A note on natural gas price transmission from TTF to other European hubs.*

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Abstract

Several recent studies pointed out to strong links among the most liquid core European natural gas markets. However, the evidence on the integration of less liquid, peripheral and core European markets is scarce. We address this topic by investigating the dynamics of daily natural gas prices quoted at six European hubs located in Germany, Poland, Czechia, Austria, Italy and Spain. We explore to what extend prices in these hubs are driven by price changes in the most liquid, benchmark European hub (TTF, Netherlands), other energy commodity prices (oil and coal) and local natural gas market fundamentals (whether conditions and gas inventories). We find that natural gas markets are driven by predominantly by changes in the benchmark hub as well as deviations from the law of one price. We also show that other energy commodity prices as well as idiosyncratic factors are important in the least squares regression, but not in a more elaborated GARCH model. These results adds to the discussion on the integration of European natural gas markets.

Keywords: European natural gas market, natural gas market integration, GARCH model.

JEL classification: C32, Q02, Q31.

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1 Introduction

Natural gas plays an important role in the European energy mix (26.7% in 2021, see IEA, 2023). It is used in residential and commercial heating, and serves as an important input for industrial production and electricity generation. In the latter case, natural gas has two advantages. It is less carbon-intensive energy source than coal, and gas-fired power plants are highly dispatachable, hence they complement well unstable renewables from wind and solar. For the above reason, natural gas is often considered to be a bridge fuel in energy transition. It is therefore not surprising that the unprecedented increases in natural gas prices observed in Europe in years 2021-2023 constituted a significant disturbance to the functioning of the European economy. This energy crisis was reflected in the substantial inflationary pressure and subdued growth, but also raised concerns with respect to energy security and the costs of the decarbonization policy. The crisis also reshaped the structure of the European natural gas markets, where gas supplies from Russia were substituted by higher imports from Norway and Algeria as well as by LNG supplies from Qatar and the US (Emiliozzi et al., 2023).

While discussing the dynamics of natural gas prices in European hubs, it is informative to see a broader picture about the functioning of the global natural gas market. It is geographically segmented into several local markets, which might be explained by transportation costs and heterogeneous institutions (see Kan et al., 2019, for a detailed overview of the global natural gas market structure). This means that natural gas prices evolve fairly independently in different parts of the world, which was especially visible after the shale gas revolution in the US (e.g., Zhang and Ji, 2018; Szafranek and Rubaszek, 2023). It can be added that the development of the LNG market over the last decades has reinforced the linkages between distant gas markets (Mu and Ye, 2018; Emiliozzi et al., 2023). As regards local natural gas markets, they tend to be highly integrated, which is also the case for European hubs (Nakajima and Toyoshima, 2019; Broadstock et al., 2020; Papież et al., 2022; Nunez et al., 2022; Szafranek et al., 2023).

The increased integration of European hubs over the last two decades has been driven by infrastructure development as well as changes in legislation aimed at the liberalization of the market. The successive gas directives regulated the development of infrastructure, gas transmission and distribution. They separated gas production from distribution activities and outlined the framework of trade with third countries. These changes in regulations have led to the development of numerous natural gas hubs in European countries, which represent market points where participants could freely trade spot and futures gas contracts, and to profound change in price formation mechanisms. It is reflected in the data reported in the International Gas Union Wholesale Gas Price Survey from 2024, which shows that between 2005 and 2023 the share of oil-indexed contracts in total transactions in Europe declined from 78% to 15%, while the share of gas-on-gas contracts increased from 15% to 84%. Consequently, wholesale gas prices are currently determined predominantly by supply and demand factors affecting quotations in the European hubs (Fulwood, 2022). This justifies the need to understand links among price changes in numerous European hubs, including the less liquid peripheral ones.

In this article we contribute to the debate on natural gas market integration by investigating the dynamics of wholesale natural gas price quoted in six European hubs. We do it by developing a dynamic error correction GARCH model, which takes into account the long-run link with the benchmark, most liquid European hub (TTF, Netherlands), but also accounts for additional factors that might exert impact on the short-run dynamics of natural gas prices. In this respect, we contribute to a series of articles that test the law of one price among European natural gas markets using standard cointegration analysis (Asche et al., 2013; Jotanovic and D'Ecclesia, 2021), its non-linear version (Renou-Maissant, 2012; Growitsch et al., 2015; Garaffa et al., 2019), or convergence tests (Mu and Ye, 2018; Bastianin et al., 2019). We also add to the discussion on the scale of integration of natural gas price dynamics in most liquid European hubs, by showing that peripheral markets might be less integrated (Broadstock et al., 2020; Papież et al., 2022; Szafranek et al., 2023). Finally, our study is closely related to the articles of Brown and Yucel (2008) and Hulshof et al. (2016), who investigated how the dynamics of natural gas prices in the US and Europe (TTF) markets are related to market fundamentals such as crude oil prices, whether conditions (heating days) and natural gas market fundamentals (storage).

The remainder of the article is structured as follows. Section 2 outlines the methodology, Section 3 describes the data, whereas Section 4 presents the main results. The last section concludes.

2 Methodology

We estimate a reduced-form model for the wholesale natural gas prices quoted in six European hubs: Germany (THE), Poland (TGE), Austria (CEGH VTP), Czechia (CZ VTP), Italy (PSV) and Spain (MIBGAS). For the sake of comparability, the specification of the model is the same for all hubs. The dependent variable is the logarithmic growth rate of prices in hub i (Δp_i). We assume that it is predominantly driven by contemporaneous changes in natural gas prices in the benchmark European hub (Δp_{NL}) as well as changes in the main alternative energy commodity prices (Δp_{oil} and Δp_{coal}). The next regressors are describing log-deviations from the law of one price, which are used to account for the mean reversion in relative prices. We look at the difference between a price in a given hub and the benchmark TTF: $(p_i - p_{NL})$, but also include the disparity between natural gas and the other two energy commodity prices, i.e. $(p_{oil} - p_{NL})$ and $(p_{coal} - p_{NL})$. It should be noted that, for the sake of comparability, all prices are expressed in €/MWh terms. Finally, similarly to what was done by Brown and Yucel (2008) and Hulshof et al. (2016), we consider two country-specific, idiosyncratic factors. The first one is gas storage, which is used for inter-temporal arbitrage against seasonal variations in natural gas consumption, which is reflected in the difference between spot and future gas natural gas prices (Fama and French, 1987; Fernandez, 2016; Rubaszek and Uddin, 2020; Rubaszek et al., 2020). This implies that the level of inventories above (below) the seasonal norm should exert negative (positive) impact on natural gas prices. For that reason, we use a variable that measures the difference between the observed filling level of natural gas storage facilities and its average value in a given 7-day window from the period 2014-2024 ($InvDev_i$). The second fundamental factor is related to weather conditions, specifically the potential impact of the outdoor temperature on natural gas prices. We take the value of negative deviation of the daily average temperature from the $15.5°C$ threshold used by the European Energy Agency as a proxy for natural gas demand related to energy needed to heat buildings ($TempDev_i$).

The implied specification of the initial econometric model, which is estimated with the least squares method separately for each hub i, is:

$$\begin{aligned}\Delta p_{it} &= \kappa + \psi_1 \Delta p_{NL,t} + \phi_1 (p_i - p_{NL})_{t-1} + \\ &+ \psi_2 \Delta p_{oil,t} + \phi_2 (p_{oil} - p_{NL})_{t-1} + \\ &+ \psi_3 \Delta p_{coal,t} + \phi_3 (p_{coal} - p_{NL})_{t-1} + \\ &+ \delta_1 InvDev_{i,t-1} + \delta_1 TempDev_{i,t-1} + \epsilon_{it}, \qquad \epsilon_{it} \sim \mathcal{N}(0, \sigma^2)\end{aligned} \tag{1}$$

where t denotes daily observations and ϵ_i is Gaussian the error term. In the second step, we augment the specification of the model for the MA(1) term, the GARCH effect and non-Gaussian distribution of the error term. This rationale behind this extension will be explained in Section 4. The implied specification of the augmented model is:

$$\begin{aligned}\Delta p_{it} &= \kappa + \psi_1 \Delta p_{NL,t} + \phi_1 (p_i - p_{NL})_{t-1} + \\ &+ \psi_2 \Delta p_{oil,t} + \phi_2 (p_{oil} - p_{NL})_{t-1} + \\ &+ \psi_3 \Delta p_{coal,t} + \phi_3 (p_{coal} - p_{NL})_{t-1} + \\ &+ \delta_1 InvDev_{i,t-1} + \delta_1 TempDev_{i,t-1} + \epsilon_{it} + \theta \epsilon_{i,t-1}, \qquad \epsilon_{it} \sim \mathcal{ST}_{v,S}(0, \sigma_t^2) \\ \sigma_t^2 &= \omega + \alpha \epsilon_{i,t-1}^2 + \beta \sigma_{t-1}^2\end{aligned} \tag{2}$$

where $\mathcal{ST}_{v,S}$ is skewed t-Student distribution with v degrees of freedom and skewness parameter S. Finally, we will also explore the simplified version of model (2), i.e.:

$$\begin{aligned}\Delta p_{it} &= \kappa + \psi_1 \Delta p_{NL,t} + \phi_1 (p_i - p_{NL})_{t-1} + \epsilon_{it} + \theta \epsilon_{i,t-1}, \qquad \epsilon_{it} \sim \mathcal{ST}_{v,S}(0, \sigma_t^2) \\ \sigma_t^2 &= \omega + \alpha \epsilon_{i,t-1}^2 + \beta \sigma_{t-1}^2\end{aligned} \tag{3}$$

to check if other fundamentals than TTF prices are really important determinants of natural gas prices.

3 Data

The analysis is based on 1699 daily observations from the period 1 January 2018 to 31 July 2024, where the initial date is determined by data availability in the Czech hub. In most cases historical data are taken from EIKON, apart from the average surface temperature that is downloaded from the NCEI webpage. The description and sources of all original series are provided in Table 1.

As regards raw data pre-processing, we have taken only those days for which Brent crude oil prices and the €/$ rates were available, which resulted in the average 259 business days per year. In the rare cases of missing observations in less liquid natural gas hubs, we took the values from the previous day. Consequently, we use the same sample of observations for all regressions.

Before discussing the characteristics of data, three issues that might lead to measurement error problems are worthy to discuss. First of all, without access to high-frequency data it is impossible to construct daily series for all energy commodity prices observed at exactly the same moment during the day. In all cases, we take *last trade* value from Eikon, but it should be kept in mind that the trades at different hubs could have taken place at different hour. Second, we transform all energy commodity prices to €/MWh using the closing exchange rates (€/PLN and €/$) and the conversion rates of 1.7MWh/bbl and 6.15MWh/tonne of coal. Again, these rates might reflect trade at different hour than that at the energy commodity markets. Third, it can be noticed that in the case of natural gas we use day-ahead prices, whereas for oil and coal it is the nearest forward price, which might affect the estimate of the link among these three commodity markets.

Let us now look at the characteristics of the energy commodity prices. Figure 1 presents the prices of natural gas in the benchmark TTF hub, Brent crude oil and ARA coal expressed in the same unit (€/MWh). It shows that natural gas was cheaper than oil and more expensive than coal at the beginning and the end of the sample, which is the standard situation in normal times. The only exception is seen at the beginning of

March 2018, when there was a short-lived spike in TTF prices, due to abnormally cold weather, low inventories and temporary supply shortages from Norway. The figure also demonstrates the scale of Russian supplies disruptions impact on natural gas prices in years 2021-23, when they were well above prices of the remaining two commodities.

Figures 2 and 3 extend the above comparison by presenting log-deviations (in %) and deviations (in €/MWh) of natural gas prices in six European hubs, crude oil, and coal from the benchmark TTF prices. In other words, these figures present deviations from the law of one price (LOOP), so that values above (below) zero indicate that a given energy commodity is more (less) expensive than the TTF. Both figures are complemented by the upper panels of Table 2, which reports descriptive statistics for log-deviations and deviations from the LOOP. Three observations are warranted. First of all, the values of the ADF test indicate that all differences are stationary, which means that there is mean reversion in energy commodity markets. This feature can be exploited in the empirical model for natural gas price dynamics. However, the values of autoregression coefficients indicate that the pace of mean reversion is heterogeneous across natural gas markets. The persistence of deviations from the LOOP is the lowest for the core German hub, which is well connected by the grid of pipelines with the Netherlands, and the highest for the distant Spanish hub. Interestingly, at the peak of the European energy crisis natural gas prices in Spain were much lower than in the core European hubs, which can be explained by relatively well developed LNG infrastructure combined with low capacity of pipeline infrastructure to transport gas to the core markets.(see Lustenberger et al., 2019, for a detailed discussion on natural gas infrastructure in Europe) As regards crude oil and coal, there is some evidence of mean-reversion, especially for coal, but deviations from equilibrium are long-lasting. The second observation is that natural gas prices in six European hubs, on average, tend to be more expensive than in the most liquid TTF. The average value of log-deviation ranges from 1.26% in Germany to 10.89% in Poland. For simple deviations, natural gas in Germany was on average 0.33€/MWh more expensive than in the Netherlands, whereas for Poland the mean difference amounted to as much as 2.77€/MWh. The third observation is that the dispersion of natural gas deviations from the LOOP, which in Table 2 is measured by the standard deviation and quantiles, is the lowest for the liquid German market, relatively low for Czechia and Austria, relatively high for Poland and Italy, and the highest for Spain. It can also be noticed that deviations from the LOOP might be substantial and amount to as much as 125€/MWh.

Next, Figure 4 presents the dynamics of energy commodity prices, i.e. the dependent variables of the empirical model described in equations (1)– (3). It illustrates substantial dispersion of natural gas log-returns, which is reflected by very high annualized standard deviations, ranging from 120.4 in Germany to 134.0% in Austria, which is about three-times higher than this dispersion measure for crude oil or coal log-returns (see the bottom panel of Table 2). The figure also points to volatility clustering, which in Table 2 is reported as in significant and high autocorrelation of squared returns. On the contrary, the autocorrelation of returns is insignificant. The inspection of Figure 4 also allows to observe common trends in natural gas prices changes across European hubs. Figure 5 quantifies this co-movement by reporting pairwise correlations. It shows that the link between the two most liquid European hubs (TTF and THE) is very strong (correlation at 0.86), the relationship between TTF and MIBGAS is rather weak (0.46), and for the remaining four hubs the coefficient ranges from 0.66 to 0.83. It also shows that the correlation of natural gas and oil prices is low (around 0.10), and somewhat higher with coal prices (about 0.20).

Finally, let us focus on the two natural gas market fundamentals: the filling level of natural gas storage facilities and heating temperature. Figure 6 demonstrates that in all countries there is a visible deterministic seasonal pattern in natural gas storage, the amplitude of which is broadly similar across countries, apart from Spain where it is relatively low. It also points to three episodes of critically low level of natural gas inventories in Germany, Austria and Czechia, which took place in March 2018, March 2021 and April 2022. In turn, Figure 7 presents the scale of average temperature deviation from the 15.5° threshold, which proxy natural gas demand required to heat buildings. It illustrates how seasonal variation in natural gas demand related to weather conditions is more pronounced in Central European countries compared to the Southern ones, which is intuitive given the geographical location of analyzed markets.

To summarize, the preliminary inspection of data shows that (i) deviations from the LOOP in European natural gas hubs are temporary, but sometimes persistent, (ii) changes in natural gas prices quoted in European hubs are highly correlated, (iii) the link between benchmark TTF and other European natural gas hubs is the strongest for the German THE and the weakest for the Spanish MIBGAS, (iv) natural gas prices are weakly correlated with other energy commodity prices, and (v) there were episodes of divergent behavior in natural gas market fundamentals, such as the filling level of storage facilities or heating demand. These five features are incorporated in the specification of model described in equation (1). On top of that, we have pointed to the existence of volatility clustering, which is incorporated in the specification of model (2).

4 Results

We start our empirical investigation, aimed at establishing drivers of natural gas prices in European hubs, by exploring linear regression that accounts for the features described in the previous section. Specifically, we estimate the error correction model described by equation (1), which allows us to measure (i) contemporaneous relationship of the dependent variable with other commodity prices, (ii) adjustment mechanism to the LOOP, (iii) a link with country-specific natural gas market fundamentals.[1] The estimation results are reported in Table 3. The estimate of the coefficient describing the contemporaneous link with the benchmark TTF is diverse across hubs and ranges from $\hat{\psi}_1 = 0.471$ in Spain to $\hat{\psi}_1 = 0.842$ in Germany. It can be noticed that all estimates of ψ_1 are significantly below unity, which implies imperfect pass-through of prices from the benchmark TTF to other market in the short-run. As regards the estimates of coefficient ϕ_1, describing the adjustment to the LOOP at the natural gas market, in all cases it is significant and negative, which implies perfect pass-through in the longer horizon. The speed of reversion to equilibrium is the fastest in Germany ($\hat{\phi}_1 = -0.668$) and the slowest in Spain

[1] We have checked extended versions of model (1), with richer dynamic specification, but they were not superior in terms of model fit to the data.

($\hat{\phi}_1 = -0.157$). These results point to high, but not perfect pass-through from TTF to other European natural gas markets, where the strength of the link is the highest for the core German market and the lowest for the distant peripheral Spanish hub.

Let us no focus on the parameters describing how the other two energy commodities affect price formation mechanism in the European natural gas hubs. The estimates of coefficients ψ_2 and ψ_3, which describe the contemporaneous reaction of natural gas price dynamics to changes in crude oil and coal prices, are in almost all cases insignificant. However, in the case of all markets there is some evidence on the adjustment of natural gas prices to LOOP deviations of TTF and the other two energy commodities. The positive and significant estimates of ϕ_2 indicate that high oil prices tend to exert upward pressure on natural gas prices in Spain, Poland and Italy. In turn, the estimated values of ϕ_3 are positive in all cases, but Spain. It should be emphasized, however, that these coefficients estimates are rather low and never exceed 5%, which would imply that the link is weak.

Table 3 also reports the estimates of the relationship between natural gas prices and both idiosyncratic fundamentals: the filling level of natural gas storage facilities and temperature conditions. As regards the estimates of parameters δ_1, in four cases of Central European hubs they are significant but of wrong sign, as the estimates imply that high level of natural gas storage leads to natural gas prices increases. Only in the case of Spain the estimate of δ_1 is significant and negative. Next, the estimates of δ_2 are positive and significant for Germany and Poland, which implies that low temperatures lead to higher heating demand for natural gas and increase its wholesale prices in the local hub. This effect is not found in the remaining markets.

Let us now discuss the quality of linear regression model. The bottom panel of Table 3 shows that the fit to the data, as measured by R^2 coefficient, is diverse across hubs and ranges from as low as 27.3% for Spain to as high as 83.0% for Germany. This panel also points to the problem of autocorrelation of residuals and their squares. Additional analyses allowed us to detect the source of residual autocorrelation. It can be attributed to the fact that LOOP deviations across natural gas hubs consist of two components, with different pace of mean reversion. Random factors, including measurement errors, lead to one-day divergence in natural gas prices. This can be accounted in model specification by incorporating MA(1) component. However, LOOP deviations might be long-lasting if they are driven by important deep markets fundamentals. This can be measured by the error correction mechanism, which is already accounted for in model (1). Mixing these two components in model (1) resulted in high ϕ_1 parameter estimates and autocorrelation of residuals. As regards the autocorrelation of squared residuals, it is related to the existence of the volatility clustering, which we reported in the previous section. We account for this feature by adding variance equation to the specification of model (1). We do it by exploring GARCH class of models, and in particular a standard GARCH(1,1) model with skewed t-Student distribution of standardized residuals. The specification of this model is given by equation (2).

The estimates of model (2) are reported in Table 4. Three initial comments are warranted. Firstly, the MA component allowed us to eliminate autocorrelation of residuals, whereas GARCH extension solved the problem of autocorrelated squared residuals. Secondly, the comparison of information criteria (AIC and BIC) of models (1) and (2) indicates that for each analyzed hub the MA-GARCH extension strongly improves the fit to data. Thirdly, by allowing for volatility clustering in residuals and changing their distribution from normal to skewed t-Student, the importance of observations from the volatile periods, e.g. those from the European energy crisis episode, for parameters estimate were diminished. This, together with the effect of adding the MA component, had very strong impact on all parameters estimates.

Let us therefore discuss new parameter estimates in the extended model. Table 4 shows that there are significant and negative MA(1) coefficient estimates, which account for the impact of random factors on short-term LOOP deviations. These estimates range from $\hat{\theta} = -0.767$ for Germany to $\hat{\theta} = -0.279$ for Spain, which means that unexpected price changes are in 27.9% (Spain) or 76.7% (Germany) reversed next day. As expected, the extension of model specification for MA component strongly diminished the estimates of adjustment coefficient ϕ_1. They are now well below 10%, which points to much slower pace of mean-reversion than in the linear regression. The extension of model specification also visibly increased the estimate of ψ_1 coefficient describing the contemporaneous link with the benchmark TTF. It now ranges from 0.734 in Poland to 0.949 in Germany. Finally, in the extended model the impact of other fundamentals became in most cases insignificant.

Given the last result, we have estimated a reduced version of model (2), in which we eliminated all fundamentals, but TTF prices, from the set of regressors (see equation 3). The results reported in Table 5 indicate that in the case of all hubs this specification is preferred compared to the full model by BIC information criterion, and in most cases of AIC criterion is considered. This implies that TTF prices are the only important determinant of natural gas prices in European hubs. Our attempts to build the richer model, which incorporates more fundamentals considered in the literature, have not allowed us to improve the quality of the model. The estimates in Table 5 indicate to a strong and similar pattern in the dynamics of natural gas prices in six European hubs. First, they strongly adjust contemporaneous changes in TTF prices ($\hat{\psi}_1$ ranges from 0.766 to 0.955). Second, random deviations from the LOOP are quickly reversed ($\hat{\theta}$ ranges from -0.317 to -0.764), whereas other deviations are eliminated by few percent a day ($\hat{\phi}_1$ ranges from -0.014 to -0.044). Third, there is visible volatility clustering, which can be taken into account by standard GARCH model. The estimates of the variance equation point to high impact of the last observation ($\hat{\alpha}$ ranges from 0.156 to 0.262), fat tails of standardized residuals (t-Student shape is below 5 degrees of freedom), which are additionally significantly skewed. Lastly, the estimates of model parameters as well as the values of information criteria indicate that the link between TTF and the German market is the strongest, followed by the strength of the link with the Czech and Austrian markets. On the contrary, peripheral Polish, Italian and especially Spanish markets are more loosely connected to the dynamics of the prices at the benchmark TTF.

5 Conclusions

In this study we have investigated how natural gas price changes in the benchmark European hub (TTF) are transmitted to other six natural gas hubs. For that purpose, we have run linear regression, in which the dynamics of natural gas prices in a given hub was explained by changes in TTF prices, deviations from the law of one price, price changes of other energy commodities (crude oil and coal) as well as natural gas market fundamentals (storage and weather conditions). The results for the linear regression pointed to the dominant role of TTF market conditions, but also to a significant role of the remaining fundamentals. However, when we accounted for linear model shortcomings (autocorrelation) and extended model specification for MA component and GARCH effect, the role of other factors than TTF prices turned out to be insignificant. In our preferred final specification of the model we have found imperfect (but close to unity) pass-through in the short-run, a sizeable reversion towards equilibrium price parity after one-off shocks and gradual reversion toward the law of one price in the long run horizon. The other finding of our investigation is that the strength of the link between European hubs and the TTF is diverse, where the level of integration is the highest for core German market and the lowest for the peripheral Spanish hub, which is not well connected to core markets by pipeline infrastructure.

Our results allow us to make the following general conclusions. The fact that if we account for TTF prices, other factors are not important for wholesale natural gas prices in European hubs, implies that policy measures aimed at introducing competition in European wholesale gas markets and integrate these markets have been partially successful. However, the fact that we found that price transmission from TTF to peripheral markets is slower than to core markets, implies that European natural gas market is not fully integrated. This result can be related to inadequate development of transport and storage infrastructure to accommodate large disturbances, as demonstrated by simulations in Lustenberger et al. (2019). This result could be also related to the recent investigation of Nunez et al. (2022), which points to the role of distances, pipeline and storage capacity for the integration of the US market. We can therefore conclude that further integration of peripheral countries could be enhanced by investment in natural gas infrastructure.

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Tables and figures

Table 1: Variable definitions.

Description	Unit	Ticker
Day ahead natural gas prices:		**Eikon:**
Netherlands (TTF)	€/MWh	TRNLTTFDA
Germany (THE)	€/MWh	TRDENCGDA
Poland (TGE)	PLN/MWh	/POXGBASE
Austria (CEGH VTP)	€/MWh	VTPDA
Czechia (CZ VTP)	€/MWh	CZVTPDA
Italy (PSV)	€/MWh	TRITPSVDA
Spain (MIBGAS)	€/MWh	MIBG-DA1-ES
Energy commodity prices 1 month forward:		**Eikon:**
Brent (crude oil)	$/bbl	LCOc1
ARA (hard coal)	$/tonne	MTFc1
Exchange rates:		**Eikon:**
EUR/USD		EUR=
EUR/PLN		EURPLN=
Filling level of gas storage facilities:		**Eikon:**
Netherlands	%	NGAS-NLD-GIE
Germany	%	NGAS-GERD-GIE
Poland	%	NGAS-POLD-GIE
Austria	%	NGAS-AUTD-GIE
Czechia	%	NGAS-CZED-GIE
Italy	%	NGAS-PSVD-GIE
Spain	%	NGAS-ENAD-GIE
Average daily temperature:		**NCEI:**
Netherlands (Utrecht)	$^{\circ}C$	NLM00006260
Germany (Berlin)	$^{\circ}C$	GMM00010385
Poland (Warsaw)	$^{\circ}C$	PLM00012375
Austria (Vienna)	$^{\circ}C$	AU000005901
Czechia (Prague)	$^{\circ}C$	EZM00011518
Italy (Rome)	$^{\circ}C$	IT000016239
Spain (Madrid)	$^{\circ}C$	SPE00120278

Table 2: Descriptive statistics

Variable	Mean	SD	min	P25	P75	max	Skew	Kurt	Level	LB p-val	Square	LB p-val	ADF
	Distribution stats.								**Autocorrelation AR(1)**				
	log price ratio vs Netherlands TTF (in %)												
Germany (THE)	1.26	3.7	-35.8	-0.4	2.8	34.5	0.40	19.36	0.40	0.00	0.15	0.00	-17.87
Poland (TGE)	10.89	9.0	-18.0	4.8	15.3	58.1	1.04	5.53	0.75	0.00	0.79	0.00	-10.23
Austria (CEGH VTP)	4.39	8.3	-30.1	-0.1	6.8	57.3	1.58	7.50	0.75	0.00	0.68	0.00	-10.18
Czechia (CZ VTP)	3.40	5.4	-24.1	0.5	5.8	41.9	1.36	9.72	0.66	0.00	0.62	0.00	-12.48
Italy (PSV)	8.25	10.2	-54.1	1.8	11.4	63.7	1.18	6.97	0.85	0.00	0.77	0.00	-8.88
Spain (MIBGAS)	1.44	17.1	-95.9	-3.4	8.8	101.9	-0.78	9.13	0.89	0.00	0.77	0.00	-9.50
BRENT oil	28.83	65.9	-171.1	-2.53	62.6	183.2	-0.55	3.04	0.99	0.00	0.98	0.00	-2.49
ARA coal	-62.60	37.3	-215.0	-78.6	-46.9	61.9	-0.01	4.67	0.98	0.00	0.96	0.00	-4.22
	price difference vs Netherlands TTF (in EUR)												
Germany (THE)	0.33	2.8	-50.8	-0.1	0.6	44.3	-2.27	133.71	0.08	0.00	0.03	0.22	-28.53
Poland (TGE)	2.77	3.4	-32.6	1.5	3.7	36.5	0.49	24.95	0.14	0.00	0.31	0.00	-23.51
Austria (CEGH VTP)	0.93	3.2	-50.0	0.0	1.7	26.8	-1.16	56.52	0.25	0.00	0.17	0.00	-22.18
Czechia (CZ VTP)	0.79	2.4	-32.1	0.2	1.6	22.3	-1.88	43.34	0.16	0.00	0.17	0.00	-26.01
Italy (PSV)	1.63	3.8	-86.8	0.6	2.8	24.6	-8.80	195.63	0.46	0.00	0.23	0.00	-20.74
Spain (MIBGAS)	-3.31	14.9	-125.0	-1.0	1.8	37.2	-4.25	23.51	0.95	0.00	0.90	0.00	-6.41
BRENT oil	-3.21	38.3	-270.3	-1.1	16.4	35.4	-2.84	12.50	0.99	0.00	0.97	0.00	-3.47
ARA coal	-23.66	33.4	-270.4	-24.3	-6.3	16.1	-2.86	13.13	0.98	0.00	0.97	0.00	-3.87
	logarithmic returns (in %)												
Netherlands (TTF)	9.18	123.5	-98.1	-2.8	2.7	70.5	-0.15	31.42	0.01	0.74	0.40	0.00	-33.24
Germany (THE)	9.25	120.4	-69.9	-2.8	2.7	68.1	0.22	21.50	0.01	0.65	0.52	0.00	-32.38
Poland (TGE)	10.25	122.2	-67.4	-2.8	2.6	60.8	0.19	16.27	0.01	0.74	0.59	0.00	-33.66
Austria (CEGH VTP)	9.68	134.0	-89.9	-3.0	3.2	129.3	1.11	53.67	-0.12	0.00	0.17	0.00	-36.76
Czechia (CZ VTP)	10.07	121.6	-66.0	-2.6	2.7	88.2	0.55	26.86	-0.03	0.29	0.49	0.00	-35.09
Italy (PSV)	10.12	123.2	-62.9	-2.7	2.7	105.0	1.22	34.02	-0.06	0.01	0.21	0.00	-35.23
Spain (MIBGAS)	6.76	123.0	-43.3	-3.3	3.4	39.7	-0.13	8.22	0.01	0.58	0.25	0.00	-32.37
BRENT oil	4.58	42.4	-29.0	-1.0	1.2	20.0	-1.38	24.63	0.04	0.11	0.22	0.00	-28.68
ARA coal	4.47	51.8	-51.5	-0.6	0.7	30.7	-2.25	61.10	0.06	0.01	0.15	0.00	-26.78

Notes: The table presents descriptive statistics for model variables. Logarithmic growth rates and log deviations were multiplies by 100. Mean and standard deviation for growth rates are annualized. LB - Ljung Box test for autocorrelation of order 1. ADF - Augmented Dickey-Fuller test. The 1% critical value of the ADF test is -3.43.

Table 3: Least Squares estimates of the model for natural gas prices dynamics

Dep. var.	Germany DE $\Delta p_{DE,t}$	Poland PL $\Delta p_{PL,t}$	Austria AT $\Delta p_{AT,t}$	Czechia CZ $\Delta p_{CZ,t}$	Italy IT $\Delta p_{IT,t}$	Spain ES $\Delta p_{ES,t}$
$\Delta p_{NL,t}$	0.842***	0.629***	0.826***	0.837***	0.748***	0.471***
	(0.026)	(0.030)	(0.053)	(0.027)	(0.042)	(0.062)
$(p_i - p_{NL})_{t-1}$	-0.668***	-0.437***	-0.353***	-0.451***	-0.232***	-0.157***
	(0.060)	(0.034)	(0.063)	(0.047)	(0.031)	(0.029)
$\Delta p_{oil,t}$	0.047	0.008	0.028	0.048	0.061	0.097
	(0.037)	(0.050)	(0.053)	(0.035)	(0.047)	(0.065)
$(p_{oil} - p_{NL})_{t-1}$	-0.003	0.024***	-0.005	-0.005	0.011***	0.026***
	(0.003)	(0.006)	(0.004)	(0.004)	(0.004)	(0.009)
$\Delta p_{coal,t}$	-0.038	-0.000	0.116**	0.029	0.066	0.133
	(0.036)	(0.056)	(0.057)	(0.032)	(0.042)	(0.083)
$(p_{coal} - p_{NL})_{t-1}$	0.017***	0.031***	0.046***	0.033***	0.026***	0.002
	(0.007)	(0.011)	(0.013)	(0.009)	(0.009)	(0.014)
$InvDev_{i,t-1}$	0.024***	0.033**	0.020***	0.045***	-0.017	-0.061***
	(0.005)	(0.015)	(0.006)	(0.007)	(0.012)	(0.014)
$TempDev_{i,t-1}$	0.049***	0.095***	-0.051**	-0.019	0.011	0.070
	(0.014)	(0.020)	(0.021)	(0.013)	(0.036)	(0.044)
Constant	0.017***	0.053***	0.047***	0.038***	0.032***	-0.004
	(0.005)	(0.009)	(0.011)	(0.008)	(0.008)	(0.012)
nobs	1699	1699	1699	1699	1699	1699
R^2	0.830	0.571	0.619	0.761	0.600	0.273
AIC	-4.108	-3.154	-3.089	-3.749	-3.206	-2.613
BIC	-4.076	-3.122	-3.057	-3.717	-3.174	-2.581
ACF for resid.	-0.018	-0.141	-0.642	-0.437	0.350	-0.097
LB p-value	0.117	0.002	0.000	0.000	0.000	0.000
ACF for sq. resid.	-0.003	0.024	-0.369	-0.447	0.332	-0.125
LB p-value	0.000	0.000	0.000	0.000	0.000	0.000

Notes: The table presents regression results for Δp_{it}. Robust standard errors in parentheses. ***, **and *stand for 1%, 5% and 10% significance levels, respectively.

Table 4: ARMAX-GARCH model estimates for natural gas prices dynamics

	Germany DE	Poland PL	Austria AT	Czechia CZ	Italy IT	Spain ES
Dep. var.	$\Delta p_{DE,t}$	$\Delta p_{PL,t}$	$\Delta p_{AT,t}$	$\Delta p_{CZ,t}$	$\Delta p_{IT,t}$	$\Delta p_{ES,t}$
$\Delta p_{NL,t}$	0.949***	0.734***	0.866***	0.899***	0.799***	0.797***
	(0.011)	(0.037)	(0.024)	(0.011)	(0.036)	(0.039)
$(p_i - p_{NL})_{t-1}$	-0.014	-0.071***	-0.022**	-0.023***	-0.053***	-0.078***
	(0.009)	(0.027)	(0.009)	(0.008)	(0.012)	(0.016)
$\Delta p_{oil,t}$	0.000	-0.029	0.011	0.014	0.046	-0.045
	(0.010)	(0.026)	(0.022)	(0.012)	(0.030)	(0.036)
$(p_{oil} - p_{NL})_{t-1}$	-0.000	0.008**	0.001	0.000	0.003	0.008**
	(0.000)	(0.004)	(0.001)	(0.001)	(0.002)	(0.003)
$\Delta p_{coal,t}$	0.025**	0.092	0.053**	0.044***	0.053	0.026
	(0.012)	(0.057)	(0.026)	(0.010)	(0.033)	(0.035)
$(p_{coal} - p_{NL})_{t-1}$	0.000	-0.006	-0.000	-0.001	0.001	-0.004
	(0.001)	(0.005)	(0.002)	(0.001)	(0.005)	(0.005)
$InvDev_{i,t-1}$	0.000	0.011	0.001	0.003**	0.001	-0.021***
	(0.001)	(0.007)	(0.001)	(0.001)	(0.005)	(0.006)
$TempDev_{i,t-1}$	0.000	0.008	-0.004	-0.007***	0.008	-0.015
	(0.002)	(0.006)	(0.004)	(0.002)	(0.013)	(0.016)
Constant	0.001	0.000	0.001	0.001	0.003	-0.002
	(0.001)	(0.004)	(0.002)	(0.001)	(0.004)	(0.004)
MA(1)	-0.767***	-0.535***	-0.687***	-0.731***	-0.353***	-0.279***
	(0.040)	(0.075)	(0.034)	(0.026)	(0.046)	(0.055)
ω	0.000***	0.000**	0.000	0.000	0.000	0.000
	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
α	0.217***	0.271***	0.157***	0.220***	0.207***	0.220***
	(0.034)	(0.055)	(0.041)	(0.059)	(0.035)	(0.027)
β	0.782***	0.728***	0.842***	0.779***	0.792***	0.779***
	(0.039)	(0.058)	(0.047)	(0.075)	(0.045)	(0.035)
t-Student shape	3.694***	4.319***	4.928***	3.673***	4.872***	4.984***
	(0.337)	(0.425)	(0.474)	(0.265)	(0.577)	(0.458)
t-Student skewness	1.024***	0.894***	1.022***	1.060***	0.970***	1.011***
	(0.040)	(0.042)	(0.039)	(0.038)	(0.033)	(0.033)
nobs	1699	1699	1699	1699	1699	1699
AIC	-5.0853	-3.5565	-3.8882	-4.7474	-3.9219	-3.2968
BIC	-5.0373	-3.5085	-3.8402	-4.6994	-3.8739	-3.2488
ACF for resid	0.025	0.005	0.043	0.005	0.047	0.051
LB p-value LB	0.303	0.847	0.073	0.835	0.053	0.034
ACF for sq. resid	-0.005	0.004	0.013	-0.009	0.007	0.052
LB p-value LB	0.829	0.87	0.594	0.716	0.757	0.032

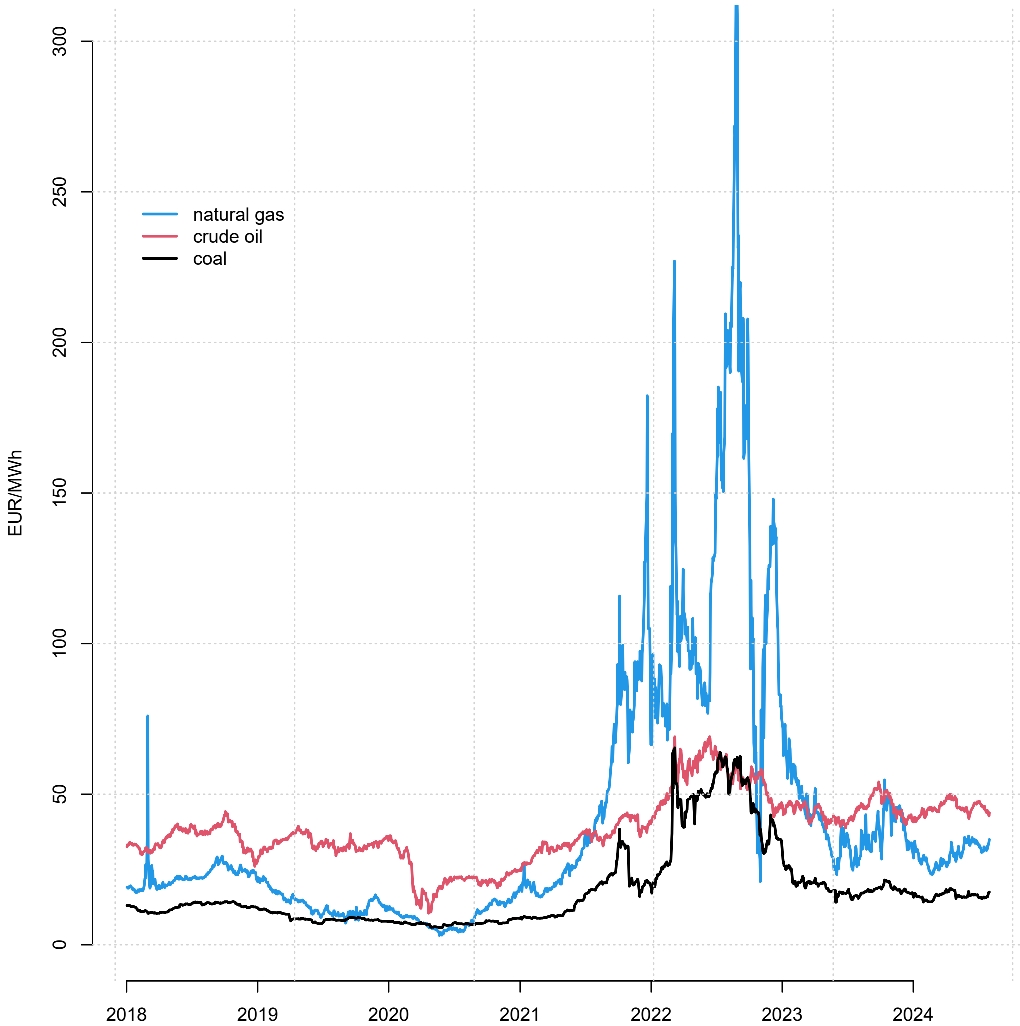
Notes: The table presents regression results for Δtge_t. Robust standard errors in parentheses. ***, **and *stand for 1%, 5% and 10% significance levels, respectively. ACF and Ljung-Box statistics are reported for standardized residuals.

Table 5: Simplified ARMAX-GARCH model estimates for natural gas prices dynamics

Dep. var.	Germany DE $\Delta p_{DE,t}$	Poland PL $\Delta p_{PL,t}$	Austria AT $\Delta p_{AT,t}$	Czechia CZ $\Delta p_{CZ,t}$	Italy IT $\Delta p_{IT,t}$	Spain ES $\Delta p_{ES,t}$
$\Delta p_{NL,t}$	0.955***	0.766***	0.882***	0.914***	0.813***	0.805***
	(0.010)	(0.031)	(0.021)	(0.011)	(0.034)	(0.035)
$(p_i - p_{NL})_{t-1}$	-0.014**	-0.035***	-0.018**	-0.016***	-0.032***	-0.044***
	(0.007)	(0.011)	(0.007)	(0.005)	(0.008)	(0.011)
Constant	0.000**	0.003***	0.001***	0.001***	0.003***	0.001**
	(0.000)	(0.001)	(0.000)	(0.000)	(0.001)	(0.000)
MA(1)	-0.764***	-0.589***	-0.691***	-0.728***	-0.373***	-0.317***
	(0.036)	(0.056)	(0.033)	(0.026)	(0.044)	(0.051)
ω	0.000***	0.000**	0.000	0.000	0.000	0.000*
	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
α	0.219***	0.262***	0.156***	0.228***	0.213***	0.224***
	(0.033)	(0.046)	(0.039)	(0.064)	(0.039)	(0.028)
β	0.780***	0.737***	0.843***	0.771***	0.786***	0.775***
	(0.038)	(0.051)	(0.045)	(0.079)	(0.049)	(0.034)
t-Student shape	3.746***	4.622***	4.969***	3.767***	4.940***	4.936***
	(0.354)	(0.446)	(0.487)	(0.284)	(0.600)	(0.461)
t-Student skewness	1.022***	0.874***	1.025***	1.059***	0.969***	1.018***
	(0.039)	(0.042)	(0.038)	(0.038)	(0.032)	(0.033)
nobs	1699	1699	1699	1699	1699	1699
AIC	-5.0882	-3.5439	-3.8874	-4.7342	-3.9166	-3.2876
BIC	-5.0594	-3.5151	-3.8586	-4.7054	-3.8878	-3.2588
ACF for resid	0.021	0.015	0.043	-0.003	0.051	0.06
LB p-value LB	0.395	0.533	0.077	0.897	0.036	0.013
ACF for sq. resid	-0.004	0.009	0.009	-0.008	0.01	0.044
LB p-value LB	0.878	0.719	0.697	0.736	0.669	0.067

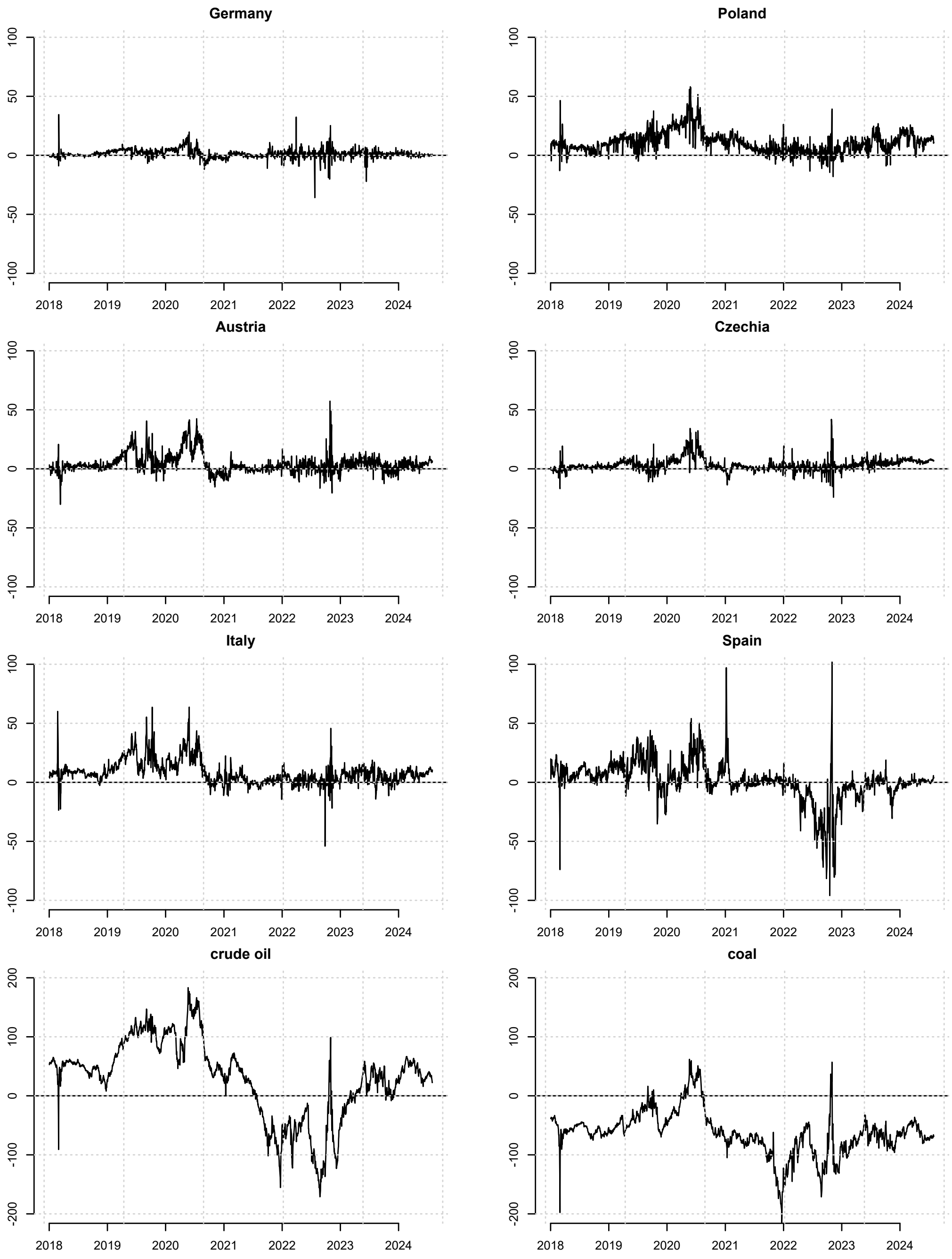
Notes: The table presents regression results for Δtge_t. Robust standard errors in parentheses. ***, **and *stand for 1%, 5% and 10% significance levels, respectively. ACF and Ljung-Box statistics are reported for standardized residuals.

Figure 1: Energy commodity prices



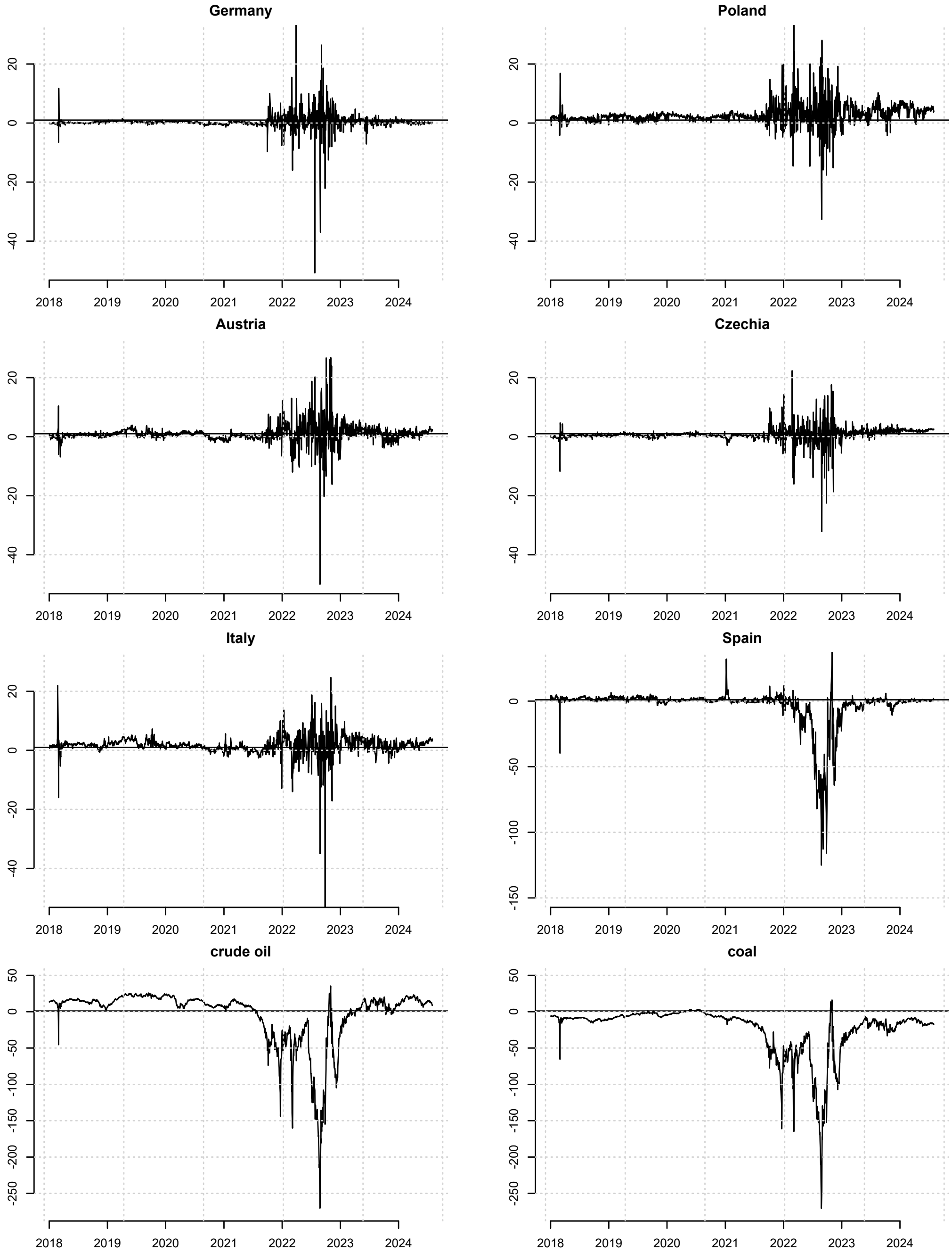
Notes: All prices are expressed in EUR/MWh: raw data were transformed using the EUR/PLN and USD/EUR closing quotes taken from EIKON and the conversion rates of 1.7MWh/bbl and 6.15MWh/tonne. The TGE premium (thick red line in left-center panel) amounts to 2.45EUR (5 Jan, 2021 - 23 Feb., 2022 average). % change stands for logarithmic growth rates multiplied by 100.

Figure 2: Log-deviations from the law of one price against TTF benchmark (in %)



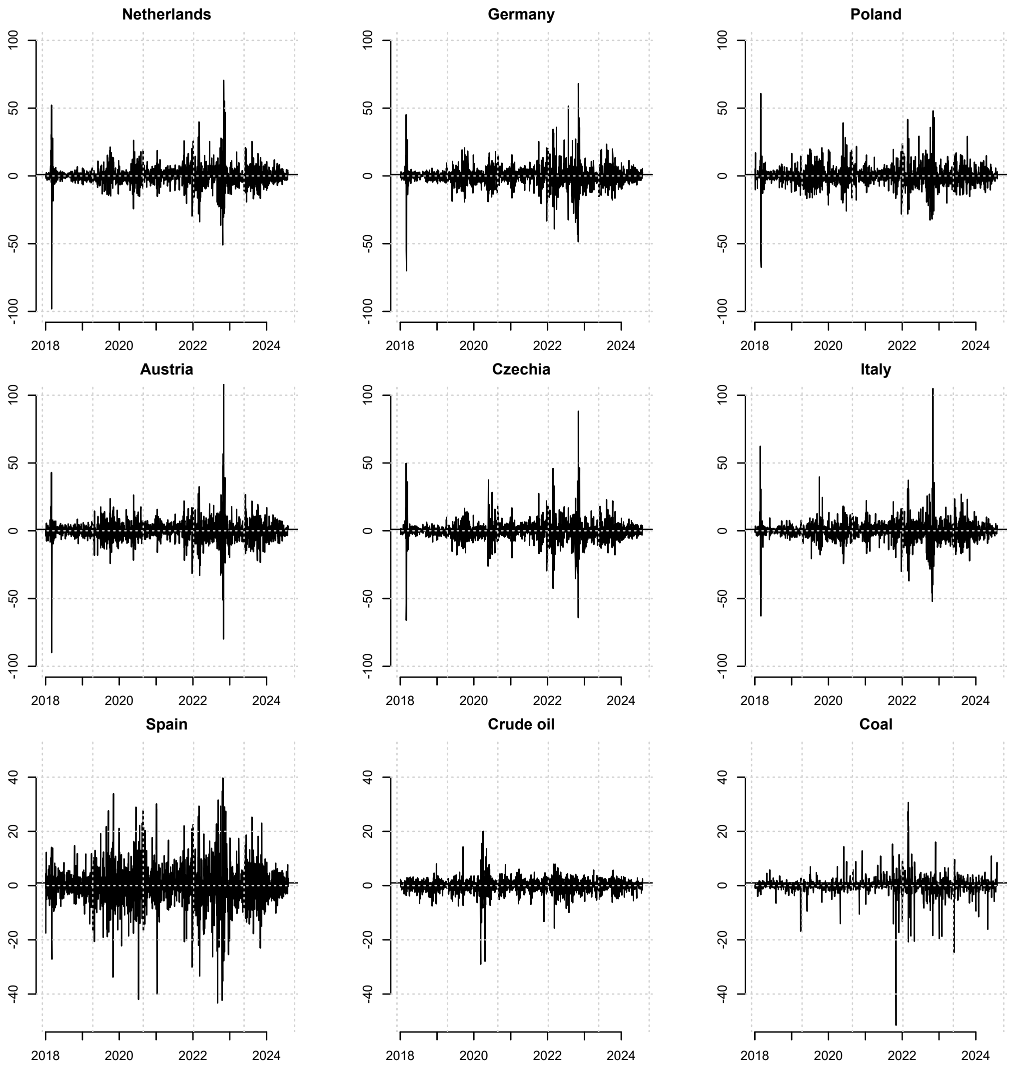
Notes: The figure presents the log-difference of natural gas at European hubs and other energy commodity prices against the Dutch TTF benchmark, which are expressed in % ($100 \times (p_{it} - p_{NL,t})$.

Figure 3: Deviations from the law of one price against TTF benchmark (in €/MWh)



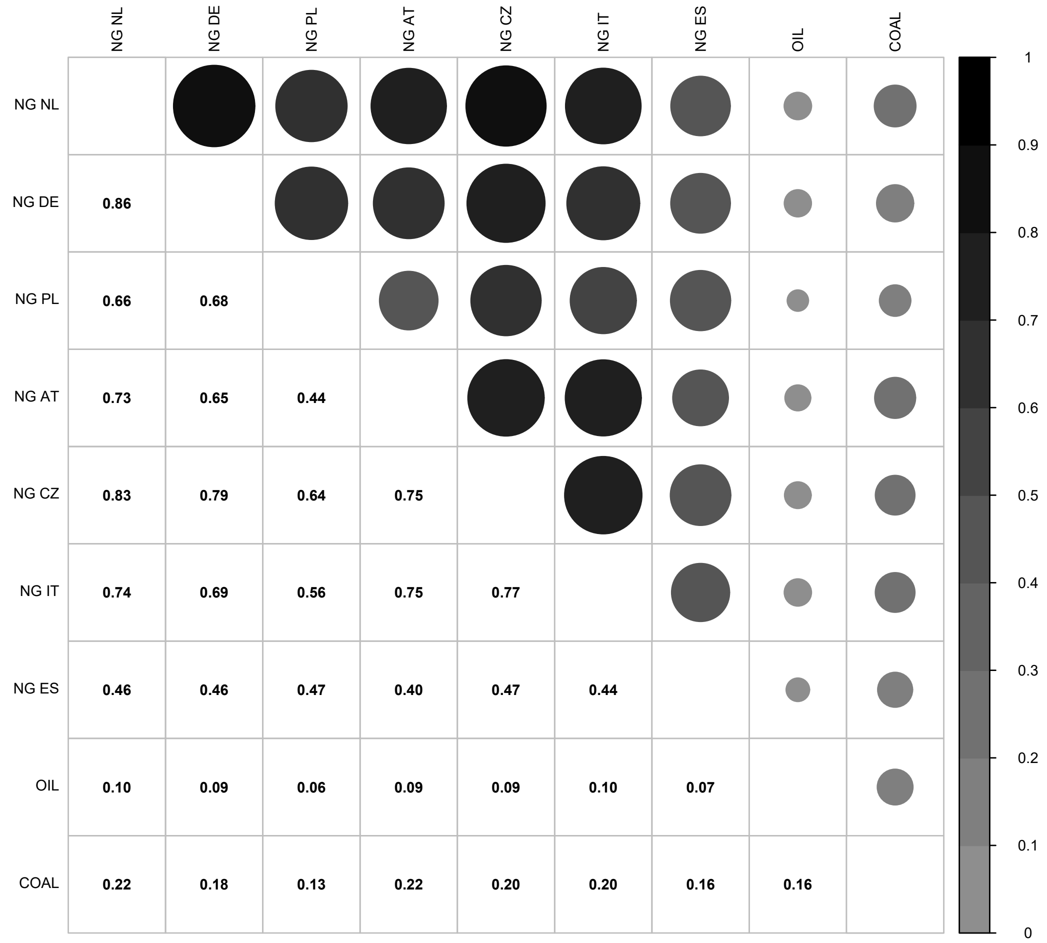
Notes: The figure presents the difference of natural gas at European hubs and other energy commodity prices against the Dutch TTF benchmark, which are expressed in €/MWh ($P_{it} - P_{NL,t}$).

Figure 4: Energy commodity price dynamics



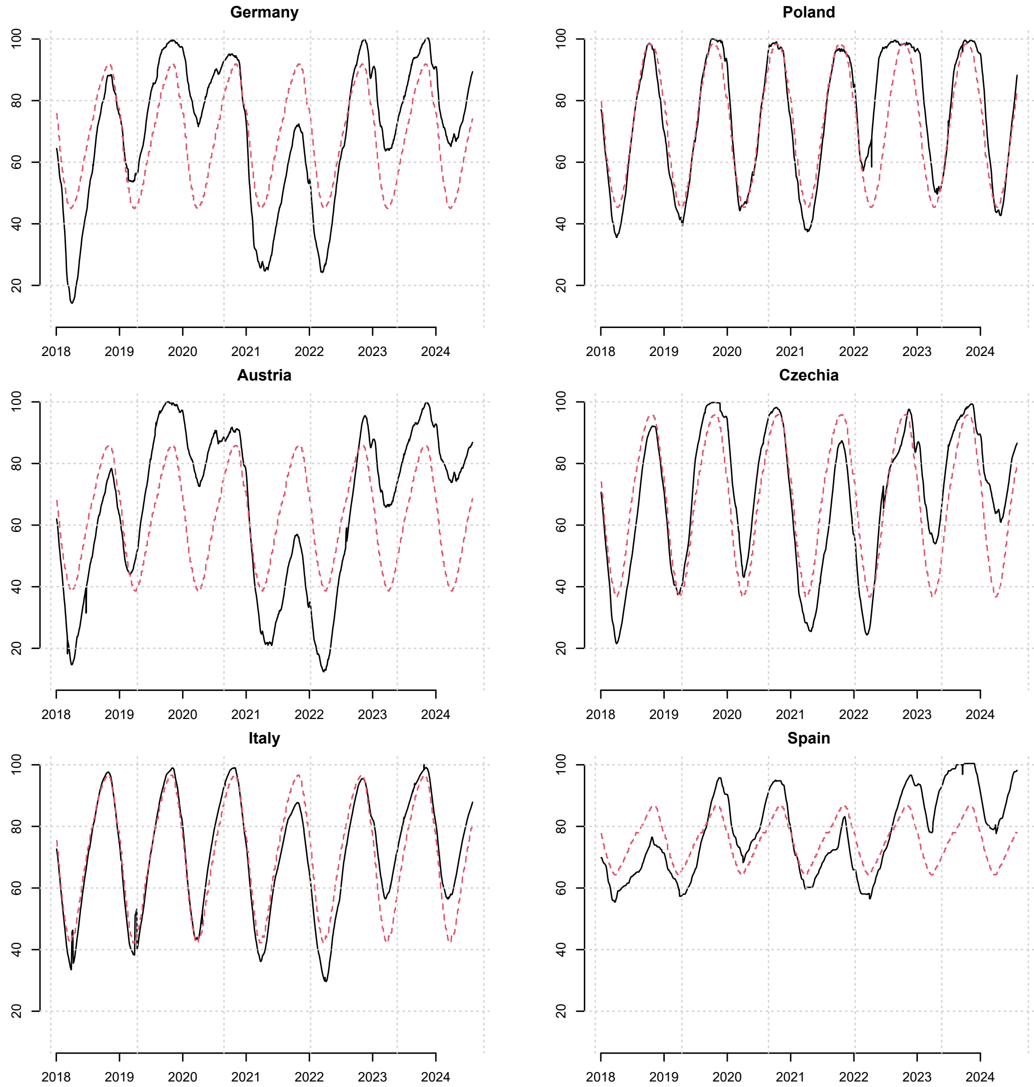
Notes: The figure presents the logarithmic returns of energy commodity prices expressed in EUR/MWh ($100 * \Delta p_{it}$).

Figure 5: Correlations among energy commodity price dynamics



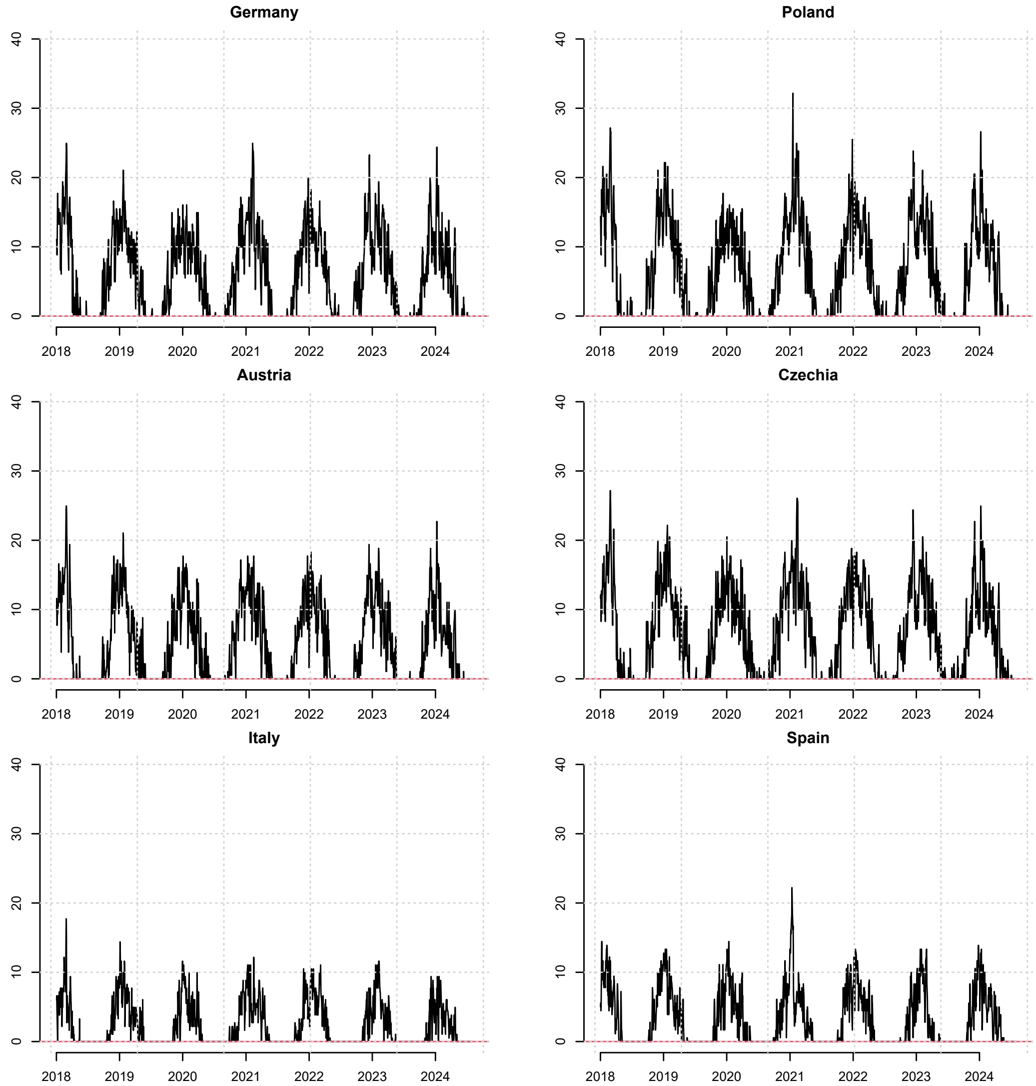
Notes: The figure presents correlation among logarithmic returns of energy commodity prices expressed in EUR/MWh.

Figure 6: Natural gas market fundamentals: natural gas storage.



Note: The seasonal patterns, which are represented by the thick red lines, are calculated as the 2014-2024 average for 7-day windows.

Figure 7: Natural gas market fundamentals: heating temperature.



Note: The figure presents heating temperature, which is calculated as the negative deviation from the heating temperature of $15.5°C$.