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

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**Abstract**

This paper examines the effects of regulations and market structures of the electricity markets in the United States (US) and the European Union (EU). Following Russia's invasion of Ukraine, the world has experienced a global energy crisis that has caused electricity prices to soar. We show that market design policies in the EU have created a tight connection between gas and electricity prices and their volatility that have resulted in a large increase in the collateral for longer maturity futures and forward contracts. We document a significant increase in EU electricity price volatility following the squeeze in the gas market that resulted in almost 50% increase in the average value of collateral required for one year European futures contracts. This created a huge cost for power utility companies that required a hedge for their exposure to electricity price risk. We show that the cumulative returns of a portfolio of EU power utilities was as much as 122.3% (and 86% on average) lower than and a portfolio comprised of US power utilities counterparts.

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## 1. Introduction

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, however, are much more complex than other commodity markets. Electricity markets 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 to electricity markets. 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 often considered the marginal electricity production technology and their operating costs are typically used to set electricity prices in the market. There is general consensus that the marginal zonal pricing model in the EU areas provides 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 recent spikes in the price of gas both in the wholesale electricity market and the longer maturity power contracts.

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 restructured competitive markets, "utilities" are commonly responsible for retail electricity service to customers and are less likely to own generation and transmission resources. 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, for example, is used in Texas and California wholesale electricity markets. These markets ofetn 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.

Natural gas markets worldwide have been tightening since August 2021. Russia's invasion of Ukraine and its decision to suspend gas deliveries to several EU member states created further disruptions that intensified the race for local supply of energy.[1] As a result, gas prices increased tenfold over the period from August 2021 to August 2022, 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.

Figure 1 shows the gas spot and futures prices for both the EU and the US markets for the period May 2020 to May 2023. Figure 1(a) shows that by August 2022, the gap between the spot price of the Dutch TTF and the Henry Hub (NYMEX) natural gas contracts reached almost 500 €/MWh and the gap between the one-month gas futures price of the Dutch TTF and the Henry Hub contracts was more than 195 €/MWh. Figure 2 shows that this divergence in gas prices resulted in a similar divergence in the price of electricity futures where the one-month European Energy Exchange (EEX) electricity futures price exceeded the front-month CME electricity futures by 230 € during the same time period.

<Figure 1: here>

Figure 2 shows the electricity time series for the day-ahead (wholesale) and the front month futures prices in the EU and the US. The top panel of Figure 2 shows that both markets exhibit very high volatility that is typical for the spot electricity markets due to changes in demand, transmission congestion and supply disruptions. There is, however, much higher cross-countries heterogeneity in the EU zone that is determined by the countries' mix of electricity generation sources.

<Figure 2: here>

[1]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 and many European countries are having to redesign their energy strategy.

The bottom panel of Figure 2 shows that the EU futures electricity price series move together with EU price of natural gas and were heavily affected by the gas market squeeze that stared in August 2021.[2] 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. The high gas prices in the EU market provided incentives for deliveries via non-Russian pipelines and via record inflows of LNG.[3] 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 United States, on the other hand, have been a net total energy exporter since 2019. According to the 2022 US Energy 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.

In this paper, we examine the financial impact of electricity markets regulations. We begin by estimating an ARMA-GARCH model for the (time-varying) volatility of the log changes in electricity prices for the front-month futures contract in the US and the EU power markets using daily data for the period from May, 26 2003 to May, 23 2023.[4] We document a structural break in the volatility in both the US and the EU markets that coincided

[2] There has been considerable debate and scepticism 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.

[3] 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.

[4] 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.

with the start of the energy crisis 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 price series than for the US series. We use the volatility forecast generated from our model to calculate implied initial and variation margin requirements for futures contracts. This allows us to assess the risk exposure and the cost of collateral for consumers and producers of electricity willing to hedge their risk exposure.

We show that the significant increase in the level and volatility of the electricity prices have resulted in large margin calls, generating 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. We show that by August 2022, the cumulative returns of a portfolio of EU power utilities was as much as 122.3% (and 86% on average) lower than the cumulative return of a portfolio comprised of US power utilities counterparts. Our regression results provide formal analysis to support the fact that EU power utility companies experience significant drop in profitability relative to their US counterparts.

Our paper provides several contributions to the literature. First, we shed light to the regulation related papers that focus on designing policies adapting price signals to the energy transition requirements (see e.g. Ignacio J. Pérez-Arriaga (2016), Joskow (2012) and Batlle *et al.* (2022)). A related line of literature has analysed the impact of renewables on electricity prices (see Fabra and Reguant (2014) and Peña *et al.* (2020). This paper provides some guidance for future electricity market regulations by considering the effects of the recent energy crisis in a context of net zero commitments.

Our paper also relates to the literature that examines the effects of geopolitical risk in energy markets. Goldthau and Boersma (2014) discussed the dual challenge faced by the energy sector. Specifically they argued 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. In relation to this claim, the 2022 World Economic Outlook published by the EIA provides evidence suggesting that climate policies and net zero commitments as well as increased geopolitical risk contributed to the run-up in energy price.[5] We contribute to this line of work by documenting how the 2021-2022 gas market squeeze lead to an energy crisis with important corporate risk effects showing that the global energy system remains highly vulnerable and that EU power market requires important reforms.

The literature on electricity pricing has addressed the relationship between spot and futures electricity prices (Carmona *et al.* (2012), Álvaro Cartea and Villaplana (2008), Algieri *et al.* (2021)) as well as the modelling of time changing volatility (see Escribano *et al.* (2011) and references there in). In an analysis of tail risk underlying futures contracts for the European and US markets Peña *et al.* (2020) conclude that the associated capital ratios required for investments in long positions on power futures contracts should be computed using time-varying volatility measures. In this paper, we focus on analysing volatility uncertainty and addressing the effect of gas and electricity linkages on the volatility of power prices in the context of energy crisis and energy transition.

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 and presents summary statistics for our sample. Section 4 outlines the research design of the paper and 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

[5] 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

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 for a 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.[6] 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 the market integration process.[7]

[6] 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.

[7] 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.

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 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.

The Electric Reliability Council of Texas (ERCOT) market and other US Independent System Operator/Regional Transmission Organization (ISO/RTO) markets use the nodal pricing mechanism. Nodal pricing is based on location-specific prices, known as nodal prices, which are 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.[8] 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 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, how-

[8]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).

ever, these interventions have intensified which has led to even more volatile flows and higher costs (see CEER, 2021).

### *2.2. Long-term Markets*

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, and Nord Pool markets in the EU (often called day ahead market or day ahead auction) or through bilateral contracts between two parties - usually power trading companies - outside of the power exchange in over the counter (OTC) deals. On the forward and futures market, on the other hand, electricity is traded between several years and one month before delivery. 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 long-term electricity markets are 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.

In this paper, we show that following the spike in volatility after the gas market squeeze, there was a large increase in 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 result in greater risks for the counterparties and 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 Jan 2020 to April 2023. 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. We also obtain spot (day-ahead), forward and futures electricity prices for different contract specifications and maturities for the US and EU markets. The day-ahead 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 A1 in the Appendix to the paper for definitions of our data series.[9] We also collect daily data on forward and futures electricity contracts from Bloomberg (OTC) and Reuters (PHELIX exchange) for the period Jan 2020 to April 2023 and May 2003 to May 2023 respectively. 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. We also download two series of daily data on OTC Germany baseload Electricity Forward Prices for one month and one year maturity. Contract delivery is physical and in high voltage grid.

To examine the financial impact of the regulatory approach during the energy crisis, we also download daily stock prices, trading volume and quarterly accounting data for power utility companies operating in the EU and North

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

America. We download quarterly data for all firms in SIC code 4911 from the COMPUSTAT North America and the Compustat Global database respectively. 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 for the period January 2010 to December 2022. All data are converted to USD using the quarterly exchange rate.

### *3.2. Summary Statistics*

Column (1) of Table 1 reports summary statistics for the price returns for each time series. The sample period is April 2020 to May 2023. The table shows that the standard deviations of daily log changes for the spot (or day ahead) return series are much larger than the forward/futures price series. The table also shows that the EU benchmark gas and power (spot/day-ahead and future) series exhibit higher volatility than the corresponding US time series. Column (2) reports the p-values from an F test for differences in volatility between the two periods - before and after the gas market squeeze. All p-value (apart from the day-ahead Texas daily return series) show that the volatility of gas and electricity returns was significantly higher during the period after August 2021.

Panel B of Table 1 reports descriptive statistics for the sample of US and EU power utilities.The mean and 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, both the average and the median EU power utility was less profitable, held more cash and paid higher dividend than the average and median US electricity firm.

*3.3. Research Design*

This subsection describes the research design of the analysis in this paper. We begin our discussion with a short description of the margin requirements and how we simulate collateral values. The European Commodity Clearing (ECC) is the central clearing house of the EEX which specializes in energy and commodity products. 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. The exact formulas for each component can be found in the ECC derivative margining.[10]

Figure 3 shows the interquartile range (IQR) for the daily EEX Futures

[10] For more detailed exposition, see https://www.ecc.de/en/risk-management/margining

returns as well as the margin requirements calculated using the methodology describe above. The figure depicts the clear change in margin requirements after August 2021 - the beginning of the gas market squeeze period.

<Figure 3: here>

### *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 section, Figures 1 and 2 suggest that there could be a structural break in the levels and/or changes of the gas and electricity time series 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.[11] The results from the test are reported in Table 1 Column (2). The results demonstrate 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.

We use an ARMA-GARCH(1,0,1,1) with t-student distributed residuals to model the time series of the power and gas price changes. The specification is as follows:

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

We use maximum likelihood to estimate the ARMA-GARCH process and produce time series for the volatility process. Figure 1 shows the time series plot of the volatility of electricity returns between May 2020 and May 2023. The figure depicts the significant rise in volatility after August 2021.

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

Using the volatility forecast generated from the estimated model, we carry out simulations of daily collateral requirements. We simulate the daily prices for a one-year forward electricity contract. The forward price process is derived from the returns 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 the relevant period. Finally, we study the distributions of collateral values during the last time period of the simulations.[12]

Finally, to examine the effect of the regulations on power utilities' performance, 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 GMM to estimate the specification as a dynamic panel. Our results remain the same. The next section describes our simulation and estimation results.

## 4. Empirical Analysis

This section describes the empirical design of the paper. First, we study of the volatility in the energy markets and its effect on long term power contracts. In particular, we analyze the changes in the collateral requirements for power futures in the face of increasing volatility of gas and electricity

[12]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.

prices. We believe that the large uncertainty associated with the collateral costs is responsible for the lack of hedging in the power markets.

### *4.1. The cost of collateral of electricity derivatives*

Power price volatility has shifted dramatically as a consequence of the energy crisis and the energy transition. This has increased the requirement for hedging operations for producers and consumer. As shown by ACER 2022[13], the liquidity of mid/long-term power contracts in Europe is low and, under high volatility conditions liquidity is at minimum levels. This diminishes the possibility of hedging. The current design of the EU electricity price signalling has not adapted to the new reality and consequently which has impacted the economy dramatically. The change of volatility in the electricity market started at the end of summer 2021, as shown in Figure 2 (see also IIT discussion paper[14]). During the last months of 2021 the flux of natural gas into Europe started decreasing prior to the Russo-Ukranian war.

The lack of market of futures power contracts in Europe, which is highly dependent on external sources of energy, is affecting significantly the Europeans. In what follows we aim to identify the causes of the lack of viability for those contracts.

The lack of storability of electricity induces the main characteristic in the power markets: the energy is produced and dispatched instantaneously. In consequence, electricity prices present relatively high volatility making the margins required in medium-term contracts to be larger, the trading capacity is lower. In the following pages we will model the electricity prices and their volatility, then we will use this modelling in order to study how does the volatility affect the collateral that my be held by an agent.

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 simu-

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

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

lations. 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 in 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 different periods. There are two different temporal periods and two different geographical series. One time period goes from April 2020 to August 2021, representing "usual" behavior of the power market, the other period spans from August 2021 to December 2022, which is a period of high volatility[15]. Geographically, there are two cases, the EU Futures time series and the US Futures time series. For each case we can simulated the power prices and, thus, the margins established by the ECC (the formula was introduced in Section 2). The first row of Figure 4 shows the prices simulated and the distribution.

In a second stage we use the previous 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 current situation. Figure 4 illustrates the time series evolution of the margins under each of the previous simulations and the global distribution. While there is a significant amount of cases in which the additional collateral stays near 0, there are many cases in which it grows significantly. In fact, the average additional collateral (see last row of Figure 4) is three times the original value of the contract. Therefore, the amount of collateral obtained in *a priori* estimations is very large, increasing the cost of trading.

<Figure 4: here>

Given the expected collateral required, it seems unlikely that futures can be traded with enough liquidity to hedge against high volatility price exposures

[15] We will refer to those periods as the non-squeeze period and the squeeze period, respectively, due to their relation with the gas squeeze.

(such as those seen in the current state in Europe). 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 after the structural break there was an almost 200% increase in the average value of the daily collateral requirements for EU electricity derivatives traders. There was also increase in collateral requirements for the US market. This increase, however, was 277% smaller. This demonstrates that the impact on EU power producers was much stronger.

### *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 3 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 underperformance 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.[16]

Figure 5 plots the equally-weighted cumulative daily returns for a sample of US and EU power utility companies. Figure 5 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 5: here>

## 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 prompt a reevaluation 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, 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. Scholars and industry practitioners have proposed various 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[17]). 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.

[16] Note that due to the effect of COVID if one compares portfolio volatilities 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

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

The evaluation of the financial impact of government regulations during the energy crisis has yielded several significant findings. Firstly, government regulations play a pivotal role in managing and mitigating the consequences of an energy crisis. By implementing policies and measures, governments can effectively respond to the crisis, ensure energy security, and stabilize the economy. Secondly, 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.

Thirdly, the financial impact of government regulations during the energy crisis varies across sectors and stakeholders. While some industries may face short-term challenges and increased costs, others may benefit from new market opportunities and incentives introduced by the regulations. Furthermore, the analysis reveals that the financial impact of government regulations depends on effective implementation and enforcement mechanisms. Governments must ensure transparency, accountability, and continuous evaluation of regulatory frameworks to maximize financial benefits and minimize unintended consequences.

Lastly, 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.

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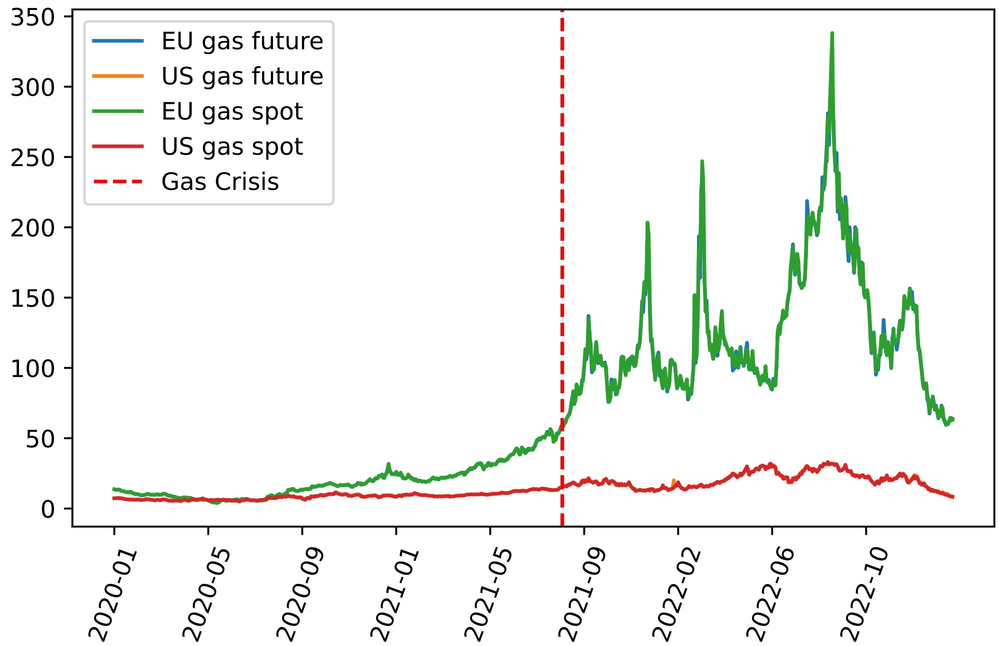
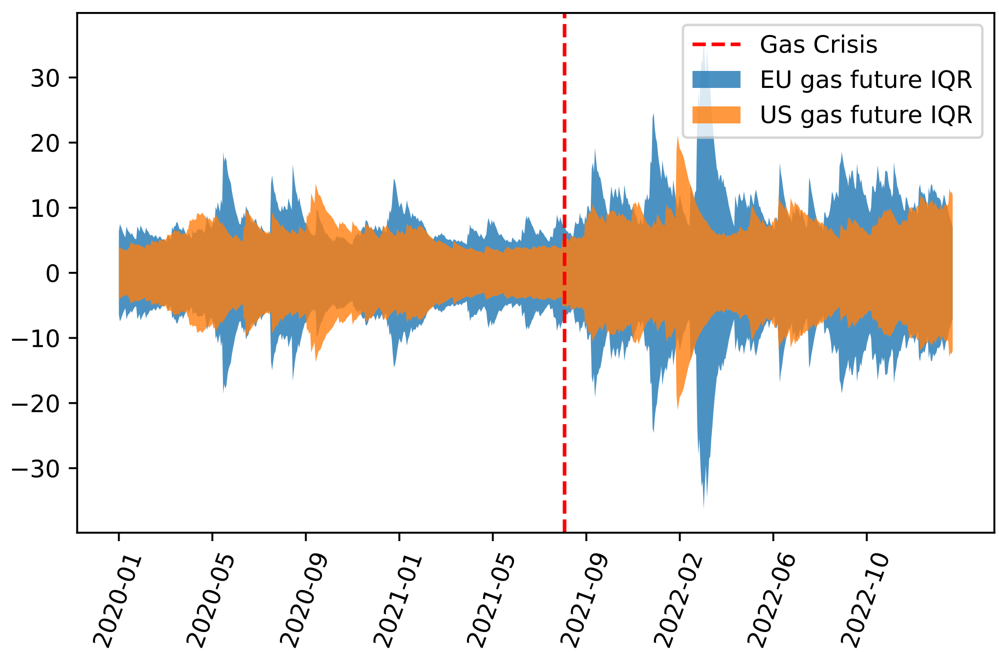



(a) Spot and Front-month Futures Gas Prices




(b) Time-varying Volatility for Front-month Futures Gas Prices

Figure 1: Price and Volatility Dynamics for Spot and Futures Gas Contracts in the EU and the US Markets

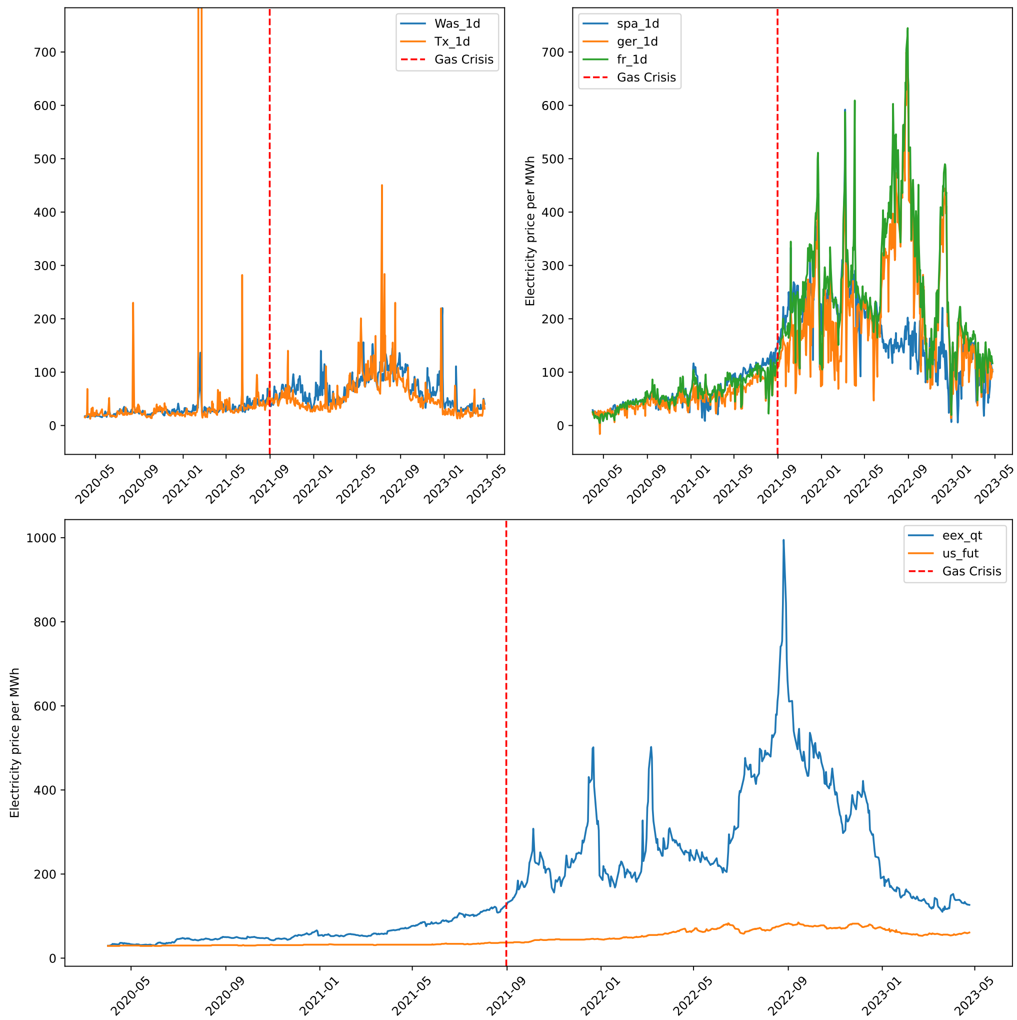



Figure 2: Comparison of Spot and Futures Electricity Prices in the EU and US markets

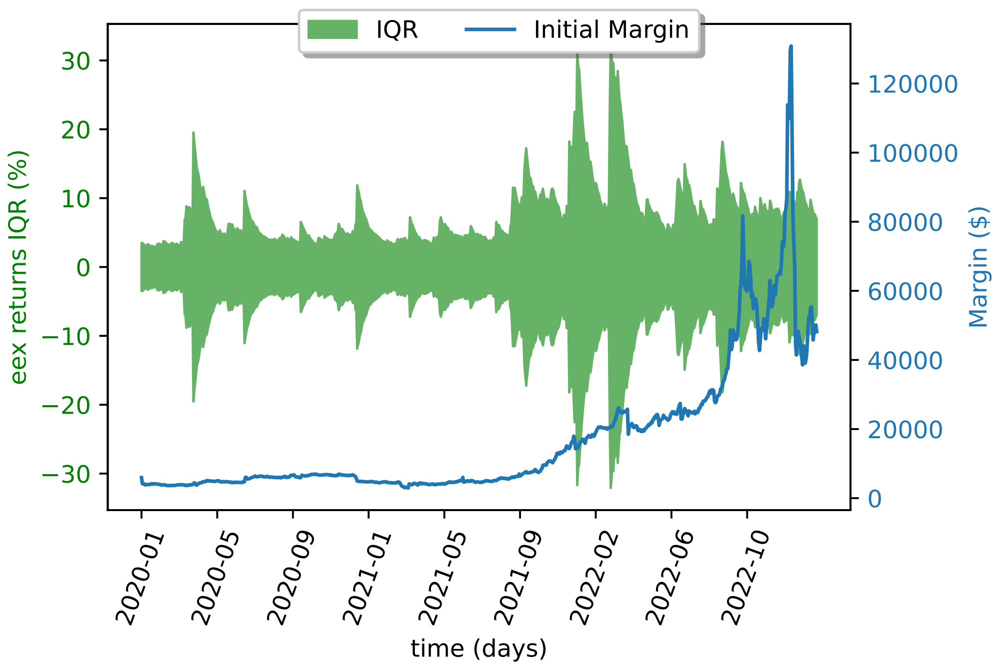



Figure 3: Inter quantile range (90%) and margins at each time period (days) for the European Future contract using the ECC margin formula.

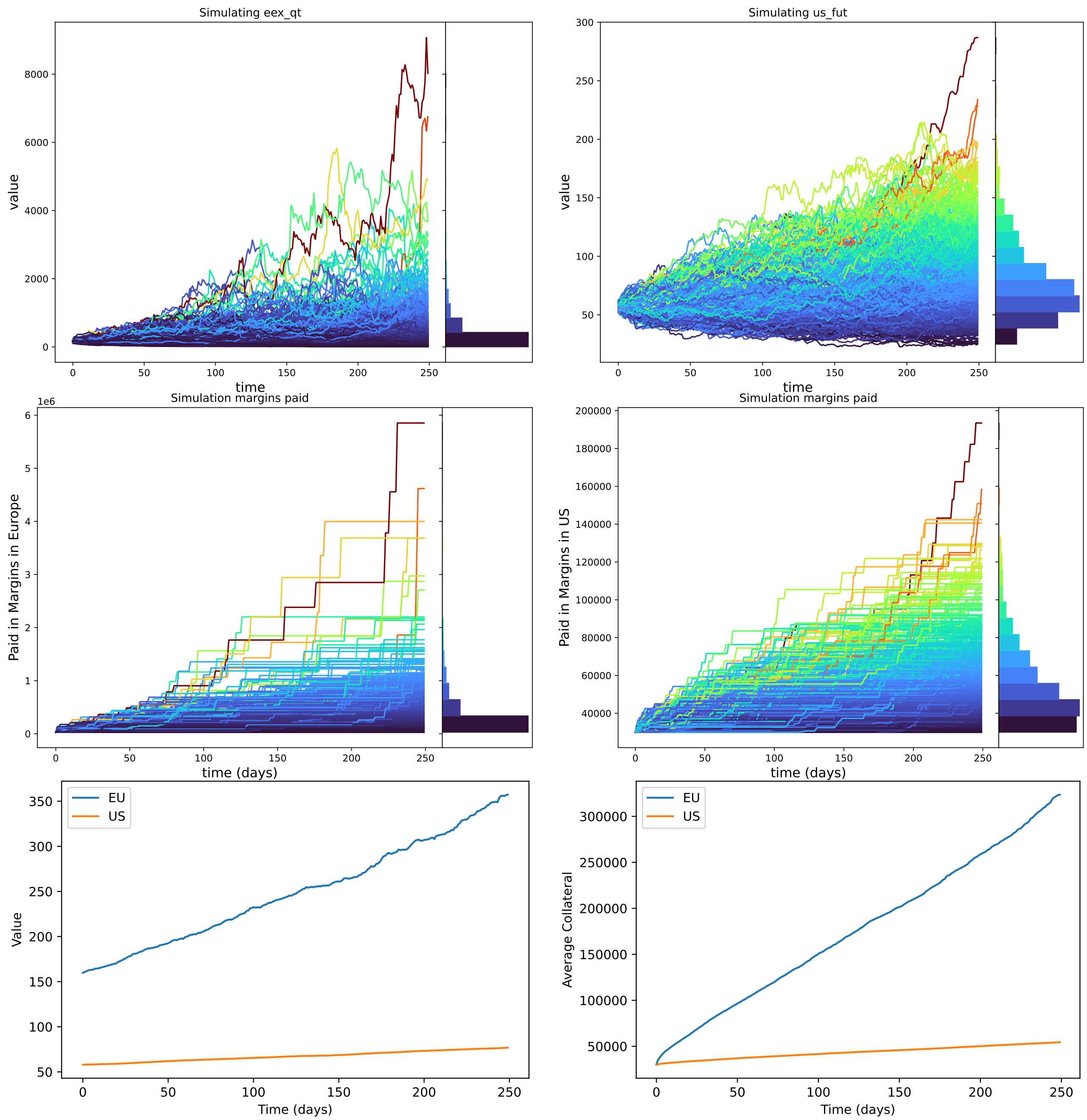
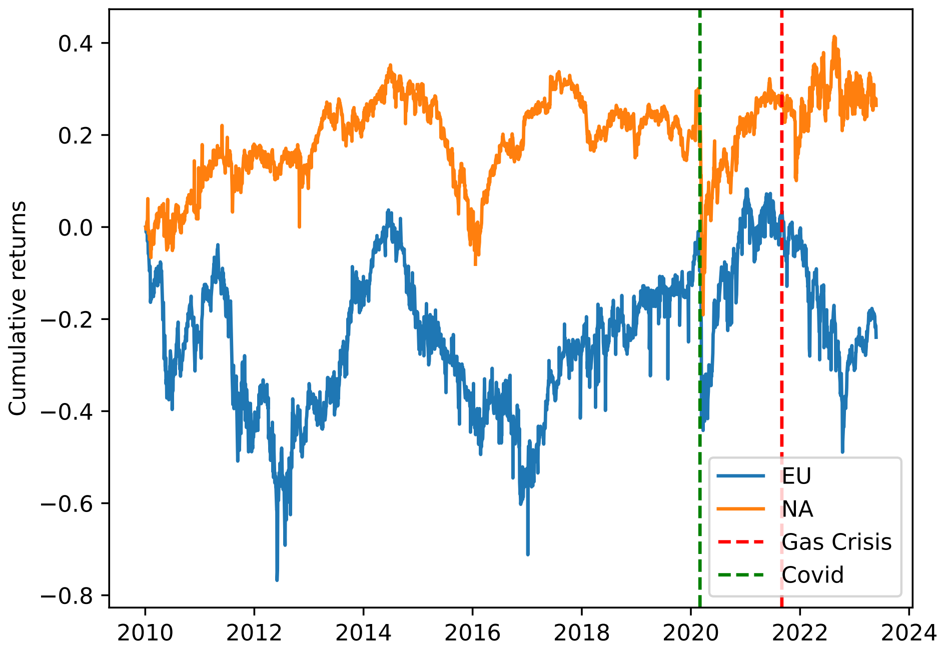
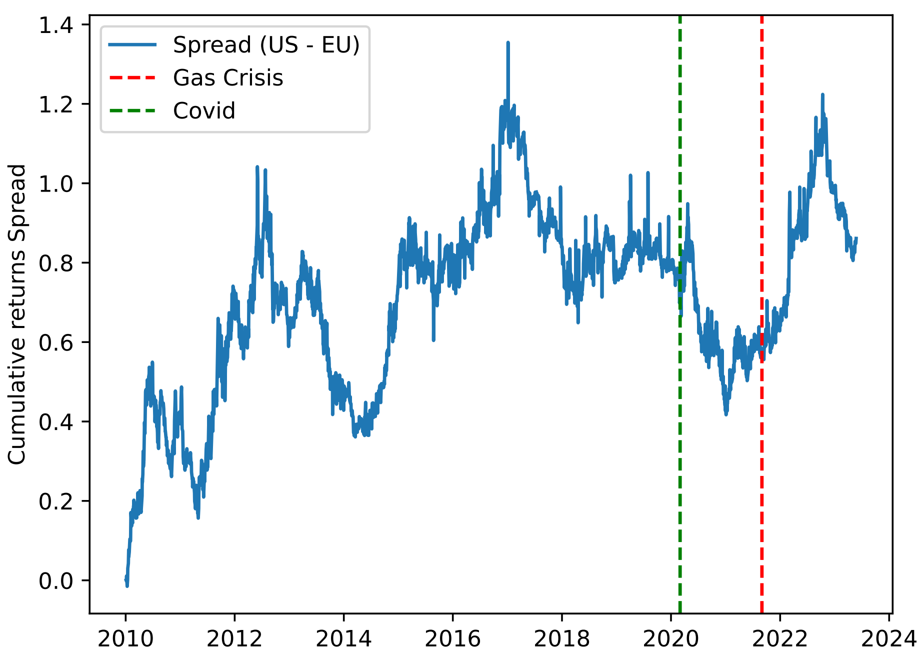



Figure 4: Simulations for the Price Paths of EEX and CME Electricity Futures (top row); the Margin Requirements (middle row); and the Average collateral Value for EU and US Futures Power Markets




(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 5: Financial Performance of Power Utilities in North American and the EU.

Table 1: Summary Statistics

The table presents summary statistics for the daily gas and electricity time series used in our analysis and for the quarterly panel 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. Column (1) of Panel A presents the descriptive statistics for the distribution of the percentage change in gas and electricity spot and forward/futures prices where as column (2) shows 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 B 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.

| | (1) | | | (2) |
|---|---|---|---|---|
| | mean | std | median | F-score |
| **Panel A: Gas and Electricity Returns Time Series (%)** | | | | |
| *Gas Futures Daily Percentage Change* | | | | |
| Henry Hub (US) | 0.36 | 6.68 | 0.49 | 1.87*** |
| Dutch TTF (EU) | 0.17 | 4.59 | 0.26 | 2.64*** |
| *Day Ahead Electricity Daily Percentage Change* | | | | |
| Spain | -0.03 | 21.37 | 0.66 | 1.98*** |
| Germany | 0.13 | 30.34 | 0.02 | 1.31*** |
| France | 0.29 | 20.44 | 0.73 | 1.42*** |
| Texas | 0.39 | 38.41 | -0.17 | 0.38 |
| East coast | 0.33 | 17.35 | 0.43 | 1.74*** |
| *Forward and Futures Electricity Daily Percentage Change* | | | | |
| German 1-month forward | 0.35 | 6.24 | 0.02 | 3.36*** |
| German 1-year forward | 0.28 | 4.33 | 0.31 | 9.92*** |
| EEX Futures | 0.31 | 5.86 | 0.14 | 6.19*** |
| CME Futures | 0.13 | 1.58 | 0.00 | 5.11*** |

Table 1: Summary Statistics Cont'd

| | 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: Simulation of Margin Requirements

The table presents the results from our simulation analysis. We simulate the daily prices for a one-year forward electricity contract. The forward price process is derived from the returns 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 squeeze - and innovations are bootstrapped from the relevant period. The p-values are obtained using different tests, t-test for the mean, F-test for the standard deviation and permutation test for the median. *, **, and *** denote 10%, 5%, and 1% significance level, respectively.

| | Simulations EU | | | | | |
|---|---|---|---|---|---|---|
| | Gas squeeze | | Before gas squeeze | | Differences (p-value) | |
| | Prices | Margins | Prices | Margins | Prices | Margins |
| **Mean** | 363.91 | 316658.92 | 409.31 | 211487.41 | -45.40 (0.98) | 105171.52 (0.00***) |
| **Sd** | 516.07 | 411623.08 | 247.47 | 175823.45 | 268.60 (0.00***) | 235799.63 (0.00***) |
| **Median** | 184.04 | 173678.03 | 346.00 | 164198.48 | -161.96 (0.00***) | 9479.55 (0.11) |
| | Simulations US | | | | | |
| | Gas squeeze | | Before gas squeeze | | Differences (p-value) | |
| | Prices | Margins | Prices | Margins | Prices | Margins |
| **Mean** | 76.38 | 54132.84 | 69.52 | 40871.44 | 6.86 (0.00***) | 13261.40 (0.00***) |
| **Sd** | 31.08 | 19930.89 | 11.20 | 7164.36 | 19.88 (0.00***) | 12766.52 (0.00***) |
| **Median** | 71.43 | 49160.55 | 68.72 | 40010.22 | 2.71 (0.01**) | 9150.33 (0.00***) |
| | Differences EU-US | | | | | |
| | Gas squeeze | | Before gas squeeze | | Differences (p-value) | |
| | Prices | Margins | Prices | Margins | Prices | Margins |
| **Mean** | 287.53 | 262526.09 | 339.79 | 170615.97 | -52.26 (0.00***) | 91910.12 (0.00***) |
| **Sd** | 484.99 | 391692.20 | 236.28 | 168659.09 | 248.72 (0.00***) | 223033.11 (0.00***) |
| **Median** | 112.61 | 124517.48 | 277.28 | 124188.26 | -164.67 (0.00***) | 329.22 (0.22) |

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 | |

## 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. |
| German 1-month forward: | OTC power contract. Source: Bloomberg |
| German 1-year forward: | OTC power contract. Source: Bloomberg |
| 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 |