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Global Natural Gas Market Integration: The Role of LNG Trade and Infrastructure Constraints

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ABSTRACT

This paper analyses the integration of global natural gas markets across North America, Europe, and Asia from 2016 to 2022. The analysis focuses on the impact of the United States emerging as a major liquefied natural gas (LNG) exporter and significant supply disruptions, including the sharp reduction in Russian pipeline supplies to Europe. We identify a structural break on 1 October 2021, coinciding with these supply disruptions and a tightening global LNG market. Using both linear and nonlinear cointegration techniques, we assess price convergence across the three regions in two subsamples: before and after the break. In the first subsample, we find strong integration between all three regional gas markets, driven by growing LNG trade and shared exposure to global spot market dynamics. However, in the second subsample, the degree of integration between the Asian and European markets weakens, with US prices decoupling from both. Granger causality analysis reveals that LNG infrastructure congestion, particularly in the US and Northwest Europe, significantly drives the widening price spreads between the US and European markets. These findings suggest that physical infrastructure plays a central role in energy market integration, especially during periods of tight market conditions, where infrastructure bottlenecks limit arbitrage opportunities.

JEL Classification: Q37, Q41, F14, C32, L95

1 | Introduction

International trade in natural gas has traditionally been divided into three main regional markets: Asia, Europe, and North America (Melamid 1994; Economides and Wood 2009; Geng et al. 2014). Historically, this segmentation has been driven by limited liquefied natural gas (LNG) transport capacity. However, the literature suggests that these markets are gradually becoming more integrated (Neumann 2009; Li et al. 2014). Market integration refers to the extent to which regional markets share information and align prices (McNew and Fackler 1997; Fackler and Goodwin 2001). Investigating this phenomenon has significant implications for supply security, as market participants in one region must increasingly consider conditions in other regions to ensure their own supply.

The integration process among the three regional gas markets has been driven by several key factors. First, some regions have experienced surplus natural gas production, while others have seen increasing consumption.[1] This imbalance has necessitated expanding the international gas trade, with LNG emerging as a critical solution. Increasing export capacities and the growth of the LNG fleet have significantly improved the technical and economic feasibility of inter-regional trade (Barnes and Bosworth 2015; Li et al. 2014). Second, many commercial agreements have shifted from traditional oil-indexed pricing in long-term contracts to greater reliance on hub-based pricing. For example, the share of Gas-on-Gas (G-o-G) competition[2] in global gas consumption rose from 31% in 2005 to 49% in 2021, while oil indexation declined from 24% to 19% over the same period (IGU 2021). The literature also suggests that the relationship between oil and natural gas prices has become more volatile, indicating a decoupling of the two commodities (Chiappini et al. 2019; Neumann 2009). At the same time, the G-o-G competition has seen a rise in spot and short-term transactions, where shifts in regional supply and demand prompt LNG exporters to redirect spot volumes (IGU 2021). These developments have increased market liquidity, enhanced opportunities for spatial arbitrage, and boosted the presence of physical traders. Third, advancements in shale gas exploration technology have fuelled a rapid increase in production in North America, commonly referred to as the shale gas revolution. As a result, the United States began exporting LNG in 2016 and has quickly become a major player in the global market, with export capacities expanding year over year (Melikoglu 2014; Wiggins and Etienne 2017).[3] Finally, European and Asian countries have adopted supply diversification strategies that combine pipelines and LNG imports to mitigate supply risks (Farag and Zaki 2024; Ritz 2019; Hinchey 2018).

Several studies have focused on global gas market integration, primarily relying on price data to measure the degree of integration. The hypothesis is that greater convergence between gas prices signifies stronger spatial arbitrage and higher levels of market integration. The most commonly used methodological approach to test this hypothesis is the cointegration technique,[4] which examines the existence of a long-run relationship between prices.[5]

Siliverstovs et al. (2005) investigated the integration of the North American, European, and Asian gas markets using monthly prices from November 1993 to March 2004. Their cointegration analysis provided evidence of integration between the Asian and European markets, while the North American market remained decoupled. The authors explain that the European and Asian natural gas markets are integrated due to similar long-term contracts and oil-indexed pricing mechanisms, which align price movements in these regions. In contrast, the North American market operates under a different, more competitive pricing system that decouples it from the oil-linked European and Asian markets, resulting in a lack of integration across the Atlantic. A similar conclusion was reached by Li et al. (2014), who examined the integration of international natural gas markets across North America, Europe, (a) and Asia from 1997 to 2011, using a convergence test and Kalman filter analysis.[6] In contrast, Neumann (2009) found evidence of increasing integration between North American and European gas markets. Using the Kalman filter to analyse data from 1999 to 2008, Neumann observed rising price convergence, particularly after 2003. This trend was attributed to the role of LNG in linking previously segmented markets across the Atlantic during this period.

However, Nick and Tischler (2014) pointed out that linear cointegration models, which assume symmetric adjustments, may be misspecified for natural gas markets where adjustments to price deviations can be asymmetric. Factors such as transaction costs and different responses to widening or narrowing spreads contribute to this asymmetry, making nonlinear cointegration a more appropriate approach. To address this, they examined the degree of integration between North American and European gas prices using a nonlinear cointegration approach that accounts for transaction costs. Their results provided strong evidence of nonlinearity in the sub-samples analysed (2000–2008 and 2009–2012). More recently, Chiappini et al. (2019) applied the momentum-threshold autoregression (M-TAR) model of Enders and Siklos (2001) with daily price data from 2004 to 2018, confirming the presence of nonlinearities and asymmetries in price adjustments in the global gas market. Their analysis also shows that the degree of interdependence between the North American and European markets has increased, whereas this has not occurred between the North American and Asian markets.

The reviewed literature shows that conclusions on regional gas market integration depend on the methods used and the key market mechanisms at play during the analysed period. Regarding market mechanisms, LNG trade offers more opportunities for spatial arbitrage, contributing to increased price convergence among the North American, European, and Asian markets. However, it remains unclear how recent developments in the global gas market—especially the emergence of the United States as a major LNG exporter since 2016 and the supply disruptions caused by geopolitical tensions between Europe and Russia, amid a tight LNG market—have impacted market integration.

This paper contributes to the literature by analysing the integration of the global gas market from 2016 to 2022, using daily futures prices across the three main regional gas markets. The North American market is represented by the Henry Hub (HH) benchmark, the Northwest European market by the Title Transfer Facility (TTF) benchmark, and the East Asian market by the East Asian Index (EAX). This analysis is particularly relevant for two main reasons. First, this period coincides with the entry of the United States into the global LNG trade, a development that may have reshaped relationships within the global gas market. Previous research on market integration largely focused on periods when the United States was a net importer of gas. Therefore, this study provides new insights into interdependencies and cointegration under different market conditions. Second, this period has seen several factors that support arbitrage in the global gas market, particularly between the United States and the other two regions, driven by the expansion of US LNG export infrastructure and the rise in spot LNG trade[7]. However, it has also witnessed factors that hinder arbitrage, such as US LNG export infrastructure and European import infrastructure operating at maximum capacity. In this context, this study provides a formal statistical analysis of the price differentials between regional gas markets and identifies a structural break in these differentials on 1 October 2021. This timing aligns with significant market disruptions, such as Russia reducing gas flows to Europe and a tightening global LNG market due to supply outages and capacity constraints (Fulwood et al. 2022; McWilliams et al. 2023). To capture the potential effects of these dynamics, we conduct the cointegration analysis over two subsamples, splitting the data on 1 October 2021. This timing aligns with significant market disruptions, including Russia's reduction of gas flows to Europe and the tightening global LNG market due to supply outages and capacity constraints (Fulwood et al. 2022; McWilliams et al. 2023).

Our results show that during the first subsample (January 2016 to September 2021) the Asian and European gas prices are cointegrated. This finding is consistent with previous studies, such as Chiappini et al. (2019), which also identified cointegration between European and Asian gas markets in earlier periods. The persistence of this integration during our sample period can be attributed to the growth of LNG trade, which has facilitated arbitrage opportunities between Europe and Asia. Both regions are subject to global supply–demand dynamics and spot market pricing mechanisms, reinforcing their integration. While Chiappini et al. (2019) found no cointegration between American and Asian prices but did find cointegration between American and European prices, our analysis reveals that American prices were cointegrated with both European and Asian prices during this period. These differences likely reflect changes in the global gas market, particularly the transition of the United States to a net exporter, which has reshaped its relationship with the European and Asian markets. However, our findings are consistent with those of Nick and Tischler (2014) and Chiappini et al. (2019), supporting the conclusion that regional gas prices are nonlinearly cointegrated. This implies that adjustments towards equilibrium happen at different speeds based on the direction of deviation from the equilibrium.

In the second subsample (October 2021—November 2022), we find no evidence of linear cointegration for any price pairs based on the Engle–Granger approach. However, when we apply the Enders–Siklos threshold cointegration method, we find evidence of threshold cointegration only for the EAX–TTF price pair. This suggests the presence of a nonlinear, asymmetric relationship between these two markets during the second subsample period, while the other pairs (HH–TTF and HH–EAX) do not exhibit such a relationship. The lack of cointegration between the American and European markets may be attributed to LNG infrastructure congestion during this period, which acts as a physical barrier to arbitrage.[8] To further investigate the decoupling of the American and European gas markets observed in the second subsample, we examine the relationship between the HH–TTF price spread and LNG infrastructure congestion. Using the Toda and Yamamoto (1995) approach, we analyse the predictive relationship between LNG infrastructure congestion and the HH–TTF price spread. In the second subsample, we find significant Granger causality from congestion to the HH–TTF spread, suggesting that infrastructure constraints are influencing price differentials. These findings underscore the critical role of infrastructure capacity in facilitating or impeding market integration between regional gas markets.

The remainder of the paper is organised as follows: Section 2 outlines the conceptual background. Following this, Section 3 discusses structural changes in the regional gas market, focusing on regional price patterns, LNG infrastructure utilisation, and LNG trade dynamics in Northwest Europe (NWE), East Asia, and the United States. Section 3.4 details our methodology. Section 5 presents the baseline results of our analysis, while Section 6 provides further results. Finally, Section 7 provides a discussion and conclusion.

2 | Conceptual Background

The concept of market integration can be traced back to Cournot, who stated that it is 'an entire territory, of which the parts are so united by the relations of unrestricted commerce, that prices take the same level throughout with ease and rapidity' (Cournot 1838). Empirical studies have examined market integration along vertical (prices at different stages of the supply chain), horizontal (prices across locations) and inter-temporal (spot and future market prices) dimensions, often employing cointegration methods (Ihle and von Cramon-Taubadel 2008; Roman and Žáková Kroupová 2022). This study focuses on the horizontal dimension of market integration, which is theoretically motivated by the Enke–Samuelson–Takayama–Judge spatial equilibrium model (Enke 1951; Samuelson 1952; Takayama and Judge 1971).

In the presence of transaction costs, the condition for arbitrage can be represented as follows:

$$p^A > p^B + \tau^{B,A} \tag{1}$$

where p^A and p^B denote prices in markets A and B, respectively, $\tau^{B,A}$ represents the transaction cost of exporting natural gas from market B to market A. Therefore, arbitrage activity may only be triggered if the implied gross profit of the trade covers transaction costs.

However, this spatial equilibrium model does not account for the infrastructure constraints on arbitrage between markets. If the import infrastructure in market A and the export infrastructure in market B are fully utilised, the price difference cannot be mitigated through arbitrage. The impact of infrastructure constraints on price relationships fundamentally differs from that of transaction costs. While transaction costs represent tangible expenses incurred during trade—such as transportation and handling fees—infrastructure constraints act as physical barriers that limit arbitrage, regardless of the price differential or the associated transaction costs (Kuper and Mulder 2016). This distinction is crucial, as it highlights a boundary to market integration: even if the price difference $\left(p^A - p^B\right)$ exceeds transaction costs $\left(\tau^{B,A}\right)$, no arbitrage mechanism can equilibrate the markets if the infrastructure is fully utilised.

The above equation is appropriate for understanding price arbitrage between the United States and Europe or the United States and Asia, where direct LNG trade occurs. The United States, being a net exporter, directly supplies LNG to both regions. However, between Asia and Europe, no significant direct LNG trade can be observed during the study period. Instead, arbitrage occurs through indirect trade via third-party LNG traders who reroute shipments based on market conditions. To represent this, let p^A and p^E be the prices in Asia and Europe, respectively, $\tau^{S,A}$ and $\tau^{S,E}$ be the transaction costs (including transportation) from swing supplier S to Asia and Europe, respectively, and $q^{S,A}$ and $q^{S,E}$ be the volumes exported from swing supplier S to Asia and Europe, respectively. Assuming that there are no binding infrastructure constraints at both the swing supplier and the importing regions, we have the following condition $p^A - \tau^{S,A} > p^E - \tau^{S,E}$. This means that swing supplier S will export LNG to Asia if the netback price in Asia $\left(p^A - \tau^{S,A}\right)$ is greater than the netback price in Europe $(p^E - \tau^{S,E})$. If the netback is higher in Europe, the supplier will prefer to export there.

3 | Structural Changes in the International Natural Gas Market

This section provides a descriptive overview of key trends in the global gas market, focusing on regional price fluctuations, LNG terminal utilisation, and shifting trade dynamics. These elements are crucial for understanding the factors influencing market integration. By examining price patterns across North America, Europe, and East Asia, along with the impact of infrastructure constraints, this section lays the groundwork for the subsequent empirical analysis.

3.1 | Trends and Fluctuations in Regional Natural Gas Prices

Figure 1 shows the logarithmic prices for the Henry Hub (HH) in the North American market, the Title Transfer Facility (TTF) in the European market, and the East Asian Index (EAX) in the East Asian region.[9] The figure demonstrates that there was a substantial decline in prices in March 2020, likely due to the outbreak of COVID-19 and its impact on natural gas demand. This was further exacerbated by historically mild temperatures.[10] Figure 1 also shows that European and Asian gas prices began to rise in the second half of 2021. This can be attributed to the resurgence of demand from the industrial and heating sectors as economic activity rebounded and extreme weather events occurred. From this period onwards, it is also evident that the HH series was not significantly affected by these increases.[11]

3.2 | LNG Terminal Utilisation and Shifting Gas Trade Dynamics

Figure 2 highlights the major shifts in the natural gas market starting in October 2021 (indicated by the grey-shaded area), coinciding with reduced gas flows from Russia to Europe

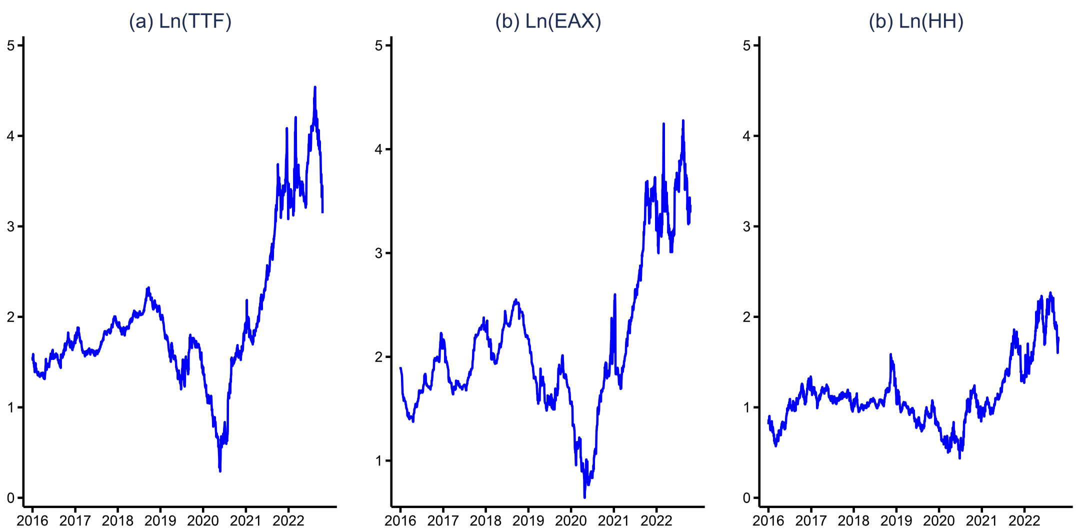

FIGURE 1 | Natural gas prices in log level. (a) Log price of TTF, (b) Log price of EAX, and (c) Log price of HH. [Colour figure can be viewed at wileyonlinelibrary.com]

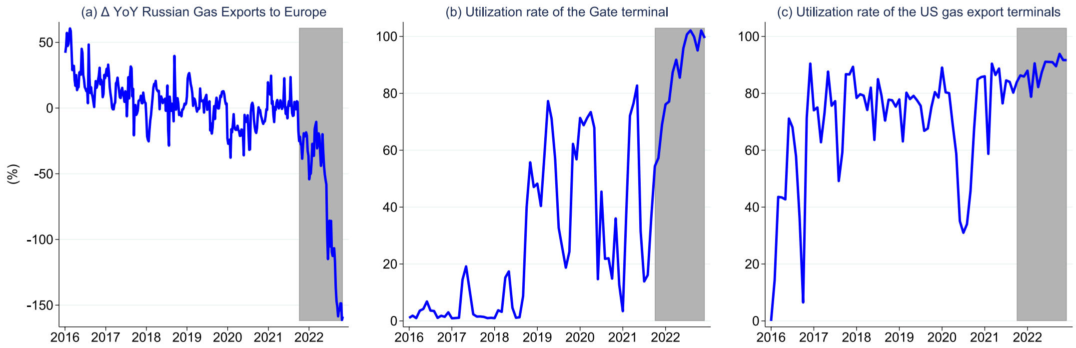

FIGURE 2 | (a) Δ YoY (%) in Russian gas exports, (b) Gate terminal utilisation rates, and (c) U.S. export terminals utilisation rates. Own construction based on data obtained from ENTSOG (2023), GIE (2024), and EIA (2023). [Colour figure can be viewed at wileyonlinelibrary.com]

(Henderson and Chyong 2023; Farag and Ruhnau 2024). Figure 2a shows a sharp year-on-year (YoY) decline in Russian gas exports to Europe, reflecting a deliberate reduction in daily flows to the level of nominations from long-term contracts, with no additional volumes supplied to the European spot market (Fulwood et al. 2022). This reduction forced Europe to increase its reliance on LNG imports, as seen in Figure 2b, which depicts a notable increase in the utilisation rate of the Gate terminal in the Netherlands, the largest import terminal for LNG in Northwest Europe. The heightened demand for LNG also caused congestion at other European import terminals (GIE 2024). Simultaneously, as shown in Figure 2c, the utilisation rate of US gas export terminals increased, nearing full capacity and reflecting a high level of exports. However, capacity constraints at both European import and US export terminals limited the ability to significantly increase LNG trade between the two regions.

3.3 | Diverging LNG Import Dynamics in Northwest Europe and East Asia

This subsection presents the year-on-year changes in LNG imports from 2016 to 2022, with separate graphs for North West Europe, Japan and Korea (combined), and China. Figure 3a shows that LNG imports to Europe increased in the last quarter of 2021, likely driven by reduced Russian gas supplies, as discussed in the previous section. This reduction led to energy security concerns and efforts to diversify away from traditional pipeline sources (Aitken and Ersoy 2023). In contrast, Figure 3b indicates that the growth rate of LNG imports in China began to slow, while pipeline imports from Russia increased, indicating a potential stabilisation or shift in the energy consumption mix (Rystad Energy 2023). Meanwhile, Figure 3c shows that LNG imports in Japan and Korea remained relatively stable, reflecting steady demand in these mature markets (Rystad Energy 2023). These varying import patterns underscore differing regional demand dynamics and suggest that Europe, Japan & Korea, and China are experiencing unique drivers and pressures in their LNG markets, likely influenced by geopolitical, economic and policy-related factors.

3.4 | US LNG Export Dynamics to Northwest Europe and East Asia

This subsection illustrates the year-on-year changes in LNG exports from the United States to North West Europe and East Asia. Figure 4a shows a significant increase in US LNG exports to Northwest Europe in the last quarter of 2021, coinciding with efforts to replace Russian gas pipeline supplies. However, despite this increase, European gas prices continued to rise sharply, suggesting that existing infrastructure and market capacities were fully utilised, limiting the potential for further imports to stabilise or reduce prices. In contrast, Figure 4b highlights a decrease in US LNG exports to East Asia during the same period. This decline reflects a shift in LNG trade dynamics, possibly due to changes in competitive pressures within the global LNG market. These trends underscore the evolving role of the United States as a key LNG supplier and the differing impacts on regional markets.

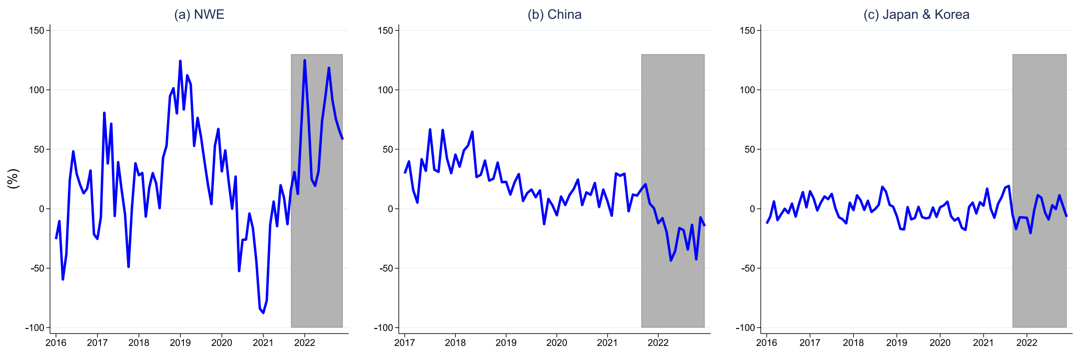

FIGURE 3 | Δ YoY (%) in LNG imports for major regions: (a) Northwest Europe (NWE), (b) China, and (c) Japan & Korea. Own construction based on data obtained from JODI (2024). [Colour figure can be viewed at wileyonlinelibrary.com]

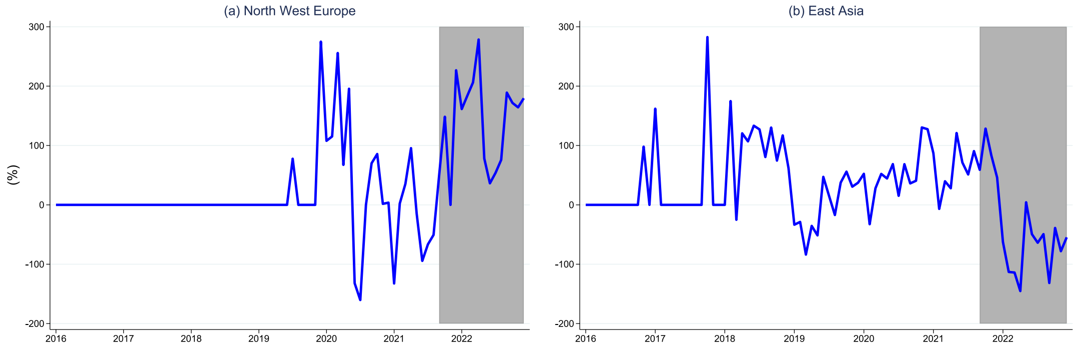

FIGURE 4 | Δ YoY (%) in US LNG exports to: (a) Northwest Europe and (b) East Asian markets. Own construction based on data obtained from the EIA (2023). [Colour figure can be viewed at wileyonlinelibrary.com]

4 | Methodology

Our analysis examines the integration of the three regional gas markets using the cointegration approach. Before conducting this analysis, we apply the augmented Dickey–Fuller (ADF) test, the Phillips–Perron (PP) test, and the Kwiatkowski–Phillips–Schmidt–Shin (KPSS) test to the three gas price series to evaluate their stationarity properties. The ADF and PP tests examine the null hypothesis of non-stationarity (i.e., the presence of a unit root), while the KPSS test examines the null hypothesis of stationarity. If the results indicate that the price series exhibits a unit root, we proceed with cointegration analysis to examine equilibrium relationships.

Previous studies have often utilised the traditional symmetric cointegration framework to analyse the integration of gas prices at both regional and intraregional levels (e.g., Siliverstovs et al. 2005; Asche et al. 2002). However, conventional cointegration tests may be misspecified when the adjustment process is asymmetric. The methodology proposed by Enders and Siklos (2001) extends the widely used Engle and Granger (1987) two-step cointegration procedure by incorporating asymmetric adjustments in the long-run relationships between gas prices. This extension, known as the Momentum Threshold Autoregressive (M-TAR) model, has been shown to perform better in the presence of asymmetry, providing more reliable results than methods that assume symmetric price adjustments. This approach has been extensively applied to analyse asymmetric adjustment in cointegration relationships between various energy prices (e.g., Hammoudeh et al. 2008; Chiappini et al. 2019; Chang et al. 2012).

In both the symmetric Engle and Granger (1987) framework and the asymmetric Enders and Siklos (2001) extension, the first step is to estimate the following model, which represents the equilibrium relationship between two regional gas price series, using ordinary least squares (OLS):

$$P_t^1 = \beta_0 + \beta_1 P_t^2 + \varepsilon_t \tag{2}$$

where P_t^1 and P_t^2 represent the logarithmic forms of two gas price series. We estimate three sets of gas price pairs: (TTF, EAX); (HH, TTF); and (HH, EAX). The residuals, $\hat{\varepsilon}_t$, obtained from Equation 2, are subsequently used in the second step of the Engle and Granger (1987) linear cointegration analysis (Equation 3) and in the second step of the M-TAR model for nonlinear cointegration as proposed by Enders and Siklos (2001) (Equation 4):

$$\Delta\hat{\varepsilon}_t = \rho_0 \hat{\varepsilon}_{t-1} + \sum_{j=1}^{p} \delta_j \Delta\hat{\varepsilon}_{t-j} + u_t \tag{3}$$

$$\Delta\hat{\varepsilon}_t = \rho_1 I_t \hat{\varepsilon}_{t-1} + \rho_2 \left(1 - I_t\right)\hat{\varepsilon}_{t-1} + \sum_{i=1}^{K} \vartheta_i \Delta\hat{\varepsilon}_{t-i} + u_t \tag{4}$$

The adjustment speed coefficients, ρ_0, ρ_1, and ρ_2, correspond to the symmetric $\left(\rho_0\right)$ and asymmetric (ρ_1 and ρ_2) cointegration models. Additionally, the inclusion of lagged values of $\Delta\hat{\varepsilon}_t$ helps to ensure that the residuals are serially uncorrelated. The Heaviside indicator function, I_t, is defined as 1 if $\Delta\hat{\varepsilon}_{t-1} \geq \tau$ and 0 if $\Delta\hat{\varepsilon}_{t-1} < \tau$, where τ is the threshold value, estimated using the consistent search method of Chan (1993).

We test for evidence of asymmetric adjustments using two hypotheses. First, we test the joint null hypothesis of no-cointegration (H_0: $\rho_1 = \rho_2 = 0$), with the critical values obtained from Enders and Siklos (2001). If the null hypothesis of no-cointegration is rejected, we test for the null hypothesis of symmetry (H_0: $\rho_1 = \rho_2$) using a standard F-test.

5 | Empirical Results

This section presents the empirical analysis of the integration of the three regional gas markets. The analysis is structured as follows: First, we test for a potential structural break on 1 October 2021, using the Chow test on the log price differentials between the price pairs, motivated by significant developments in the global gas market. Next, we examine the linear cointegration relationships between the gas price pairs using the Engle–Granger two-step approach. We then conduct a nonlinear cointegration analysis, employing the MTAR model to investigate potential asymmetries in price adjustments. Finally, we estimate symmetric and asymmetric error correction models to assess the short-term dynamics and adjustments towards the long-run equilibrium for each price pair.

5.1 | Structural Break Analysis

We hypothesise that the relationships among our variables of interest may be affected by a potential structural break on 1 October 2021. This break date is driven by major developments in the natural gas markets, as discussed in the previous section. For instance, in the latter half of 2021, geopolitical tensions—particularly Russia's deliberate reduction of gas exports to Europe—significantly disrupted supply. This caused a major shock in the global gas market, leading to tighter market conditions.

To formally test for this break, we follow Büyük şahin et al. (2013) and Luong et al. (2019), conducting a Chow (1960) test on the log price differentials between the price pairs. We perform the test using the following specification:

$$S_t = \theta + \lambda TR_t + \phi_1 \phi S_{t-1} + \phi_2 \phi S_{t-2} + \phi_3 \phi S_{t-3} + \epsilon_t, \tag{5}$$

Here, TR_t represents a linear trend, θ is a constant term, and ϕS_{t-1}, ϕS_{t-2} and ϕS_{t-3} represent the lagged values of the dependent variable, where ϕ_1, ϕ_2 and ϕ_3 are the coefficients on the lagged terms.

The resulting F-statistics are 17.413 (significant at the 1% level), 4.328 (significant at the 1% level), and 2.867 (significant at the 5% level) for the spreads EAX–TTF, HH–TTF and HH–EAX, respectively, with 5 and 1764 degrees of freedom. Given these significant statistics, we conclude that a structural break occurred around 1 October 2021. Consequently, the analysis is conducted over the period from 1 January 2016 to 1 November 2022, divided into two subsamples, with 1 October 2021, as the split date.

TABLE 1 | Linear cointegration analysis.

Price pair	Subsample	β_0		β_1		R^2	EG (1987)
EAX-TTF	First	0.244[a]	[0.015]	0.973[a]	[0.009]	0.895	−5.087[a]
	Second	1.122[a]	[0.098]	0.663[a]	[0.027]	0.687	−2.841
HH-TTF	First	0.323[a]	[0.012]	0.397[a]	[0.007]	0.682	−4.478[a]
	Second	0.404[b]	[0.160]	0.382[a]	[0.044]	0.215	−1.908
HH-EAX	First	0.284[a]	[0.014]	0.376[a]	[0.007]	0.645	−4.718[a]
	Second	1.036[a]	[0.214]	0.212[a]	[0.060]	0.043	−1.628

Note: The first subsample includes data from 1 January 2016 to 30 September 2021, while the second subsample includes data from 1 October 2021 to 1 November 2022. Standard errors of the estimated coefficients are given in the square brackets. The column titled 'R^2' gives the goodness of fit for the regressions. The last column displays the Engle and Granger (1987) test statistic (EG (1987)) for cointegration, with a significant test statistic suggesting that the residuals are stationary, thus confirming cointegration between the variables. The number of lags for the Engle–Granger cointegration test was selected using the AIC. The critical values of this test are obtained from MacKinnon (2010). The symbols a and b denote significance at the 1% and 5% levels, respectively.

Summary statistics for the three price series over the two subsamples are provided in Table A1 in Appendix A, which shows a shift towards higher prices and greater variability in the gas markets after September 2021. The results of the unit root tests for the log levels and their differences are also presented in Table S2. The results show that all the time series in log levels are I (1) variables, meaning they are non-stationary in levels but become stationary after first differencing. Therefore, cointegration analysis is an appropriate tool to investigate their joint properties.

5.2 | Examining the Linear Cointegration

In the context of testing for linear cointegration, we apply the two-step approach proposed by Engle and Granger (1987). This approach involves first estimating the equilibrium relationship for each price pair according to the specification in Equation 2. In the second step, we obtain the residuals from this regression and apply the Engle–Granger residual-based cointegration test to determine whether the residuals are stationary.[12]

Table 1 presents the results of the two-step analysis, with the last column providing the test statistics for the stationarity of the residuals, which indicate whether the variables are cointegrated. For the EAX–TTF pair, the estimated β_1 is 0.973 in the first subsample, indicating that a 1% increase in the TTF price is associated with a 0.973% increase in the EAX price. However, β_1 drops to 0.663 in the second subsample. The estimated β_1 coefficients from the cointegration regressions of HH against EAX and TTF are relatively lower. In the first subsample, the estimated β_1 is 0.397 for HH–TTF and 0.376 for HH–EAX. In the second subsample, the estimated β_1 for HH–TTF remains stable at 0.385, while HH–EAX declines sharply from 0.376 to 0.214, indicating a weakening price linkage.

The results also show that the estimated coefficient β_0 varies across the three pairs (EAX–TTF, HH–TTF, and HH–EAX) and the two subsamples, with a notable increase in the second subsample. For example, β_0 rises from 0.244 to 1.122 for EAX–TTF, from 0.323 to 0.404 for HH–TTF, and from 0.283 to 1.036 for HH–EAX. This increase suggests that baseline price levels across the three markets have risen over time, indicating a growing divergence in market conditions. This divergence may be due to differences in regional supply and demand balances, transportation costs, or market-specific factors such as regulatory changes affecting natural gas pricing.

The Engle–Granger test statistics in the last column of Table 1 indicate that the three price pairs are cointegrated in the first subsample. However, in the second subsample, the test statistics are not statistically significant, providing no evidence of linear cointegration.

5.3 | Examining the Nonlinear Cointegration

In the preceding subsection, the Engle–Granger test, which assumes a linear and symmetric adjustment process, indicates that there is no evidence of cointegration for any of the price pairs during the second period. This subsection examines estimates from the MTAR model proposed by Enders and Siklos (2001), which explicitly accounts for potential asymmetries in the adjustment process towards equilibrium. This analysis aimed to determine whether there is evidence of asymmetries in the first subsample, which would suggest that the adjustment process occurs at different speeds depending on the direction of deviations from equilibrium (positive vs. negative), rather than symmetrically. Additionally, we seek to establish whether the MTAR model provides evidence of cointegration for any of the price pairs in the second subsample period.

Table 2 presents the results of the MTAR cointegration test. Column (1) shows the estimated threshold values, which indicate the point at which adjustments switch between regimes for positive and negative deviations from equilibrium. Although the estimated thresholds are close to zero, our analysis shows that models with an estimated threshold value perform better—according to the information criteria—than models assuming a fixed threshold of zero. Columns (2) and (3) show the estimated parameters of ρ_1 and ρ_2, as specified in Equation 4. Here, ρ_1 represents the speed of adjustment in response to positive deviations from equilibrium, whereas ρ_2 represents the speed of adjustment for negative deviations. If the absolute value of ρ_1 is greater than that of ρ_2, this indicates that the adjustment process is faster in response to positive deviations from equilibrium. Conversely, if $|\rho_2|$ is greater, the adjustment is faster in response to negative deviations from equilibrium. For example, in the

TABLE 2 | Nonlinear cointegration analysis.

Price pair	Subsample	(1) Threshold	(2) ρ_1	(3) ρ_2	(4) Φ (H_0: $\rho_1 = \rho_2 = 0$)	(5) F (H_0: $\rho_1 = \rho_2$)
EAX-TTF	First	−0.023	−0.026[a]	−0.120[b]	27.555[b]	25.492[b]
			(−2.390)	(−7.276)		[0.000]
	Second	0.050	−0.208[b]	−0.070	5.909[c]	3.665[c]
			(−3.230)	(−1.622)		[0.057]
HH-TTF	First	0.012	−0.008	−0.044[b]	12.849[b]	5.586[b]
			(−0.671)	(−5.035)		[0.018]
	Second	−0.068	−0.020	−0.090[a]	2.915	2.218
			(−1.308)	(−2.029)		[0.138]
HH-EAX	First	0.033	−0.083[b]	−0.025[b]	15.521[b]	8.665[b]
			(−4.480)	(−3.427)		[0.003]
	Second	0.010	−0.002	−0.031[a]	2.029	1.393
			(−0.119)	(−2.011)		[0.239]

Note: The first subsample includes data from 1 January 2016 to 30 September 2021, while the second subsample includes data from 1 October 2021 to 1 November 2022. Column (1) provides the estimated threshold values. Columns (2) and (3) provide the estimated coefficients in Equation 4. t-statistics for the estimated coefficients are given in brackets. Column (4) shows the null hypothesis tests for the threshold cointegration with the critical values from Enders and Siklos (2001) as follows: C.V (1%) is 8.310; C.V (5%) is 6.050; C.V (10%) is 5.060. Column (5) gives the second null hypothesis. The symbols a, b, and c denote significance at the 1%, 5%, and 10% levels, respectively.

relationship between EAX and TTF in the first subsample, the estimated threshold is −0.023, with adjustment coefficients of −0.026 for positive deviations and −0.120 for negative deviations. This result indicates that positive deviations from equilibrium (where $\Delta\varepsilon_{t-1} \geq -0.023$) are eliminated at a relatively slower rate of 2.6% per day. In contrast, negative deviations from equilibrium are adjusted at a much faster rate of 12% per day. Consequently, there is substantially slower convergence towards equilibrium for positive deviations (above the threshold) than for negative deviations (below the threshold). These findings suggest that arbitrageurs are more active in exploiting larger profitable opportunities depending on the direction the spread is moving from its equilibrium position. This also implies that during the first subsample period, the market adjusts more rapidly when EAX prices are decreasing relative to TTF prices. This conclusion is consistent with Chiappini et al. (2019), although the estimated speeds of adjustment in both regimes during our sample period are higher than their estimates. In the second subsample, the estimated threshold is 0.015, with adjustment coefficients of −0.208 for positive deviations and −0.070 for negative deviations. This outcome indicates that positive deviations from equilibrium are eliminated rapidly, at a rate of 20.8% per day. The results for negative deviations do not show significant adjustment, as the coefficient for negative shocks is statistically insignificant.

Column (4) in the table presents the test of the joint null hypothesis of no cointegration with MTAR adjustment $\left(H_0: \rho_1 = \rho_2 = 0\right)$. The results indicate that this null hypothesis is rejected for each price pair in the first subsample, as the test statistic exceeds the critical values provided by (Enders and Siklos 2001). Given this result, we proceed to test the null hypothesis of $H_0: \rho_1 = \rho_2$. The results, shown in Column (5), indicate that this null hypothesis is rejected, supporting the presence of asymmetric adjustment. However, in the second subsample, Column (4) shows that the null hypothesis of no cointegration is rejected only for the EAX–TTF price pair. The lack of nonlinear cointegration for the HH–TTF and HH–EAX pairs suggests a decoupling of the US gas market from the European and Asian markets during this period.

5.4 | Results of the (a)symmetric Error Correction Model

In this step, we estimate both symmetric and asymmetric error correction models (ECMs) to examine the adjustment processes of individual prices towards equilibrium. We estimate the symmetric or asymmetric ECM for each price pair based on the cointegration results from the previous subsection.

Table 3 presents the estimation results for the two subsamples.[13] The magnitude of the error correction term (ECT) indicates the speed at which deviations from equilibrium are corrected. For instance, if the ECT is −0.250, it suggests that approximately 25% of the deviation is corrected each day, implying that full correction to equilibrium would take about 4 days. The results indicate that, for the EAX–TTF pair in the first subsample, the ECT for EAX in the high regime is −0.003 and statistically insignificant, suggesting no adjustment to positive deviations. In the low regime, the ECT for EAX is −0.090 and statistically significant, indicating a correction towards equilibrium for negative deviations. For TTF, the ECT is −0.020 and statistically significant in the high regime and −0.020 and statistically significant in the low regime, indicating adjustments in both cases. In the second subsample, the ECT for EAX is −0.116 and statistically

TABLE 3 | Results of symmetric and asymmetric ECM.

Subsample	Model	Regime	EAX	TTF	HH	TTF	HH	EAX
First	Symmetric		-0.034^{a}	0.017^{a}	-0.028^{a}	0.015^{b}	-0.023^{a}	0.025^{a}
			(−5.426)	(2.699)	(−4.220)	(1.981)	(−3.612)	(3.302)
	Asymmetric	High	−0.003	0.020^{b}	−0.007	0.007	-0.042^{b}	0.079^{a}
			(−0.476)	(2.643)	(−0.622)	(0.551)	(−2.316)	(3.684)
		Low	-0.090^{a}	0.020^{c}	-0.038^{a}	0.019^{b}	-0.023^{a}	0.010
			(−7.861)	(1.686)	(−4.763)	(2.029)	(−3.348)	(1.198)
Second	Asymmetric	High	-0.116^{c}	0.105				
			(−2.088)	(1.415)				
		Low	-0.105^{b}	−0.035				
			(−2.951)	(−0.724)				

Note: The first subsample includes data from 1 January 2016 to 30 September 2021, while the second subsample includes data from 1 October 2021 to 1 November 2022. 'Symmetric' and 'Asymmetric' refer to the symmetric and asymmetric ECM. The ECTs in the asymmetric models are estimated separately for two regimes—'High' and 'low'—based on the momentum threshold autoregressive (M-TAR) approach outlined in Section 3.4. Specifically, the Heaviside indicator function identifies whether the system is in a high or low regime depending on the threshold value. Additionally, the first difference terms are also estimated separately for the two regimes. For brevity, these results are not presented here but are available upon request. The asterisks a, b, and c attached to the coefficients represent the significance levels at the 1%, 5%, and 10%, respectively.

significant in the high regime and −0.105 and statistically significant in the low regime, indicating strong adjustments for both positive and negative deviations. For TTF, the ECT is 0.105 and statistically insignificant in the high regime, and −0.035 and statistically insignificant in the low regime, suggesting a lack of significant adjustments. Comparing the two subsamples, the first shows active adjustments for both EAX and TTF, with significant responses to arbitrage opportunities. In contrast, the second subsample reveals a pronounced response in the EAX market, particularly for positive deviations, while the TTF market's responsiveness diminishes, indicating a shift in price correction dynamics between the Asian and European markets over time.

6 | Further Results

In the baseline results, we observe that the American gas market price is no longer cointegrated with the European and Asian prices during the second subsample period. This section examines the potential driver of the log spread between HH and TTF prices. Following Luong et al. (2019) and Luong (2023), we apply Toda and Yamamoto (1995), a modified Granger (1969) non-causality test.[14] Specifically, we investigate infrastructure congestion as a potential driver, focusing specifically on congestion at LNG import terminals in Northwestern Europe (NWE) and LNG export terminals in the United States Our hypothesis is that Granger causality between regional price differentials and LNG infrastructure utilisation is bidirectional. Wider regional price differentials can drive higher utilisation of connecting infrastructure as traders exploit arbitrage opportunities. Conversely, congestion at LNG terminals, whether at import terminals in NWE or export terminals in the United States, can widen regional price differentials by restricting LNG flow. We focus on the average utilisation rate of US export terminals and the Gate terminal in the Netherlands, which has one of the largest import capacities in NWE. The rationale for using the average utilisation rate is that it serves as a comprehensive measure of the infrastructure's capacity to respond to regional price signals. High average utilisation rates signal supply chain bottlenecks, leading to wider price spreads as the market struggles to balance regional supply and demand. Additionally, we investigate the specific impact of congestion at the Gate terminal. We obtain data on the utilisation levels of US LNG export terminals from the Energy Information Administration (EIA) (EIA 2023). These data are available on a monthly basis, and we assume that each monthly figure represents the average daily utilisation rate for all days within that month. For utilisation data on the Gate terminal, we use daily data from Gas Infrastructure Europe (GIE) (GIE 2024). However, no data are available for the utilisation rates of corresponding LNG infrastructure in East Asian countries.

Table 4 reports the results of the Toda and Yamamoto (1995) Granger causality tests between the HH–TTF spread and two measures of infrastructure congestion: average congestion across the United States and NWE, and specific congestion in NWE. In the first subsample, none of the test statistics is statistically significant, indicating no evidence of Granger causality in either direction between infrastructure congestion and the HH–TTF spread. In contrast, in the second subsample, the test statistics for the congestion measures indicate a different pattern. The results show that average congestion across the United States and NWE Granger causes the HH–TTF spread at conventional significance levels, suggesting that increased congestion is associated with variations in the HH–TTF spread. Similarly, congestion specifically in NWE also shows a statistically significant Granger causal effect on the spread, reinforcing the influence of regional infrastructure constraints on market price differentials. We do not find statistically significant evidence of a bidirectional relationship (i.e., from the HH–TTF spread to congestion), suggesting that infrastructure congestion is more directly determined by physical and logistical constraints than by market price signals. These findings imply that

TABLE 4 | Causality tests for HH-TTF spread.

	First subsample		Second subsample	
	To spread	From spread	To spread	From spread
Average congestion (US and NWE)	10.300	6.100	12.300[a]	6.200
	(0.110)	(0.420)	(0.030)	(0.280)
Congestion (NWE)	9.200	8.300	11.400[a]	6.900
	(0.170)	(0.220)	(0.044)	(0.230)

Note: This table reports the Toda and Yamamoto (1995) tests for Granger causality between the log HH–TTF spread and the listed factors. 'Average congestion (US and NWE)' refers to the average congestion level of LNG export infrastructure in the US and LNG import infrastructure in Northwest Europe (NWE). 'Congestion (NWE)' represents the congestion level of LNG import infrastructure in NWE only. 'To spread' indicates the test that a variable does not Granger cause the spread and 'from spread' is the test for whether the spread does not Granger cause the infrastructure congestion. The χ^2 statistic is on the first line, and the asymptotic p-value is on the next line in parentheses.
[a]Statistical significance at the 5% level.

infrastructure congestion, particularly in the second subsample, plays a significant role in driving the price spread between the US and European gas markets, underscoring the importance of infrastructure capacity for market integration.

7 | Discussion and Conclusion

This study investigates the market integration hypothesis among gas price benchmarks in Europe, the United States, and Asia from January 2016 to October 2022. We hypothesise that a structural break on 1 October 2021, divides the sample period into two subsamples. This break aligns with a period of market tightness and supply constraints in the gas market, particularly in Europe. During this time, the market was marked by Russia reducing its spot market supply and fulfilling only long-term contract volumes, which led to increased LNG imports in Europe and congestion in LNG infrastructure. This situation coincided with congested export infrastructure in the United States and relatively decreased LNG imports in East Asia, driven by the economic slowdown in China.

The results of this analysis reveal that the presence and strength of price convergence across the two subsamples and market pairs vary, suggesting that external shocks significantly influence the integration process among the three regional gas markets. In the first subsample, the findings indicate both linear and nonlinear cointegration, demonstrating more robust integration across the regions. However, in the second subsample, no evidence of linear cointegration is found for any of the price pairs, pointing to a potential weakening or disruption of integration. Notably, we observe threshold cointegration between the Asian and European gas markets during this period, indicating a nonlinear relationship between these regions in the second subsample. Three potential reasons may explain the observed asymmetry in price transmission. First, differences in market participants' expectations and risk tolerance can lead to asymmetry, where the magnitude of deviations from equilibrium influences their responses. Second, noise traders—acting on misperceptions—may drive prices away from equilibrium in one regional market, causing larger price differentials until arbitrage by informed traders restores balance. Third, market frictions, such as transportation costs, infrastructure bottlenecks, and the availability of futures contracts, can create thresholds for price adjustments, resulting in distinct regimes of market responses to deviations from equilibrium (Farag et al. 2024; Hammoudeh et al. 2008; Ihle and von Cramon-Taubadel 2008).

The linear and nonlinear cointegration between the Asian and European gas benchmarks over our sample period aligns with the earlier findings of Siliverstovs et al. (2005), Li et al. (2014), and Chiappini et al. (2019). However, our analysis identifies a relatively higher degree of integration between these two markets in the first subsample (January 2016—September 2021). This continued integration can be attributed to the significant growth in LNG trade, with Europe and Asia accounting for 90% of global trade under inter-regional competition during this time (Rystad Energy 2023). This growth was accompanied by increased flexibility in LNG trading, particularly due to shorter-term contracts, which further facilitated price convergence (IGU 2023). The relative decline in the degree of integration during 2021–2022 can be explained by reduced LNG imports from East Asia, primarily driven by China's slow economic growth, as discussed in Section 3.3.

For the integration between the American and other regional gas benchmarks, our study finds that HH is nonlinearly cointegrated with other benchmarks in the first subsample (January 2016 to September 2021). This finding aligns with Chiappini et al. (2019), who also found evidence of asymmetric adjustments between the American and European gas markets but did not find such a relationship between the American and Asian markets over the period 2004–2018. A key development during our sample period is the United States becoming a net exporter of natural gas and increasing its LNG export capacity. However, our analysis indicates that the American gas market decoupled from the other regional markets in the second subsample (October 2021—November 2022). The lack of cointegration between the European and American markets could be attributed to congested LNG infrastructure during this period. Although LNG trading volumes from the United States to Europe increased, infrastructure operating at full capacity—such as pipelines, transportation fleets, and terminals—limited the ability to exploit arbitrage opportunities. This supports our hypothesis discussed in Section 2 that the efficiency of the arbitrage mechanism and the extent of market integration are critically dependent on the capacity of the infrastructure facilitating commodity trade. Regarding the lack of cointegration between the Asian and American markets, this may be due to the relatively low LNG trade volume during this period, as explained in Section 3.4.

Our analysis yields two main implications. First, the interdependence between the Asian and European gas markets, despite external shocks, indicates that changes in one market can significantly impact the other. This underscores the importance of considering broader market dynamics when assessing each market's supply security. Effective management of demand and supply shocks may be achieved through bilateral policies, such as sharing information on LNG trade flows, production levels, and demand forecasts, thereby enhancing coordination and ensuring supply security. Second, our findings suggest that physical infrastructure plays a crucial role in energy market integration, particularly during tight market conditions, which differentiates it from financial markets (see Yang et al. (2003) for a related example). In financial markets, contagion effects often drive integration under stress, while energy markets are constrained by infrastructure bottlenecks, making infrastructure a critical factor to consider in any analysis of energy market integration. Therefore, market participants need to be aware of changing dynamics and the potential breakdown of long-term price relationships during periods of high physical infrastructure utilisation.

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Conflicts of Interest

The authors declare no conflicts of interest.

Data Availability Statement

The authors have nothing to report.

Endnotes

[1] Figure A1 in Appendix A compares the development of gas production and consumption between 2012 and 2022. It shows that production has significantly increased in export regions that do not have pipeline connections to the main gas import regions. This has been facilitated by the export of LNG.

[2] Gas-on-Gas (G-o-G) competition refers to a pricing mechanism in which natural gas prices are determined by supply and demand dynamics in competitive markets (IGU 2021; GIIGNL 2022).

[3] For example, the United States significantly expanded its LNG liquefaction capacity from 16 bcm in 2016 to 131 bcm in 2022, accounting for 62% of the global increase during this period (Rystad Energy 2023).

[4] Cointegration refers to a statistical property of two or more non-stationary (unstable) time series variables. When two or more time series are individually non-stationary but a linear combination of them is stationary, the series are said to be cointegrated. This implies the existence of an equilibrium relationship among the variables, despite short-term fluctuations (Engle and Granger 1987).

[5] For a detailed review of the empirical methods used to examine the degree of spatial integration in natural gas markets, see Dukhanina and Massol (2018).

[6] The convergence test used in Li et al. (2014) is the Phillips and Sul (2007) test, which examines whether natural gas prices across regions are moving towards a common long-term trend. The Kalman filter is applied to estimate time-varying relationships between price pairs, allowing the authors to track the gradual evolution of these relationships.

[7] For example, the share of spot LNG in the market averaged 28% during the period 2016–2022, compared to below 5% in 2005 (IGU 2021).

[8] For detailed data on LNG terminal utilisation rates during this period, see Figure 2 in Section 3, which illustrates the increase in European LNG import terminal utilisation and US export terminal capacity constraints.

[9] These prices are derived from the bid-offer ranges observed at the respective hubs for delivery in the subsequent month (front-month gas futures). In cases where price data were missing for certain days, the observations were forward-filled using the price from the most recent preceding day.

[10] For example, the decreased demand for heating in the residential and commercial sectors due to milder temperatures led to a drop of more than 3% year-over-year during the first quarter of 2020. This resulted from a decrease of over 5% in heating degree days across the main consumption regions (IEA 2020).

[11] Note that an outage at the Freeport LNG export terminal—the second-largest LNG export facility in the U.S.—in June 2022 temporarily relieved pressure on the US gas market (IGU 2023).

[12] This analysis is conducted with daily frequency. To ensure the robustness of our findings, we also perform the cointegration analysis using weekly data. Aggregating the data to a weekly frequency helps mitigate the potential noise and volatility inherent in daily price movements, smoothing out short-term fluctuations. The results are presented in the Tables A3 and A4 in Appendix B.

[13] The results of diagnostic checks for each estimated ECM (including tests for serial correlation and normality) indicate that the estimated models perform reasonably well. For brevity, we do not report the diagnostic checks here. However, they are available upon request.

[14] This approach is motivated by the findings of Clarke and Mirza (2006), which show that pretesting for cointegration can result in severe over-rejections of the null hypothesis of non-causality. In contrast, the augmented lag method proposed by Toda and Yamamoto offers better control for Type I error rates, while generally retaining adequate power. Simulation results indicate that this method performs consistently well across various data-generating processes, with robust performance regardless of the stationarity or cointegration properties of the variables.

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Supporting Information

Additional supporting information can be found online in the Supporting Information section.