Rising US LNG Exports and Global Natural Gas Price Convergence

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Acknowledgements

Abstract

We assess how rising exports of US liquefied natural gas (LNG) affect the convergence of natural gas prices worldwide. Using standard principal component analysis and cointegrating techniques, we show that the degree of co-movement between global benchmark prices for natural gas has strengthened since the United States began the large-scale export of LNG in 2016. At the same time, we find that global natural gas prices do not yet adhere to the relative law of one price. Our results also suggest that issues related to storage access in Alberta between 2017 and 2019 have limited price co-movements between major benchmarks for natural gas in the United States and Canada. In addition, we use vector error correction models to show that natural gas prices in Europe and Asia respond negatively to increased exports of US LNG. These results may have implications for the development of future LNG export capacity in Canada.

Topics: International topics; Market structure and pricing
JEL codes: C32, F15, K41, L95

Résumé

Nous évaluons les répercussions de la hausse des exportations américaines de gaz naturel liquéfié (GNL) sur la convergence des prix du gaz naturel à l'échelle mondiale. Au moyen d'une analyse en composantes principales classique et de techniques de cointégration courantes, nous montrons que le degré de covariation entre les prix de référence mondiaux du gaz naturel s'est accru depuis que les États-Unis se sont lancés dans l'exportation massive de GNL, en 2016. Toutefois, nous constatons que les cours mondiaux du gaz naturel n'adhèrent pas encore à la loi du prix unique. Nos résultats indiquent aussi que l'accès difficile à des installations de stockage en Alberta entre 2017 et 2019 a limité la covariation des principaux prix de référence du gaz naturel aux États-Unis et au Canada. De plus, nous utilisons des modèles vectoriels à correction d'erreurs pour montrer que les prix du gaz naturel en Europe et en Asie réagissent négativement à la hausse des exportations américaines de GNL. Ces résultats pourraient avoir des implications pour le développement d'une éventuelle capacité d'exportation de GNL au Canada.

Sujets : Questions internationales; Structure de marché et fixation des prix
Codes JEL : C32, F15, K41, L95

Overview

Large-scale liquefied natural gas (LNG) exports from the United States are a relatively recent phenomenon. We are the first to empirically assess how the rapid rise in US LNG exports since 2016 has affected price convergence between natural gas markets in North America and overseas.[1]

The paper is structured as follows. We begin by providing a brief overview of recent developments in the natural gas industry. Next, we examine how growing US LNG exports affect co-movements among benchmark prices for natural gas using standard principal component analysis (PCA), bivariate cointegration testing and dynamic ordinary least squares (DOLS). We then formally evaluate how much of the recent natural gas price convergence can be attributed to US LNG exports by estimating vector error correction models (VECMs) and examining both their variance decomposition and their impulse response functions. We conclude by offering a brief discussion of potential implications for Canada's LNG industry, which is projected to generate significant investment, employment and royalty revenue over its life cycle (Conference Board of Canada 2020).

Consistent with the existing literature, our findings show that convergence between price benchmarks for natural gas in the United States, Europe and Asia has increased in recent years. Our results also suggest that local market challenges in Alberta from 2017 to 2019 limited price convergence between the major US and Canadian natural gas benchmarks. Despite a strengthening of the long-term relationship between reference prices, natural gas traded in different markets does not yet adhere to the relative law of one price (LOOP).

This paper extends the existing literature by showing that rising US LNG exports have contributed to a more integrated global natural gas market. We demonstrate that US LNG exports explain a considerable proportion of variation in the natural gas markets in Europe and, to a lesser extent, Asia. In addition, we find that a positive shock to US LNG exports places downward pressure on natural gas prices in both of these regions. This may become an increasingly important consideration for exports of Canadian LNG.

Introduction

Past empirical research has found evidence of intracontinental connectedness among benchmark prices for natural gas (King and Cuc 1996; Asche, Osmundsen and Tveterås 2002; Robinson 2007; Li, Joyeux and Ripple 2014). In contrast, intercontinental price convergence has historically been limited by distance, transportation costs and regional differences in supply and pricing mechanisms (Barnes and Bosworth 2015; Barbe and Riker 2015). However, the growing development of natural gas liquefaction facilities and delivery points around the globe

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[1] At the time of writing, we are unable to identify other published papers that focus specifically on the impact of rising US LNG exports on price convergence between major global benchmarks for natural gas.

is creating new opportunities for suppliers to take advantage of price differences between markets that have been traditionally disconnected (Neumann 2009; Brown and Yücel 2009; Li, Joyeux and Ripple 2014; Barnes and Bosworth 2015). The development of LNG export capabilities in the United States—given the country's status as the world's largest producer of natural gas—could soften traditional constraints and bring about lasting change to the trade of natural gas and global market connectedness.

The growing use of horizontal drilling and hydraulic fracturing technologies, which began in the early 2000s, fundamentally changed the North American natural gas market (CFTC 2018). By 2010, the US shale revolution had led to significant growth in low-cost gas supply. This caused natural gas prices in Canada and the United States to decouple from European and Asian benchmarks (**Chart 1**; **Figure 1**). In the years that followed, oversupply in the North American market led to a substantial widening of shale spreads to European and Asian benchmark prices for natural gas. By exporting domestic LNG overseas, natural gas producers in Canada and the United States could profit from the spread between natural gas prices in North America and those in the rest of the world (CFTC 2018; API 2014).

Chart 1: **North American natural gas prices have remained below international benchmarks since the US shale revolution**
Prices expressed in US dollars per metric million British thermal unit
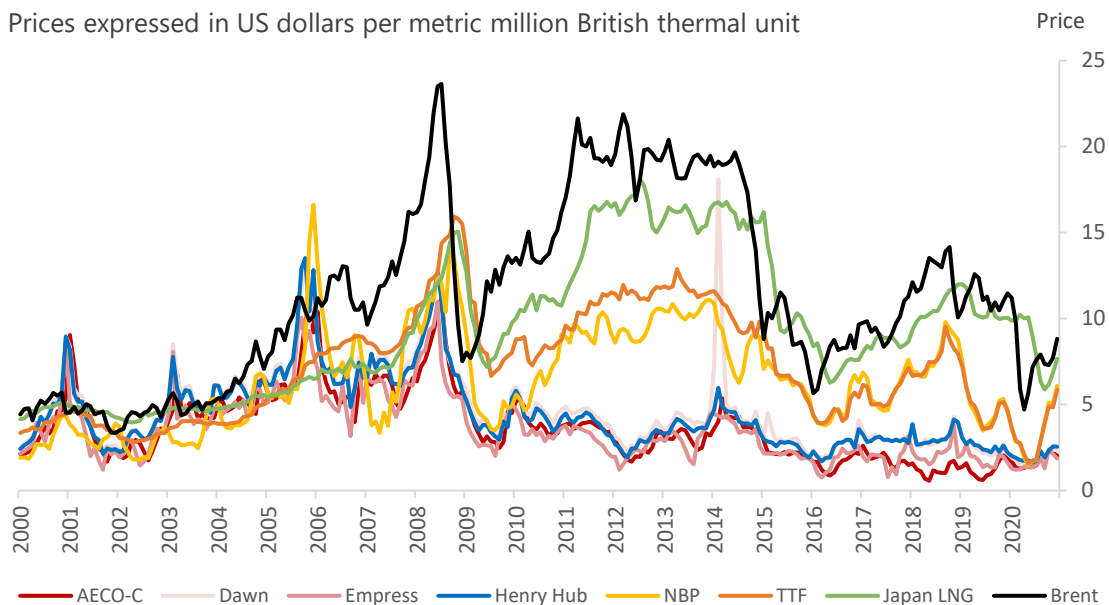
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.
Sources: Canadian Association of Petroleum Producers, Bloomberg, Energy Information Administration and the World Bank

Last observation: December 2020

US regulators moved quickly to approve the construction of LNG export terminals, which allowed the United States to begin exporting natural gas by sea from the Gulf Coast in 2016 (**Chart 2**; EIA 2020). Since then, US LNG exports have risen considerably, making up more than half of all growth in global LNG exports (IEA 2020). US LNG now accounts for approximately 10 percent of global liquefied natural gas trade, including around 16 percent of LNG imports in the European Union and 5 percent of LNG imports in Japan (IEA 2020; European Commission

2020; US Department of Commerce International Trade Administration 2020). Furthermore, US LNG exports now represent around 10 percent of total US marketable natural gas production and are expected to rise further to satisfy growing global demand (EIA 2020).

US LNG exports are contributing to the integration of distant and regionally disjointed natural gas markets in several ways. First, US LNG is expected to increase the global adoption of North

Chart 2: **US LNG exports have increased dramatically since 2016**

Seasonally adjusted and expressed in million cubic feet

Million cubic feet
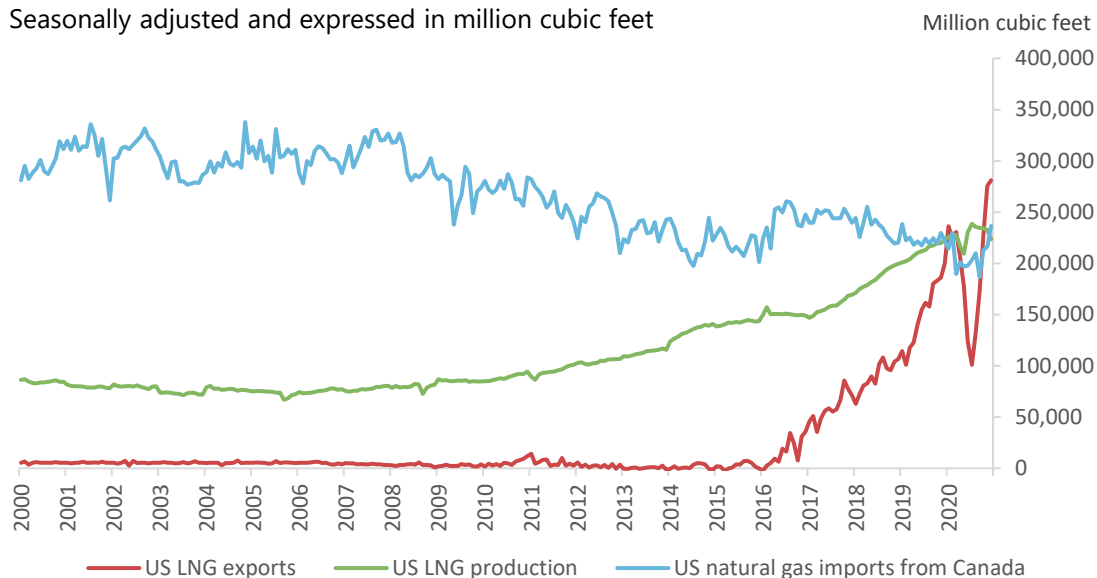
Note: LNG is liquefied natural gas.
Source: Energy Information Administration

Last observation: December 2020

American LNG delivery contract structures. These structures have comparatively more flexible terms and fewer destination clauses (Chiappini, Jégourel and Raymond 2019). Second, growing US LNG export capacity is contributing to the ongoing shift away from long-term fixed-price contracts for natural gas toward short-term and spot-based transactions (TFC 2018; EIA 2020; Till and McHich 2020). Finally, the growing worldwide trade of US LNG is furthering the transition from oil indexation to gas-on-gas competition by highlighting market inefficiencies produced by linking natural gas prices to crude oil (CFTC 2018; Till and McHich 2020).

Studying the effects of rising US LNG exports on global prices for natural gas can help producers better understand how Canadian LNG exports may affect pricing for Canadian natural gas. This is important because the development of Canada's LNG industry—which should spur significant investment, employment and royalty revenue for both federal and provincial jurisdictions—requires natural gas pricing in overseas markets to remain robust and above landed costs for Canadian LNG projects (Conference Board of Canada 2020; Romaniuk, Kralovic and Asghar 2018).[2] Market integration may also have implications for shale spreads. These form part of the cost advantage Canadian LNG currently has over other major LNG

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[2] Landed costs for Canadian LNG projects represent the price needed in international markets for Canadian LNG projects to be profitable. Landed costs include supply as well as transportation costs.

exporters. They also serve as one of the primary drivers behind the development of North America's LNG export industry (Venkatachalam and Milke 2021; Goncalves 2016).

To assess the impact of rising US LNG exports, we apply a number of frequently used econometric techniques from the literature on natural gas market integration. Specifically, we employ PCA, cointegration testing and regressions, and VECMs. Following Siliverstovs et al. (2005), we use PCA to preliminarily assess co-movements in natural gas prices and identify sets of potentially cointegrated price benchmarks. We then use bivariate cointegration testing, which has long been central to the study of price convergence, to detect pairwise trends in natural gas pricing. Evidence of cointegration is leveraged using DOLS. This technique, employed by Chiappini, Jégourel and Raymond (2019), allows us to evaluate the strength of the long-term relationship between pairs of natural gas prices and to subsequently test for the relative LOOP. Finally, we develop a VECM to assess how US LNG export flows have affected movements of natural gas prices in Europe and Asia.

Data

We gather monthly natural gas price data for a 21-year period from January 2000 to December 2020. The benchmarks provide coverage of the world's largest and most distinct natural gas markets: North America, Europe and Asia (**Figure 1**). To facilitate comparability, we convert some natural gas benchmarks, as well as Brent crude oil prices, so that all benchmarks are expressed in US dollars per metric million British thermal units (MMBtu). Descriptive statistics for all of the price series are shown in **Table A-1** in the **Appendix**.

Figure 1: Geographic distribution of price benchmarks
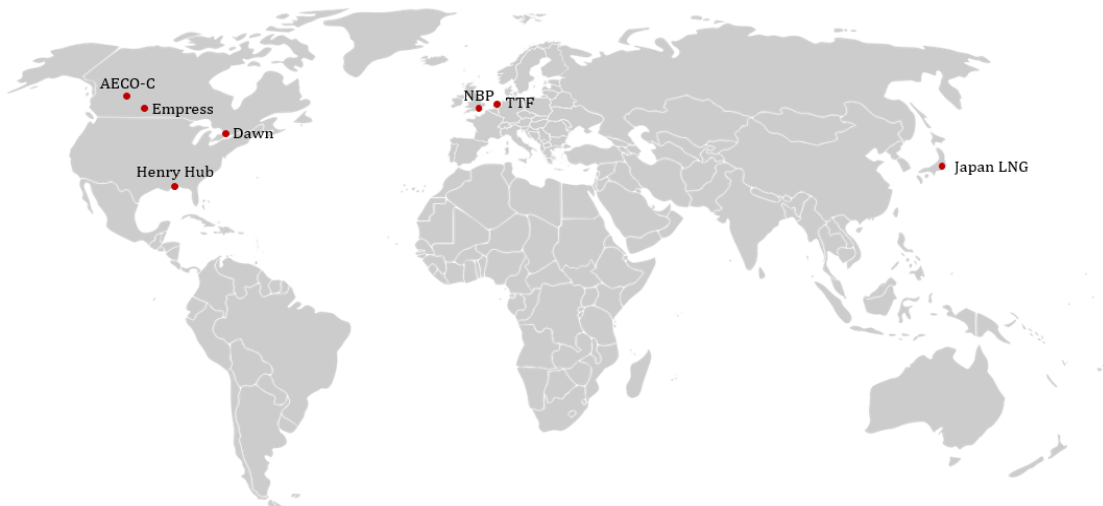
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.
Source: Wikipedia Commons, author illustration

Henry Hub is the most important and widely quoted natural gas reference price in the United States. Located on the US Gulf Coast near most of the country's LNG export terminals, this

highly liquid trading hub encompasses a multitude of intercontinental natural gas pipelines and storage facilities. The price of gas traded at Henry Hub is generally considered to be a barometer of overall market conditions for natural gas in the United States.

AECO-C is the predominant natural gas trading price in Alberta, where most of Canada's natural gas is produced. Because the rise of US LNG exports coincides with local market disruptions in Alberta (discussed below), we also include in our analysis two regional Canadian natural gas benchmarks that reflect the trading price of natural gas at Enbridge's Dawn Hub (Ontario) and Pembina's Empress plant (Alberta). Despite also being associated with Canadian facilities, these reference prices were comparatively less affected by the regional structural challenges that affected AECO-C pricing between 2017 and 2019 and may thus better represent the Canadian natural gas market over the study period. To our knowledge, this is one of few papers to use multiple Canadian natural gas reference prices in a study of global natural gas market integration.

Europe's natural gas market is represented by the United Kingdom's National Balancing Point (NBP) and the Netherlands' Title Transfer Facility (TTF) rate. The NBP benchmark serves as the chief pricing point for natural gas futures traded on the Intercontinental Exchange (ICE) and is generally viewed as one of the most liquid trading points for natural gas in Europe. The TTF is similar to the NBP but serves as a virtual trading point for natural gas within the Dutch gas network. Japanese LNG import prices are used to represent natural gas pricing in Asian markets, where demand for LNG is growing most strongly (IEA 2020). Finally, Brent crude prices are included for comparison, as is commonly done in the existing literature.

In addition, we use a number of pertinent variables to model natural gas price dynamics. Our principal independent variable of interest is US LNG exports by destination region.[3] We include natural gas imports from countries other than the United States as a control variable. Natural gas storages are included because they play a crucial role in providing seasonal flexibility and balancing differences between supply and demand for natural gas. In addition, we use common measures of coldness and heat—heating degree days and cooling degree days—as proxies for energy demand.[4] Some variables have been converted so that they can be expressed in the same unit of measurement and thus more easily compared across regions. **Table A-2** in the **Appendix** presents descriptive statistics for all of these explanatory variables.

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[3] US LNG exports to Europe are defined as the sum of exports to Belgium, Croatia, France, Greece, Italy, Lithuania, Malta, the Netherlands, Poland, Portugal, Russia, Spain and the United Kingdom.

[4] Publicly available historical data on Japanese heating and cooling degree days were not found. As such, we construct these series using weather data from the Japan Meteorological Agency. Heating degree days were calculated for each of the country's five largest population centres—Tokyo, Yokohama, Osaka, Nagoya and Sapporo—before being averaged together. We follow the same approach to calculating cooling degree days.

Co-movement of global natural gas prices

To examine co-movements among natural gas prices and assess how integrated the global natural gas market already is, we estimate principal components for the covariance matrix of the various natural gas benchmarks in log level from 2000 to 2020.

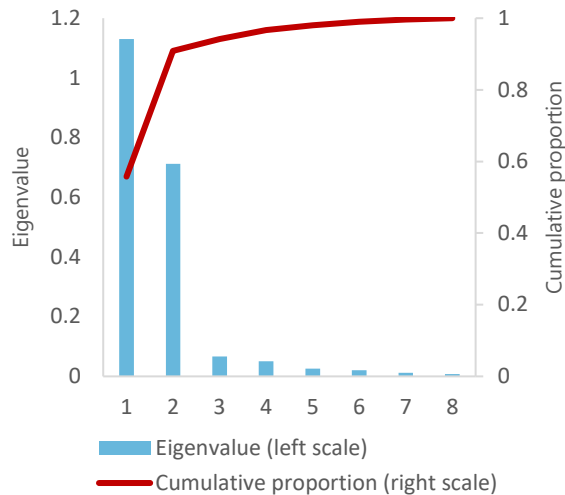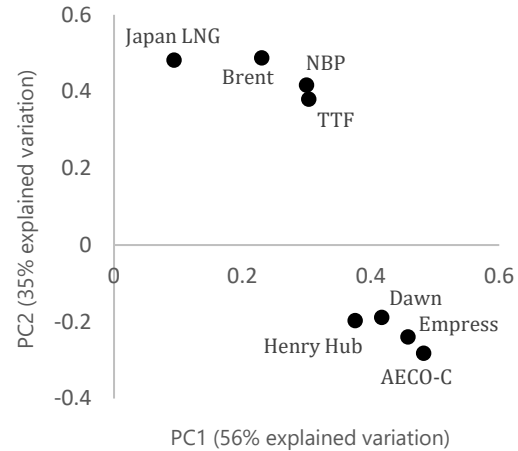**Chart 3:** Scree plot (2000–20)

Chart 4: Representation of price benchmarks on first plane (2000–20)

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

If gas markets were already closely interconnected, then price dynamics would be sufficiently captured by a single dominant principal component (Siliverstovs et al. 2005). However, **Chart 3** indicates that two price benchmarks are needed to explain at least 90 percent of the total variation in natural gas prices. Components beyond this point offer only marginal explanatory value. A Bai-Ng (2002) test, used to choose the number of factors in a principal components framework, confirms the use of two principal components. Since more than one factor is needed to describe natural gas pricing dynamics, we conclude that international gas markets are not fully integrated. This result is consistent with findings presented by Siliverstovs et al. (2005) and Li, Joyeux and Ripple (2014).

Clustering patterns in **Chart 4** indicate that two broadly distinct markets for natural gas exist:

- one for North American benchmarks (Henry Hub, AECO, Dawn and Empress)
- one for European and Asian benchmarks as well as Brent crude

These results suggest that oil indexation remains a feature of natural gas pricing in both Europe and Asia.[5] The pattern plot also supports the conclusion reached by Li, Joyeux and Ripple (2014), who find that North American natural gas benchmarks display behaviour that is

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[5] Oil indexation, in part, explains why the correlation between Brent and North American natural gas benchmarks has historically been weaker than the correlation between Brent and European as well as between Brent and Asian, natural gas prices (Table A-3).

fundamentally different from European and Asian prices. Overall, the clustering patterns in **Chart 4** show that intercontinental natural gas markets are not yet integrated.

To assess whether natural gas prices have become more interconnected since 2016, we separate the data into two periods: 2000 to 2015 and 2016 to 2020. We then examine how clustering patterns have evolved from one period to the next. The grouping of price benchmarks more tightly on the pattern plot in the latter period points to increased co-movement in global natural gas markets.

Chart 5: Representation of price benchmarks on first plane (2000–15)
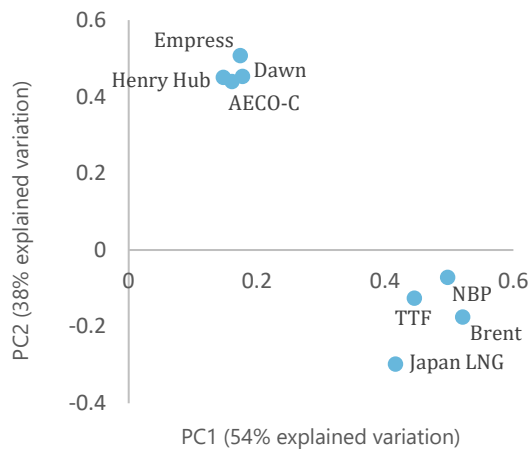
Chart 6: Representation of price benchmarks on first plane (2016–20)
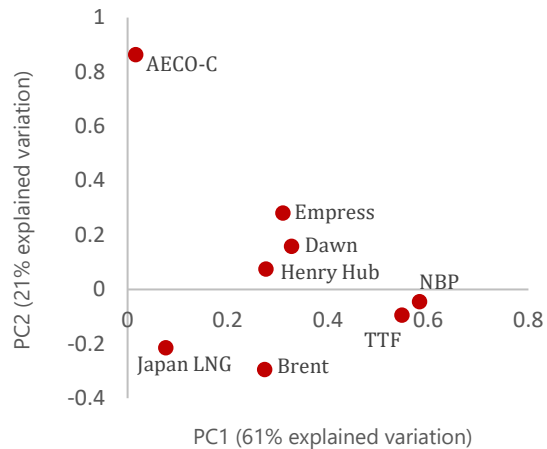
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Chart 5 shows strong regional clustering of natural gas prices before the United States began exporting LNG by sea. However, these regional price clusters dissipate when using data from 2016 onward. In **Chart 6**, most of the North American reference prices cluster tightly with overseas benchmarks. These results extend existing literature by suggesting that price convergence between North American and overseas natural gas benchmarks has become more pronounced since the United States began exporting more significant volumes of LNG.[6]

Results shown in **Chart 6** also suggest that co-movement between AECO and other North American natural gas prices has become less pronounced since 2016. We hypothesize that this is because of localized pipeline interruptions that temporarily affected Alberta's natural gas

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[6] As a robustness check, we produce additional pattern plots to show that convergence between benchmarks had not begun, in any meaningful sense, before 2016 (**Chart A-1**, **Chart A-2** in the **Appendix**). We also estimate principal components of the covariance matrix using price benchmarks expressed in first difference (**Chart A-3**, **Chart A-4** in the **Appendix**). This analysis further suggests that co-movement among natural gas prices has strengthened since 2016.

market from 2017 to 2019 (King 2021). Limited pipeline capacity combined with the specific design of natural gas contracts in Alberta resulted in significant volatility in the local market.[7]

Natural gas market integration

For natural gas markets to be integrated, we expect prices to follow common long-term trends. Cointegration is sufficient to verify that prices tend to follow the relative LOOP, thus we test for this between pairs of price benchmarks. We first examine stationarity in the price series using unit root testing. Because we identify structural breaks in all price series,[8] we employ a technique developed by Zivot and Andrews (1992) to test the null hypothesis that a series possesses a unit root against the alternative hypothesis that it is stationary when allowing for a structural break. We perform this test on all of the price benchmarks, allowing for a break in the intercept, the trend, and the intercept and trend.

Table 1: Zivot–Andrews unit root test results

Price benchmark	Log level			First difference of log level		
	Intercept	Trend	Intercept and trend	Intercept	Trend	Intercept and trend
Henry Hub	-4.23	-3.98	-4.93	-15.91***	-15.76***	-15.90***
AECO-C	-4.91	-4.93***	-5.24**	-13.79***	-13.73***	-13.76***
Empress	-5.61***	-5.55***	-6.16***	-18.01***	-17.90***	-18.00***
Dawn	-4.59	-4.50	-4.97***	-14.98***	-14.84***	-14.95***
NBP	-5.44***	-5.38***	-5.45**	-8.21***	-8.10***	-8.25***
TTF	-3.83	-3.90	-3.93	-7.10***	-6.94***	-7.11***
Japan LNG	-4.57	-3.40	-4.63	-7.94***	-7.73***	-7.96***
Brent	-4.14	-3.88	-4.30	-9.46***	-9.29***	-9.51***

** denotes statistical significance at the 5 percent level
*** denotes statistical significance at the 1 percent level.
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Table 1 shows only limited evidence of stationarity for most of the logged price benchmarks. When we perform the same Zivot–Andrews test on the first difference of logged prices, however, we find that all of the benchmarks are stationary. Hence, we conclude that natural gas price series are integrated of degree one, as established by the existing literature (Siliverstovs et al. 2005; Ramberg and Parsons 2012).

To accommodate structural breaks, we apply a bivariate Gregory–Hansen residual-based cointegration test. This allows for the testing of cointegration in the presence of a structural

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[7] AECO-C volatility ultimately eased after the Temporary Service Protocol (TSP) was introduced in 2020. The TSP prevented previously interruptible natural gas flows from being curtailed and thus ensured that pipeline maintenance did not impede the injection of gas into storage (King 2021).

[8] Structural breaks in the price series are identified by a Quandt–Andrews breakpoint test (**Table A-4** in the **Appendix**).

shift taking place in the sample.[9] The break date identified by the cointegration equation (1) produces the strongest evidence against the test's null hypothesis of no cointegration.

$$Henry\ Hub_t = \mu_1 + \mu_2\varphi_{t\tau} + \gamma_1 P_{it} + \gamma_2 P_t\varphi_{t\tau} + \epsilon_t \tag{1}$$

$$where\ \varphi_{t\tau} = \begin{cases} 0, & t \leq [n\tau] \\ 1, & t > [n\tau] \end{cases}$$

Here, μ_1 and γ_1 represent the intercept and cointegrating slope coefficients, respectively, before the endogenously determined regime shift, which occurs in period τ. Moreover, μ_2 and γ_2 denote changes in the intercept and cointegrating slope coefficients, respectively, following the regime shift. P_i represents natural gas price benchmarks other than Henry Hub, which is always specified as the dependent variable of interest. All price series are expressed in log level.

The Gregory–Hansen cointegration test produces three statistics: the ADF^*, Z_s^* and Z_t^*.[10] Under the null hypothesis, statistically significant test statistics show that a particular benchmark is cointegrated with Henry Hub. To assess whether US LNG exports have had an impact on price convergence in natural gas markets, we first perform the cointegration test using price data from 2000 to 2015 and then again with data over the entire study period. By splitting the data into two periods, we can better examine whether the cointegrating relationship between Henry Hub and all other benchmarks has strengthened since 2016. Break dates identified by the test typically coincide with important structural changes or events affecting the natural gas industry. **Table 2** and **Table 3** display the results for the two periods.

Table 2: Gregory–Hansen cointegration test results (2000–15)

Price benchmark	ADF^*	Z_s^*	Z_t^*	R^2	Break date
AECO-C	-10.88***	-148.40***	-10.91***	0.89	2008M7
Empress	-6.45***	-117.46***	-9.30***	0.89	2009M9
Dawn	-5.51***	-159.33***	-11.32***	0.91	2009M11
NBP	-4.91	-39.00	-4.46	0.20	2010M8
TTF	-4.54	-33.04	-4.29	0.17	2009M5
Japan LNG	-4.34	-34.83	-4.29	0.15	2008M1
Brent	-4.87	-35.53	-4.43	0.16	2009M8

*** denotes statistical significance at the 1 percent level.
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; $ADF^* = \inf_{\tau \in T} ADF(\tau)$; $Z_s^* = \inf_{\tau \in T} Z_s(\tau)$; $Z_t^* = \inf_{\tau \in T} Z_t(\tau)$.

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[9] We test for cointegration while allowing for the possibility of a regime shift, defined as a shift in the level and slope coefficients (Gregory and Hansen 1996). The cointegration test is also performed while allowing for a level shift as well as a level shift with trend. Results are similar across all specifications (**Table A-5**, **Table A-6** in the **Appendix**).

[10] Gregory and Hansen (1996) define the test statistics as follows: $ADF^* = \inf_{\tau \in T} ADF(\tau)$, $Z_s^* = \inf_{\tau \in T} Z_s(\tau)$, $Z_t^* = \inf_{\tau \in T} Z_t(\tau)$. That is, an ADF, Z_s and Z_t test statistic is produced for every time period in the sample. The smallest value is then retained and compared with the appropriate critical value in Table 1 of Gregory and Hansen (1996).

Table 2 shows that the US and Canadian natural gas markets were highly integrated before the rise in US LNG exports. This is evidenced by the statistically significant cointegrating relationship estimated between Henry Hub and AECO-C, Dawn and Empress, respectively. At the same time, we find limited evidence of cointegration between Henry Hub and all other natural gas price benchmarks as well as Brent crude. As expected, the break dates identified in this period generally point to the decoupling of market-based and oil-indexed natural gas prices, which occurred as a result of the US shale revolution. Similar break dates across all benchmarks are taken as evidence of a common trend among global natural gas prices in this period, consistent with strong co-movement exhibited by prices before 2009 (**Chart 1**).

Table 3: Gregory–Hansen cointegration test results (2000–20)

Price benchmark	ADF^*	Z_s^*	Z_t^*	R^2	Break date
AECO-C	-4.73	-127.86***	-9.60***	0.86	2016M4
Empress	-7.40***	-151.08***	-10.71***	0.85	2014M2
Dawn	-7.04***	-211.81***	-13.54***	0.88	2012M10
NBP	-5.74***	-50.57**	-5.32**	0.27	2010M1
TTF	-5.48***	-49.65**	-5.37**	0.26	2009M6
Japan LNG	-5.01**	-42.04	-4.89	0.21	2009M5
Brent	-5.45**	-51.44**	-5.44**	0.22	2009M4

** denotes statistical significance at the 5 percent level.
*** denotes statistical significance at the 1 percent level.
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; $ADF^* = \inf_{\tau \in T} ADF(\tau)$; $Z_s^* = \inf_{\tau \in T} Z_s(\tau)$; $Z_t^* = \inf_{\tau \in T} Z_t(\tau)$.

Results in **Table 3** suggest that the North American natural gas market has remained relatively well integrated since 2016. However, we note that the degree of interconnectedness between Henry Hub and AECO-C has decreased somewhat in recent years. The ADF test statistic produced when estimating the cointegrating relationship between Henry Hub and AECO-C—which was statistically significant in the prior period—no longer points to cointegration. This supports results from the PCA, which finds that AECO-C has evolved independently of its North American counterparts since 2016. In fact, the break date associated with the cointegrating vector between Henry Hub and AECO-C corresponds closely to when Alberta faced issues related to accessing storage for natural gas during the 2016 summer injection season.

Table 3 also provides crucial evidence of cointegration between Henry Hub and NBP and between TTF and Japan LNG, respectively. These results suggest that joint movements between natural gas pricing in the United States and other international natural gas markets have become more prevalent since 2016. Again, these findings are all consistent with results obtained from the previous pattern plot assessment, which shows increased co-movement between Henry Hub and overseas benchmarks since the United States began exporting significant volumes of LNG. The finding of a statistically significant cointegrating vector between Henry Hub and all other price benchmarks since 2016 suggests a rapid increase in the

degree of integration between global natural gas markets. This supports research conducted by Li, Joyeux and Ripple (2014), who suggest that natural gas markets could become integrated relatively quickly following the export of significant volumes of natural gas from the United States to less competitive regions.

It is important to note that the co-movement between intercontinental natural gas prices has historically come as a result of underlying contractual linkages between natural gas and crude oil (Brown and Yücel 2009; Li, Joyeux and Ripple 2014). However, as the degree of connectedness between natural gas and crude oil prices continues to weaken, as Chiappini, Jégourel and Raymond (2019) show to be occurring, evidence of cointegration between natural gas prices may increasingly be suggestive of true market integration.

Long-term relationship between natural gas prices

We now examine how much the long-term relationship between Henry Hub and other international benchmarks has changed since 2016. To do so, we follow Chiappini, Jégourel and Raymond (2019) and apply pairwise DOLS. We use this technique because of the evidence of cointegration between Henry Hub and all other benchmarks and because it allows for the robust estimation of long-term parameters in small samples. We then explicitly test the coefficients produced by DOLS to verify whether pairs of prices adhere to the relative LOOP. That is, we verify whether relative natural gas prices are constant in the long run.

$$Henry\ Hub_t = \mu + \beta_1 P_{it} + \sum_{j=-p}^{j=q} \gamma_j \Delta(P_{i(t+j)}) + \epsilon_t \qquad (2)$$

Equation (2) is estimated by regressing Henry Hub on every other price benchmark, P_i, leads and lags of that benchmarks' first difference, q and p respectively, as well a constant term, μ (Stock and Watson 1993). The optimal number of leads and lags is selected by the Schwarz criterion. We employ Newey–West standard errors and specify all price series in log level.

To specifically assess the impact of US LNG exports on the long-term relationship between Henry Hub and other price series, we estimate equation (2) using data from three periods, according to the approximate break dates identified by the previous cointegration testing. We examine changes in the long-term relationship between Henry Hub and the other price benchmarks through changes in β_1 across the three different estimation periods.

Table 4: Dynamic ordinary least squares results with Henry Hub

Period	Coefficient	AECO-C	Empress	Dawn	NBP	TTF	Japan LNG	Brent
2000–08	β_1	0.97***	0.93***	1.02***	0.70***	0.36***	0.82***	0.62***
2009–15	β_1	0.87***	0.81***	0.83***	0.03	0.28	-0.01	0.15
2016–20	β_1	0.09	0.78***	0.82***	0.47***	0.46***	0.32	0.69***

*** denotes statistical significance at the 1 percent level.Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Results in **Table 4** suggest that the long-term relationship between Henry Hub and AECO has weakened since 2016. This is reflected in the change in the β_1 coefficient, which was near unity before the rise in US LNG exports but becomes small and statistically insignificant thereafter. At the same time, we find that Henry Hub's long-term relationships with Dawn and with Empress have remained strong and significant throughout the study period.

The long-term relationships between Henry Hub and all three overseas natural gas benchmarks, as well as Brent, have strengthened notably since 2016. These relationships were economically small and statistically insignificant from 2009 to 2015. Our findings suggest that US LNG exports may have contributed to further integrating global natural gas markets and support results from the previous PCA and cointegration tests.

Applying pairwise DOLS with Brent as the dependent variable of interest, we find that the long-term relationships between overseas natural gas prices and crude oil has weakened since 2016 (**Table A-7** in the **Appendix**). This result is consistent with findings by Chiappini, Jégourel and Raymond (2019) and shows that the strengthening long-term relationships between overseas natural gas prices and Brent crude are not the result of potentially improved oil market integration.

We extend our assessment of the long-term relationship between benchmark prices by formally testing whether pairs of natural gas prices adhere to the relative LOOP. We follow Siliverstovs et al. (2005) and Chiappini, Jégourel and Raymond (2019) in applying a Wald test for every estimation period to test the null hypothesis that $\beta_1 = 1$. Statistically significant test statistics are thus taken as evidence that the relative LOOP does not hold between prices. The t-statistics produced by the Wald test are shown in **Table 5**.

Table 5: Relative law of one price with Henry Hub

Period	AECO-C	Empress	Dawn	NBP	TTF	Japan LNG	Brent
2000–08	-0.82	-1.31	-1.21	-3.03***	-9.30***	-1.21	-3.92***
2009–15	-3.29***	-2.13**	-2.40**	-7.37***	-3.12***	-5.56***	-4.95***
2016–20	-10.93***	-1.85	-3.39***	-12.26***	-11.68***	-3.51***	-2.13**

** denotes statistical significance at the 5 percent level.
*** denotes statistical significance at the 1 percent level.
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

We fail to reject the relative LOOP between Henry Hub and AECO, Dawn and Empress, respectively, between 2000 and 2008. This result supports those presented by Siliverstovs et al. (2005), who find that the relative LOOP held within North America between 1993 and 2004. However, we show that it has weakened in North America since. Furthermore, we reject the relative LOOP between Henry Hub and both European price benchmarks at the 1 percent level in all three estimation periods. These results are consistent with those presented by Chiappini, Jégourel and Raymond (2019), who find little evidence to suggest that natural gas prices

between the United States and Europe adhere to the relative LOOP. Although we accept that it held for Henry Hub and Japan LNG between 2000 and 2008, we ultimately reject the null hypothesis in the two subsequent periods.

Overall, relative LOOP testing indicates that natural gas prices are not constant and the global market for natural gas is not yet perfectly integrated, despite the increased price convergence observed since 2016. This is consistent with findings from the PCA, which shows that global natural gas benchmark prices have not yet fully converged.

Responsiveness of global prices to US LNG exports

We now assess to what extent US LNG exports affect European and Japanese natural gas prices. For each overseas price benchmark—NBP, TTF and Japan LNG—we estimate an unrestricted VECM and subsequently examine the associated variance decompositions and impulse response functions. The choice to use VECMs is principally motivated by evidence of cointegration between natural gas price benchmarks and because these models are simple, well identified and widely used in the analysis of market integration.

We acknowledge that linear error correction models may possess some shortcomings because they do not provide the same flexibility or forecasting precision as regime-switching models, which allow for the periodic decoupling of oil and natural gas prices (Asche, Oglend and Osmundsen 2017; Brigida 2014). However, it is unclear whether non-linear models would offer meaningful improvements on the VECM, given the fact that this paper focuses on providing a preliminary assessment of the impact of rising US LNG exports rather than on generating forecasts for the relative value of natural gas to oil.

$$y_t = \mu + \alpha(\beta y_{t-1}) + \sum_{j=1}^{p} \Gamma_j y_{t-j} + \sum_{j=1}^{p} \Psi_j x_{t-j} + \epsilon_t \tag{3}$$

$$\text{where } y_t = \begin{bmatrix} Henry\ Hub_t \\ US\ LNG\ Exports_t \\ Imports_t \\ Brent_t \\ Storage_t \\ P_t \end{bmatrix}$$

In equation (3), $\alpha(\beta y_{t-1})$ denotes the error-correction term that drives y_t toward its long-run equilibrium. The number of lags employed, p, is selected by the Schwarz criterion. We define μ as a 6×1 vector of constant terms, Γ_i as a $6 \times p$ vector of coefficients for the lags of the endogenous variables, and Ψ_j is a $6 \times p$ vector of coefficients for the lags of the exogenous variables. Finally, ϵ_t denotes a 6×1 vector of standard normal error terms that are assumed to follow a white-noise process with no autocorrelation and zero mean.

A selection of general and region-specific variables commonly used in the literature concerned with modelling natural gas prices (Brown and Yücel 2008; Nick and Thoenes 2014) is included in each of the three VECMs. Henry Hub is specified in each model because it is cointegrated

with European and Asian natural gas reference prices. Brent is specified to control for the practice of oil indexation in natural gas contracts, which has historically been used in both Europe and Asia. Crude oil prices have also been shown to act as a good proxy for broad macroeconomic conditions (He, Wang and Lai 2010). All other variables are region-specific and thus differ depending on whether we estimate the model for European or Asian natural gas prices. Beyond the primary impulse variable of interest, US LNG exports, we include natural gas imports and storage volumes. All of these endogenously specified variables are non-stationary. Following Brown and Yücel (2008), we include heating and cooling degree days, as well as deviations from normal heating and cooling degree days, for both Europe and Japan.[11] This is done to capture unseasonably warm or cool weather, which is a strong determinant of demand for natural gas. All of these temperature variables are found to be stationary and are specified exogenously. Finally, we include exogenous indicator variables to reflect the start of US LNG exports in 2016, which is viewed as a major structural change within the industry.[12]

US LNG exports, imports of natural gas and natural gas storage are adjusted using a Census X-12 process to correct for seasonality in the natural gas industry. Due to data limitations, the VECMs used to model European natural gas prices are estimated from 2009M3 to 2020M12, while the VECM used to model Japan LNG prices includes data from 2008M1 to 2020M12. Rank and maximum eigenvalue criteria confirm the existence of a statistically significant cointegrating equation at the 5 percent level in each of the estimated models. The error correction term of interest is found to be negative and statistically significant in all three estimated VECMs, indicating that the models converge toward their long-run equilibrium. The models generate a good fit of NBP, TTF and Japan LNG prices with an R-squared value of 0.58, 0.55, and 0.83, respectively.[13, 14]

Shocks are identified using a Cholesky decomposition with variables specified in decreasing order of exogeneity. We define impulse responses in a manner that we deem to be reflective of global natural gas market dynamics because there is no single clear or empirically established way of ordering variables. We also take some inspiration from the structural VAR identification employed by Nick and Thoenes (2014). Henry Hub is specified first because changes in US natural gas prices are generally viewed as being driven by factors such as extreme weather conditions, domestic inventories and production disruptions, which are not included in the model (Brown and Yücel 2008). US LNG exports and natural gas imports are

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[11] Deviations from normal heating (cooling) degree days are defined as the difference between historical and actual heating (cooling) degrees in a given month.

[12] We follow Siliverstovs et al. (2005) in specifying an exogenous impulse dummy variable, which is equal to 1 at the date of interest, t, and 0 otherwise. We also include an exogenous transitory impulse dummy variable, which has a value of 1 at the date of interest, t, a value of -1 at $t+1$, and 0 otherwise.

[13] The Schwarz criterion finds that three is the optimal lag length to use in each of the three models. Other information criteria identify different lag lengths, but we generally find the model fit to be similar. Autocorrelation and heteroskedasticity diagnostic test results are also used to inform lag length selection decision.

[14] Each model passes a White test for heteroskedasticity and a Lagrange multiplier autocorrelation test, indicating that residuals have constant variance and are uncorrelated (**Table A-8**; **Table A-9** in the **Appendix**).

ordered next because natural gas trade flows to Europe and Asia are assumed to be affected by contemporaneous changes in prices for North American natural gas. We subsequently specify Brent crude because changes in oil prices are not assumed to meaningfully affect natural gas trade flows (Nick and Thoenes 2014). We order gas storage next because Nick and Thoenes (2014) highlight the importance of allowing storage to respond contemporaneously to changes in gas prices. This is done to capture the effects of intertemporal price arbitrage conducted by commercial storage operators. Ordering gas storage in this way also allows storage to be directly affected by changes in oil prices and natural gas trade flows. Overseas natural gas price benchmarks, which are of greatest interest in this study, are ordered last and are thus allowed to respond contemporaneously to changes in all of the previously specified variables.

Chart 7: **Variance decomposition and impulse response functions**[15]

a. Variance decomposition of NBP

b. Response of NBP to innovations

c. Variance decomposition of TTF

d. Response of TTF to innovations

e. Variance decomposition of Japan LNG

f. Response of Japan LNG to innovations
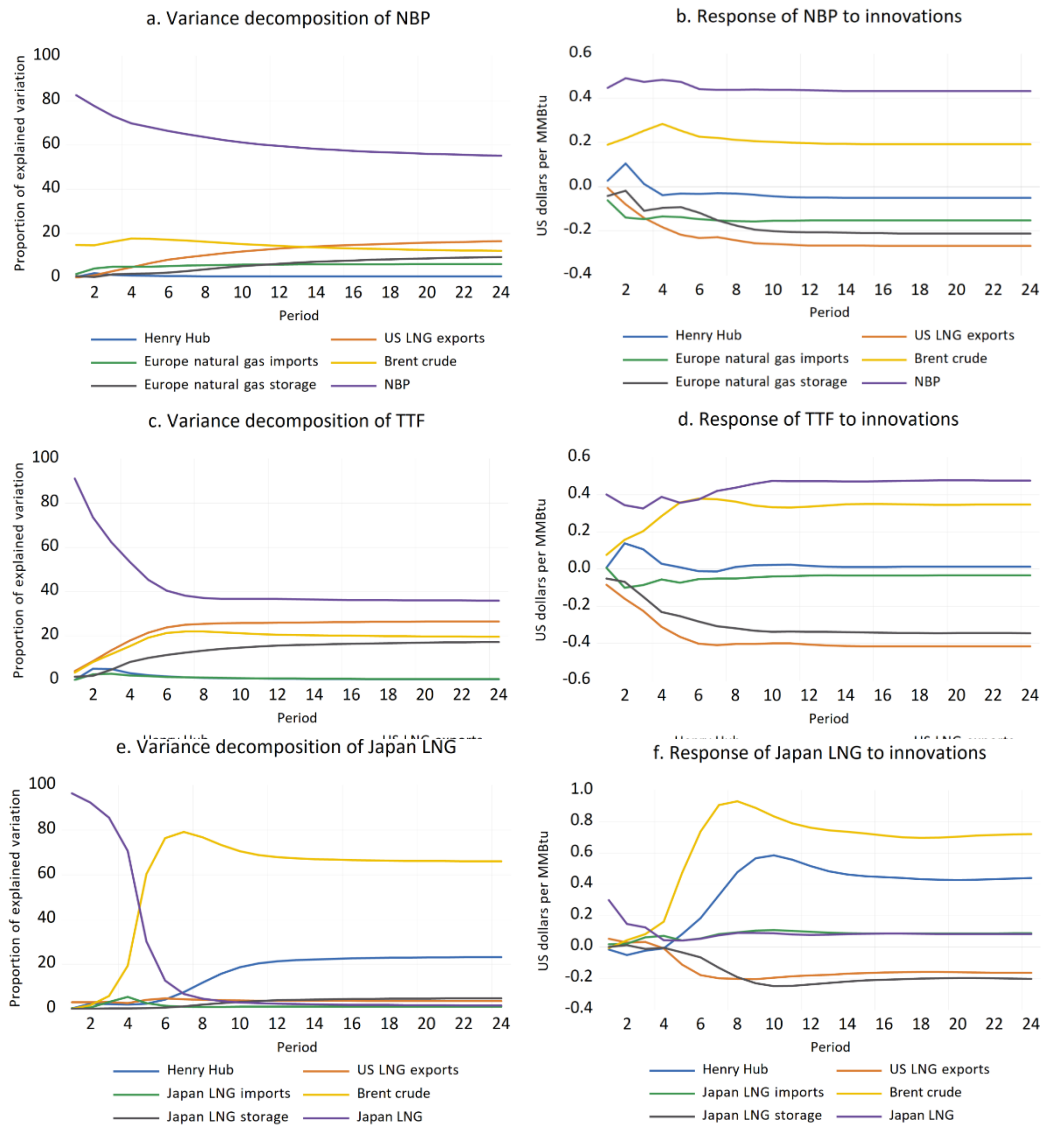
[15] **Chart A-5**, **Chart A-6** and **Chart A-7** in the **Appendix** show 95 percent confidence intervals for IRFs for each estimated model.

Chart 7 shows the models' variance decomposition. Results suggest that US LNG exports explain around 17 and 27 percent of variation in NBP and TTF pricing, respectively, over a 24-month horizon. In Japan, Brent explains most of the variation in natural gas prices, while US LNG exports explain 5 percent of the variation in natural gas prices. This result partly reflects the higher prevalence of oil indexation in Asian natural gas contracts as well as the fact that US LNG exports still represent only a small portion of all LNG imported into Japan (Till and McHich 2020; EIA 2020).

Impulse response functions, also displayed in **Chart 7**, indicate that natural gas prices in both Europe and Asia respond negatively to increases in US LNG exports. In particular, we find that a Cholesky one-standard-deviation shock to US LNG exports is associated with a US$0.27/MMBtu and US$0.42/MMBtu decrease in NBP and TTF prices (from US$6.50 and US$5.86 in December 2020), respectively. In Japan, meanwhile, the same shock to US LNG exports leads to a decrease of US$0.17/MMBtu after 24 months (from US$7.66 in December 2020). Overall, these findings indicate that LNG prices in Europe and Asia are converging toward a lower level in the long run. This supports past research, which shows that natural gas prices are expected to decrease in regions importing US LNG (Deloitte 2013). Consistent with our expectations, results show that European and Asian natural gas prices respond:

- negatively to an increase in storage volumes
- positively to an increase in Brent crude prices

We also note that natural gas imports from the rest of the world generally have a smaller effect on European and Asian natural gas prices than LNG imported from the United States. This finding reflects the disruptive nature of US LNG in the global trade of natural gas.

Impulse response functions are found to be somewhat sensitive to different variable orderings. As a result, we also produce generalized impulse response functions (GIRFs) that are order-invariant and thus do not require us to make subjective assumptions about how variables are related.[16] Like the IRFs defined with a Cholesky decomposition, these GIRFs suggest that NBP, TTF and Japan LNG prices respond negatively to shocks to US LNG exports (**Chart A-8** in the **Appendix**). The magnitude of the GIRF responses is found to be very similar to the IRFs.

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[16] The residual covariance matrix is found to be reasonably diagonal for all three of the estimated VECMs. This gives us confidence that the GIRFs can be meaningfully interpreted (Kim 2013).

Implications for Canada and further work

Additional access to world markets provided by LNG projects currently underway in Canada would benefit the country's energy sector and improve its terms of trade. By building LNG export facilities, Canadian producers would be provided with a new outlet for domestic natural gas supply. This would help Canada diversify its export market away from the United States, whose demand for Canadian natural gas is trending down as it becomes more self-sufficient in natural gas supply. The construction of Canadian LNG export terminals would also partially insulate domestic producers from pipeline interruptions, changes to regulations and other potential issues in accessing the market in the United States.

At the same time, greater integration of natural gas markets could have some negative implications for Canada's burgeoning LNG industry. In its reference case, the EIA projects that the United States could effectively double its LNG exports between 2020 and 2030 (EIA 2021). We show that such a signficiant expansion of US LNG exports would put downward pressure on natural gas prices in both Europe and Asia. This expansion, combined with the sizable LNG export projects currently being developed in Australia and Qatar, would further contribute to the growth of global LNG supply. As a result, the pricing environment in the LNG market may be altered substantially by the time Canada begins exporting LNG in 2023 (Jaremko 2021). A weaker environment for international prices, as well as a smaller differential between North American and overseas natural gas benchmarks, would consequently put some higher-cost Canadian LNG projects at risk of becoming less profitable or uneconomic. This, in turn, could dampen the projected economic benefits associated with the development of Canada's LNG industry.

Since the rapid rise in the US LNG exports are a relatively recent phenomenon, future research could explore some of the following:

- The sensitivity of Asian natural gas prices to increased US LNG imports as adoption of gas-on-gas competition grows.
- The effect that increased LNG export capacity in countries other than the US has on international prices and market connectedness.
- The extent to which Canadian natural gas is already reaching overseas markets through existing US LNG export facilities and the degree to which US LNG exports are being spurred by imports of Canadian natural gas.
- The influence that US LNG exports has on North American natural gas prices.
- The impact of increasingly globalized natural gas markets on natural gas price volatility.

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Appendix

Table A-1: Descriptive statistics for price benchmarks

Price benchmark	Unit of measure	Mean	Standard deviation	Minimum	Maximum	Source
Henry Hub	USD/MMBtu	4.46	2.21	1.70	13.82	EIA
AECO-C	USD/MMBtu	3.69	2.10	0.53	11.24	CAPP
Empress	USD/MMBtu	3.56	1.92	0.76	11.00	Bloomberg
Dawn	USD/MMBtu	4.69	2.40	1.58	18.09	Bloomberg
NBP	USD/MMBtu	6.31	2.91	1.43	15.76	Bloomberg
TTF	USD/MMBtu	7.12	3.17	1.58	15.93	World Bank
Japan LNG	USD/MMBtu	9.34	4.04	3.96	18.11	World Bank
Brent	USD/MMBtu	11.36	5.31	3.32	23.91	World Bank

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; EIA is Energy Information Administration; CAPP is Canadian Association of Petroleum Producers. All price benchmarks are expressed in US dollars per metric million British thermal unit.

Table A-2: Descriptive statistics for other variables

Variable	Unit of measure	Mean	Standard deviation	Minimum	Maximum	Source
US LNG exports to Europe	Million cubic feet	6,726.50	20,628.16	0.00	123,143.00	EIA
US LNG exports to Japan	Million cubic feet	5,306.25	6,582.60	0.00	54,004.00	EIA
EU-27 natural gas imports	Thousand metric tons	13,463.30	2,066.447	7,721.51	18,477.45	Eurostat
Japan LNG imports	Thousand metric tons	5,769.97	1,197.38	3,4921.94	8,439.43	Japan METI
Europe natural gas storage	Terawatt-hour	538.02	249.88	13.16	1118.59	GIE
Japan LNG storage	Terawatt-hour	54.46	8.00	37.08	75.83	JOGMEC
EU-27 HDD	Degree days	242.03	177.43	8.18	587.21	Eurostat
EU-27 CDD	Degree days	7.44	13.10	0.00	60.27	Eurostat
Japan HDD	Degree days	405.84	242.22	0.00	788.05	JMA, author calculations
Japan CDD	Degree days	5.68	8.88	0.00	29.31	JMA, author calculations

Note: HHD is heating degree days; CDD is cooling degree days; EIA is Energy Information Administration; Japan METI is the Japan Ministry of Economy, Trade and Industry; GIE is Gas Infrastructure Europe; JOGMEC is Japan Oil, Gas and Metals National Corporation; JMA is Japan Meteorological Agency; LNG is liquefied natural gas; EU-27 refers to the 27 European Union countries.

Chart A-1: Representation of price benchmarks on the first plane (2000–10)

Chart A-2: Representation of price benchmarks on the first plane (2005–15)

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Chart A-3: Representation of differenced price benchmarks on the first plane (2000–15)
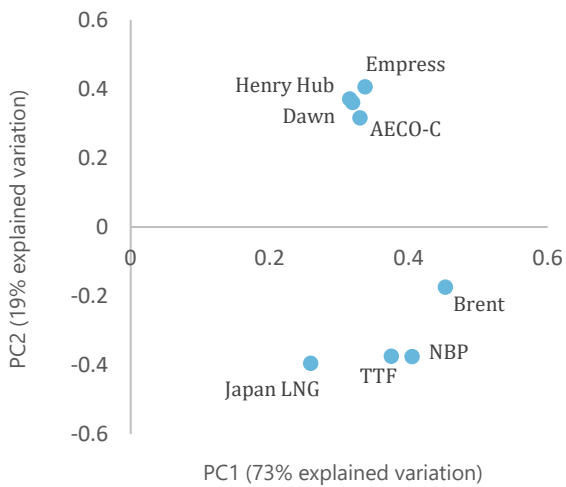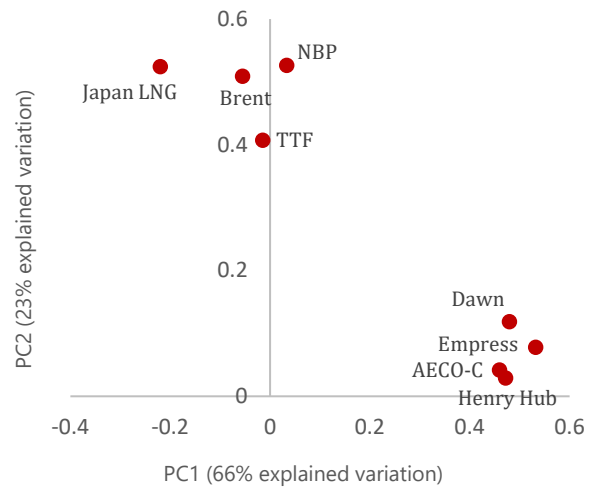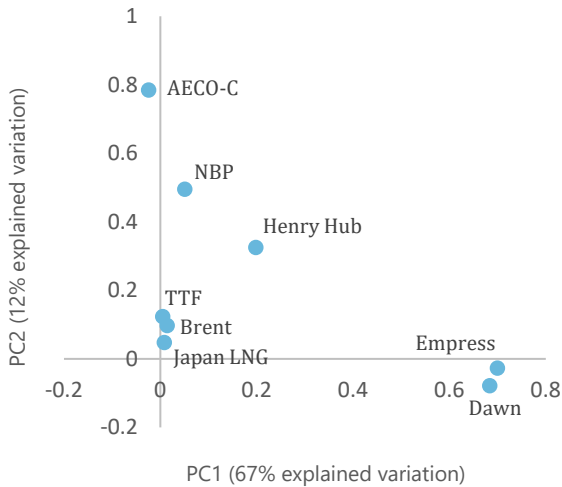

Chart A-4: Representation of differenced price benchmarks on the first plane (2016–20)
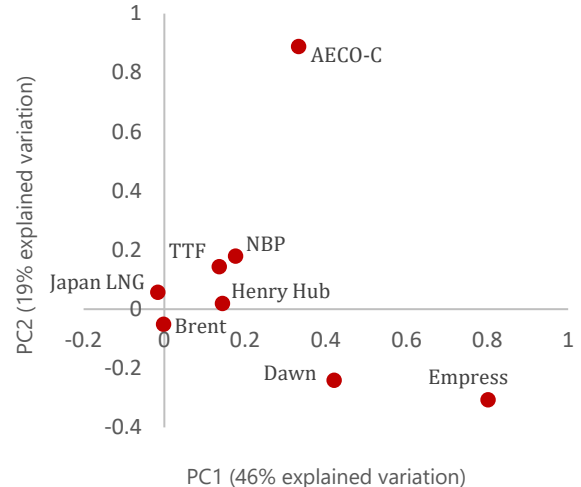
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Table A-3: Correlation matrix

	Henry Hub	AECO-C	Empress	Dawn	NBP	TTF	Japan LNG	Brent
Henry Hub	1							
AECO-C	0.93	1						
Empress	0.76	0.69	1					
Dawn	0.70	0.62	0.98	1				
NBP	0.35	0.34	0.30	0.30	1			
TTF	0.28	0.31	0.26	0.26	0.85	1		
Japan LNG	-0.17	-0.14	-0.05	-0.02	0.70	0.80	1	
Brent	0.13	0.13	0.16	0.17	0.79	0.84	0.85	1

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Table A-4: Quandt–Andrews breakpoint test results

	AECO-C	Empress	Dawn	NBP	TTF	Japan LNG	Brent
Maximum LRE F-statistic	108.28	61.25	145.24	269.10	269.80	186.06	308.49
Probability	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Break date	2016M4	2013M8	2014M1	2010M9	2008M10	2008M10	2009M4

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; LRE is likelihood ratio. Trimming parameter is set to 15 percent.

Table A-5: Gregory–Hansen cointegration test results (2000–15)

Price benchmark	Model	ADF^*	Z_s^*	Z_t^*	R^2	Break date
AECO-C	Level shift	-5.03**	-145.06***	-10.78***	0.88	2008M5
	Level shift with trend	-10.85***	-148.42***	-10.91***	0.89	2008M5
Empress	Level shift	-6.67***	-119.85***	-9.52***	0.84	2012M6
	Level shift with trend	-6.75***	-119.93***	-9.54***	0.84	2005M1
Dawn	Level shift	-10.61***	-142.78***	-10.72***	0.85	2009M9
	Level shift with trend	-10.60***	-142.88***	-10.77***	0.85	2005M10
NBP	Level shift	-4.99**	-35.54	-4.34	0.19	2010M3
	Level shift with trend	-5.12**	-37.37	-4.50	0.43	2010M3
TTF	Level shift	-4.60	-30.41	-4.16	0.14	2009M5
	Level shift with trend	-4.81	-31.55	-4.27	0.34	2003M8
Japan LNG	Level shift	-4.20	-26.63	-3.82	0.10	2009M8
	Level shift with trend	-4.88	-30.17	-4.14	0.12	2003M8
Brent	Level shift	-4.84**	-36.60	-4.59	0.13	2009M8
	Level shift with trend	-4.77	-36.56	-4.60	0.37	2009M10

** denotes statistical significance at the five percent level.
*** denotes statistical significance at the one percent level.
Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; $ADF^* = \inf_{\tau \in T} ADF(\tau)$; $Z_s^* = \inf_{\tau \in T} Z_s(\tau)$; $Z_t^* = \inf_{\tau \in T} Z_t(\tau)$.

Table A-6: Gregory–Hansen cointegration test results (2000–20)

Price benchmark	Model	ADF^*	Z_s^*	Z_t^*	R^2	Break date
AECO-C	Level shift	-3.87	-73.17***	-6.71***	0.80	2016M2
	Level shift with trend	-3.98	-74.44***	-6.81***	0.80	2016M2
Empress	Level shift	-7.11***	-141.54***	-10.25***	0.85	2016M11
	Level shift with trend	-7.18***	-140.76***	-10.30***	0.85	2016M1
Dawn	Level shift	-6.58***	-191.47***	-12.50***	0.88	2017M4
	Level shift with trend	-7.06***	-197.14***	-12.83***	0.89	2009M9
NBP	Level shift	-5.74***	-50.32***	-5.32***	0.26	2010M1
	Level shift with trend	-5.71***	-50.07**	-5.32**	0.59	2010M1
TTF	Level shift	-5.44***	-45.95**	-5.19***	0.25	2009M6
	Level shift with trend	-5.42**	-46.64	-5.21**	0.54	2009M6
Japan LNG	Level shift	-4.96**	-36.90	-4.58	0.20	2009M5
	Level shift with trend	-5.51***	-36.80	-4.57	0.38	2003M8
Brent	Level shift	-5.51***	-52.88***	-5.53***	0.21	2009M4
	Level Shift with trend	-5.48***	-52.70**	-5.54***	0.53	2009M4

** denotes statistical significance at the five percent level.

*** denotes statistical significance at the one percent level.

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; $ADF^* = \inf_{\tau \in T} ADF(\tau)$; $Z_s^* = \inf_{\tau \in T} Z_s(\tau)$; $Z_t^* = \inf_{\tau \in T} Z_t(\tau)$.

Table A-7: Dynamic ordinary least squares results with Brent

Period	Coefficient	AECO-C	Empress	Dawn	NBP	TTF	Japan LNG	Henry Hub
2000–08	β_1	1.45***	1.21***	1.30***	0.98***	1.06***	1.39***	1.42***
2009–15	β_1	0.16	0.15	0.26	0.87***	0.89***	1.07***	0.21
2016–20	β_1	-0.27***	0.48***	0.52**	0.41***	0.45***	1.22***	0.74***

Note: AECO-C is Alberta's gas trading price; NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas.

Table A-8: White heteroskedasticity test results for estimated vector error correction models

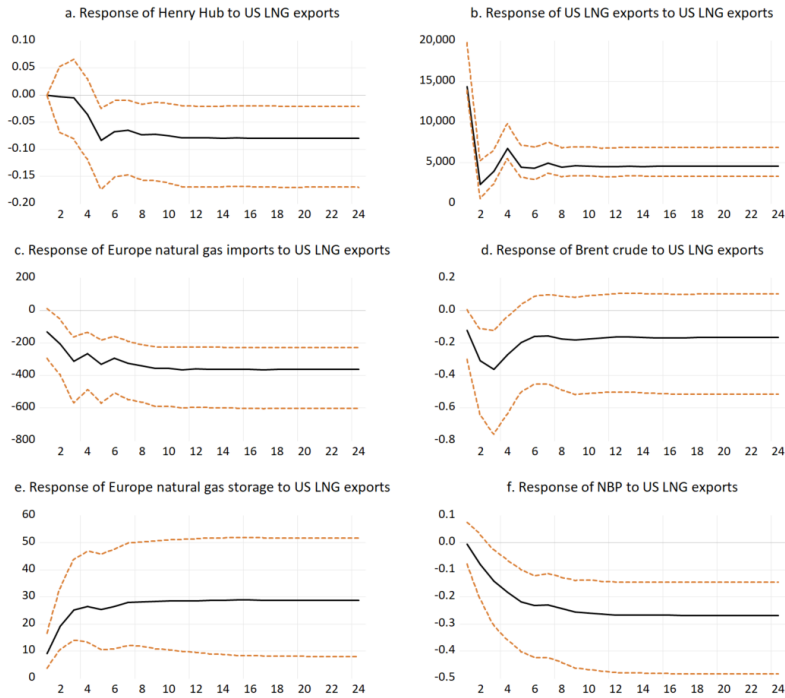| Model	Chi-Square Statistic	Probability
NBP	1574.09	0.13
TTF	1531.70	0.36
Japan LNG	1539.86	0.30

Note: NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas. White heteroskedasticity test is performed with no cross terms.

Table A-9: Lagrange multiplier autocorrelation test results for estimated vector error correction models

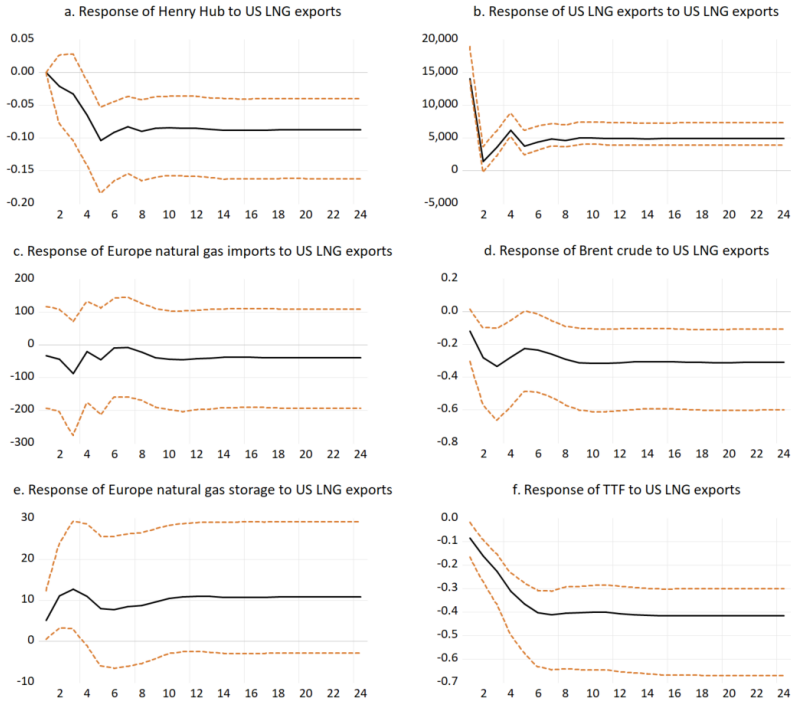| Model	Lag	LRE statistic	Probability
NBP	1	33.25	0.60
	2	61.79	0.980
	3	97.36	0.77
	4	131.04	0.79
TTF	1	18.62	0.99
	2	52.37	0.96
	3	87.78	0.93
	4	34.25	0.86
Japan LNG	1	47.35	0.10
	2	80.80	0.23
	3	118.98	0.23
	4	164.65	0.12

Note: NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquefied natural gas; LRE is likelihood ratio.

Chart A-5: 95 percent confidence intervals for impulse response functions—National Balancing Point model

a. Response of Henry Hub to US LNG exports

b. Response of US LNG exports to US LNG exports

c. Response of Europe natural gas imports to US LNG exports

d. Response of Brent crude to US LNG exports

e. Response of Europe natural gas storage to US LNG exports
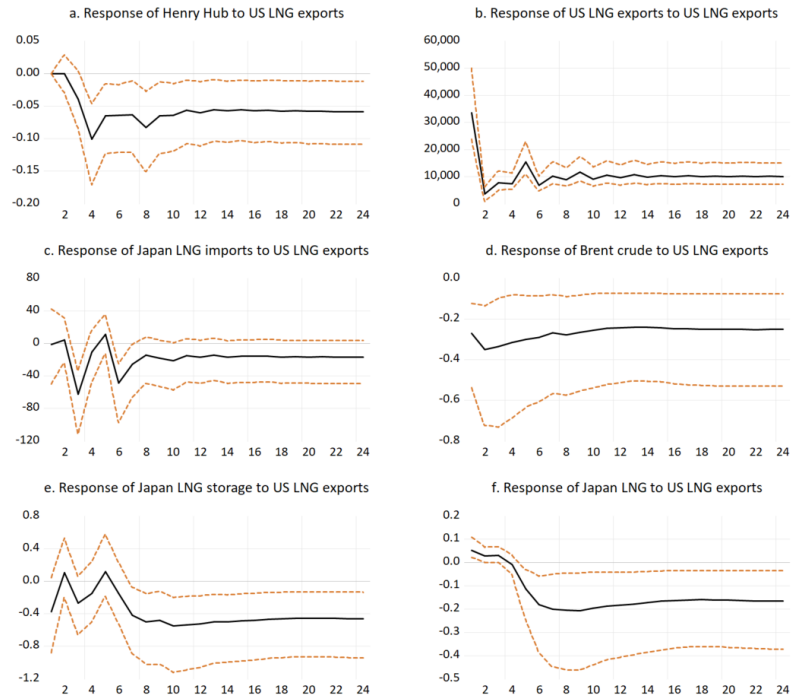
f. Response of NBP to US LNG exports

Note: NBP is the United Kingdom's National Balancing Point; LNG is liquified natural gas. Confidence interval is constructed using Hall's percentile bootstrap method with 1000 replications. IRFs show the response to a one standard deviation shock to US LNG exports.

Chart A-6: 95 percent confidence intervals for impulse response functions—Title Transfer Facility model

a. Response of Henry Hub to US LNG exports

b. Response of US LNG exports to US LNG exports

c. Response of Europe natural gas imports to US LNG exports

d. Response of Brent crude to US LNG exports

e. Response of Europe natural gas storage to US LNG exports
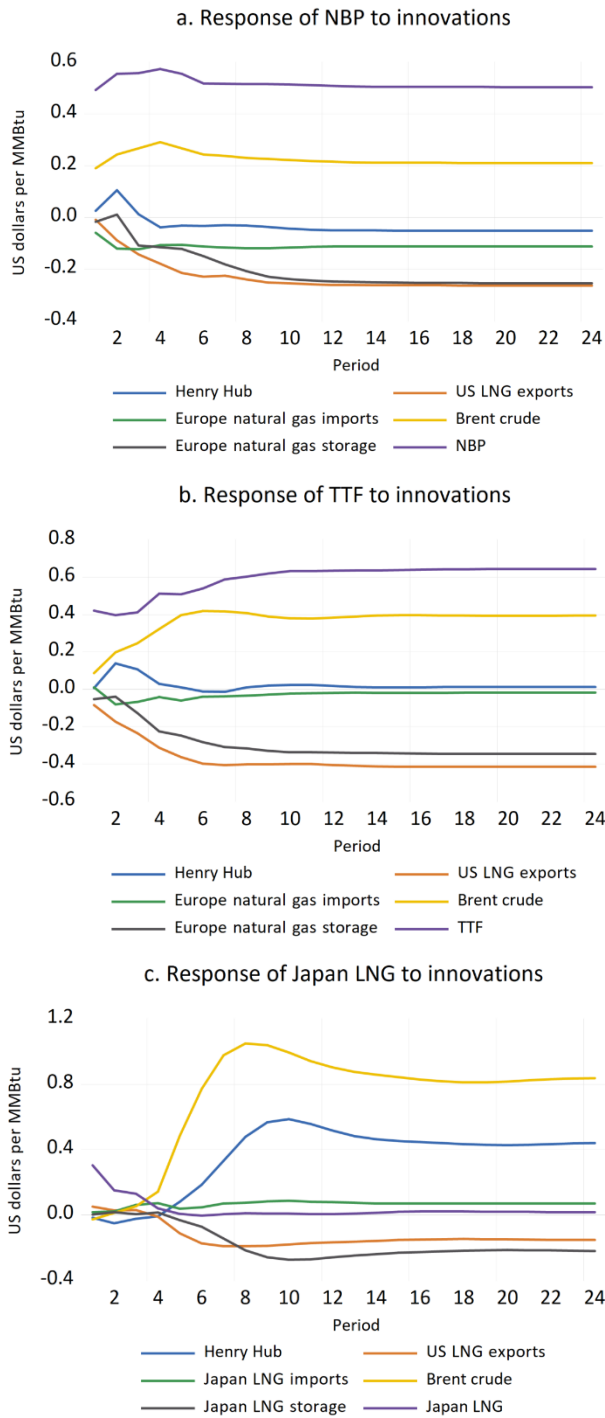
f. Response of TTF to US LNG exports

Note: TTF is the Netherlands' Title Transfer Facility; LNG is liquified natural gas. Confidence interval is constructed using Hall's percentile bootstrap method with 1000 replications. IRFs show the response to a one standard deviation shock to US LNG exports.

Chart A-7: 95 percent confidence intervals for impulse response functions—Japan liquefied natural gas model

a. Response of Henry Hub to US LNG exports

b. Response of US LNG exports to US LNG exports

c. Response of Japan LNG imports to US LNG exports

d. Response of Brent crude to US LNG exports

e. Response of Japan LNG storage to US LNG exports

f. Response of Japan LNG to US LNG exports

Note: LNG is liquefied natural gas. Confidence interval is constructed using Hall's percentile bootstrap method with 1000 replications. IRFs show the response to a one standard deviation shock to US LNG exports.

Chart A-8: Generalized impulse response functions

a. Response of NBP to innovations

Legend: Henry Hub, US LNG exports, Europe natural gas imports, Brent crude, Europe natural gas storage, NBP

b. Response of TTF to innovations

Legend: Henry Hub, US LNG exports, Europe natural gas imports, Brent crude, Europe natural gas storage, TTF

c. Response of Japan LNG to innovations

Legend: Henry Hub, US LNG exports, Japan LNG imports, Brent crude, Japan LNG storage, Japan LNG

Note: NBP is the United Kingdom's National Balancing Point; TTF is the Netherlands' Title Transfer Facility; LNG is liquified natural gas; LNG is liquified natural gas. GIRFs show the response to a generalized one standard deviation shock to US LNG exports.