Deliverability and Regional Pricing in U.S. Natural Gas Markets

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Abstract: During the 1980s and early 90s, interstate natural gas markets in the United States made a transition away from the regulation that characterized the previous three decades. With abundant supplies and plentiful pipeline capacity, a new order emerged in which freer markets and arbitrage closely linked natural gas price movements throughout the country. After the mid-1990s, however, U.S. natural gas markets tightened and some pipelines were pushed to capacity. We look for the pricing effects of limited arbitrage through causality testing between prices at nodes on the U.S. natural gas transportation system and interchange prices at regional nodes on North American electricity grids. Our tests do reveal limited arbitrage, which is indicative of bottlenecks in the U.S. natural gas pipeline system.

1. Introduction

During the 1980s and early 90s, interstate natural gas markets in the United States made a gradual transition away from the regulation that had characterized the three previous decades. The 1978 Natural Gas Policy Act and subsequent actions by the Federal Energy Regulatory Commission and the U.S. Congress gradually opened up interstate natural gas pricing to market forces. With plentiful pipeline capacity, a surge in natural gas production and growth in consumption, a new order emerged in which freer markets and arbitrage closely linked movements in natural gas prices throughout the United States, as De Vany and Walls (1993, 1995, 1999), Doane and Spulber (1994), and MacAvoy (2000) have documented. Production varied to meet seasonal changes in demand, and prices did not show much volatility.

U.S. natural gas markets continued to evolve throughout the 1990s. Natural gas consumption grew—propelled by the rapid growth of its use in electric power generation, which was driven by regulatory changes and the emergence of new technology. As consumption grew, production and net imports failed to keep pace with the gains in heating season demand (**Figure**

1). Summer production and imports gradually rose to near winter levels, and the market relied more heavily on storage to meet the seasonal variation in demand.[1] At the same time, prices became more volatile.[2] Moreover, once pipeline companies were no longer guaranteed a rate of return (MacAvoy 2000), their incentives to build the excess capacity necessary to accommodate rising peak winter usage was reduced.

By 2000, U.S. natural gas markets looked substantially different than they had in the late 1980s. With the seasonal variation in consumption dependent on inventories rather than changes in production, prices became more volatile, and according to Brown and Yücel (2007), inventory swings figured prominently in that volatility. In addition, as some pipelines were pushed to capacity, the physical means for arbitrage was limited, and the links between regional natural gas prices throughout the United States seemingly weakened, as shown by Marmer, et al. (2007).

These changes in market conditions raise a question about how well the pipeline system supports the arbitrage required to integrate regional natural gas markets in the United States. To examine this issue, we use a series of causality tests to assess whether arbitrage between Henry Hub and two regional nodes on the U.S. natural gas transmission system has become limited. The tests involve daily natural gas prices at Henry Hub and two regional nodes on the U.S. natural gas transmission system, as well as electricity prices at two regional interchange nodes on the North American electricity grids—with these electricity prices being indicative of regional demand conditions for natural gas. Our testing reveals limited arbitrage, which suggests that a lack of pipeline capacity contributes to the volatility of regional natural gas prices in the United States.

2. Price Shocks and Regional Natural Gas Markets

To examine how natural gas price shocks are transmitted across the United States and how fluctuations in regional demand might influence natural gas pricing, we undertake a series of causality tests involving daily natural gas and electricity prices at major trading nodes for the period February 3, 1997 through January 17, 2007. The natural gas prices include those at Henry Hub, Transco Zone 6 and Topock, and the electricity prices are for PJM and Palo Verde. Although regulation may affect the demand and supply conditions at any of these five trading nodes, the prices at each are set by the interaction of market forces.

Henry Hub can thought of as the principal upstream market for natural gas in the United States. Near New Orleans, Henry Hub comprises a series of 16 pipeline interconnects at a single facility that draw their supplies from the largest concentration of natural gas producing regions in the country and nearby terminals for importing Liquefied Natural Gas (LNG). These pipelines directly serve markets throughout the U.S. East Coast, the Gulf Coast, the Midwest, and up to the Canadian border. Interconnections with pipelines across Texas link the Henry Hub market to those in the U.S. West. Serletis and Herbert (1999) find that the Henry Hub spot price is strongly correlated with the NYMEX futures price, which is the most widely traded natural gas contract in the world. As such, the Henry Hub price represents a national market price for natural gas that is determined relatively close to the wellhead.

Transco Zone 6 and Topock are two regional trading nodes on the North American natural gas transmission system downstream from Henry Hub, and their prices represent market conditions in the U.S. East and U.S. West, respectively. Transco Zone 6 is a natural gas market center along 300 miles of pipeline, covering a six-state area from Virginia to New York City.

Topock is a regional transportation and pricing node for natural gas on the California-Arizona border.

In the two regions we examine, considerable natural gas is used to generate electricity. Moreover, natural gas is the marginal fuel for generating electricity in both regions (Hartley et al, 2007). Consequently, fluctuations in electricity prices can be used to examine how changing regional demand affects the dynamics of U.S. natural gas markets. Accordingly, we consider the interchange electricity prices at two major nodes on the North American electricity grid—PJM in the East and Palo Verde in the West.[3] PJM is a system of interconnected transmission lines that functions as an interchange to supply electric power for Central and Eastern Pennsylvania, nearly all of New Jersey, Delaware, Western Maryland, and Washington D.C. Originally developed as a switch yard for the Palo Verde nuclear power plant in Arizona, Palo Verde is an electricity transmission interchange that offers direct access to power generation and demand centers throughout the U.S. Southwest and southern California. It can also serve markets in the Pacific Northwest and northern Rockies through interconnecting transmission lines.

2.1 Testing for Arbitrage

We test for causality in two chains of prices. For the U.S. East, the chain from upstream to downstream is Henry Hub, Transco Zone 6 and PJM. In the U.S. West, the chain from upstream to downstream is Henry Hub, Topock and Palo Verde. As shown in **Figures 2 and 3**, prices in each of the two groupings are likely to show correlation. The causality tests allow us to trace price shocks that originate close to natural gas supplies, are transmitted downstream to regional natural gas markets, and are pushed onward to regional electricity markets. They also allow us to investigate whether shocks originating in regional electricity markets are transmitted backward to regional natural gas markets and then upstream to Henry Hub. Taken together, the causality tests can reveal whether natural gas prices are well arbitraged between Henry Hub and the two regional trading nodes. A lack of such arbitrage would imply delivery constraints in the natural gas pipeline system.

In the absence of delivery constraints, we would not expect variations in regional conditions (such as regional demand for natural gas to generate electricity) to exert an influence on regional natural gas prices without also affecting the price at Henry Hub. Any regional fluctuation in natural gas demand would be supplied by the national market, and the regional price fluctuations would be arbitraged back to the Henry Hub price. With pipelines reaching capacity or natural gas flows otherwise restricted, arbitrage could be limited. Regions with constrained delivery could see natural gas price movements that are independent of those at Henry Hub. Such bottlenecks could be the result of physical limitations, regulatory inhibitions, or monopolization.[4]

An alternative approach to ours is to test for simple cointegration between upstream and downstream natural gas prices. The lack of simple cointegration between natural gas prices across regions would suggest the possibility of a breakdown in the law of one price brought about by the lack of arbitrage. Cointegration testing does not allow for the potential influence of intervening factors, such as changes in transportation costs, that might affect long-term pricing relationships without being indicative of a breakdown in arbitrage. The causality testing we undertake provides a more comprehensive examination of the transmission of price shocks, and when it reveals a breakdown in arbitrage, there is greater assurance that such a breakdown has occurred.[5]

2.2 About the Data

For purposes of analysis, we use daily data covering the period from February 3, 1997 through January 17, 2007. These data cover a nearly ten-year period after the seasonality of production has come to an end and storage is used to meet seasonal swings in demand. The period also contains numerous episodes of volatile natural gas and electricity prices.

As the first step in our analysis, we examine the properties of each price series as represented in natural logs. The two regional natural gas prices are somewhat more volatile than the Henry Hub price, although the volatility of the Transco Zone 6 price is lower relative to its mean (**Table 1**). We see more price volatility in the U.S. West, with the electricity price more volatile than the natural gas price.

Augmented Dickey-Fuller tests reveal that natural gas prices at Henry Hub and Topock and the electricity price at Palo Verde are difference stationary (**Table 2**). Similar testing finds that the natural gas price at Transco Zone 6 and the electricity price at PJM are trend stationary.

2.3 Cointegration Tests

The finding that the Henry Hub, Topock and Palo Verde prices are difference stationary raises the possibility that these series may be cointegrated. Two integrated series are cointegrated if they move together in the long run. Cointegration implies a stationary, long-run relationship between the two difference-stationary series. As such, the cointegrating term provides information about the long-run relationship. If cointegration is not taken into account, the relationship between the cointegrated variables could be misspecified, and/or parameters could be inefficiently estimated.[6]

The Johansen procedure reveals that Henry Hub and Topock prices are trend cointegrated, which implies a long-term relationship with a drift (**Table 3**). The estimated value of β is 1.007, which indicates that a one-percent change in the Henry Hub price is met with about a one-percent change in the Topock price and vice-versa. The adjustment coefficients are -.0140 for Henry Hub and .0277 for Topock, indicating that the Topock price adjusts to errors in the long-term relationship between the two prices at about twice the rate that the Henry Hub price adjusts. Similar testing finds the electricity price at Palo Verde price is neither cointegrated nor trend cointegrated with the Henry Hub or Topock natural gas prices at the five-percent level (**Table 3**).

2.4 Bivariate Models and Estimation Procedures

Causality testing generally requires the use of stationary variables. Accordingly, our causality tests use differences of logged prices at Henry Hub, Topock and Palo Verde, and deviations from trends in the logged prices at Transco Zone 6 and PJM. Errors in the trend cointegrating relationship are also used in causality tests involving Henry Hub and Topock prices together.

We use standard causality testing to examine how price changes are transmitted between natural gas and electricity pricing nodes. All tests are conducted with natural logs of the variables in their stationary form. For any pair of upstream and downstream prices that do not have a cointegrating relationship, we use the following generalized specification to test for causality:

$$SPD_t = a_1 + \sum_{i=1}^{n} b_{1i} SPU_{t-i} + \sum_{i=1}^{n} c_{1i} SPD_{t-i} + \mu_{1t} \quad \textbf{(1)}$$

$$SPU_t = a_2 + \sum_{i=1}^{n} b_{2i} SPD_{t-i} + \sum_{i=1}^{n} c_{2i} SPU_{t-i} + \mu_{2t} \quad \textbf{(2)}$$

where SPD_t and SPU_t represent the appropriate stationary form of the downstream and upstream prices, respectively; a_1, a_2, b_{1i}, b_{2i}, c_{1i} and c_{2i} are parameters to be estimated; and μ_{1t} and μ_{2t} are white noise residuals.

Because the Henry Hub and Topock price series are cointegrated, we account for cointegration in their relationship by specifying a vector error-correction model in which changes in the dependent variable are expressed as changes in both the independent and the dependent variable, plus an error-correction term, as recommended by Engle and Granger (1987). For cointegrated variables, the error-correction term reflects the deviations from the long-run cointegrating relationship between the variables. The coefficient on the equilibrium error reflects the extent to which the dependent variable adjusts during a given period to deviations from the cointegrating relationship that occurred in the previous period. The resulting model is as follows:

$$\Delta PD_t = a_3 + \sum_{i=1}^{n} b_{3i} \Delta PU_{t-i} + \sum_{i=1}^{n} c_{3i} \Delta PD_{t-i} + \alpha_3 CI_{t-1} + \mu_{3t} \tag{3}$$

$$\Delta PU_t = a_4 + \sum_{i=1}^{n} b_{4i} \Delta PD_{t-i} + \sum_{i=1}^{n} c_{4i} \Delta PU_{t-i} + \alpha_4 CI_{t-1} + \mu_{4t} \tag{4}$$

where the *CI* is errors in the estimated trend cointegrating relationship (PD-α-$\beta \cdot PU$-γt); a_3, a_4, b_{3i}, b_{4i}, c_{3i}, $c_{4i,}$ α_3 and α_4 are parameters to be estimated; and μ_{3t} and μ_{4t} are white noise residuals.[7] The coefficients α_3 and α_4 represent the adjustment to equilibrium error in the long-term relationship between the upstream and downstream prices.

For the models that do not contain a cointegrating relationship, causality runs from the upstream to the downstream price if the b_{1i} are jointly significant. Similarly, causality runs from the downstream price to the upstream price if the b_{2i} are jointly significant. For the error-correction models, causality runs from the upstream price to the downstream price if α_3 and the b_{3i} are jointly significant, and causality runs from the downstream price to the upstream price if α_4 and the b_{4i} are jointly significant.

2.5 Natural Gas and Electricity Pricing

In examining the transmission of price shocks between Henry Hub and the two regional natural gas nodes, we find bidirectional causality (Table 4). Movements in the Henry Hub price lead movements in Transco Zone 6 and Topock prices.[8] In addition, movements in the two regional natural gas prices lead those at Henry Hub.[9]

In both the U.S. East and U.S. West, we find bidirectional causality between regional natural gas and electricity prices. Movements in the Transco Zone 6 and Topock prices lead those of the PJM and Palo Verde prices, respectively. Similarly, movements in the PJM and Palo Verde electricity prices lead the natural gas prices in their respective regions.

Such findings are expected because natural gas is the marginal fuel most commonly used for electricity generation in these two regions. When a region's electricity prices are driven up by strong demand, the demand for natural gas is likely to rise in the region, pulling up its price. Similarly, when regional natural gas prices are pushed up by more costly supply, the cost of electricity generation will rise in the region.

We also find no causality between the Henry Hub natural gas price and regional electricity prices. Because regional electricity prices influence natural gas price movements in their respective regions, the absence of a relationship with the Henry Hub price of natural gas suggests the likelihood that regional electricity prices exert an independent influence on regional natural gas prices that is not arbitraged back to Henry Hub.

3. Assessing the Influence of Regional Electricity Prices

Multivariate tests provide a means to more throughly assess the possibility that regional electricity prices exert an independent influence on regional natural gas prices that are are not arbitraged back to Henry Hub. For the U.S. East market, we specify the following multivariate tests:

$$STZ6_t = a_5 + \sum_{i=1}^{n} b_{5i} SHH_{t-i} + \sum_{i=1}^{n} c_{5i} STZ6_{t-i} + \sum_{i=1}^{n} d_{5i} SPJM_{t-i} + \mu_{5t} \quad \textbf{(5)}$$

$$SHH_t = a_6 + \sum_{i=1}^{n} b_{6i} STZ6_{t-i} + \sum_{i=1}^{n} c_{6i} SHH_{t-i} + \sum_{i=1}^{n} d_{6i} SPJM_{t-i} + \mu_{6t} \quad \textbf{(6)}$$

where *STZ6* is the stationary form of the natural gas price at Transco Zone 6; *SHH* is the stationary form of the natural gas price at Henry Hub; *SPJM* is the stationary form of the electricity price at PJM; a_5, a_6, b_{5i}, b_{6i}, c_{5i}, c_{6i}, d_{5i} and d_{6i} are parameters to be estimated; and μ_{5t} and μ_{6t} are white noise residuals. Equation 5 can be used determine whether PJM electricity prices exert an independent influence on Transco Zone 6 natural gas prices when the effects of Henry Hub prices are taken into account. Similarly, equation 6 can used to determine whether the regional electricity prices affect natural gas prices at Henry Hub natural when Transco Zone 6 prices are taken into account.

For the U.S. West market, where Henry Hub and Topock prices are trend cointegrated, we specify the following tests:

$$\Delta PT_t = a_7 + \sum_{i=1}^{n} b_{7i}\Delta PHH_{t-i} + \sum_{i=1}^{n} c_{7i}\Delta PT_{t-i} + \sum_{i=1}^{n} d_{7i}\Delta PPV_{t-i} + \alpha_7 CI_{t-1} + \mu_{7t} \quad \textbf{(7)}$$

$$\Delta PHH_t = a_8 + \sum_{i=1}^{n} b_{8i}\Delta PT_{t-i} + \sum_{i=1}^{n} c_{8i}\Delta PHH_{t-i} + \sum_{i=1}^{n} d_{8i}\Delta PPV_{t-i} + \alpha_8 CI_{t-1} + \mu_{8t} \quad \textbf{(8)}$$

where *PT* is the price of natural gas at Topock; *PHH* is the price of natural gas at Henry Hub; *PPV* is the price of electricity at Palo Verde; *CI* is errors in the trend cointegrating relationship between Henry Hub and Topock prices; a_7, a_8, b_{7i}, b_{8i}, c_{7i}, c_{8i}, d_{7i}, d_{8i}, α_7 and α_8 parameters to be estimated; and μ_{7t} and μ_{8t} are white noise residuals. Equation 7 can be used to determine whether Palo Verde electricity prices exert an independent influence on Topock natural gas prices when the effects of Henry Hub prices are taken into account. Similarly, equation 8 shows can be used to determine whether regional electricity prices affect natural gas prices at the Henry Hub when Topock prices are taken into account.

As shown in Table 5, the two pairs of tests provide similar results. In both regions, the Henry Hub price has a significant effect on regional natural gas prices. In addition, each regional electricity price exerts a significant independent influence on its respective regional natural gas price. Natural gas prices in both regions have a significant effect on Henry Hub prices, but electricity prices in neither region are significant.

Movements in regional natural gas prices are shaped by movements in both Henry Hub natural gas prices and regional electricity prices. The influence of regional electricity prices on regional natural gas prices is not arbitraged back to Henry Hub. The lack of arbitrage suggests constraints in natural gas delivery from Henry Hub to both the U.S. East and U.S. West markets.

4. Conclusion: Delivery Constraints and U.S. Natural Gas Prices

The agents in the newly deregulated U.S. interstate natural gas market inherited a pipeline system with a regulatory-era capacity that facilitated relatively free-flowing natural gas and arbitrage. As consumption grew, however, capacity along existing lines failed to keep pace because the new environment didn't offer the incentives for pipeline companies to build the capacity necessary to handle rising peak loads. The result has been bottlenecks and a breakdown in the pricing conditions once found in the newly freed natural gas market.

Electricity prices in both the East and West markets exert an independent influence on natural gas prices in their respective regions, but these effects are not arbitraged back to the natural gas price at Henry Hub. These findings imply that delivery constraints limit the arbitrage between regional natural gas markets—with regional prices driven by factors that are independent of those in play at Henry Hub.

Our findings suggest that an assessment of the market conditions that follow shortly after a market restructuring should be considered preliminary. In the wake of restructuring, the inherited capital stock will reflect the regulatory environment in which it was created, rather than new market realities. Over time, the new environment will reshape the capital stock—whether the changes reflect simple market incentives, new regulatory inhibitions and/or monopolization. For natural gas, the result has been the development of bottlenecks in the regional transmission of natural gas, which seem to have inhibited arbitrage during episodes of peak demand and reduced the integration of prices across the United States.

5. Post Script: Natural Gas Storage

Brown and Yücel (2007) find that storage is an important determinant of the U.S. natural gas prices. Natural gas storage might also play role in the relationship between Henry Hub and regional natural gas prices. In particular, regional storage can be a substitute for transmission capacity, and low storage volumes in a given region may be associated with associated with sharp natural gas price movements during episodes of strong regional demand. Because storage data are available only on a weekly basis and for three relatively large geographic regions, we leave such an investigation for further research.

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Figure 1
U.S. Natural Gas Consumption, Production and Imports

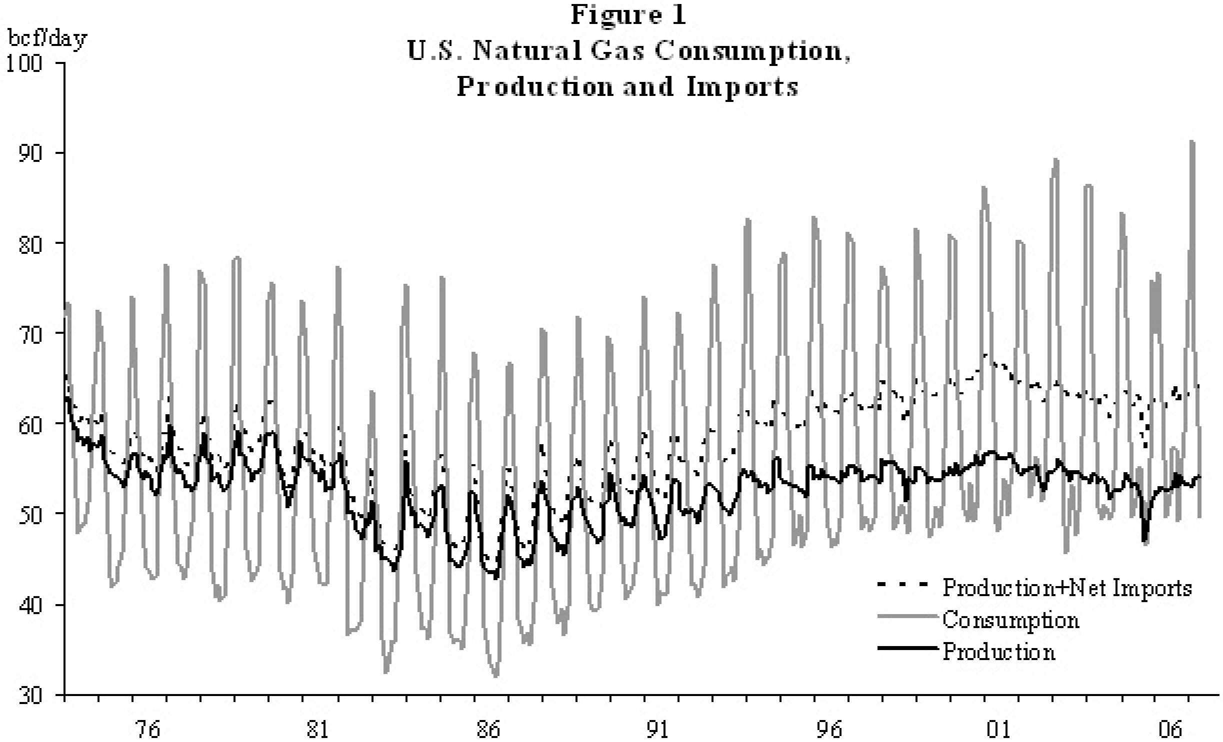
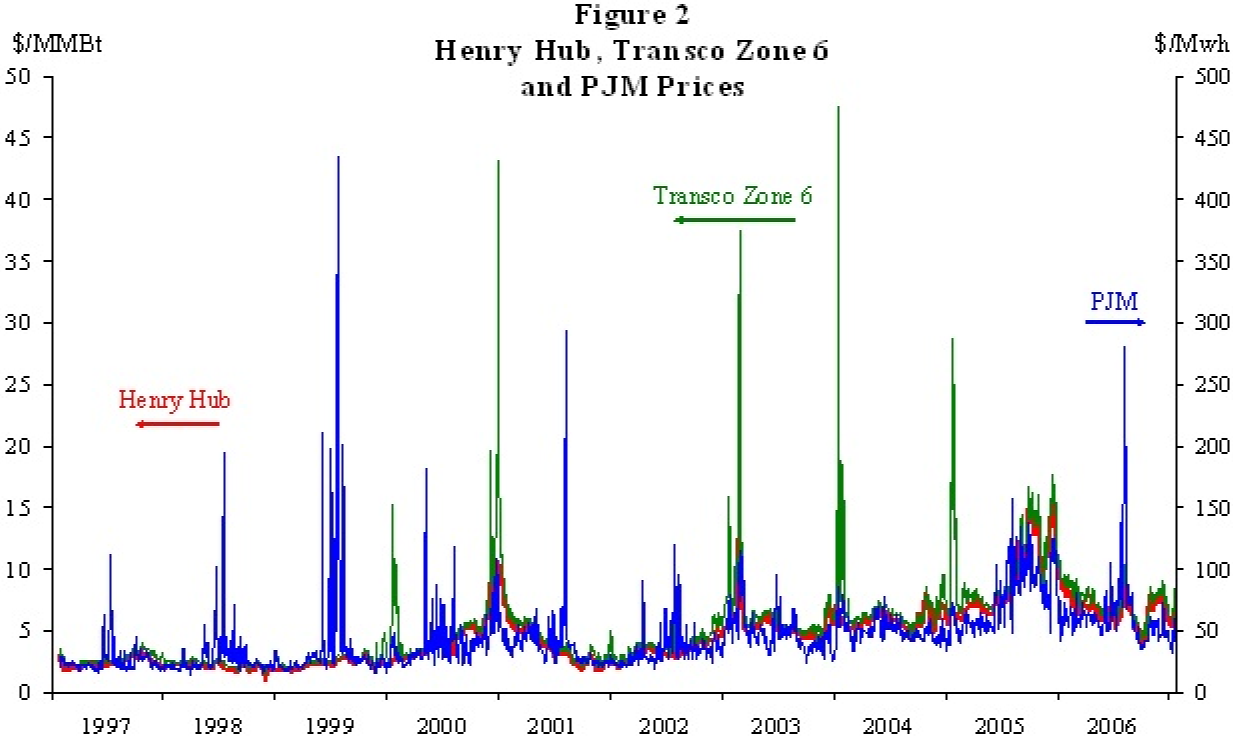


Figure 2
Henry Hub, Transco Zone 6 and PJM Prices



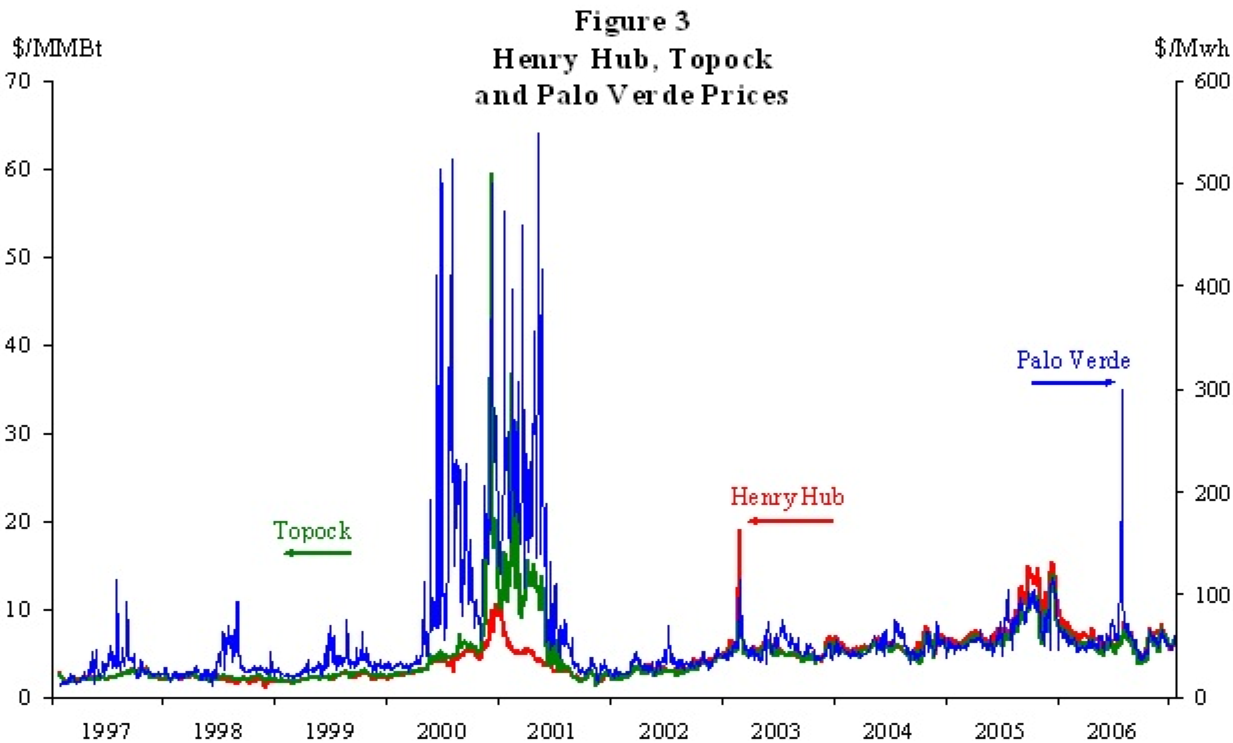


Figure 3
Henry Hub, Topock
and Palo Verde Prices
$/MMBt
$/Mwh
70
60
50
40
30
20
10
0
600
500
400
300
200
100
0
Topock
Henry Hub
Palo Verde
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006

Table 1: Descriptive Statistics
(Logs of Daily Data, February 3, 1997 through January 17, 2007)

	Henry Hub	Transco Zone 6	Topock	PJM	Palo Verde
Mean	1.3744	1.5152	1.4136	3.6640	3.8263
Median	1.4351	1.5476	1.4940	3.6507	3.7600
Std. Dev.	0.5188	0.5327	0.5641	0.4871	0.6362
Normalized Std. Dev.	37.75	35.16	39.91	13.29	16.63

Table 2: Unit Root Tests
(Logs of Daily Data, February 3, 1997 through January 17, 2007)

	Augmented Dickey-Fuller Tests		
variables	Levels	Linear Trend	First Differences
Henry Hub	-1.6340	-2.6514	-12.3499**
Transco Zone 6	-2.0612	-3.4487*	n/a
Topock	-1.8280	n/a†	-12.0731**
PJM	-4.8706**	-5.3210**	n/a
Palo Verde	-2.3100	n/a†	-9.4332**

+, * and ** denote significance at better than 0.1, 0.05 and 0.01 percent, respectively. †Linear trend is not significant.

Table 3 A: Bivariate Johansen Cointegration Tests
(Henry Hub and Topock)

	Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
logged	p=0	0.00435	13.3972	9.1727
	p≤1	0.002	4.224*	4.224*
	Standardized Eigenvalues or βs with Standard Errors			
		Henry Hub	Topock	
		1	-1.00674	
		0	(0.1454)	
	Standardized α Coefficients with Standard Errors			
		Henry Hub	Topock	
		0.003932	0.01737	
		(0.00406)	(0.00593)	
logged, with trend	Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
	p=0	0.009735	27.63621**	20.58261*
	p≤1	0.003347	7.053602	7.053602
	Standardized Eigenvalues or βs with Standard Errors			
		Henry Hub	Topock	Trend
		1	-0.527475	-0.000303
		0	(0.06947)	(5.1E-05)
	Standardized α Coefficients with Standard Errors			
		Henry Hub	Topock	
		-0.01399	0.027694	
		(0.00741)	(0.01083)	

$^{+}$, * and ** denote significance at better than 0.1, 0.05 and 0.01 percent, respectively.

Table 3 B. Bivariate Cointegration Tests
(Henry Hub and Palo Verde)

	Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
logged	p=0	0.004943	9.7879	7.537251
	$p \leq 1$	0.001479	2.250734	2.250734
	Standardized Eigenvalues or βs with Standard Errors			
		Henry Hub	Palo Verde	
		1	-0.766694	
		0	(0.17212)	
	Standardized α Coefficients with Standard Errors			
		Henry Hub	Palo Verde	
		0.000123	0.032338	
		(0.00359)	(0.01204)	
logged, with trend	Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
	p=0	0.008694	16.84569	13.28132
	$p \leq 1$	0.002341	3.564371	3.564371
	Standardized Eigenvalues or βs with Standard Errors			
		Henry Hub	Palo Verde	Trend
		1	-0.445159	-0.000366
		0	(0.082769)	(0.00011)
	Standardized α Coefficients with Standard Errors			
		Henry Hub	Palo Verde	
		-0.008004	0.065314	
		(0.00605)	(0.02028)	

+, * and ** denote significance at better than 0.1, 0.05 and 0.01 percent, respectively.

Table 3 C. Bivariate Cointegration Tests
(Topock and Palo Verde)

<table>
<tr><td rowspan="4">logged</td><td>Ho:
rank=p</td><td>Eigenvalue</td><td>Trace Statistic</td><td>Max
Eigenvalue
Statistic</td></tr>
<tr><td>p=0
p≤1</td><td>0.006362
0.002013</td><td>12.79010
3.069084+</td><td>9.721013
3.069084+</td></tr>
<tr><td colspan="4">Standardized Eigenvalues or βs with Standard Errors

Topock: 1, 0
Palo Verde: -0.895093, (0.12131)</td></tr>
<tr><td colspan="4">Standardized α Coefficients with Standard Errors

Topock: -0.009356, (0.00683)
Palo Verde: 0.036427, (0.01483)</td></tr>
<tr><td rowspan="4">logged, with trend</td><td>Ho:
rank=p</td><td>Eigenvalue</td><td>Trace Statistic</td><td>Max
Eigenvalue
Statistic</td></tr>
<tr><td>p=0
p≤1</td><td>0.007511
0.002022</td><td>14.56483
3.08294</td><td>11.48188
3.08294</td></tr>
<tr><td colspan="4">Standardized Eigenvalues or βs with Standard Errors

Henry Hub: 1, 0
Palo Verde: -0.80714, (0.10615)
Trend: -0.000203, (0.00014)</td></tr>
<tr><td colspan="4">Standardized α Coefficients with Standard Errors

Henry Hub: -0.011942, (0.00771)
Palo Verde: 0.043952, (0.01672)</td></tr>
</table>

+, * and ** denote significance at better than 0.1, 0.05 and 0.01 percent, respectively.

Table 4. Bivariate Causality Tests for Natural Gas and Electric Prices

U.S. East Markets	Dependent Variables					
explanatory variables	Transco Zone 6	Henry Hub	PJM	Transco Zone 6	PJM	Henry Hub
Henry Hub	.0000**	.0000**			.2364	.0000**
Transco Zone 6	.0000**	.0001**	.0007**	.0000**		
PJM			.0000**	.0113*	.0000**	.1346
Optimal Lags	18	18	8	8	19	19
	R^2=.94 Adj R^2=.94	R^2=.06 Adj R^2=.05	R^2=.77 Adj R^2=.77	R^2=.94 Adj R^2=.94	R^2=.77 Adj R^2=.77	R^2=.06 Adj R^2=.04

U.S. West Markets	Dependent Variables					
explanatory variables	Topock†	Henry Hub†	Palo Verde	Topock	Palo Verde	Henry Hub
Henry Hub	.0000**	.0000**			.4649	.0000**
Topock	.0000**	.0076**	.0001**	.0000**		
Palo Verde			.0000**	.0000**	.0000**	.2165
Optimal Lags	30	30	30	30	30	30
	R^2=.25 Adj R^2=.23	R^2=.08 Adj R^2=.05	R^2=.20 Adj R^2=.17	R^2=.27 Adj R^2=.24	R^2=.18 Adj R^2=.15	R^2=.08 Adj R^2=.05

Optimal lag length is determined by the Akaike information criterion. †Causality test includes term to account for errors in trend cointegration. Reported values are joint significance—with $^+$, * and ** denoting significance at better than 0.1, 0.05 and 0.01 percent, respectively.

Table 5. Multivariate Tests for Natural Gas Prices

U.S. East Markets			U.S. West Markets		
	Dependent Variables		Dependent Variables		
explanatory variables	Transco Zone 6	Henry Hub	Topock†	Henry Hub†	explanatory variables
Henry Hub	.0000**	.0000**	.0000**	.0000**	Henry Hub
Transco Zone 6	.0000**	.0000**	.0000**	.0033*	Topock
PJM	.0400*	.6344	.0000**	.8639	Palo Verde
Optimal Lags	11	15	6	15	Optimal Lags
	R^2=.95 Adj R^2=.95	R^2=.07 Adj R^2=.05	R^2=.22 Adj R^2=.21	R^2=.06 Adj R^2=.04	

Optimal lag length is determined by the Akaike information criterion. †Causality test includes term to account for errors in trend cointegration between Topock and Henry Hub. Reported values are joint significance—with $^{+}$, * and ** denoting significance at better than 0.1, 0.05 and 0.01 percent, respectively.

Notes:

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1. In the average year, inventories are built during May, June, July, August, September and October, when U.S. natural gas production and imports typically exceed consumption. In the average year, U.S. natural gas consumption exceeds production and imports in November, December, January, February and March. During those months, current production, imports *and* inventories are used to meet consumption.

2. Over the period from January 1996 through May 2007, the monthly wellhead price of natural gas had a normalized standard deviation nearly three times higher than that for the period from January 1985 through December 1995.

3. The North American electricity grid is broken up into a number of nearly autonomous regions, which prevents the direct arbitrage of prices by moving electricity across the continent.

4. See Natural Gas Regulation Committee (2002).

5. A more complete model of natural gas pricing could reveal periods of time in which regional and Henry Hub prices of natural gas prices move together and periods in which capacity constraints prevent arbitrage. If the episodes without arbitrage occur with sufficient frequency, causality testing will be sufficient to reveal a breakdown in arbitrage. Such testing will not identify the specific episodes.

6. See Engle and Yoo (1987).

7. If a one-unit change in the upstream price occurs over the long run, it will be met with a β change in the downstream price over the long run.

8. The model for Henry Hub and Topock prices yields estimated coefficients on the cointegrating term of -0.0114 and .0327 for Henry Hub and Topock equations, respectively — with only the latter coefficient significant at better than 5 percent.

9. These findings are similar to those of Brown and Yücel (1993), who found that price shocks transmitted through U.S. natural gas markets could originate either at the wellhead or in those end-use markets in which extensive fuel-switching is possible.