The Effectiveness of Regulations in Electricity Markets: The Financial Impact of the Global Energy Crisis

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Abstract

We analyze the financial impact of electricity market regulations. Following Russia's invasion of Ukraine, the world experienced a global energy crisis that caused natural gas prices to soar. We show that regulatory policies in the EU, designed to establish a well-integrated electricity market, also created a tight connection between gas and electricity prices. The unprecedented volatility spike and the subsequent tightening of collateral requirements created a significant cost for EU power utilities required to hedge their exposure to electricity price risk. We document an almost seven-fold increase in the average collateral value required for one-year EU futures contracts. We provide empirical evidence that following the gas market squeeze, the EU power utilities experienced lower sales and profitability relative to their US power utilities counterparts. We show that the risk-adjusted return on a portfolio comprising of EU power utilities was significantly lower than that of a counterfactual portfolio.

Keywords: Electricity markets, regulation effectiveness, global energy crisis
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1. Introduction

"France's power mostly comes from nuclear and hydroelectric stations and is relatively cheap to produce, yet the EU market aligns prices to natural gas. The single European electricity market does not work, it is an aberration.", Bruno Le Maire, French Finance Minister on Bloomberg, September 2021

The electricity sector plays a pivotal role in driving economic growth and sustainable development. Electricity markets are subject to extensive regulatory oversight due to their large potential impact on social welfare. Governments around the world have established regulatory bodies and set policies to ensure reliability, affordability, and sustainability in the electricity sector. These regulations encompass a wide range of issues, including market structure, price regulation and environmental targets. Electricity markets are much more complex than other commodity markets. They must accommodate long-term contracting and investment decision-making to ensure an adequate and reliable supply of electricity. Balancing the need for long-term investment feasibility with the short-term dynamics of supply and demand introduces further complexity. Considering the financial, engineering and political challenges and their impact on society, designing effective electricity markets regulations is an issue of crucial importance as market design choices influence the cash flows accruing to energy producers, the structure of capital stock in the system and consequently the cost of energy transition.

In this paper, we examine the effectiveness of the regulatory approaches adopted in the United States and Europe in the context of the recent global energy crisis triggered by the Russian invasion of Ukraine. We shed light on the strengths and weaknesses of these regulatory approaches and the need for market re-design that will support the ongoing energy transition. The United States and Europe, while sharing a common objective of achieving energy security and decarbonization, have evolved distinct electricity market structures and regulations.

Historically, many electricity utilities were vertically integrated and therefore controlled the entire supply chain of electricity generation, transmission, and distribution. However, in recent decades, many countries and regions have undertaken liberalization efforts in their electricity markets. Liberalization has led to unbundling of utilities along the supply chain and a diverse landscape of regulatory frameworks and market structures. Electricity is often traded in wholesale markets, where generators sell their electricity to utilities, independent power producers, and other market participants. Wholesale prices are determined through competitive bidding or market clearing mechanisms such as auctions.

In the European Union, electricity prices are determined per bidding zone (usually a EU member country) in a system of marginal pricing, also known as a pay-as-clear market, where all electricity generators get the same price for the power they are selling at a given moment. Electricity producers bid into the market and the cheapest electricity is bought first, next offers in line follow. Once the full demand is satisfied, everybody obtains the price of the last producer from which electricity was bought. Natural gas combined cycle power plants (NGCC) are typically the marginal electricity production technology and their operating costs are used to set electricity prices in the EU market.

Until recently, there was general consensus that a single EU energy market with a marginal zonal pricing model provided greater efficiency, and incentives to support the green energy transition and investment in cheaper renewable energy sources. A major drawback of the marginal zonal pricing model is that gas-powered plants are still needed to generate electricity in may parts of the EU, and they are effectively setting the power price. Recently, there has been a gradual move towards allowing real-time market trading to set prices rather than using fixed price long-term contracts. These policies have meant even greater European exposure to the volatility of natural gas prices both in the wholesale electricity market and the longer maturity power contracts. Figure 1 illustrates the main point of the quote by the French Finance minister in the beginning of this section. The figure plots the average day-ahead electricity price in France and the EU natural gas price benchmark - the Dutch TTF front month futures contract. Even thought only around 16% of French energy supply is produced from natural gas, the correlation between the two price series is 0.94.[1]

<Figure 1: here>

In the United States, some parts of the wholesale electricity market are still traditionally regulated, meaning that vertically integrated utilities are responsible for the entire flow of electricity to consumers. Other parts of the wholesale market (the Northeast, Midwest, Texas, and California) are restructured competitive markets. In these restructured competitive markets, "utilities" are commonly responsible for retail electricity service to customers and are less likely to own generation and transmission facilities. These markets are run by independent system operators (ISOs). ISOs use competitive market mechanisms that allow independent power producers and non-utility generators to trade power. Nodal pricing, with markets clearing at every node, is commonly used in these wholesale dergulated electricity markets. These markets often display large locational price differences. Policy makers in many European countries have advocated for a move to a model of locational pricing (nodal), which would result in power prices set at a much more granular level that reflects the actual costs of electricity.

Energy markets in the European Union experienced a tumultuous period. Prices for natural gas, crude oil, and electricity began to rise in 2021, then spiked after the Russian invasion of Ukraine in February 2022. While there has been a partial decline in prices since then, the trajectory ahead is still uncertain.[2] Natural gas markets worldwide have been tightening since August 2021, the so called gas market squeeze. The gas price spikes in the EU market, however, were much more extreme as the US remained (to a large degree) insulated from this global energy shock. The United States have been a net total energy exporter since 2019. According to the 2022 US Energy

[1]There has been considerable debate and skepticism with some experts pointing to this surge in power prices is a sign that the EU energy market mechanisms are failing, while others regarding the event as a temporary effect of the long-term EU renewable energy transition.

[2]Russia used to provide 40% of the gas supply to Europe at the start of the energy crisis. Russia has cut its gas exports to the EU by around 90% since the invasion. As a result, gas prices in the EU increased tenfold over the period from August 2021 to August 2022

Information Administration (EIA) report, US total energy exports exceeded total energy imports by about 3.82 quadrillion British thermal units (quads) in 2021, an increase of about 7.6% from 2020. In contrast, the 2023 Eurostat's energy statistics show that the EU and its member states are all net importers of energy. In 2020, 58% of the energy available in the EU was produced outside the EU member states.

Figure 2 illustrates the different impact of the gas market squeeze for the EU area and the US. The figure plots the TTF-HH spread - the difference between the (normalized) futures prices of the Dutch TTF (EU benchmark) and the Henry Hub (US benchmark) front month natural gas contracts - for the period August 2018 to December 2022.[3] We convert both time series into price indices with base level of 100 at the beginning of the sample period to remove the effect of the contract size and the exchange rate. The spread is computed as the difference between the EU and the US price indices. The figure shows that before August 2021 (the beginning of the gas market squeeze), natural gas price levels in both regions moved together with EU price level being relatively lower. After the gas market squeeze, however, the gap between the EU and the US natural gas price levels widened and at its peak the EU gas price was more than 195 €/MWh higher the US price.

<Figure 2: here>

Figure 3 plots the standard deviation of daily log price difference for the futures prices for the Dutch TTF and Henry Hub front month natural gas contracts for the period August 2018 to December 2022. We use a three-month rolling window to compute the standard deviation of daily returns for for each series. The figure shows that while the spike in volatility of US gas prices following the gas squeeze was similar to previous peaks, in the EU market, the volatility increased almost four times from its level in August 2021.

[3] The TTF refers to the Title Transfer Facility, a virtual marketplace based in the Netherlands where shippers and buyers trade gas supplies. It is considered the reference point to monitor and understand Europe's gas market. The settlement prices at Henry Hub (the official gas delivery location of the NYMEX) are used as benchmarks for the entire North American natural gas market and parts of the global liquid natural gas (LNG) market.

<Figure 3: here>

As power is an essential part of many production processes, the demand for energy commodities is relatively inelastic. Primary energy sources needed for power generation are hard to replace quickly, as supply is constrained by physical infrastructures, and the extraction of some commodities (e.g. natural gas, oil and coal) is concentrated at a limited number of sites. While short-term arbitrage was not possible, the high gas prices in the EU market provided incentives for deliveries via non-Russian pipelines and via record inflows of LNG.[4] The US accounted for two-thirds of this additional LNG supply. As a result, the reliance of Europe on the global LNG market increased dramatically, in particular on destination-flexible LNG bought on the spot market. The prevailing consensus is that Europe's decision to remove its reliance on Russian energy sources has resulted in a long-term dependence on expensive imports of liquefied natural gas, raising concerns about its industry competitiveness in the future.

In this paper, we examine the financial impact of electricity markets regulations in the EU before and after the gas market squeeze on the EU power utilities. We compare their financial performance to that of their US counterparts. We begin by estimating an ARMA-GARCH model for the log changes in electricity prices using daily data for the front-month futures contract in the US and the EU power markets.[5] We document a structural break in the electricity price volatility for both markets that coincided with the start of the gas market squeeze in August 2021. We show that the change in the average volatility before and after the structural break is significantly larger for the EU electricity futures price series than for the US series.

We use the ARMA-GARCH models to simulate daily futures prices for one year period. We use the clearing house margin requirement to calculate mar-

[4] The strong LNG inflows to Europe in 2022 were partly enabled by China's lower LNG imports levels because of slower economic growth and Covid-induced lock-downs.

[5] ARCH-type methodology has been widely used in the literature (e.g. see Koopman *et al.* (2007), Hellström *et al.* (2012), and Escribano *et al.* (2011)). The underlying assumption in these studies is that seasonal effects in the conditional mean account for a significant proportion of the conditional mean dynamics whereas the GARCH-type component accounts for the periods of high volatility.

gins for each day of the contract. This allows us to assess the risk exposure and the cost of collateral for consumers and producers of electricity that are required hedge their risk exposure. We show that the significant increase in the level and volatility of the electricity prices in the EU resulted in large margin calls, generating large liquidity risks for derivatives users. We examine the financial impact of the energy crisis on the power utilities in the US and the EU markets. Our regression results show that following the gas market squeeze, the EU power utility companies experienced significantly lower sales and a sharp drop in profitability relative to their US counterparts. We also show that portfolios comprising of power utilities generated negative excess returns after August 2021. The decline in excess return, however, is much stronger for EU firms relative to their US counterparts and for portfolios comprised of fossil fuel power utilities relative to power utilities that use renewable sources.[6]

Our paper provides several contributions to the literature. The recent surge in energy prices has led to many papers studying their implications for current policy. Lorenzoni and Werning (2023), Blanchard and Bernanke (2023) and Gagliardone and Gertler (2023) find that energy prices can explain recent inflation developments. Kharroubi and Smets (2023) study their implications for the natural rate of interest whereas Chan *et al.* (2022) and Langot *et al.* (May, 2023) study effects on aggregate demand in an open-economy heterogeneous-agent New Keynesian setting. Langot *et al.* (May, 2023) conduct a policy analysis for France, backing out the shocks that rationalize the data and then using the model for policy counterfactuals. Auclert *et al.* (2023) show that any individual country's monetary tightening is costly and of limited use in fighting inflation after an energy price shock; but that it comes with positive externalities on other energy importers. Inversely, fiscal policy can be very powerful in cushioning the effects of energy price shocks, but tends to have negative externalities on other countries. In light of these results, a promising combination of monetary and fiscal policy could be one that focuses on aggressive, coordinated monetary tightening, combined with fiscal relief targeted to the poor—crucially, avoiding energy price subsidies.

[6] This is consistent with the policy debates in the EU that argued that the high energy prices have hurt utilities that were not hedged with long-term contracts, and also produced high profits for infra-marginal technologies (those cheaper than natural gas combined cycles).

Our paper is also related to the literature that focuses on designing policies that adapt price signals to support the green energy transition (see e.g. Ignacio J. Pérez-Arriaga (2016), Joskow (2012) and Batlle *et al.* (2022)). The unexpected sharp increase in fossil fuel prices after the Russian invasion of Ukraine, has generated substantial uncertainty. Broad-based energy price subsidies proliferated as governments struggled to shield consumers from rising and volatile energy prices. Unfortunately, these subsidies masked the price signals given by the relatively more expensive fossil fuel prices compared with other products including clean energy.

Our paper is also related to the line of studies that analyze the impact of renewables on electricity prices (see Fabra and Reguant (2014) and Peña *et al.* (2020). The impact of renewables on electricity price, is considered through the merit-order effect of low-cost renewable capacity displacing conventional sources (Peura and Bunn (2021), Baldick (2012)). Several papers, however, have added nuances to this view by including output variability in the analysis. Al-Gwaiz *et al.* (2017) show that ignoring such operational factors may overstate the competitiveness of a spot market because producers may exploit their competitors' operational constraints in their bidding strategies, and Sunar and Birge (2019) find that renewables may even increase power prices if the system operator imposes penalties that reduce quantities of power sold to the market in the face of intermittent output.

Our paper also relates to the literature that examines the effects of geopolitical risk in energy markets. Goldthau and Boersma (2014) discuss the dual challenge faced by the energy sector. Specifically they argue that while the energy world enters a new phase with increased emphasis on renewables and energy efficiency, it is forced to rapidly respond to increasing geopolitical tensions that threaten global energy security and energy sustainability. According to IEA's World Energy Outlook 2022, the recent spikes in energy prices can be attributed to ambitious climate policies and net zero commitments, as well as to the heightened geopolitical risks.[7] Our main contribution centers around analyzing the impact of the gas market constraints following

[7] Full report available at https://www.iea.org/news/world-energy-outlook-2022-shows-the-global-energy-crisis-can-be-a-historic-turning-point-towards-a-cleaner-and-more-secure-future

the energy crisis, which posed substantial risks for corporations. This underscores the inherent vulnerability of the global energy system.

The remainder of this paper is organized as follows. The next section discusses the background to the study. Section 3 describes our data collection process, presents summary statistics for our sample and outlines the research design of the paper. Section 4 presents our empirical results. Section 5 concludes the paper and highlights opportunities for future research in the area.

2. Background to the study

This section provides background to the study. Electricity has always been viewed as an essential service. Electricity is generated at power plants and moves through a complex system, called the grid, of electricity substations, transformers, and power lines that connect electricity producers and consumers. Because of these technical properties, electricity markets have emerged as regulated design markets. Wholesale electricity markets usually operate as a centralized market (power pool) or decentralized market (bilateral contracts). The markets in a liberalized electricity system are spot (day ahead and intra-day), futures, balancing, ancillary services, and retail. In the wholesale market, short term contracts are carried out in the spot market (day-ahead and intra-day markets) and long term contracts are traded OTC or in the futures market, which covers trades from one week up to several years. To maintain grid frequency and system stability, supply and demand has to be constantly balanced in real time due to the lack of storage capacity in power systems. System balancing is carried out via the balancing and ancillary services market to accommodate any shortfalls or oversupply in the spot market. The spot electricity markets determine the quantities generated and consumed as well as the prices paid for energy and related services at each time and location. The long-term markets for trading electricity power contracts, on the other hand, allow market participants, such as generators, utilities, and large consumers, to hedge against price volatility and manage their long-term electricity supply and demand needs.

In the European Union, electricity prices are determined per bidding zone which in most cases is identical to a country.[8] Such an approach is called zonal pricing. In the zonal market, the market is cleared on the basis of simplified transmission constraints. Under zonal pricing, only transmission capacity limitations between the different zones are considered in the market-clearing process. The transmission lines within a zone are assumed to have unlimited capacity. This assumption is more and more challenged in the context of the EU goal for energy transition. One important factor is the changing pattern of network flows due to the integration of renewables. Europe's zonal configuration is becoming a limiting factor for the efficiency of market integration.[9]

In the US, some regions/states have implemented deregulation and have restructured their markets, allowing for competitive electricity supply whereas other regions/states have remained heavily regulated. The wholesale pricing mechanism therefore varies among different regions and states but commonly include auctions, day-ahead markets, and real-time markets where supply and demand factors determine prices. Utilities and power providers can also enter into long-term contracts called Power Purchase Agreements (PPAs). PPAs involve negotiated pricing arrangements between electricity generators (such as renewable energy developers) and utilities or other buyers. In regulated markets, electricity rates are set by regulatory authorities such as state public utility commissions. Regulators determine the pricing structures and allowable returns for utilities based on cost-of-service analyses, which consider the costs of generation, transmission, distribution, and other operational expenses.

US Independent System Operator (ISO) markets, such as the Electric Reliability Council of Texas (ERCOT), use the nodal pricing mechanism. Nodal pricing is based on location-specific prices, known as nodal prices, which are

[8] As of 2021, exceptions are Sweden (4 bidding zones), Denmark (2 bidding zones) and Italy (7 bidding zones). Norway (5 bidding zones) is outside of the EU but part of the internal electricity market. Conversely, Germany shares a bidding zone with Luxembourg, as well do the Republic of Ireland and Northern Ireland.

[9] An important argument behind the more simplistic representation of the network in the market clearing was that it facilitated horizontal integration across formerly national markets (see e.g. Meeus *et al.* (2005)). Indeed, the EU market became the world's largest electricity market in terms of traded volumes.

determined for individual nodes within the electricity grid. A node represents a specific location, such as a substation or a point of interconnection, where electricity is generated, consumed, or transmitted. This approach allows for more granular pricing and reflects the actual congestion and losses experienced in the transmission system. Nodal prices are often expressed as Locational Marginal Prices (LMPs), which represent the marginal cost of supplying electricity at a particular node. LMPs take into account various factors, including generation costs, transmission congestion, losses, and other system constraints. Nodal and zonal systems differ primarily in the way transmission constraints are considered in the market. A nodal system considers every node in the transmission grid and clears the market on the basis of a direct current (DC) approximation of the power flow equations in which every transmission line is accounted for.

2.1. Spot Markets

Spot electricity markets, also known as wholesale markets, facilitate the immediate purchase and sale of electricity for near-term delivery.[10] These markets are designed to match the real-time supply of electricity with the fluctuating demand. Market operators continuously monitor the grid and adjust supply and demand in response to changing conditions, such as unexpected outages or changes in demand, to maintain grid reliability.

The price for wholesale electricity can be predetermined by a buyer and seller through a bilateral contract (a contract in which a mutual agreement has been made between the parties) or it can be set by organized wholesale markets. The spot market operator, typically an ISO or RTO, collects all bids and arranges them in ascending order of price. Generators offer their electricity supply into the market by submitting bids indicating the quantity of electricity they can provide and the price at which they are willing to sell. Demand-side participants, such as utilities, submit bids indicating

[10] For example, Pennsylvania-New Jersey-Maryland Interconnection (PJM) operates a wholesale electricity market that spans Delaware, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM operates a Real-Time Energy Market (five minutes) and a Day-Ahead Market (one day forward).

the quantity of electricity they need and the price they are willing to pay. The market is then cleared by accepting bids starting from the lowest price until the total demand is met. The clearing price is determined by the last accepted bid, which sets the market price for all transactions. After the market clears, market participants are paid or charged based on the market price and their accepted bids. Generators receive payment for the electricity they supplied, while buyers pay for the electricity they consumed at the market price. Unlike the liberalized parts of the US electricity market that apply nodal pricing, EU electricity markets rely on uniform pricing within bidding zones. The fundamental principle of the EU zonal pricing is that hourly day-ahead prices are the same for all nodes in the zone. The market clearing in a zonal pricing system may create infeasible power flows within the zones that are usually managed by ordering participants to change their generation/consumption after the day-ahead market has cleared. Such interventions are supposed to be infrequent and have insignificant effect. Recently, however, these interventions have intensified which has led to even more volatile flows and higher costs[11].

2.2. Long-term Markets

The restructuring of the wholesale electricity markets has been accompanied by the development of derivatives markets. Well-functioning derivatives markets are of high importance for market participants, since electricity is practically non-storable, and hence, subject to extreme price volatility. These markets allow participants to enter into contracts for electricity supply over an extended period of time. The Real-Time Energy Market lets market participants buy and sell wholesale electricity during the course of the operating day. The Real-Time Energy Market balances the differences between day-ahead commitments and the actual real-time demand for and production of electricity. Day-ahead trading either takes place on the spot market of the respective power exchange such as the NYMEX/CME in the US and the EEX, the Nord Pool and other markets in the EU (often called day ahead market or day ahead auction) or through bilateral contracts between two

[11] See https://www.ceer.eu/documents/104400/-/-/5ef3cb7d-e2e2-5484-5ba8-344b3f3a4e3f

parties - usually power trading companies - outside of the power exchange in over the counter (OTC) deals. Forward and futures markets, on the other hand, trade electricity contracts from one month to several years to delivery.

The long-term electricity markets are typically financial rather than physical and they allow market participants to hedge their generation or consumption volumes in the longer-term. In most markets, longer-term hedging can be OTC or through standardized futures, forwards (commercial name deferred settlement (DS) futures) and options. Neither forwards nor futures usually lead to physical delivery of electricity: they are cash-settled in the delivery (or settlement) period. Liquidity among the different products and maturities varies considerably.

Power producers and retailers use forward contracts to hedge against spot-revenue volatility. In the United Kingdom, for example, more than 90% of electricity is traded as forward contracts specifying a quantity to be delivered in subsequent spot markets[12]. Moreover, the pricing of forward contracts differs from spot-market cost competition. In addition to the underlying generation costs, forward electricity prices are determined by the market participants' hedging of risk exposures (Bessembinder and Lemmon 2002), reflected in sustained forward premium, that is, differences in forward and spot prices for the same delivery period (Longstaff and Wang (2004), Redl and Bunn (2013), Weron and Zator (2014). Regulators have long encouraged forward trading as a means to curtail market power and reduce prices (e.g., Borenstein (2002)).

In this paper, we show that following the spike in volatility generated by the gas market squeeze, there was a large increase in the margin requirements for power futures traders. This meant that counterparties – including power utilities – came under pressure to meet large margin calls. In order to maintain their hedge, energy firms had to either source cash or collateral to meet the new margin requirements through credit lines and loans extended by banks, or shift to OTC transactions. A sizable shift by utilities towards the OTC markets, however, will likely result in greater risks for the counterparties and

[12] See https://www.ofgem.gov.uk/publications/ofgems-annual-report-2008-2009

the stability of the financial system.

3. Data and Research Design

3.1. Sample Data

This section describes our sample data, presents summary statistics and describes our research design. This paper uses several data sources. We obtain daily prices for gas and electricity spot and futures contracts for the period August 2018 to Decemeber 2022. The time series for the US gas spot price (Henry Hub) is from the St. Louis Fed database, the Henry Hub Natural Gas Futures prices are from the CME-NYMEX exchange, and the Dutch TTF Gas Futures prices are from the ICE exchange. The day-ahead electricity prices come from Red Electrica for the EU markets and from the Electric Reliability Council of Texas (ERCOT) for the US market (using nodal prices). See Table 5 in the Appendix to the paper for definitions of our data series.[13] We use daily data on German power futures EEX Phelix DE/AT Baseload Quarterly Energy Future Continuation 1 for the same period. The EEX is the most liquid power futures market in Europe.

To examine the financial impact of the regulatory approach during the energy crisis, we obtain daily stock prices for power utility companies operating in the EU and North America for the period August 2018 to December 2022. We download quarterly accounting data for all firms in SIC code 4911 from the COMPUSTAT North America and the Compustat Global database respectively for the period January 2010 to December 2022. We apply the standard filters to clean the data. We drop all observations for which data on total assets, revenues, capital expenditures, long and short-term debt, shares outstanding and stock price are missing. We also remove all penny stocks (share price lower than $1), all companies with negative book equity and all firms traded OTC or on a junior exchange (*e.g.* TSX Venture). The final sample consists of 46 EU and 160 North American (US and Canada) power utilities. All data are converted to USD using the quarterly exchange rate.

[13] All prices are measured in $ per mmbtu. We convert all €/MWh prices to $ per MWh using daily exchange rates.

3.2. Summary Statistics

Panels A and B of Table 1 report summary statistics for the log price returns for pas and electricity price series. The sample period is Aug 2018 to July 2021 (period before the gas market squeeze) and Aug 2021 to Dec 2022 (the gas market squeeze). The table shows that the EU benchmark gas and power (spot/day-ahead and futures) return series exhibit higher volatility than their US counterpart return series. The last column of the table reports the F-scores from an F test for differences in the volatility (standard deviation) between the two periods - before and after the gas market squeeze. The F-value (apart from the day-ahead Texas daily return series) provide evidence that the volatility of gas and electricity returns was significantly higher during the period after August 2021.[14]

Panel C of Table 1 reports descriptive statistics for the sample of US and EU power utilities. The average (and the median) EU power utility firm is larger but has significantly lower capital investment as a proportion of total assets. Over the sample period 2010 and 2022, the average (median) EU power utility was less profitable, held more cash and paid higher dividend than the average (median) US power utility.

3.3. Research Design

This subsection describes the research design of this paper. As discussed in the introduction, natural gas prices have a large impact on price formation and market clearing in EU electricity markets. Uribe et al. (2018), amongst other researchers, have documented that when power generation is costly and both power and gas are closer to maximum price levels, the correlation between the price of gas and the price of power is not only positive, but is also significantly stronger than at other times when both goods are relatively abundant.

[14] Wholesale electricity prices in Texas were especially volatile prior to the gas market squeeze. A major winter storm in February 2021 led to significant energy disruptions in Texas. Extreme cold temperatures restricted the flow of natural gas for power generation, and many wind turbines froze. These supply constraints caused large increases in electricity prices in the ERCOT day-ahead market.

Following the drastic increase in natural gas prices, EU countries adopted emergency regulations to address high energy prices during the energy crisis. By the end of 2022, European countries' bill to shield households and companies from soaring energy costs climbed to nearly 800 billion euros surpassing the 2020 EU's 750-billion-euro COVID-19 recovery fund.

In this paper, we showed that while government subsidies shielded retail consumers, there was a significant cost on the EU power utilities that were required to hedge their longer-term electricity exposure. We begin our discussion with a short description of the margin requirements on EU electricity contracts and explain how we simulate the required collateral values. The European Commodity Clearing (ECC) is the central clearing house of the European Energy Exchange AG (EEX) which specializes in energy and commodity trading. In the US, the equivalent of the ECC is the derivatives clearing organization (DCO) that is regulated by the Commodity Futures Trading Commission (CFTC).

The CME and the EEX use a margining system to calculate the collateral requirements for the derivative products traded on these exchanges. The system, adopted by many option and futures exchanges worldwide, is a standardized portfolio analysis of risk (SPAN) system that calculates potential changes in the value of a trading member's portfolio over a time horizon that is needed to liquidate the portfolio.

Single margin parameters (SMPs) are values which quantify risk of futures positions and are used to determine the Initial Margin for derivatives. The SMPs are calculated each business day. The single margin parameter quantifies the price change risk over the liquidation period and is a multiple of a contract's returns' standard deviation. For a given contract X and day t the single margin parameter $M_X(t)$ is given by:

$$M_X(t) = p_X(t) \cdot \sigma_X(t) \cdot \sqrt{l_X} \cdot R_X(t)$$

where $p_X(t)$ is the contract settlement price, $\sigma_X(t)$ is an exponentially weighted standard deviation of past observations, l_X is the liquidation period (days) and $R_X(t)$ is the risk multiplier. For more details about how to compute each component of the SPAN model, see ECC derivative margining dopcuments at https://www.ecc.de/en/risk-management/margining.

The next subsections describes how we estimate an ARMA-GARCH model for electricity returns and explains how we simulate initial margin requirements for a long position in a futures contract for (i) the gas market squeeze using the EU shocks; and (2) the gas market squeeze using US shocks.

3.4. Volatility Modeling and Estimation

In this section, we describe how we model the volatility of daily electricity returns over our sample period. As discussed in the introduction to this paper, Figure 3 suggests that a (possible) structural break occurred in the volatility of electricity returns following the gas market squeeze. We formally test this hypothesis using the Fisher equality of variances test applied to the spot and future price series in the EU and US markets.[15] The results from the test are reported in last column of Table 1. The F scores suggest that we can reject the null hypothesis of equal variances at conventional levels of significance for all but one the of commodity time series - the Texas day-ahead electricity price series.

To simulate daily prices for an electricity futures contract we require a return generating process. We use an ARMA-GARCH(1,0,1,1) with t-student distributed residuals to model electricity returns. The specification is as follows:

$$
\begin{aligned}
R_{t+1} &= \Phi_0 + \Phi_1 \, R_t + u_{t+1} \\
u_{t+1} &= \sqrt{h_{t+1}} \, \epsilon_{t+1} \quad \epsilon_{t+1} \sim t_\nu \\
h_{t+1} &= \kappa + \alpha \, u_t^2 + \beta \, h_t
\end{aligned}
$$

We use maximum likelihood method to estimate an ARMA-GARCH process

[15] See Agresti and Kateri (2021) for details.

and obtain forecast for the GARCH volatility and derive the innovations (shocks to electricity returns) for the period before and after the gas market squeeze. Using the volatility forecast from the estimated model and the generated shocks, we carry out simulations of daily collateral requirements.

We simulate the daily prices for a one-year electricity futures contract. We compute the futures prices using the electricity return process, which follows the estimated ARMA-GARCH model. The innovations are obtained by bootstrapping from the historical innovations. We split the time period into two sub-periods - before and after the gas market squeeze - and innovations are bootstrapped from each period. We also study the distributions of collateral values under different scenarios during the last period (day) of the simulations.[16] By comparing the characteristics of the distributions on the last day of the simulations, we can quantify the cumulative effect of gas market squeeze for the EU vs US regulations.

Next, we examine the effect of EU regulations on power utility firms during the gas market squeeze, we estimate the following general form regression specification:

$$Firm\ \ performance = Gas\ \ Market\ \ Squeeze \times EU + Controls$$

where $Firm\ performance$ is the (i) change in revenues; (ii) profitability; or (iii) unlevered beta. We include the standard control variables - size, investment, and MTB (Tobin's Q). Since sales and profitability are persistent, we also include lags in these regression specifications. The estimation results for the specification above are based on fixed effects OLS regressions with standard errors clustered at the firm level. We also use system GMM (see Arelano and Bond, 1992) to estimate the specification as a dynamic panel. Our results remain the same.

Finally, we examine the financial impact of the gas market squeeze on the

[16]Since, the simulations were based on the same process with the same distribution of innovations, it makes sense to study the price levels rather than the observed returns.

stock market performance of the EU power utility firms. First, we compute the risk adjusted returns from a one-factor model for two different portfolios of power utilities: one with high exposure to natural gas and one with high exposure to renewables (nuclear, wind, solar and hydro). We compute both alphas (risk adjusted excess returns) as well as cumulative daily returns.

We construct a control portfolio for the sample of EU power utilities by applying the synthetic control method introduced by Abadie et al. (2010). We use our sample of US power utilities to create a synthetic counterfactual. The weights of the synthetic portfolio are obtained using a minimum distance estimator that is applied to a series of restrictions on the cumulative stock returns.

Let $R_{1,t}$ denote the return of the stock of the EU power utility firm for which we want to measure the effect of the gas market squeeze. The synthetic portfolio is built using the US stocks that were not exposure to the single EU energy market regulations and the shock of the gas market squeeze to replicate the performance of the security of interest. These sets of stocks constitute the control group $(R_{2,t}, \ldots, R_{J,t})$. For the synthetic portfolio, we estimate the weights, w_j^*, by solving the optimal tracking problem:

$$min_w \sum_{t=T_1}^{T_2} (R_{1,t} - \sum_{j=2}^{J} w_j R_{j,t})^2$$

The estimation period $[T_1, T_2]$ is from August 2018 to July 2021 (before the gas market squeeze). In addition, we include restrictions on the estimated weights, such as nonnegativity constraints constant the weights and that the weights sum to one. For more details on the estimation procedure see Abadie et al. (2010) and Castro-Iragorri (2019) for an application to stock market returns using M&A events. The next section describes our simulation and estimation results.

4. Empirical Analysis

This section presents our empirical results. By the end of 2022, power price volatility has shifted dramatically as a consequence of the energy crisis. This spike in volatility increased the requirement for hedging operations for producers and consumer. As shown by ACER 2022[17], the liquidity of mid/long-term power contracts in Europe was extremely low. This created additional barriers to the possibility of hedging.

The lack of storability of electricity creates the unique characteristics of the power markets: the energy is produced and dispatched instantaneously. As a consequence, electricity prices display relatively high intra-day as wel as lower frequency volatility making the margins required in medium-term contracts larger, and the trading capacity lower. In the next subsection, we model the electricity prices and their volatility. Then, we use the model to examine how the volatility affects the required collateral for a long position under different shock scenarios.

4.1. The cost of collateral of electricity derivatives

We have used the model presented in order to study the past volatility in prices. It can also be used to study the effect of electricity prices trough simulations. In particular, we are interested in the effect of the high risk situation in the collateral requirements of a futures power contract. The following initial values are used for the simulation. First, we select as benchmark the German Futures, with 1 year time to expiration. Secondly, we set the initial value equal to 730 (which is the number of hours within a month) times the price of the MWh.

We simulate the value of the contract for 252 days (1 year) using as shocks for the simulation a bootstrap sample covering the gas squeeze period from August 2021 to December 2022. As we showed previously, the margin requirements rise abruptly after August 2021. We carry out two simulations,

[17] https://www.acer.europa.eu/events-and-engagement/news/press-release-acer-publishes-its-final-assessment-eu-wholesale

using the shocks for the German Future and using the shocks observed for an equivalent US futures contract for the same period. The later one was not affected by the extent of the energy crisis experienced in Europe and provides a benchmark scenario for comparison. The margins used are the established by the ECC (the formula was introduced in Section 2). The first row of Figure 6 shows the prices simulated and the price distributions.

In the second stage of our analysis, we use the results of the simulations and the futures contract to analyze the collateral under each simulation of an agent which is long in the future. We aim to understand what is the amount of collateral that is implicitly required to the power provider in the each scenario. Figure 6 illustrates the time series evolution of the margins under each of the previous simulations and the global distribution (second row). While there is a significant amount of cases in which the additional collateral does not surpass 1M (10 times the initial value of the contract), there are many cases in which it grows significantly. In fact, the average additional collateral (see last row of Figure 6) is four times the original value of the contract. Therefore, the amount of collateral obtained in *a priori* estimations is very large, increasing the cost of hedging.

<Figure 6: here>

Given the expected collateral required, it seems unlikely that futures can be traded with enough liquidity to hedge against high volatility price exposures (such as those seen in the Europe Union). It is therefore difficult to perform risk management using cash as a collateral. Given that the product that is being hedged is electricity it could be possible to use a collateral stored electricity. For instance central clearing houses should own storing devices such as reservoirs that in essence allow storage of electricity. Thus, a different type collateral could be a guarantee to generate the promised electricity by the contract.

We believe that the hedge should be provided by institutions that can store electricity, those institutions are not so exposed to rises in the electricity price since they own the underlying. And the institutions providing the hedge would benefit from taking the premiums of managing the risk.

Table 2 presents the results from our simulation analysis. The results show that there is a structural break in the electricity prices which induces a rise of almost 300% in the average electricity price with high levels of volatility. This leads to a 700% increase in collateral requirements. The rise in collateral requirements is much higher than the one in prices due to the rampant volatility observed in the power markets in the past years.

4.2. Financial Performance of Power Utilities

We turn to our second step in analysis the effect of policy regulations on the financial performance of US and EU power utility firms.

Table 4 documents the time series evolution of cumulative returns of two equally weighted portfolios of power corporations (the EU equity portfolio and the US equity portfolio). Reported figures include Mean returns and standard deviations calculated for two sub-periods determined by the start of the gas market squeeze in August 2021. Reported estimates for risk-adjusted returns demonstrate a clear decrease in risk-adjusted returns for the European power portfolio in the aftermath of August 2021. However, this is not the case for the US portfolio benchmark. In fact, the US power portfolio exhibits higher risk-adjusted returns after the introduction of the gas squeeze, as US-based power corporations benefit from higher power prices. The under-performance of the EU portfolio in the second sub-sample (aftermath of the gas squeeze) is remarkable, considering that the first sub-sample covers the COVID crisis in March-April 2020.[18]

Figure 7 plots the equally-weighted cumulative daily returns for a sample of US and EU power utility companies. Figure 7 illustrates the main finding of this paper is a simple way. It shows that before August 2021 the two return series move together and after that period they diverge, reaching on 26th November 2022 a maximum difference of 122.3%.

<Figure 7: here>

[18] Note that due to the effect of COVID if one compares portfolio volatility before and after the gas squeeze the EU portfolio volatility is lower in the aftermath of the gas squeeze. However this is not the case if we analyze risk adjusted returns or if define the first sample from June 2020 in the aftermath of the COVID crisis

We have extended the analysis of power utilities by studying the returns of portfolios based on their exposure to gas. We build two pair of portfolios, for Europe and North America, based on the companies business. One one hand we will have companies that are more green and less exposed to fossil fuels, specially gas, on the other hand will be the companies that are more exposed to fossil fuels.

With the portfolios constructed, we separate them in two time periods, from January 2019 until August 2021 (when the gas squeeze starts), and from August 2021 until July 2023. Then we estimate the parameters of the CAPM framework for each portfolio in each time-window. Table 4 shows the alphas of the regression. There is evidence that the changes in the alphas between those periods is significant. The portfolios' alphas diminished after the gas squeeze but, nevertheless, the European green portfolio has been less affected than brown portfolio. This effect is not so clear in the US.

Power utilities that are included on our green portfolios produce electricity at a very low cost, although higher CAPEX. As we mentioned, Europe has a zonal market where large amounts of electricity is sold and there are some adjustments based on the grid and more (in contrast, US has nodal pricing), we believe that this frame leads to large amounts of low-cost electricity being sold at gas price electricity. Thus, the green companies in Europe have performed better the gas crisis.

5. Conclusions

The energy crisis, particularly in Europe, coupled with the increasing reliance on renewable energy sources, necessitates a departure from the traditional approach of marginal pricing tied to fossil fuels. These challenges have prompted the recent re-evaluation of the existing market design's ability to address the current energy landscape. The transition towards low-carbon electricity generation, within the context of geopolitical tensions and crisis, signifies a paradigm shift in both the power system and market dynamics. Consequently, price volatility is expected to be a prominent characteristic of the energy transition, emphasizing the need for a transformation of the current energy system. Academics and industry experts have offered solutions aimed at reforms to adapt the power market to the demands of the energy transition (see IIT 2023 working paper "An assessment of the electricity market reform options and a pragmatic proposal" and references therein[19]). However, these solutions must account for the geopolitical energy crisis and the challenges associated with achieving the net-zero ambitions by 2050. The anticipated increase in volatility may adversely impact consumers and producers in a market with limited liquidity for long-term contracts.

This paper argues that the tight connection between natural gas and electricity prices in the EU has generated significant burden for energy producers and consumers. Following the gas market squeeze, the electricity prices rose too – even though fossil fuels generate less than 40% of electricity at EU level. This is due to the fact that the electricity price is determined on the so-called merit order principle. The spike in electricity prices led to inflationary pressures not seen in Europe in decades, squeezing household budgets and increasing the cost of living, especially of those more vulnerable. In Europe, businesses faced the double impact of rising energy costs and a potential decline of consumer spending due to households' increased energy-related expenses.

Throughout 2022, many EU countries introduced measures to ease the impact of price spikes on citizens, e.g. by reducing VAT or by offering subsidies to households and companies. We provide evidence that the unprecedented volatility spike and the subsequent tightening of collateral requirements created a significant cost for EU power utility required to hedge their exposure to electricity price risk. We document an almost 700% increase in the average collateral value required for one-year EU futures contracts. We provide empirical evidence that following the gas market squeeze, the EU power utilities experienced lower sales and profitability relative to their US power utilities counterparts. We show that the risk-adjusted return on a portfolio comprising of EU power utilities was significantly lower that the equivalent US portfolio.

Government regulations play a pivotal role in managing and mitigating the

[19] https://www.eprg.group.cam.ac.uk/wp-content/uploads/2023/03/text2305.pdf

consequences of an energy crisis. By implementing policies and measures, governments can effectively respond to the crisis, ensure energy security, and stabilize the economy. The strong increases in natural gas prices have prompted substantial switching to the use of coal rather than natural gas to generate electricity in Europe. The increased use of coal is in turn is driving up CO2 emissions from electricity generation globally. While government regulations impose certain costs on industries and businesses, they also yield positive financial outcomes in the long run. These regulations incentivize investments in renewable energy sources, energy efficiency, and clean technologies, fostering the development of a more sustainable and resilient energy sector.

Investments in oil and natural gas have declined in recent years as a result of two commodity price collapses – in 2014-15 and in 2020. This has made supply more vulnerable to the sorts of exceptional circumstances that we see today. At the same time, governments have not been pursuing strong enough policies to scale up clean energy sources and technologies to fill the gap. The financial impact of government regulations should be considered alongside broader societal and environmental benefits. While the immediate costs may be apparent, the long-term advantages in terms of reduced carbon emissions, improved air quality, and sustainable energy systems are essential for addressing the global challenges of climate change and achieving a more sustainable future.

Our results inform the recent efforts of the European Commission (EC) to mitigate the soaring price of electricity in the EU (European Commission, 2021). The EC acknowledges the theoretical convenience of the current price setting mechanism, while also calling for an urgent debate regarding novel pricing and regulatory mechanisms to make the system more resilient to the kind of shocks observed in 2021 and 2022. In particular, the EC highlights the need to isolate the European system from the great uncertainty implied by the variability of fossil fuel markets, particularly natural gas, and more importantly, from an energy security perspective, to gain independence from geopolitical aspirations external to the EU (European Commission, 2021). Future research is needed to inform further this policy debate.

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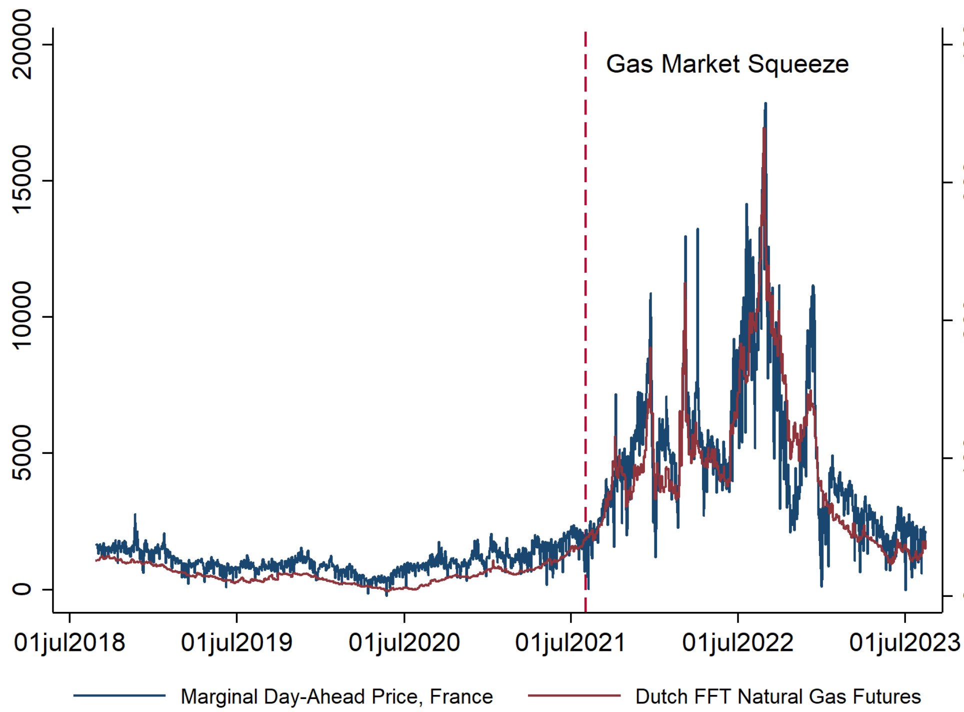


Figure 1: Marginal Day Ahead Electricity Market in France and the Dutch TTF Natural Gas Futures Prices

The figure shows the average marginal electricity price from the French day-ahead market (€/MWh) and the Dutch TTF front month futures prices (€) for the period August 2018 to June 2023.

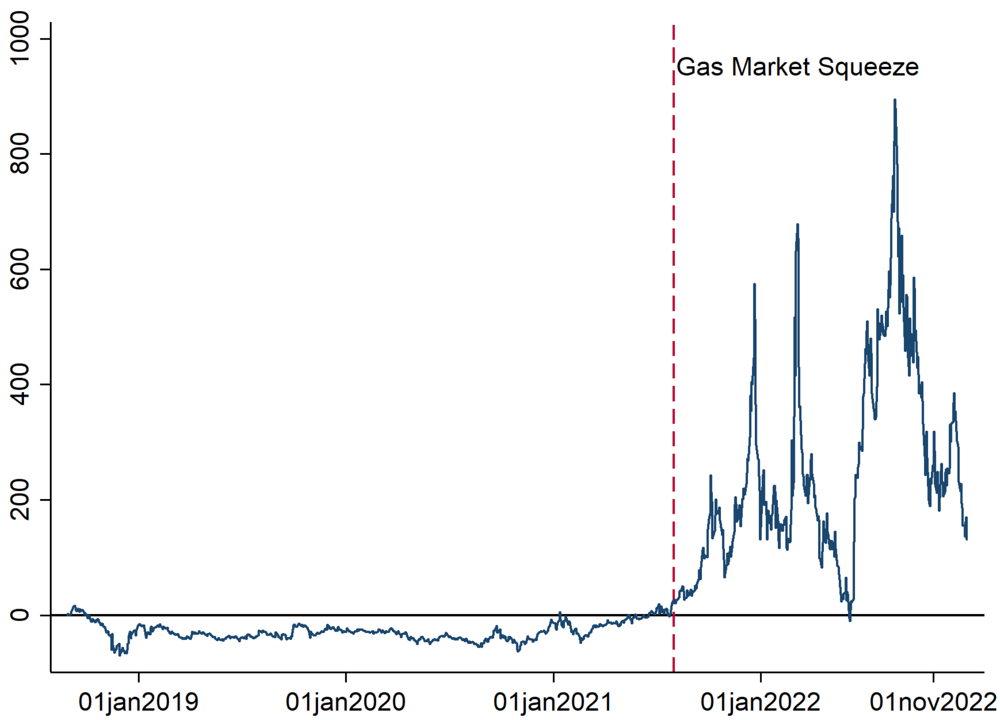


Figure 2: Spread between the EU and US Front-month Futures Gas Prices

The figure plots the difference between the (normalized) futures prices of the Dutch TTF and Henry Hub front month natural gas contracts for the period August 2018 to December 2022. We convert both time series into price indices with base level of 100 at the beginning of the sample period to remove the effect of the contract size and the exchange rate. The spread is computed as the difference between the EU and the US price indices.

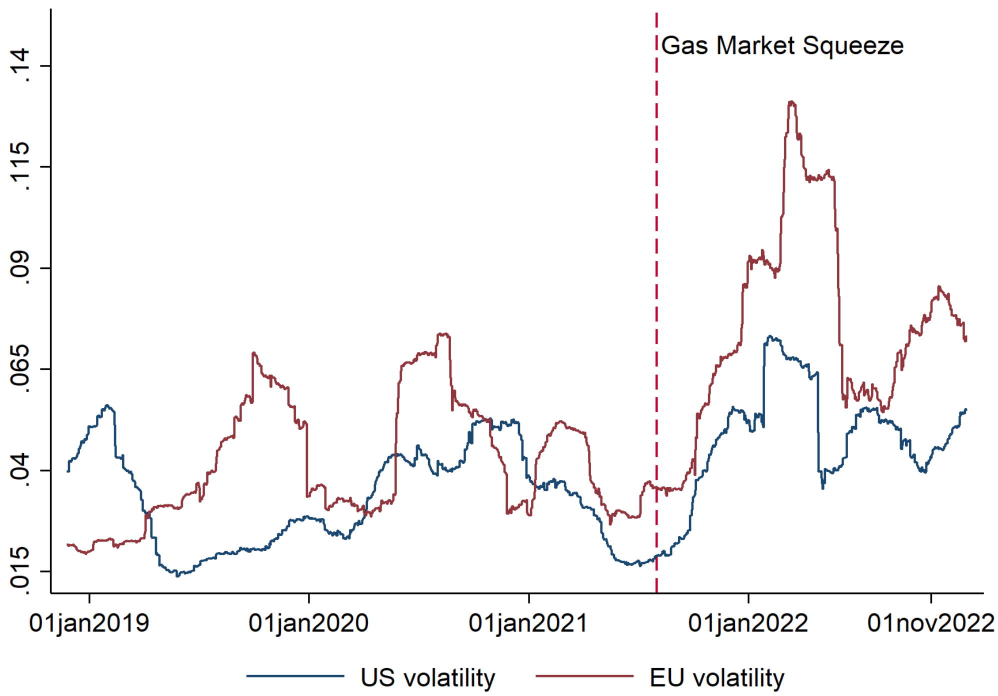


Figure 3: Daily Volatility of EU and US Front-month Natural Gas Futures

The figure plots the standard deviation of daily log price difference for the futures prices for the Dutch TTF and Henry Hub front month natural gas contracts for the period August 2018 to December 2022. We use a three-month rolling window to compute the standard deviation of daily returns for for each series.

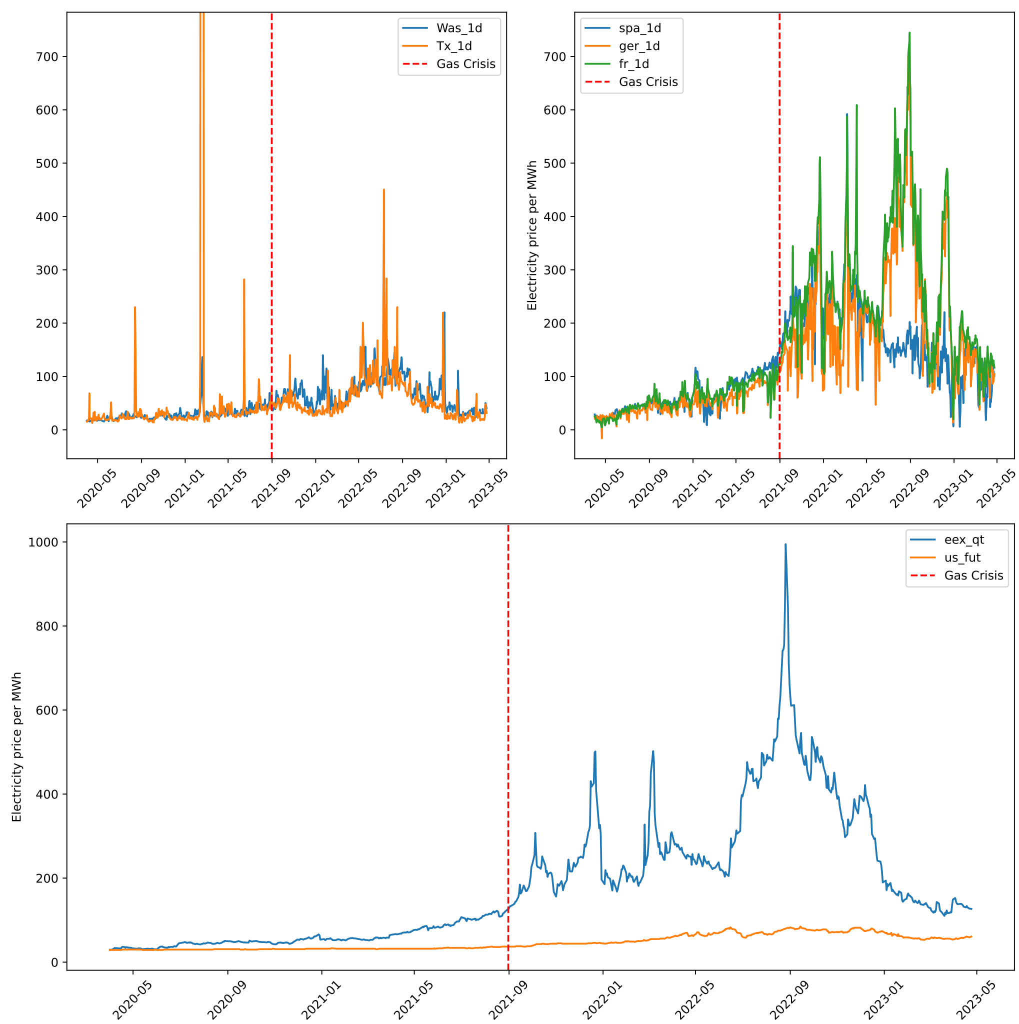


Figure 4: Comparison of Spot and Futures Electricity Prices in the EU and US markets

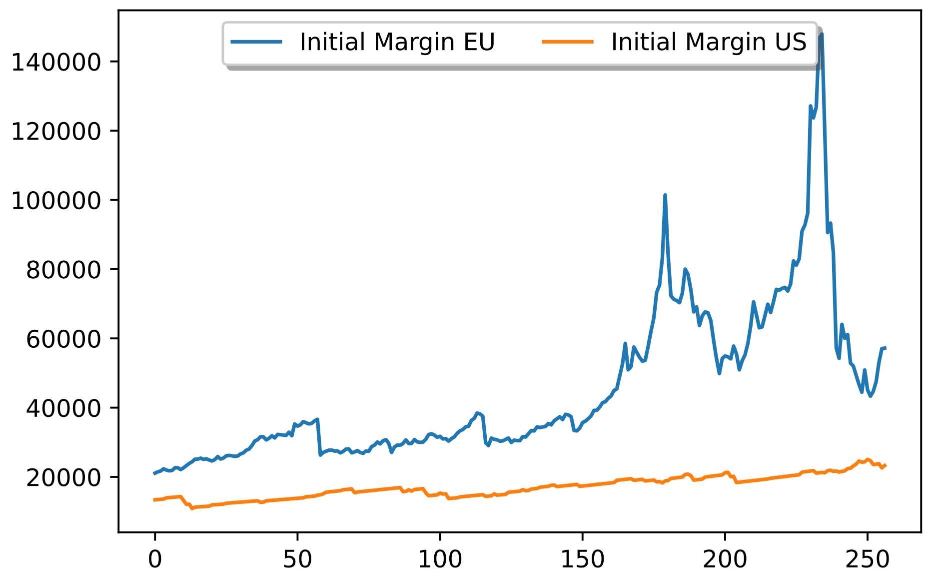


Figure 5: Initial Margin Requirements during the Gas Market Squeeze

The figure plots the margin requirements for EU and US electricity futures contracts. Margin values are computed for each time period (day) using the ECC (CME) margining formula for the EU and the US futures prices. The US margins have been normalized to correct for the size and exchange rate differences in the two price series.

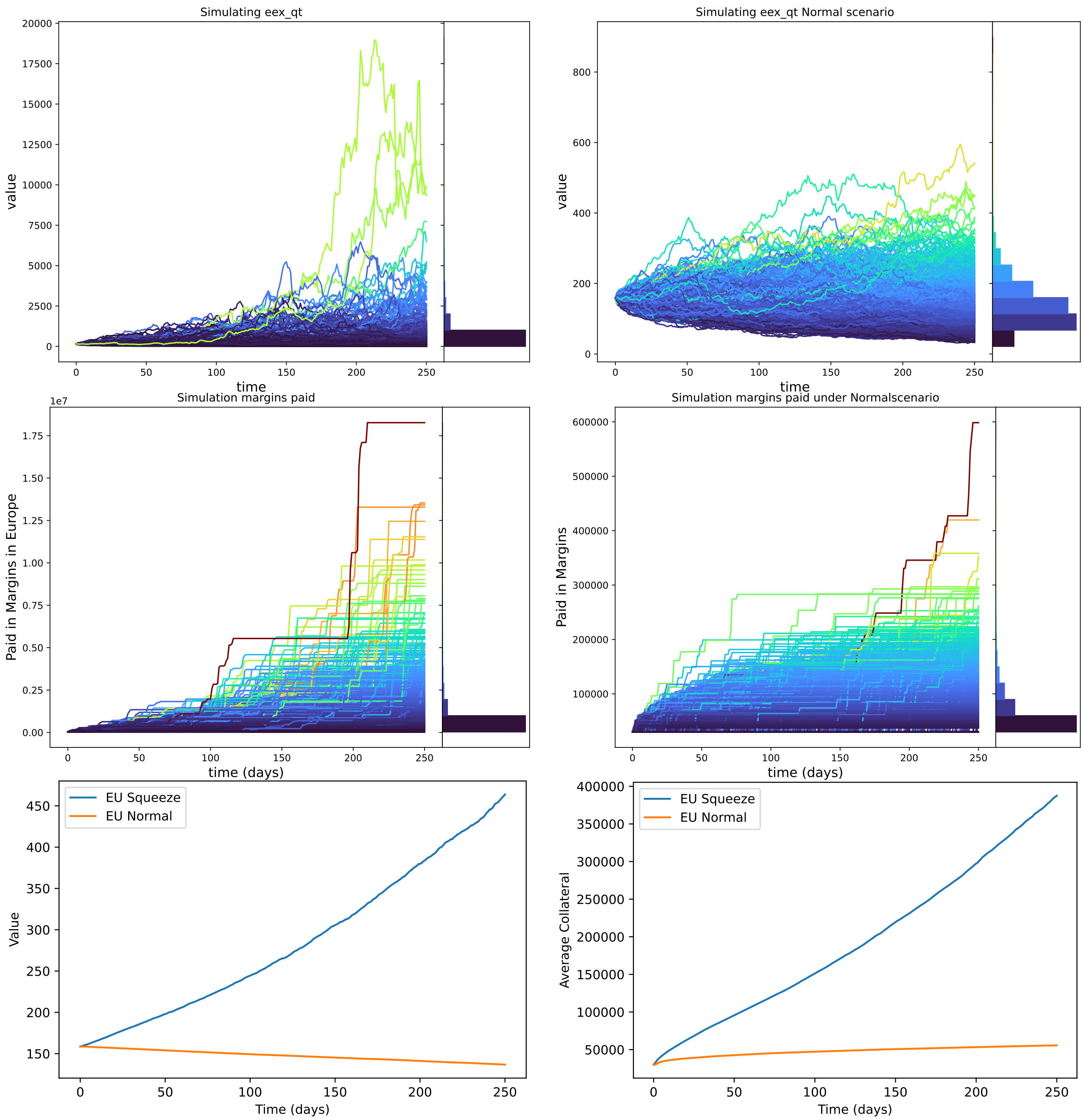
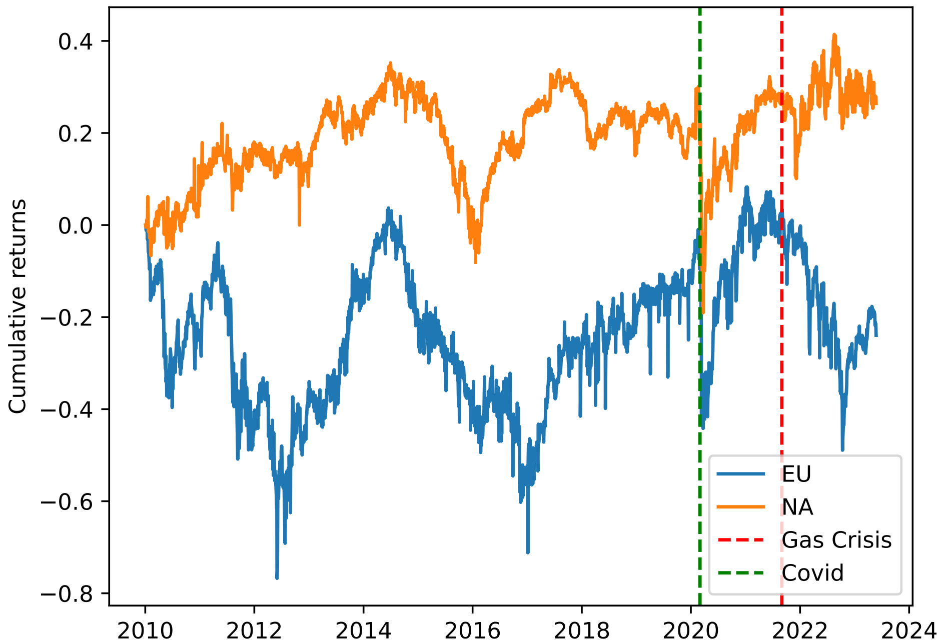
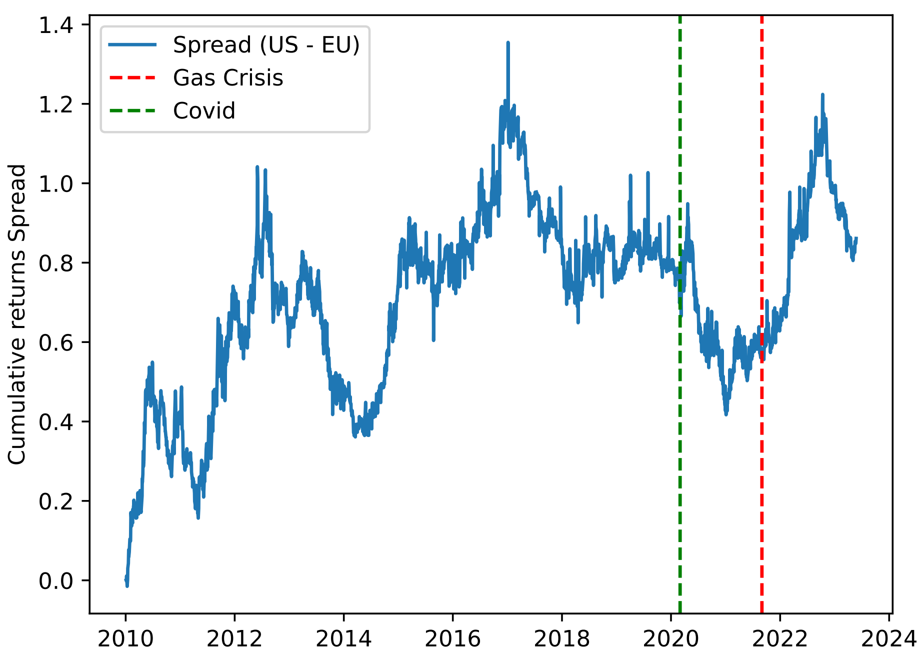


Figure 6: Distribution of Futures Prices and Average Margin Requirements

The figure plots the results from our simulations for the price paths of the EEX futures in the EU regulatory regime and the EEX futures in the counterfactual regime (top row). The middle panel shows the results from the simulations of the margin requirements (middle row). The Average collateral Value for EU and US Futures Power Markets are plotted at the bottom row of the figure.



(a) Daily Cumulative Returns on Portfolios of North American and EU Power Utilities



(b) Spread in Daily Cumulative Returns between Portfolios of North American and EU Power Utilities

Figure 7: Financial Performance of Power Utilities in North American and the EU.

Table 1: Summary Statistics

The table presents summary statistics for the daily log price differences in natural gas and electricity prices used in our analysis and for the quarterly accounting data on EU and US power utility companies. The sample period is April 2020 to December 2022 for the time series data and Jan 2010 to Dec 2022 for the financial data. Panels A and B present the descriptive statistics for the distribution of the percentage change in natural gas futures and electricity day-ahead and futures contracts. The last column reports the results from an F-test for differences in volatility of price changes between the periods before (April 2020 to Aug 2021) and after (Aug 2021 to Dec 2022) the gas market squeeze. *, **, and *** denote 10%, 5%, and 1% significance level, respectively. Panel C presents summary statistics for the power utilities financials. Our sample contains 46 EU and 160 North American power utility companies. Variable definitions are in Table A1 in the Appendix.

	Before (April 2020-July 2021)			After (Aug 2021-Dec 2022)			F-scores
	Mean	St Dev	Median	Mean	St Dev	Median	
Panel A: Futures Natural Gas							
Henry Hub Futures	0.02%	3.46%	-0.04%	0.12%	4.68%	0.45%	1.87***
Dutch TTF Futures	0.06%	4.23%	-0.12%	0.17%	8.12%	0.30%	2.64**
Panel B: Day-Ahead and Futures Contracts							
Electricity Day Ahead							
Spain	0.14%	44.81%	2.06%	-0.11%	84.13%	0.22%	1.98***
Germany	0.89%	79.10%	0.67%	0.16%	85.54%	0.20%	1.31***
France	0.80%	52.28%	3.60%	0.11%	60.83%	1.17%	1.42***
Texas	0.23%	66.84%	0.59%	-0.09%	73.85%	0.30%	0.38
East coast	0.19%	46.42%	0.60%	0.02%	51.63%	-0.05%	1.74***
Electricity Futures							
EEX Futures	0.90	19.55	0.61	0.07	18.20	-0.75	6.19***
CME Futures	0.65	4.96	0.00	0.33	5.46	0.00	5.11***

Table 1: Summary Statistics Cont'd

Panel C: Power Utilities Financials					
	Mean	Sd	Median	25%	75%
US Power Utilities Sample					
Assets	$ 21,502	$ 33,005	$ 9,071	$ 4,109	$ 25,914
Turnover	$ 3,918	$ 9,047	$ 1,347	$ 561	$ 3,539
Leverage	35.90%	0.1209	33.95%	29.32%	40.38%
Tobin Q	0.8786	0.5669	0.831	0.6545	1.0142
Investment	4.05%	0.0326	3.39%	1.83%	5.53%
Profitability	2.07%	0.0159	2.07%	1.61%	2.58%
Cash Liquidity	2.56%	0.055	0.87%	0.15%	3.00%
Payout	1.03%	0.0193	0.87%	0.19%	1.19%
Observations	6,546				
EU Power Utilities Sample					
Assets	€51,172	€75,869	€15,297	€1,752	€59,401
Turnover	€12,343	€21,132	€2,412	€274	€15,185
Leverage	35.56%	0.1894	33.38%	21.97%	48.69%
Tobin Q	0.7958	0.5178	0.7004	0.4756	0.9766
Investment	3.35%	0.0442	2.21%	1.10%	4.03%
Profitability	1.80%	0.0124	1.90%	1.34%	2.42%
Cash Liquidity	8.89%	0.0799	7.37%	3.57%	11.24%
Payout	8.58%	0.2738	0.39%	0.20%	0.62%
Observations	1,121				

Table 2: Initial Margin Requirements during the Gas Market Squeeze

The table presents the results from our simulation analysis. We simulate the daily prices for a one-year (252 days) futures electricity contract. We compute futures electricity prices using the futures returns generated from the ARMA-GARCH process we estimated using front month futures contracts for the period Aug 2018 to Dec 2022. The innovations are obtained from bootstrapping the estimated ARMA-GARCH innovations. The EU scenario is computed using innovations obtained from the EU futures contract whereas for the US control innovations are based on the ARMA-GARCH innovations for the US time series.

Panel A: European Futures Contract		
	Price	Collateral
Mean	$469.66	$387,456.46
std	1,070.19	826,726.49
5%	$20.60	$30,000.00
95%	$1,719.19	$1,458,320.50
Median	$185.91	$145,950.66
Skew	11.02	8.57
Panel B: US Control Futures Contract		
	Price	Collateral
Mean	$137.95	$55,742.85
std	62.75	33707.04
5%	60.81	30000.00
95%	254.95	121964.17
Median	126.05	42971.48
Skew	1.44	2.60
Differences		
	Price	Collateral
Mean	331.71	331713.61
std	1007.44	793019.45
5%	-40.22	0.00
95%	1464.24	1336356.33
Median	59.86	102979.18
Skew	9.58	5.97

Table 3: Financial Performance of Power Utilities

The table presents results for the financial performance of our sample of power utilities. Panel A reports summary statistics for portfolios of equally weighted cumulative daily returns whereas Panel B reports the estimation results for our regression specification. Each regression pertains to our sample of EU and North American power utility firms for the period from January 2010 to December 2022. The dependent variables are (1) change in revenues; (2) profitability; and (3) unlevered beta. Variable definitions are in Table A1 in the Appendix. All regressions include dummy variables for the sample year and country level fixed effects. p-values based on robust standard errors, clustered across firms, are reported in parentheses. *, **, and *** denote 10%, 5%, and 1% significance level, respectively.

Panel A: Portfolios of (EW) Cumulative Daily Returns						
	Before Gas Squeeze			Gas Squeeze		
	EU	US	Diff	EU	US	Diff
Mean	-0.26	0.34	-0.61	-0.41	0.46	-0.87
std	0.15	0.07	0.09	0.15	0.04	0.12
Median	-0.21	0.35	-0.56	-0.41	0.45	-0.87
25%	-0.34	0.29	-0.63	-0.51	0.43	-0.94
75%	-0.15	0.41	-0.56	-0.27	0.48	-0.74

Panel B: Utilities Corporate Perfomance						
	Δ Revenues		Profitability		Unlevered beta	
	(1)		(2)		(3)	
Lag Δ Revenues	0.971***	(0.00)				
Lag Profitability			0.379***	(0.00)		
Gas Squeeze	0.0245*	(0.06)	-0.000287	(0.12)	0.0531*	(0.067)
Gas Squeeze # EU	-0.0677***	(0.004)	-0.00374***	(0.007)	-0.0709	(0.164)
Lag MTB	-0.0255*	(0.061)	-0.00213**	(0.019)	0.279***	(0.00)
Lag Investment	0.276**	(0.041)	-0.0198**	(0.026)	0.0811	(0.781)
Country & year dummies						
Observations	2,808		2,845		2,845	

Table 4: Stock Market Performance of Power Utilities

The table presents results for the stock market performance of our sample of power utilities. Panel A reports the risk adjusted returns obtained from a one factor model for different portfolios (formed by the degree of exposure to natural gas prices), before and after the gas squeeze. Panel B reports the cumulative daily returns for the portfolio of EU power utilities and the synthetic portfolio comprising of US power utilities for the gas market squeeze period August 2021 to December 2022. We derive the weights of the synthetic portfolio using a minimum distance estimation for the period August 2018 to July 2021 (the estimation window). *p*-values are based on t-tests for differences in regression coefficients. *, **, and *** denote 10%, 5%, and 1% significance level, respectively.

Panel A: Risk-adjusted Returns			
	Green before squeeze	Green after squeeze	p-value difference
EU	0.040 (0.572)	-0.150 (0.021**)	0.000***
US	0.089 (0.811) p-value?	-0.250 (0.248) p-value?	0.000***
	Brown before squeeze	Brown after squeeze	p-value difference
EU	-0.090 (0.648)	-0.317 (0.002***)	0.000***
US	0.020 (0.950)	-0.266 (0.374)	0.000***

Panel B: Cumulative Returns			
	Before squeeze	After squeeze	p-value difference
EU			
Synthetic EU			

Appendix A1: Variable definitions

Variable	Definition
Panel A: Gas and Electricity Prices	
Gas Spot Price:	US gas spot benchmark. Measured in $ per mmbtu. Source: Federal Reserve st Louis
Gas Future Price	Natural gas front month Henry Hub futures traded in the Chicago Mercantile Exchange (CME). Measured in $ per mmbtu. Source: Bloomberg
Day-ahead price :	The power price in the day-ahead market in each respective zone. East coast refers to prices in Washington D.C.
EEX Futures:	Power futures traded in the EEX
CME Futures :	Power futures traded in the CME
Panel B: Power Utilities Financials	
Tobin's Q (MTB)	Total assets minus book equity plus market equity divided by total assets.
Revenues (million USD)	Total revenues; Size is the logarithm of total revenues.
Investment	Capital expenditures divided by total assets.
Profitability	Operating income (earnings before interest, taxes, depreciation, and amortization) divided by divided by total assets.
Leverage	Leverage is defined as total book debt divided by total book assets.
Cumulative daily returns	Calculated by taking the cumulative product of the daily percentage change.
Beta	Computed for each sample quarter using daily returns
EU	Dummy variable equals 1 if EU power utility
Gas squeeze	Time dummy for the period 2021Q4 to 2022Q3