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ABSTRACT

From 2015 to 2023, the United States transformed from a net importer of natural gas to the world's largest liquified natural gas (LNG) exporter. We find that this surge in LNG exports has reconnected U.S. gas prices to world market prices, after a hiatus of "shut-in" fracked gas. We estimate that the domestic gas price effect of this recoupling is comparable to a $30/ton carbon tax. For coal prices, which are coupled to gas through competition in the power sector, this effect is comparable to a $20/ton carbon tax. Using the NREL ReEDS model, we estimate that this recoupling reduces U.S. 2030 power sector CO2 emissions by roughly 145 million metric tons. These domestic estimates contribute to estimating the overall climate impact of LNG exports.

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1. Introduction

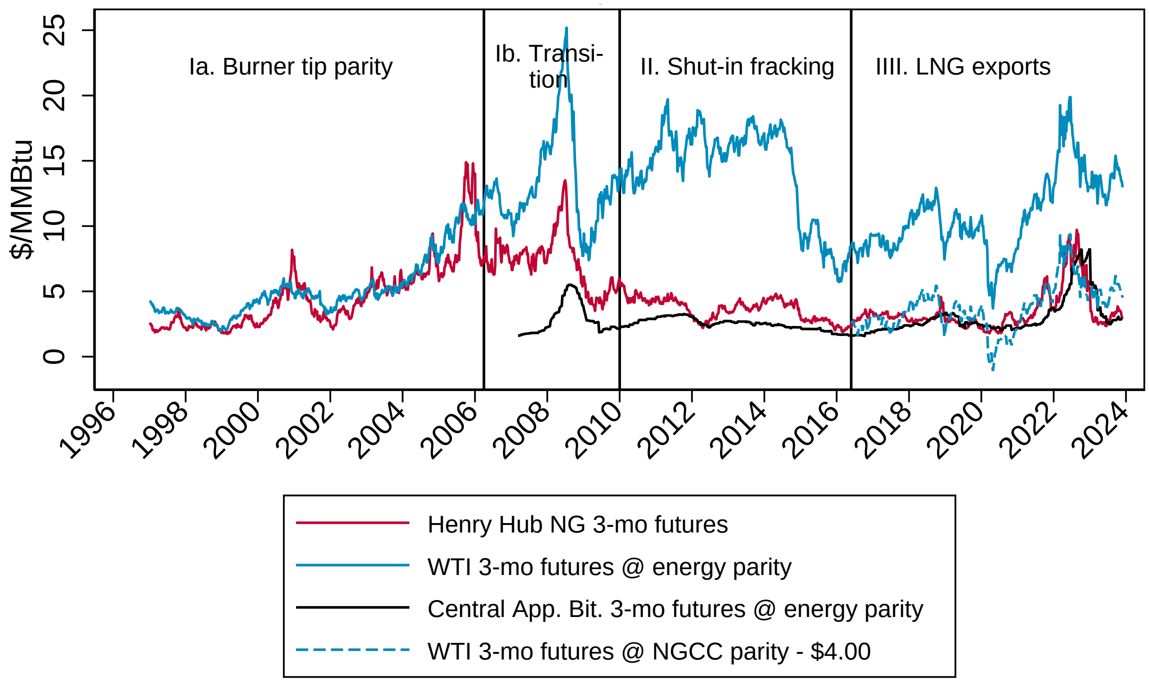
For decades, the United States was a net importer of natural gas, primarily by pipeline from Canada. With the advent of hydraulic fracturing (fracking), vast new natural gas resources became available and industry interest in natural gas exports increased. The first application for a liquified natural gas (LNG) export facility, Cheniere Energy's Sabine Pass, was filed in September 2010 and approved in August 2012 by the Department of Energy (DOE), which grants licenses for natural gas exports to non-Free Trade Agreement countries.[1] The first U.S. shipment of LNG was in February 2016.[2] Export capacity grew rapidly, and by 2017, the U.S. was a net gas exporter. In 2023, the United States exported 18% of production and now leads the world in gas exports.[3]

This paper examines the market and domestic climate implications of this dramatic shift from a net importer to the leading exporter on domestic natural gas prices and on domestic energy markets. Our main finding, based on econometric analysis of domestic and international fuels prices bolstered by institutional evidence, is that the U.S. LNG exports have connected U.S. gas prices to world markets, and in particular to the price of oil – in contrast to the situation prior to LNG exports in which the flood of fracked gas and constrained export options kept domestic wholesale gas prices far below world levels. Moreover, because gas and coal are in direct competition for generation of electricity in the United States, coal and gas prices are also coupled. Thus, the connection of LNG prices with international prices implies connection between U.S. coal and international fuel prices, even though U.S. trade in coal is limited.

This narrative is depicted in Figure 1, which shows 3-month futures prices for Henry Hub gas, West Texas Intermediate (*WTI*) oil, and Central Appalachian coal from 1997 to 2023. For comparability, oil and coal prices have been expressed in dollars per million British thermal units (MMBtu), the native unit of U.S. gas prices. The figure divides this 26-year period into four regimes, which are based on industry developments discussed further in Section 2. Initially (regime Ia), gas and oil were substitutes for firing coal boilers in manufacturing and in the power sector, so arbitrage at the "burner tip" aligned domestic gas and oil prices (Brown (2005), Brown and Yücel (2008), Hartley et al. (2008)). In 2006, fracked gas started entering the market, depressing gas prices, although they still tracked oil, albeit with a lower correlation (Ib). With the expansion of production from the Haynesville in 2009, followed by the Marcellus in 2010, fracked gas flooded into the U.S. market, displacing imports and fully disconnecting gas prices from oil and international gas prices (II).

[1] U.S. Department of Energy, Final Opinion and Order Granting Long-Term Authorization to Export LNG From Sabine Bass LNG Terminal to Non-Free Trade Agreement Nations, August 7, 2012.
[2] Reuters, "Cheniere to export first U.S. LNG cargo to Brazil on Wednesday", February 24, 2016.
[3] Preliminary estimate based on cumulative natural gas exports and marketed production data for the 11 months to November 2023 (Source: U.S. Energy Information Administration).

Figure 1. Henry Hub natural gas price, *WTI* oil price at energy parity and at natural gas combined cycle parity (adjusted for liquefaction, transport, and regasification costs), and Central Appalachian coal price at energy parity, all 3-month futures ($/MMBtu).



With the advent of LNG exports in 2016 (III), however, U.S. gas prices started to reconnect to international fuels prices, but with two twists. First, the high cost of liquefaction, transportation, and regasification (LTR) drives a wedge between domestic gas prices and landed regasified prices at destination. The LTR cost, which is confidential business information, has been estimated by industry analysts to be approximately $4.00/MMBtu in 2019, and we adopt this value adjusted for inflation.[4] Second, by 2016 gas was mainly used to generate electricity using natural gas combined cycle (NGCC) units, which are more thermally efficient than gas-fired steam generators (e.g., Hartley et al. (2008)). For regime III, Figure 1, therefore, also plots the WTI price in $/MMBtu, adjusted for NGCC thermal efficiency less the $4.00 LTR cost. Evidently, since 2016 these three series have moved together: oil and gas because they compete internationally in power generation and because Asian and, to a lesser extent, European LNG contracts are typically indexed to oil (Han et al. (2021), JOGMEC (2023))), and coal and gas because they compete domestically in power generation.

The apparent re-coupling of gas and coal prices to world prices has important implications for the U.S. energy transition and greenhouse gas emissions. We estimate that the resulting increase in domestic prices due to LNG exports is approximately comparable to imposing a carbon tax on natural gas of $30 per metric ton (MT) of CO_2 emissions, and a carbon tax on coal of $20/MT, in

[4] Sources for these and other coefficients used to construct Figure 1 are discussed in Section 3.

the absence of exports. Our projected future gas and coal prices are higher than those in standard energy policy simulations.[5] To quantify the impact of these higher prices on U.S. power sector emissions, we use the National Renewable Energy Laboratory's ReEDS model under a no-LNG exports counterfactual, in which LNG prices are not connected to world prices, and our empirically supported scenario in which they are. We estimate U.S. power sector CO_2 emissions to be 145 million metric tons, or one-third, less in 2030 under the LNG export scenario than under the no-export counterfactual. In a second, retrospective counterfactual, we estimate that gas prices during the shut-in fracking period were approximately $2.30/MMBtu less than they would have been had domestic prices been coupled with international prices by LNG exports (95% confidence interval ($1.32/MMBtu, $3.29/MMBtu).

Citing this dramatic and largely unexpected rise in LNG exports, on January 26, 2024, the Biden Administration announced a pause on DOE export license approvals pending analysis of the market and climate implications of LNG exports.[6] This paper provides a partial analysis of these effects, with a focus on domestic fuel prices and emissions over the short and medium term. A full analysis would further consider the implications for international gas and coal prices, international switching from coal to gas, renewables penetration, the life-cycle emissions of LNG (e.g., Roman-White et al. (2019) and Howarth (2024)), and the long-term implications for the international transition to renewables of these long-lived fossil fuel investments.

This paper contributes to the literature on the determinants of natural gas prices. Han et al.'s (2021) review of the literature from 2000-2019 confirms that, before roughly 2006, there was a stable long-run relation between Henry Hub and *WTI* prices (Brown (2005), Brown and Yücel (2008), Hartley et al. (2008)). That relationship, however, weakened and then broke down altogether as fracked gas entered the U.S. market (Ramberg and Parsons (2012), Zhang and Ji (2018), and Roberts (2019)). The literature documents the indexing of Asian and, to a lesser extent, European gas contract prices to oil prices (Li, Joyeux, and Ripple (2014), Han et al (2021)), and suggests that European and Asian markets have become more integrated with the expansion of LNG trade in the late 1990s when Qatar began exporting (Li, Joyeaux, and Ripple (2014), Aguiar-Conraria et al. (2022)). Chiappini, Jégourel, and Raymond (2019), Aguiar-Conraria et al. (2022), and Halser, Paraschiv, and Russo (2023) provide suggestive evidence that U.S. and European gas markets became more connected in the late 2010s. Relative to this literature, this paper connects the regimes to institutional (historical) developments, confirms those dates by empirical estimation of break dates and rolling regressions, extends the sample to

[5] See for example the U.S. Energy Information Administration (EIA) Annual Energy Outlook (2023) and the simulations in Bistline et al. (2023).
[6] Various government entities have commissioned reviews of the market and environmental impacts of LNG exports (FN: 2012, 2014, 2015 market studies, and 2019 NETL study). Those studies predate the LNG export boom, however, and the modest increase in gas prices they project relative to the no-exports case stem from increased gas demand for exports, not from domestic prices reconnecting to international prices.

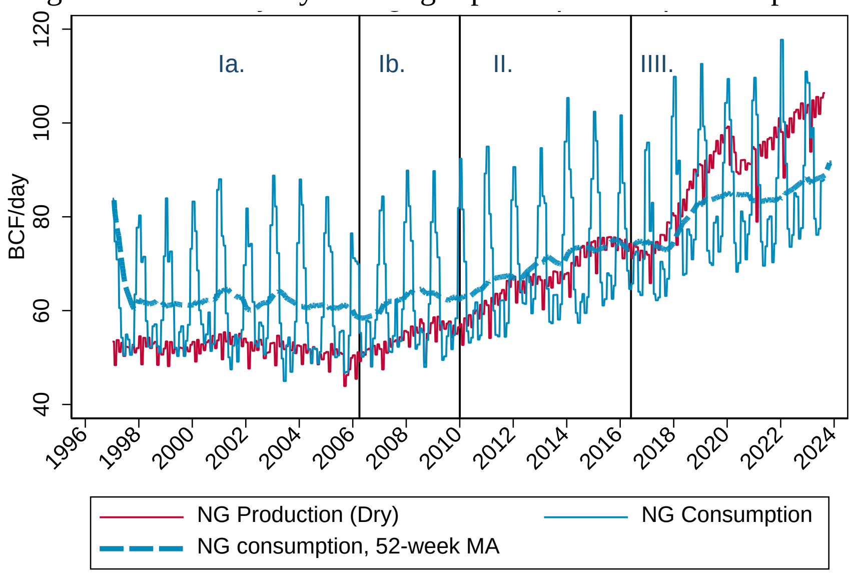
include the Ukraine crisis, incorporates domestic coal prices, and estimates the magnitude of the domestic price impact of LNG exports through the re-coupling channel.

2. U.S. Natural Gas Imports, Exports, Production, and Use

2.1. Natural Gas Production and Consumption

Figure 2 shows the production and consumption of natural gas in the United States from January 1997 through November 2023. In 2006, production began to increase because of gas extraction from shale formations using hydraulic fracturing (fracking), which more than offset the slow decline in conventional gas production.[7,8] As fracking technology improved and production costs declined, U.S. production doubled from 51 billion cubic feet per day (Bcf/d) in 2006 to 100 Bcf/d in 2022.[9]

Figure 2. U.S. monthly natural gas production and consumption



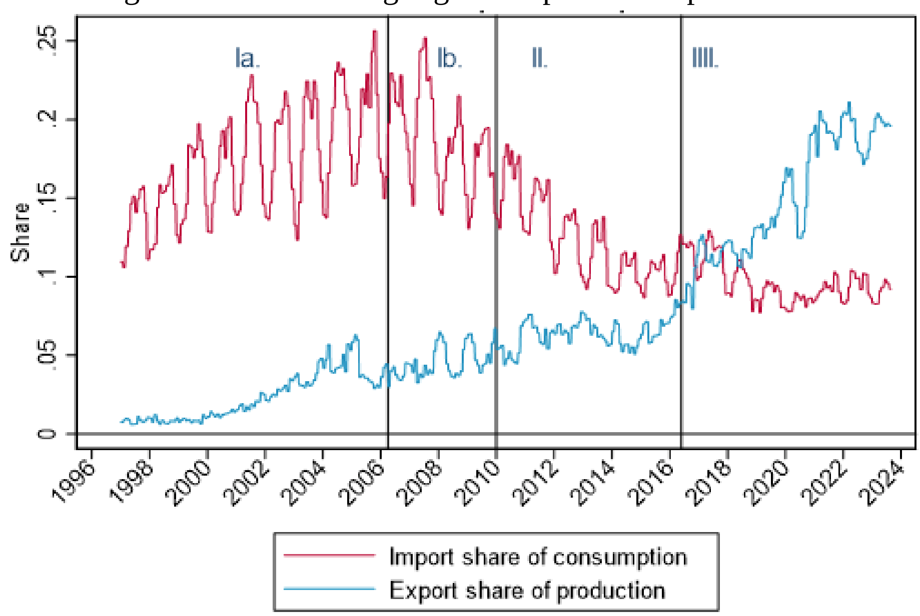
Domestically, natural gas is used for power generation (38% of gas used in 2022), residential heating and cooking (15%), commercial heating and cooking (11%), industrial uses (mainly heat, process heat, and chemical feedstock; 32%) and transportation (4%).[10] The space heating and power applications have large but different seasonal factors resulting in a large and complex seasonal pattern for overall natural gas consumption. These seasonal fluctuations in demand are smoothed by underground storage dispersed around the country.[11]

[7] EIA, *Natural Gas Year in Review 2006*.
[8] EIA, "U.S. dry natural gas production growth levels off following decline in natural gas prices", June 11, 2012.
[9] EIA, *U.S. Dry Natural Gas Production [Dataset]*. Date accessed: February 9, 2024.
[10] EIA, *Natural gas explained*. Date accessed: February 9, 2024.
[11] EIA, "Weekly Natural Gas Storage Report", February 1, 2024.

As shown in Figure 3, prior to the fracking revolution, the United States imported approximately 15% of its consumption, but became a net exporter in 2017. In 2023, the United States exported approximately 20% of its production, although because of pipeline capacity restrictions in certain regions it still imports natural gas (99% by pipeline from Canada with the rest being LNG purchased on the international market).[12]

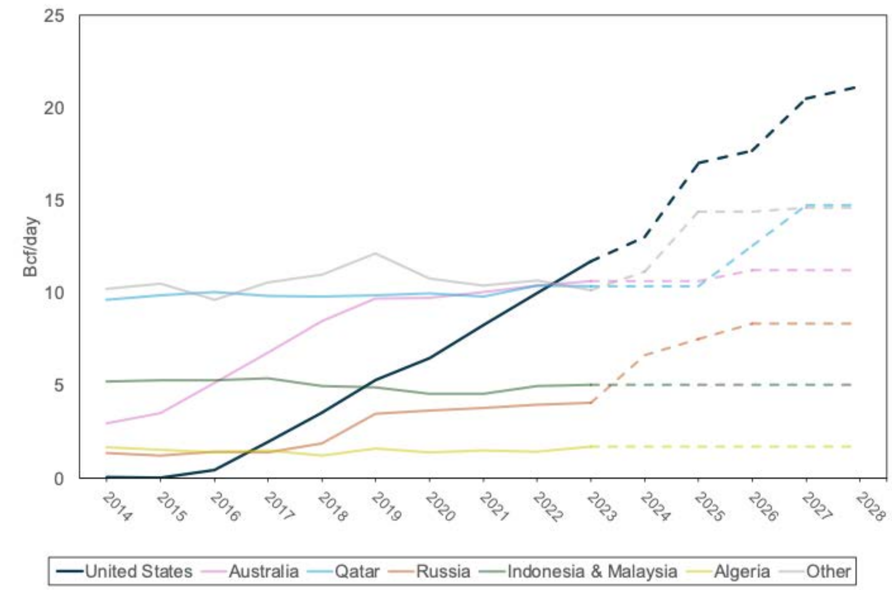
The post-2016 increase in natural gas exports is primarily due to the development of LNG export facilities. Construction of an LNG export facility requires the approval of the Federal Energy Regulatory Commission, which has jurisdiction over safety, siting, operation, and environmental considerations. Exports to a Free Trade Agreement county from an LNG facility are automatically approved. Under Section 3 of the Natural Gas Act, exports to a non-Free Trade Agreement country require an export license from the Department of Energy (DOE), which must issue the license unless it finds that the exports are not in the public interest.

Figure 3. U.S. natural gas gross import and export shares



[12] EIA, *Natural gas explained*. Date accessed: February 9, 2024.

Figure 4. LNG exports by country, 2014-2023 and projected expansion based on projects currently under construction.[13]



In response to LNG export applications, starting with the application of Cheniere Energy, Inc. in September 2010[14], the DOE undertook an analysis and concluded that LNG exports were in the public interest, and the DOE has subsequently approved multiple LNG export applications. Currently, the United States has LNG export capacity of 13.8 Bcf/d, and projects under construction with approved permits constitute an additional 11.2 Bcf/d.[15] As seen in Figure 4, in the first half of 2023, the United States exported 11.6 Bcf/d as LNG, the most of any nation, and projects under construction will make the United States the dominant LNG exporter, in addition to its pipeline exports which totaled 8.8 Bcf/d in the first half of 2023, mainly to Mexico. The export license pause announced on January 26, 2024 affects pending and future export license applications. The export capacity of facilities with pending applications totals 22.6 Bcf/d.[16]

2.2. Historical Regimes

The use of natural gas within the U.S. power sector has changed significantly over the past 25 years. In the early 2000s, natural gas and petroleum were largely used to fire steam boilers,

[13] Sources for natural gas export data are the International Energy Agency (2018-2022 exports) and Refinitiv (2023). Export projections (2024-2028) are based on estimated date of completion of LNG projects under construction (Sources: EIA and Global Energy Monitor).
[14] U.S. Office of Fossil Energy and Carbon Management, "The Department of Energy's Role in Liquified Natural Gas Export Applications", November 8, 2011.
[15] EIA, *Liquefaction Capacity File [Dataset]*. Date accessed: February 2, 2024.
[16] U.S. Office of Fossil Energy and Carbon Management, "Summary of LNG Export Applications of the Lower 48 States", December 13, 2023.

including co-firing steam boilers with residual fuel oil. As noted by Brown (2005), this margin of substitution between oil and gas in the power sector and industry created competition at the "burner tip" that caused U.S. natural gas prices to track oil prices during this period. In spring 2006, however, the use of petroleum for power generation began to decline as natural gas prices fell and gas was substituted for residual fuel oil. Generation by petroleum in 2006 was almost half that in 2005, falling further to less than 2% of generation by 2010.[17]

Although shale gas production by fracking started to grow in 2006, it started to surge in 2010 with the ramp-up of production from the Marcellus formation in Pennsylvania.[18] During the early 2010s, fracking production continued its strong increase, but exports were only by pipeline to Canada and Mexico; although LNG export applications had been approved, their long construction times meant that increased U.S. production would need to be consumed in North America. As a result, in the first half of the 2010s, domestic production supplanted Canadian imports and the import share of consumption fell (Figure 3).

This period in which natural gas production was necessarily consumed in North America ended with the substantial completion of Cheniere Energy's Sabine Pass Train 1 on May 27, 2016.[19] The initial LNG export facilities, including Sabine Pass Train 1, were financed by long-term offtake agreements priced at Henry Hub plus a liquefaction charge.[20] However, subsequent capacity has been financed using fewer long-term offtakes and more flexible contracts that permit the LNG exporter to sell at international prices.[21] Moreover, starting in 2022 there has been interest in offshore LNG export facilities that would sell into short-term markets; these so-called "fast gas" facilities have less capacity than onshore facilities but can be built in a much shorter time.[22] The trend towards more nimble international markets is complemented on the import side by floating storage and regasification units, which are shipborne regasification units that can be deployed globally to locations where import demand is increasing.[23,24]

Based on this historical narrative, we identify four institutional regimes: (Ia) the Burner Tip Parity regime, from the 1990s through the sharp drop in the use of oil for firing steam boiler generators in April 2006; (Ib) a Fracking Transition period from April 2006 through the start of fracking production in the Marcellus in January 2010, during which fracking production started to increase and residual fuel oil use in generation essentially ceased; (II) the "Shut-in" Fracking

[17] EIA, *Electricity Explained*. Date accessed: February 3, 2024.
[18] EIA, "Pennsylvania drives Northeast natural gas production growth", August 30, 2011.
[19] PR Newswire, "Cheniere and Bechtel Announce Substantial Completion of Train 1 at Sabine Pass", May 31, 2016.
[20] White & Case, "Trend Spotting in the fast-moving LNG market", October 5, 2021.
[21] International Group of Liquefied Natural Gas Importers, *Annual Report 2023*, 13 July, 2023.
[22] Reuters, "New Fortress Energy proposed to build first U.S. offshore LNG export facility", March 31, 2022.
[23] EIA, "Floating LNG regasification is used to meet rising natural gas demand in smaller markets", April 27, 2015
[24] Hydrocarbon Processing, "Europe's LNG import capacity set to expand by one-third by end of 2024", November 28, 2022.

regime from January 2010 (the start of Marcellus gas production) through the opening of Sabine Pass Train 1 in May 2016; and (III) the LNG Export period which continues to this day. The dates of these regimes are judgmental, the transitions are not sharp, and these national dates mask regional variation. Still, the regimes capture key changes in the uses and sources of U.S. natural gas, and we use them in our empirical analysis.

2.3. The Evolution of Coal in the U.S. Power Sector

In 2005, 50% of electricity was generated using coal. Coal generation started to decline in 2009, with the fall in demand in the financial crisis, then continued to decline as low natural gas prices drove out coal generation (e.g., Coglianese, Gerarden, and Stock (2020)). By 2020, coal's share of generation had fallen to 19%, largely supplanted by natural gas generation. Originally used primarily for base load generation, coal has increasingly been used to fill in seasonal and even daily fluctuations in demand (Graeter and Schwartz (2020), Holland et al. (2022)) and as such is competing directly with NGCC generators. As a result, in many parts of the country, on the margin coal generation has been competing directly with natural gas generation for dispatch. Coal production has fallen in all coal-producing regions. In 2022, 44% of production by weight was from the Powder River Basin and 27% was from Appalachia, although because Appalachian coal has a higher energy content than Powder River Basin coal and sells for a higher price, these shares are closer when measured in energy units and reverse when measured in value.

3. Price Data

***Prices*.** We use daily price data on Henry Hub natural gas prices and *WTI* oil prices from the U.S. Energy Information Administration (EIA), which provides both spot and 3-month futures prices. Coal prices are 3-month futures from S&P Global; spot coal prices are not available because there is no effective spot market in coal. For Henry Hub and *WTI*, the 3-month futures price closely tracks the spot prices for both Henry Hub and *WTI*, with the exception of rare spikes in the spot price associated with extreme conditions that induce supply, distribution, or storage disruptions (hurricanes, Texas freezes, the COVID shutdowns in March-April 2020, etc.). For the empirical analysis, we use the 3-month futures prices of Henry Hub and *WTI* both to eliminate these disruption-induced spikes (which introduce outliers unrelated to the long-run relations of interest) and to align with the 3-month futures coal prices. Henry Hub and *WTI* spot-futures spreads are shown in Appendix Figure A1.

Coal types, ranks, and energy content vary by their basin of extraction and also within that basin. A given coal-fired power plant has limited short-run scope for substituting one category of coal for another; for example, using higher-sulfur coal requires different environmental controls than low-sulfur coal, and sub-bituminous coal from the Powder River Basin requires different handling facilities than bituminous coal from Appalachia. The market structure differs substantially across basins, with the Powder River Basin dominated by a few very large mines and Appalachia having a large number of smaller mines. Figure A2 shows 3-month futures prices for Central Appalachia, Northern Appalachia, Illinois Basin, and Powder River Basin coal. All prices except the Powder River Basin coal price move together. For our analysis, we use the Central Appalachian price for medium-sulfur bituminous coal from southern West Virginia, eastern Kentucky, and northern Tennessee.

Because the analysis here focuses on low frequency relationships, we convert the daily data to weekly using the closing price on Friday or, if Friday is a holiday, the final trading day of the week.

As can be seen in Figure 5, international natural gas prices track oil prices. Historically, many international landed LNG contracts are indexed to oil or refined products (Han et al. (2021)), particularly in Asia (Chandra (2020)). The Japan Organization for Metals and Energy Security estimates that 72% of Japanese import contracts for 2022 delivery were indexed to oil, and that, as of 2023, 58% of contracts for delivery in 2030 were indexed to oil (JOGMEC 2023). The prevalence of oil indexation is changing, however, and JOGMEC reports that 25% of 2030-delivery contracts are indexed to Henry Hub. There are multiple international trading hubs. Appendix Figure A3 shows that, as the market has matured, prices have converged across European trading hubs. During the run-up to and the first 18 months of the Ukraine war, natural gas deliveries to Europe were constrained then severely disrupted, resulting in historically high prices due to LNG delivery capacity constraints (EU prices are truncated in Figure 5).

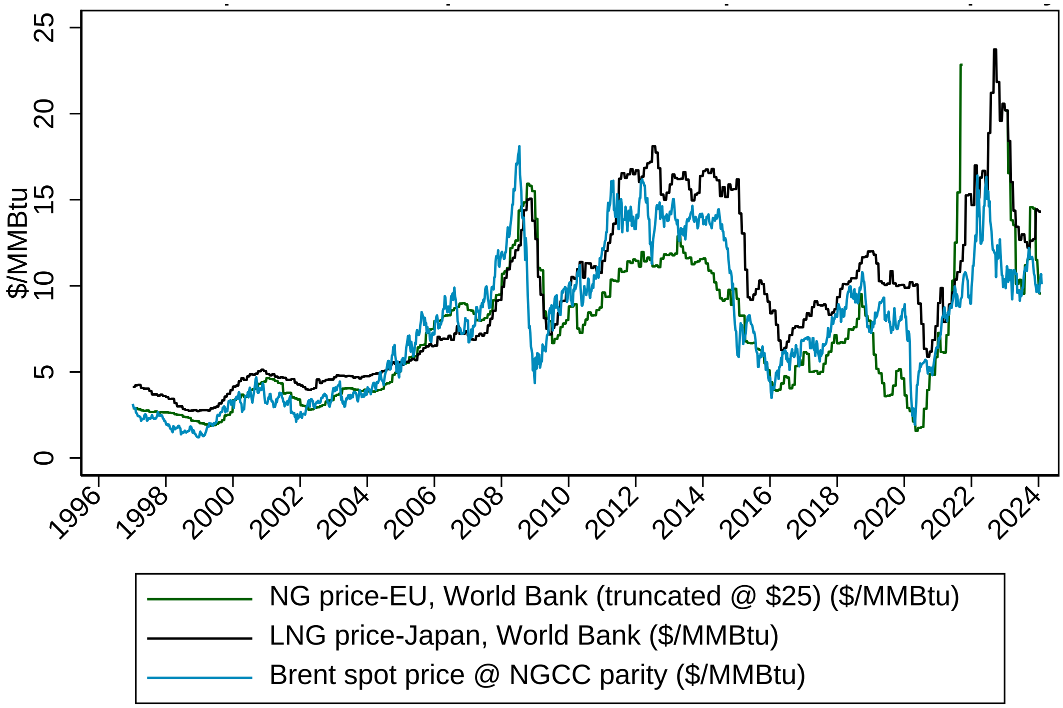
Parity conversion coefficients. We use two sets of parity coefficients to compare fuel prices. Energy parity converts fuels from their native price units (e.g., barrels) to dollars per million British thermal units using thermal content conversion factors from the Energy Information Administration.[25] Natural gas combined cycle parity adjusts oil and coal prices both for their energy content and for the relative thermal efficiency improvement in combusting natural gas in a modern combined cycle unit compared to firing a steam boiler, using average U.S. natural gas steam boiler and combined cycle heat rates for 2015 from the EIA.[26] In all cases natural gas prices (which are quoted in \$/MMBtu) are the numeraire. Using these EIA conversion factors, the energy parity coefficient on *WTI* is 0.172, and the NGCC parity coefficient on *WTI* is 0.127.[27]

[25] For WTI, 5800 MMBtu/bbl from U.S. EPA, Monthly Energy Review, Appendix A, British Thermal Unit Conversion Factors. For coal by rank, we use contract specifications, with 12,500 Btu/short ton for Central Appalachian bituminous.

[26] U.S. EIA, *Electric Power Annual* 2022, Table 8.2.

[27] Brown (2005) and Brown and Yücel (2008) modify the energy parity coefficients to reflect that residual fuel oil and distillate are used to fire steam boilers, and residual fuel oil and distillate trade respectively at a discount and a premium relative to *WTI*. Using historical refined product price data, Brown (2005) estimates a burner tip parity coefficient for residual fuel oil of 0.1511, and Brown and Yücel (2008) estimate burner tip parity coefficients of 0.1325 for residual fuel oil and of 0.2060 for distillate. Arguments can be made for each but given the ambiguity of

Figure 5. Composite gas spot price for Europe and Japan and Brent spot price at NGCC parity.



Liquefaction, transportation, and regasification (LTR) costs for LNG are proprietary. Molnar (2022) estimates liquefaction costs to be $2.40/MMBtu, regasification to be $0.40/MMBtu, and transport costs that depend on distance, with LTR totaling approximately $4.50/MMBtu for shipments to Europe and slightly higher for shipments to Asia, with wide ranges for each of the cost components. Fortis (2017) estimates sustainable U.S.-Europe price spreads of $4.50/MMBtu and U.S.-Asia price spreads of approximately $6.40/MMBtu, slightly higher than the older estimates in Songhurst (2014). Tsafos (2019) suggests that in 2019 liquefaction fees had dropped to around $2/MMBtu, but also shows a wide range of actual export-landed price spreads based on actual cargo data. We adopt an estimate of $4/MMBtu for LTR costs and refer to this as an analysts' central estimate, but we note considerable uncertainty around this figure. We convert this $4/MMBtu estimate circa 2019 to a nominal time series using the Producer Price Index for all manufacturing from the U.S. Bureau of Labor Statistics.

4. Empirical Results

This section quantifies the long-term relationships between the Henry Hub, *WTI*, and Central Appalachian Bituminous prices, and also summarizes results for Brent and European natural gas prices. The methods used are the standard for the analysis of long-run relationships in time series

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which to use, and the fact that these coefficients are estimated from historical price data, we simply use the energy parity coefficient of 0.172 for *WTI*.

data: unit root tests, cointegration tests and estimates, break tests, and rolling regressions. Over the full sample, unit root tests indicate that all these series have unit roots.

4.1. Henry Hub and *WTI*

Panel (a) of Table 1 summarizes cointegration statistics for the Henry Hub-*WTI* relation over the institutional break dates. The first three columns present tests of the null of non-cointegration, either with an unrestricted coefficient on *WTI* or a coefficient restricted to be energy or NGCC parity. The final two columns report estimated cointegrating coefficients, where for the final regime (III) two cointegrating estimates are reported: an unrestricted coefficient and a restricted coefficient in which the intercept in the cointegrating regression is constrained to equal the analysts' $4.00/MMBtu (2019$) estimate of the LTR cost.

Consistent with Brown and Yücel (2008), there is clear evidence of cointegration in regimes Ia (Burner tip parity). The estimated cointegrating coefficient in Regime Ia is 0.178, remarkably close to and within one standard error of the energy parity value of 0.172. This inference is confirmed by the rejection of a unit root in *HH* – 0.172**WTI* (first row, second column).

There is also clear evidence of cointegration in Regime III (LNG). Using the analysts' $4.00/MMBtu estimate of LTR costs, the estimated cointegrating coefficient is 0.122, and a 95% confidence interval around this estimate contains the NGCC parity value of 0.127.

Evidence of cointegration in Regime II (Shut-in fracking) is nonexistent. In Regime Ib (Transition), the evidence is mixed, with the unrestricted Engle-Granger test rejecting the non-cointegration null but the unit root tests on the theoretical parity residuals indicating a lack of cointegration with those coefficients. In addition, the estimated coefficient of 0.076 is small and does not align with any theoretical value.

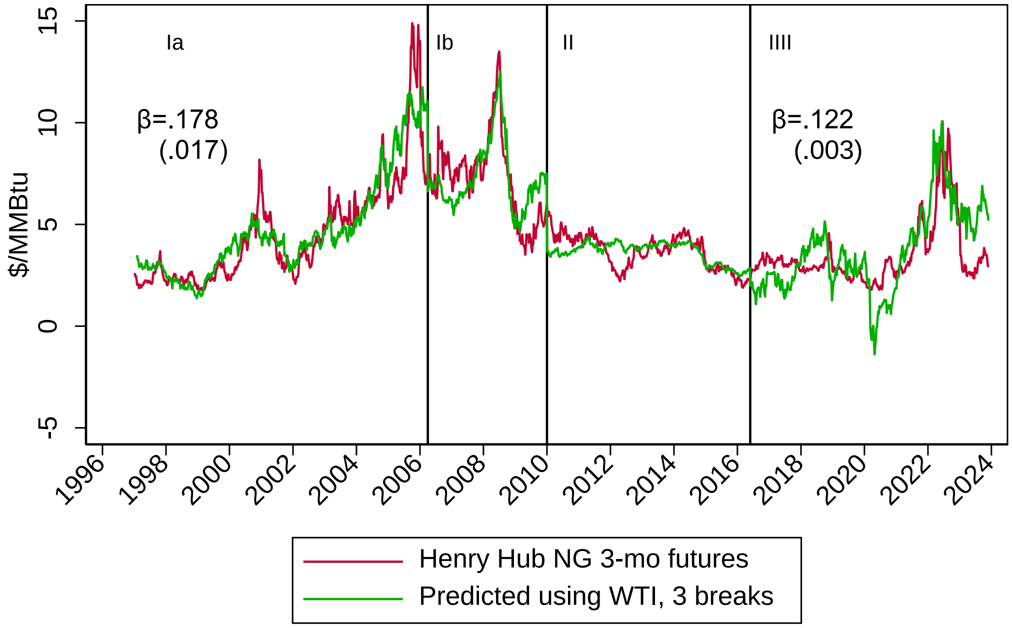
The predicted values from the dynamic ordinary least squares (DOLS) cointegrating regressions are shown in Figure 6, where the predicted values in regime III impose the $4.00/MMBtu intercept and the estimated cointegrating coefficients are shown for the two regimes for which there is the strongest evidence of cointegration (Ia and III). Evidently, the predictions fit well in regimes Ia and III, less well in regime Ib, and poorly in regime II (beyond estimating the mean of *HH* over that period).

Table 1. Cointegration tests and estimates: Henry Hub and *WTI*

Regime	Period	Cointegration tests: Unre-stricted	Imposing parity? Energy	Imposing parity? NGCC	$\hat{\beta}$ Intercept restricted? No	$\hat{\beta}$ Intercept restricted? Yes
(a) HH and WTI: Institutional break dates						
Ia	2/3/1997 - 4/1/2006	-3.94**	-3.82**	-3.90**	0.178 (0.017)	
Ib	4/1/2006 - 1/1/2010	-3.96**	-2.61	-3.02	0.076 (0.013)	
II	1/1/2010 - 5/27/2016	-3.10	-2.29	-2.48	N/A	
III	5/27/2016 - 11/27/2023	-3.52*	-3.42*	-3.72**	0.069 (0.013)	0.122 (0.003)
(b) HH and WTI: Estimated break dates						
Ia	2/3/1997 - 1/16/2006	-3.85**	-3.90**	-3.71**	0.190 (0.017)	
Ib	1/16/2006 - 1/5/2009	-3.94**	-2.07	-2.54	0.050 (0.008)	
II	1/5/2009 - 11/17/2014	-2.43	-2.28	-2.39	N/A	
III	11/17/2014 - 11/27/2023	-3.85**	-4.12***	-4.29***	0.068 (0.013)	0.122 (0.003)

Notes: The unrestricted cointegration test is the Engle-Granger Dicky Fuller test with 6 lags and MacKinnon critical values. The cointegration tests imposing a parity coefficient are Dickey-Fuller unit root tests of the null of a unit root, possibly with drift, against the alternative of a trend stationary series, for the series HH - beta0*WTI, where beta0 is the parity coefficient (0.172 for energy parity, 0.127 for NGCC). Cointegrating coefficients are estimated using the Stock-Watson DOLS estimator with 6 leads and lags and Newey-West HAC standard errors with 12 lags. For the "Restricted intercept" estimates, the intercept is constrained to be the $4.00 LTR cost (indexed nominal). For panel (b), the break dates are estimated by minimizing the sum of squared residuals in the unrestricted regression of HH on WTI over the three regime dates, subject to a minimum regime duration of 3 years to ensure sufficient within-regime oberservations . Tests reject the null of no cointegration, or of a unit root, at the *10%, **5%, and ***1% level.

Figure 6. Henry Hub price and three-break cointegrating predicted values using *WTI* price and cointegrating coefficients in Table 1(a) (regime III estimate imposes $4.00/MMBtu intercept)



In addition to the institutional break dates, we estimated the three break dates by the minimum sum of squares; those dates, along with the associated cointegrating coefficients, are reported in Panel (b). The estimated break dates differ somewhat from the institutional break dates, most notably with the fracking boom and LNG regimes both starting earlier. Taken at face value, the earlier start date of the current regime could be associated with the increase in exports to Mexico, and thus expanding demand, before the opening of the LNG terminals. Because the maintained hypothesis here does not align with the assumptions underlying break date inference theory (which conventionally assumes stationarity), we are not able to test for the number of breaks nor conduct inference on the break date. Despite these differences in dates, both the conclusions about cointegration and the estimated cointegrating coefficients within the three regimes are quite similar whether the breaks are institutional or estimated. Overall, we interpret the estimated break dates as consistent with the institutional dates.

Figure 7 shows rolling estimates and 95% confidence bands for the oil and gas cointegrating coefficient, estimated using DOLS with a 6-year window, along with the DOLS estimates and 95% bands estimated over the institutional regimes. Note that the lack of cointegration in regime II and arguably in regime Ib means that the estimand is not, in those regimes, a cointegrating coefficient. In regime Ia, the rolling estimates align with the coefficient equaling energy parity. In regime III, the coefficients align with NGCC parity if the $4.00/MMBtu LTR cost is imposed, and even if not, at the end of the sample the rolling estimates are close to the NGCC parity value.

Figure 7. Time-varying oil and gas cointegration estimates: Rolling regressions and institutional break regressions with estimated intercept (red) and imposing $4.00 LTR cost (blue)

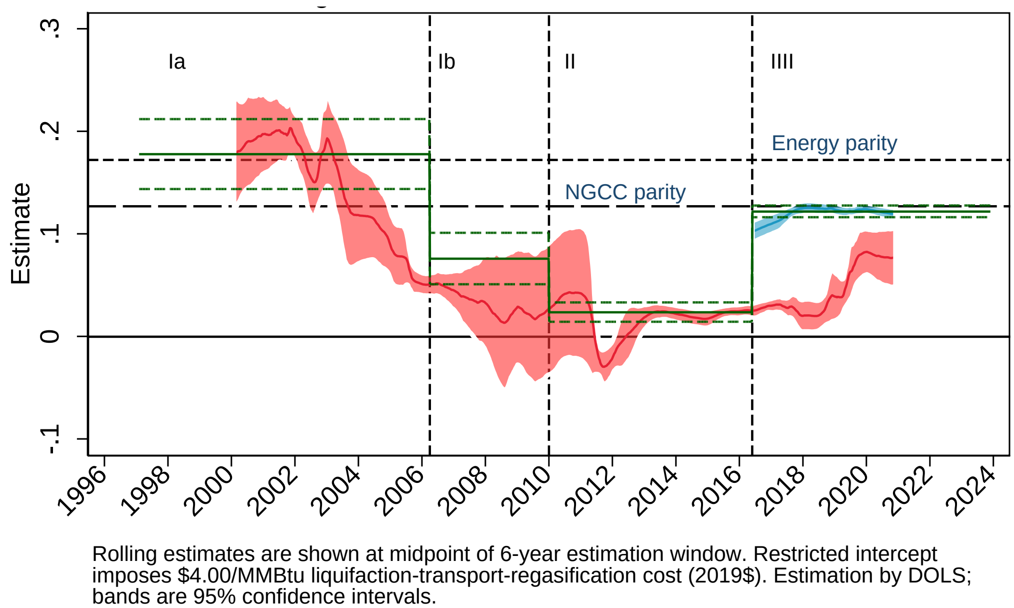
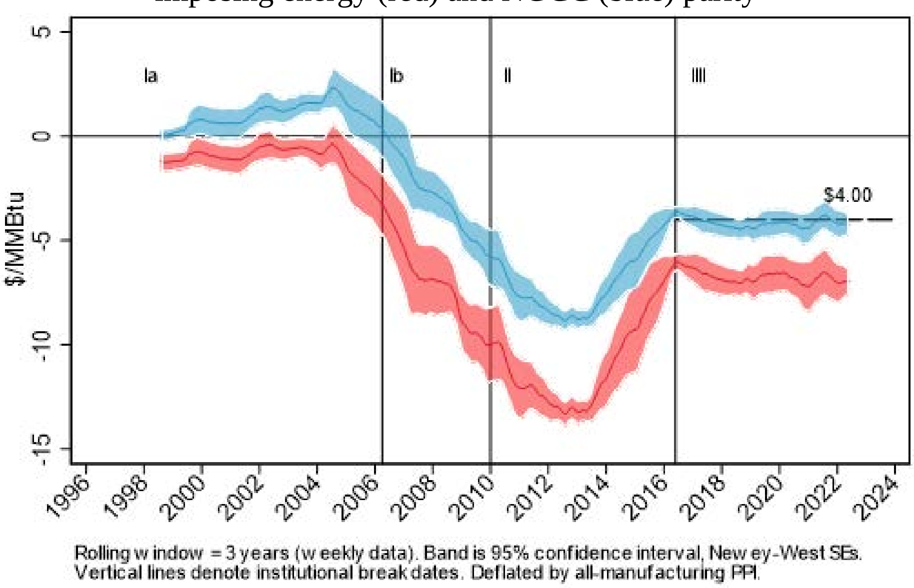


Figure 8. Time-varying estimate of real *HH-WTI* spread
imposing energy (red) and NGCC (blue) parity



As was discussed, there is considerable uncertainty surrounding the LTR cost. Under the hypothesis that LNG is being sold into markets indexed by oil at NGCC parity (regime III), it is possible to estimate the LTR cost as the mean of the spread, $HH - 0.127WTI$. Figure 8 shows rolling estimates of the mean of this spread and also the mean of the energy parity spread, *HH* – 0.172*WTI*. At the beginning of the sample, there is a modest spread relative to *WTI* at energy parity, consistent with modest additional costs of roughly $0.50/MMBtu for pipeline transport of natural gas to an average power sector customer (Brown (2005)). In Regime III, the spread between *HH* and *WTI* at NGCC parity is remarkably constant in real terms, averaging $4.22/MMBtu (standard error = $0.19/MMBtu), an estimate consistent with the industry analysts' estimate, which was computed using different methodologies and data (technoeconomic analysis, industry reports, cargo export pricing and landed values).

The analysis here focuses on three-month-ahead futures contracts for Henry Hub and WTI. The results are robust to considering spot, prompt month, or more distant futures contracts, see Appendix Table A1.

4.2. Henry Hub and Coal

Cointegration statistics for the *HH* – Central Appalachian bituminous coal price (*CAPP*) are reported in Table 2. Panel (a) provides results for the full sample and the institutional regimes (because the coal price series starts in the middle of regime Ib, regimes Ib and II are combined). As can be seen in Figure 1, movements in *CAPP* lag Henry Hub: over the full sample, the correlation between *HH* and *CAPP* is maximized at a lag of 15 weeks. One possible explanation for this lag is that, because mining and transportation of coal takes time, the long delays between executing a contract and delivery induce lags in contract prices; another might be the thin trading in near-term coal futures. In any event, if *HH* and *CAPP* are cointegrated with a lag, then ignoring the lag introduces stationary variation into the cointegrating residual, which could reduce the efficiency of the cointegration estimates and reduce the power of the tests. Panel (b) of Table 2, therefore, considers cointegration between HH_{t-15} and $CAPP_t$ over the full sample of institutional regimes. Panel (c) reports results when the break date is estimated.

The results in Table 2 provide strong evidence that *HH* and *CAPP* prices are cointegrated, at least over the second regime, using either the institutional or estimated break dates. The estimated break date is March 2010 and aligns with the onset of the shut-in fracking regime, not with the May 2016 institutional date of the onset of the LNG regime. The estimated cointegrating coefficients during the two institutional regimes are statistically significantly different at the 10% level using the contemporaneous specification (panel (a)) and at the 1% level using the lag specification (panel (b)). In all specifications, the estimated cointegrating coefficient in the final regime falls between the energy parity value of 0.04 and the NGCC parity value of 0.0305; the NGCC parity value, but not the energy parity value, falls within a 95% confidence interval for the panel (a) specification, the reverse is true for the panel (b) specification, and both parity values are rejected using the panel (c) specification.

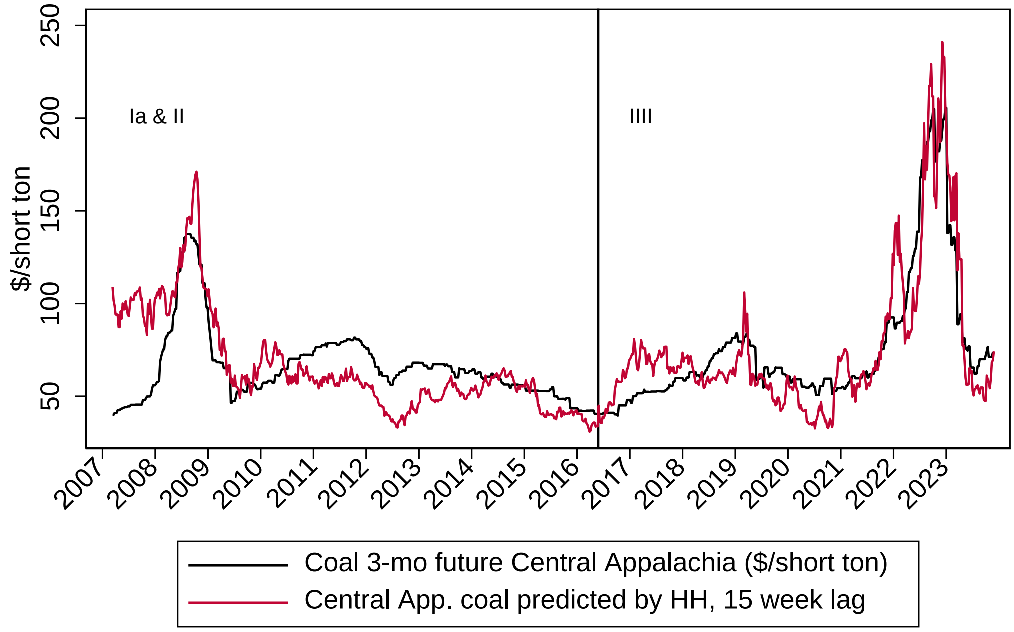
Table 2. Cointegration statistics: Henry Hub and Central Appalachian bituminous coal

Regime	Start date	Cointegration tests: Unre-stricted	Imposing parity? Energy	NGCC	Cointegrating coefficient
(a) Institutional break dates					
Full	3/12/2007 - 11/27/2023	-3.65*	-3.64**	-3.50**	0.0341 (0.0071)
Ib + II	3/12/2007 - 5/27/2016	-2.54	-2.54	-2.54	0.0591 (0.0150)
III	5/27/2016 - 11/27/2023	-3.15	-3.16*	-3.16*	0.0329 (0.0019)
(b) Institutional break dates, 15 week lag of HH					
Full	3/12/2007 - 11/27/2023	-4.29**	-3.84**	-3.56**	0.0424 (0.0086)
Ib + II	3/12/2007 - 5/27/2016	-2.65	-2.49	-2.48	0.0819 (0.0144)
III	5/27/2016 - 11/27/2023	-4.77***	-4.79***	-4.30***	0.0380 (0.0020)
(c) Single estimated break date, 15 week lag of HH					
Ib + II	3/12/2007 - 3/1/2010	-2.83	-2.49	-2.25	0.0649 (0.0142)
III	3/1/2010 - 11/27/2023	-5.27***	-5.52***	-5.10***	0.0355 (0.0017)

Notes: Cointegrating regressions are HH - beta0*Coal, where the energy parity value of beta0 is 0.04 and the NGCC value of beta0 is 0.0305. Cointegration regressions have an unrestricted intercept. See the notes to Table 1. Tests reject the null of no cointegration, or of a unit root, at the *10%, **5%, and ***1% level.

Figure 9 plots the predicted values of *CAPP* based on the cointegrating regressions in panel (b) of Table 2, which use HH_{t-15} to predict *CAPP*. The fit is most pronounced during the Ukraine period, however, the low-frequency movements in coal and natural gas also track during prior fluctuations.

Figure 9. Central Appalachian coal price and single-break predicted values using Henry Hub price and cointegrating regressions in Table 2(b)



One possible explanation for the cointegrating coefficient falling between the energy and NGCC parity values is that the marginal coal and gas units in the Southeast that would equate marginal costs in gas-Central Appalachian dispatch have thermal efficiencies that differ from the national averages.

4.3. European Gas and Oil Prices

As discussed in Section 3, international gas prices are linked to oil prices, including by LNG contracts being indexed to oil prices. This linkage is evident in Figure 5, which plots a monthly index of European gas prices. In Table 3, we quantify this relationship using weekly data on prompt month futures prices at the two main European hubs, the National Balancing Point (NPB) in the UK and the TTF in the Netherlands. The regressions cover the period from November 2014 (when the TTF data started) through June 2021, prior to the disruptions preceding the Ukraine war. The tests based on the restricted cointegrating coefficients all strongly point to cointegration, although the unrestricted test does not, perhaps unsurprisingly given the short sample. For both trading hubs, the estimated cointegrating coefficients are within one standard error of the NGCC parity value. These results provide statistical evidence supporting the discussion in Section 3 of international LNG prices being indexed to oil prices, in turn justifying the use of oil prices as a benchmark against which to assess U.S. prices.

Table 3. Cointegration tests and estimates: Brent and European price indexes

Hub	Sample	Cointegration tests: Unre-stricted	Imposing parity? Energy	NGCC	Cointegrating coefficient
TTF	11/10/2014 - 6/1/2021	-3.36	-4.06***	-3.83**	0.113 (0.0181)
NBP	11/10/2014 - 6/1/2021	-3.28	-4.48***	-4.09***	0.110 (0.0203)

Notes: TTF is the Netherlands trading hub, NBP is the UK virtual National Balancing Point. Cointegrating regressions are gas - beta0*Brent, where the energy parity value of beta0 is 0.172 and the NGCC value is 0.127. Cointegration regressions have an unrestricted intercept. Sample ends with the runnup to the Ukraine war. See the notes to Table 1. Tests reject the null of no cointegration, or of a unit root, at the *10%, **5%, and ***1% level.

5. Implications for U.S. Fuel Prices

We now provide two estimates of the effect of LNG exports, specifically of HH-WTI recoupling at NGCC parity, on Henry Hub prices. Our primary, prospective estimate compares out-of-sample forecasts of fuel prices with recoupling to forecasts computed under the counterfactual of no recoupling; the difference between the two is the estimate of the effect, by forecast horizon, of LNG exports on prices. The second estimate is retrospective and flips the factual and counterfactual and asks what prices would have been during institutional regime II (shut-in fracking), had there counterfactually been LNG exports and recoupling at NGCC parity.

5.1. Prospective estimate

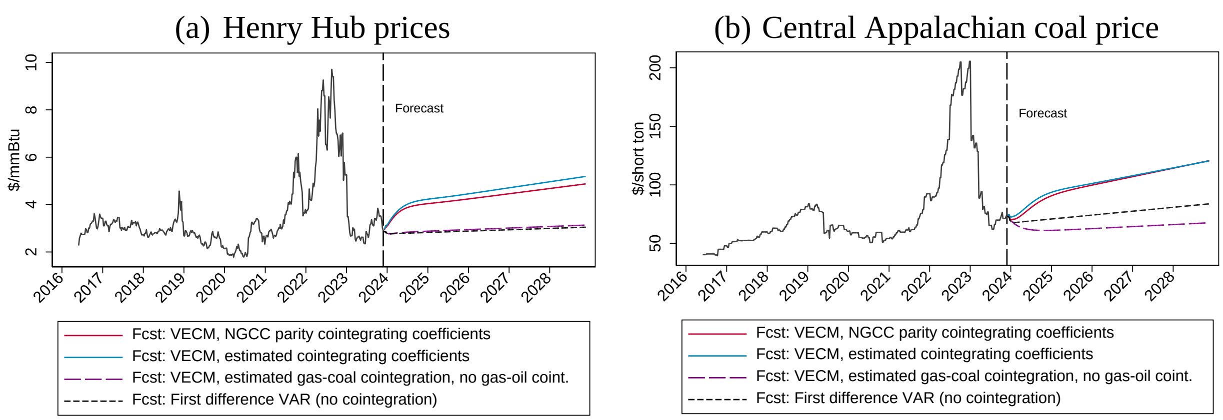
The first estimate compares time series price forecasts with gas-oil coupling to forecasts made assuming decoupling. Specifically, we produce two sets of forecasts of fuel prices using a three-variable system comprised of (HH_t, WTI_t, $CAPP_t$). In the first, we impose cointegration between *HH* and *WTI* and between *HH* and *CAPP* by estimating the triangular cointegrated system, (ΔWTI_t, $HH - \hat{\beta}_{WTI}\, WTI_t$, $HH_t - \hat{\beta}_{CAPP}\, CAPP_t$), where $\hat{\beta}_{WTI}$ is the regime-III estimated cointegrating coefficient from Table 1 panel (a) with the \$4.00/MMBtu LTR cost imposed and $\hat{\beta}_{CAPP}$ is the cointegrating coefficient from Table 2 panel (b), in both cases for institutional regime III. Under the counterfactual of no reconnection, *HH* and *WTI* would not be cointegrated, so there would be only one cointegrating vector, so the triangular system is (ΔWTI_t, ΔHH, $HH_t - \hat{\beta}_{CAPP}\, CAPP_t$). As two additional comparisons, we also estimate a triangular system with two cointegrating vectors, in which the estimated cointegrating coefficients on *WTI* and *CAPP* are replaced by their theoretical NGCC parity values, and we estimate a vector autoregression

(ΔWTI_t, ΔHH, $\Delta CAPP_t$), in which there is no cointegration. The coefficients of these triangular cointegrating systems were estimated over regime III.

The resulting four forecasts of natural gas and coal prices through 2030 are shown in Figure 10. There is little difference between the two forecasts that impose recoupling (using estimated or NGCC parity cointegrating coefficients). Neither is there much difference between the forecasts that do not impose recoupling (either imposing gas-coal cointegration or not). Imposing recoupling, however, has a large effect: after 48 months, *HH* prices are \$1.60/MMBtu, or 54%, higher under the recoupling scenario than under the shut-in scenario (both with gas-coal cointegration, estimated coefficient), and *CAPP* prices are \$40/short ton, or 64%, higher under recoupling than not. These estimates depend on fuel price spreads on Nov. 27, 2023 (our final observation), since they are computed as forecasts as of that date; using a different date or using updated data would yield a different estimate of the price effect of LNG prices.

The mechanism leading to higher prices under recoupling is that gas prices rise from their currently low values to their fundamental value which is determined by the *HH* – *WTI* spread. The dynamic adjustment is not immediate, with *HH* prices rising to their fundamental value over the course of 6 months. For coal prices, adjustment takes more than a year, consistent with the 15-week lag between *HH* and *CAPP* discussed in Section 4.2.

Figure 10. Forecasts of (a) natural gas and coal prices
with (solid) and without (dashed) gas-oil recoupling



As a point of comparison, a natural gas price increase of \$1.60/MMBtu approximately corresponds to a \$30/MT carbon tax, and a bituminous coal price increase of \$40/short ton approximately corresponds to a \$20/MT carbon tax. As another comparison, a wholesale natural gas price increase of $1.60/MMBtu corresponds to roughly a 10% increase in national average residential prices for natural gas.[28]

5.2. Retrospective Estimate: Early LNG Exports

The second estimate of the effect of LNG exports on the Henry Hub price is the mean difference between the observed HH price in regime II and the counterfactual estimate of what HH prices would have been, had prices recoupled with WTI in 2010 at NGCC parity. Specifically, the estimator is the mean over institutional regime II of $HH_t - 0.127WTI_i - \widehat{LTR}_t$, where 0.127 is the NGCC parity coefficient and $\widehat{LTR}_t$ is the estimated LTR cost computed as the mean of inflation-adjusted $HH_t - 0.127WTI_t$ over regime III.[29] The resulting estimate of the effect of LNG exports on Henry Hub prices is $2.31/MMBtu, with a 95% confidence interval of ($1.32/MMBtu, $3.29/MMBtu) (nominal dollars).

For coal, the cointegrating coefficients in Table 2 fall between the energy and NGCC parity values. If energy parity is used, then during regime II but with, counterfactually, HH-WTI recoupling, Central Appalachian coal prices would have been higher by an estimated $58/short ton, with a 95% confidence interval of ($33/short ton, $82/short ton). If NGCC parity is used, this estimate is $76/short ton, with a 95% confidence interval of ($43/short ton, $108/short ton).

The prospective and retrospective counterfactuals answer different questions: how much lower prices would be going forward, without recoupling, versus how much higher prices would have been during regime II, had HH and WTI been coupled. Despite this conceptual difference, it is interesting to note that the 95% confidence interval for the estimated effect of recoupling on Henry Hub prices for the retrospective counterfactual ($1.32/MMBtu, $3.29/MMBtu) contains the prospective counterfactual estimates at the 48-month forecast horizon, $1.60/MMBtu.

6. Implications for U.S. Power Sector Emissions, Prices, Generation, and Capacity

In the previous section, we identified the effect of recoupling induced by LNG exporting on domestic natural gas and coal prices. In principle, the upward pressure on domestic prices would result in substitution away from those fossil fuels, including for electricity generation. At the daily or weekly frequency, natural gas and coal prices are key drivers of competition among

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[28] In 2022, the national average U.S. residential natural gas price was $14.75/cubic foot or $14.20/MMbtu (U.S. EIA)

[29] Equivalently, the mean over regime II of $HH_t - 0.127WTI_t - \widehat{LTR}_t$ is the difference in the means of $HH_t - 0.127WTI_t$ over regime II minus III. Because the regimes to not overlap, the variance of the difference in means is approximately the sum of the variances of the two sample means over the different regimes. To compute standard errors, because of serial correlation the variances were estimated using the Barlett kernel with 12 lags.

fossil-fired and non-fossil-fired electricity generation units (EGUs). Over longer horizons, natural gas and coal prices affect EGU capacity investment and retirement decisions.

To simulate the short- and medium-run effects of recoupling on the power sector, we use the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) capacity expansion model (Ho et al., 2021).[30] ReEDS is a quantitative equilibrium model that projects the evolution of the utility-scale power sector for the contiguous United States using a system-wide, least-cost approach, subject to policy and operational constraints.[31] Essentially, the ReEDS model solves the social planner's problem of minimizing the aggregate system cost of maintaining and dispatching an endogenous set of EGUs to serve exogenous, inelastic demand in every region of the contiguous United States during each modeled period.

Our simulations are based on the Mid-case scenario from the 2023 Standard Scenarios Report, which scenario uses central or median values for core inputs such as technology costs, uses the AEO2023 Reference Case coal, natural gas, and uranium prices, assumes end-use electricity demand growth averaging 1.8% per year, and includes both state and federal (but not local) electricity sector policies as they existed in September 2023 (Gagnon et al., 2023). Following common practice for ReEDS (e.g., Gagnon et al., 2023), we solve the model using myopic expectations, in which current-period prices and policies are assumed to extend into the future. Our simulations are for the period 2023-2030, with the model solved in one-year steps.

We identify the effects of recoupling on the electric power sector by simulating the Mid-case scenario with adjusted coal and natural gas fuel prices based on our four alternative forecasts shown in Figure 10. The ReEDS model takes annual fuel prices for each U.S. Census Division as exogenous inputs, which inputs the Mid-case scenario draws from the AEO2023 Reference Case.[32] To incorporate information from our fuel price forecasts, we subtract the difference between our forecast annual average (i.e., across weeks within a year) fuel price and the AEO2023 Reference Case national annual average (i.e., across Census Divisions within a year) fuel price. Our approach preserves the signal from our forecast via the variation in mean annual fuel prices while also incorporating persistent, idiosyncratic differences in fuel prices across Census Divisions that are unlikely the result of changes in LNG exporting. As additional points of comparison, we also simulate scenarios using the unadjusted AEO2023 Reference Case fuel

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[30] We use the version of the ReEDS model from NREL's 2023 Standard Scenarios Report (Gagnon et al., 2023). The ReEDS model documentation is available on NREL's website at https://www.nrel.gov/docs/fy21osti/78195.pdf. For a list of publications using the ReEDS model, visit https://www.nrel.gov/analysis/reeds/publications.html.

[31] Although the ReEDS modeling framework is sophisticated, it does not capture every potentially relevant factor. It has a simplified representation of transmission networks and does not model strategic interactions between specific market and non-market actors or rules. Our results should be interpreted within the context of these modeling choices. A more complete list of model-specific caveats is available in the models' documentation (Ho et al. 2021).

[32] Within the ReEDS modeling framework natural gas prices can be exogenous inputs or endogenous variables. Coal prices, however, can only be exogenous. All our model runs specify natural gas and coal prices as exogenous inputs.

prices and using the adjusted fuel prices based on our VAR forecast including a $30/MT carbon tax.

Table 4 presents results from our ReEDS model runs in 2030, the last year of our simulations. The outcomes include CO_2 emissions from electricity generation in million metric tons (MMT), average bulk system electricity prices in dollars per megawatt-hour ($/MWh), average retail electricity prices in cents per kilowatt-hour (¢/kWh), total annual electricity generation in terawatt-hours (TWh), and electricity generation capacity in gigawatts (GW). Column (1) reports results for the ReEDS model run using coal and natural gas prices based on the NGCC parity cointegrating coefficients forecast. Column (2) reports results for the scenario using prices based on the full set of estimated cointegrating coefficients forecast. Column (3) reports results for the estimated gas-coal cointegrating coefficient without gas-oil cointegration forecast scenario. Column (4) reports results for the model run using fuel prices based on the VAR. Column (5) reports results for the scenario using AEO2023 reference prices. Finally, Column (6) reports results for the model run using fuel prices based on the VAR including a $30/MT carbon tax.

The differences in outcomes across our ReEDS model runs mirror the differences in our fuel price forecasts. Emissions, prices, generation, and capacity are quite similar in Columns (1) and (2), as are the outcomes in Columns (3) and (4). Comparing Columns (2) and (3), provides an estimate of the impact of recoupling relative to gas-coal cointegration. Under recoupling, emissions are lower by 145 million metric tons, or 33%, mainly due to substitution from gas-fired generation to non-fossil generation driven by increased investment in non-fossil generation capacity. Average bulk system electricity prices are 9.4% higher and average retail electricity rates are 3.8% higher under recoupling.

It is potentially illuminating to contrast the results from model runs using our fuel price forecasts with the run using AEO2023 reference case fuel prices, Column (5). The results in Column (5) are most similar to the results based on our no-recoupling forecasts. Relative to Column (3), emissions in Column (5) are 11% higher, and coal-fired generation is 94% higher, mainly because AEO2023's coal price forecast ($53.30/short ton) is significantly lower than our coal-gas cointegration coal price forecast ($74.90/short ton).[33]

We can also compare the results of recoupling to the impacts of a $30/MT carbon tax policy. Indeed, the results in Column (6), the ReEDS model run using VAR-based fuel prices, including a $30/MT carbon tax, are quite similar to the recoupling results in Column (2). However, emissions are 12% lower, and coal-fired generation is 36% lower, because the effective coal price is relatively higher under the VAR-based $30/MT carbon tax scenario. Thus, recoupling is comparable to imposing a $30/MT carbon tax on gas and a $20/MT carbon tax on coal.

[33] The natural gas price forecasts are more similar at $3.01/MMbtu and $3.42/MMbtu, respectively.

Table 4: Power Sector Emissions, Prices, Generation, and Capacity Under Alternative Forecasts

Year 2030	(1)	(2)	(3)	(4)	(5)	(6)
Annual CO2 Emissions (MMT)	296.06	286.64	431.82	428.01	479.27	252.67
Average Bulk System Electricity Price ($/MWh)	48.08	48.37	44.21	43.78	44.45	48.13
Average Retail Electricity Rate(¢/kWh)	13.49	13.52	13.03	12.99	13.00	13.60
Annual Electricity Generation (TWh)						
Coal	65.04	65.10	74.60	64.40	144.38	41.48
Gas	553.64	528.79	894.35	896.85	838.57	547.85
Other	4151.76	4177.82	3792.60	3798.96	3778.56	4183.09
Generation Capacity (GW)						
Coal	123.41	123.52	141.36	122.46	142.56	78.91
Gas	382.92	380.30	386.77	411.06	384.71	414.03
Other	1442.18	1455.18	1274.48	1266.90	1270.66	1473.32

Source: Authors' calculations using the ReEDS model. Scenarios (1) – (6) are defined in the text.

We note that the price projections in the previous section and the emissions in Table 4 posit a specific price path for WTI. WTI prices that are higher (or lower) would result in emissions reductions that are greater (or less) than those projected here.

7. Discussion

The central hypothesis of this paper – that U.S. gas prices have recoupled to world energy prices, in particular to oil prices – is likely to be controversial. From an historical perspective, this recoupling should not be surprising, however, because there are multiple margins on which fossil fuels compete; indeed, the period of shut-in fracking, which we date from 2010 to 2016, was the historical exception in which domestic gas prices disconnected from global fuels markets.

We have made the statistical case for this recoupling. That empirical evidence is bolstered by market evidence of the internationalization of pricing, for example the increasing ability of Japanese LNG importers to sign contracts either indexed to oil or to Henry Hub, and the fact that recently U.S. upstream gas producers have been signing contracts for U.S. production indexed to

Brent or to Asian gas prices.[34] We recognize, however, that there are counterarguments. Once built, LNG export terminals operate near capacity, effectively making the marginal gas consumer (and thus price-setter) domestic consumption. Still, there is short-run flexibility in adjusting capacity utilization rates to market conditions, there is medium-term flexibility in capacity through the new technology of offshore liquefaction facilities (so-called fast LNG plants), and long-term contracts take into account projected industry expansion plans. Ultimately, the question of recoupling seems to us to be an empirical one.

The recoupling hypothesis, if correct, has major ramifications. As our two estimates of the price impacts of this recoupling indicate, the recoupling has resulted in gas prices that are substantially higher than they would have been without LNG exports – we estimate, prospectively, an LNG-induced increase of approximately $1.60/MMBtu. The mechanism behind this price increase – recoupling to global markets – is different than the mechanism behind the market studies used in prior assessments of the economic impact of LNG exports, which focused on domestic supply and demand considerations with domestic prices set in autarchy. Because gas and coal prices are connected through widespread competition in the U.S. power sector, this price increase translates to coal as well, and in effect operates akin to a modest carbon tax on gas and coal of roughly $20-$30/MT of CO_2. We estimate that this increase in domestic prices has expedited the decline in the use of gas and coal historically and, prospectively, is associated with further emissions reductions in the power sector of 145 million metric tons of CO_2 in 2030, compared to the no-recoupling counterfactual. This is arguably an underestimate because it only considers the power sector and omits reductions in residential and commercial gas use.

One theme of this paper has been the ever-evolving nature of natural gas markets and pricing. Even if our recoupling hypothesis is correct, that recoupling need not be permanent, and one can imagine a situation in which eventually U.S. LNG export capacity freezes, fracking technology continues to advance, and the shut-in gas period of regime II is effectively reestablished, resulting in lower gas and coal prices domestically – in effect lifting the effective "LNG carbon tax" on domestic consumers of gas and coal and increasing foreign natural gas prices. Whether that situation arises depends on future technological innovation and future policy decisions concerning LNG permitting.

A complete analysis of the market and climate implications of LNG exports – that is, the full study called for as part of the January 2024 LNG export pause – would address additional considerations beyond domestic prices and CO_2 emissions. Those considerations include impacts on international prices, effects of increased gas supply on international generation choices, and long-run market and emissions impacts given the long-lived nature of LNG export facilities. A full analysis of climate impacts would also consider the life-cycle emissions associated with LNG exports, including methane emissions leaks through the LNG supply chain and ongoing

[34] See for example the EOG 2023 Fourth Quarter earnings report, p. 8.

regulatory changes that will affect evolving technology and upstream emissions.[35] Beyond market and climate impacts, a full review of the consequences of LNG exports would also include local environmental effects of LNG export facilities, their impacts on local communities, and geopolitical considerations.

[35] For example, the Inflation Reduction Act includes a tax on upstream methane emissions and the U.S. EPA has issued a proposed rule regulating methane emissions from the oil and gas sector. Although liquefaction has historically been powered by gas, some new facilities are being electrified. In addition, transport vessels can be built to use “boil-off” gas as a fuel rather than release it to the atmosphere. See Roman-White et al. (2019) and Howarth (2024).

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Appendix Tables and Figures

Table A1. Cointegration tests and estimates for Henry Hub and *WTI*: Spot and various futures contract horizons

Regime:	I			Ia			II			III		
Futures horizon (months)	Cointegration tests: Unre-stricted	Cointegration tests: Energy parity	$\hat{\beta}$	Cointegration tests: Unre-stricted	Cointegration tests: Energy parity	$\hat{\beta}$	Cointegration tests: Unre-stricted	Cointegration tests: Energy parity	$\hat{\beta}$	Cointegration tests: Unre-stricted	Cointegration tests: NGCC parity	$\hat{\beta}$
Spot	-4.33**	-4.32***	0.166	-2.97	-2.40	0.075	-3.27	-2.44	0.025	-4.22**	-4.57***	0.118
			(0.015)			(0.013)			(0.005)			(0.003)
1	-4.39***	-4.37***	0.173	-3.13	-2.43	0.075	-3.24	-2.38	0.024	-3.67*	-4.33***	0.119
			(0.016)			(0.012)			(0.005)			(0.003)
2	-4.39***	-4.32***	0.177	-3.58*	-2.60	0.077	-3.20	-2.33	0.024	-3.59*	-3.94**	0.120
			(0.017)			(0.012)			(0.005)			(0.003)
3	-3.92**	-3.80**	0.178	-4.01**	-2.62	0.076	-3.10	-2.30	0.024	-3.51	-3.74**	0.122
			(0.017)			(0.013)			(0.005)			(0.003)
6	-3.67*	-2.68	0.159	-4.31**	-2.46	0.071	-3.39	-2.29	0.025	-3.39	-3.47**	0.123
			(0.010)			(0.013)			(0.005)			(0.003)
9	-4.67***	-4.08***	0.157	-3.72*	-2.62	0.062	-3.10	-2.11	0.026	-3.92**	-3.32*	0.123
			(0.006)			(0.014)			(0.005)			(0.002)
12	-4.15**	-3.89**	0.165	-3.21	-2.87	0.046	-3.67*	-2.29	0.027	-3.20	-3.15*	0.123
			(0.009)			(0.011)			(0.004)			(0.002)
15	-5.32***	-3.94**	0.165	-4.41**	-2.54	0.043	-2.93	-2.20	0.030	-4.21**	-3.35*	0.124
			(0.011)			(0.011)			(0.004)			(0.002)
18	-3.94**	-1.39	0.144	-3.70*	-2.20	0.042	-3.11	-2.00	0.033	-3.93**	-3.17*	0.125

Notes: Estimated coingegrating coefficients have unrestricted intercepts in regimes Ia, Ib, and II, and restrict the intercept to equal the nominal LTR cost in regime III. Unit root and cointegration tests reject the null at the *10%, **5%, ***1% level. See the notes to Table 1.

Figure A1. Spot-futures spreads for Henry Hub (upper) and *WTI* (lower)

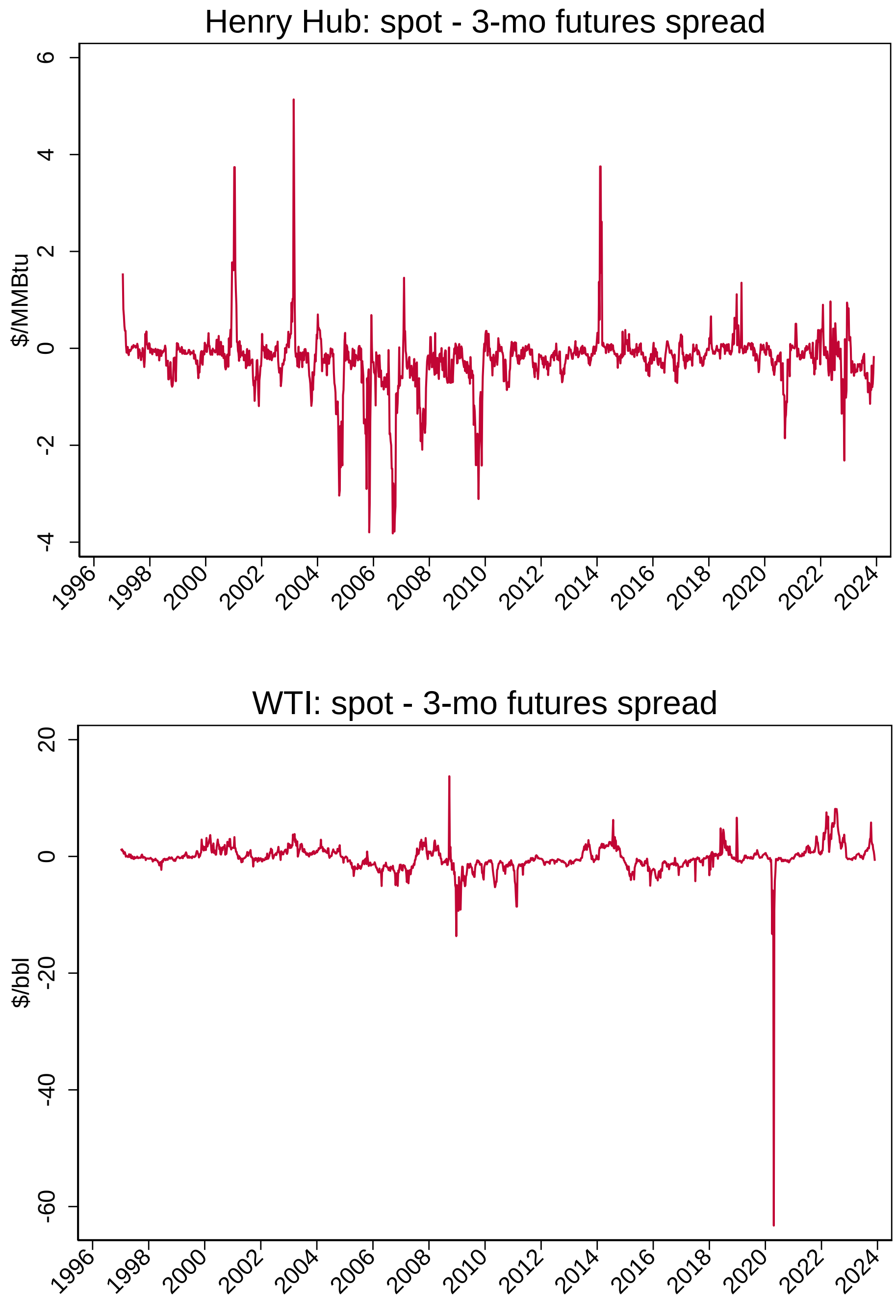

Figure A2. 3-month futures coal prices for four U.S. basins at energy parity

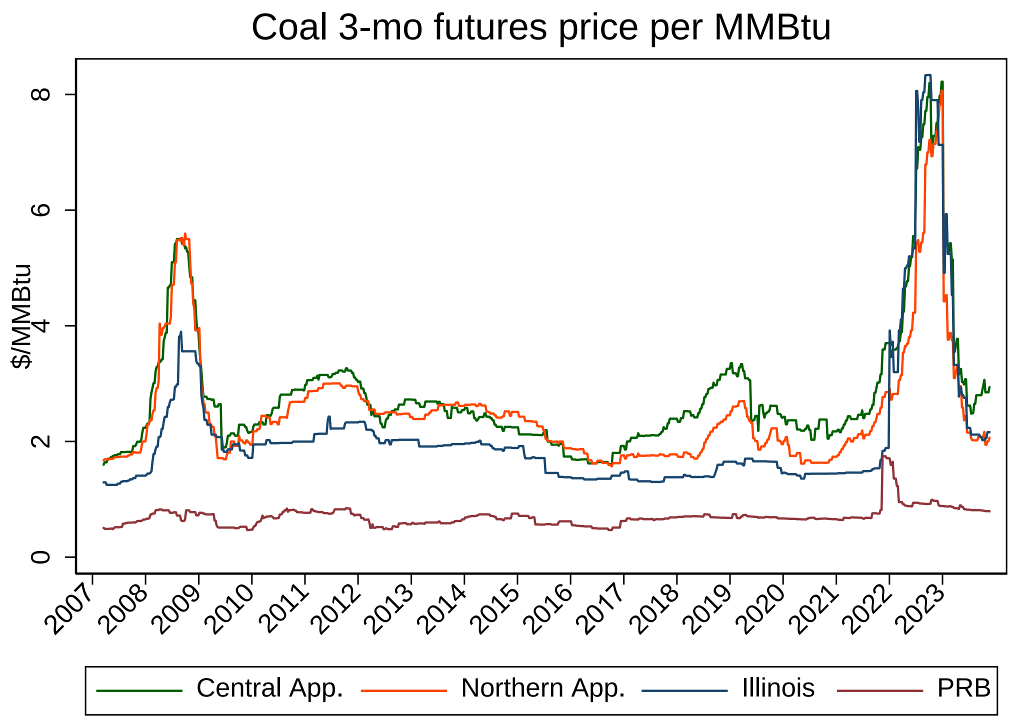

Figure A3. Spot gas prices at various European hubs:
Full sample (upper) and 2010-2021 (pre-Ukraine) (lower)