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# Rockets and feathers in power futures markets? Evidence from the second phase of the EU ETS

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ABSTRACT

This paper examines the possibility of asymmetric transmission of $CO_2$ prices to electricity futures prices in the second phase of the European Emission Trading Scheme. We would like to assess whether output prices tend to respond more quickly to input price increases than decreases: this phenomenon is known as "rockets and feathers" in the literature. Compared to Zachmann and von Hirschhausen (2008), who carried out a similar analysis for Germany in the first phase of the Emission Trading Scheme with data from 2005 to 2006, our study spans a longer timeframe (July 2007–June 2010), with a presumably more mature permit market, and includes three additional European countries (France, Belgium and the Netherlands). Results do not provide empirical evidence of statistically significant differences in the response of power prices to positive and negative shocks in $CO_2$ allowance and fuel markets.



## 1. Introduction

As part of its commitment to the Kyoto Protocol, in January 2005 the European Union started a cap-and-trade scheme of $CO_2$ emission permits, the European Emission Trading Scheme (EU ETS). The ETS is the largest emission trading scheme in the world, and the first international one for $CO_2$ emissions. It currently includes 30 states (27 EU member states, plus Iceland, Norway and Liechtenstein) and covers over 12,000 industrial installations performing emission intensive activities above certain capacity thresholds and responsible for about half of Europe's $CO_2$ emissions. Under the ETS, a restricted number of allowances (EUAs) is allocated to participating states for a sequence of years ("phase" or trading period). Member States draw up national allocation plans (NAPs) which determine how many emission allowances each industrial installation receives in a trading period. The power and heat sector accounts for about 40% of total emission allowances (Kettner et al., 2010). Large $CO_2$ emitters must monitor and annually report their emissions, and every year they must return an amount of allowances equivalent to their $CO_2$ emissions in that year. Companies that keep their emissions below the level of their allowances can sell their excess permits, while those facing difficulty in keeping emissions in line with allowances can take measures to reduce pollution (such as investing in more efficient technology or using less carbon-intensive energy sources) or buy the extra allowances they need on the market, or both.

The first phase of the ETS, from 2005 to 2007, was considered a "trial phase". In 2006 it became evident that most installations had been oversupplied with carbon credits in the first phase, and as a result the spot price of $CO_2$ collapsed. The main features of the EU ETS and the insights provided by the first phase are described in Kettner et al. (2010), while Hintermann (2010) develops a structural model of spot allowance prices in the trial period. The second phase started in 2008 and will run until December 2012; this time frame coincides with the first commitment period of the Kyoto Protocol. The European Commission reduced allowances by 6.5% relative to the emissions reported in 2005 and raised the penalty for non-compliance with the commitments to 100 €/ton $CO_2$.[1] Furthermore, while the majority of

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[1] For an electricity generator using natural gas (coal), this would translate into approximately 40 (80) € per excess MWh produced, using the average emission factors provided by the International Energy Agency (2011a). The marginal cost of generating electricity in a natural gas (coal) steam turbine is approximately 30 (20) €/MWh.

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allowances (90%) are still allocated free of charge, based on installations' historical emissions ("grandfathering"), the states now have the option of auctioning up to 10% of the allowances. The third phase of the ETS is expected to run from January 2013 until December 2020; its most relevant features will be the inclusion of additional industrial sectors and greenhouse gases, the establishment of more stringent emission reductions for participating installations and the progressive phase-out of free allocations. Survey evidence suggests that market participants expect the burden and costs of compliance to rise significantly in phase 3 (Anderson et al., 2011).

Since EUAs can be traded freely within the scheme, in principle the ETS should ensure not only that total emissions are reduced, but also that emission reductions are made by the installations with the lowest abatement costs. While ETS emissions in 2010 fell by about 8% relative to 2005 (European Commission, 2011), several papers (e.g. Böhringer et al., 2005; Oberndorfer and Rennings, 2007) have questioned the cost efficiency of the cap-and-trade program in achieving emission reductions. Analysts have also cast doubts on the ability of currently observed EUA prices to drive low carbon investments (van Renssen, 2012). Zhang and Wei (2010) provide a comprehensive overview of current research on the ETS.

The focus of this paper is an examination of possible asymmetric transmission of $CO_2$ prices to electricity futures prices in the second phase of the EU ETS. In principle, "economic theory suggests no pervasive tendency for prices to respond faster to one kind of cost change than to another" (Peltzmann, 2000). However, a number of studies in the agricultural, financial and gasoline markets have found empirical evidence that output prices tend to respond more quickly to input price increases than decreases. The phenomenon is known as "rockets and feathers" in the literature. Meyer and von Cramon-Taubadel (2004) and Frey and Manera (2005) survey the broader literature on asymmetric price transmission.

The energy economics "rockets and feathers" literature is particularly rich and has examined the often-made public complaint that retail gasoline prices rise faster when oil prices are rising than they fall when oil prices are falling. A detailed summary of the existing empirical literature on gasoline markets is provided by Grasso and Manera (2007): out of 23 studies surveyed, 14 find evidence of asymmetric pass-through. Results may vary even for the same country, depending on model specification and data frequency. For example, Borenstein et al. (1997) study the US gasoline market using weekly data from 1986 to 1992 and find that retail gasoline prices react more quickly to increases in crude oil prices than to decreases over the period analyzed. On the other hand, Bachmeier and Griffin (2003) employ the standard Engle–Granger cointegration approach on daily US data in 1985–1998, and find no evidence of asymmetry.

There are numerous explanations of how market failures drive asymmetric price adjustment in the oil-gasoline market. One possible underlying cause is that firms are engaging in price collusion. When costs drop, each firm slowly adjusts its final price because it does not want to signal that it is cutting its margins and breaking away from the collusive agreement; however, when costs increase the firm raises its price quickly to show other firms it is adhering to the agreement. Thus, retail prices respond faster to cost increases than decreases. Another possible explanation is the existence of menu costs that preclude instantaneous price adjustments, even when firms have no market power. Accounting rules and inventory valuation offer alternate explanations for the sluggish adjustment of final prices: for example, when a historical criterion is adopted to value inventories, the firm does not adjust its output immediately when costs change, but waits until the stock of inputs bought at the old price is depleted. Finally, consumer search costs, which generate market power in specific locations, may matter.

Asymmetric price transmission could potentially arise in electricity markets, if prices adjust differently to positive or negative price changes in the markets of inputs for power production (e.g., fuels or emission allowances). However, in this context possible drivers of asymmetric pricing differ from the ones in oil-gasoline markets. Explanations based on inventory capacity constraints or menu costs frictions are not applicable, because power demand has to meet supply in real time and prices adjust regularly to reflect market conditions. Consumer search based theories also do not apply, because electricity retail rates rarely reflect instantaneous variations in wholesale prices. Market participants (in particular, power generators) may engage in price collusion, although this does not necessarily imply an asymmetric response of power prices to positive or negative input price shocks. Asymmetric pricing may also be the result of bidding behavior, as pointed out by Wölfing (2009). Although several papers examined the interaction of power, fuel and carbon prices in the first and second phase of the ETS (Bunn and Fezzi, 2007; Fell, 2010; Keppler and Mansanet-Bataller, 2010; Nazifi and Milunovich, 2010), to the best of our knowledge Zachmann and von Hirschhausen (2008) provide the first and only empirical attempt to analyze the possibility of asymmetric pricing in wholesale electricity markets, with an application to power and $CO_2$ prices in Germany in 2005–2006. The authors conclude that rising prices of EUAs have a stronger impact on wholesale electricity prices than falling prices. Our study analyzes the issue further with a higher-frequency dataset spanning a longer timeframe (daily observations from July 2007 to June 2010) and including four European countries (Germany, France, Belgium and the Netherlands). We also investigate the possibility that power prices may respond asymmetrically to changes in coal and natural gas prices, although the main focus of the analysis remains on the interaction of $CO_2$ and power prices.

A finding of "rockets and feathers" in this setting would have important implications for the distribution of costs and benefits associated with cap-and-trade programs aimed at reducing $CO_2$ emissions. Evidence of asymmetric pricing would suggest that buyers in electricity markets cannot take advantage of price reductions that would have occurred sooner, had price transmission been symmetric. In other words, asymmetric pricing would imply a different distribution of welfare between buyers and sellers in electricity futures markets, relative to the one obtained under conditions of symmetry.

## 2. Data

Our study examines the pass-through of $CO_2$ and fuel prices to wholesale power prices. We do not consider impacts on retail power prices, because these depend on long-term arrangements (like fixed price contracts and regulated tariffs) and do not reflect the volatility of wholesale electricity prices. As a result, there is no direct correspondence between rising and falling wholesale electricity market prices and prices paid by the consumers (Reinaud, 2007), although this might change in the future with the introduction of real-time pricing.

Wholesale markets for electricity can be categorized into spot (or day-ahead), real-time (or balancing) and derivatives markets. Participants typically include generators, marketers (or retailers) and industrial customers directly connected to the transmission grid.[2] In spot markets, these agents submit power demand and supply bids for the 24 hours of the following day; after bids are ranked in merit order, the hourly market clearing price is determined by the intersection of supply and demand. Real-time markets are used to price short-term deviations in supply and demand from the day-ahead market. Derivatives markets allow electricity trading in the longer term to hedge against or profit from price fluctuations: for this reason, they are characterized by the presence of market speculators. Financial instruments can be standardized and traded on regulated exchanges

[2] The vast majority of end-use customers participate instead in retail electricity markets, if these exist at the distribution level.