Price Dynamics under Structural Changes with Unknown Break Points among

North America Natural Gas Spot Markets

Kannika Duangnate
Department of Agricultural Economics
Texas A&M University
kannika@tamu.edu

James W. Mjelde
Department of Agricultural Economics
Texas A&M University
j-mjelde@tamu.edu

David A. Bessler
Department of Agricultural Economics
Texas A&M University
d-bessler@tamu.edu

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Abstract

Potential structural changes among eight North America natural gas spot markets are investigated. Evidence from parameter instability tests of the long-run pricing relationship infers possible structural changes occurred around 2000 and again around 2009. Possible contributing factors to the structural changes around 2000 are U.S. Federal Energy Regulatory Commission Order, California's electricity crisis, 9/11 terrorist attacks, changes in imports, and increased price volatility. The likely major contributing factor to the break occurring around 2009 is the shale gas revolution. Extreme weather events appear to cause transient instability, which should not be considered structural shifts. Results shade some light on why previous studies have conflicting results; the failure to consider structural changes. Further studies regarding potential structural changes and their effects on the natural gas market are necessary.

Key words: parameter instability, structural changes, break points, natural gas

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In response to the 1970's energy crisis, major deregulation policies where enacted in Canada and United States that broke up integrated monopolies in the natural gas sectors (North American Energy Working Group 2002). One outcome of this deregulation was the development of market center and hubs (U.S. Energy Information Administration (EIA) 1995), which serve as natural gas spot markets. Approximately 30 such centers are operating in some capacity in the U.S. and Canada (U.S. EIA 2009) enhancing the trading options of buyers and sellers (National Energy Board 2002). In addition, natural gas futures trading with delivery at Henry Hub, Louisiana began in April 1990 on the New York Mercantile Exchange (Leitzinger and Collette 2002). Since deregulation, natural gas prices have been driven by market supply and demand conditions, as illustrated by findings of market competitiveness and allocative efficiency (DeVany and Walls 1993; Walls 1994a; Doane and Spulber 1994; King and Cuc 1996; Serletis and Rangel-Ruiz 2004; Park, Mjelde, and Bessler 2008; Apergis, Bowden, and Payne 2015). Supply side factors influencing natural gas prices consist of variations in domestic natural gas production, the volume of imported and exported gas, and the level of gas storage (U.S. EIA 2014a). Demand side factors consist of weather variability, economic growth, and other energy prices (U.S. EIA 2014a).

Although most of the major deregulation polices had been enacted by 1994, regulatory agencies are continuously updated regulations and enacting new policies. Further, supply and demand shocks affecting the natural gas sector are continuously occurring. U.S. Federal Energy Regulatory Commission (FERC), for example, issued FERC Order 637 in 2000. This Order revised the regulatory structure in response to increasing competition in the natural gas industry in an attempt to improve the efficiency of the markets (U.S. FERC 2000). Obvious shocks to the system are hurricanes in the Gulf of Mexico, which disrupt the supply of natural gas and unusual weather patterns across the U.S (Alterman 2012; Lin and Wesseh 2013).

The recent increase in horizontal drilling in conjunction with hydraulic fracturing, resulting in increased gas production (U.S. EIA 2011, 2014a), is a prime example of changing supply conditions. One outcome of increasing domestic supply has been declining prices. Natural gas spot prices at Henry Hub were $5 to $8 per million British thermal units (MMBtu) during 2003 to 2008, but decreased to $2 to $4 per MMBtu during 2009 to 2014 (U.S. EIA 2015d). Declining prices contribute to decreases in imported natural gas and increases in exports (U.S. EIA 2013b, 2013c). One demand side response to the abundant domestic gas supplies and relatively low natural gas prices has been an increase in U.S. industrial natural gas. Industrial natural gas consumption in 2014 was approximately 24% higher than that in 2009 (U.S. EIA 2015c). In 2014, approximately 27% of U.S. electricity was generated by natural gas; it was 75% higher than U.S. electricity generated by natural gas in 2001 (U.S. EIA 2015a).

Continuous regulatory changes, technological advances, and demand and supply shocks may be altering the sector's supply and demand relationships. The objective of this study is to investigate the possible existence of structural changes with unknown break points among North America natural gas spot markets. The study aims to determine if the "long-run" pricing relationships among North America natural gas spot markets have changed overtime. A vector error correction model (VECM) applied to eight spot markets provides the basis for determining if structural breaks in the long-run relationships among the markets have occurred. An association between identified break points and actual events are identified. Changing dynamic pricing relationships may influence trading and natural gas policy and influence infrastructure, such as pipeline systems. As such, the study should be of interest not only to those interested in energy markets, but also researchers interested in market structural changes and time series analysis.

Price Dynamics in Natural Gas Markets

Many studies suggest that the deregulation of natural gas has improved natural gas market performance (DeVany and Walls 1993, 1994; Walls 1994a, 1994b; Doane and Spulber 1994; King and Cuc 1996; Kleit 1998; Serletis and Rangel-Ruiz 2004; Cuddington and Wang 2006; Park, Mjelde, and Bessler 2008; Mohammadi 2011; Apergis, Bowden, and Payne 2015). Market integration is one of fundamental topics that have been used to monitor market performances. DeVany and Walls (1993, p. 1) state, "The relationship between commodity prices at geographically dispersed locations is evidence of market performance." If spatially separated markets for a homogenous good are integrated into one market, their prices will be interrelated and the "law of one price" holds under the constraints of transaction costs (King and Cuc 1996).

A common empirical technique to examine market integration is the cointegration model introduced by Engel and Granger (1987). DeVany and Walls (1993, p. 2) claim, "Cointegration provides a way to test for arbitrage-free pricing in time varying series." Two non-stationary series are cointegrated (move together in the long-run) if they have a linear combination that is stationary (Engel and Granger 1987). DeVany and Walls (1993) find that the natural gas markets had become more competitive as most of market-pairs were not cointegrated in 1987, but more than 65% of the markets had become cointegrated by 1991. Walls (1994a) finds that natural gas spot markets at dispersed locations are connected, whereas, Walls (1994b) find that natural gas markets are strongly integrated within the production field, but much less integrated between the field and city markets.

King and Cuc (1996) apply time-varying parameter (Kalman Filter) analysis, which allows for dynamic structure changes, to evaluate the level of price convergence in North America natural gas spot markets. They find that price convergence in all North America natural gas spot markets has increased since deregulation; yet, there exist an east-west split in natural gas pricing. In response to King and Cuc's (1996) findings, Serletis (1997) employs both Engle and Granger's (1987) approach and Johansen's (1988) maximum likelihood approach to investigate whether there exist an east-west split in North American natural gas markets. He finds that the east-west separation does not exist. Cuddington and Wang's (2006) empirical results from autoregressive models of pairwise price differentials suggest that markets in the East and Central regions are highly integrated, but these markets are quite separated from the more integrated Western market.

One shortcoming of the above analysis is they use bivariate techniques; studies have extended these techniques to include more than two series. These studies tend to use vector autoregressive (VAR) and/or vector error correction models (VECM) to analyze price dynamics in the natural gas pricing literature. Using a VAR model, DeVany and Walls (1996) suggest the law of one price holds over most of the natural gas markets. Employing a VECM, Serletis and Rangel-Ruiz (2004) find evidence of decoupling of crude oil and natural gas prices and a high degree of interconnectedness between U.S. Henry Hub and AECO Alberta natural gas prices since deregulation. Their study also indicates that natural gas prices in North America are largely defined by the U.S. Henry Hub price. Considering more diverse natural gas spot markets, Park, Mjelde, and Bessler (2008) employ a VECM to study dynamic interactions among North America natural gas spot markets and each market's role in price discovery for 1998-2007. They find that natural gas spot markets in North America are highly integrated but the degree of integration varies among the markets. Natural gas markets in Oregon, Illinois, and Louisiana are found to be the most significant markets for price discovery. Using 11 natural gas markets, Olsen, Mjelde, and Bessler (2014) results support earlier studies' findings that markets are integrated but the degree of integration varies among the market; the closer markets are located to each other, the larger the degree of integration. It appears that eastern markets provide relatively more information to western markets than western markets provide to eastern markets, there is no east-west split market in the U.S. Unlike previous studies, Olsen, Mjelde, and Bessler (2014)'s findings suggest that AECO, Alberta, is less important for price discovery than other Canadian markets.

Mohammadi (2011) examines long-run relationships and short-run dynamics of upstream-downstream pricing behavior in the U.S. natural gas industry and finds that natural gas markets are integrated but subject to regime shifts and asymmetric adjustments, suggesting market imperfections. Two regime shifts are found; one in the late 1990 regarding the implementation of regulatory reform and another during 2005-2009, a period of high volatility in energy prices. His results also indicate that shocks from both demand and supply sides play important roles in determining short-run price movements while demand shocks are the primary factor of natural gas prices in the long run. Considering weekly data from March 1994 to September 2011, Lin and Wesseh (2013) find the existence of regime-switching in the natural gas market. They suggest that the shift in the early part of 1994 was because of oil shortages, whereas, the shift between 1998 and 2002 was related to Hurricane Mitch. The largest shift, however, is attributed to hurricane-related gas shortages in North America and the financial crisis in 2008. Similarly, Apergis, Bowden, and Payne (2015) find a structural break occurred during 1994 to 1995; they identified the cause of this break as a response to the deregulation of natural gas industry. Wakamatsu and Aruga (2013) examine whether U.S. shale gas production affects the structure of the U.S. and Japanese natural gas markets. They find a structural break in natural gas prices and consumption around 2005, suggesting that shale gas production may have led to changes in the relationships between the U.S. and Japanese natural gas markets. The U.S. and Japanese markets have become more independent since the shale gas revolution.

Empirical Methods

Tests for Structural Changes in Cointegrated VAR models

Hansen and Johansen's (1999) test that investigates the cointegration relationships based on the Lagrange Multiplier type test is applied to identify the potential structural changes in pricing relationship among North America natural gas spot markets. The test examines the constancy of the cointegrating vectors in a VECM. A VECM with *k*-1 lags is

(1) $$\Delta X_t = \mu + \alpha\beta' X_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta X_{t-i} + e_t$$

$$= \alpha\beta^{*\prime} X_{t-1}^{*} + \sum_{i=1}^{k-1} \Gamma_i \Delta X_{t-i} + e_t, \qquad t = 1, \ldots, T,$$

where $X_t^* = (1', X_t')$, $\beta^* = (\delta', \beta')$, $\mu = \alpha\delta'$ is constant term, α, β, δ, and Γ are parameters, 1 is a vector of one, X is a vector of variables, and p and k are integers (Hansen and Johansen 1999). The error terms e_t are assumed to be independent and Gaussian with mean zero and covariance matrix Ω (Hansen and Johansen 1999). $\alpha\beta'$ is expected to have reduced rank such that α and β are (p x r) matrices of full rank where r ($< p$) is the number of cointegrating vectors (Hansen and Juselius 1995). The long-run structure is identified by the cointegration space spanned by β while the short-run structure is identified through α and Γ_i (Johansen 1995). Note, the constant term μ is restricted to satisfy the condition $\alpha_\perp' \mu = 0$ such that no deterministic trend is allowed in the model (Hansen and Johansen 1999).

Equation (1) can be rewritten as

(2) $$Z_{0t} = \alpha\beta^{*\prime} Z_{1t} + \Gamma Z_{2t} + e_t, \qquad t = 1, \ldots, T,$$

where $Z_{0t} = \Delta X_t$, $Z_{1t} = X_{t-1}^*$, $Z_{2t} = \Delta X'_{t-1}, \ldots, \Delta X'_{t-k+1}$, and $\Gamma = (\Gamma_1, \ldots, \Gamma_{k-1})$ (Hansen and Johansen 1999). Maximum likelihood estimation involves a reduced rank regression of Z_{0t} on Z_{1t} and Z_{2t} (Hansen and Johansen 1999). Regression of Z_{0t} and Z_{1t} on Z_{2t} yields residuals $R_{0t}^{(T)}$ and $R_{1t}^{(T)}$, which are defined as (Hansen and Johansen 1999)

$$R_{0t}^{(T)} = Z_{0t} - M_{02}^{(T)}\left\{M_{22}^{(T)}\right\}^{-1} Z_{2t},$$

$$R_{1t}^{(T)} = Z_{1t} - M_{12}^{(T)}\left\{M_{22}^{(T)}\right\}^{-1} Z_{2t},$$

$$R_{et}^{(T)} = e_t - M_{e2}^{(T)}\left\{M_{22}^{(T)}\right\}^{-1} Z_{2t},$$

where

$$M_{ij}^{(t)} = \sum_{s=1}^{t} Z_{it} Z_{jt}',$$

$$M_{ej}^{(t)} = \sum_{s=1}^{t} e_t Z_{jt}', \qquad i, j = 0, 1, 2.$$

The analysis in which the parameter Γ has been eliminated is based on the following regression equation (Hansen and Johansen 1999)

(3) $\quad R_{0t}^{(T)} = \alpha\beta^{*\prime} R_{1t}^{(T)} + R_{et}^{(T)}, \qquad t = 1, \dots, T.$

Hansen and Johansen's (1999) tests are based on recursively estimating the VECM adding one observation at time. If the recursive estimation is based on equation (2), the Z-representation, all parameters are estimated recursively at each time step (Hansen and Johansen 1999). If the recursive estimation is based on equation (3), the R-representation, the constancy of parameters β is analyzed given that the short-run dynamics are constant over time (Hansen and Johansen 1999).

It is emphasized that the null hypothesis of the test is parameter constancy but a specific alternative is not stipulated (Hansen and Johansen 1999). Hansen and Johansen (1999, p. 307) note, "We regard the recursive analysis as a misspecification test where the purpose is to detect possible instabilities in the parameters when there is no prior knowledge of structural breaks or time dependencies in the parameters."

For the base sample $t \in \{1, \dots, n\}$, $n = T_0, \dots, T$, let β^* be normalized on $\bar{c}$ such that $\hat{\beta}_c^{*(n)} = \hat{\beta}^{*(n)}\left(\bar{c}'\hat{\beta}^{*(n)}\right)^{-1}$ and define $\hat{\alpha}_c^{(n)} = \hat{\alpha}^{(n)}\hat{\beta}^{*(n)\prime}\bar{c}$, such that $\alpha_c^{(n)}\,\beta_c^{*(n)\prime} = \alpha^{(n)}\,\beta^{*(n)\prime}$. A maximum test for constancy of β^* (the difference between $\hat{\beta}^{*(n)}$ and $\hat{\beta}^{*(T)}$) is given by a sequence of test statistics (Dennis 2006),

(4) $$Q_T^{(n)} = \left(\frac{n}{T}\right)^2 trace\left\{\left(V^{(T)}\right)^{-1} S^{n\prime}\left(M^{(T)}\right)^{-1} S^n\right\},$$

where $V, M,$ and S are given by

(5) $$V^{(T)} = \hat{\alpha}_c^{(T)\prime}\left(\hat{\Omega}^{(T)}\right)^{-1}\hat{\alpha}_c^{(T)},$$

(6) $$M^{(T)} = T^{-1}c_\perp' S_{11} c_\perp,$$

(7) $$S^{(n)} = c_\perp'(S_{01}^{(n)} - \hat{\alpha}_c^{(T)}\hat{\beta}_c^{*(T)\prime}S_{11}^{(n)})'\left(\hat{\Omega}^{(T)}\right)^{-1}\hat{\alpha}_c^{(T)}$$

$$= c_\perp'(S_{01}^{(n)} - \hat{\alpha}^{(T)}\hat{\beta}^{*(T)\prime}S_{11}^{(n)})'\left(\hat{\Omega}^{(T)}\right)^{-1}\hat{\alpha}^{(T)}.$$

In Hansen and Johansen (1999), the test statistic $Q_T^{(n)}$ is based on a first order approximation of the score function $S^{(n)} = M^{(n)}\left(Tc_\perp'\left(\hat{\beta}_c^{(n)} - \hat{\beta}^{(T)}\right)\right)'$. In this study, the score function as given in equation (7) is directly used following Bruggeman, Donati, and Warne (2003) because the first order approximation may lead to ill-behaved $Q_T^{(n)}$ in some situation, such as when the sample size is small (Dennis 2006).

Data

To allow for regional dispersion, eight natural gas spot prices in Canada and United States are considered: AECO Hub, Alberta, Canada; Chicago City Gate, Illinois;

Dominion South Point, Pennsylvania; Henry Hub, Louisiana; Malin, Oregon; Oneok, Oklahoma; Opal, Wyoming; and Waha Hub, Texas. These markets have been identified in previous studies as important pricing markets. AECO Hub is included to represent Canada because in 2014 about 99% of U.S. pipeline-imported natural gas came from Canada and 51% of pipeline natural gas exports went to Canada (U.S. EIA 2015e). Henry Hub is an important market for pricing of the North America natural gas spot and future markets (Serletis and Rangel-Ruiz 2004; U.S. EIA 2013a, 2015d). Park, Mjelde, and Bessler (2008) find Chicago is a dominant market for price discovery among North America natural gas spot markets. Texas, Pennsylvania, Louisiana, Oklahoma, and Wyoming were the top five natural gas producing states in 2013 (U.S. EIA 2014b). Texas, California, Louisiana, New York, and Florida were the top five natural gas consuming states in 2013 (U.S. EIA 2015b). Natural gas is delivered to California, which is one of the top five natural gas consuming states, through Malin (U.S. EIA 2014d).

Weekday nominal prices of natural gas from May 3, 1994 to October 31, 2014 giving 5,340 observations are used (Bloomberg L.P. 2014). Any missing values are replaced by the prior day's price. Each price is a volume-weighted average price for natural gas to be delivered on the next day. All prices are in U.S. dollars per MMBtu. All price series are natural logarithm-transformed before any estimation. Summary statistics on the natural logarithms of each price series are presented in table 1. The logarithm-transformed data are plotted in figure 1.

Augmented Dickey-Fuller (ADF) and Kwiatkowski-Philips-Schmidt-Shin (KPSS) tests are used to test for unit roots (non-stationary) in logarithms of the prices. Failure to reject the null hypothesis of unit root for the ADF implies the natural gas spot prices at all markets except Opal are non-stationary (table 2). Under the null hypothesis of unit root, the ADF test may have lower power against the alternative hypothesis of stationarity (DeJong et al. 1992). KPSS test statistics imply that the null hypotheses of stationarity are rejected for all series. Both ADF and KPSS test statistics indicate that all price series are stationary after first differencing.

Empirical Results

Before conducting parameter instability tests of the cointegrated VAR model, Schwarz loss measures are used to determine the cointegrating rank and lag length simultaneously. This method provides better large sample results in Monte Carlo simulations than the trace test method (Wang and Bessler 2005). The Schwarz loss criterion suggests a rank of six cointegrating vectors with five lags (table 3). This suggests a potential weekday influence in the natural gas spot markets. Olsen, Mjelde, and Bessler (2014) also find a weekday effect with prices tending to be lower in the middle of the week.

Structural Changes in the VECM

Tests for constancy of β in the VECM with the rank of six and five lags are performed. Following Hansen and Johansen (1999), both the Z- and R-Form statistics are presented graphically in figure 2. Note as $n \rightarrow T$, the test statistics approach zero and eventually equal zero when $n = T$. The null hypothesis of parameter constancy is rejected when the test statistic is greater than the 5% critical value.

The Z-and R-Form statistics are consistent with each other (figure 2). The test statistics starting from the beginning of 1996 to 2009 are greater than the 5% critical value; implying the null hypothesis of constancy of β is rejected. There is a shift around 2009. The hypothesis of constancy, however, is only marginally rejected during the period 1996 to 2000. There appears to be another shift around the end of 2000. Instability of β implies that the long-run relationships are not constant over the period 1994 to 2014. There appears to be three distinct time periods.

Sub-period Analysis

Because of the β instability, for further analysis, the data is divided into three sub-periods: May 3, 1994 to September 29, 2000, October 2, 2000 to December 31, 2009, and January 1, 2010 to October 31, 2014. Schwarz loss measures indicate three lags are appropriate in each sub-period, but the number of cointegrating vectors (rank) varies by subsamples. The ranks are three, seven, and four for the three sub-periods (table 3). Given these lags and ranks, each subsample is tested for constancy of β.

Most test statistics of both Z- and R-representations are below the 5% critical line, implying the long-run relationships in the first sub-period are constant (figure 3). The test statistics, however, spike from the end of 1995 to the beginning of 1996. This spike is consistent with the test statistics for the entire sample (figure 2). The spike signals that something unusual occurred at the end of 1995. High natural gas prices as a result of cold weather that caused very rapid decline in natural gas stocks, which were already low because of unusually cold weather in November and December 1995 (U.S. EIA 1996) may be the possible cause.

Test statistics are also generally less than the 5% critical value for the second subsample except begining at the end of 2005 extending into 2007 (figure 4). Such inconsistency is also detected when testing constancy of β using the entire data set. Hurricanes Katrina and Rita in 2005 are possibly behind the instability. These hurricanes caused damage to the U.S. natural gas and petroleum infrastructure; many Gulf of Mexico wells, processing plants, and pipelines were closed (U.S. EIA 2010). In addition to the hurricane season, the start of the increase in domestic production associated with shale gas are likely behind this inconstancy.

Both the Z- and R-represention test statistics using the third subsample reject the null hypothesis during 2012 and also spike at the beginning of 2014 (figure 5). Compared to 2011, average natural gas spot prices in 2012 fell considerbly throughout the U.S. as the contribution of a mild 2011-2012 winter, continuously high natural gas invetories, and increaing natural gas production in the Marcellus and Eagle Ford basins (U.S. EIA 2013a). The spike in 2014 is not seen when using the entire data set. This spike is most likely associated with the North Polar Vortex, which led to unusual extremely cold weather affecting a large part of Canada and the U.S. during the winter of 2013-2014; resulting in increased natural gas spot prices (U.S. EIA 2014c).

Structural Breaks

When using the entire data set, the evidence of β inconstancy suggests that the potential presence of structural changes in the North America natural gas spot market may have occurred during 2000 and around the end of 2009. Subsequent sub-period analyses suggest constancy in each of the three sub-periods; further suggesting there are three periods of differing long-run relationships. Transitory rejection of the null hypothesis of constancy of β in each sub-period should not be considered as structural changes.

The shift during 2000 to 2001 may be related to unexpectedly high and volatile natural gas prices (Alterman 2012; Joskow 2013). Henry Hub and the NYMEX futures prices clearly show a period of increased prices and volatility around this time period (figures 1 and 6). These may be results of FERC Order no. 637 in 2000 which involves removing some pipeline price ceilings (U.S. FERC 2000). Alterman (2012) suggests natural gas price volatility at the end of 2000 was due to the second coldest November on record since 1895. Joskow (2013, p. 340) notes, "…there had been a gas supply overhang during the 1990s and that as demand caught up with supply more expensive gas production sources would have to be relied upon to balance supply and demand, including more imports from Canada…" U.S. natural gas imports had been increasing (U.S. EIA 2015e). Ratios of U.S. natural gas imports to U.S. dry natural gas production are high in the 2000s relative to the 1990s and peak during 2005-2007 (figure 7). Increases in imports might be a sign of market instability, as the U.S. natural gas industry become more critically dependent on imports. Moreover, the 2000-2001 California electricity crisis and the 9/11 terrorist attack resulting in a global economic recession may have caused part of the price volatility during 2000-2001 (Alterman 2012; Lin and Wesseh 2013).

In the entire sample (figure 2), the test statistics marginally reject the null hypothesis around 2009 and are below the 5% critical value after 2009. Inference is that the long-run relationships changed around 2009. The U.S. EIA (2011) claims that shale gas is a "game changer" for the U.S. natural gas market. Because of the increased domestic natural gas production, the U.S. becomes less import-reliance and is expected to become a net exporter in natural gas. Ratios of U.S. natural gas imports to U.S. dry natural gas production have been decreasing since 2009 (figure 7). Also, price volatility decreased after 2009 (figure 6). Less import-dependency of the U.S. natural gas industry can also be observed by the response of natural gas prices to changes in natural gas storage that has become larger after the significant increase in domestic production (Chiou-Wei, Linn, and Zhu 2014).

Conclusions and Discussion

Tests for constancy of β, which are the long-run relationship parameters, are used to discover the possible existence of structural changes in the North America natural gas spot markets during 1994 to 2014. Instability of β indicates that the long-run relationships among natural gas spot markets in North America change around 2000 and again around 2009.

As most of the major deregulation polices had been enacted by 1994, the first sub-period (May 1994 – September 2000) appears to be the phase that the natural gas industry was maturing and becoming competitive as a result of the development of natural gas trading hubs and spot markets, and derivatives markets (Joskow 2013).

Many events around 2000 time may have contributed to structural change at this time. Unexpectedly high and volatile natural gas prices, the 2000-2001 California electricity crisis, 9/11 terrorist attacks, FERC Order No.637, and increases in imports appear to have contributed to expensive and volatile natural gas prices during the 2000 decade. The U.S. natural gas market was more import-intensive in the second sub-period

(October 2000 – December 2009), as ratios of U.S. natural gas imports to U.S. dry natural gas production were high relative to other period.

Tests for parameter instability reveals the constancy of β after 2009. Shale gas production is possibly behind this change as technological advancement are leading to accessing large-scale natural gas which has augmented domestic natural gas production. Larger stable supplies encourage market stability, as the natural gas industry becomes less import reliant.

The above discussion is in no way a cause and effect analysis. The time series analysis suggests several break points and the anecdotal evidence provides several possible events that may have contributed to the breaks. Further, the analyses use daily day, although the long run is never specifically defined, this concept must be taken in light of daily data and time series methodologies. With these caveats, several general inferences and suggestions for future research arise from the results. From an academic standpoint, inconsistent results in the literature, such as importance of markets to in pricing relationships and whether there exists an east-west split in North America natural gas markets or not, are possibly results of not only different methodologies employed and markets included but also the time period of the data. Ignoring the presence of structural changes may lead to misleading results and poor ex ante forecasts (Stock and Watson 2009; Breitung and Eickmeier 2011). Rather than considering data with long periods of time, realizing when a structural break occurs and using an appropriate time period of data set may improve forecasting performance.

As expected, in general, regulatory agencies are able to alter markets. Specifically, it appears FREC with its policies can and does alter the natural gas market. Not only a major FERC order, but also a multitude of major events impacted the natural gas at the start of the second sub-period. It is shown that more transitory events such as weather shocks can alter relationships but these events appear to be short lived. The change occurring around 2000 was longer lived implying time is necessary for the markets to learn and respond to regulatory changes. The goal of improving market competitiveness and efficiency, given economic theory of regulations, should affect long-run pricing relationships and the profitability of the natural gas sector.

Structural changes in the natural gas market probably affect each individual market's role in price discovery; markets that were important for price discovery might become less important as a result of a change in industry. Such information is helpful to energy traders. Because of the shale gas revolution, excess demand regions may become excess supply; in response to such conversion, expanding existing pipeline systems and constructing new systems to be bidirectional may improve transportation in the natural gas industry. All of these changes may influence pricing relationships.

Further studies regarding evidences of parameter inconsistency in natural gas pricing long-run relationship are necessary, along with the potential effect these changes have on the natural gas market. Issues being further studied include splitting the time periods into the three sub-periods for innovation accounting analysis and comparison of forecasting performance. Studies that not only identify breaks in the natural gas market structure but also the effects of the breaks on the market are necessary. The impact of using various data from various time periods needs further exploration. Such studies provide insights not only into the natural gas market but also why, sometimes, conflicting results studies are obtained by different studies.

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Table 1. Summary Statistics on the Natural Logarithms of Natural Gas Spot Price at Eight Markets

Statistics	AECO Hub	Chicago	Dominion South	Henry Hub	Malin	Oneok	Opal	Waha Hub
Mean	1.083	1.360	1.383	1.338	1.247	1.256	1.100	1.267
Maximum	2.720	3.715	3.219	2.964	4.030	3.459	3.367	3.199
Minimum	-0.713	0.207	0.140	0.030	-0.073	0.058	-1.897	0.077
Std. Dev.	0.666	0.512	0.515	0.516	0.588	0.508	0.587	0.510
Skewness	-0.335	0.161	0.227	0.118	-0.092	0.012	-0.246	-0.003
Kurtosis	2.215	2.574	2.308	2.351	2.552	2.320	2.561	2.351
Jarque-Bera	237.080	63.551	152.537	106.311	52.247	103.047	96.649	94.025
Probability	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Table 2. Augmented Dickey-Fuller (ADF) and Kwiatkowski-Philips-Schmidt-Shin (KPSS) Test[a] Statistics of Eight Natural Gas Spot Prices in the Natural Logarithms

	ADF		KPSS	
Price Series	t-Stat	Lag[b](k)	LM-Stat	Bandwidth[c]
		Test in Level		
AECO Hub	-2.581	3	4.824	56
Chicago	-2.954	19	3.662	56
Dominion South	-2.859	19	2.990	56
Henry Hub	-3.019	2	3.708	56
Malin	-2.787	11	4.155	56
Oneok	-3.158	10	3.819	56
Opal	-3.714	7	4.224	56
Waha Hub	-2.994	15	3.938	56
		Test in First Difference		
AECO Hub	-50.497	2	0.048	53
Chicago	-20.382	18	0.046	139
Dominion South	-18.168	18	0.064	33
Henry Hub	-59.951	1	0.042	24
Malin	-24.902	10	0.043	75
Oneok	-25.514	9	0.050	76
Opal	-36.245	6	0.024	63
Waha Hub	-21.064	14	0.051	82

Note: Under the null hypothesis of non-stationarity (unit root), the ADF test critical value at 1%, and 5% levels are -3.430 and -2.860; the null is rejected when t-Stat is less than the critical value (Said and Dickey 1984). Under the null hypothesis of stationarity, the KPSS test critical value at 1% and 5% levels are 0.739 and 0.463; the null is rejected when LM-stat is greater than the critical value (Kwiatkowski et al. 1992).

[a] Only constant term is included in equations.

[b] Lag (k) is selected from 0 to 20 based on Schwarz information criteria (SIC).

[c] Bandwidth is estimated using the Newey-West (1994) method.

Table 3. Schwarz Loss Measures on One to Eight Co-Integrating Ranks and One to Five Lags on VECM models

No. of Rank	One Lag	Two Lags	Three Lags	Four Lags	Five Lags
	Entire Data May 3, 1994 - October 31, 2014				
1	-47.722	-48.054	-48.238	-48.301	-48.337
2	-47.830	-48.130	-48.285	-48.346	-48.370
3	-47.886	-48.153	-48.297	-48.351	-48.371
4	-47.928	-48.179	-48.307	-48.356	-48.372
5	-47.957	-48.197	-48.318	-48.363	-48.373
6	-47.985	-48.213	-48.325	-48.366	-48.374*
7	-47.991	-48.216	-48.327	-48.364	-48.371
8	-47.989	-48.214	-48.325	-48.362	-48.369
	First Sub-Period: May 3, 1994 - September 29, 2000				
1	-49.440	-49.865	-50.050	-50.006	-50.000
2	-49.663	-49.970	-50.122	-50.048	-50.022
3	-49.809	-50.058	-50.175*	-50.094	-50.044
4	-49.832	-50.073	-50.175	-50.089	-50.036
5	-49.843	-50.071	-50.160	-50.075	-50.016
6	-49.848	-50.073	-50.154	-50.065	-50.002
7	-49.840	-50.062	-50.142	-50.053	-49.990
8	-49.832	-50.055	-50.134	-50.046	-49.982
	Second Sub-Period: October 10, 2000 - December 12, 2009				
1	-49.961	-50.286	-50.375	-50.378	-50.338
2	-50.055	-50.340	-50.399	-50.393	-50.342
3	-50.132	-50.381	-50.424	-50.397	-50.345
4	-50.203	-50.406	-50.432	-50.396	-50.339
5	-50.240	-50.415	-50.435	-50.393	-50.330
6	-50.254	-50.425	-50.437	-50.391	-50.326
7	-50.269	-50.435	-50.441*	-50.392	-50.325
8	-50.266	-50.432	-50.437	-50.388	-50.321
	Third Sub-Period: January 1, 2010 - October 31, 2014				
1	-52.818	-53.365	-53.501	-53.487	-53.362
2	-53.096	-53.478	-53.602	-53.566	-53.401
3	-53.216	-53.528	-53.609	-53.566	-53.400
4	-53.300	-53.561	-53.612*	-53.561	-53.391
5	-53.337	-53.559	-53.597	-53.539	-53.367
6	-53.341	-53.547	-53.580	-53.519	-53.349
7	-53.331	-53.534	-53.564	-53.502	-53.332
8	-53.326	-53.528	-53.556	-53.492	-53.321

Note: The asterisk '*' indicates minimum values of Schwarz loss measure.

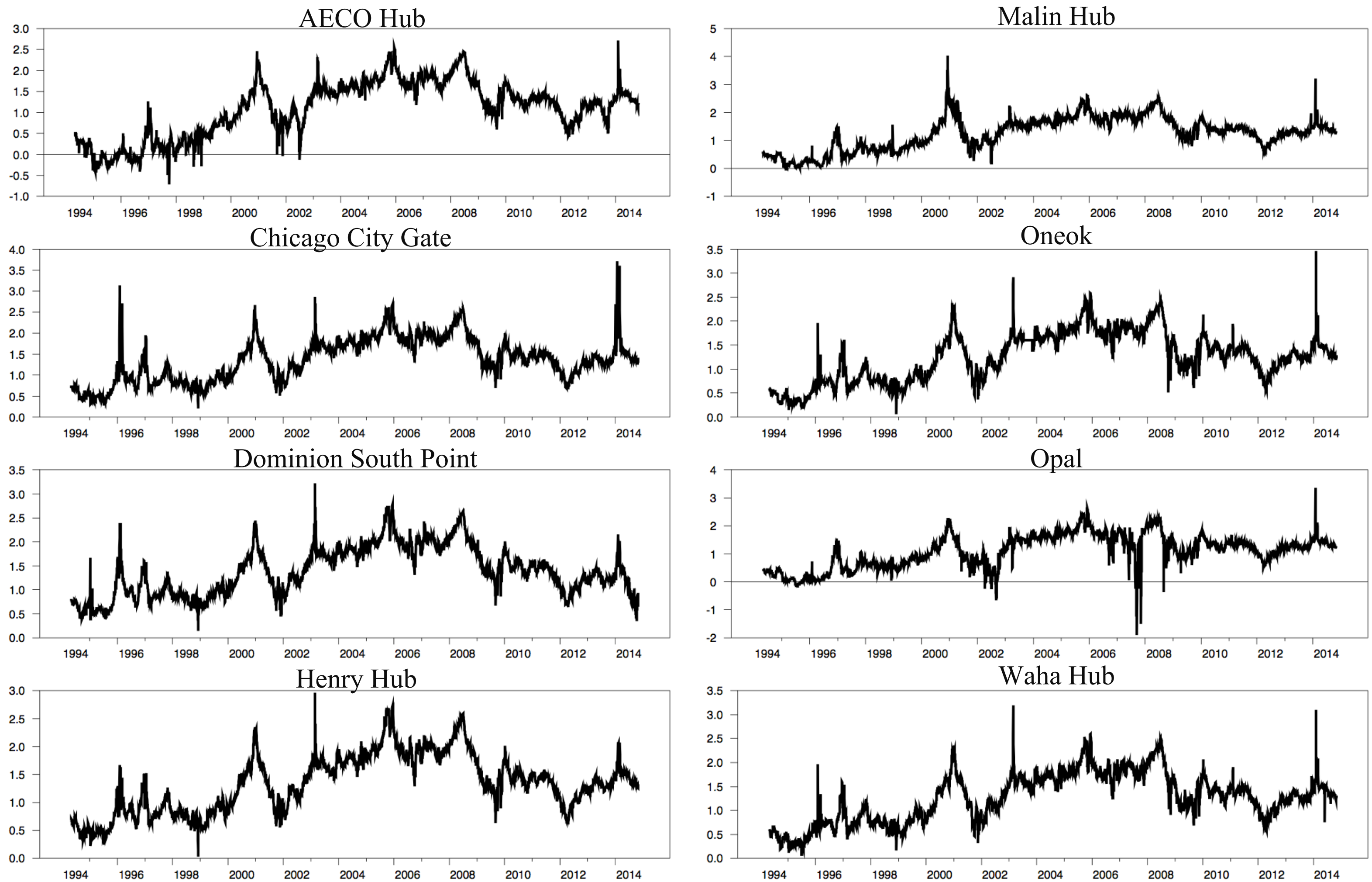

Figure 1. Plots of eight natural gas spot prices in the natural logarithms (May 3, 1994 - October 31, 2014)

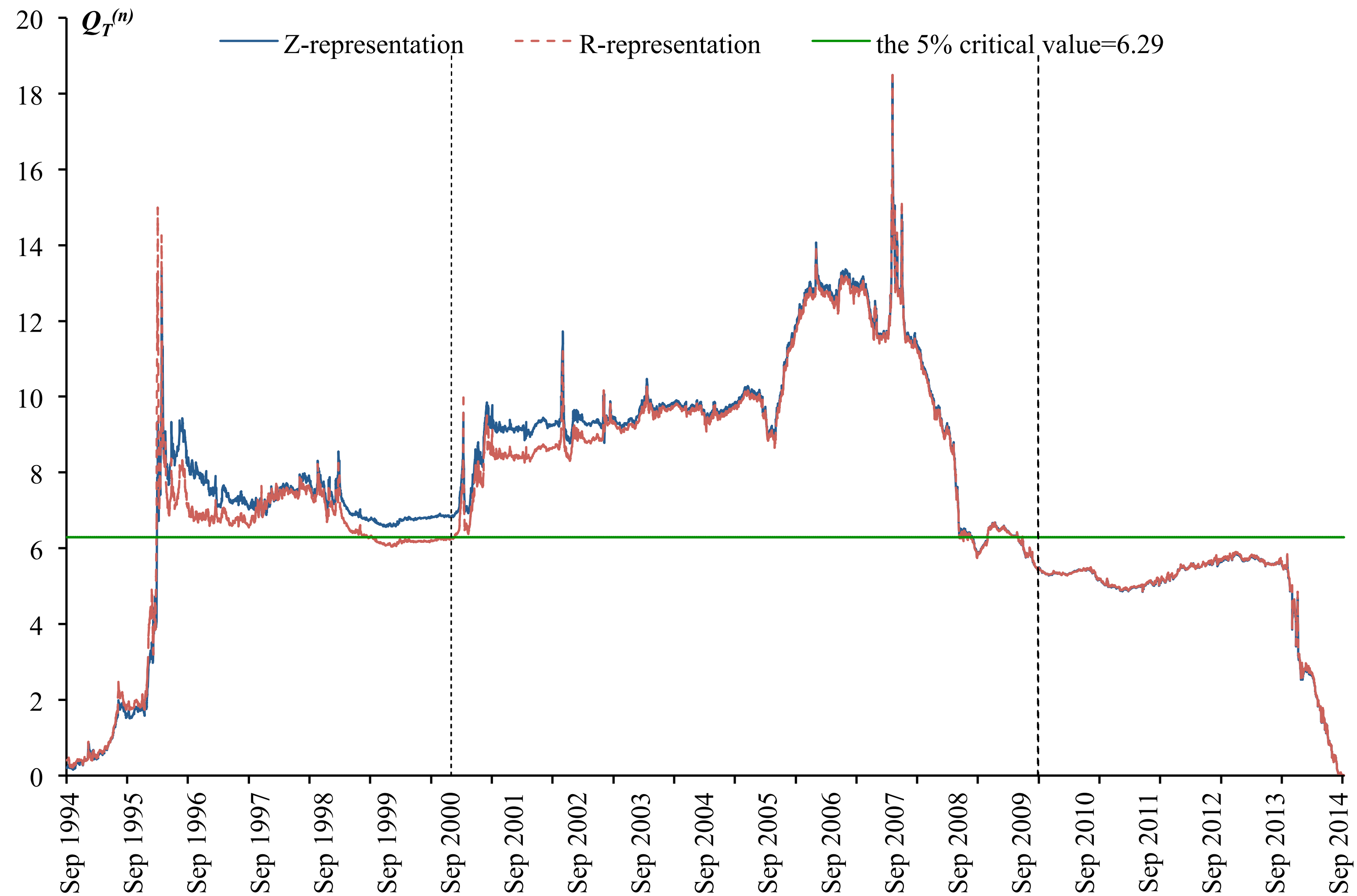

Figure 2. Plots of sup $Q_T^{(n)}$ for the entire data set (May 3, 1994 to October 31, 2014

Notes: The first vertical dash line indicates October 2, 2000. The second vertical dash line indicates January 1, 2010.

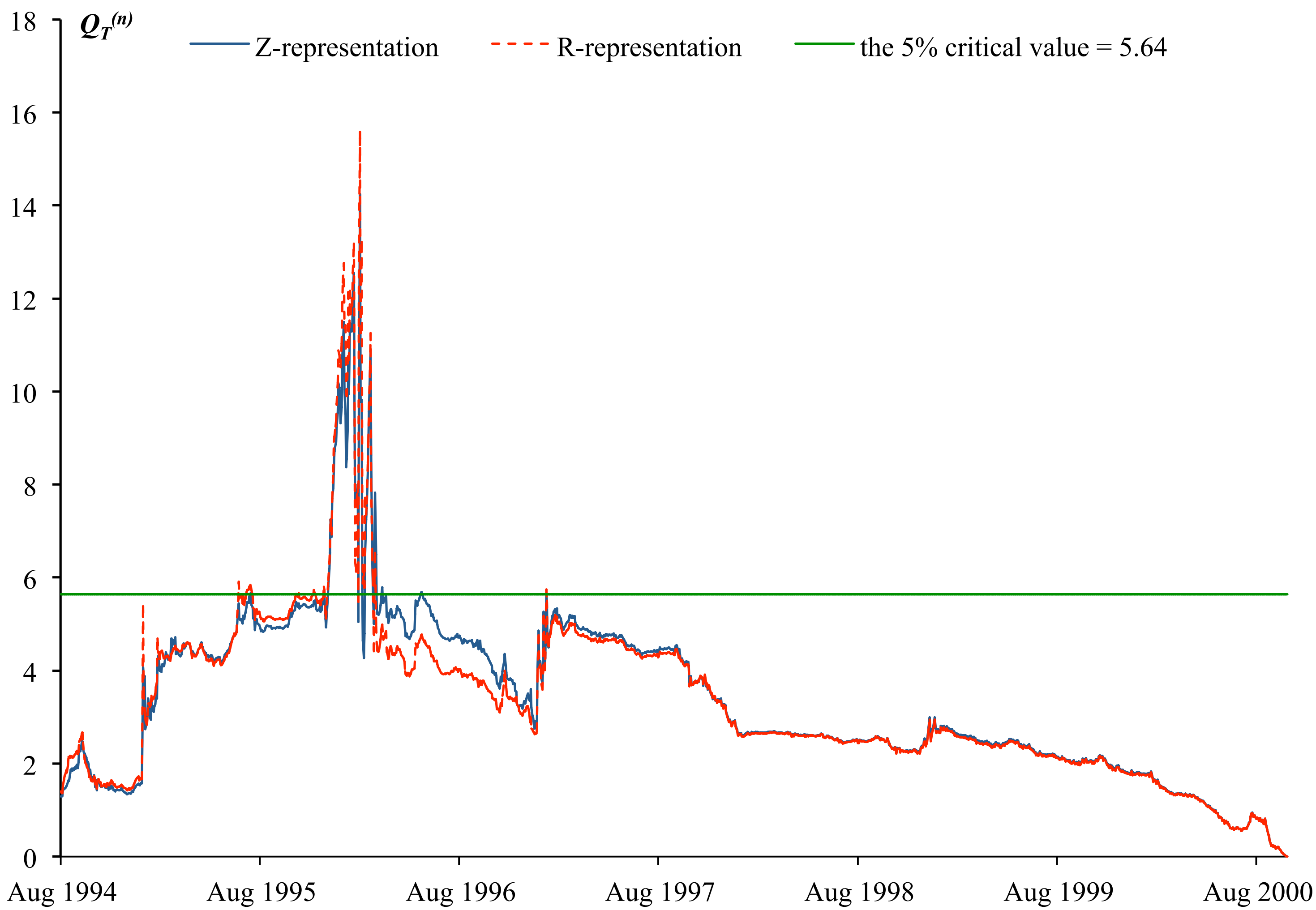

Figure 3. Plots of sup $Q_T^{(n)}$ for the first sub-period (May 3, 1994 - September 29, 2000)

Figure 4. Plots of sup $Q_T^{(n)}$ for the second sub-period (October 2, 2000 - December 31, 2009)

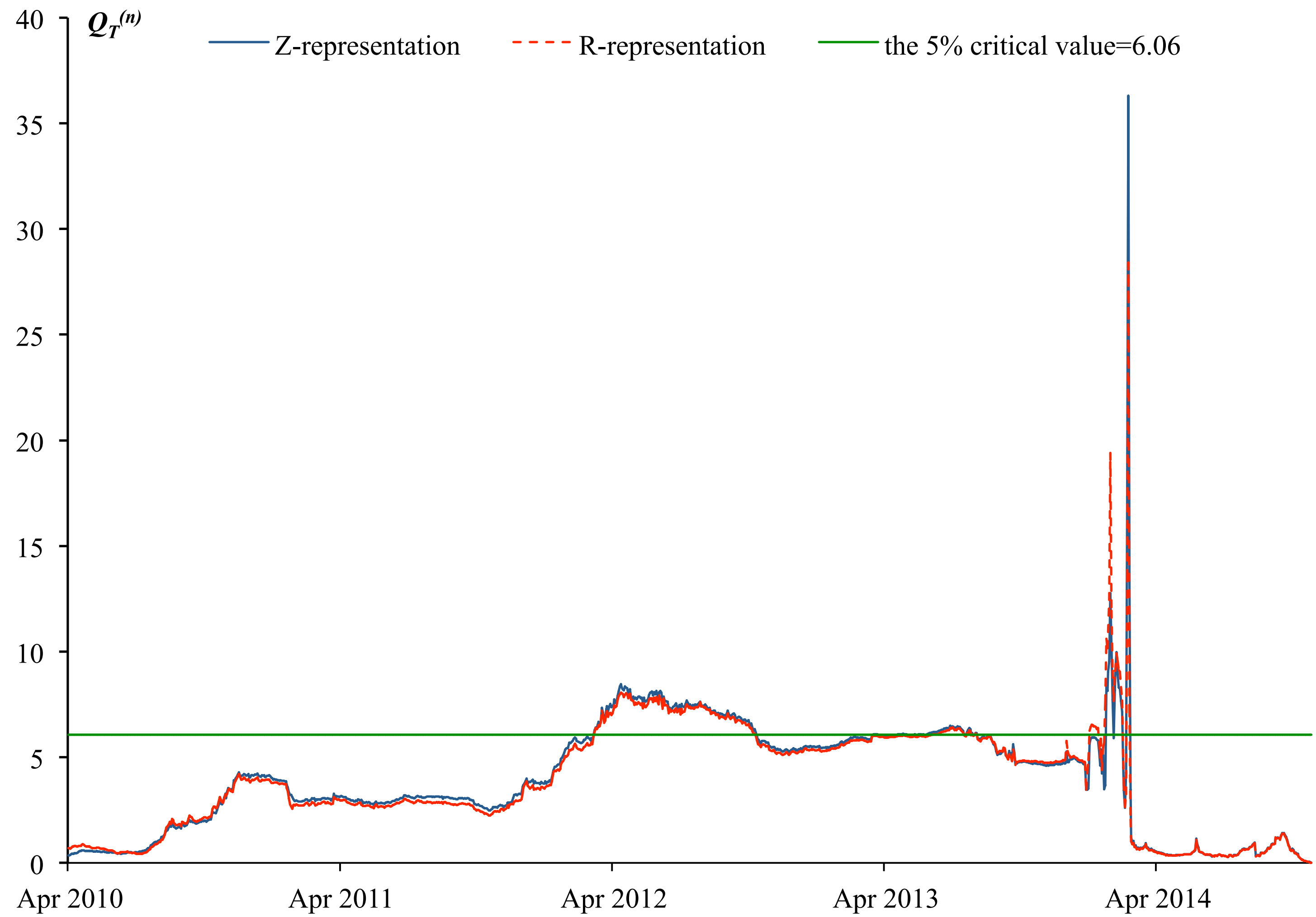

Figure 5. Plots of sup $Q_T^{(n)}$ for the third sub-period (January 1, 2010 - October 31, 2014)

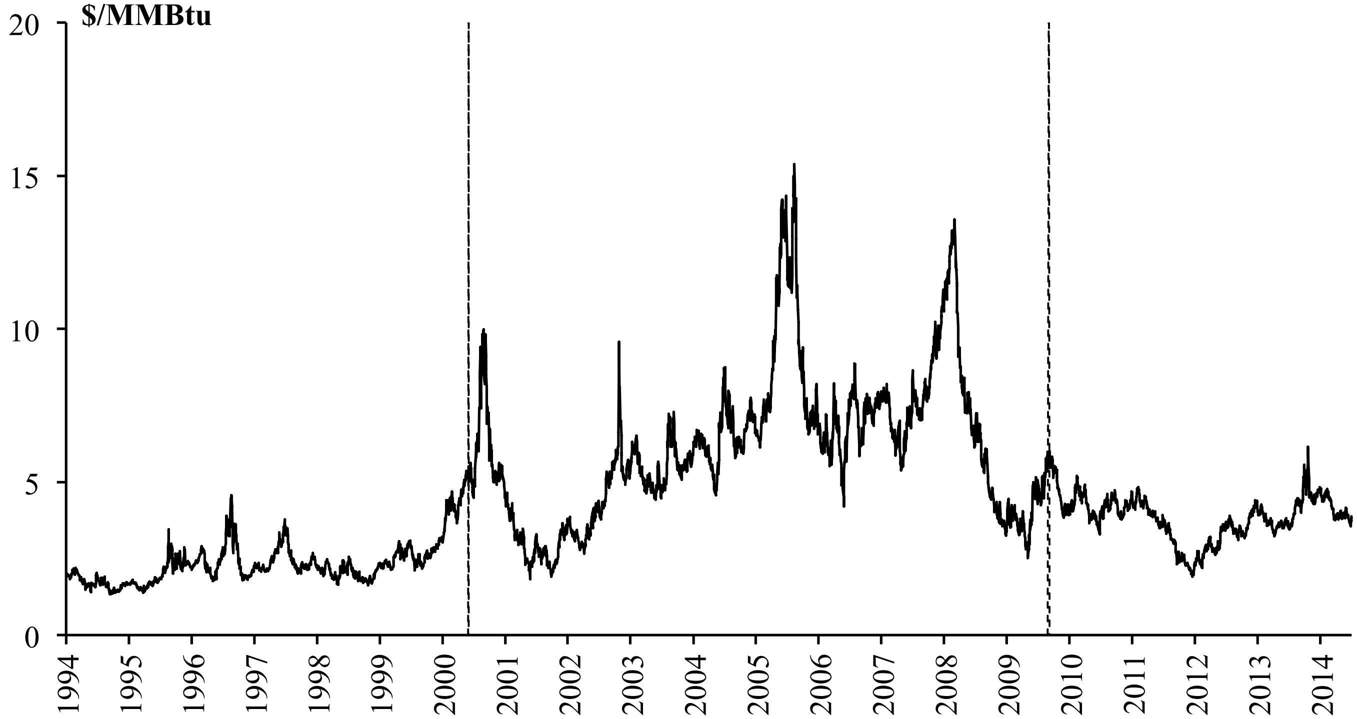

Figure 6. Daily natural gas futures prices (NYMEX) (May 3, 1994 – October 31, 2014) (U.S. EIA 2015d)
Notes: The first vertical dash line indicates October 2, 2000. The second vertical dash line indicates January 1, 2010.

Figure 7. Percents of U.S. annual natural gas imports to dry natural gas production ratio (1994-2014)
Notes: The first vertical dash line indicates year 2001. The second vertical dash line indicates year 2010.