquisitions and significant entry by startup power generation companies. Competition among electric power producers affected wholesale prices for electric power in comparison to regulated utilities. Lower wholesale prices for power resulted from greater efficiencies in power production and lower price-cost margins. Wholesale competition has already been in progress for some years and its effects can be seen in the prices for electricity offered to commercial and industrial (C&I) customers. Also, competition among retail electricity suppliers helped to reduce markups over the cost of purchased electric power by improving marketing efficiencies and lowering margins. This already is reflected in the lower prices offered to C&I customers and similar effects should be observed as competition for residential customers intensifies.

A vast amount of new generation came online, with the highest proportion of this generation coming in the form of natural gas-fired generators. The top panel of figure (2) plots the current capacity of electrical generation by initial year of operation and fuel type.[18] Since

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[15] See PJM website: http://www.pjm.com/about-pjm.aspx

[16] MISO website: https://www.midwestiso.org/AboutUs/Pages/AboutUs.aspx

[17] Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy. 2006

[18] Source: Source: U.S. Energy Information Administration (EIA).

2000, nearly 237 gigawatts of natural gas-fired generation capacity was added. This new generation was provided largely by independent power producers, who "[favor] natural gas generation due to short construction times and low capital costs." Another critical component of the shift to natural gas-fired generation is the transition from steam turbines to combined-cycle units. This transition led to higher utilization rates, as well as a relocation of the units among peaking and baseload generation.[19]

In conjunction with the new natural gas generation, wind generation also supported the overall trend in increasing the overall generation capabilities since 2000. From 1997 to 2007 electrical generation increased 19 percent with the most sizeable contributions to this growth coming from natural gas and wind generators. In addition to the overall growth in electrical generation, the ownership structure of electrical generation went through a drastic transition beginning in 2000. The bottom panel of figure (2) plots the generation capacity of independent power producers over the period from 1990-2009. Beginning in 2000, through both new builds and divestitures the ownership of electrical generation moved from utilities to independent power producers. From a 1997 level of 28,063,532 megawatt hours, independent power producers grew generation to 1,287,751,218 megawatt hours by 2007; an increase of almost 5000 percent. While independent power producers have a diverse mix of generation by resource type, independent power producers do utilize natural gas and nuclear at much higher proportions than the levels of the electrical utilities across the country.

Clearly, restructuring access of transmission created a structural shift in who and how much generation was made available to the wholesale electricity market. As access to transmission was ensured to third party power producers, more generation came online that also happened to be more efficient. Furthermore, a series of divestitures separating ownership rights of the generation units of legacy utilities from their transmission divisions moved more

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[19] U.S. Energy Information Administration (EIA). *Today in Energy.* July 5, 2011.

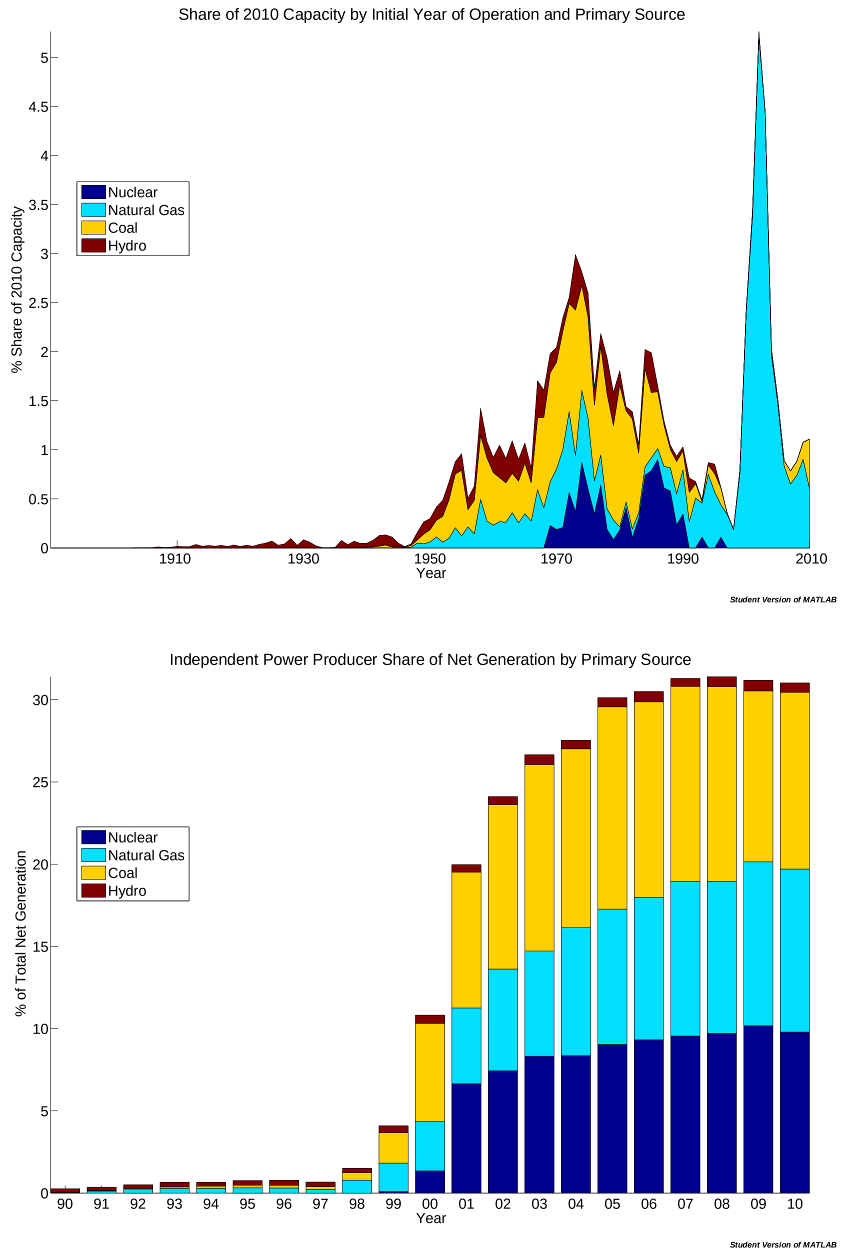

Figure 2: Electricity capacity (panel A) and generation (panel B) by fuel type
Source: Energy Information Adiministration

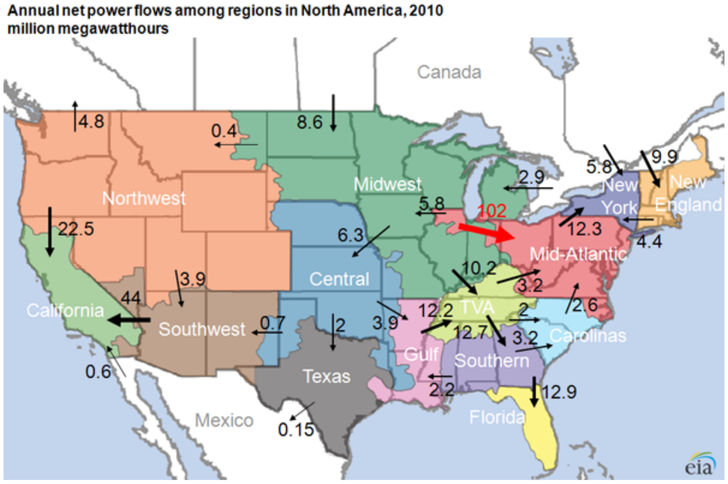

Figure 3: Annual regional trade flows within the U.S.
Source: Energy Information Administration

generation to independent power producers. We propose that these ancillary effects of the FERCs 2000 order created a more competitive market place for wholesale electricity as well as integrated the localized markets into a national market.

## 1.2 Market Convergence

Three economic forces drive convergence in wholesale electricity markets. First, trade in electric power across transmission facilities within regional markets drives market integration. Figure (3) plots the annual inter-regional trade flows across the country for 2010.

Figure (3) suggests that the international trade theory model might be a plausible explanation for the convergence result. Hydroelectric rich regions in Pacific north-west and Tennessee Valley are net exporters of electricity, while relative scarcer supply regions in California and New York are net importers. In 2010, California imported as much as 25 percent of its total electricity needs.[20] Furthermore, the abundance of nuclear generation in the northern

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[20] EIA. *Today in Energy*. December 19, 2011.

Illinois area is exported across parts of the Midwest Independent System Operator (MISO) region to a final destination back within the PJM RTO, indicating that there is likely many instances of intraregional flows that serve a similar function to the inter-regional ones. While the pattern in figure (3) demonstrates that trade between regions is occurring, the overall electricity volume of electricity moving across regions still makes up a small percentage of the overall load.

Second, both within and between regional markets, we find evidence of economic arbitrage despite the absence of transmission interconnects. Companies that demand electric power can shift their usage across regions. Perhaps more significantly, companies that supply wholesale electric power operating in multiple regions can shift their production across regions. This type of economic arbitrage is increased by the consolidation of firms in the electric power generation industry.[21] Following the open access to transmission an influx of new entrants entered into the market coupled with the divestiture of several generation units by legacy utilities. Since then, a series of mergers and acquisitions have dominated the national wholesale electricity industry. In just the year 2012, the merger of Duke and Progress Energy as well as the merger of Constellation and Exelon created the largest and third largest utility companies in the country. Furthermore, the proposed merger of NRG and GenOn would create a single independent power producer responsible for electricity generation in 47 Gigawatts of capacity in 21 states, across four system operators, and all three interconnections.[22]

In addition to the integration of the public utilities and independent power producers, the ISOs and RTOs are consolidating. Entergy announced that they will be joining the MISO independent system operator. In addition to the region controlled by Entergy, MISO

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[21] Firms almost always face the tradeoff of offering differentiated products or capturing scale economies. Krugman (1980) shows as the boundaries of firms cross over boundaries, the arbitrage and movement of scarce resources can be internalized within the firm absent any physical movement of the final product.

[22] E.I.A. *Today in Energy.* September 6, 2012.

works closely with PJM to manage the largest span of transmission lines in the Eastern interconnect.

Third, market integration reflects factor price equalization across geographic locations. Stigler and Sherwin (1985) explain that merely "[the] competition of [buyers] can bring about equality in the [price of a good], allowing for [transportation] costs, in the various areas where [the good is sold].... and is well known in trade theory as the factor equalization theorem." Energy resource supplies, notably natural gas and coal can be traded and transported across regions. Saravia (2003) found the forward premium in the New York wholesale electricity market fell upon the introduction of non-generating buyers into the wholesale market. In the particular case of wholesale electricity the natural application of this idea would be to relate how the competition in the retail markets for electricity may affect the wholesale market.

## 2 Data

The primary data set used in the analysis consists of daily day-ahead spot market prices data from fourteen of the major trading hubs across the country. Each individual price series is publicly available from the Intercontinental Exchange, a platform for wholesale power transactions that issues approximately 70 percent of next day trading activity.[23] The price series for each trading hub are volume weighted averages for all the transactions completed by the end of that trading day. Our data set ranges from January 2001 to December 2010, and includes the trading hubs: Cinergy,[24] California-Oregon Border (COB), Entergy, ERCOT, Four Corners, Mead, Mid-Columbia (Mid-C), NEPOOL, NP-15, NYISO, Palo Verde,

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[23] For a brief summary of the data set see www.eia.gov/electricity/wholesale. The price series were gathered from ICE North American Power Report found at: www.theice.com/marketdata/reports/ReportCenter.shtml#report/54.

[24] Due to transitions in the major trading hub in the Ohio area, the AEP Dayton trading hub is substituted in for the Cinergy hub for the January 2005-January 2010 part of the sample. Furthermore, each price series is converted to real 2010 dollars by using the chain price index from personal consumption expenditures.

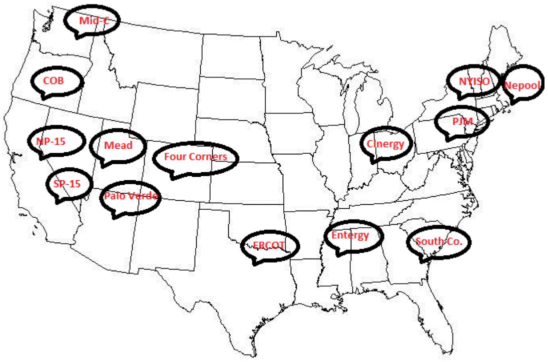

Figure 4: Map of the fourteen trading hubs throughout the United States

PJM-West, SP-15, and Southern Company (SOCO). Figure (4) provides the approximate geographic location of these fourteen trading hubs. These trading hubs not only represent a nice span geographically, but also represent the majority of day ahead trading in wholesale power.

For all of the analysis, the daily price series will be averaged to the monthly level. Table (1) presents the summary statistics of the fourteen series. On average wholesale prices tend to be higher in the northeast(NEPOOL and NYISO) and in California (NP-15 and SP-15). Figure (5) plots the average monthly price over time, while the eastern trading hubs and western trading hubs are plotted separately in figure (6). From these figures, it is clear that correlation among the series is present throughout the sample. In 2001, prices in the trading hubs in the Western Interconnection were well above both the national average as well as their own average over the rest of the decade. Following 2001, wholesale electricity prices trend upwards until the peak of business cycle. In the latter part of the sample, factors including the recession and lower natural gas prices led to lower wholesale electricity prices across all of the trading hubs. Each of these series is expected to have some amount of serial-correlation, that could bias some of the empirical results as noted by Stigler and Sherwin

|  | Mean | Std. Dev. | $N$ | Date of 1st Trade | Interconnection |
|---|---|---|---|---|---|
| Cinergy | 51.79 | 16.57 | 119 | 1/2/2001 | Eastern |
| COB | 59.10 | 42.32 | 115 | 3/16/2001 | Western |
| Entergy | 53.09 | 18.33 | 120 | 1/1/2001 | Eastern |
| Ercot | 57.56 | 26.57 | 117 | 4/18/2001 | Texas |
| Four Corners | 59.57 | 19.12 | 97 | 12/13/2002 | Western |
| Mead | 59.23 | 19.46 | 108 | 1/9/2002 | Western |
| Mid-C | 57.77 | 46.16 | 119 | 1/5/2001 | Western |
| Nepool | 70.74 | 22.44 | 120 | 1/10/2001 | Eastern |
| NP-15 | 67.95 | 47.06 | 119 | 1/3/2001 | Western |
| Nyiso | 61.42 | 18.97 | 86 | 11/7/2003 | Eastern |
| Palo Verde | 65.81 | 49.14 | 120 | 1/5/2001 | Western |
| PJM-West | 62.37 | 20.61 | 120 | 1/2/2001 | Eastern |
| Southern Co. | 54.85 | 18.14 | 108 | 12/7/2001 | Eastern |
| SP-15 | 70.30 | 51.29 | 120 | 1/8/2001 | Western |

Table 1: Summary statistics of the monthly averages of price ($/Mega-watt hour) series across all fourteen trading hubs. For each hub the mean and standard deviation are reported as well as the number of months in which trades were reported on the Intercontinental Exchange. Additionally, the date of the first trade is reported as well as the particular interconnection that the trading hub resides.

(1985). Figure (7) plots the percent log difference of each series to account for any serial correlation. As evidenced by the transformed price series - a large amount of correlation across trading hubs still persists. To investigate the presence of a unit root amongst each price series, we utilize the Dickey-Fuller test as well as the Phillips-Perron tests. Table (2) reports the augmented Dickey-Fuller test and Phillips-Perron $p$-values for each of the prices series in log levels. We reject the null hypothesis that the price series possesses a unit root for all of the series, except NYISO, at a 5-percent significance level for at least one of the tests. As noted in table (1), the NYISO trading hub is the price series observed for the least amount of months, consequently leading both tests to suffer from low power.[25] For most of the series, both test statistics suggest rejection of the null hypothesis of a unit root and that the underlying price series are stationary.

## 3 Empirical Results

In this section, we empirically investigate the hypothesis that there is a national market for wholesale electric power. First, we look at the how the price dispersion among all the trading hubs has evolved since FERC order 2000. A downward trend both amongst trading hubs within the same interconnection as well as across interconnections is found over a range of different dispersion measures. Next, we implement a multi-variate Granger causality test to gauge the level of interdependence amongst the price series. In these tests, evidence of Granger causality is found for most pairs of the trading hubs is found, and this pattern tends to strengthen in the latter half of the sample. Each of these tests provide evidence that the prices at the trading hubs under study are tied together. These results do appear stronger amongst hubs closer geographically and within the same interconnection.

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[25] Despite not being significant at the 5-percent level, both test statistics for the NYISO hub would reject the null hypothesis of a unit root at the 10-percent level.

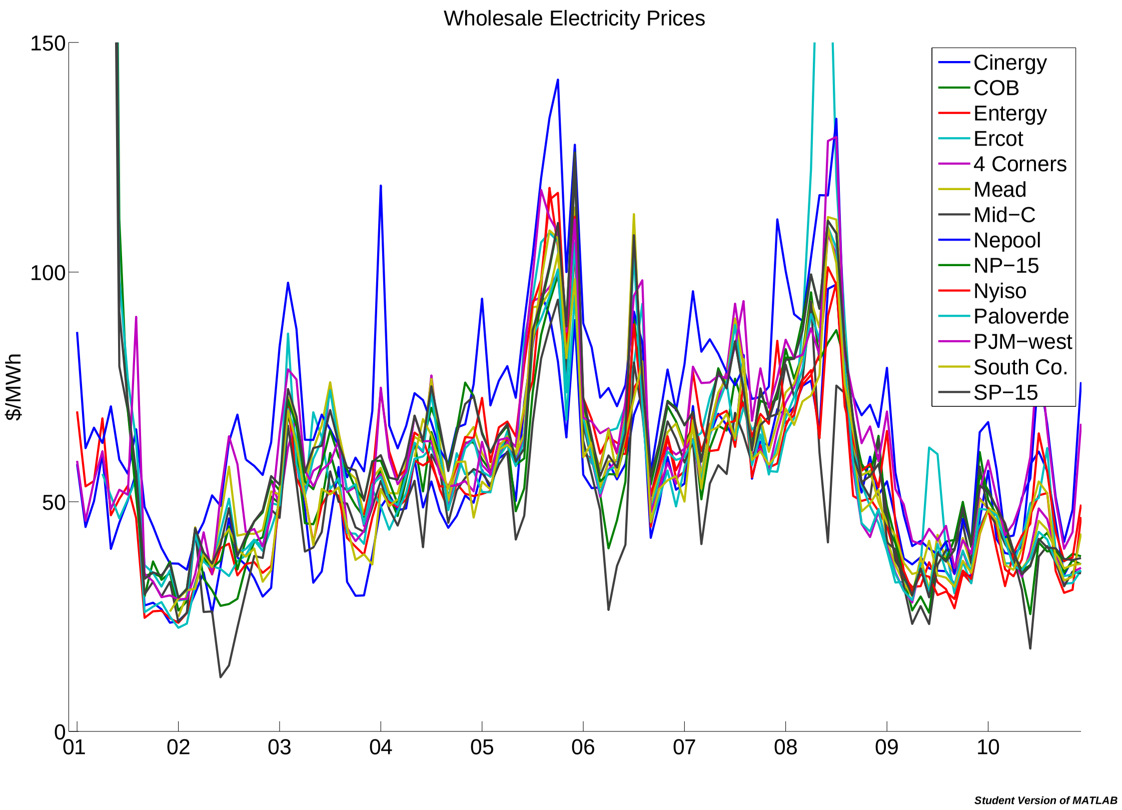

Figure 5: Average Monthly Prices at several trading hubs across the country

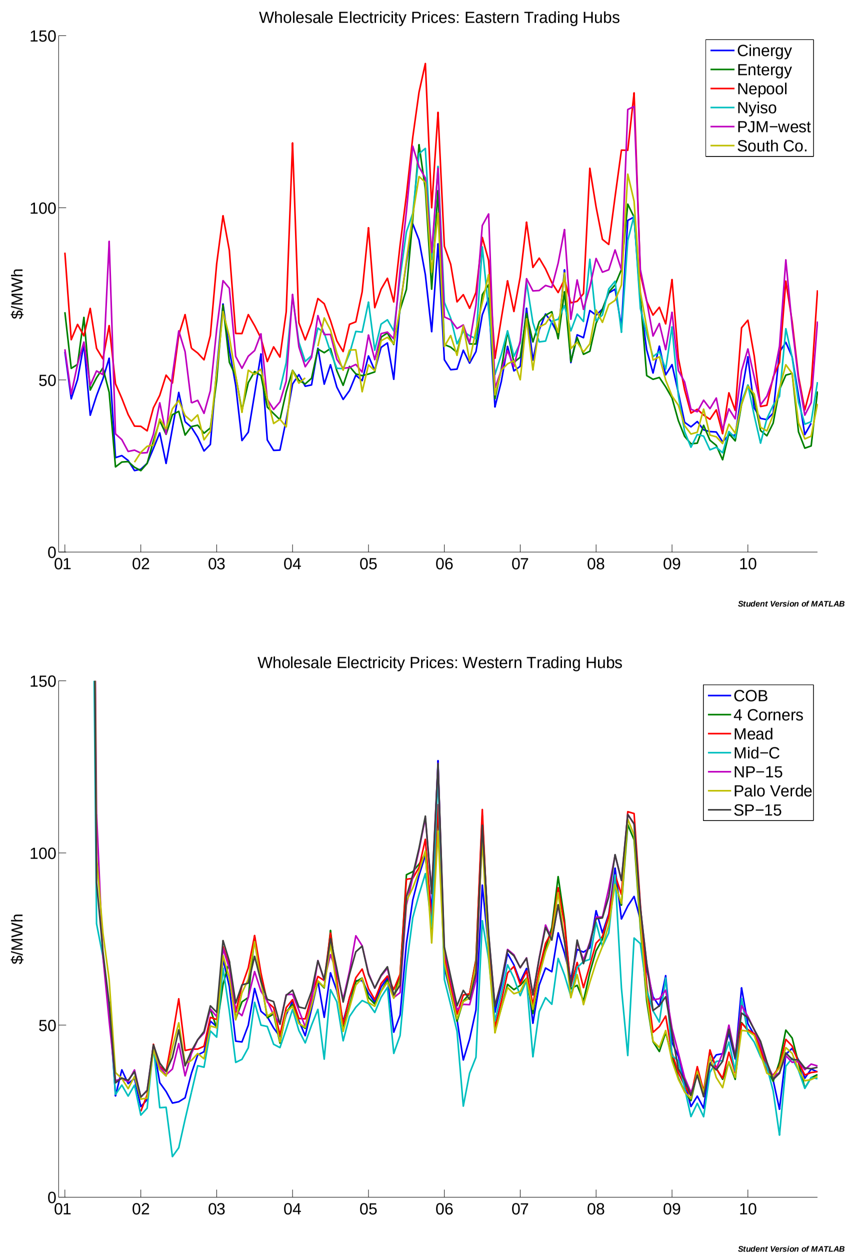

Figure 6: Average Monthly Prices at Eastern (top panel) and Western (bottom panel) trading hubs

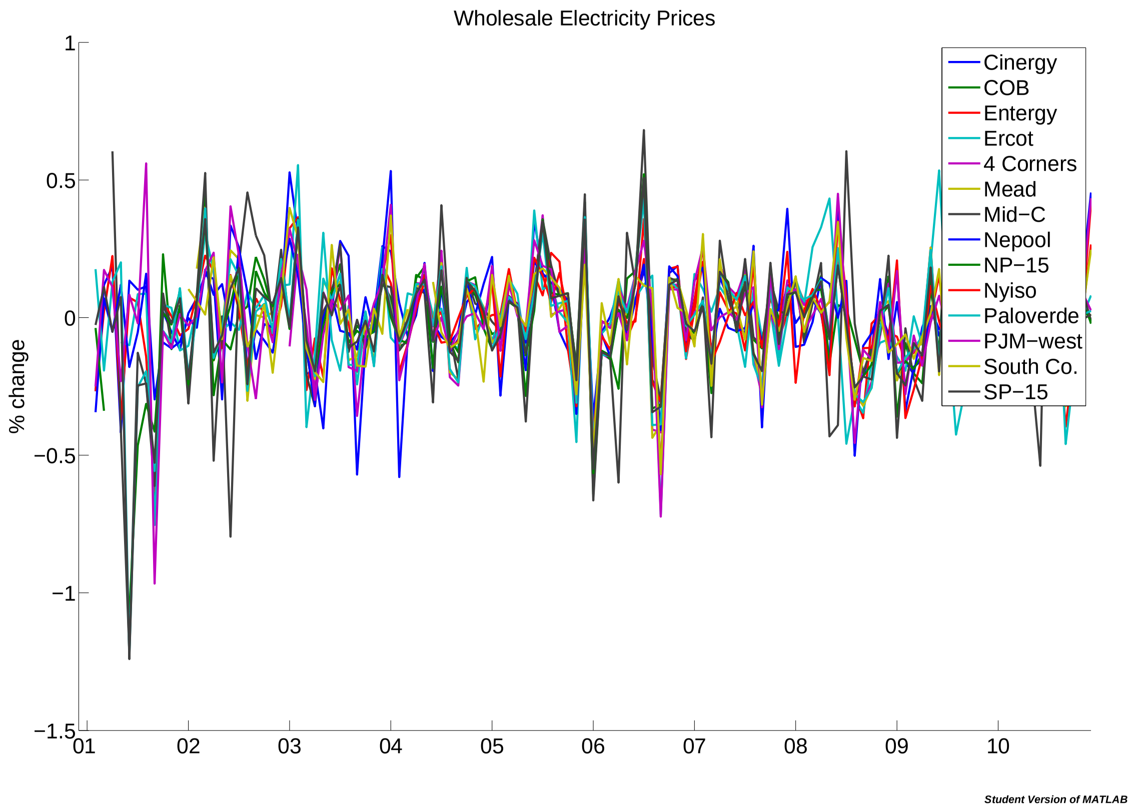

Figure 7: Average Monthly Prices at several trading hubs across the country

| Trading Hub | Dickey-Fuller $p$-value | Phillips-Perron $p$-value |
|---|---|---|
| Cinergy | 0.0142 | 0.0293 |
| COB | 0.0371 | 0.0511 |
| Entergy | 0.0489 | 0.0567 |
| ERCOT | 0.0566 | 0.0411 |
| Four Corners | 0.0391 | 0.0418 |
| Mead | 0.0051 | 0.0064 |
| Mid-C | 0.0035 | 0.0046 |
| NEPOOL | 0.0182 | 0.0270 |
| NP-15 | 0.0039 | 0.0031 |
| NYISO | 0.0524 | 0.0678 |
| Palo Verde | 0.0072 | 0.0064 |
| PJM-West | 0.0076 | 0.0140 |
| South. Co. | 0.0145 | 0.0200 |
| SP-15 | 0.0073 | 0.0056 |

Table 2: Dickey-Fuller and Phillips-Perron $p$-values testing the null hypothesis of the presence of a unit-root for each trading hub price series. The test statistics are calculated based on the sample in which prices are observed, and each price series is transformed using the natural logarithm.

Next, we implement principal component analysis methods to further investigate the level of co-movement amongst the prices at each of the trading hubs and how this has changed over time. By looking at the loadings of the first principle component, we are able to non-parametrically estimate the relative importance of each trading hub in explaining the variance of the other series, as well as how much variance of each series can be explained by the co-movement of all the series. By estimating the first principal component over a rolling window through the time series we are able to identify how the explanatory power of the principal component has evolved since the turn of the century. In this analysis, we find that the r-squared of the first principal component has progressively increased throughout the sample for each of the trading hubs with the exception of Mid-C.[26] All of the results found using

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[26] The Mid-Columbian trading hub serves the Pacific northwest region which has large amounts of cheap hydro electric generation for extended periods of time during the year.

PCA, are robust to alternative explanations including the price of natural gas or business cycles as a common influences as well as seasonality.

Lastly, we inspect how the effect of being separated by an interconnection has changed over time. By using the relative price volatility of trading hubs within the same interconnection as a control for the role of distance in affecting volatility, we are able to identify the effect of being separated by an interconnection on relative price volatility. By observing these relative price volatilities through time, we are able to make inferences on how this role of the interconnection has evolved. In our baseline specification, it is found that while being separated by an interconnection does increase the volatility of the relative prices of two trading hubs, this effect has diminished in the last half of the sample. In each part of the analysis the conclusion is the same: the emergence of one lone national market.

## 3.1 Price dispersion

As transaction costs decrease the bound on the arbitrage condition will bind at smaller price discrepancies leading to less dispersion in prices. As our lone market hypothesis was motivated by the guaranteed access to transmission mandated by FERC order 2000, a lowering of transaction costs, we would expect to see the cross-sectional price dispersion to decrease as we move through the sample. Figure (8) plots several measures of dispersion across all of the trading hubs in the sample over the full sample period, 1/2001–12/2010.[27] In the top panel, the range, mean absolute deviations, and median absolute deviations of the prices across trading hubs are plotted for each month over 2001–2010. Each measure of dispersion has a downward trend over the decade of focus. This observation is seen most evidently from the mean and median absolute deviations which are more robust to isolated deviations of a lone price series than the range measure. In the bottom panel, the standard deviation of

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[27] The full cross-section is an unbalanced panel due to different first trade dates across trading hubs as noted in table (1).

prices across trading hubs is plotted over time. Not surprisingly, a strong drop in standard deviation in the cross-section occurs early in the sample and remains low throughout the remainder of the sample.

To further investigate the potential effects of trading hubs being located across interconnects, and disaggregate potentially confounding affects occurring at regional levels we plot the same set of dispersion measures for the trading hubs in the Eastern Interconnect and Western Interconnect separately in figure (9). Interestingly, separating the trading hubs in this way elucidates a couple of key features in the how the prices across the country have evolved. In the first year of our sample, 2001–02, much of the price dispersion nationally was coming from large differences in prices in the west; see figure (9) bottom panel. The events in California including the scandal involving Enron, and rolling blackouts for most of the 2001 summer are likely drivers of most of this dispersion. The effects of these events appear to have been isolated to the western part of the country, as the prices and dispersion in the eastern part of the country were substantially lower; see figure (9) top panel. Since 2004, the price dispersion in the eastern part of the country has been steadily trending downward. This downward trend also has occurred in the west with the lone up-tick in price dispersion coming in the month of June of 2008 when prices in the Mid-C and COB trading hubs were well below the national average due to a large influx of cheap hydro electric power from the above average snowfall that season.

The above analysis is suggestive that the price dispersion across trading hubs across the country has come down since FERC order 2000, a result consistent with falling transaction costs. However, this analysis lacks any statistical evaluation of whether these hubs could be inferred as belonging to the same market. In the following sections, we utilize several methods including Granger causality and principal component analysis that allow us to make such inferences.

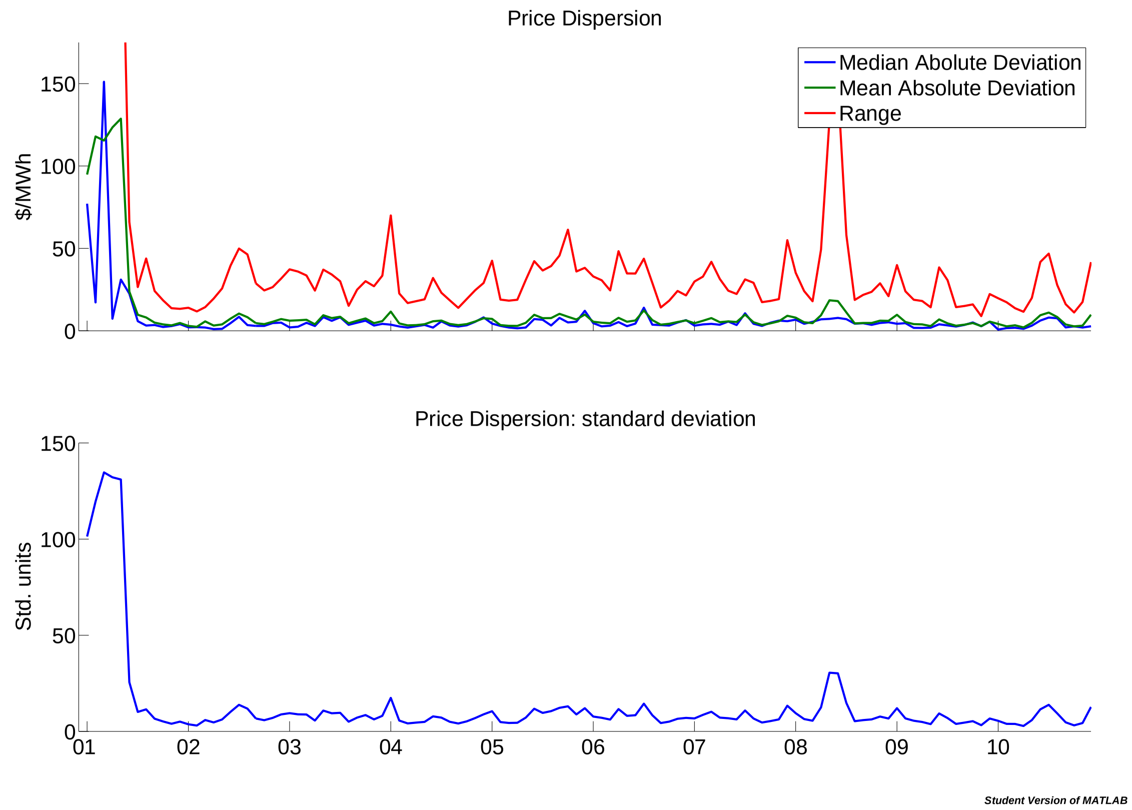

Figure 8: Various Dispersion Measures for all of the trading hubs in the sample over the period 2001–2010

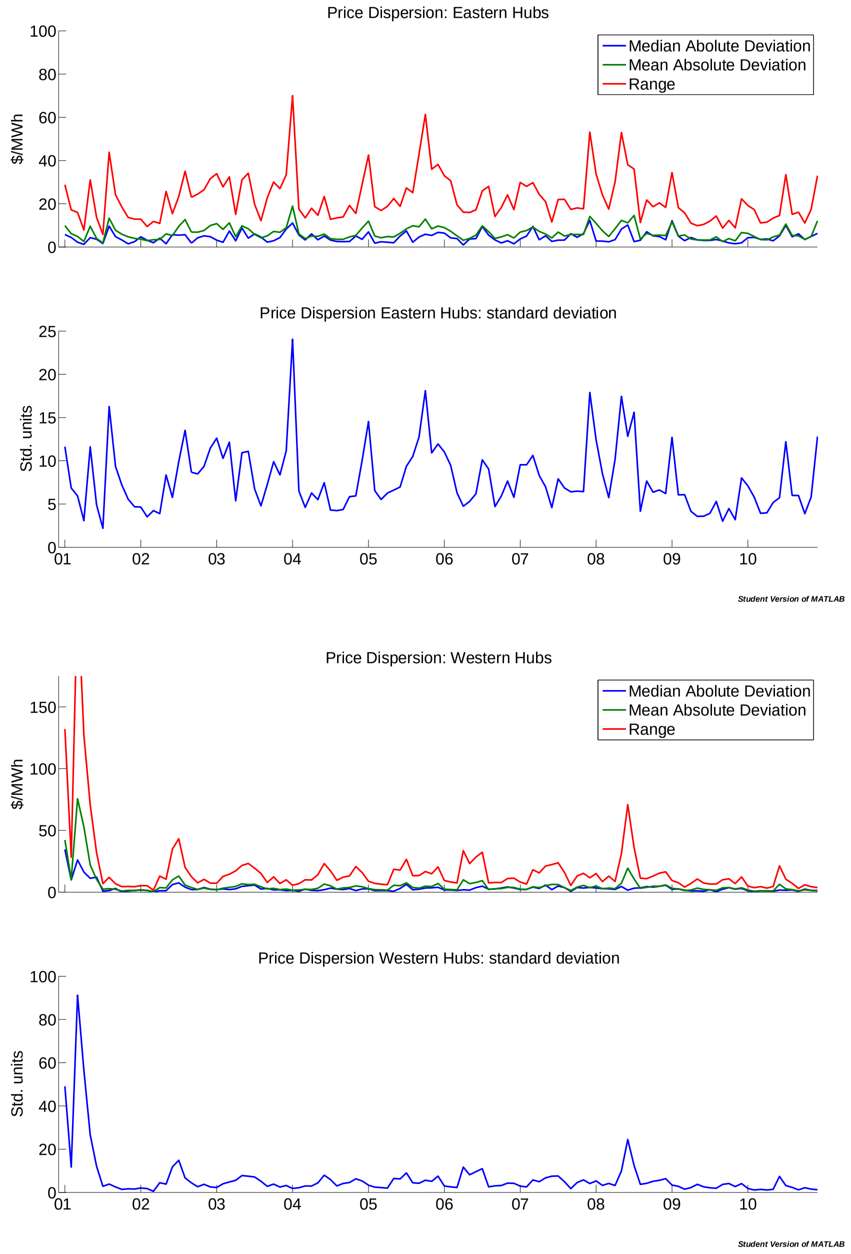

Figure 9: Various Dispersion Measures for the trading hubs in the Eastern Interconnection (top panel) and the Western Interconnection (bottom panel) the sample over the period 2001–2010

## 3.2 Granger Causality

Moving beyond the static framework of cross-sectional dispersion, we next implement the Granger Causality test.[28] Granger (1969) empirically evaluates the predictive quality of past values of another series in predicting the current level of the series of interest. Formally, the Granger Causality test involves computing the Wald statistic characterized by the null hypothesis that information of the series is not predictive of the other. A statistically significant statistic allows one to reject the null hypothesis in favor of the alternative that the series "Granger causes" the other. To implement the Granger causality test, a vector autoregression of lag order $l$ is estimated.[29] Once the VAR is estimated, the Wald statistic of restricting the coefficients on alternative series lagged values is computed for each dependent variable equation. For completeness, the Wald statistic for the null hypothesis of setting all the coefficients to zero is also reported for each regression.

Tables (3) and (4) presents the $p$-values of all 64 of the Granger causality tests for the first and second half of the sample, respectively.[30] The results presented in tables (3) and (4) mirror those found in the previous section. With the exception of Entergy in the first half of the sample, all of the prices collectively are found to "Granger cause" each of the price series at statistically significant levels; each row in the last column of both tables.

Two other patterns become evident from this analysis. First, the number of price series that are statistically significant at a ten percent level increases as we move from the first

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[28] Given that the rest of the empirical methods require a balanced panel, the following analysis is restricted to the eight trading hubs that we observe for the entire sample: Cinergy, Entergy, Mid-C, NEPOOL, NP-15, Palo Verde, PJM-West, and SP-15.

[29] The number of lags is found by using the final prediction error (FPE), Akaike's information criterion (AIC), Schwarz's Bayesian information criterion (SBIC), and the Hannan and Quinn information criterion (HQIC) lag-order selection statistics. In our particular setting, each of the criteria used found the optimal VAR lag length to be one.

[30] There are 56 pairwise Granger causality tests, i.e. restricting the coefficients for lags of $P_j$ in the regression for $P_i$ for $i \neq j$. There are eight additional tests, one test for the restriction of all of the coefficient lags of the alternative prices series for each regression.

half of the sample to the latter half; columns (1)-(8) in each table. In the first half of the sample, 16 of the pairwise Granger causality tests are found to be significant at the ten percent level. In the second half of the sample, the number of such tests that are significant at the ten percent level is 22. Interestingly, of these Granger causality tests that were found to be significant at the ten percent level the total and share of cases involving price series located in different interconnections (i.e. one in the Eastern Interconnect and the other in the Western Interconnect) increased. In the first half of the sample, only three of the 16 significant Granger tests involved trading hubs in separate interconnections, while in the latter half of the sample this number becomes thirteen (of 22) or almost 60 percent.

The second pattern that emerges from the Granger causality tests comes in the role of two particular trading hubs: Mid-C and NEPOOL. The Mid-C trading hub and the NEPOOL trading hubs were the only two trading hubs whose $p$-values were uniformly lower in the second part of the sample; third and fourth columns in both tables. This pattern suggests that these trading hubs are having more explanatory power (at least at one month lag) in the movement of the other price series. In the case of Mid-C, this result is coupled with the fact that no lone price series' Wald statistic was significant at the 5 percent level in the latter half of the sample; third row in table (4). For NEPOOL in the latter half of the sample, only PJM-West and Mid-C are found to be statistically significant at the 5 percent level; fourth row in table (4). Interestingly, these two trading hubs have consistently exhibited the lowest (Mid-C) and highest (NEPOOL) prices across the country in the latter part of our sample. While the Pacific Northwest often is endowed with large amounts of cheap hydroelectric generation from melting snow in the mountains, the northeast part of the country has been routinely troubled with transmission constraints both for electricity and natural gas. As these two trading hubs represent extremes of the range of supply conditions for electricity, the pattern of increasing dependence of other price series on past values of these two price series suggests that generators and industry players may in fact be responding to shocks to supply conditions.

In the Granger causality tests, a level of interconnectedness is developing suggestive of an integrated national market, with the dependence across interconnections growing over time.[31] Both tests thus far have presented evidence of the hypothesis of an emerging national market. In the next section, we investigate the level of co-movement among all the trading hubs' price series using principal component analysis (PCA).

## 3.3 Principal Component Analysis (PCA)

In order to further the investigate the level of integration amongst the prices of the trading hubs, we employ the techniques of principal component analysis. PCA "is a multivariate technique in which a number of related variables are transformed to (hopefully, a smaller) set of uncorrelated variables.[32]" By finding the *orthogonal regression* line that minimizes the deviations perpendicular to the line itself, PCA generates scores that explain the most variance within the series as possible. More formally, principal components can be motivated by the trying to decompose the variation in a multivariate series $P_{it}$ accordingly:

$$P_{it} = \Gamma_i F_t + \epsilon_{it} \tag{1}$$

where $F_t$ are the principal components and the source of the common variation amongst the multivariate series, while $\epsilon_{it}$ is the idiosyncratic variation of each series. In general, the

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[31] The VAR and subsequent Granger causality tests were also estimated on the residual series from each price series being regressed on the producer price index of natural gas, the Chicago Fed National Activity (CFNAI) 3-month moving average, as well as quarterly dummies. The qualitative patterns found are similar, and are available from the authors upon request.

[32] Jackson (1991)

| Dependent Variable | Cinergy | Entergy | Mid-C | NEPOOL | NP-15 | Palo Verde | PJM-West | SP-15 | All |
|---|---|---|---|---|---|---|---|---|---|
| Cinergy | | 0.019 | 0.294 | 0.013 | 0.532 | 0.603 | 0.056 | 0.834 | 0.012 |
| Entergy | 0.648 | | 0.505 | 0.071 | 0.705 | 0.272 | 0.244 | 0.195 | 0.161 |
| Mid-C | 0.325 | 0.875 | | 0.906 | 0.466 | 0.005 | 0.781 | 0.000 | 0.002 |
| NEPOOL | 0.369 | 0.003 | 0.291 | | 0.890 | 0.213 | 0.982 | 0.352 | 0.023 |
| NP-15 | 0.824 | 0.079 | 0.536 | 0.669 | | 0.001 | 0.483 | 0.000 | 0.000 |
| Palo Verde | 0.975 | 0.019 | 0.250 | 0.440 | 0.400 | | 0.353 | 0.000 | 0.000 |
| PJM-West | 0.856 | 0.000 | 0.104 | 0.019 | 0.102 | 0.223 | | 0.656 | 0.000 |
| SP-15 | 0.842 | 0.034 | 0.251 | 0.624 | 0.699 | 0.011 | 0.336 | | 0.002 |

Table 3: Wald statistic $p$-values of alternative exclusion tests for each trading hub price series as estimated from the vector auto-regression on the first half of the sample.

| Dependent Variable | Cinergy | Entergy | Mid-C | NEPOOL | NP-15 | Palo Verde | PJM-West | SP-15 | All |
|---|---|---|---|---|---|---|---|---|---|
| Cinergy |  | 0.584 | 0.006 | 0.003 | 0.115 | 0.110 | 0.412 | 0.194 | 0.000 |
| Entergy | 0.842 |  | 0.000 | 0.000 | 0.191 | 0.040 | 0.035 | 0.358 | 0.000 |
| Mid-C | 0.085 | 0.393 |  | 0.355 | 0.569 | 0.663 | 0.390 | 0.752 | 0.001 |
| NEPOOL | 0.151 | 0.417 | 0.005 |  | 0.274 | 0.965 | 0.014 | 0.766 | 0.008 |
| NP-15 | 0.977 | 0.464 | 0.019 | 0.187 |  | 0.636 | 0.038 | 0.597 | 0.049 |
| Palo Verde | 0.939 | 0.208 | 0.001 | 0.056 | 0.145 |  | 0.005 | 0.284 | 0.001 |
| PJM-West | 0.438 | 0.049 | 0.000 | 0.000 | 0.014 | 0.003 |  | 0.026 | 0.000 |
| SP-15 | 0.953 | 0.253 | 0.026 | 0.178 | 0.171 | 0.429 | 0.017 |  | 0.021 |

Table 4: Wald statistic $p$-values of alternative exclusion tests for each trading hub price series as estimated from the vector auto-regression on the second half of the sample.

number of principal components $F_t$ can range from one to the number of series in the cross section. In our particular setting, it will be useful to concentrate most of the analysis on the first principal component; the lone component explaining the most variation across all of the series.

Figures (10) plots the first two principal components and the scores estimated from the standardized prices over the full sample. Two key features emerge from the figure: (i) all price series load positively onto the first principal component, (ii) the loadings of the second principle component are less systematic and seem to be in two groups. The hubs within the western interconnect all tend to load negatively onto the second principal component, while the hubs within the eastern interconnect tend to load positively onto the second principal component. Though the first principal component is clearly a weighted average of all of the price series and could be interpreted as "National wholesale electricity price index" much like the activity indices commonly found in the macro literature.[33] The second principal component clearly represents whatever divergence exists among the trading hubs across the interconnects orthogonal from the variation explained by the first principal component. While figure (10), estimated on the entire sample, is indicative of a high level of co-movement amongst all of the price series, it does not provide any indication of how this pattern has evolved.

A useful measure in determining how the model of equation (1) explains the variation in the price series is by examining the decomposition of the variance explained by the principal component(s) as well as the variation left unexplained (if not all principal components are used) across all the series. Table (5) displays this decomposition of the variances for each of the price series in the data estimated for each half of the sample. In general, the first principal component does a very good job of explaining most of the variation in the data

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[33] See Stock and Watson (1999) for a discussion of the methodology.

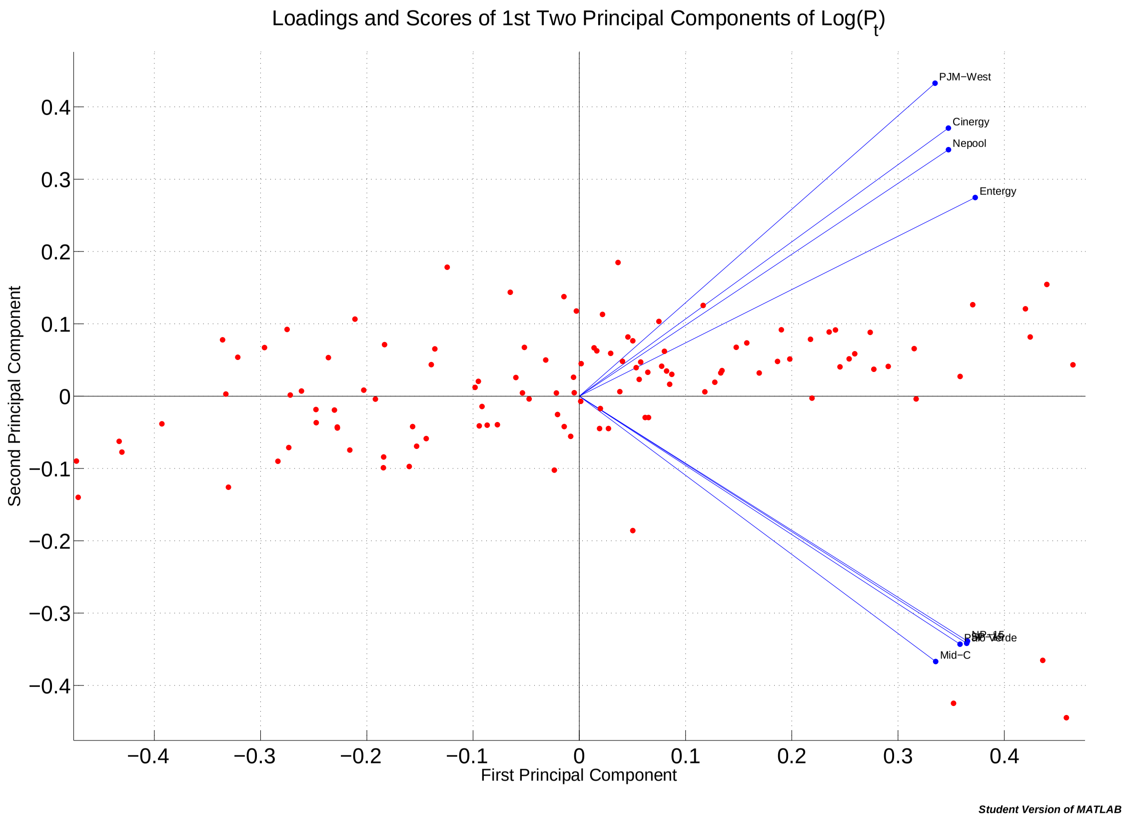

Figure 10: Plot of Loadings and Scores for first two principal components of Log Prices

Table 5: Variance Decomposition of Log Price series on 1st Principal Component for each half of the sample

1st half

| $P_i$ | 1st PC | Idiosyncratic |
|---|---|---|
| Cinergy | 0.74 | 0.26 |
| Entergy | 0.82 | 0.18 |
| Mid-C | 0.72 | 0.28 |
| Nepool | 0.67 | 0.33 |
| NP-15 | 0.78 | 0.22 |
| Palo Verde | 0.76 | 0.24 |
| PJM-West | 0.64 | 0.36 |
| SP-15 | 0.79 | 0.21 |

2nd half

| $P_i$ | 1st PC | Idiosyncratic |
|---|---|---|
| Cinergy | 0.89 | 0.11 |
| Entergy | 0.93 | 0.07 |
| Mid-C | 0.62 | 0.38 |
| Nepool | 0.88 | 0.12 |
| NP-15 | 0.93 | 0.07 |
| Palo Verde | 0.93 | 0.07 |
| PJM-West | 0.85 | 0.15 |
| SP-15 | 0.93 | 0.07 |

across all series and across both samples. The first principal component explains at least 64 percent of the variation in every series, while explaining close to 90 percent for several of the series in the second half of the sample. From this table it is clear that a large amount of the variation each series displays could be explained by one component, and that this trend has increased through the sample. Put differently, all of the series display a high level of co-movement and this co-movement has increased over the sample.

Given the lack of explicit exogenous variation, it is important to check the robustness of any results against alternative explanations. A plausible alternative explanation for the results thus far would be an omitted factor that influences all of the price series. To gauge whether such an explanation alters the results, we run the same variance decomposition on the residuals of regressions of each price series on the producer price index for natural gas, the Chicago Fed National Activity Index (CFNAI) 3-month moving average, and quarterly dummies. Table (6) presents the variance decomposition results of the first principal component of the residual series. While the variance explained by the first principal component is less across both samples, the general pattern of the increasing co-movement amongst the series still persists. The variance explained by the first principal component increases through the

Table 6: Variance Decomposition of Residual series on 1st Principal Component for each half of the sample

1st half

| $e_i$ | 1st PC | Idiosyncratic |
|---|---|---|
| Cinergy | 0.47 | 0.53 |
| Entergy | 0.37 | 0.63 |
| Mid-C | 0.53 | 0.47 |
| Nepool | 0.50 | 0.50 |
| NP-15 | 0.72 | 0.28 |
| Palo Verde | 0.70 | 0.30 |
| PJM-West | 0.59 | 0.41 |
| SP-15 | 0.70 | 0.30 |

2nd half

| $e_i$ | 1st PC | Idiosyncratic |
|---|---|---|
| Cinergy | 0.76 | 0.24 |
| Entergy | 0.78 | 0.22 |
| Mid-C | 0.48 | 0.52 |
| Nepool | 0.65 | 0.35 |
| NP-15 | 0.82 | 0.18 |
| Palo Verde | 0.82 | 0.18 |
| PJM-West | 0.70 | 0.30 |
| SP-15 | 0.82 | 0.18 |

sample for all of the series except Mid-C, who has a dip of only 5 percent. By the latter half of the sample, the first principal component explains more than 70 percent of the variation for most of the series. While some of the co-movement found amongst the original price series is driven by natural gas prices as well as business cycle and seasonality effects, there still appears to be a high level of co-movement amongst the series after controlling for such alternative explanations. This additional co-movement also seems to becoming stronger over time; results consistent with the emergence of a national market.

Another way to depict the pattern found in variance decomposition analysis is to document the evolution of the $R$-squared statistic of the first principal component for each price series. Figure (11) plots the $R$-squared statistics of the first principal component for each price series estimated on a three year rolling window through our sample.[34] With the exception of Mid-C, the $R$-squared statistic for each series trends upwards through the sample, with all the series having an $R$-squared statistic over 0.80 by the end of the sample. Interestingly, the strongest gains come from trading hubs in the Eastern Interconnect. Early in the sample, the first principal component more closely tracts the co-movements of the price

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[34] We make steps of 3 months from the initial sample which consists of the years 2001-03, to get to our final sample which consists of the three year sample 2008-10.

series in the Western Interconnect. As the price series across the interconnections become more correlated, the first principal component is able to explain a growing proportion of the variance of each of the trading hubs in the Eastern Interconnect.

PCA offers a non-parametric method of testing whether a transformation of the data allows for a reduction in the number of variables necessary to explain a large portion of the original variation. While the explanatory power of the first principal component has progressively increased since 2001, the effect of being separated by a transmission interconnect does appear to be informative of the relative connectedness of trading hubs. In the next section, we address the issue of being separated by an interconnect and gauge how it has progressed through time.

## 3.4 How much do the transmission interconnections matter?

In testing the empirical importance of the US/Canadian border, Engel and Rogers (1996) propose a method to empirically sort out the border effects controlling for distance. In a similar way, our goal is to determine the effect being separated by an interconnect system has on the volatility of prices between two trading hubs controlling for the distance between the two hubs. For this empirical exercise, we take the standard deviation of the relative price ratio (in log first differences) over the entire sample for each of the 28 possible pair of trading hubs.[35] For each pair, the distance between the two trading hubs was gathered. Lastly, we build a dummy variable that indicates whether the particular pair of trading hubs lies in different transmission interconnects. Our preferred empirical specification is characterized by the regression equation given by:

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[35] To check the robustness of our results we will also report the 90-10 interquartile as well as the median absolute deviations.

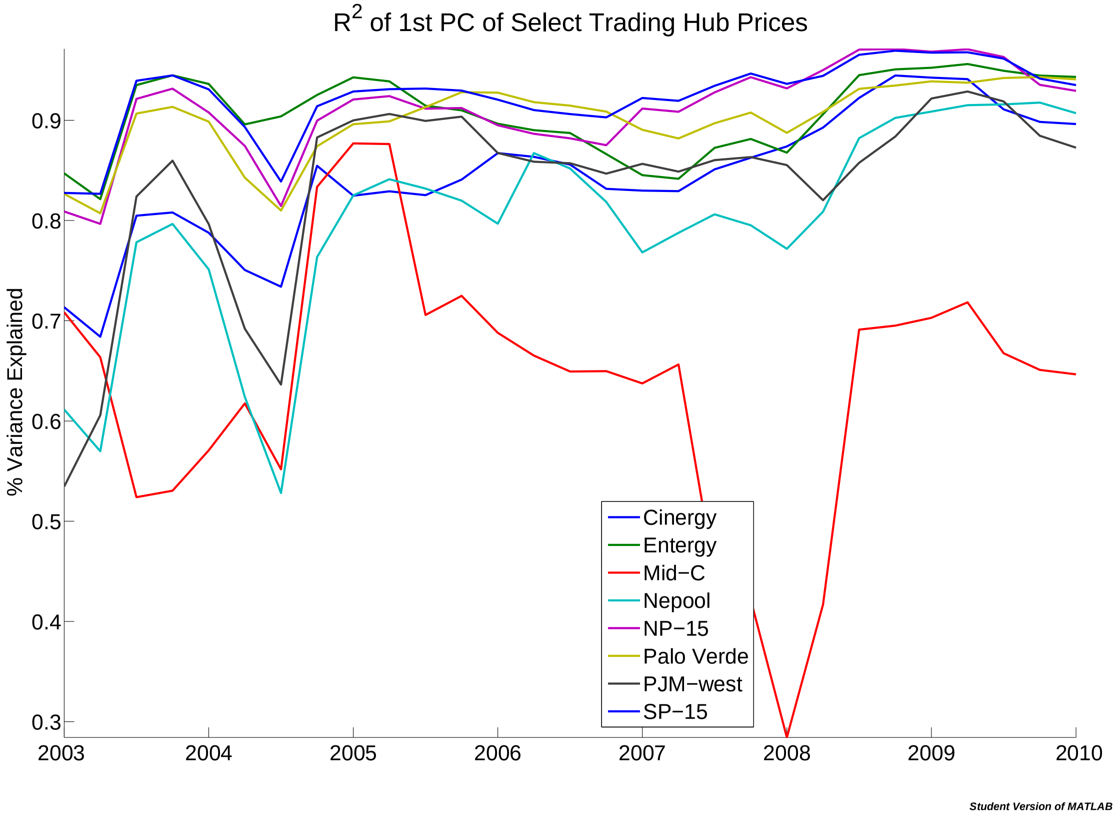

Figure 11: Plot of the evolution of R-squared of 1st principal component over the period 2003–2010

$$V(P_{ij}) = f(\text{distance}_{ij}) + \gamma Interconnect_{ij} + \rho Interconnect_{ij} * (LastFiveYrs.) + \kappa_i + \xi_j + u_{ij} \qquad (2)$$

where $u_{ij}$ is assumed by distributed normally and $f(\cdot)$ takes some parametric form such as natural logarithm. Given the assumed concave effect distance will have on volatility, our hypothesis is that $f' > 0$ and $f'' < 0$. The specification that chooses the parametric form $f(\cdot) = \alpha d + \beta d^2$ allows us to empirically test the hypothesis of distance having a concave effect on volatility; $\alpha > 0$ and $\beta < 0$. Likewise, if being across transmission interconnects has a meaningful impact on the relative volatility of prices then we would expect $\gamma > 0$. Lastly, if the effect of the being separated by an interconnection has diminished as a consequence of the integration of markets we would expect that $\rho < 0$.

Table (7) presents the regression results for each of the alternative specifications given by parametric alternatives to equation (2). As expected distance has a positive effect on the volatility between trading hubs. This effect is seen to be statistically significant across all specifications of the $f(\cdot)$ as well as different measurements for the volatility measure; rows two or three for each column. In the regression specifications with a the quadratic specification (columns II, IV, VI, VIII, X, and XII) the coefficient on squared distance has a statistically significant negative effect on the volatility of prices across all specifications, supporting the hypothesis that distance's effect on volatility is concave. Interestingly, this decreasing effect of distance, while statistically significant, is economically negligible. This result likely comes from the physical and engineering restraints governing electricity transmission.[36]

The role of being separated across interconnections, on the other hand, appears to be decreasing through the sample with a interaction coefficient of -0.071 in our preferred spec-

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[36] The EIA estimate that the electricity loss due to transmission is about 7 percent.

ification, column (IV). In fact with the estimated coefficient on the interconnect dummy variable of 0.105, it can be imputed that the "width" of an interconnection has fallen by as much 67 percent in the decade following FERC order 2000. It should be noted that in the specifications involving the median absolute deviations measure of volatility the coefficient on the interaction between the interconnect dummy and the last five years indicator is weakly positive but not statistically significant. In this section, we investigated the effect of being in different interconnections and how it has developed since 2001. In the next section, we explore the possibility of identifying the role of per-unit transaction costs across trading hub pairs.

## 3.5 Estimating Per-Unit Transaction Costs

Limited to only price data, a structural model of arbitrage similar to Spiller and Huang (1986) must be used to estimate the per-unit transaction costs between trading hub pairs. In principle, it is possible to decompose the variation in the prices between two hubs into three regimes: (1) autarky (2) arbitrage binding in one direction or (3) arbitrage binding in the other direction. The task of the model will then be to classify the observed price difference between two hubs $P_{i,t} - P_{j,t}$ as belonging to the one of the three regimes:

$$P_{i,t} - P_{j,t} = \alpha + \epsilon_{1,t} \tag{3}$$

$$P_{i,t} - P_{j,t} = \overline{T}_2 + \nu_{2,t} \tag{4}$$

$$P_{i,t} - P_{j,t} = -\overline{T}_3 - \nu_{3,t} \tag{5}$$

where (3) represents the state of autarky (transaction costs not binding), (4) represents the state of transaction costs in one direction are binding, and (5) represents the state where

|  | Standard Deviation |  |  |  | 90%-10% quantile |  |  |  | Median Absolute Deviations |  |  |  |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
|  | (I) | (II) | (III) | (IV) | (V) | (VI) | (VII) | (VIII) | (IX) | (X) | (XI) | (XII) |
| Constant | -0.255 | 0.038 |  |  | -0.722 | 0.082 |  |  | -0.161 | 0.023 |  |  |
|  | (0.124) | (0.027) |  |  | (0.254) | (0.062) |  |  | (0.050) | (0.013) |  |  |
| log(Distance) | 0.062 |  | 0.028 |  | 0.157 |  | 0.082 |  | 0.036 |  | 0.022 |  |
|  | (0.019) |  | (0.010) |  | (0.040) |  | (0.022) |  | (0.008) |  | (0.005) |  |
| Distance |  | 0.000 |  | 0.000 |  | 0.000 |  | 0.000 |  | 0.000 |  | 0.000 |
|  |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |
| Distance$^2$ |  | -0.000 |  | -0.000 |  | -0.000 |  | -0.000 |  | -0.000 |  | -0.000 |
|  |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |  | (0.000) |
| Interconnect | 0.055 | 0.043 | 0.095 | 0.105 | 0.044 | -0.006 | 0.134 | 0.111 | 0.002 | -0.008 | 0.018 | 0.015 |
|  | (0.029) | (0.029) | (0.014) | (0.015) | (0.060) | (0.063) | (0.032) | (0.039) | (0.011) | (0.013) | (0.007) | (0.009) |
| Interconnect*Last Five | -0.071 | -0.071 | -0.071 | -0.071 | -0.041 | -0.041 | -0.041 | -0.041 | 0.005 | 0.005 | 0.005 | 0.005 |
|  | (0.017) | (0.016) | (0.008) | (0.007) | (0.037) | (0.037) | (0.019) | (0.018) | (0.007) | (0.007) | (0.004) | (0.004) |
| R-squared | 0.588 | 0.614 | 0.910 | 0.925 | 0.565 | 0.580 | 0.893 | 0.895 | 0.628 | 0.636 | 0.889 | 0.887 |

Table 7: Regression results for the Engel and Rogers (1996) regressions. For each alternative specifications all of the coefficients are reported with the bootstrapped standard errors

the transaction costs in the other direction are binding. Typically, $\epsilon_{1,t}$ is assumed to be distributed normally, while $\nu_{2,t}$ and $\nu_{3,t}$ are distributed as a truncated normal distribution to prevent transaction costs from being negative. By making these distributional assumptions, the model becomes a standard finite mixture model with parameters $(\alpha, \overline{T}_2, \overline{T}_3, \sigma_1, \sigma_2, \sigma_3)$ to be estimated by maximum likelihood.[37] Unfortunately, large variations are required in order to have estimates robust to the distributional assumptions. Furthermore, the model suffers from an identification problem in regions of the parameter space that yield price differences that appear normally distributed. To gauge how serious this identification problem is for our setting, we use the Jarque-Bera and Lilliefor hypothesis tests to determine how plausible it is that each of the 91 pairs of price differences are distributed normally. In close to half of the pairs either within the three interconnects or across the interconnects, we fail to reject the null hypothesis that the price difference between the trading hubs is distributed normally.[38] Consequently, we caution the use of structural arbitrage models in recovering per-unit transaction costs in the wholesale electricity markets.

# 4 Conclusion

A national market for wholesale electric power in the US has emerged following industry open access to transmission in 2000. Cross-sectional dispersion has decreased steadily in the decade following the introduction of the wholesale market. In addition, growing Granger Causality through the sample supports the presence of an emerging national market. We utilize the multivariate technique, principle component analysis, to determine the level of overall co-movement amongst the price series and how this co-movement has grown over time. Although there is strong evidence of integration between the series, the analysis suggests a

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[37] The parameters $\sigma_1, \sigma_2$, and $\sigma_3$ are the spread parameters in the normal or truncated normal distributions.

[38] These results hold for either of the statistical tests we chose to use.

division between the eastern and western parts of the market. We also find border effects of 300 miles between the interconnects in the latter half of the sample. This effect has decreased by almost 67 percent since the first half of the sample.

The absence of transmission between the interconnects and significant border effects suggests that the national market is not yet fully integrated, even within the one-month horizon. Construction of transmission facilities between the interconnects would complete the development of the US wholesale market for electric power. Our analysis suggests that transmission facilities connecting the three regions would result in substantial gains from trade.

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