Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?

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Abstract

Regression analysis suggests that zonal averages of locational marginal prices under the nodal market are about 2% lower than the balancing energy prices that would occur under the previous zonal market structure in ERCOT. The estimates for the nodal market price effects are found after controlling for such factors as natural gas prices, total system load levels, non-dispatchable generation levels, the treatment of local congestion costs, and the treatment of the revenues received by the market from the auctioning of transmission rights. Our finding is limited to periods which are not characterized by price spikes in the wholesale market.

Keywords: Electricity market restructuring; deregulation; locational marginal pricing; ERCOT

JEL Codes: L51, L11, L94, Q48

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1. Introduction

During 1999-2001, the Electric Reliability Council of Texas (ERCOT) wholesale market was redesigned to foster competition among generators and provide a foundation for retail competition. Instead of adopting a nodal market structure like the one adopted by the PJM Interconnection (http://www.pjm.com/about-pjm/who-we-are.aspx), the Public Utility Commission of Texas (PUCT) opted to use a zonal representation of the transmission network for the "commercial network model." The zonal market in 2001 consisted of a single zone for all of ERCOT. From 2002 until late 2010, the market operated with four or five zones which were re-examined annually. Transmission constraints between those zones would result in inter-zonal differences in energy prices (Woo, et al., 2011). The costs of re-dispatching the system to resolve local transmission congestion within each zone were uplifted to load-serving entities (LSEs).

ERCOT's choice of a zonal market structure was largely driven by the fact that ERCOT had historically operated with ten control centers corresponding to ten utility service areas or zones. The transition to a zonal market structure with centralized markets for ancillary services operated by the ERCOT Independent System Operator (ISO) could be achieved with relative ease. Detailed dispatch instructions in each zone were carried out by "qualified scheduling entities" (QSEs) in response to portfolio dispatch instructions from ERCOT. The design and implementation of a PJM-style nodal structure with locational marginal pricing (LMP) would have been a more ambitious undertaking, requiring detailed command and control of generators by the ERCOT ISO.

Problems with the zonal market structure quickly emerged. Following the launch of the new wholesale market, the costs of managing each zone's local transmission congestion quickly mounted. Uplifting these local congestion costs to all LSEs within the zones underscored the need to better assign local congestion costs to entities responsible for the costs. Moreover, the distortion of economic incentives due to the zonal approximation and the inefficiency of the re-dispatch process for intra-zonal congestion motivated the implementation of a commercial network model that would provide for more accurate geographically-differentiated wholesale market clearing prices (Baldick, 2003). After lengthy discussion and debate starting in 2003, in 2005 the PUCT ordered the transition to a nodal commercial network model.

The ERCOT's transition to a nodal market structure was long and controversial. A 2004 study projected that the switch from a zonal to nodal market could yield a ten-year net present value of $339 million in system-wide operational benefits, above the implementation costs envisioned at the time (Tabors Caramanis & Associates, 2004). A number of interests questioned this projection, while the transition moved forward slowly in the next six years. The estimated cost of implementing the nodal market ballooned from $125 million (Hinsley, 2006) to $550 million (Petterson, 2011) by the time the nodal system was finally functional in December 2010 – many years later than initially scheduled.

The theoretical appeal of nodal electricity markets may be traced to Schweppe, et al (1988) and Baughman, et al (1997), with generation centrally dispatched to respect transmission constraints and transactions settled at LMPs (Ma, et al, 2003). A number of studies have estimated the potential savings associated with moving from a zonal market to a nodal market, including Tabors Caramanis & Associates (2004), and Green (2007). A comparison of cost and savings estimates for various U.S. markets is provided in Climate Policy Initiative (2011).

Corroborating these studies, back-casts performed by the ERCOT staff suggest $90 to $180 million of local congestion cost savings during the first six months of nodal market operation (Cleary, 2011). Additional savings in regulation ancillary service costs have also been realized as a result of switching to a nodal market structure (Cleary, 2011). These cost savings are partly attributable to dispatch instructions that are issued every 5 minutes by the ERCOT ISO under the nodal system, unlike the zonal market which operated in 15-minute intervals. With the nodal system's more frequent dispatch, the need for operating reserves has been reduced. However, these savings could arguably have been achieved under a zonal market structure through a similar reduction in the operating time interval from 15 minutes to 5 minutes.

While there is empirical evidence of the impact of the change in market structure on the costs of local congestion and regulation ancillary services, the same cannot be said of the impacts of the change to a nodal system on the wholesale energy market settlement prices paid by LSEs. Hence, the goal of this paper is to answer the following question, "did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?"

This question is important, timely, and relevant because wholesale market prices are used to settle the payments under many contracts among parties in the ERCOT market for retail sales and for wholesale supplies of electricity. For example, many large industrial energy consumers contract with retail electric providers to purchase power at real-time wholesale prices – that is, balancing energy costs under the former zonal market or the zonal demand-weighted average of LMPs under the new market structure. For these consumers, reduction in wholesale prices was one of the anticipated benefits from switching to a nodal system. After two years of nodal market operation, some evidence of this benefit should now be visible.

Controlling for differences in load levels, the impact of price spikes, natural gas prices, the treatment of local congestion managements costs, operational alerts, changes in the revenues from the auction of transmission rights, and other variables, we examine how the change in market structure affected wholesale market settlement prices. We indeed find evidence of price reductions following the implementation of the nodal market. The price reductions, however, differ greatly by zone. These findings are of interest to market design efforts elsewhere, since many other wholesale markets are considering similar re-design.

This paper does not assess the gains in efficiency and changes in dispatch costs resulting from the switch to a nodal market system. Furthermore, with merely two years of data available on the operation of ERCOT's nodal market system, a comparison of the long-term costs and benefits is not yet possible. Our focus is merely on changes in the wholesale prices paid by un-hedged load-serving entities and large industrial energy consumers who purchase power based on real-time market prices or have contracts with prices indexed to wholesale prices.

The following section briefly explains the differences between the two market structures adopted by ERCOT. Our modeling approach is described in section 3. Section 4 presents results from a regression-based approach. Section 5 offers an explanation to some of our modeling results. The final section provides conclusions and observations.

2. Wholesale market settlement prices for retail loads under the two market structures

The zonal wholesale market structure in place from January 2002 until the end of November 2010 was designed to support bilateral contracts between generators and LSEs. There was no centralized day-ahead market for energy nor centralized dispatch of resources. Consequently, ERCOT's wholesale structure was sometimes categorized as a "min-ISO." Nonetheless, ERCOT operated a centralized market for balancing energy. In addition to managing congestion and operating the balancing energy market, ERCOT administered day-ahead ancillary services markets and acted as the default provider for balancing energy and ancillary services for LSEs who failed to self-arrange their required amounts of energy and ancillary services.

After the introduction of the "relaxed balanced schedule" policy in November 2002, an LSE could designate the balancing energy market as a source for a portion of its load obligation. Further, the ERCOT ISO procured any additional generation (balancing up) or generation reductions (balancing down) to match supply and demand on a near-real-time basis (i.e., with a notice period of between 10 and 20 minutes). QSEs with generation in excess of their scheduled amounts or with the capability to curtail or interrupt their purchases were encouraged to submit offers to provide balancing up energy to ERCOT. The balancing energy market thus served as a spot market for generation and demand, providing price signals and transparency, encouraging demand side response, and fostering more efficient use of available system resources. While less than 10% of ERCOT's total generation requirements were satisfied through balancing energy, the balancing energy price became the *de facto* market price, was closely followed, and was used as an index price in many contracts.

To establish the wholesale market price of balancing energy by first ignoring inter-zonal transmission limits, ERCOT created a *bid stack* or supply curve of all offers to provide balancing up and balancing down energy obtained from QSEs, ordering all offers from lowest to highest. Offers were accepted until the market requirement was met. All winning offers received the market-clearing price. Thus, the balancing energy price reflected the marginal offer price of generation transacted through this central market. The QSEs associated with LSEs that were deficient in energy were billed for the costs that ERCOT incurred in procuring energy on behalf of the LSE. When transmission constraints between zones were binding, ERCOT performed generation redispatch, resulting in different zonal market prices for balancing energy.

Congestion within each zone was managed primarily through ERCOT's use of out-of-merit-order (OOM) instructions. Under an OOM instruction, a resource that was not already scheduled for deployment at full capacity could be deployed by ERCOT to increase production to address a transmission congestion problem on the "import" side of a constraint. Conversely, a resource that was not already scheduled to be deployed at minimum capacity could be deployed by ERCOT to decrease production to address a transmission congestion problem on the "export" side of a constraint. OOM costs were uplifted to load-serving entities and were eventually borne by consumers.

To prevent dominant generators from exercising market power, supply offer caps were set. During the zonal market period, the offer cap rose over time from $1,000 per MWh to $1,500 per MWh in March 2007 to $2,250 per MWh in March 2008. It was not unusual for market prices to reach, or even occasionally exceed, the caps. Prices in excess of the caps could occur when certain inter-zonal transmission constraints were simultaneously binding during periods that coincided with the acceptance of high-price energy offers.[1] In June 2008 the PUCT took actions to change ERCOT's pricing model to reduce the likelihood of prices exceeding the offer caps.

As in many restructured wholesale markets, prices have been volatile (Woo et al., 2011b). Moreover, inter-zonal transmission constraints have caused wide differences among prices in the four zones within the ERCOT market (Woo et al., 2011a; Baldick, 2012).

Despite the investment in transmission and the consolidation of the ten control areas into a single control area, transmission congestion remained a challenge under the zonal structure. Within these zones, local congestion was greater than anticipated, particularly in the Dallas-Fort Worth area, the Rio Grande Valley, Laredo, and parts of West Texas. The practice of uplifting

[1] For a more technical explanation, see Dan Jones, Potomac Economics, MCPE and Offer Cap/Floor Consistency, etc., presentation to ERCOT TAC/WMS, June 13, 2008, available at: www.ercot.com/content/meetings/wms/keydocs/2008/0613/Jones_TAC_(20080613).ppt.

the costs associated with managing local congestion led to inefficient and inequitable outcomes. Consequently, the PUCT ordered ERCOT to transition to a nodal structure after less than two years of operations under the zonal structure. After a lengthy implementation period, the new nodal market began operations on December 1, 2010.

Under the nodal structure, ERCOT plays a central role in dispatching all resources, using a security-constrained economic dispatch (SCED) model. The nodal prices are used to determine the compensation provided to generators, while a demand-weighted average of the nodal prices within various zones is calculated for billing LSEs for wholesale energy purchases on behalf of their customers' consumption.

The new zones used in the calculation of the zonal average locational marginal prices (LMPz) generally correspond with the zones defined under the previous market structure, although the former South zone was split up to permit Austin Energy and CPS Energy (San Antonio) to have their own zones. A day-ahead market with unit commitment and co-optimization of energy and ancillary services was also introduced. The offer caps on wholesale market prices were raised to $3,000 per MWh at the start of the nodal market and further raised to $4,500 per MWh in June 2012 (effective August 2012) to encourage the construction of new generating capacity. In August 2012, the PUCT approved a plan to gradually raise the offer caps to $9,000 per MWh.

Under both market structures, wholesale generation prices were based on offers from generators. However, some of the costs of managing congestion were based on ERCOT-approved costs, rather than offers, under the zonal market. Under neither of the market structures have resources been "co-optimized" in real time for energy and ancillary services.

A simplistic comparison of the average wholesale prices paid by LSEs under the two market structures could be highly misleading for a number of reasons. Wholesale market prices in ERCOT are highly sensitive to natural gas prices, and those prices dropped precipitously during the summer of 2008 and have remained generally lower in the nodal market years than the later part of the zonal market years. While the management of local transmission congestion was a cost-based service separate from wholesale market generation costs under the previous zonal market structure, it is now based on marginal offers and its cost is a component of LMPs under the nodal system. Thus, local congestion management costs must be either added to the wholesale energy costs under the zonal market or subtracted from LMPs in the nodal market to achieve a meaningful comparison. The introduction of the nodal market coincided with an increase in the wholesale offer cap – the maximum price a generator may offer to provide energy generation. The summer of 2011 was one of the hottest on record in Texas, leading to higher-than-expected demand and numerous price spikes. A cold front in early February 2011 led to unusual price spikes. This market's increasing reliance upon generation from wind farms has placed downward pressure on energy prices in recent years. Considerably more revenue has been raised through auctions of transmission rights under the nodal market. These revenues are refunded to LSEs, and thus may be regarded as a benefit of the nodal market from the LSE's perspective. Using a variety of regression techniques, we seek to control for the effects of these exogenous factors on the wholesale prices faced by LSEs.

Our research focus on the wholesale prices faced by LSEs but recognizes that under these two market structures, wholesale prices were formulated through different market mechanisms and differ in what they represent. Regardless of the differences in their origin, however, these are the prices paid by un-hedged LSEs and are the basis for many contractual arrangements among participants in the ERCOT market. This underscores the usefulness and relevance of our price comparison. We emphasize that we are not quantifying or making any statement about changes in efficiency between the two market designs, although we presume that, *ceteris paribus*, the nodal market is more efficient.

3. Approach

To explore whether the introduction of the nodal market altered wholesale prices, we run a set of regression models to explain price movements caused by their fundamental drivers: natural gas prices; the overall level of demand; non-dispatchable generation (i.e., nuclear power and wind generation); and residual time-dependence captured by binary indicators for hour-of-day, day-of-week and month-of-year. A large number of functional forms were tested to represent the nonlinear relationship between total system load and wholesale prices.

In the initial set of models presented here, the regressions signify the two market structure periods using a binary variable, which is zero until December 1, 2010, and becomes one thereafter. The nodal dummy interacts with the variables representing natural gas prices and non-dispatchable generation to recognize that the change in market structure may have affected the relationships between these factors and wholesale prices.

Generation from dispatchable power plants (i.e., those fueled with natural gas and coal) was not modeled explicitly because their outputs are endogenously determined to meet electricity demand. Moreover, the quantity of natural gas generation is highly correlated with total system demand in ERCOT. Consequently, its inclusion would lead to severe multicollinearity problems, causing imprecision in our regression results.

Our regressions' dependent variable is the wholesale settlement price, which was the market clearing price of balancing energy under the zonal market structure and the weighted average of the locational marginal prices within each zone (LMPz) under the nodal market structure. Two adjustments were made to the price data. First, all of the zonal balancing energy prices were scaled-up to reflect the average annual cost of local transmission congestion management.[2] Second, the monthly amounts of revenues received from auctions of transmission rights and refunded to LSEs were used to adjust the interval-level price data.

The first adjustment recognizes that under the zonal market structure, local congestion costs were uplifted and separately paid by LSEs. Hence, a comparison of zonal balancing energy prices to LMPz prices in the nodal market must adjust for this difference. As calculated in Table 1, the zonal prices should be raised by about $0.37 per MWh, based on data for 2008 and 2009[3] to account for this difference.

Table 1. **Average Local Congestion Costs per MWh Under the Zonal Market**

	2008	2009
Local Congestion Costs for all Zones ($ Millions)	$111.7	$115.1
MWh Generation	312,401,085	312,203,592
Average Cost of Local Congestion ($/MWh)	$0.36	$0.37

Sources: ERCOT Demand and Energy Reports and Market Operations Presentations to the ERCOT Board, all posted on www.ercot.com.

[2] Local transmission congestion cost data for each 15-minute interval during the zonal market period were sought from ERCOT. However, these data are not available.
[3] We were unable to obtain comparable data for 2010.

The second adjustment recognizes that the revenues received by ERCOT from auctions of transmission rights are refunded to LSEs via a credit to the costs paid by LSEs. The refund factors (expressed as a $/MWh reduction in price) were set the same across all zones under the zonal market structure, but varied among each of the zones once the nodal market was established.[4] The allocation of the refund amounts to various zones was provided to the authors by the ERCOT Market Monitor, Potomac Economics. Costs which were not directly assigned to a specific zone were spread among all zones on a consistent dollars per MWh basis. The revenues from the auction of transmission rights and subsequent credits increased sharply under the nodal market. It is therefore appropriate to make an adjustment for this factor given that the nodal market was specifically implemented to better manage transmission congestion. Annual averages are presented in Table 2, along with the average difference in refund factors between the zonal and nodal markets within our study period.

Table 2. Annual Average Factors ($/MWh) to Reflect Refunds of Revenues from Transmission Rights

	2008	2009	2010	2011	2012	Average Difference from Zonal to Nodal
North	$0.4633	$0.5596	$0.3357	$0.7814	$0.6393	-$0.2575
Houston	$0.4633	$0.5596	$0.3357	$0.8821	$0.7217	-$0.3491
South	$0.4633	$0.5596	$0.3357	$1.1539	$0.9441	-$0.5961
West	$0.4633	$0.5596	$0.3357	$2.9665	$2.2476	-$2.1542

[4] See Potomac Economics, IMM Report to the ERCOT Board of Directors, Sept. 18, 2012.

Regressions are run for four zones within the ERCOT market: North (including Dallas), Houston, West, and South. The zone designated as South under the zonal structure was split into numerous zones when the market structure was changed. To develop a comparable price series for the South zone during the nodal market period, we used the consumption-weighted average price of the new (smaller) South zone, Austin zone, and CPS (San Antonio) zone. The weights were based upon 15-minute energy consumption data for the new zones. The relatively-small West zone tends to exhibit unusual price patterns due to the zone's large share of the state's wind power projects and its unusually high load growth in recent years caused by expanded oil and gas production activity.

In addition to the fundamental drivers noted at the beginning of this section, a binary variable was constructed to reflect the start time of any operational alert. Alerts are typically called when physical operating reserves drop below a predetermined threshold level set by the ERCOT ISO. Thus, these alerts tend to reflect a scarcity of generation resources. They are called on a system-wide, rather than on a zonal or nodal, basis. Once these alerts are issued, wholesale market prices tend to rise until the problem prompting the alert has been resolved. For the zonal period, the ending times of alerts are available from ERCOT's Monthly Operations Reports.[5] However, a comparable series of ending times have not been recorded since the change to a nodal market. To minimize any bias, we use a binary indicator to signify the start time of the alert and permit the alert to have an effect on a zone's wholesale market price for the next four hours. The choice of the four-hour period is based on the alert durations observed in the zonal market years.

[5] These are posted on www.ercot.com under the monthly meeting materials of the Reliability and Operations Subcommittee.

We obtained 15-minute price and total energy demand data for the period of January 1, 2008 to October 31, 2012 from ERCOT's website, along with quantities of nuclear and wind generation.[6] We downloaded daily natural gas prices for Henry Hub from the DOE/EIA.[7] We use the Henry Hub price instead of the local natural gas price (e.g., Houston Ship Channel) for two reasons. First, this precludes the possibility that the local natural gas price may be endogenous, affected by the local natural gas used for electricity generation. Second, the Henry Hub price is highly correlated with the local natural gas price ($r > 0.95$). The daily natural gas prices were assumed constant across all 15-minute intervals within each day for which the natural gas price was quoted.

Suppressing the subscript used to designate the four individual zones, the model may be written as:

$$Y_t = \alpha + \sum_m \beta_m X_{mt} + \sum_i \mu_i M_{it} + \sum_j \omega_j W_{jt} + \sum_k \eta_k H_{kt} + \psi N_t + \sum_{t-16}^{t} \phi_t A_t$$
$$+ \sum_m \mu_m X_{mt} N_t + \varepsilon_t \qquad (1)$$

In equation (1), the price Y_t in a 15-minute interval t is driven by m explanatory variables $\{X_{mt}\}$(i.e., total zonal demand, generation from nuclear power plants, generation from wind farms, and the price of natural gas), binary indicators that account for the month of the year (M_{it}), day of the week (W_{jt}), and hour of the day (H_{kt}), and a binary indicator of whether the market had a nodal structure in the interval N_t. Operational alerts A with lags of up to 16 intervals are permitted. The coefficients μ_m on the interaction between the nodal dummy variable, N_t, and the m explanatory variables allow the slope coefficients to change by μ_m when the market structure changed. The disturbance term ε_t is assumed to follow a stationary AR(1) process such that $\varepsilon_t = \rho\varepsilon_{t-1} + \upsilon_t$, where υ_t = is white noise.

[6] See: http://planning.ercot.com/reports/demand-energy/. Note that users must register with ERCOT to request permission to access this website.
[7] See: http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm. Last accessed November 12, 2012.

The coefficients to be estimated are α, { β_m }, { μ_i }, { ω_k }, { η_k }, ψ, ϕ and ρ . We estimate them using the following 3-step process: Step 1: Apply the Yule-Walker procedure to the full sample to estimate the AR(1) parameter ρ. Step 2: Transform all variables using the following formula: $Z_t^* = Z_t - \rho Z_{t-1}$. Step 3: Apply robust estimation to the transformed variables, yielding consistent estimates for the coefficients that are free from the undue influence of outliers.

We use a large sample of 169,529 15-minute observations to estimate four sets of coefficients, one for each of the ERCOT zones modeled. Descriptive statistics for key variables are provided in Table 3. The Phillips-Perron unit-root test results indicate that the wholesale market prices data series are stationary, thus obviating concerns of spurious regressions.

Table 3. Descriptive Statistics. For the period of January 2008 through October 2012. The values for energy in the last three rows represent energy in a 15 minute interval.

Variable	Mean	Standard Deviation	Minimum	Maximum
North Zone Price ($/MWh)	39.95	97.13	-999	3032
Houston Zone Price ($/MWh)	42.33	111.08	-1536	3805
West Zone Price ($/MWh)	37.34	122.72	-1981	3199
South Zone Price ($/MWh)	43.07	114.3	-2292	4514
Natural Gas Price	4.82	2.40	1.82	13.31
Nuclear Generation (MWh)	1155	193	541	756
Wind Generation (MWh)	656	429	0	2066
Total System Demand (MWh)	9162	2289	5106	17104

Our preliminary estimation suggests that the wholesale price series are characterized by outliers – namely, price spikes and dips with large studentized residuals' size that are well over 3.5. Hence, we adopt a robust regression estimation method to estimate our regression coefficients. The results reported in Table 4 below use the M estimation method in SAS software based on Huber (1973). A cut-off point of 4.5 was used in the estimation, although values of 3.5 and 4 yielded virtually-identical results. The other three robust regression estimation methods available in SAS software were also tested and provided similar results, except when the LTS method is applied to the model for the West Zone.

Dampening the effects of outliers in the estimation is reasonable because price spikes occurred much more frequently in 2011, following the implementation of the nodal market, for reasons unrelated to the market structure switch. As noted above, the summer of 2011 was one of the hottest in the recorded history of Texas. Also, offer caps in the wholesale market were raised to $3,000 per MWh by the PUCT when the nodal market was implemented. Thus the increased frequency and level of wholesale price spikes was, at least in part, due to factors other than the introduction of a nodal market structure. The robust regression approach was adopted so that the price performance of the nodal market would not be "penalized" for these price spikes. Including an additional variable in the regression model to represent the level of the prevailing price or offer cap would be problematic because one of the changes in the level of the cap coincided with the introduction of the nodal market on December 1, 2010, thus prompting multicollinearity concerns. Thus, our modeling focuses on "normal" market conditions, rather than the periods of high prices which are intended to represent capacity scarcity payment to generation in ERCOT's energy-only design.

Certainly, a simulation approach using a production costing model would provide an alternative means of exploring this problem, although the model of price formation under price spike conditions is not well represented in any commercial models (Foley *et al*., 2010). Moreover, a simulation approach would require a lot of information that is not publicly-available. And, assumptions would need to be made about bidding behavior. As a result, we are relying exclusively upon publicly-available data to implement a transparent regression-based modeling approach. To be fair, whether this approach is empirically valid should be ultimately judged by the reasonableness of the empirical findings reported below.

4. Results

4.1 Nodal market price effects

A variety of specifications representing the relationship between electricity demand and prices were tested. Our base case uses a simple piecewise linear relationship, $Y_t = \alpha + \beta_1 X_{1t} + \beta_2 X_{2t} + \ldots,$ where X_1 represents the demand in the zone and X_2 *(HighDemand)* is set equal to the zonal demand if system demand is at or above the 90th percentile of demand and 0 otherwise.[8] Thus, the slope of the relationship between zonal demand and price is β_1 under most operating conditions, but increases to $\beta_1 + \beta_2$ when system demand is high.

Table 4 reports the regression coefficient estimates, all significant at the 1% level. [9] Under conditions not characterized by spikes in wholesale prices, the introduction of the nodal market is found to have lowered prices between \$0.54 and \$1.42 per MWh in the three larger

[8] The results are very similar if the 95th percentile is used to construct the dummy variable or high demand.
[9] If one is interested in the impacts of a 1000 MW change in baseload generation or the level of overall system demand upon wholesale prices, the coefficient estimates may be multiplied by 250 MWh (= 1000 MW * 15 minutes / 60 minutes per hour), instead of 1000 MWh.

zones, after controlling for the effects of natural gas prices, system demand, non-dispatchable generation, month of the year, operational alerts, day of the week, and hour of the day.

In this regression, variables expressing the interaction between the level zonal demand and the nodal dummy were dropped. The estimated coefficients were not consistently significant, and their inclusion led to some instability in the estimation. Lags of 16 intervals (4 hours) for the system alert were retained on the models for the West and South zones, but were reduced to 7 intervals for the other two zones. The longer lags had insignificant coefficients and some of the estimated coefficients had implausible (negative) signs in the North and Houston zones.

Table 4 shows that a $1/MMBTU increase in the natural gas price raises electricity wholesale prices by between $5.80 and $6.58 per MWh during the zonal market period in the three largest zones, suggesting marginal market-implied heat rates of around 6,000 Btu/kWh.[10] As reflected in the coefficient on the interaction between natural gas prices and the nodal dummy, these marginal heat rates were much lower in the nodal period, perhaps reflecting some efficiency gains. The price effects of non-dispatchable wind and nuclear generation are very similar for the non-West zones, lending support to our regression specification. The difference in price effects in the West zone is due to (a) all nuclear generation being outside the West zone, and (b) the transmission constraints that limit wind energy export from the West zone to non-West zones.

[10] Please note that this market heat rate value is a weighted average of relevant heat rates in some periods and negligible impacts in other periods. It does not reflect the heat rates of particular power plants.

Table 4. **Coefficient Estimates from Base Model**

Variable: coefficient	Dependent variable: market price			
	North	Houston	West	South
R^2	0.76	0.77	0.66	0.76
Nodal: ψ	6.214	8.075	4.125	8.124
Natural Gas Price: β_1	5.798	6.553	5.284	6.576
Zonal Demand: β_2	0.0081	0.0153	0.0696	0.0124
HighDemand: β_3	0.0005	0.0006	0.0086	0.0008
Wind Generation: β_4	-0.0071	-0.0076	-0.017	-0.0073
Nuclear Generation: β_5	-0.0055	-0.0051	-0.0049	-0.0062
Interaction of Nodal Dummy with:				
Natural Gas Price: μ_1	-1.528	-1.784	-3.721	-2.7
Wind Generation: μ_2	0.0035	0.0036	-0.0021	0.0023
Nuclear Generation: μ_3	-0.0018	-0.0021	0.0048	0.0017
Average Price Change ($/MWh)	-0.91	-0.54	-9.72	-1.42

For brevity, this table does not present coefficient estimates for the intercept and binary variables representing month, day, or hour. The impacts of alerts are also not reported, in light of its long lag structure. *P*-values for all estimates are below 0.0001.

As reported on the bottom row of Table 4, these estimated coefficients imply that the introduction of the nodal market has yielded average price declines in the North, Houston, and South zones of $0.91, $0.54, and $1.42 per MWh, respectively. This is the sum of the coefficient estimate for ψ and a term formed by the product of the estimates for (μ_1 to μ_3) and the mean values of natural gas price, wind generation and nuclear generation.[11]

[11] Estimation of our model with no interactions between the nodal dummy variable and explanatory variables yield results suggesting there have been no savings from the switch to a nodal market structure. We are grateful for comments form an anonymous reviewer which convinced us of the need to include interactive variables to capture how the change in market structure affected the formulation of wholesale prices.

4.2 Sensitivity analysis

To test the sensitivity of our estimates for the nodal effects, we tried alternative estimation techniques. Alternative estimation approaches included the MM method (Yohai 1987); the least trimmed squares high breakdown value estimator or LTS (Rousseeuw and Leroy 1987); and the S method (Rousseeuw and Yohai 1987). The results from robust regression are generally similar, regardless of the estimation algorithm used. However, the coefficient on the nodal dummy for the West zone strays from other estimates when the LTS method is applied.

We are inclined to downplay the high estimated change in prices for the small West Zone, due to the unusual market conditions in that small zone. The unusually-high load growth in that region has created many significant local transmission bottlenecks recently. Recent high local prices in the areas of West Texas are due to strong economic growth. Inadequacies in the transmission infrastructure in that region cannot be readily controlled for in our model. This situation has recently drawn attention from the PUCT and the state's legislature.

A number of variables were added in hopes of obtaining more-realistic coefficient estimates for the West zone. Wind generation divided by demand in the West zone was tested, but the estimated coefficient assumed a value with the wrong sign. A variable representing Texas crude oil production was tested for inclusion in the models for both the West and South zones, but its inclusion had little effect on the values of the other coefficients. Given the difficulties inherent in modeling the anomalous situation in that zone, we opine that our results for the West zone should be downplayed.

Table 5 presents the results when a 3^{rd}-order polynomial expression is used to represent the relationship between the level of demand in a zone and the wholesale price. A properlyspecified polynomial relationship should also be able to reflect the non-linear relationship between zonal demand and wholesale prices. The levels of estimated savings are just slightly lower. We have omitted results for the West zone, since the estimated coefficients on the polynomial representing the relationship between zonal load and prices in that zone failed to yield a well-behaved monotonically-increasing relationship.

Table 5. **Coefficient Estimates from Model using Zonal, rather than System, Load**

Variable: coefficient	Dependent variable: market price		
	North	Houston	South
R^2	0.76	0.77	0.76
Nodal: ψ	5.614	6.478	6.919
Natural Gas Price: β_1	5.707	6.264	6.455
(Zonal Demand: β_2	0.0236	0.0679	0.0504
(Zonal Demand)^2: β_3	-4.447	-18.95	-14.048
(Zonal Demand)^3: β_4	0.411	2.245	1.707
Wind Generation: β_5	-0.0071	-0.0077	-0.0073
Nuclear Generation: β_6	-0.0056	-0.0052	-0.0066
Interaction of Nodal Dummy with:			
Natural Gas Price: μ_1	-1.461	-1.474	-2.544
Wind Generation: μ_2	0.0035	0.0036	0.0022
Nuclear Generation: μ_3	-0.0016	-0.0018	0.0023
Average Price Change ($/MWh)	-0.95	-0.34	-1.24

For brevity, this table does not present coefficient estimates for the intercept and binary variables representing month, day, or hour. The impacts of alerts are also not reported, in light of its long lag structure. *P*-values for all estimates are below 0.0001. (Zonal Demand)^2 was divided by 1,000,000 and (Zonal Demand)^3 was divided by 1,000,000,000 in order to illuminate β_3 and β_4.

4.3 Summary

In summary, we considered numerous approaches to compare the prices faced by un-hedged LSEs and industrial energy consumers who opt for a real-time pricing product under the two market structures. Those which we judged to be the most empirically plausible found a reduction in price following the introduction of the nodal market under “normal” market conditions (i.e., conditions not characterized by spikes in wholesale prices). Our results for the West zone are impaired by some recent local transmission bottlenecks for which we cannot readily control using econometric models, and are consequently downplayed.

5. Interpretation of results

When interpreting these results, a number of factors should be kept in mind. First, it is possible that the differences in the price changes in the different zones is, in part, attributable to how certain costs were allocated to the various zones under ERCOT’s former market rules. During the zonal market period, many costs incurred in a particular zone were allocated among all zones. Under both zonal and nodal market operations, portions of the revenues from the auction of transmission rights may be credited to all zones, though such transmission lines may have greater benefits to LSE in some zones more than others. Many of ERCOT’s formulas for allocating costs and revenues were changed when the market structure changed. This may explain some of the differences in our results for different zones within ERCOT.

Second, other changes coincided with the change from a zonal to nodal market, and are thus difficult to control for using statistical methods. As mentioned earlier, the zonal market relied upon 15-minute operating intervals, while SCED is solved and resources are provided with dispatch instructions every five minutes – or more often – under the nodal market structure. One consequence of the increased frequency of dispatch instructions was a reduction in the need for regulation ancillary services (i.e., governor response) from power plants, which has freed-up power plants to provide generation or other ancillary services.[12] The change in market structure also resulted in an initial loss of demand response when the advance notice of real-time balancing energy prices that LSEs and large industrial energy consumers enjoyed under the zonal market was replaced with after-the-fact calculations of nodal prices under the new market. This initial lack of advanced price information also hampered the ability of fast-start generators to participate effectively in the market. A day-ahead market was also introduced as the nodal market opened.

Finally, some of the unique recent problems in West Texas are difficult to control for using a statistical model. One might suspect each of these changes to have also had some impact on wholesale market prices.

6. Conclusions

We contribute to the debate over the benefits and costs of transitioning a zonal electricity market to a nodal market structure by analyzing how the costs paid by LSEs in the ERCOT market were affected when ERCOT changed its structure. After controlling for differences in the fundamental drivers of wholesale prices and making necessary price adjustments, we find that the costs paid by LSEs declined, on average, in ERCOT in the months following the adoption of a nodal market. We estimate that the declines in the North, Houston, and South zones were between 1.3% and 3.3%, using a piecewise linear relationship between zonal demand

[12] In hopes of controlling for this effect, data on physical reserves for each 15-minute period during the time the zonal market was in operation was requested. However, ERCOT was not able to fulfill this request.

and prices or between 0.8% and 2.9% if a 3rd-order polynomial relationship between demand and prices is assumed. These savings are about 2%, when the savings in each of the three largest zones are weighted based on the relative sizes of those zones.

Ironically, the reduction in wholesale prices from the implementation of the nodal market might be viewed by some as a concern. In recent years, low natural gas prices and increased wind farm generation have also reduced electricity prices in ERCOT which has, in turn, impaired the economics of power plant construction (Woo, et al., 2012). Having no “capacity market” or other means of enforcing minimum planning reserve margins, resource adequacy became the market’s top concern in 2012 and 2013. This led the PUCT to explore means of raising prices to encourage investment in new resources. It appears as though the nodal market’s design may have contributed to the drop in prices that the PUCT has now sought to reverse.

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