Assessing the Degree of Spot Market Integration For U.S. Natural Gas: Evidence from Daily Price Data

by

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Abstract: This paper assesses the degree of market integration in the U.S. natural gas market following the FERC's 'open access' reforms of the late 1980s. Daily spot prices at 76 market locations from 1993 to 1997 are used to examine (i) the geographic extent of the market, which depends on the extensiveness of LOOP equilibrium conditions throughout the pipeline network and (ii) the *speed* with which market forces move prices toward equilibrium in the face of ongoing price shocks.

Our empirical results suggest that the East and Central regions form a highly integrated market, but that this market is quite segmented from the more loosely integrated Western market. Thus, although the FERC reforms have contributed towards national integration, limited physical connectivity between the West and the other regions leaves incomplete the agenda of creating a single national market for natural gas.

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I. Introduction

In the 1980s and early 1990s, the Federal Energy Regulatory Commission (FERC) implemented a series of far-reaching regulatory reforms. These reforms were designed to decouple the production and trading of the commodity natural gas from its transportation. Advocates argued that the production and consumption of natural gas involves many buyers and sellers for a very homogeneous product. Pipeline transportation service, on the other hand, is highly concentrated and therefore needs some sort of regulatory oversight. The FERC sought to guarantee ‘open access’ to all market participants on a nondiscriminatory basis. By fostering greater competition among producers and gas shippers, the agency hoped to create a market that was ‘national’ in scope and efficient in allocating resources:

> The Commission's primary aim in adopting [Order No. 636] is to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service. The Commission will do this by regulating pipelines as merchants and as open access transporters ... The first goal is to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible. As the House Committee Report to the Decontrol Act stated, ‘All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies.’[12] (FERC, 1992, p.7)

This quotation implies that an ‘active’ nationwide spot market for natural gas was not already in existence as of 1992[1] and invites the research question addressed here: what

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[1] By active, we mean a market populated by many profit maximizing suppliers facing multiple demanders, cost-minimizing end-users facing multiple suppliers, and unfettered arbitragers.

is the state of gas market integration in the post reform era? Has a single national market emerged or is the industry still better thought of as a collection of markets that are highly, or perhaps just somewhat, segmented?

This paper uses daily data on 76 pricing points in the U.S. wholesale spot market over the 1993-97 period to address these questions. Two interrelated aspects are considered: (1) the geographic domain(s) over which the LOOP holds as a *long-run* equilibrium condition after due allowance for transport, transactions and other arbitrage costs and (2) the speed with which profit-motivated arbitrage activities move prices toward LOOP in the face of underlying supply and demand shocks.

These two considerations clearly rest on the concept of an economic market or trading market. The classical definition of an economic market from Cournot was repeated in Alfred Marshall's ***Principles***:

> Economists understand by the term of market, not any particular marketplace in which things are bought and sold, but the whole of any region in which buyers and sellers are in such free intercourse with one another that the prices of the same goods tend to equality easily and quickly …

Marshall went on to add that:

> the more nearly perfect a market is, the stronger is the tendency for the same price to be paid for the same thing at the same time in all parts of the market; but of course if the market is large, allowance must be made for the expense of delivering the goods to different purchasers; each of whom must be supposed to pay in addition to the market price a special charge on account of delivery (Marshall, 1920, p. 270).

Marshall's conception of a market clearly (1) focuses on trading markets (not, say, anti-trust markets[2]) – the domain over which the LOOP holds, (2) acknowledges the po-

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[2] The industrial organization literature (e.g., Spiller and Huang (1986), Scheffman and Spiller (1987), and Geroski (1998)) makes a clear distinction between the concepts of 'trading markets' and 'antitrust markets.' We are not concerned with the latter in this paper.

tential importance of transactions costs, and (3) refers explicitly to the speed of adjustment ('easily and quickly').

There is also a broader motivation or context for the research in this paper: the voluminous literature on arbitrage and LOOP. This literature spans many subfields of economics, and active research in this area has been using increasingly sophisticated econometric techniques, richer datasets, and commodity-level disaggregated data. Our paper is one of several in this literature that takes a micro approach focusing on a particular industry.[3] With international economics applications in mind, Taylor (2001) observes:

> As recent survey articles show, there has been a remarkable surge lately in research on purchasing power parity (PPP) and the law of one price (LOOP). Once dismissed as dull topics, these subjects have rightly taken a place back on the main stage of a field where issues of market integration and the extent of the market have been central ever since the very foundation of the discipline. The study of international and regional markets, the choice of open- versus closed-economy models, and many other important issues for theory, empirics, and policy rest on what economists can say about the existence of one market or many.

As the literature review in Kleit (1998) confirms, there is a growing literature on the geographic extent of U.S. natural gas spot markets. Our paper differs from previous empirical investigations in several ways. **First**, we have a much richer dataset, with high-frequency (daily) data for a large number of geographically diverse pricing points over the 1993-97 period. **Second**, we conduct a detailed analysis of the statistical properties of the individual series. Virtually all prices were found to be unit root (or I(1)) processes with very long serial correlation, and non-normal distributions (high skewness and extremely

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[3] See Goldberg and Verboven (2005) on the integration of the European auto market. Just as the European countries exerted a distinct effort to integrate the national car markets in Europe, the FERC sought to create and integrate the domestic natural gas markets in the U.S.

large kurtosis).[4] These characteristics have important implications for alternative approaches[5] for modeling equilibrium price gaps, defined as $x_t^{ji} \equiv p_t^j - p_t^i$, where p_t^i and p_t^j are the logs of market prices at locations i and j $(i, j = 1,...,n)$. Importantly, we should expect to find equilibrium price gaps[6] between locations i and j within a multi-node pipeline network with varying degrees of connectivity only in situations where i and j lie within the same economic market. **Third,** *autoregressive (AR) models* are used to test for the presence of bilateral equilibrium price gaps and, if they exist, to estimate the speeds of adjustment toward equilibrium. The presence of equilibrium gaps and estimated speeds of adjustment are measures of the degree of market integration. Although the AR model is a widely accepted framework for LOOP and purchasing power parity (PPP) studies (see, e.g., Taylor (2001) and Goldberg and Verboven (2005)), it has not been used to study natural gas market integration.[7]

The use of the AR model is recommended for its flexibility for modeling very long serial correlations and its robustness to nonstandard error distribution properties. It is also ideal for capturing the rich information embedded in the price and price gap dynamics. Our approach explicitly presumes that markets adjusts gradually (in the context where we

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[4] Skewness and substantial kurtosis are time series properties shared by many commodities. See Deaton and Laroque (1992).

[5] These statistical properties limit the applicability of approaches that rely on maximum likelihood methods where the underlying likelihood function is assumed to be normal with no, or at most first-order serial correlation. This potentially includes what we call 'regime-switching arbitrage cost' (RS-AC) models, where truncated normal distributions characterize the error process in each regime. See, e.g., Spiller and Huang (1986) and Spiller and Wood (1988) for standard references, and Kleit (1998, 2001) for applications to the gas and electricity sectors.

[6] Price gaps across locations, called "price basis" in the gas industry, are closely watched by market participants and form the basis of gas trading by many firms.

[7] AR models have also been used to study the persistence of firm profitability in the industrial organization literature. (See, e.g., Geroski and Jacquemin (1988)).

have daily observations) and estimates the speed of adjustment towards market equilibrium.[8] Previous gas market studies have generally used *monthly* data (e.g., Spulber and Doane (1994), King and Cuc (1996), Serletis (1997), and Kleit (1998)). Our use of daily data provides a much more detailed look at market dynamics in an era where an extensive set of spot markets has evolved and matured.[9] This is important, as Taylor (2001) recently showed that severe underestimation of speeds of market adjustment will occur when using data of lower frequency than the frequency of actual market transactions.

The datasets used in early studies included only a limited number of pricing points in order to study a longer time period, but this precluded a detailed analysis of the *geographic* extent of the market. The absence of detailed daily data for a large number of pricing locations *prior* to the open access regime precludes any sort of 'before' analysis that could then be compared to the 'after deregulation' period studied in this paper; spot markets developed as a result of the reforms.[10]

The rest of the paper is organized as follows. Section II provides background on the U.S. gas industry to motivate why open access may lead to market integration. Sec-

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[8] The RS-AC model, in contrast, assumes continuous equilibrium with periodic switching between two equilibrium regimes – one 'no arbitrage-profit' equilibrium and one 'no trade' equilibrium between two locations.

[9] De Vany and Walls (1993) and Walls (1994a, b) study the early regulatory transition period, 1987-1991, using *daily* spot gas price series. However, as Brinkmann and Rabinovitch (1995) note, the daily prices did not fluctuate much due to infrequent trading in the early "open access" years. They report that during the second quarter of 1991, for example, the daily price listed for the Columbia Gas Pipeline pricing point in Louisiana changed only five times. Therefore, the information gain from high frequency data is compromised by the lack of active trading in the early years. This is less of an issue for the period 1993-97 used here, because spot markets matured following 'open access' reforms.

[10] De Vany and Walls (1993) and Walls (1994a, b) try to show that spot gas markets are becoming more integrated over time by considering different sub-periods of their dataset to see if price series become more closely related to each other over time. This exercise may be appropriate for a data sample where (i) the markets are not integrated in the early period, but integrated in the later period, and (ii) this trend dominates the seasonal cycle.

tion III describes our dataset on daily spot market prices and summarizes their key statistical properties. Section IV lays out the conceptual framework for assessing the geographic extent of the market, then discusses the use of AR models to test for the existence of equilibrium price gaps and, when they exist, to estimate price gap dynamics in response to price shocks. Section V reports our empirical findings on the extent of market integration based on AR models for all 2850 price gaps. Section VI concludes.

II. The Natural Gas Industry

Table 1 shows the major gas producing regions and gas flow directions. Important features of the industry include the following: (i) the majority of pipeline corridors permit one-way rather than two-way flows (from production to consumption regions), (ii) most U.S. natural gas is produced in the Gulf of Mexico, Texas, Louisiana, New Mexico, Oklahoma, Western Canada and the Rocky Mountains, (iii) the major sources of gas supply from the Gulf of Mexico and the Anadarko/Arkoma regions do not go westward and (iv) only a very small fraction of the supply from the Rocky Mountains and the San Juan Basin goes eastward. Therefore, one might suspect that gas markets in the East are not well connected with markets in the West.

As mentioned in the Introduction, regulatory reforms in network industries such as natural gas and electricity have been characterized by the deregulation of the production sector, where concentration is low,[11] and the ‘open access’ to the highly concentrated transmission sector. By the early 1990s, the natural gas industry had completed the proc-

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[11] There are about 23,000 gas producers in the United States, ranging from small independent operations to large international oil companies. The seven largest producers account for about 30% of total U.S. natural gas production (see IEA 1998, p. 68).

ess of production deregulation and open access to the interstate natural gas pipelines.[12] See Leitzinger and Collette (2002) for a review of natural gas industry restructuring.

Table 1: Major Gas Supply Regions and Gas Flow Directions

Producing Region	States	Share (%)	Gas Flow Direction
Gulf of Mexico	Offshore	25.8	Southeast, Northeast, Midwest
Gulf Coast	South Louisiana Texas RRC Districts 1, 2, 3, and 4	15.7	
East Texas	North Louisiana Texas RRC Districts 5, 6	5.4	
Anadarko/Arkoma	Oklahoma, Arkansas Texas Panhandle Kansas	13.8	Midwest, Northeast
Permian Basin (TW)	East New Mexico Western Texas	7.6	California, Midwest
Rockies (RK)	Colorado, Utah, Wyoming	7.0	California, Midwest (small fraction)
San Juan Basin (SJ)	West New Mexico	4.6	California
Appalachian (AP)	Pennsylvania, West Virginia New York, Ohio	2.4	Northeast
Western Canada	Alberta, British Colombia	13.5	Western U.S., Midwest, Northeast
Total		95.8	

Note: Column 3 is the share of each producing region in the total U.S. consumption in 1996.
Source: Compiled from tables and tests in *Deliverability on the Interstate Natural Gas Pipeline System*, Energy Information Administration (EIA), May 1998.

Integration of regional markets via the regulated pipeline distribution network has been an important step in bringing together buyers and sellers. The extent of regional market integration is an important indicator of market performance and efficiency.

A significant development in the regulatory reform process was the emergence of active spot markets for natural gas.[13] Here large numbers of gas users buy gas directly on

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[12] Canada also decontrolled wellhead gas prices, mandated open access to pipelines, and relaxed regulations on natural gas exports to the U.S. in the mid-1980s. Our data set includes four pricing points for Canadian gas along the U.S.-Canada border.

a short-term basis from large numbers of gas sellers. The share of spot market volume of the total U.S. gas consumption rose rapidly from 5 percent in 1983 to more than 70 percent in 1987-88 (Sutherland 1993, p. 1195). Since then, the share of the spot market has fallen gradually to about 40% in 1995 (Dahl and Matson 1998, p. 397).[14]

Several factors have contributed to the development and functioning of the spot markets. First, the gas merchant function -- previously carried out by interstate pipelines -- was taken on by emerging gas trading and marketing companies. Dahl and Matson (1998, p. 398) reported that there were about 50 gas trading companies that purchased gas for resale in 1986. That number increased to more than 350 companies in 1991 before consolidating at roughly 260 in 1995. These companies are constantly looking for areas of excess supply or high demand in order to capture a profitable spread (Sturm 1997). Second, market centers have developed along the interconnection points of the pipeline network. Market centers provide many services that facilitate gas trading and transportation, such as gas loans, balancing and information services like electronic bulletin boards. Third, a pipeline capacity release market has also developed, whereby unused capacity can be sublet to other shippers. Fourth, pipeline expansion has eliminated certain bottlenecks

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[13] Today, natural gas spot markets supply a large share of the total U.S. natural gas consumption, which in turn accounts for about a quarter of energy consumed in U.S. (24% in 2000).

[14] During the early years of the spot market's evolution, most gas spot deals were made on the last week of each month during which gas shippers nominated for capacity they would use for the following month. The last week of each month is called the "bid week." The duration of the contract for spot gas is usually set to coincide with the bid week, i.e., equal or less than a month. Gas that remains unsold during bid week and gas purchased in excess of actual needs can be resold any time during the month. For this "swing gas," the delivery date is usually the next day. The volume of swing gas is relatively small in comparison to the bid week transactions in the early years, but its importance has increased relative to the bid week market over time (Herbert and Kreil (1996)). An important source of swing gas in the downstream market (city gate) during the heating season is gas withdrawals from storage. Herbert, Thompson, and Todaro (1997) reported that about 27 percent of monthly consumption of natural gas in the East Consuming Region during the heat-

and increased the connectivity of the pipeline system. As a result of these developments, gas producers and sellers have more choice in selling and buying natural gas.

III. Time Series Properties of Gas Price Series

Our daily dataset on wholesale spot prices throughout the U.S. natural gas transmission network is from *Gas Daily*, a leading trade publication.[15] From their collection of roughly 100 trading locations (as of early 1998), we selected 76 series that continued through the end of our sample period, January 4, 1993 to December 31, 1997. These 76 pricing points cover all the major producing regions and city gates, as summarized in Table 2. Column 4 shows that average city gates prices are higher than prices in the production regions.[16]

Following standard practice when working with high-frequency financial and commodity price data, the statistical analysis in this paper uses natural logarithms of prices. It is well known that the log transformation greatly reduces skewness and kurtosis, and log differences have a ready interpretation as percentage returns. Three representative price series (in logs and first-differences in logs) are shown in Fig. 1. Henry Hub and Sonat are two major pricing points in the Louisiana-Onshore South (LS) region; Kern River is in the Rocky Mountain (RK) region. The Henry Hub price series, arguably the most

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ing season (November to February) is gas withdrawals from storage. The East Consuming Region is defined to include all States east of the Mississippi River except Mississippi, plus Iowa, Nebraska, and Missouri.

[15] *Gas Daily* analysts survey daily those companies that trade natural gas to obtain a representative number of deals at each pricing point. The volume-weighted average daily price at each market place is reported. All prices are quoted in dollars per million British Thermal Units ($/mmBtu). Prices at a particular marketplace include all the gathering and transportation costs up to that point.

[16] Fifty-seven of the 76 price series start from January 4, 1993, each with 1247 observations. The other 19 series begin somewhat later and/or have some missing (non-holiday) weekday observations. Table 2 shows that the series with missing observations are either city gate series or series on the U.S.-Canada border. Seven series have a starting date later than January 4, 1993; six of these are city gate series.

important pricing point, often remained unchanged for a week or so in early 1993. By late 1993, however, it started to change virtually every day. The Kern River series, however, did not start to change every day until late 1995. This indicates that all daily gas markets are generally becoming liquid over time, but market liquidity differed across locations.

Table 2: The Natural Gas Pricing Regions

Region (Code)	Total Number of Price Points in Our Data from Jan 4/93- Dec 31/97	Number of Price Points with no Missing Observations	Average Price (1993-1997)
Eastern Regions			
Louisiana-Onshore South (LS)	15	15	2.15
East Texas-North Louisiana (TE)	6	6	2.05
East-Houston-Katy (TG)	3	3	2.08
South-Corpus Christi (TS)	10	10	2.03
Appalachia (AP)	2	2	2.45
US-Canada East Border (CE)	2	1	2.45
Mid-Atlantic City gates (MA)	6	0	2.46
Subtotal	44	37	
Central Regions			
North-Texas Panhandle (TN)	3	3	1.89
Permian Basin Area (TW)	2	2	1.89
Oklahoma (OK)	7	7	1.95
Midwest City gates (MW)	7	0	2.45
Subtotal	19	12	
Western Regions			
New Mexico-San Juan Basin (SJ)	2	2	1.65
Rocky Mountain Area (RK)	5	5	1.58
California Border City gates (CA)	4	0	1.96
US-Canada West Border (CW)	2	1	1.45
Subtotal	13	8	
Total	76	57	

Notes: Column 4 is the cross-sectional mean of the average (over time) prices of all the price series in each pricing region. The pricing regions (LS, TE, TG and TS) are in the producing regions of Gulf of Mexico, Gulf Coast and East Texas. The pricing regions (TN, OK) are in the Andarko/Arkoma producing region.

Fig. 1: Three Daily Natural Gas Price Series

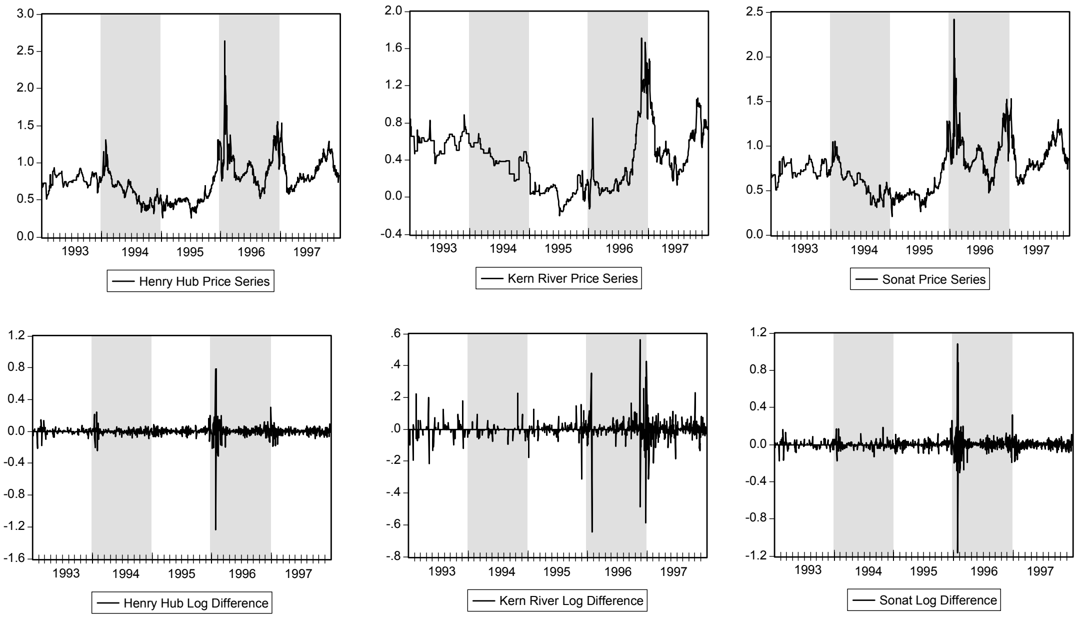

Table 3: Summary Statistics of Individual Natural Gas Price Series

	Henry Hub	Sonat	Kern River
Unit Root Test Results on Log Price Series:			
Ng-Perron MZa Test	-14.19	-13.60	-5.24
Ng-Perron MZt Test	-2.66	-2.61	-1.52
Chosen Lag Length	14	14	13
KPSS Trend Stationarity Test	0.35 ***	0.36 ***	0.60 ***
Chosen Lag Length	28	29	29
Statistics on Log Price series:			
Skewness	-2.32	-2.52	-0.64
Kurtosis	6.96	7.64	4.61
Jarque-Bera	30.96	39.07	3.53
Statistics on First-Differences of Log Series			
Skewness	-2.14	0.89	-1.35
Kurtosis	123.55	126.88	52.33
Jarque-Bera	755359.98	796923.57	126693.15

Note: The asymptotic critical values for the Ng-Perron MZa test are: -23.80 (1%), -17.30 (5%), and -14.20 (10%). The critical values for their MZt test are -3.42 (1%), -2.91 (5%), and -2.62 (10%). The critical values for the KPSS test are: 0.216 (1%), 0.146 (5%), and 0.119 (10%).

There is a stark visual difference between the Henry Hub and the Kern River series during the period December 1995 to March 1996. The gas price at Henry Hub was extremely volatile, while the gas price at Kern River remained relatively calm. During this period, almost all series in the East fluctuated as sharply as Henry Hub series while Kern River behavior is typical of prices in the West. This suggests that gas markets in the East and West were not well integrated, at least during the 1995/96 heating season. This is investigated more formally in Section V.

Fig. 1 suggests some key 'stylized facts' about commodity price series, which are further documented in Table 2. First, the logged series in the top panel are I(1) or unit root processes; they are not mean reverting. After first-differencing (as in the lower panel), the series are mean stationary. Table 2 tests these hypotheses formally using two approaches. The Ng-Perron MZa and MZt tests take the presence of a unit root as the null hypothesis. We use the form of the tests where the alternative hypothesis is trend reversion. The tests 'fail to reject' the unit root hypothesis for these three series. The KPSS tests, which take trend stationarity (i.e. no unit root) as the null hypothesis, corroborate these findings. They easily rejects the null for all three series. These results are typical for commodity price series. The vast majority are well-characterized as I(1) processes, as one would expect *a priori*.[17] Appendix I, which report both Ng-Perron and KPSS tests for the all 76 gas price series, is available on request.

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[17] With test size of 1%, the Ng-Perron MZa and MZt tests reject the unit root hypothesis in favor of trend stationarity in only 4 of the 76 cases. The KPSS test rejects the trend stationary null hypothesis (where the alternative is unit root) for all 76 prices.

A second feature of the price series – whether in log-levels or log-differences -- is significant higher-order serial correlation. The average lag length is 16 days, with a range from zero to 22 (the maximum lag considered in out tests).[18] A third feature of the log-difference series is the huge kurtosis. The Jarque-Bera statistic produces resounding rejections of the normality hypothesis for all three series.

Fig. 2 shows two representative price gaps. The price gap between Henry Hub and Sonat in the Louisiana region is typically small. When large price gaps appear, they are fleeting. In contrast, the price gap between Henry Hub and Kern River in the Rocky Mountain region varies considerably over time. We discuss the unit root test results for these two price gaps in section V, but here emphasize their statistical properties: price gaps are invariably (modestly) skewed, fat-tailed, and non-normal. The skewness, kurtosis, and Jarque-Bera statistics for the Henry Hub-Sonat price gap are 3.5, 34.38, and 53701.5, respectively. The corresponding statistics for the Henry Hub-Kern River price gap are 1.34, 6.25, and 923.59. The other price series or price gaps have similar statistical properties.

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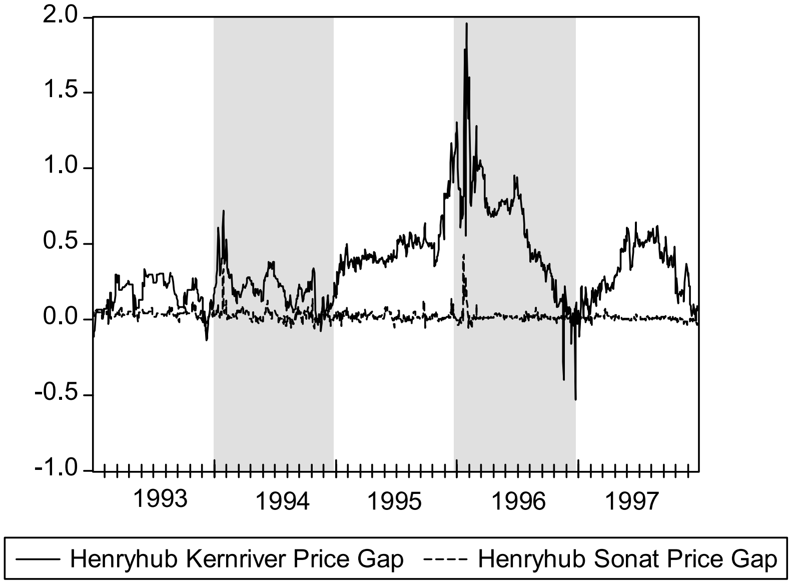
[18] The lag selection techniques used in unit root tests to mop up residual serial correlation point to long lag lengths – 13-14 lags in the Ng-Perron tests (using their recommended modified Akaike information criterion (MAIC)). Even longer lags (20-30 days) are selected when implementing the KPSS tests (using the Newey-West/Bartlett kernel criterion). Appendix I shows the lag lengths chosen using the MAIC for all 76 series. Higher-order serial correlation is also apparent from inspection of autocorrelation functions, Ljung-Box statistics, etc.

Fig. 2: Two Representative Price Gap



IV. Price Gaps and Market Delineation

This section argues that when gas prices at geographically dispersed pricing locations are I(1) processes (as is the case with our dataset), one can make sharp inferences about the geographic extent of a market or markets by studying bilateral price gaps. In particular, *there is an equilibrium or stationary price gap between two locations, if and only if they are within a single (or integrated or unified) market.*

Our starting point is Stigler and Sherwin's (1985) definition of a (single) market:

Definition of a Market: Assuming transactions (including transport costs) are stationary for the time period under consideration, we say k locations lie within a single (unified or integrated) market, if (small) shocks to supply or demand from any location in the market cause *equal* equilibrium changes in price at all k locations, i.e. $\Delta P^1 = \Delta P^2 = ... = \Delta P^k$.[19]

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[19] Stigler and Sherman (1985, p.557): "The test of a market that we shall employ is the similarity of price movements within the market…The criterion could fail to identify a single market if the costs of 'transportation plus transactions' were highly volatile between parts of that market, but that is an improbably circumstance."

We begin by exploring the implications of this definition for equilibrium price gaps in the context of a pipeline network where transport costs may make gas flows uneconomic between some nodes and where capacity constraints may limit arbitrage activity. After determining when there should/should not be equilibrium price gaps, we discuss the use of AR models to allow for the possibility of gradual, not necessarily instantaneous, market adjustment toward equilibrium in response to supply and demand shocks due to adjustment costs, informational lags, temporary capacity constraints, etc.

From the Stigler-Sherwin definition of market, it follows immediately that supply or demand shocks from anywhere within a market will leave *all* bilateral price gaps *in that market* unchanged in equilibrium. That is, even though individual prices are I(1) processes, all bilateral gaps for locations in the same market are stationary. Conversely, when pairs of locations do *not* lie in the same market, due to high transactions costs and/or capacity constraints, there will not be any linear relationship linking them in the long run. In this case, the price gaps will be nonstationary variables, like the underlying prices themselves.[20]

It is critical to note that a single market does *not* require that each and every pair of nodes within the market be connected with active trade. Along some arcs, trade may be capacity constrained. Along others, the transport cost may be prohibitive relative to the size of the equilibrium price gap, so that no trade flow occurs. Yet with sufficient inter-

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[20] Note that the Werden and Froeb (1993) critique does not apply here. They show that when prices are I(0) – stationary -- then an equilibrium price gap *always* exists whether or not markets are integrated or completely unrelated. Moreover, they show that an AR(1) model of price gaps will produce a spurious estimate of speed of adjustment toward that equilibrium. They don't discuss the case where prices are I(1). In this case, there will not be equilibrium price gaps between locations unless they lie within an integrated market.

connectivity, a single market emerges. To see this, recall the Enke-Samuelson-Takayama-Judge (ESTJ) model of spatial equilibrium in the presence of transport costs and capacity constraints. The following Kuhn-Tucker conditions that hold in competitive equilibrium:[21]

$$(1) \qquad (p^j - p^i - r^{ij})Q^{ij} \leq 0$$
$$(2) \qquad (p^j - p^i - r^{ij})(\overline{Q}^{ij} - Q^{ij}) \geq 0 \text{ for all } i \text{ and } j,$$

where Q^{ij} is the export from market i to j, r^{ij} is the (logarithm of) total transactions cost (including FERC-regulated transport tariffs) for moving gas from location i to j, and $\overline{Q}^{ij}$ is the corresponding pipeline capacity.

Clearly there is an equilibrium price gap, defined by the LOOP equality $p^j - p^i = r^{ij}$, between locations with positive, unconstrained trade ($0 < Q^{ij} < \overline{Q}^{ij}$).[22] Can points that are not connected by direct trade, or where trade is capacity constrained, nevertheless lie in the same market? The answer is yes. A simple example illustrates the fundamental point.[23] Suppose locations (1, 2) and (2, 3) are connected by active trade with transport costs r^{21} and r^{23}. Trade between 1 and 3 is capacity constrained. Hence, conditions (1)-(2) imply two binding LOOP conditions among the 3 nodes: $p^1 = p^2 + r^{21}$ and $p^3 = p^2 + r^{23}$ and an inequality. (The price gap between 1 and 3 is greater than the direct transport cost r^{31} (or r^{13}), because the capacity constraint limits prof-

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[21] See Barrett (2001) for a recent discussion. Samuelson noted that conditions are just the Kuhn-Tucker or complementary slackness conditions from the classic 'transportation problem' in linear programming.

[22] Conditions (1)-(2) also imply that the optimal trade flow is zero when the price gap is less than the associated direct transport cost. When there is a binding capacity constraint on shipments from i to j, on the other hand, the price gap will exceed direct transport cost.

[23] In general, one needs k-1 independent LOOP conditions if k points are to lie in a single market.

itable arbitrage.) Although (1, 3) trade is capacity constrained, an equilibrium price gap for (1, 3) exists: $p^3 - p^1 = r^{23} - r^{21}$. (Subtract one of the binding LOOP conditions from the other).

Turning to disequilibrium adjustment, empirical investigations of LOOP generally specify a gradual or partial adjustment mechanism:

$$x_t - \tilde{x} = \lambda(x_{t-1} - \tilde{x}) + \varepsilon_t \tag{3}$$

when an equilibrium price gap $\tilde{x}$ exists. The deviation from long-run equilibrium in period t, $x_t - \tilde{x}$, is hypothesized to be a fraction ($0 \le \lambda \le 1$) of the previous period's deviation, $x_{t-1} - \tilde{x}$, plus an error term. Λ measures persistence of the disequilibrium; 1-λ (>0) measures speed of adjustment or convergence. This formulation implies the linear AR(1) specification -- the 'basic model' in the huge literature on the LOOP (Taylor (2001, p.474)):

$$x_t = c + \lambda x_{t-1} + \varepsilon_t \tag{4}$$

where $c = (1-\lambda)\tilde{x}$. In the extreme case where $\lambda = 1$, a shock to x_t is permanent. Price gap x_t has a unit root, i.e. is nonstationary, implying that the two underlying locations in the price gap do not lie in the same market. At the other extreme where $\lambda = 0$, deviations from long run equilibrium are fleeting, serially uncorrelated events. Thus, the market is perfectly integrated. The conventional way of summarizing the speed of price adjustment is the half-life (HL) of a shock. It measures the number of periods it takes for a one unit shock to shrink to half of its initial value. For an AR (1) process, HL = $\ln(0.5)/\ln(\lambda)$.

Section V estimates AR models for all for all bilateral price gaps in our dataset– there are 76*75/2 of them. To allow for the strong serial correlation, higher order AR(q) rather than AR(1) models are required. For each gap, we test to see if the unit root hypothesis can be rejected in favor of the alternative of stationarity. If so, the two locations must lie within the same market. When equilibrium exists, we use the estimated AR model to calculate the associated impulse response function (IRF) and half life of the adjustment process. Comparing the geographic pattern of stationary and nonstationary price gaps and the associated speeds of adjustment for the stationary pairs provides a detailed assessment of the geographic extent of the natural gas markets in the U.S.

V. AR Models of Price Gaps: Empirical Results

A q-order autoregressive process is used to capture the time series behavior of each bilateral price gap:

$$x_t = \mathrm{c} + \lambda_1 x_{t-1} + \ldots + \lambda_q x_{t-q} + \varepsilon_t , \tag{5}$$

where the superscripts (i, j) are dropped for notational simplicity.[24],[25] The price gap x_t may be stationary (i.e. $\sum \lambda_i < 1$) or it may contain a unit root (i.e., $\sum \lambda_i = 1$). In the stationary case, an equilibrium price gap exists: $\tilde{x} = \mathrm{c} / (1 - \lambda_1 - \lambda_2 - \ldots - \lambda_q)$.

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[24] We use the Ng-Perron modified Akaike criterion to choose lag length. Higher-order serial correlation in the price gaps presumably reflects the time series properties of unobservable supply and demand shocks, the speed with which traders and arbitragers respond to profitable price gaps, and expectation considerations.

[25] We included a linear time trend in the AR specification to capture ongoing regulatory change. We are sympathetic with recent efforts to identify other determinants of equilibrium price gaps. Kleit (1998), covering the period 1984 to 1993, emphasizes that deregulation may be a gradual process rather than a single discrete shift in the regulatory environment. His empirical analysis includes three dummies suggested by Spulber and Doane [1994] for various phases in FERC regulations. Our dataset begins in January 1993, more than two years after all major pipelines had gained open access.

Ng-Perron unit root and KPSS stationarity tests were carried out for all 2850 bilateral price gaps in order to determine whether each gap was best modeled as: (i) a mean stationary AR(q) model, (ii) a trend stationary AR(q) model (to allow for the possibility of a secular time trend in transactions costs) or (iii) a unit root process. In this section, we focus on the Ng-Perron MZt unit root test results with test size equal to 10%. With this choice, we have opted to err on the side of declaring a price gap stationary and estimating its (potentially long) half life, rather than concluding that the gap is nonstationary (and the HL meaningless.)[26]

For higher-order AR models, the half-life of a shock needs to be derived from the impulse response functions (IRF) rather than calculated from the simple formula in Section IV.[27] As nonmonotonic IRFs are not uncommon, the HL is defined as the *last* time that the IRF crosses 0.5.[28] Recall that, for nonstationary gaps, the HL calculation is not a meaningful measure of speed of adjustment. Although the IRF may or may not cross 0.5, it never converges to zero.

To illustrate, consider the price gaps in Fig. 2 above. Visual inspection suggests clear rejection of the *continuous* LOOP hypothesis both the Henry Hub-Sonat and Henry Hub-Kern River price gaps. Large price gaps disappear quickly in the Henry-Hub-Sonat case, whereas they appear to be very persistent in the Henry Hub-Kern River case. Formal unit root tests confirm this visual impression: The unit root hypothesis is rejected for the

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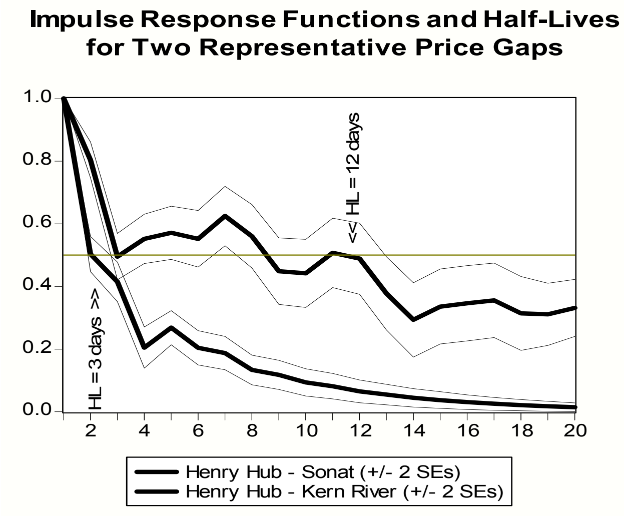
[26] Appendix II containing additional detail on model selection is available on request.

[27] There are two numerical methods to compute the IRFs for higher-order AR models; they produce identical results. One can simulate the dynamic effects on the price gap of a one unit shock to the error term in the AR equation. Alternatively, one can transform the AR(q) model into its corresponding MA(∞) representation; the MA (moving average) coefficients are the impulse responses. See Hamilton (1994, p. 10 and p.71, respectively) for details.

Henry Hub-Sonat price gap, while the tests fail to reject the null for the Henry Hub-Kern River gap. Fig. 3 shows the respective IRFs obtained from the estimated AR models. The IRF for Henry Hub-Sonat dies out quickly, with half life equal to 3 days. The IRF for Henry Hub-Kern River falls somewhat initially but fails to converge to zero, reflecting the presence of a unit root. Thus, it appears that Henry Hub and Sonat lie in the same market; Henry Hub and Kern River do not.

Fig.3


Impulse Response Functions and Half-Lives for Two Representative Price Gaps

How typical are these observations based on the two price gaps? Clearly, one needs to consider other bilateral price comparisons. The rest of this section presents a detailed analysis of the geographic extent of the market by summarizing various interesting statistics involving the *many* pricing points within and between various geographic regions as grouped by *Gas Daily*. We first consider a 3 by 3 'broad region' matrix where all pricing locations are categorized as East, Central, or Western. Next, we turn to a more

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[28] See Chueng and Lai (2000) on nonmonotonic IRFs resulting from higher-order AR models.

disaggregated 15 by 15 regional matrix. In each case (3 by 3 or 15 by 15), the lower triangular of the matrix summarizes information on all of the intra and inter-regional market pairs.

The results for the broad regional aggregates (East, Central and West) are summarized in Table 6. Sixty-five percent of the 2850 gaps are found to be mean stationary. Just shy of 9% are trend stationary,[29] and the remaining 26% are unit root processes. The average half life for the mean and trend stationary gaps is 5.8 days. As the Table 6 clearly shows, the percentage of stationary price gaps and their estimated half lives vary considerably within and between the three broad regions. Virtually all (>99%) of the price gaps within the East are (mean or trend) stationary; their average half life of 4.8. Comparing the ***within-region*** statistics for the East, Central, and West, one sees that the percentage of unit root gaps rises from <1%, to 5%, to 23% while the corresponding HLs for the stationary gaps average 4.8, 5.7 and 6.3 respectively. That is, considering only ***within*** broad region gaps, there are fewer converging gaps and their speed of convergence is slower as we move from East to Central to West. The degree of market integration is higher within the East or Central regions than it is within the Western region.

The findings for the *inter*-region price gaps are more dramatic. Fully 84% of the price gaps involving one pricing location in the East and a second in the West do not converge to equilibrium. For the small number of gaps that do converge, the HL averages

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[29] Trend stationary gaps suggest situations where there have been very small, but statistically significant changes in transactions costs over time, perhaps due to gradual changes in the regulatory regime or increments to capacity between various nodes. Statistically significant time trend were found for only 253 (or 8.8%) the 2850 price gaps. The trends were small in magnitude, ranging from -.0073 percent to +.0073 percent per day (or -/+ 1.46 % per year, assuming 200 market days per year.)

11.6 days (roughly twice as long as the within-region HLs). For the price gaps involving the Central and West regions, 77% are non-converging. The 23% of gaps that do converge have an average HL of 11.6. Taken together, the results in Table 4 suggest considerable market segmentation between the West, on one hand, and the East and Central regions on the other.

Overall, the results suggest that the East and Central regions are well integrated; the Wet less so. Furthermore, the degree of integration between the large East/Central market and the West is limited. The West is better described as a somewhat fragmented, separate market rather than one that is highly integrated with the East and Central regions. To this extent, it appears that the FERC's open access policies had not, as of the mid-1990s, succeeded in creating a single national wholesale market for natural gas.

Table 4: Broad Region Results on Extent of Market Integration

		Broad Region		
Broad Region	Data	Eastern	Central	Western
Eastern	No. of Bilateral Gaps	946		
	% that are mean stationary	90%		
	% that are trend stationary	10%		
	Average of Half Life from Chosen AR Model	4.8		
	% that are Unit Root Processes	<1%		
Central	No. of Bilateral Gaps	836	171	
	% that are mean stationary	79%	84%	
	% that are trend stationary	16%	11%	
	Average of Half Life from Chosen AR Model	5.9	5.8	
	% that are Unit Root Processes	5%	5%	
Western	No. of Bilateral Gaps	572	247	78
	% that are mean stationary	15%	23%	64%
	% that are trend stationary	1%	0%	13%
	Average of Half Life from Chosen AR Model	11.6	11.6	6.3
	% that are Unit Root Processes	84%	77%	23%

Of course, this is a broad picture. If one disaggregates the three broad regions into the 15 smaller regions, additional insights are obtained. Table 5 shows the percentage of price gaps that are nonconverging (i.e. unit root processes) for the 15 region aggregation. For ease of reference when considering a particular region (either its row or column), both the upper and lower triangular portions of the symmetric matrix are shown. The shaded portions of the matrix show the gaps *within* each of the three broad regions, as reported in Table 4 above but with more underlying detail, along with their respective averages (1%, 5%, and 23%). Table 6 provides analogous information on half lives for the 15x15 region price gap matrix.

The following observations are obtained from the 15-region analysis:

1. Looking down the diagonal of the matrix, we see that the *within-region* degree of market integration varies considerably. Most pricing pairs within each of the seven Eastern regions (01-LS through 07-MA) lie within an integrated market, but adjustment half-lives for pricing points within the MA region are considerably larger than the norm. Intra-regional integration within the various Central regions (08 through 11) is somewhat lower, in that there are more non-converging price gaps.

2. For the San Juan (SJ) region in the West, we apparently have the extreme situation that the two pricing points do not lie within a single market. For the Rocky Mountain (RK) region, half of the within-region price gaps are nonstationary as well. Within the TN (Central) region, 33% of the price gaps are nonstationary. For the stationary gaps, on the other hand, the speed of adjustment is very rapid (HL =2).

3. The East-West segmentation that we highlighted based on the 3x3 matrix is due mostly to price gaps involving the Canadian West (CW) and gaps involving MA (in the East) and other East or West pricing locations. The other East-West linkages are much tighter.

4. Similarly, if we look deeper into the segmentation between the Central and West regions, we find that gaps involving the CW and/or the U.S. Midwest (MW) are primarily responsible. The other linkages are much tighter in the sense that HLs are lower, but there are still large percentages of gaps that do not converge to equilibrium.

Table 5:
Average Intra- and Inter-Regional Summary of
Percentage of Price Gaps that are Unit Root Processes

		1-Eastern							1-Eastern Total	2-Central				2-Central Total	3-Western				3-Western Total
BroadRegion_i	Region_i	01-LS	02-TE	03-TG	04-TS	05-AP	06-CE	07-MA		08-TN	09-TW	10-OK	11-MW		12-SJ	13-RK	14-CA	15-CW	
1-Eastern	01-LS	0%	0%	0%	0%	0%	7%	0%	0%	0%	0%	14%	3%	6%	87%	85%	97%	100%	91%
	02-TE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	21%	0%	8%	83%	83%	88%	92%	86%
	03-TG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	0%	2%	83%	80%	92%	100%	87%
	04-TS	0%	0%	0%	4%	0%	0%	0%	1%	10%	0%	16%	0%	7%	65%	82%	90%	100%	85%
	05-AP	0%	0%	0%	0%	0%	0%	8%	1%	0%	0%	0%	0%	0%	50%	80%	50%	100%	69%
	06-CE	7%	0%	0%	0%	0%	0%	8%	3%	0%	0%	0%	0%	0%	50%	70%	25%	100%	58%
	07-MA	0%	0%	0%	0%	8%	8%	7%	2%	0%	0%	0%	2%	1%	75%	77%	67%	92%	76%
1-Eastern Total		0%	0%	0%	1%	1%	3%	2%	***1%***	2%	0%	12%	1%	5%	76%	82%	84%	98%	84%
2-Central	08-TN	0%	0%	0%	10%	0%	0%	0%	2%	33%	33%	10%	0%	11%	83%	87%	75%	100%	85%
	09-TW	0%	0%	0%	0%	0%	0%	0%	0%	33%	0%	14%	0%	11%	100%	80%	63%	100%	81%
	10-OK	14%	21%	5%	16%	0%	0%	0%	12%	10%	14%	10%	0%	6%	93%	74%	75%	100%	81%
	11-MW	3%	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%	0%	57%	83%	36%	100%	67%
2-Central Total		6%	8%	2%	7%	0%	0%	1%	5%	11%	11%	6%	0%	***5%***	79%	80%	59%	100%	77%
3-Western	12-SJ	87%	83%	83%	65%	50%	50%	75%	76%	83%	100%	93%	57%	79%	100%	30%	25%	75%	42%
	13-RK	85%	83%	80%	82%	80%	70%	77%	82%	87%	80%	74%	83%	80%	30%	50%	0%	20%	25%
	14-CA	97%	88%	92%	90%	50%	25%	67%	84%	75%	63%	75%	36%	59%	25%	0%	0%	25%	8%
	15-CW	100%	92%	100%	100%	100%	100%	92%	98%	100%	100%	100%	100%	100%	75%	20%	25%	0%	29%
3-Western Total		91%	86%	87%	85%	69%	58%	76%	84%	85%	81%	81%	67%	77%	42%	25%	8%	29%	***23%***

Table 6:

Average Intra- and Inter-Regional Half-Lives

Based on Chosen AR Model (w or w/out Trend) and Excluding Unit Root Gaps

Upper Traingle or	(All)

Average of Half Life from Chosen AR Model		BroadRegion_j	Region_j																
		1-Eastern							1-Eastern Total	2-Central				2-Central Total	3-Western				3-Western Total
BroadRegion_i	Region_i	01-LS	02-TE	03-TG	04-TS	05-AP	06-CE	07-MA		08-TN	09-TW	10-OK	11-MW		12-SJ	13-RK	14-CA	15-CW	
1-Eastern	01-LS	2.9	4.1	3.1	5.8	5.1	4.0	6.3	4.4	5.8	6.9	5.7	6.0	5.9	6.5	3.9	10.5		5.3
	02-TE	4.1	2.9	2.4	2.6	8.2	4.8	7.1	4.1	3.2	3.5	3.6	8.2	5.4	6.5	3.4	5.0	26.0	6.5
	03-TG	3.1	2.4	2.3	2.4	6.8	5.5	6.2	3.5	2.7	2.8	3.1	10.1	5.6	3.0	4.7	5.0		4.4
	04-TS	5.8	2.6	2.4	2.2	8.4	5.2	7.6	4.7	2.7	3.0	3.1	9.5	5.6	3.7	3.4	5.5		4.0
	05-AP	5.1	8.2	6.8	8.4	2.0	2.8	6.1	6.4	10.2	9.0	9.1	5.5	7.9	9.0	6.5	38.3		23.0
	06-CE	4.0	4.8	5.5	5.2	2.8	3.0	3.9	4.4	4.3	4.3	4.6	4.6	4.6	6.5	7.3	25.5		17.1
	07-MA	6.3	7.1	6.2	7.6	6.1	3.9	7.1	6.7	7.5	7.4	7.5	5.4	6.7	17.3	7.4	35.5	31.0	22.1
1-Eastern Total		4.4	4.1	3.5	4.7	6.4	4.4	6.7	***4.8***	4.9	5.3	5.1	7.2	5.9	7.2	4.8	23.3	28.5	11.6
2-Central	08-TN	5.8	3.2	2.7	2.7	10.2	4.3	7.5	4.9	2.0	2.3	2.6	7.2	4.6	3.0	3.0	4.0		3.5
	09-TW	6.9	3.5	2.8	3.0	9.0	4.3	7.4	5.3	2.3	2.0	3.1	8.6	5.3		3.0	3.7		3.4
	10-OK	5.7	3.6	3.1	3.1	9.1	4.6	7.5	5.1	2.6	3.1	2.5	8.8	5.2	4.0	3.3	7.3		5.0
	11-MW	6.0	8.2	10.1	9.5	5.5	4.6	5.4	7.2	7.2	8.6	8.8	3.6	6.8	13.0	6.7	23.9		18.3
2-Central Total		5.9	5.4	5.6	5.6	7.9	4.6	6.7	5.9	4.6	5.3	5.2	6.8	***5.7***	10.6	4.3	16.3		11.6
3-Western	12-SJ	6.5	6.5	3.0	3.7	9.0	6.5	17.3	7.2	3.0		4.0	13.0	10.6		3.3	5.8	7.0	4.6
	13-RK	3.9	3.4	4.7	3.4	6.5	7.3	7.4	4.8	3.0	3.0	3.3	6.7	4.3	3.3	2.6	5.9	5.3	4.6
	14-CA	10.5	5.0	5.0	5.5	38.3	25.5	35.5	23.3	4.0	3.7	7.3	23.9	16.3	5.8	5.9	3.8	17.7	6.9
	15-CW		26.0					31.0	28.5						7.0	5.3	17.7	9.0	10.2
3-Western Total		5.3	6.5	4.4	4.0	23.0	17.1	22.1	11.6	3.5	3.4	5.0	18.3	11.6	4.6	4.6	6.9	10.2	***6.3***

5. The two pricing points in eastern Canada (CE) lie within an integrated market and have a HL=3. Similarly, the two border prices in western Canada (CW) are integrated, but with a much longer HL = 9. The intra-CE-CW combinations indicate that the pricing points in CE are not integrated with those in CW. One, therefore, suspects that the East-West segmentation that we find in the U.S. wholesale gas market may also characterize the Canadian markets, although more (non-border) Canadian pricing points would have to be analyzed to reach a definitive conclusion.

6. The Canadian West (CW) pricing points are not well integrated with the rest of the pipeline network, with the exception of the CW-RK linkages; for CW-CA, the average HL = 17.7.[30] This stands in sharp contrast with the CE pricing points, which appear to be well-integrated with other locations throughout the East and Central regions.

VI. Conclusions

Did the FERC initiated restructuring of the U.S. natural gas market in the 1980s and early 1990s achieve its stated objective of creating a competitive nationwide market? Using daily data at 76 locations in the post-reform period, 1993-97, this paper estimates autoregressive models for all 2850 bilateral price gaps to assess the geographic extent of the market or markets. We find that roughly 74% percent of the 2850 bilateral price gaps are stationary, implying these location pairs lie within the same market. The adjustment to price shocks within the broad regions (East, Central and West) is quite rapid, especially for the East and Central regions. For most *stationary* price gaps our estimated half-lives are in the range of two days to two weeks, suggesting rapid adjustment toward market equilibrium. (These estimated half lives are, for example, much faster than the 'glacial' speeds of adjustment of 3-5 years reported in the international economics literature on PPP. See Rogoff (1996).)

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[30] This is consistent with the *Gas Daily* (June26, 2001) observation that "the [Pacific] Northwest part of the United States regularly provides profitable wholesale marketing opportunities, especially for companies with knowledge of the complicated systems and tricky circumstances for shipping gas in the region."

The bulk of the *nonstationary* price gaps (implying equilibrium price gaps do not exist), as well as the stationary gaps with slow speeds of adjustment, involve pricing locations in the West vs. East or West vs. Central regions. The findings suggest that the East and Central regions form a highly integrated market, but that this market is quite segmented from the more loosely integrated Western market. Thus, although the FERC's 'open access' reforms of the late 1980s have contributed towards national integration, limited physical connectivity between the West and the other regions leaves incomplete the agenda of creating a single national market for natural gas.

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*** Not intended for publication. Available on Request ***

Appendices for "Assessing the Degree of Spot Market Integration For U.S. Natural Gas: Evidence from Daily Price Data by John T. Cuddington and Zhongmin Wang

Appendix I: Unit Root Test Results for All 76 Price Series

Pricing Point	Region	Starting Date	No. of Obs.	Obs. Missing 1/	Ng-Perron MZa test	Ng-Perron MZt test	NP test Lag Choice 2/	KPSS Test
CNG North Point	AP	1/4/1993	1247	0	-17.21	-2.93 **	22	0.26 ***
Columbia, App	AP	1/4/1993	1247	0	-20.34 **	-3.19 **	21	0.26 ***
Cal. Border, Kern River Station	CA	5/1/1995	665	3	-11.56	-2.38	11	0.14 *
Cal. Border, Wheeler Ridge	CA	12/20/93	969	39	-5.61	-1.66	0	0.57 ***
SW gas to end-users	CA	1/4/1993	1235	12	-6.14	-1.71	9	0.82 ***
SW gas to utilities	CA	1/4/1993	1234	13	-12.64	-2.48	19	0.83 ***
Iroquois	CE	1/4/1993	1245	2	-17.98 **	-3.00 **	19	0.24 ***
Niagara (NFG, Tenn)	CE	1/4/1993	1247	0	-20.1 **	-3.17 **	20	0.27 ***
PGT (Kingsgate)	CW	11/1/1993	1038	0	-4.62	-1.42	8	0.58 ***
NW Sumas	CW	1/4/1993	1247	0	-10.37	-2.16	9	0.5 ***
ANR	LS	1/4/1993	1247	0	-14.08	-2.65	14	0.37 ***
Columbia	LS	1/4/1993	1247	0	-13.79	-2.63	14	0.35 ***
FGT Z1	LS	1/4/1993	1247	0	-13.45	-2.59	14	0.53 ***
FGT Z2	LS	1/4/1993	1247	0	-18.28 **	-3.02 **	18	0.33 ***
Henry Hub	LS	1/4/1993	1247	0	-14.19	-2.66	14	0.35 ***
Koch (Areas 3-6)	LS	1/4/1993	1247	0	-17.19	-2.93 **	22	0.37 ***
NGPL (La.)	LS	1/4/1993	1247	0	-14.54	-2.7	14	0.52 ***
Sonat	LS	1/4/1993	1247	0	-13.6	-2.61	14	0.35 ***
Texas E. (ELA)	LS	1/4/1993	1247	0	-15.82	-2.81	16	0.31 ***
Texas E. (WLA)	LS	1/4/1993	1247	0	-12.6	-2.51	13	0.39 ***
Texas Gas SL	LS	1/4/1993	1247	0	-14.06	-2.65	14	0.35 ***
Transco Z3. St 50, 62, 65	LS	1/4/1993	1247	0	-15.74	-2.81	16	0.36 ***
Transco Z4. St 85	LS	1/4/1993	1247	0	-17.12	-2.93 **	14	0.35 ***
Trunkline ELA	LS	1/4/1993	1247	0	-13.35	-2.58	14	0.36 ***
Tennessee	LS	1/4/1993	1247	0	-13.05	-2.55	14	0.35 ***
CNG, FT	MA	05/31/95	642	5	-11.02	-2.33	18	0.20 **
Columbia Gas, FT	MA	12/1/1994	758	13	-12.24	-2.44	1	0.26 ***
National Fuel Gas, FT	MA	4/3/1995	681	7	-4.60	-1.47	1	0.26 ***
Tennessee, Zones 4-5, FT	MA	10/3/1994	799	11	-8.42	-2.01	15	0.20 **
Tex. E., Zone M-3, FT	MA	1/4/1993	1223	24	-21.19 **	-3.25 **	16	0.17 **
Transco, Zone 6, FT	MA	1/4/1993	1211	36	-21.47 **	-3.28 **	12	0.15 **
Chicago LDCs, large end-users	MW	1/4/1993	1236	11	-12.03	-2.45	22	0.33 ***
Chicago, small end-users	MW	1/4/1993	1234	13	-13.23	-2.57	22	0.30 ***
Cons. Pwr, large end users	MW	1/4/1993	1232	15	-24.97 ***	-3.53 ***	19	0.26 ***

Cons. Pwr, small end users	MW	1/4/1993	1226	21	-25.78	***	-3.59	***	19	0.23	***
Mich Con, large end users	MW	1/4/1993	1231	16	-25.24	***	-3.55	***	22	0.29	***
Mich Con, small eu	MW	1/4/1993	1225	22	-29.37	***	-3.83	***	22	0.26	***
Northern Natural TBS	MW	1/4/1993	1230	17	-7.96		-1.96		21	0.60	***
ANR	OK	1/4/1993	1247	0	-11.66		-2.41		22	0.57	***
NGPL (Midcont.)	OK	1/4/1993	1247	0	-12.8		-2.53		22	0.56	***
NorAm (North/South)	OK	1/4/1993	1247	0	-15.79		-2.81		19	0.53	***
Northern (Mid 11)	OK	1/4/1993	1247	0	-12.5		-2.5		22	0.54	***
ONG	OK	1/4/1993	1247	0	-15.12		-2.75		22	0.55	***
PEPL	OK	1/4/1993	1247	0	-10.44		-2.28		22	0.57	***
Williams	OK	1/4/1993	1247	0	-10.98		-2.34		22	0.56	***
CIG (N. syst)	RK	1/4/1993	1247	0	-5.82		-1.62		10	0.59	***
DJ Basin	RK	1/4/1993	1247	0	-7.99		-1.94		13	0.43	***
Kern River	RK	1/4/1993	1247	0	-5.24		-1.52		13	0.6	***
Northwest, domestic	RK	1/4/1993	1247	0	-6.07		-1.65		10	0.61	***
Questar	RK	1/4/1993	1247	0	-8.25		-1.95		16	0.58	***
El Paso SJ	SJ	1/4/1993	1247	0	-9.08		-2.12		16	0.75	***
TW (Ignacio, pts south)	SJ	1/4/1993	1247	0	-8.14		-1.94		17	0.59	***
Koch (Areas 7, 8, 10)	TE	1/4/1993	1247	0	-16.68		-2.89		22	0.5	***
Lone Star	TE	1/4/1993	1247	0	-18.4	**	-3.03	**	15	0.53	***
NGPL TexOk	TE	1/4/1993	1247	0	-13.51		-2.6		22	0.53	***
Tennessee, 100 leg	TE	1/4/1993	1247	0	-20.53	**	-3.2	**	22	0.39	***
Texas Eastern (ETX)	TE	1/4/1993	1247	0	-16.61		-2.88		22	0.53	***
Texas Gas (entire Z 1)	TE	1/4/1993	1247	0	-12.52		-2.5		14	0.39	***
Florida Gas	TG	1/4/1993	1247	0	-15.77		-2.81		17	0.54	***
Transco Z2 St. 45	TG	1/4/1993	1247	0	-13.6		-2.61		14	0.42	***
Trunkline North	TG	1/4/1993	1247	0	-13.74		-2.62		22	0.52	***
NGPL (Permian)	TN	1/4/1993	1247	0	-15.37		-2.77		19	0.57	***
Northern (Mid 10)	TN	1/4/1993	1247	0	-13.36		-2.58		22	0.55	***
Transwestern	TN	1/4/1993	1247	0	-13.65		-2.61		9	0.59	***
Florida Gas	TS	1/4/1993	1247	0	-11.96		-2.45		14	0.55	***
HPL	TS	1/4/1993	1247	0	-13.4		-2.59		16	0.55	***
Koch (Area 9)	TS	1/4/1993	1247	0	-11.68		-2.42		14	0.54	***
MidCon Tex (UTTCO)	TS	1/4/1993	1247	0	-11.83		-2.43		14	0.55	***
NGPL (STX)	TS	1/4/1993	1247	0	-13.5		-2.6		13	0.56	***
Tennessee	TS	1/4/1993	1247	0	-15.63		-2.8		22	0.53	***
Texas Eastern (STX)	TS	1/4/1993	1247	0	-12.89		-2.54		13	0.55	***
Transco Z1 St 30	TS	1/4/1993	1247	0	-13.38		-2.59		13	0.54	***
Trunkline South	TS	1/4/1993	1247	0	-12.44		-2.49		22	0.55	***
Valero	TS	1/4/1993	1247	0	-17.35	**	-2.95	**	22	0.53	***
Transwestern	TW	1/4/1993	1247	0	-12.88		-2.54		9	0.6	***
El Paso PB	TW	1/4/1993	1247	0	-15.6		-2.79		22	0.6	***

Notes: 1. Observation missing between the starting and end date – excluding holidays and weekends.
2. Lag length is selected for NP tests using the Modified Akaike Information Criterion (see Ng-Perron 2001))

Appendix II: AR(k) Model Selection for the Price Gaps

To select an appropriate AR model, we ran KPSS stationarity tests and Ng-Perron MZa and MZt unit root tests for each price gap. We consider both variants of the KPSS test. One, denoted, KPSS_C in Table AII-1 below, takes mean stationarity as the null hypothesis. The second, denoted KPSS_T, takes trend stationarity as the null. The presence of a unit root should produce a rejection with either variant. We construct a database with all 2850 test results for KPSS_C and KPSS_T, including an indicator variable that takes a value of 1 or 0 depending on whether each test statistic implies a failure to reject the null or a rejection of the null at the 1% level. The count of the indicator variable indicates the number of mean or trend stationary cases. Its average for any specified subset of the data (such as the (i, j) cell in the regional summary matrices) reveals the proportion of stationary cases.

For the Ng-Perron unit root tests (in contrast to the KPSS stationarity tests), the null hypothesis is the *presence* of a unit root. Again there are two variants, depending on whether the alternative hypothesis is mean or trend stationarity. These variants denoted NP-C and NP-T in Table AII-1. Again the table reports the results based on indicator variables in our database. A "0" indicates failure to reject the unit root hypothesis, while "1" indicates mean or trend stationarity due to a rejection of the NP-C or NP_T test at the 10% level. Note that again the count of the indicator gives the number of stationary cases, and its average the proportion of stationary cases in the dataset of all 2850 price gaps. To reiterate, all percentages in the Table refer to the % of cases deemed to be stationary or trend stationary from the respective tests. That is, they reflect *rejections* in the case of all unit root tests, and 'failures to reject' stationarity in the case of the KPSS tests. The Table also reports an indicator on the statistical significance of the time trend in an AR model of the price gap if one *assumes* that the gap is indeed stationary.

The task was to decide which gaps are best viewed as nonstationary, mean stationary, and trend stationary, respectively. We decided to focus on the Ng-Perron MZt tests.[31] Given the two variants of the tests, there are four possible combinations of results for the NP_C and NP_T tests, a captured by their respective indicator variables: ((0,0), (1,0), (0,1) and (1,1). Each of these combinations has a plausible interpretation and implied model, as shown in Appendix Table II-2.

Based on the presumptions from Appendix Table II-2, we sorted all 2850 price gaps according to the NP_C and NP_T results, and also examined the significance of the

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[31] The Ng-Perron MZa statistic produces very similar results. For all of the NP tests, we selected the lag length k using the modified Akaike information criteria recommended by Ng and Perron (2001). In addition, for each price gap, an AR model with constant, time trend, and k lags is estimated. Dummy variable indicating whether the t-statistic on the trend is greater than 1.96 in absolute value is reported, but this critical value is appropriate only if the gap is indeed stationary.

Appendix Table II-1

Comparison of Various Unit Root and Stationarity Test Results for All 2850 Price Gaps

		BroadRegion_j		
BroadRegion_i	Data	1-Eastern	2-Central	3-Western
1-Eastern	Count of Bilateral Gaps	**946**		
	Average of KPSS_T_ACCEPT_1%	**73%**		
	Average of NPT_MZa_Reject_10%	**86%**		
	Average of NPT_MZt_Reject_10%	**87%**		
	Average of Trend is Significant	**10%**		
	Average of KPSS_C_ACCEPT_1%	**94%**		
	Average of NPC_MZa_Reject_10%	**99%**		
	Average of NPC_MZt_Reject_10%	**99%**		
2-Central	Count of Bilateral Gaps	836	**171**	
	Average of KPSS_T_ACCEPT_1%	51%	**39%**	
	Average of NPT_MZa_Reject_10%	67%	**80%**	
	Average of NPT_MZt_Reject_10%	68%	**84%**	
	Average of Trend is Significant	17%	**11%**	
	Average of KPSS_C_ACCEPT_1%	84%	**82%**	
	Average of NPC_MZa_Reject_10%	93%	**92%**	
	Average of NPC_MZt_Reject_10%	95%	**92%**	
3-Western	Count of Bilateral Gaps	572	247	**78**
	Average of KPSS_T_ACCEPT_1%	3%	6%	**87%**
	Average of NPT_MZa_Reject_10%	6%	11%	**68%**
	Average of NPT_MZt_Reject_10%	6%	11%	**68%**
	Average of Trend is Significant	4%	0%	**17%**
	Average of KPSS_C_ACCEPT_1%	28%	30%	**63%**
	Average of NPC_MZa_Reject_10%	12%	22%	**72%**
	Average of NPC_MZt_Reject_10%	16%	23%	**73%**

trend term. The selected model for each possible situation is shown in Appendix Table II-3.

Table AII-2: Possible Outcomes for Ng-Perron MZ_t Unit Root Test Specifications With and Without Trend Term

	NP-C test – fail to reject. NP-C dummy = 0	NP-C test – reject NP-C dummy = 1
NP-T test result: fail to reject (i.e. NP-T indicator dummy = 0)	**I.** Conclude: ρ=1 When using the ADF or PP tests, one can test whether the Trend is insignificant, in which case it can be deleted. The test is nonstandard. Test is not available when using NP-test.	**II.** Conclude: P(t) = C Perhaps NP-T test did not reject unit root because of low power.
NP-T test result: reject unit root (i.e. NP-T indicator dummy = 1)	**III.** **Conclude: P(t) = C + bT With b≠0.** The NP-C test is biased in favor of unit root when there is in truth a significant Trend. (Perron). We would expect to find a significant trend coefficient b in this case. If there is no unit root, the hypothesis test on @trend is standard normal.	**IV.** Conclude: P(t) = C seems to be the true model! NP-C test rejects unit root. In spite of the reduced power when @trend is included in the NP-T test, it correctly rejected unit root. So it suggests P(t) = C + bT With b=0.

Appendix Table II-3

Model Choice for Estimating Half Life, if Appropriate (i.e. No Unit Root)

			NPC_MZt_Reject_10%	
NPT_MZt_Reject_10%	Trend is Significant	Data	0	1
0	0	Sum of Bilateral Gaps	**693**	**411**
		Sum of Trend is Significant	**0**	**0**
	1	Sum of Bilateral Gaps	**34**	**62**
		Sum of Trend is Significant	**34**	**62**
0 Sum of Bilateral Gaps			**727**	**473**
0 Sum of Trend is Significant			**34**	**62**
1	0	Sum of Bilateral Gaps	**20**	**1439**
		Sum of Trend is Significant	**0**	**0**
	1	Sum of Bilateral Gaps	**8**	**183**
		Sum of Trend is Significant	**8**	**183**
1 Sum of Bilateral Gaps			28	1622
1 Sum of Trend is Significant			8	183

			NPC_MZt_Reject Unit Root?	
	Trend is Significant	Data	No	Yes
NPT_MZt_Reject_Unit Root? -	No	Sum of Bilateral Gaps Sum of Trend is Significant	**Price Gap has Unit Root**	**Trend Stationary Price Gap**
	Yes	Sum of Bilateral Gaps Sum of Trend is Significant	**Price Gap has Unit Root t stat is not normal.**	**Mean Stationary Price gap**
NPT_MZt_Reject_Unit Root? -	No	Sum of Bilateral Gaps Sum of Trend is Significant	**Confilting Results: assume Price Gap has Unit Root**	**Trend Stationary Price Gap**
	Yes	Sum of Bilateral Gaps Sum of Trend is Significant	**Mean Stationary Price gap**	**Mean Stationary Price gap**

Appendix III:
The Link between Price Gap Stationarity and Market Integration

The text argues that price gaps among locations that lie within an integrated market must be stationary, i.e. they exhibit mean reversion, if transport costs are constant (or, more generally, mean stationary). One might ask: isn't it possible to have equilibrium price gaps even between locations that are not connected, especially if there are some common economic factors (such as inflation or weather conditions that impact prices in both locations)? This Appendix provides the answer: it is ***possible*** but highly unlikely, if the individual price series are I(1) variables as the empirical evidence in Appendix I strongly suggests.

To demonstrate this point, one ask what are the underlying factors that causes prices to be I(1)? At the most general level, the answer must be economy-wide ('common') and/or location-specific determinants of supply and/or demand that are, in turn, are I(1) variables. Suppose the long-run equilibrium[1] prices in location 1 and 2 are functions of three I(1) variables (and possibly some stationary variables as well): (1) the log of the economy-wide price level P(t), (2) location-specific demand determinant such as real income in each region, denoted D1(t) and D2(t), and (3) location-specific supply determinants denoted S1(t) and S2(t):

(1) $$p1(t) = \beta_{11} + \beta_{12}P(t) + \beta_{13}D1(t) + \beta_{14}S1(t) + \varepsilon 1(t)$$

(2) $$p2(t) = \beta_{21} + \beta_{22}P(t) + \beta_{23}D2(t) + \beta_{24}S2(t) + \varepsilon 2(t)$$

Now consider the extreme case of I(1) prices in two locations that are, by assumption, completely unconnected. In this case, D1 and S1 have no impact on p2 and D2 and S2 have no effect on p1. They are completely location-specific. P(t), in contrast, is a common economy-wide factor.

Can the price gap be stationary under these circumstances? Subtracting (1) from (2) yields an expression for the price gap:

(3)

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[1] We ignore any dynamic considerations including gradual adjustment toward the equilibrium as they are not relevant for the present discussion. They would be incorporated by adding lagged prices and/or lagged supply and demand determinants to equations (1) and (2).

$$p2(t) - p1(t) = \beta_{21} - \beta_{11} + (\beta_{22} - \beta_{21})P(t) + [\beta_{23}D2(t) + \beta_{24}S2(t)] - [\beta_{13}D1(t) + \beta_{14}S1(t)] + \varepsilon 2(t) - \varepsilon 1(t)$$

From (3), we see that the price gap will almost always be nonstationary when the two pricing locations are unconnected. It will be stationary in spite of the complete segmentation (and equal to β_{21}-β_{11}) in the implausible cases where ALL of the following conditions hold:[32]

(Condition 1) $\beta_{12} = \beta_{22}$

(Condition 2) $\beta_{13}D1 + \beta_{14}S1 = 0$

(Condition 3) $\beta_{23}D2 + \beta_{24}S2 = 0$

Condition 1 says that each (and every) common factor must affect an **equal** impact on prices in both regions. This is reasonable if the common factor is the price index perhaps, but more questionable for weather conditions or world oil prices, which could have differential impact across locations even if the weather and oil prices were themselves completely uniform across regions.

Conditions 2 and 3 say that, for BOTH locations, the (long-run) impact of location-specific demand and supply shocks just cancel each other out so that the **only** thing that causes the local price (p1, p2) to be I(1) is the common factor P(t). That is, D1 and S1 are cointegrated and D2 and S2 are cointegrated.[33]

As conditions (1)-(3) are unlikely to hold, the price gap between two locations that do not lie within an integrated market will virtually always be nonstationary if the two prices themselves are nonstationary.

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[32] Technically, these three conditions are sufficient, not necessary. Tautologically, from (3) we can see that the price gap will be stationary if and only if the left-hand-side is a cointegrating relationship.

[33] If the only common factor is the price level with a coefficient of one, this amounts to saying that the LR relative prices, p1-P and p2-P, are constant due to the serendipitous canceling of D and S shocks at both locations.