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Bachelor Thesis

Cost pass-through of emission allowances in electricity wholesale prices

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1. Introduction

"That is what is at stake: our ability to live on planet Earth,
to have a future as a civilization.
I believe this is a moral issue.
It is your time to seize this issue;
it is our time to rise again to secure our future"

– Al Gore

This extract of Al Gore's famous speech 'An inconvenient truth' addresses the importance of climate change as one of the most pressing issues of our time. In 2001, the Kyoto protocol, a treaty that aimed at unifying the world community in tackling this issue was ratified and signed. The partaking countries, which are mainly responsible for the current climate change, agreed to reduce the emission of greenhouse gases to a certain level. The European Union chose to implement a cap and trade system, the European Union Emission Trading Scheme (EU ETS), to meet their requirements. In this scheme, a limited number of emission allowances are allocated to the polluting companies, which may then be traded between the parties. An often-discussed issue in the EU ETS is the occurrence of windfall profits, which occur when companies are able to charge their customers a mark-up for the allowances, even when those where given to the company for free. This phenomenon was first analysed by Sijm et al. (2006) and has been the topic of somewhat extensive research. The price of emission allowances might affect the demand and prices of input fuels, such as coal and natural gas and therefore might induce changes in the merit order, which is central in the electricity pricing mechanism. This raises the question of the interaction of emission allowances with electricity and the input fuels, such as coal or gas.

The aim of this paper is to analyse the effect of emission allowances on the electricity price by focussing on the cost pass-through of the allowance price. Therefore, the following research questions are posed:

- How are electricity prices affected by the emission trading scheme?
- What are the interactions between emission allowances and other fossil fuels?
- Is there a cost pass-through of emission allowances into electricity prices?

This paper will aim to answer these questions by, first, introducing the European carbon market, its regulatory framework, main players, provide an overview of the pricing of emission allowances and how the existence of allowances might lead to windfall profits. In a second part, the European electricity market will be introduced: its market structure and organisation, the generation and consumption mix, as well as its price formation process. This part gives an overview of the electricity sector and helps the reader to understand how the electricity price will be affected by changes in the marginal price of production. The next and central part of this paper contains the econometric analysis, which will be the tool used for answering the questions outlined above. Here, the techniques used for the analysis, cointegration analysis and vector error correction models, will firstly be presented and then be used to test whether electricity prices can be partly explained by emission allowance prices. If there were a significant relationship between the two variables, then the data would support the theory of cost pass-through of emission allowances into electricity prices. Therefore, this paper will initially assume an exogenous price formation process and in a second part allow interactions between the prices.

2. EU ETS

2.1. Environmental and Historical Context

To understand the effect of carbon emission on the temperature of the Earth one must look at the factors influencing climate. According to Maslin (2004), a planet's climate is the result of several factors: its mass, its distance from the sun and the composition of its atmosphere, particularly the amount of greenhouse gases (GHG) present in the atmosphere.

The relation between the energy input coming from the sun and the output from its loss back into space controls the temperature on Earth. The energy gained from the sun's radiation is trapped naturally in the land and oceans resulting in a warming of the Earth's surface and an emission of infrared radiation. GHGs trap this radiation and reemit it, thus warming up the atmosphere: this is referred to as the Earth's natural greenhouse. Whenever the amount of gases present in the atmosphere grows, the temperature on Earth rises. Some examples of greenhouse gases are water vapour, carbon dioxide, ozone, methane and nitrous oxide.

From those gases, the one most responsible for greenhouse gas emission is carbon dioxide, with almost three quarters of the total. Carbon dioxide follows a natural movement in the ecosystem of the Earth that is represented by the carbon cycle. In the past, variations in the carbon cycle resulted from changes in the Earth's climate, which in turn, came mostly from alternations in the orbit of the Earth. Riebeek (2011) states that over the past 800 000 years, carbon dioxide levels in the atmosphere were closely correlated to temperature. While climate has changed in the past and some of the aspects of the current climate have been seen before, others have not. Today's concentration of CO_2 in the atmosphere is at a half-million-year high, which it has reached at a very fast rate and similarly, the temperature is at least at a 500-year high. According to the IPCC report 2014 the former is the main reason for concern.

Today, human activity contributes to climate change by causing changes in the amount of greenhouse gases, aerosols and cloudiness present in the atmosphere. The most flagrant example is the excessive use of fossil fuels and land-use change. Those are unnaturally taken out of their geologi-

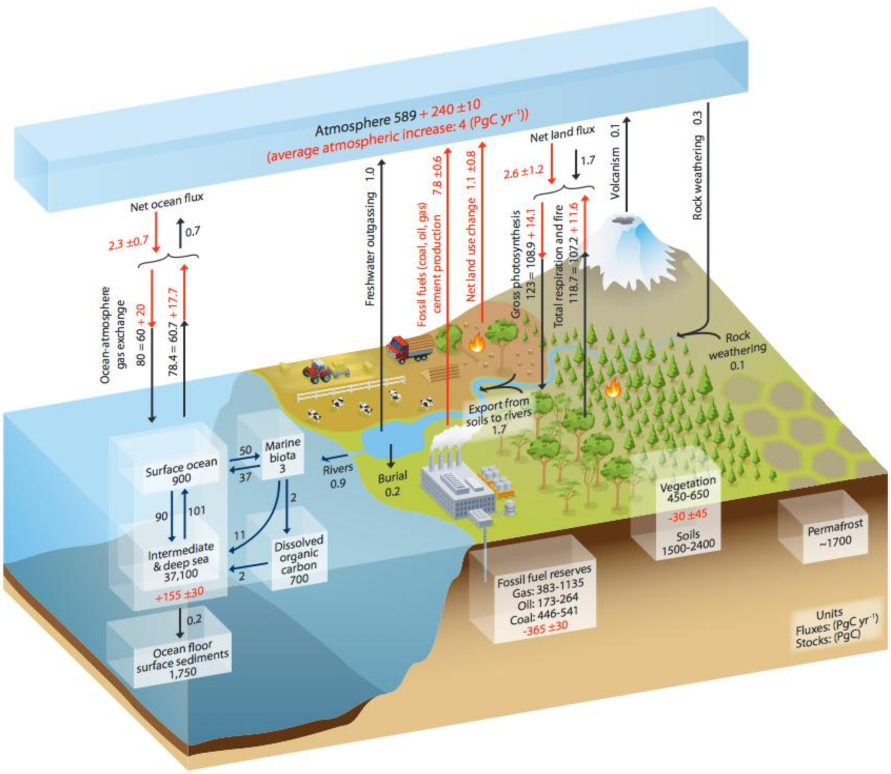

Figure 1: Schematic of the carbon cycle (Source: IPCC report 2013)

cal reservoirs where they would have stayed until they would have escaped naturally through volcanic activity, presumably at a much later date. According to the IPCC (2007) in the 1990's, the men-made flows of carbon from geological reservoirs to the atmosphere were 6.4 GtC (billion tons of carbon) per year.

Maslin (2004) explains that global warming is estimated to cause climatic change by the end of the 21st century, thus affecting our natural, social and economic environment. But great uncertainties remain because of our inability to predict future developments. Water is expected to be the main issue related to climate change, leading to, for example, floods and a lack of fresh water access. The IPCC report 2014 estimated that the global mean surface temperature could rise between 1 and 4° C by 2100. Because of this, the global mean sea level would rise between 45 and 82 cm by 2100.

The three most GHG intensive sectors are energy (71.5%), agriculture (13.0%) and industrial processes (5.6%) and are therefore the most important contributors to global warming. (World Resource Institute, 2011)

Figure 1 shows the pathway of carbon in the Earth's atmosphere, water and soil.

In 1979, the first World Climate Conference raised concerns regarding the increased presence of carbon dioxide in the atmosphere. In the 1980's and 90's, several conferences on climate change were initiated in order to encourage more concrete action. In 1988, the World Meteorological Organisation and the United Nations Environmental Programme created the Intergovernmental Panel on Climate Change (IPCC) that aimed to "provide the world with a clear scientific view on the current state of knowledge in climate change and its potential environmental and socio-economic impacts" (IPCC, 2014, S. §1). Also in 1988, the General Assembly of the United Nations passed a resolution, initiated by Malta for "the protection of global climate for present and future generations of mankind"[1]. In 1990 the IPCC issued its first report, stating that climate change is a real concern and that human activity was likely to contribute to it.

Consequently, in 1992 at the United Nations Conference on Environment and Development (UNCED), also known as the Rio Earth Summit, the international environmental treaty "United Nations Framework Convention on Climate Change" (UNFCCC) was negotiated. Its aim was to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (Article 2, UNFCCC) by negotiating a worldwide agreement in reducing greenhouse gases and limiting the impact of global warming. One of the most important steps towards reaching this goal was the adoption of the Kyoto protocol in 1997.

In 2001, 186 countries ratified and signed the Kyoto Protocol, thus making it a legal treaty. It specifies the principles for a worldwide treaty for cutting greenhouse gas emission and entered into force in 2005 after Russia's ratification. Therefore, the treaty includes at least 55 countries accounting for more than 55% of total CO_2 emission, which makes it legally binding[2]. Today, all industrialised countries, except for the USA and Canada (which withdrew from the protocol in 2013) have ratified the Kyoto protocol.

The six targeted gases are listed in Appendix A of the Kyoto Protocol. They include the greenhouse gases Carbon dioxide ($C0_2$), Methane (CH_4), Nitrous oxide (N_20) and Sulphur Hexafluoride (SF_6); and two groups of

[1] Resolution A/RES/43/53; 6th December 1988
[2] The process was delayed by the USA's withdrawal from the protocol. Accounting for a quarter of global emission, their withdrawal was considered a major setback.

gases: Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) that altogether account for almost the entire greenhouse effect[3]. In 2012, Nitrogen Trifluoride (NF_3) was added to the list.

From those gases, the one responsible for the biggest part of greenhouse gas (GHG) emission is carbon dioxide (73.4%). Methane (16.7%) and nitrous oxide (8.19%) account for only a smaller part of total emission. The remainder have a share of less than 2% but are still included because of their much longer lifetime and rising emission trend. (World Resource Institute, 2011)

For these gases, the Kyoto protocol declares a clear emission-reduction goal: in a first commitment period (2008-2012) at least a 5% cut of 1990 levels has to be achieved. Then, in a second commitment period, from 2013-2020, the goal is set at 18% of 1990 levels. It was decided that in order to reach these emission levels, different individual targets would be imposed on the parties of the Kyoto protocol. As developed countries were considered to be principally “at fault” for historic GHG emissions, they were given a higher share of the total reduction. The EU for example, agreed to cut their emission levels in the first commitment period by 8% of 1990 levels and by 20% of 1990 levels in the second commitment period.

Further, the Kyoto Protocol has set some ground rules for three mechanisms that aim to support the states to reach their target emission levels by allowing that some emission reduction may be done abroad. These “Kyoto mechanisms” are Emission Trading, Clean Development Mechanism (CDM) and Joint Implementation (JI). CDM and JI are project-based mechanisms that allow states to earn credits (Emission reduction units (ERU) in JI or Certified Emission Reduction (CER) in CDM) that are considered equivalent to reducing their own emission, by financing or conducting “emission-reduction” projects in another country. The difference between those two mechanisms is that JI is implemented between two industrialised countries, which both have an emission reduction goal; and that CDM is negotiated between an industrialised and a developing country[4]. Emission trading allows industrialised states to trade their allowed emission amongst each other. The targeted emission goal is therefore divided into Assigned Amount Units (AAU). Whenever a state has an emission capacity that is not equal to the emission goal, it can buy or sell it to other countries. Therefore a new market for emission reduction has been created. Since carbon dioxide is the main GHG, the market where emission reduction is traded is commonly referred to as the “carbon market”. (UNFCCC, 2014)

The Kyoto protocol allowed a number of mechanisms for its members to achieve the reductions agreed upon, amongst which is the “burden sharing” mechanism. This allows the member states to group together and achieve a common emission goal. The member states of the EU agreed to a “burden sharing agreement” in 1998 in which each state is given a specific emission target (from -28% for Luxembourg to +27% for Portugal).

The EU chose to implement a cap and trade system called the European Union Emission Trading Scheme to meet the Kyoto protocol’s mandatory requirements. Note, that this is not the same scheme as the one defined by the Kyoto protocol.

[3] Other potentially harmful greenhouse gases are already covered by other means, such as the “Montreal Protocol on Substances that Deplete the Ozone Layer” of 1987.

[4] The idea is that JI and CDM would allow states to reduce emission in the place that is the most cost-efficient and to encourage the development of environmental-friendly technology in developing countries.

2.2. The economics of cap and trade

In economic theory, the problem of an abundant presence of greenhouse gases is an example for an "externality" (Rezai, Foley, & Taylor, 2009), a market failure that is often associated with environmental problems. Externalities are the uncompensated impact that third parties face due to the action of another market participant. It is considered to be a negative externality when it imposes external costs on third parties and a positive externality when a third party receives external benefits.

Climate is referred to as a public good, meaning it is non-excludable and non-rivalrous: individuals cannot be effectively excluded from using the good and the use of it by one individual does not infringe on its use by others. A common problem with public goods is that markets without any public policy do not deliver an efficient amount of this good due to a lack of incentives for a self-restriction in consumption.

The actors responsible for greenhouse gas emission cause global warming, therefore generating costs to the world and to future generations. Emitters do not need to compensate those who are disadvantaged by climate change, which means that the pricing mechanism without any public intervention does not work. Therefore climate change is an externality that is not corrected for, unless policy interferes.

The classical market mechanisms do not lead to efficient outcomes because of these negative externalities. They need to be internalised by changing the suppliers' private costs so that they match the social costs[5] to restore efficiency to the market mechanisms. The goal that regulators have to set themselves is to identify the optimal amount of pollution.

In standard theory of externalities, four approaches to counter externalities were developed, mainly throughout the first half of the 20th century[6]:

- Taxes: Pigou (1920) showed how taxes can set a marginal cost on pollution that equals the marginal damage caused by it. Therefore taxing the emitters makes them pay for the social costs they are causing.
- Quantitative restrictions: using a "command-and-control" mechanism to limit the volume of emission.
- Defining property rights: Coase (1960) argued that as long as private property rights are defined and there are no transaction costs, trade will lead to an efficient use of resources.
- Create a platform that brings those affected by the problem together with the ones that cause it. (Meade, 1951)

When it comes to climate change, Stern (2007) sets it apart from other externalities (such as overfishing, water pollution, storage of nuclear waste, etc.) by mentioning four distinct characteristics: First, climate change is a global issue, in cause and consequence. The impact that emission of greenhouse gases have, is independent of where it comes from as they disperse into the atmosphere, but the impacts are likely to fall unevenly around the world. Second, the effect caused by climate change is (quasi-)permanent and growing. It will endure for a very long time period, once the gases are emitted. The effects are already felt today and are likely to increase over

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[5] Social Costs: Include both the private costs and any other external costs to society arising from the production or consumption of a good or service. When a good has a negative externality, the social costs are higher than the private costs.

[6] For more information on different approaches such as pollution rights, firm-specific prices, subsidies or taxes used in environmental economics refer to Wiesmeth (2012).

time, with the next generation feeling it stronger than the current one. Third, the final outcome of the impact is uncertain. There are considerable risks concerning scale and timing. Finally, the impact of climate change will most definitely importantly affect the global economy if it is not controlled. Therefore, an analysis of climate change must consider non-marginal changes in society and economy.

Economic policy instruments use price signals to incentivise the actors to make the changes towards an efficient outcome, i.e. some form of regulation. According to Hepburn (2006), price instruments should be favoured when "the appropriate response varies between different regulated firms, there are information problems so the regulator does not have the necessary knowledge about the firm costs". In climate change, the information available to the regulatory body is very restricted. Additionally, the costs to reduce emission can vary greatly between the individual firms.

A cap-and-trade mechanism attempts to internalise the external effect through a market for certificates. In this sense, a public agency issues a limited amount of certificates, which have to be owned when producing a polluting activity, thus creating scarcity and a demand for them. The central authority, by these means, can put an effective "cap" on the negative effect (the cap equals the sum of the certificates issued). After this initial allocation, the permits may be traded between market participants, allowing the creation of a market price, hence the name, cap-and-trade. (Wiesmeth, 2012; Baldwin, Cave, & Lodge, 2011)

The economic model of a cap and trade system can be explained using a two-firm-model, as depicted in Figure 2. This model considers two firms under perfect market conditions (no transaction costs, no uncertainty, rational market actors, etc.) with increasing marginal pollution abatement cost curves, meaning that each firm pays an increasingly higher price for reducing pollution by one additional unit. If no regulations were applied, they would both choose to abate none of their emission, as this would minimise their costs and therefore maximise their gains. Figure 2 depicts the two distinct marginal abatement curves. The costs of reducing pollution of firm X is measured from right to left and for firm Y, it is measured from left to right.

The horizontal axis represents the maximum abatement allowed by the model, which is typically exogenously defined in the form of a cap. The blue and red lines represent the marginal abatement costs of both firms, X and Y respectively.

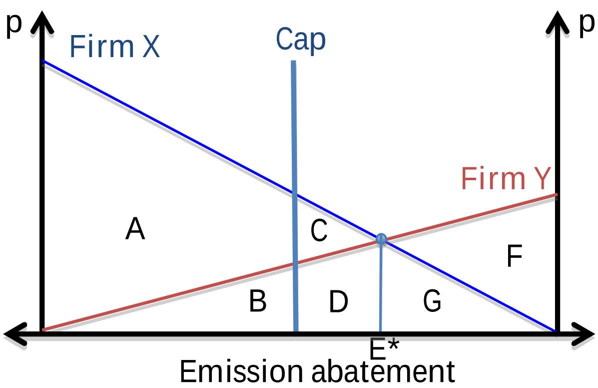


Figure 2: Cap and Trade mechanism

In Figure 2, the area below the marginal abatement cost curve to the origin represents the prices of reducing pollution by a particular quantity for Firm X (Y). It is important to note that they face different marginal abatement costs, which is represented by the slopes of the curves in Figure 2. The point where the two curves intersect, E* represents the economically efficient point for the given total emission, since at this point the marginal abatement costs of both firms are equal and therefore it is not possible that one of them reduces its emission any further at lower costs than the other. In other words, the total abatement costs are minimised for the predetermined cap. Any policy instrument should therefore aim to achieve this economic and emission efficiency.

A cap-and-trade system aims to do exactly that. It initially introduces a cap, which sets a maximum emission equal to the efficient level, represented graphically by the length of the horizontal axis. In a second step, certificates are distributed to the firms that give them the right for pollution, which they are allowed to trade amongst each other. Although other allocation methods are possible, for simplicity, each firm is given the same amount of certificates in this example. Initially, the abatement costs for firm X are C + D + G and B for firm Y. Each firm faces marginal abatement costs given by its marginal abatement curve. Adding these costs together yields the total abatement costs. At this level, firm X and Y are willing to pay a price maximally equal to their respective marginal abatement costs. When the cap is set in the way it is in our example, firm X has higher abatement costs than firm Y and will therefore be willing to buy more permits from Y, who faces lower abatement costs and will therefore be willing to sell some of its certificates. This process continues until one or both market participants are not willing to buy or sell their allowances anymore. This is the case, when their marginal emission abatement costs are equal, which is represented by the intersection of the two curves at point E*. The resulting abatement cost for both firms equal to B + D for firm Y and G for firm X, resulting in overall efficiency gains from trade equal to C.[7]

One of the main advantages in using a cap and trade mechanism for pollution reduction is its allocatory advantage. That means, the efficient redistribution of the polluting activity towards the market participant that is able to make the most use of it in terms of wealth creation (as explained above). Additionally, the outcome of the cap and trade system is very foreseeable. This results from the binding cap that limits emission to a maximum level. This is a main advantage, compared to other market-based instruments such as a tax. Further, the regulatory costs are considered to be low as a market "once established, the trading system runs on its own accord" (Baldwin, Cave & Lodge, 2011, p.199). Moreover, the danger of capture, which occurs when the relationship between regulator and regulated party becomes too close, such that there is a risk that the regulated companies' interests are presented as the public one, are significantly reduced, since no such relationships are being formed in a market. Additionally, regulated firms are flexible in the implementation of changes and can therefore choose how they wish to act after balancing their individual pollution costs against their abatement costs. This is possible, as the rules implemented in a cap-and-trade system are usually not very complex and hence allow a number of ways for pollution reduction. (Baldwin, Cave, & Lodge, 2011)

Nevertheless, cap and trade systems have several imperfections. First, the premise for the functioning of a cap and trade mechanism is a healthy market for its permits. This means that there has to be no uncertainty, full information, etc. Additionally, there remain some needs for intervention by a regulatory authority, since the rules of the system have to be enforced to ensure that only those who are allowed to use their pollution rights use them and that they are not used excessively. This results in additional costs that have to be accounted for. Also, permits do not offer any direct repayment for those affected by pollution, as it solely inflicts a punishment on the polluting party. However, it might be possible to reallocate some compensation towards the affected party if the cap and trade mechanism yields a government revenue (i.e. trough auctions). Moreover, regulatory lag might be a problem in the case of a cap and trade system. For example, if the number of allowances, which have been given away was not set correctly (as it happened in Phase 1 of EU ETS; see part 2.3.2), this can only be cor-

[7] The same result can be achieved through a tax, by setting the tax where the marginal abatement costs of both firms are equal.

rected for in a later period, when allowances are distributed again. Permits might also be used as a mechanism to create market entry barriers by hoarding them. Additionally, permits may lead to windfall profits when they are allocated freely (see part 2.5). (Baldwin, Cave, & Lodge, 2011)

2.3. The EU ETS

2.3.1. Overview

The EU ETS covers around 45% of total greenhouse emission from the 28 participant EU countries. It consists of three distinct phases: a pilot phase (2005-2007), a second phase (2008-2012) that coincides with the first commitment period of the Kyoto protocol and a third phase (2013-2020), which overlaps with the second commitment period of the Kyoto protocol. (see below)

The participation in the EU ETS system is mandatory for companies that are part of one of the sectors specified in Annex I of the Kyoto protocol, such as for carbon dioxide: power and heat generators, energy intensive industry and commercial aviation; for nitrous oxide: production of certain acids; for perfluorocarbons: aluminium production. The EU ETS system considers every single industrial installation that has rated thermal input exceeding 20 MW and aircraft operator (as of 2012) as individual participants. They amount to around 11'000 individual plants, which will receive emission allowances accordingly. The currency of the EU ETS system is the European Union Allowance (EUA) that allows its owner to emit 1 tonne of carbon dioxide or an equivalent amount of one of the other greenhouse gases after adjusting for its global warming potential.

The EU member states develop a national allocation plan (NAP), in which they each propose a limit for the total emission of the relevant installations to the European Commission. After their approval, the member states receive an allocation of EUAs that they can distribute to the plants according to their NAPs. The individual plants are required to have an approved monitoring plan that indicates how they monitor and report their emission over the year. The data on their emission will be verified and on the 30^{th} of April every year the corresponding number of allowances has to be submitted by each plant.

An important part of EU ETS is the method of allocation. Several different approaches were used over its first two phases; namely, grandfathering, benchmarking and auctioning (see part 2.5).

2.3.2. Phase 1

The pilot phase was introduced to prepare the market participants for the next, more important period of the EU ETS, when the mechanism would be needed to work effectively to achieve the requirements of the Kyoto protocol. The individual countries would submit their NAP, with their required quantity of CO_2 for validation to the European Commission. In this initial phase only power generators and energy intensive industries were included in the system to provide information and know-how for market participants, as well as for regulators to ensure a better market functioning in the future. Allowances were made available for free and a fine of 40 € was amended in case of non-compliance. Due to a lack of reliable data on emission levels, the caps in this phase were given on a best-guess basis but were retrospectively found to be too high, which resulted in a price close to zero. Surplus allowances of the first phase could not be used in the second phase of the EU ETS.

The first phase of EU ETS showed a very volatile EUA price. According to Alberola, Chevalier and Chèze (2007) the price development in the first period can be subdivided into three distinct periods marked by two structural breaks. The first phase goes from the beginning of trading until April 2006. Initially, prices started out at around 10€/allowance, this number tripled to reach around 30€ per allowance in 2006 and fell sharply in the same year after the news about a possible over allocation emerged in April 2006. This marks the start of the second period, which lasted from April 2006 to October 2006. In this period, the price of an EUA allowance remained between 10 and 20 € per allowance. Finally, the third period of EUA trading from October 2006 onwards was marked by a complete collapse of EUA spot prices. Prices declined steadily to fall under €1 in February 2007 and finish the year with a price almost equal to €0.

In contrast, the prices of Phase II futures had a different trajectory. While they followed the Spot price closely in the first two periods, the prices separated themselves completely from the spot price in the third period. Phase II EUAs increased to between €20-€25 while the spot price fell to zero. This separation in prices is mainly attributed to the fact that emission allowances could not be banked nor used in the subsequent period.

2.3.3. Phase 2

The second phase of the EU ETS coincides with the first commitment period of the Kyoto protocol from 2008–2012. The goal of this phase was to reach the emission targets conveyed in the burden sharing agreement to meet the total EU reduction agreed upon in the Kyoto protocol. Five new participant countries were included in the EU ETS: Romania, Bulgaria, Iceland, Norway and Liechtenstein. The individual countries would again provide NAPs with their requests for allowances. The sectors that would be covered by the second phase EU ETS are listed in the Annex II of the Kyoto protocol. In 2012, the aviation industry was added to the EU ETS, where the cap was set at 97% of a reference period (2004–2006) and 85% of the allowances were given away for free. It includes all routes between two EU ETS countries,

In the other sectors, allowances were still given away for free in at least 90% of cases, while the member states were allowed to choose how much of the remaining 10% would be auctioned off. Another possibility for participants in the second phase was to buy CDM and JI credits to account for their emission, which allowed for a more cost-effective emission reduction option. This allowed global emission trading that started as a result of the Kyoto protocol to be linked with the EU ETS. The countries were allowed to limit the extent to which the individual plants were allowed to use those as an alternative.

In the second phase, the cap was lowered by additional 6.5% compared to 2005 levels. Nevertheless, allowances remained too generously allocated as the 2008 economic crisis notably reduced demand for them, resulting in a growing surplus in emission allowances on the market and a therefore low EUA price.

All in all, the price for a EUAs was significantly more stable in the second period than in the preceding one, which is partly due to the adjustments made to account for previous errors (see above).

2.3.4. Phase 3

The third phase of the EU ETS coincides with the second commitment period of the Kyoto protocol from 2013–2020. Several new changes are implemented to harmonise rules across the different regions.

A EU-wide cap replaces the cap system of national caps. The cap set in 2013 would be lowered linearly by 1.74% per year compared to the 2008 –2012 reference period to reach a final 21% lower emission compared to 2005. A different cap is applied to the aviation sector, where it remains constant at 95% of the 2004–2006 reference period. The penalty for non-compliance in 2013 is 100€/tCO_2.

However, the main change that was implemented for the third period of EU ETS was its new main allocation method: auctioning. While the European Commission stated that allowances should mainly be given away freely in the first two periods, now they will be auctioned away. In this sense, 40% of allowances would be auctioned off in 2013 and this number would grow in the subsequent years. Every sector would receive different percentages of allowances for free. The manufacturing industry initially receives 80% of allowances for free, a number that will drop annually to 30% in 2020. The aviation sector will receive 85% of allowances for free over the entire period. Finally, electricity generators would have to buy all of their allowances in 2013, with the exception of some, mostly Eastern European plants that would initially receive some of their allowances for free but will also have to buy them by 2020. However, due to a growing surplus in allowances resulting from 2008 financial crisis, the European Commission has decided to postpone some of the auctioning of allowances to a later date (but still in the second commitment period).

Another change came in the case of free allocation of allowances with regards to the allocation method: allowances would henceforth be distributed on the basis of actual production (benchmarking), which allows a more flexible approach when dealing with new market entrants or changes in the business cycle instead of historical values (grandfathering) but.

2.4. The European Carbon Market

2.4.1. Overview

The EU ETS has become the biggest emission market in the world. Ever since the beginning of EUA trading activity, the volume of the market has kept rising constantly. The European Commission (2013) states that the volume traded grew from 94 million allowances in 2005 to 460 and 998 million in 2006 and 2007 respectively. This development continued in the second period as volumes continued growing steadily from 2.3 billion in 2008 to 6.7 billion allowances in 2011. In 2010, the European carbon market accounts for around 84% of the value of the total carbon market. (European Commission, 2014)

The market participants in the EU ETS can be broadly divided into two groups: obligatory participants and voluntary participants. The obligatory participants include all those that are required to cover their emission by buying emission allowance certificates. Their aim is to buy certificates to not be fined for non-compliance. For example, electricity producers need to cover their emission from burning fossil fuels. Voluntary participants are speculators in the market, betting on a certain price movement by buying or selling either the allowances or their derivatives.

EUAs can be traded through several different channels: as bilateral agreements, over-the-counter or through organ-

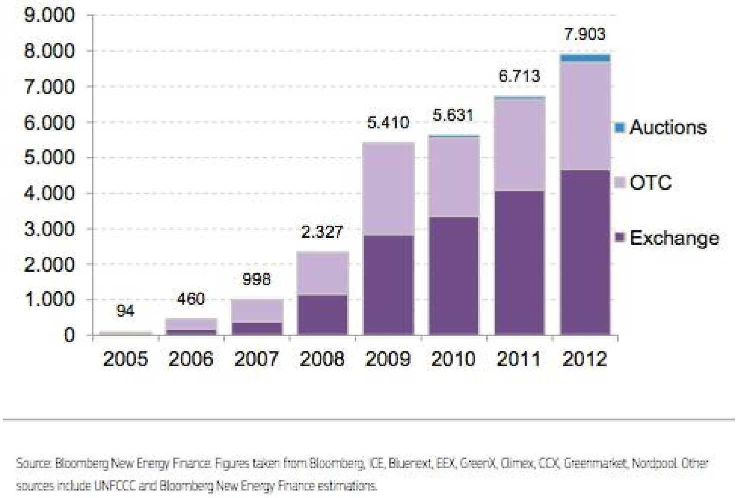


Figure 3: Trading volumes in EU emission allowances in mT (European Commission, 2013)

ised markets. Bilateral agreements are made directly between two parties, which generally have good market knowledge and are made without the involvement of any intermediaries. The trades are typically large in size and the prices are not publicly released. OTC trades are the biggest part of EUA transactions, with almost 70% of the total transactions (Ellermann, Convery, & de Perthuis, 2010). Trading might also be done through organised exchanges, which offer standardised trading possibilities through electronic platforms. They often clear transactions that have been made bilaterally or through a broker and execute block trades that do not have to be reported as long as a minimum volume has been surpassed through a block trade facility. There are several exchanges on which EUA certificates may be traded, for example the ECX in the United Kingdom, the BlueNext in France, the NordPool in Norway, the EEX in Germany and the EXAA in Austria.

Exchanges allow several different contract types in which EUAs may be traded, such as spot contracts, futures, swaps, options, each with different delivery period options. Cash or spot contracts are used for a delivery up to two days in advance and allow a market participant to receive an immediate cash payment in exchange for a EUA. Forward and future contracts are standardised contracts with a fixed future delivery date, volume and price and allow the buyer to fix a price for its future emission. By convention, delivery is set to December for any given year. (Ellermann, Convery, & de Perthuis, 2010)

In the beginning of EUA trading, most of the allowances were traded OTC. This slowly changed as organised exchanges developed and trading on exchanges became more commonly used year by year. The crisis in 2008 favoured organised exchanges because of the absence of a counterparty risk, resulting in over half of the allowances being traded on organised exchanges in Q4 2008. In 2012, around 7.9 billion allowances were traded with a total value of €56 billion. Over half of these were traded on exchanges, while most of the remaining allowances were still traded OTC and a small amount was auctioned. (see Figure 3).

2.4.2. EUA - Price formation

Christiansen, Arvanitakis, Tangen, & Hasselknippe(2005) were the first to analyse the price drivers of EUAs and found that policy and regulatory issues, market fundamentals, such as the weather, production levels and fuel-switching were the main price determinants affecting emission allowances. Chevalier (2012) outlined three fundamental price drivers for carbon prices: institutional decisions, energy prices and weather events. Institutional decisions affect the supply side for EUAs and the latter two may be summarised under factors that influence the demand side, which would also include other factors such as economic growth etc.

On the supply side, institutional decisions affect the price of CO_2 allowances by affecting the expected and effective supply of allowances. Chevalier analysed structural changes in the carbon price to determine possible changes from institutional decisions. He found three moments of structural breaks: one on May, 28th 2007 and a period (that counts for two structural breaks, one that marks the beginning and the other that marks the end of the adjustment period) of structural change between December, 30th 2008 and February, 11th 2009, which coincides with the impact of the financial crisis on the carbon price. Chevalier (2012, S. p.29) argues, that the "first break is somewhat of smaller magnitude than the other two, and may be related to the 2006 yearly compliance event. Therefore, the first breakpoint may be directly related to the effects of institutional news by the European Commission concerning the publication of yearly verified emissions" and follows that in case of the period of structural change, "it may be more appropriate to run separate regressions in sub-samples (before and after the crisis)" to account for differences in fundamental price drivers for these allowances.

On the other side, factors that affect the demand side for EUAs are for example weather events, economic growth and energy prices. Weather events such as forest fires, earthquakes or large changes in temperature influence the EUA price by affecting the energy supply and demand. The most important of these are changes in temperature (Chevallier, 2012), which affect the demand for emission certificates. For example, very cold (hot) temperatures demand a stronger use of heating (cooling), which in turn demands a higher amount of electricity that is made available by using fuel, which increases emissions and therefore the demand for emission allowances. Economic growth is a strong indicator for demand for EUAs. Whenever the economy is strong, and the demand for goods is accordingly high, there will be a higher industrial activity. These larger production needs are accompanied by a greater need for CO_2 emission and therefore an increased demand for emission allowances and vice versa. (Chevallier, 2012) Empirical findings indicate that fuel prices are the most important price drivers of carbon prices(Convery & Redmont, 2007; Mansanet-Bataller, Pardo, & Valor, 2007; Keppler & Mansanet-Bataller, 2010). The EUA price is affected by energy prices (such as coal or natural gas) through several channels. They affect the producing process of the companies concerned by the EU ETS, which directly relates to CO_2 emissions and hence demand for emission allowances. Higher energy prices typically lead energy-intensive companies to choose lower production levels, which in turn lower the need and demand for emission allowances and vice versa. Also, as power producers make up an important part of the carbon market players, a crucial aspect of carbon price determination will be based on the fuel switching behaviour of these players. For example, assuming that every company decides that they will switch from a high carbon production, such as coal to a low carbon intensive production, such as natural gas, this would immediately lead to a lower emission level and therefore to a reduced demand for emission allowances and vice versa. Chevallier (2012) found that oil and natural gas have a positive price impact on emission allowances, while coal has a negative effect on it. (Chevallier, 2012)

2.5. Windfall profits and the Electricity Sector

A cap and trade system creates a market for a public good and as such creates a price for the usage of this good (see part 2.2). In the case of the EU ETS, this is a price on carbon dioxide emission, which is represented as the price of an emission allowance. The aim is to adjust the prices of emission producing goods in the economy so that they reflect the costs of the polluting effect in their products. One highly politicised theme is the resulting higher retail prices, especially when it comes to electricity prices. It is a very sensitive subject since the energy-intensive industries are vital to several member states' economies and therefore have strong lobbying power. Moreover, the issue is politically very important as low-income households are highly affected as they typically pay a bigger part of their income on energy. There have been major discussions over the effects of emission trading on the electricity industry and on whether and how much prices would be affected. (Wråke, 2009)

In this context, it is possible that emission allowances lead to windfall profits in the electricity sector. Ellermann & Buchner (2007, p.73) say, that there was a "significant outcry about 'windfall profits', especially from energy-intensive industrial firms [and that] regulators initiated formal investigations into windfall profits in several countries, including the Netherlands and Germany". It is possible to differentiate between two types of windfall profits: First, they might result from an over-allocation of allowances. This means that too many allowances are given to a market player, which he will therefore be able to use to cover his own emission and sell the remainder to the other market players, resulting in a free profit. The other, subtler, type of windfall profit comes from pricing the value of the emission allowance into the marginal production costs. This is possible when taking the view that holding the emission certificates is an opportunity cost for the company (see below). The pricing difference of marginal production costs becomes especially interesting when looking at the electricity market, since there, the equilibrium price equals the marginal cost of the power plant, which has to be brought into operation to satisfy total demand (see part 3.3.1).

Special attention needs to be given to the allocation method, since it has a significant impact on the profits made through the cap and trade system. Two of the main allocation methods are free allocation and auctioning.

Auctioning, which economic theory broadly supports as the "better" method (see Cramton & Kerr (2002), Hepburn et al. (2006)), consists in allocating allowances according to the highest bidding price a market participant is willing to pay. Traditional arguments that favour auctions as the better allocation method are: economic efficiency, rent distribution, competitiveness effects, legal considerations, incentives and transaction costs (Hepburn et al. (2006)).

However, auctioning was not chosen as the main allocation method at the beginning of the EU ETS. The reasons for choosing free allocation is usually a strong lobbying by big companies, as well as competitiveness issues. The allocation method used is a form of free allocation, grandfathering (see part 2.3), which will therefore be the main focus here. Grandfathering provides allowances on the basis of their historical or expected future requirements. However, there is an economic reason for giving away allowances for free through grandfathering, as it was seen to prevent sudden jumps in production costs and hence in in electricity prices (which would surely have occurred under auctioning). In a later stage of the EU ETS, benchmarking was introduced, which provides allowances on the basis of a specific benchmark, such as the number of products manufactured for a given plant.

Economic theory suggests that the permit price is expected to be priced into the marginal production costs of any company using them, whether the allocation has been done using grandfathering or auctioning. That is because, even when the initial endowment has been given away for free, the allowances still have an intrinsic value and therefore represent an opportunity cost to the company, which could for example sell these for a profit. Goeree et al. (2010) show in an experimental research project that under grandfathering, the opportunity costs of free permits are completely passed through and that windfall profits occur under free allocation.

From an efficiency point of view, in a cap and trade system, it is irrelevant whether one or the other is used, since through trade the allowances are going to be distributed to the market actor that can make the most economical use out of it (see Part 2.2). However, the difference between the allocation methods becomes evident when looking at the wealth redistribution from the cap and trade system in the

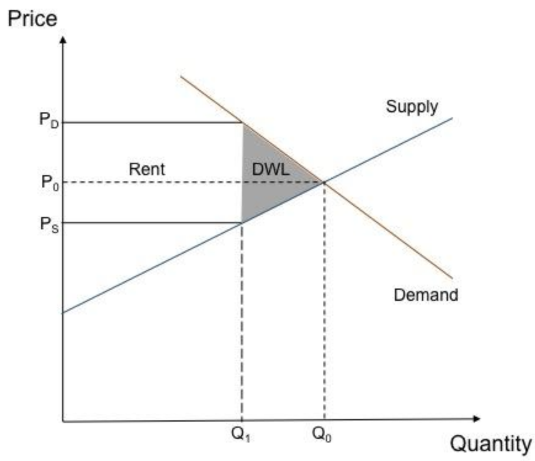


Figure 4: Rent from a cap and trade system

two cases.

A cap and trade system inflicts a distortionary tax on products, which use the pollutant, e.g. fossil fuels. Figure 4 shows how the product price changes when it is affected by the emission trading scheme. Here, the tax, equal to the permit cost per unit is depicted as the gap between the price paid by the supply and the demand side ($P_D - P_S$). The wedge between the two prices gives rise to a scarcity rent (as shown in Figure 4) and where it goes to depends on the allocation method used.

Under auctioning, the rent goes to the government in the form of the compensation received for auctioning the allowances. Cramton and Kerr (2002, p.14) argue that the government could use the revenue generated through the auctions to reduce the tax distortions (see Figure 4) created throughout the economy, for example: it ”can be used to reduce labor or consumption taxes, benefiting all taxpayers. Payroll taxes can be cut or personal exemptions increased, benefiting the poor and middle classes. The deficit can be reduced, providing benefits to current borrowers and future generations. Auction revenue can be used to directly compensate afflicted workers, and provide transition assistance to help them change industries or locations. It can be used cut the capital gains tax and hence benefit capital owners”.

Under grandfathering, however, the rent goes to the market participants directly receiving the allowance. This line of argument is based on the assumption that the opportunity cost of holding the emission allowance will be priced onto the marginal production costs to some extent. The pass-through of emission allowances can therefore result in windfall profits, when the price of the emission allowance is priced onto the marginal production costs.

The issue of windfall profits raises significant questions on the impact of the EU ETS on electricity prices:

- How are electricity producers going to act when allowances are allocated for free?
- Will there be a cost pass-through, as suggested by economic theory?
- What factors will affect the electricity price and the pass-through of emission allowance prices?

To answer these questions, the next part will provide an overview of the electricity market, its history, organisation, structure and price formation. Through this analysis, it will become apparent how it is possible for electricity producers to pass the cost of the emission allowances through. In the final part, an econometric analysis will be carried out to find empirical evidence in support of or contradicting a pass-through.

3. Power markets

3.1. The liberalisation of the electricity sector

In the 1960’s, the European electricity industry was typically publicly owned, usually in the form of one large vertically integrated company that would control the entire value chain from generation to supply. With the expansion of the European economy, electricity demand grew stronger. As this development continued, European states became more dependent on oil imports, which were the prime source of energy generation. The potential dangers of this dependency would become apparent during the oil crisis of 1973. Hence, European countries took measures to ensure their own national interests. For example, France built up their nuclear energy program and as part of the OECD, the IEA was founded in 1974 to counterbalance the power of the OPEC. However, these measures resulted in heterogeneous prices in most European countries. In the 1980s, European countries recognised the impact that these price discrepancies had on their competitiveness in the world markets and decided to take action, resulting in the idea of a liberalised electricity sector. (Stockinger, 2001)

At first, energy security in the Community was the main aim of common energy policy efforts. Only in the late 1980s the attention shifted towards competition in the internal energy market. The European Commission issued a green paper, "The Internal Energy Market" that explains how the creation of an internal energy market was planned. The four procedures defined in the paper, involved: -implementing the general single market provisions in the energy sector; -the determined application by the Commission of already existing general EC Treaty Law, such as the general competition rules; -finding a satisfactory equilibrium between energy and the environment; -the application of additional, appropriate and specific case-by- case means (specific energy directives) to be adopted by the Council (Eikeland, 2004)

After a time consuming process it passed the first energy directive 96/92/EC in 1996 concerning common rules for the internal market in electricity. It established rules for generation, transmission and distribution as well as for the organisation and functioning of the electricity sector and access to the market.
The aim of the directive was to divide the electricity sector into four independent segments: generation, transmission, distribution and supply, with generation and supply becoming competitive markets, whereas transmission and distribution should remain monopolies, as they were conceived to be natural monopolies.

In practise, instead of creating a single market, several liberal markets developed, leading the Commission to develop alternatives and a second directive. Directive 2003/54/EC of the European Parliament and of the Council, concerning common rules for the internal market in electricity and repealing Directive 96/92/EC, was adopted in 2003. The second energy directive aimed to accelerated market opening, by taking into consideration the criticisms on network access and regulation and implementing more liberal options. It aimed to establish common rules for the generation, transmission and distribution of electricity by establishing "rules relating to the organisation and functioning of the electricity sector, access to the market, the criteria and procedures applicable to calls for tenders and the granting of authorisations and the operation of systems." (Article 1, Directive 2003/54/EC).

Again, the changes made as a result of the second directive successfully transformed the landscape of the electricity sector, but some problems remained. In 2005, an inquiry by the Commission identified several shortcomings that remained in the energy sector[8], including "an inadequate current level of unbundling between network and supply interests", a dependency of customers on suppliers through long term contracts, too little market integration between member states, an absence of transparency, etc. The resulting third electricity Directive 2009/72/EC states that, in order to improve competition, the cross border access for "new suppliers of electricity from different energy sources as well as for new providers of power generation" should be eased. Furthermore, ownership unbundling will be implemented to prevent discrimination in the operation of the network and to promote investments in infrastructure.

[8] Commission Decision (EC) Num. 1682, of 13 June 2005, Initiating an Inquiry into the Gas and Electricity Sectors pursuant to Article 17 of Council Regulation EC Num. 1/2003, see also http://ec.europa.eu/competition/sectors/energy/inquiry/

3.2. Market organisation

Before liberalisation, most of electricity trading took place on the basis of bilateral agreements, mostly Over the Counter agreements (OTC). In these contracts, typically a broker acts as an anonymous intermediary for the transaction between two counterparties or alternatively the counterparties trade directly with each other. The settlement of these contracts varies between 24 hours to several years ahead.

After liberalisation, European countries introduced power exchanges, which would provide liquidity to the market. The volume traded on those exchanges is typically lower than for bilateral agreements. Trading often takes place through auctions. In these auctions, energy suppliers and demanders place their offers and bids into the system. Then, both parties' price offerings are taken into account and a market-clearing price (or system price) is set according to supply and demand. The price of these auctions will often be used as a reference point in bilateral agreements. The settlement of the products traded on power exchanges is usually prior to the bilateral trading settlement, sometimes only several hours before delivery. Figure 5 shows the volume traded OTC relative to the volume traded on power exchanges (PX). It shows that trading is still mainly taking place outside the regulated markets. Nevertheless, some markets show very high power exchange volumes but this might be because some countries incentivise the use of certain power exchanges or even make their use mandatory (see countries marked with an asterisk in Figure 5) in the regulatory framework. Generally, those countries have higher trade volumes on power markets.

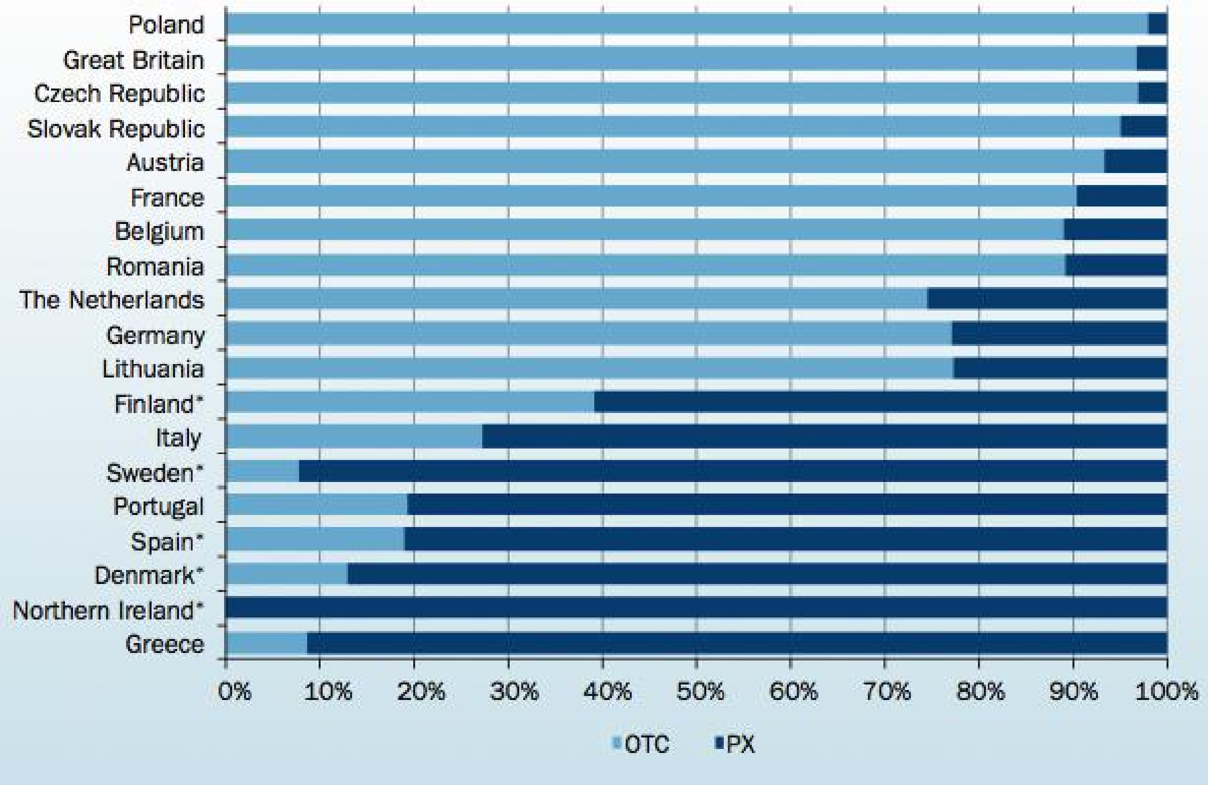


Figure 5 : Comparison of volume traded in bilateral Over the Counter agreements and power exchanges (Source: European Wind Energy Association (2012))

The power market is organised in two types of products: physical and financial. The most important physical power market is the day-ahead market, also referred to as spot market. There, a price for every hour of the delivery day is determined. The intraday market serves to adjust the trades already made in the day-ahead market. The closing of the day-ahead market also marks the market opening of the intraday market.

The day-ahead market usually has two types of products: hourly contracts, that allow the market participants to balance their portfolio of physical contracts; and block contracts that allow the market participants to bring complete power plant capacities into the auction process. The day-ahead market closes 12-36 hours earlier than actual delivery and bids can be placed from this point on.

The intraday market, also referred to as hour-ahead or adjustment market, allows market participants to adjust the balance of their portfolio of physical contracts after the day-ahead market has closed. Those changes can result from several factors: changing weather conditions, changing market conditions (i.e. financial crisis) or plant outages.

The Transmission System Operator (TSO) needs to balance generation and consumption of electricity since it does not own the generation directly anymore. This is done through a regulating or balancing power market, where the TSO adjusts for any differences between generation and consumption. The Annual ERGEG Report 2009 named inadequate integration of balancing markets as the main barrier in achieving a single European electricity market. France and the UK made some progress in cross-border balancing with the implementation of a new model in 2009. (European Wind Energy Association, 2012)

3.3. Power prices

3.3.1. Spot price formation

When it comes to pricing electricity, liberalisation has marked a breaking point in the fundamental pricing mechanisms. Before liberalisation, prices were determined as the average cost of power generation. Afterwards, in a competitive market, prices are expected to equal the short-term marginal costs and, in the long run, should not exceed the long run marginal costs. In a competitive market, prices fluctuate according to supply and demand, which have a very unique behaviour when it comes to electricity. (Haas, Redl, & Auer, 2009)

Supply in the competitive power market comes from the individual power plants, which each give their individual bid prices into the system. Each of those plants uses different technologies and input factors to generate power, therefore the marginal generation costs for each plant may vary greatly. Typically, hydro or nuclear plants have comparatively low marginal costs, whereas coal or gas powered plants have considerably higher ones. The different bids are put in ascending order and then, the plants will be used according to the merit order so that they meet the demand for electricity at each moment in time. That is, the cheapest plant will be the one that is used until its capacity cannot cover the market demand, then the second cheapest is used and so on until demand is met. Therefore, the market price is defined by the bid of the last power plant needed to satisfy total demand and hence the equilibrium price equals the marginal cost of the power

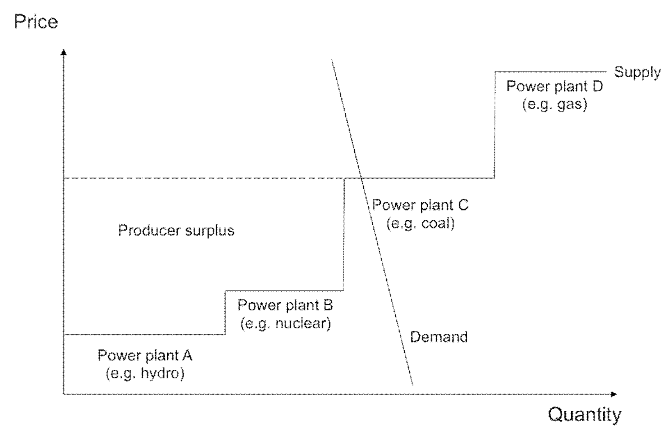


Figure 6: Electricity supply and demand

plant, which has to be brought into operation to satisfy total demand. Figure 6 shows a typical simplified supply and demand diagram. It can be seen that the power plant used as the marginal power plant is very important for the equilibrium price. In our example, if, ceteris paribus, power plant C had had higher marginal costs (as long as they don't exceed the marginal costs of the next power plant, here power plant D), those would have been expected to be completely reflected in the equilibrium price. However, the power plants with lower marginal costs may also affect the equilibrium price, although this relationship is not as straightforward as for the marginal power plant. For example, a hydro-based power plant may have a more or less full water reservoir, which strongly influences the quantity they are able to put into the market. This would be reflected as a broader horizontal line in their input to the supply curve in Figure 6. If it were sufficiently wide, it may be able to change the supply curve such that the equilibrium power plant changes to one with a lower bid price.

Demand in the electricity market is somewhat distinct in that it is characterised by its very low price elasticity, at least in the short run. In the long run, however, it is possible to change to alternative electricity suppliers. Figure 6 shows the stepped supply curve that results from the pricing process of the electricity market and the very inelastic demand in a typical supply/demand diagram.

Electricity has some distinct characteristics that have to be accounted for when explaining its price behaviour. It sets itself apart from other commodities, as it is almost impossible to be stored[9]; therefore the usual pricing mechanisms, which would include a convenience yield that refers to opportunity costs in form of storage costs for its calculation, cannot be referred to (see part 3.3). For the same reason, at any given moment, supply and consumption must be equal. Additionally, there are certain requirements on electricity usage to prevent power system failures, blackouts, etc.: its input into the power grid and outtake must be equal at all times, it has to be maintained within a predefined voltage range and the maximum grid transmission capacity must not be exceeded. Those characteristics and restrictions are the reason for some distinct pricing behaviours of electricity: seasonalities, spikes, mean reversion and high volatility.

Seasonality effects vary depending on the country or region. Inelastic demand in the short run, but also in the medium run, paired with the non-storability characteristic of electricity yields daily, weekly effects, which depend on human activity (such as the typical daily routine) and seasonal patterns, which depend on the weather and climate. E.g. in the Nord Pool region, known for its harsh winters, prices are higher during that period than in summer (Simonsen, Weron, & Birger, 2004), whereas in the EEX, depending on the year, prices are either highest in summer or in winter (Blöchinger, 2008).

Spikes indicate an important change of the price in a very short timeframe. Prices at one hour may be ten times higher than the price of the preceding hour, but these high prices usually quickly revert to their previous levels. Here again, inelastic demand plays a vital role. When there is an upward shift in demand, the demand curve might equal supply at a much more expensive power plant yielding a higher price. The process is especially sensible when demand is just around the maximum capacity of a power plant, as a slight increase in consumption that exceeds the plant's maximum capacity would make the next, possibly much more expensive, power plant the price setting plant. Another reason for the occurrence of spikes, which does not include a shift in demand, is the removal of cheap plants from the system. Simonsen et al. (2004) define three common reasons for

[9] Actually, it is possible to store electricity, but only at high costs and is almost never done.

a market removal: planned maintenance of the plant or transmission grid; technical problems, predicted or not; and abuse of market power.

Mean reversion is a characteristic that is common in commodity markets. When there is a strong price movement, they will usually be drawn back towards the long-term mean. Blöchinger (2008) argues that the deviations from the mean in the electricity market are due to weather events in the short (such as sudden weather events, temperature) and medium run (amount of rain and snow). In the long run, upward movements in the demand curve can increase prices. However, there is a balancing effect as consumers can switch to alternative energy sources and therefore returning the demand curve to its long-term mean.

High volatility[10] can be observed in electricity prices. Simonsen et al. (2004) found a volatility of 16% for the Nord Pool market, which is known for its low volatility compared with other electricity markets. This compares to typical volatilities of 1.5% for stock indices, below 4% for individual stocks, below 0.5% for bonds, 2-3% for crude oil and 3-5% for natural gas. (Simonsen, Weron, & Birger, 2004) There are several reasons that explain the higher volatility in electricity markets. Mihaylova (2009) states that, "high volatility on electricity markets is mainly due to production and transmission limitations, forecast errors, supply and demand shocks and the electricity market design", the latter of which refers mainly to the daily auctioning of electricity, which requires market participants to make daily forecasts of the price level and lead to high spot price volatility when they are wrong.

3.3.2. Price formation in future / forward markets

The high volatility and price spikes, forces market participants to protect themselves from high price fluctuations in the future, making the forward market crucial for electricity wholesalers and consumers. (Bessembinder & Lemmon, 2002)

Pricing electricity futures is also affected by the characteristics of electricity, notably by its non-storability. Conventional future pricing methods for physical commodities is given by the cost of carry approach (or theory of storage), which was developed by Kaldor (1939) using the current spot price (S_t), the convenience yield (c), interest rates (r) and storage costs (s) to determine a no-arbitrage relationship between spot and future prices in the form: $F_{t,T} = S_t e^{(r+s-c)(T-t)}$. The convenience yield represents the effects related to owning the commodity physically, against holding the futures contract, such as selling it in case a shortage might occur at a future time period or using it for production. However, Bassembinder & Lemmon (2002) maintain that electricity futures do not behave in the same way, because of electricity's non-storable character.

Further, Bassembinder & Lemmon (2002) provide an alternative approach, by looking at the relationship between the future price and future spot price. This equilibrium approach expects the future price to comprise two factors: the expected risk premium, or forward premium and a forecast of the future spot price, which is based on market participants' expectations of price developments[11]. This means that under rational expectations and risk neutral market actors the forward price will be equal to the spot price and would only deviate from it in case of unexpected shocks. Bassembinder & Lemmon (2002) tested this model and found that, under low expected volatility or low expected demand, the forward power price is a downward biased predictor of the future spot price

[10] Volatility is typically defined as the standard deviation of returns
[11] See also Bausch & Schwenker (2009)

and similarly, under high expected volatility or high expected demand, future prices exceed expected spot prices because of positive skewness in the spot power price distribution; therefore confirming the presence of a premium in future prices.

Redl (2011) analysed the European electricity forward market using data from the EEX and the NordPool. In line with economic theory on an equilibrium relationship, he found a relationship between year-ahead baseload electricity prices and year-ahead generation costs, which may be viewed as approximations of future electricity prices. He also established that the current spot price has an important impact on forward prices and states that this might indicate a behavioural pricing component in forward prices.

The European Commission stated in a communication paper from 2007 that forward prices are influenced by forward fuel prices, cost of new generation capacity or capacity retirement, water reservoir levels, weather trends, interconnector capacities, CO_2 prices and economic growth. Asymmetries in forward prices reflect the different expectations regarding spot prices in their own markets. (European Commission, 2007)

3.4. Energy and carbon price interactions

The interaction of energy and carbon prices is rather complex. On the one hand, energy prices impact the demand for emission allowances through the production process. On the other hand, the price of emission allowances also directly affects the demand for energy as it increases the price of the marginal energy production. However, the latter effect depends on the emission intensity of the energy mix. Part 2.2 showed that in a cap and trade system, firms will compare their marginal abatement costs with the price of emission allowances to make their production and emission decisions.

In the electricity market, part 3.3 showed that the equilibrium price is determined by the marginal cost of the power plant, which has to be brought into operation to satisfy total demand. However, by putting a price on carbon emission, another cost factor has been added to the production process of each power plant and therefore affects the equilibrium electricity price. Depending on the carbon intensity of the power plant, the carbon costs will have a different impact on the marginal production costs, which could induce changes in the merit order. Figure 7 shows how emission affects the marginal production costs of the different power plants and therefore the equilibrium price in a typical electricity supply and demand framework. The marginal production costs are given by the ratio of fuel costs (FC; such as coal, gas, oil, etc.) and the plant's efficiency (η): $MC = \frac{FC}{\eta}$. However, when introducing the cost of carbon emission, the marginal cost also includes the emission factor of the input factor: $MC = \frac{FC}{\eta} + \frac{EF}{\eta} \times EC$, where EF is the emission factor and EC is the emission cost (equal to the price of an emission allowance in the EU ETS). (Delarue & D'haeseleer, 2007)

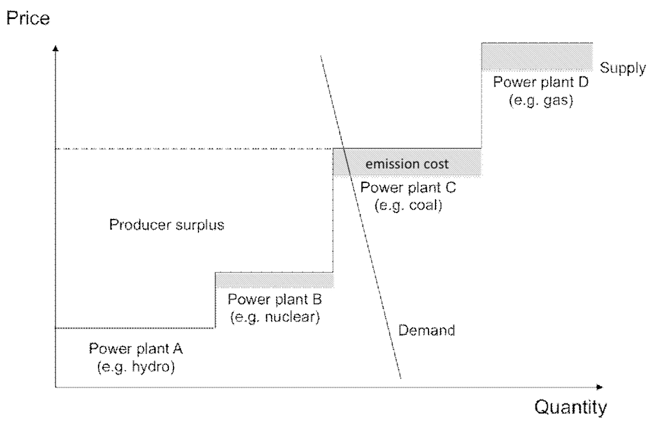


Figure 7: Electricity supply and demand with emission costs

A switch from one power plant to another solely induced by a change in the price of emission certificates occurs, for example if two plants have similar marginal production costs but one has a more important emission per unit of electricity produced and will therefore be more affected by a change in the emission allowance price. It is therefore interesting to compare different generation mixes and their emission sensitivity. For example, coal-fired power plants have low marginal production costs compared with natural gas-fired power plants but in the latter, lower emission levels occur in the producing activity. Therefore, if the price for emission is high enough, it becomes cheaper to produce using natural gas compared to coal. The emission cost for which the two technologies have equal marginal costs is called the "switching point". (Chevallier, 2012)

The switching point, for example between coal and gas, is given by the following relation: $EC = \frac{\eta_{coal} \times FC_{gas} - \eta_{gas} \times FC_{coal}}{\eta_{gas} \times EF_{coal} - \eta_{coal} \times EF_{gas}}$. In this example, if emission costs are lower than the switching point, coal production is cheaper than gas, and when the emission costs are above the switching point, natural gas production would be more profitable.

For electricity power producers it is very interesting to look at two indicators: the dark spread and spark spread. The dark spread denotes the profit of a coal-powered plant from selling a unit of electricity, including the purchase of the fuel necessary for the production of this unit. The spark spread represents the equivalent of the dark spread for a natural gas-powered plant. However, these two indicators have to be adjusted by the emission price when there is a market for allowances, such as the EU ETS. These are given by the clean dark spread and clean spark spread. The clean dark spread (in Euro/MWh) is the difference between the peak electricity price (p_{pelec}) and the price of coal (p_{coal}) used to generate electricity, which is corrected for the energy output of the coal plant and the CO_2 costs. It is given by the following relation: $clean\ dark\ spread = p_{pelec} - (p_{coal} \times \frac{1}{\rho_{coal}} + p_t \times EF_{coal})$, where ρ_{coal} is the thermal efficiency of a typical coal-fired power plant (around 30% according to Reuters) and EF_{coal} is the emission factor of a typical coal-fired power plant (around $0.95tCO_2/MWh$ according to Reuters). Similarly, the clean spark spread (in Euro/MWh) is given by the relation: $clean\ spark\ spread = p_{pelec} - (p_{natgas} \times \frac{1}{\rho_{natgas}} + p_t \times EF_{natgas})$, where ρ_{natgas} is the thermal efficiency of a typical natural gas-fired power plant (around 49% according to Reuters) and EF_{natgas} is the emission factor of a typical natural gas-fired power plant(around $0.41tCO_2/MWh$ according to Reuters). (Chevallier, 2012)

The switch price is the threshold above which an electricity producer will choose to switch from coal to natural gas production, inversely for below the switch price. The switching price is given by the following relation: $switching\ price = \frac{cost_{natgas}/MWh - cost_{coal}/MWh}{tCO_{2_{coal}}/MWh - tCO_{2_{natgas}}/MWh}$, where $cost_{natgas}$ is the cost of producing a MWh of electricity based on net CO_2 emissions of natural gas (in Euro/MWh), $cost_{coal}$ is the cost of producing a MWh of electricity based on net CO_2 emission of coal (in Euro/MWh), $tCO_{2_{coal}}/MWh$ is the emission factor (in tCO_2/MWh) of a typical coal-fired power plant and $tCO_{2_{natgas}}/MWh$ is the emission factor (in tCO_2/MWh) of a typical natural gas fired power plant. (Chevallier, 2012)

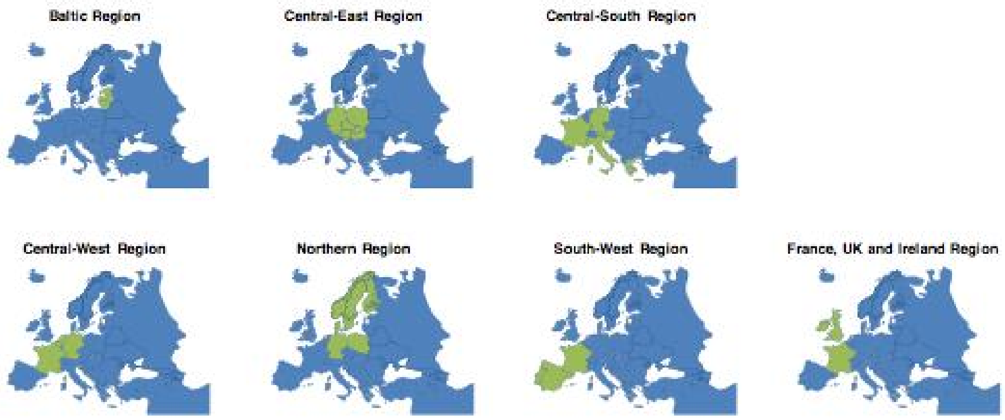
3.5. Market structure

The objective of a fully integrated market as explained above, has yet to be reached. Therefore, at the 11th Florence Forum meeting in 2004, it was decided to hold seven electricity "mini-fora" that would cover the problems and develop solutions in specific geographic areas. Those fora took place between November 2004 and February 2005[12].

In 2006, the European Commission decided that, in order to achieve a Single European electricity market, it would be necessary to take an intermediary step: the formation and development of Regional Energy Markets. The electricity market was separated in seven regional initiatives (see Figure 8): the Baltic, Central-East, Central-South, Central-West; Northern, South-West and France-UK-Ireland regions. In those smaller areas, the Commission hoped to have a more important impact through a bottom-up approach (CEER, 2010).

The seven regions depicted above are not necessarily distinct from each other. Five countries (Austria, France, Germany, Poland and Slovenia) are present in more than one region and France and Germany even in four different ones. Each region has a large operational independence and defines its priority issues and internal working arrangement under the structure proposed by the European Regulators' Group for Energy and Gas (ERGEG). (European Commission, 2010)

There are still several regional electricity markets in Europe as the interconnector capacity between those regions is insufficient for an entirely uniform market. The bottlenecks in transmission are likely to remain, as their removal would be too costly. This separation results in regionally distinct heterogeneous electricity prices. The ENTSO-E (2012) identified over 100 possible bottlenecks in Europe for the next decade. Nevertheless, recent research shows an increasing correlation between European day-ahead power prices: Ecorys (Rademaekers, Slingenberg, & Morsy, 2008) published an analysis of the European wholesale energy markets. It found an increase in traded volumes, market participants and price correlation between the exchanges in the period from 2002-2007. It also found that liquidity and price correlations increased as a result of higher physical connection capacities and market coupling initiatives. ESMT Competition Analysis (Nitsche, Ockenfels, Röller, & Wiethaus, 2010) stated that power price correlations between Germany and its neighbouring countries increased in the period from 2004 to 2009.



Source: ERGEG

Figure 8: The seven Regions of the Electricity Regional Initiative

[12] The achievements of these fora were analysed in a discussion paper by the ERGEG, „Global Assessment of the Results of the 1st Series of Mini Fora on Congestion Management and Potential Impacts on the Draft Guidelines: Working Paper Approved 02-03-2005"

3.5.1. European market

The European Union had an electricity consumption of 2856 TWh in 2008, increasing by 30% between 1990 and 2008 (see Figure 9). In 2008, the highest share in demand comes from Germany with 526 TWh, France with 433 TWh and the UK with 342 TWh. The Nordic region only accounted for 356 TWh in the same time period. In the end of 2008, the start of a strong recession decreased the industries' electricity consumption and so, growth rates in 2009 were negative. (Ruska & Similä, 2011)

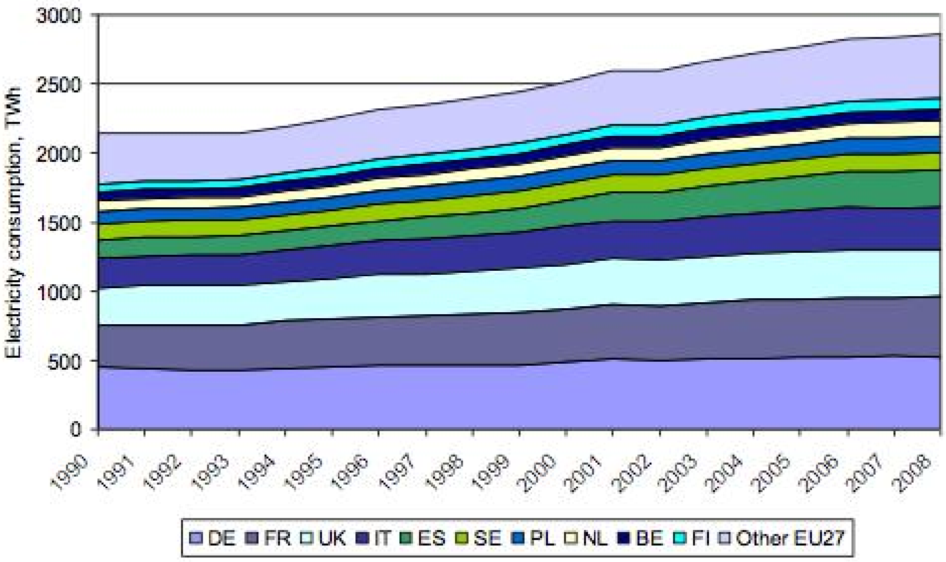


Figure 9: The EU final electricity consumption development between 1990 and 2008 (Source: Eurostat)

The annual ENTSO E report in 2012 indicated that annual consumption in ENTSO E[13] was on the decrease compared to 2010 levels, resulting in an overall consumption of 3336 TWh. This decrease is mainly due to important opposite developments in different countries. The Nordic and Baltic countries, as well as the UK, France, Switzerland, Austria, Slovakia and Slovenia increased their consumption, while all other decreased theirs. Compared to 2010, Norway was the only country that increased by more than 5%, while the highest decreases came from Macedonia (-5,4%), Luxembourg (-5,4%), and Cyprus (-6,3%).

The consumption mix of electricity use per sector in Europe is depicted in Figure 10. In 2008, the largest sector was the Industrial sector with around 40% of total consumption, followed by the residential and commercial sector with 29% and 26% respectively. The latter is also the fastest growing sector with a cumulative growth of 35.6% over the past 10 years. (IEA, 2011)

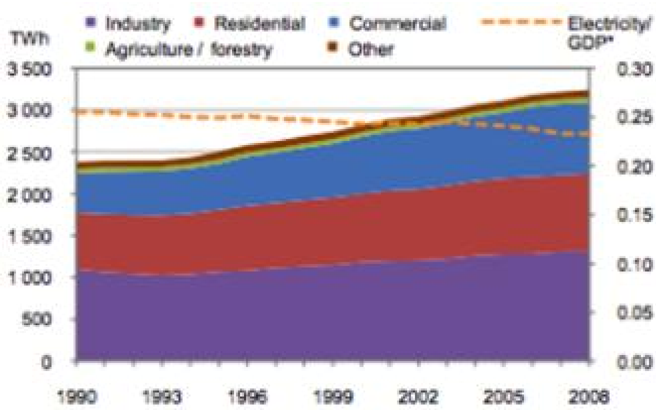


Figure 10: Electricity use per sector and per unit of GDP, Source: IEA (2010)

The energy generation rate is almost equivalent to the consumption rate in the ENTSO-E system. The main reason is the comparably limited trade opportunities with partners outside of the ENTSO-E system such as Russia, Ukraine or Turkey in comparison with the ones inside the system. (ENTSO-E, 2013)

Energy generation in 2012 amounts to 3383 TWh. The main contributors to power

[13] Emmission Network of Transmission System Operators for Electricity

generation were Germany with 17,5% and France with 16%. Great Britain (9,1%), Italy (8,5%) and Spain (8,5%) were also above the 5% contribution mark and except for Sweden (4,8%), Norway (4,4%) and Poland (4,4%), all others contributed less than 3% to the energy generation.

The trend over the past few years shows that energy generation is switching towards renewable energy sources and away from fossil fuel generation, non-renewable hydro and nuclear generation. Fossil fuel generation decreased from 1653 TWh in 2010 to 1561 TWh in 2012, while renewable energy sources generation increased from 700 TWh to 887 TWh in the same time period. The energy mix for 2011 and 2012 can be seen in Figure 11. In 2012, the main contribution in energy generation comes from fossil fuels (46,1%), followed by an almost equal share in nuclear (25,5%) and renewable energy sources (26,2%). For the first time, the latter reached over a quarter of total generation. (ENTSO-E, 2013)[14]

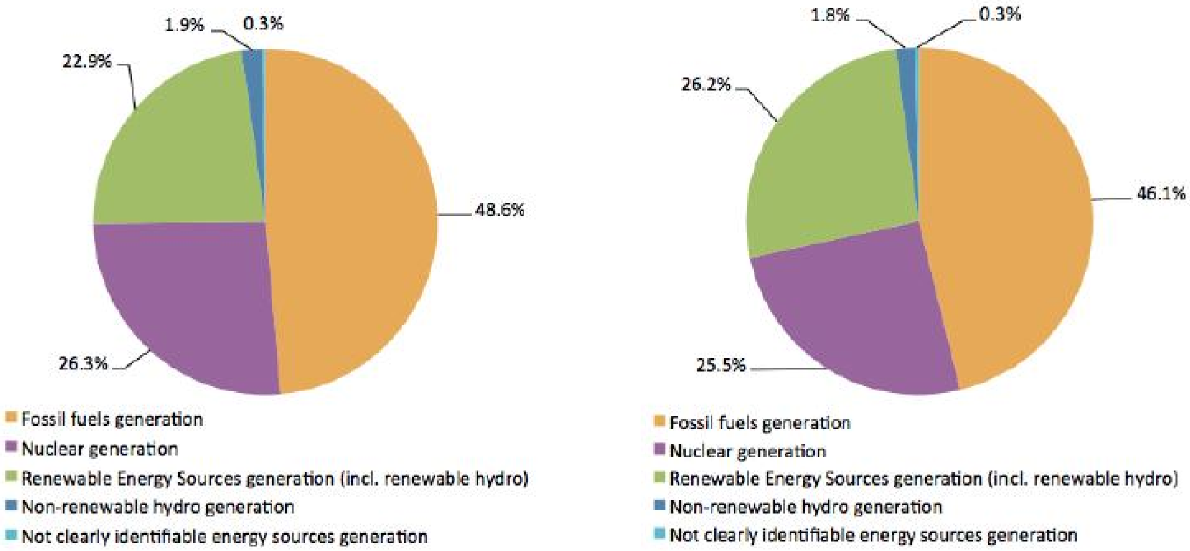


Figure 11: Generation mix in 2011 and 2012 (from left to right)

3.5.2. Market overview: selected countries

This section provides a comprehensive analysis of four relevant electricity sectors, which will also be used in the subsequent parts for the empirical analysis. Two countries and two regions will be presented: Germany, France, the Nord Pool Area (Sweden, Norway, Finland and Denmark) and the United Kingdom.

3.5.2.1. NordPool Region

NordPool ASA was the first cross border power exchange in the world. It was created in 1996 by Norway and Sweden and later joined by Finland (1997), Denmark West (1999) and Denmark East (2000). In 2002, NordPool separated itself from its physical spot operation that would become NordPool Spot AS that is owned equally by NordPool SAS and the national transmission companies of the member countries. In 2008, Nasdaq OMX acquired NordPool Clearing and NordPool Consulting[15]. National balancing markets are put into place by the TSO's of the member countries: Svenska Kraftnät (Sweden), Statnett SF (Norway), Fingrid (Finland), Ener-

[14] A more detailed analysis of the European energy sector may be found in the ENTSO-E reports (i.e. ENTSO-E, 2013)
[15] In the following, the term NordPool will refer to Nasdaq OMX, as well as Nord Pool Spot.

ginet (Denmark). (European Commission, 2012; IPA, 2006)

The main actors in the electricity market can trade via bilateral contracts or through the NordPool. The latter offers different market services through several channels: the spot market for physical contracts (Elspot), the financial derivatives market and clearing services for OTC and bilateral market contracts. The system price that results from Elspot is the same in Norway, Sweden, Finland and Denmark. It is the reference price for the derivatives market. The system price does not account for physical capacity limits in the transmission grid. Clearly, the system does have limits and therefore congestions appear during some periods. Those bottlenecks are managed by subdividing the market into different price areas in which the system price acts as reference. Elspot closes 36 hours prior to delivery. Hence, Elbas, the intraday market in the Nordic region functions as a balancing market to the Elspot market. It is open 24 hours a day and allows trades up to an hour before delivery. (NordPool Spot, 2014)

The generation mix in the NordPool area consists of the joined generation of its member countries. With around 10% of total generation, Denmark supplies electricity mainly by use of fossil fuels and wind. Finland represents 20% of total generation and uses hydro (20%) and other renewables (15%), nuclear (30%) and fossil fuels (35%). Norway almost only uses hydro power for the generation of 35% of the areas electricity. And the biggest contributor (40%) is Sweden who mainly uses hydro and nuclear power for generation. In total, around half of overall generation is produced using hydropower. Nuclear power is still an important part (20%) of total generation, as well as fossil fuels (around 15%, which is largely coal based). Wind and other renewables account for only a marginal amount of total generation.

In 2013, 370 market participants were active n the Nordpool exchange. During this year, 349 TWh[16] were traded on the physical market and 887TWh on the financial market.[17]

3.5.2.2. *Germany*

In 1998, the German electricity market became fully competitive after the Energiewirtschaftsgesetz (EnWG) passed. It organises the grid operation and access. The European Energy Exchange (EEX) covers the spot, futures markets and clears OTC deals. The balancing group concept is very important in the German electricity market. The physical system users are obligatorily assigned to a balancing group. The balancing group is responsible to match production and generation by using its own generation or by buying electricity from other areas. Net exchanges from trading between balancing groups are reported to the TSO’s. The four TSO’s, Tennet, Amprion, 50Hertz and TransnetBW divide the control of the German market between them. (IPA, 2006)

The EEX is the result of the merger between the Leipzig Power Exchange and the European Power Exchange. 80 participants from Germany and a total of 248 participants from 25 different countries are trading on the EEX. The EEX offers a broad range of products from spot and derivatives for electricity to emission allowances from the EU Emission Trading Scheme. The derivatives market includes futures and option contracts based on the Physical Electricity Index (Phelix). The prices resulting from the exchange are considered as benchmark for OTC trading. (European Commission, 2012)

In 2010, Germany’s energy mix consisted mainly of fossil fuels, where crude oil and petrol products made

[16] These figures include the Baltic Exchange, as the two markets integrated as of June 2013
[17] Data from NordPool Spot and Nasdaq OMX Commodities

out around 34%. Solid fuels consist equally of lignite and hard coal and together they make out 23% of the energy mix. Wind was the main supplier in renewable energy generation and the total share of renewable energy was 11% in 2010. After the Fukushima incidents of 2011, Germany decided to shut down 8 nuclear power plants in 2011 that accounted for 8300 MW. The building of renewable power plants in the north, leading to a planned share in renewable energy production of 35% for 2020, increases the bottleneck between the North and the South. (European Commission, 2012)

Four private companies, E.ON, RWE, EnBW and Vattenfall are the main players in the electricity market (around 80% of market share in 2010). The spot market EPEX traded 238 TWh in 2011 (47% of Germany's power consumption) with an average price of 51 €/MWh (+10% compared to 2010). In comparison with the neighbouring countries, the German price level is moderately competitive due to good weather conditions for renewable energy production.

3.5.2.3. France

France implemented the ITO model for unbundling the electricity market. The TSO regulating the French system is the Réseau de Transport d'Electricité (RTE), owned by Electricité de France (EDF). EDF, a DSO in the French electricity market accounts for 95% of total distribution. The French electricity market is one of the most concentrated in the EU and is largely dominated by EDF[18], which accounts for 91% of the total installed capacity. The three biggest generators together even account for 99% of the total installed capacity. (IPA, 2006)

In 2001, the energy exchange Powernext was established, where trading takes place under the responsibility of the RTE and guaranteed by Clearnet. Powernext is responsible for spot and future trading. In 2008, Powernext's day-ahead and intraday activities were incorporated into the EPEX Spot SE and in 2009, the French Power Futures market (Powernext Futures) was transferred to the EEX Power Derivatives GmbH. Nevertheless, 84% of trading takes place on the OTC market. France is highly interconnected with their neighbours through successful market integration with Belgium, the Netherlands[19], Luxembourg and Germany. In 2011, the average energy price was 48,9€/MWh. (European Commission, 2012)

France's energy mix mostly comes from the nuclear sector, accounting for 41% of total inland consumption in 2010. With 31%, oil is the second biggest contributor and gas (16%) comes third. In generation, nuclear energy also makes up the biggest share with 76% and renewable energy is second (15%). (European Commission, 2012)

3.5.2.4. United Kingdom

The UK electricity market is fully open and the supply competition counts seven well-established suppliers. In Great Britain[20], the transmission network is owned by three companies, National Grid in England and Wales, Scottish Power and Scottish Hydro-Electric in Scotland, that are all operating under one TSO. In Northern Ireland, Northern Ireland Electricity (NIE) owns the electricity grid. The System Operator (SONI) calls off power based on a contractual least cost dispatch. (European Commission, 2012)

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[18] The only EDF competitors, GDF-Suez (5.5% of installed capacity) and E.On-France (3% of installed capacity), have a negligible share of the market.
[19] Trilateral Market Coupling in 2006
[20] England, Wales and Scotland

Three exchanges operate in the UK electricity market, namely APX UK, Nasdaq OMX N2EX[21] and Intercontinental Exchange (ICE). The volume traded on the APX day ahead market reached 2.5 TWh in 2011. The volume on the N2EX day ahead market reached 18.7 TWh in 2011. In total, 8.5% of trading took place on exchanges, with the biggest part being traded OTC. The average day-ahead price in the UK was 56.5/MWh in 2011. The price level is above the level of central European countries. (European Commission, 2012)

In 2010, UK energy mainly came from natural gas with 40% of total consumption. Renewables only held a share of 3%. Power generation came mostly from gas fired power plants and solid fuels that accounted for 46% and 28% respectively of the total 381TWh generated in 2010. Renewables represented 8% of generation. In generation, EDF Energy, E.ON and Drax, the three biggest utilities, accounted for 44% of the total, implying a moderate level of market concentration.

3.6. Hypothesis

The first part of this paper gave a brief overview of the environmental and historical process, which led to the implementation of the EU ETS. , the mechanisms of a cap and trade system and more specifically its implementation in the EU ETS, as well as the price behaviour of EUAs were introduced. Finally, the economic theory behind the occurrence of windfall profits due to a cost pass-through despite free allocation is explained. The most important points, which have to be taken from this part are: The introduction of emission allowances put a price on carbon emission, which will be reflected in the price of products, that are emitting the pollutant. This cost pass-through might yield windfall profits under free allocation of allowances.

The second part outlined the basic structure and properties of the electricity market by describing fairly the new liberalised electricity market: the market delimitations in Europe, the generation and consumption mix, as well as the market organisation and the pricing mechanisms and price behaviour. The most significant points in this part are: The liberalised electricity market has a very unique pricing behaviour, resulting from its properties (e.g. non-storability) and the very inelastic short run demand. The electricity market is getting more and more integrated, which makes prices converge across countries. The power plant used at the margin is highly important for the price of electricity. Which plant operates at the margin is influenced amongst others by the price for emission certificates (e.g. fuel switching). Therefore, electricity prices are expected to be affected by the generation mix, especially the price of the marginal power plants and the emission allowance price. Moreover, the differences between the countries are likely to be less pronounced, the more integrated their markets are. For example, France’s and Germany’s pass-through levels are likely to be more alike becaouse of the high level of interconnectedness between these two countries. Contrarily, the UK’s and NordPool’s pass-through levels are expected to be more independent from the other regions.

All in all, the expected cost pass-through effect results from power plants’ adjustment of marginal generation costs for the permit price. How the pass-through is measured in the electricity prices depends on the emission intensity and efficiency of the plant used at the margin. The more emission intense it is, the higher the need to buy emission allowances to cover the production. Similarly, if the plant has a low efficiency, it will need to consume more raw material (i.e. burn more coal) to produce a MWh of electricity and therefore have a higher de-

[21] The N2EX was launched in January 2010

mand for emission allowances to cover production. However, it is difficult to assess what is considered a full pass through of the allowance price, since there is very limited information on the marginal plant. This means that even if there is evidence that electricity prices are influenced by emission prices, the coefficient might be difficult to interpret. However, the pass-through is considered to be full (100%) if the entire costs a plant had to face for their emission have been added to their marginal price. For example, a plant A that produced 1.2 MWh by burning one ton of coal (efficiency of 0.3 and heat content[22], ζ, of around $7\text{MWh}/t_{coal}$[23]) for which they paid 100€/t and had an emission factor of $1t_{CO2}/t_{coal}$ would have had to buy two emission allowances for 5€/allowance. Assuming that all other costs (i.e. labour) are negligible, the marginal electricity price expected for a full pass-through would be $p_{electricity} = MC_A = \frac{p_{coal}+EF_{coal}\times p_{EUA}}{\eta_A \times \zeta_{coal}} = 50€/MWh$ from which approximately $\frac{EF_{coal}\times p_{EUA}}{p_{coal}+EF_{coal}\times p_{EUA}} \approx 4.76\%$ come from emission allowances.

Finally, the following hypothesis can be formulated: There is a cost pass-through of emission allowances into electricity prices even with free allocation of allowances. The level of pass-through differs according to the generation energy mix of the country or region, where the marginal power plant is especially important. Depending on the generation mix and marginal generator, the impact of emission allowances price changes might vary. The integration of electricity markets results in more similar price levels, making the generation mix of the individual countries somewhat less important. Therefore the more the markets are integrated, the closer the expected pass-through levels should be.

4. Empirical Analysis

4.1. Literature review

Before starting the empirical analysis, this paper provides an overview of the literature on the dynamics between emission allowance and electricity prices. Each of the papers presented will shed light on some of the aspects of these interactions. Sijm et al. (2006) were one of the first papers to empirically analyse the pass-through of emission allowances into electricity prices. The paper of Prete and Norman (2013) extends the work of Zachmann & von Hirschhausen (2009) on an asymmetric cost pass-through of emission allowances on electricity prices. Fezzi & Bunn's (2009) paper is the most similar to this paper, as it analyses the interactions between electricity, gas and carbon prices by means of a VECM in the pilot phase of EU ETS. Finally, Aatola et al. (2013) research the impact of emission allowances on the integration process of the European electricity market.

Sijm et al. (2006) published a paper in 2006, which analyses the cost pass-through of EUA certificates into power prices and the profits from EUAs, which are made by power stations. First, they state that the expected theoretical pass-through rate is 100% even when EUAs are allocated for free, as there is an implicit price on EUAs in the form of opportunity costs. This rate might deviate from a full pass-through as a result of several factors. Sijm et al. (2006) expect that these incomplete rates come from differences between the work-on and add-on rate. These refer to the price increase resulting from CO_2 on electricity or input fuels respectively. They

[22] The heat content refers the theoretical amount of energy produced by the raw material at full efficiency
[23] ARA coal, which is traded on the EEX has a calorific value of 6000kcal/kg, which equals 6.9733MWh/t

use two distinct data series for their analysis. First, using daily year-ahead forward electricity contracts from Germany and the Netherlands, as well as daily forward contracts for emission allowances, coal and gas for the period January–December 2005 and another focussing on the spot market, including hourly spot electricity prices for the period from January 2005–March 2006 and hourly spot electricity prices in 2004. Sijm et al. (2006) estimate an OLS model of the form $P_t = \alpha + \beta_1 CO2_t^{c,g} + \beta_2 F_t^{c,g} + \varepsilon_t$ on the one-year forward data and apply a "bootstrapping" method to measure the accuracy of their estimations. , they compare the hourly spot electricity prices between 2004 and 2005 in Germany by regressing their difference on the difference in the coal price and the cost of an emission allowance. Sijm et al. (2006) use the static COMPETES (Comprehensive Market Power in Electricity Transmission and Energy Simulator) model for several countries (Belgium, France, the Netherlands, the United Kingdom and Germany) to model estimates of CO_2 cost pass-through and compare these results to the Integrated Planning Model, a power sector model for the EU developed by ICF Consulting. They attempt to model the profits made through free allocation of emission allowances through the COMPETES model and explain three different approaches to estimate windfall profits in the power sector. Their analysis found that there is presence of pass-through of the opportunity costs of emission allowances to electricity prices under free allocation but it might be imperfect, as under certain conditions the work-on and add-on rates might not be equal. Their estimates and models show "cost pass-through rates between 60 and 100% for wholesale power markets in Germany and the Netherlands" (Sijm, Neuhoff, & Chen, 2006, S. 67) and that electricity prices rise by between 3 and 18€/MWh for a EUA price of 20€/t_{CO_2}. This rather large price range can be explained by the uneven impact of the EUA price, which varies strongly with the carbon intensity of the marginal power plant. Furthermore, they estimate windfall profits at 300-600 million €/year in the Netherlands with a EUA price of 20€/t_{CO_2}.

Prete and Norman (2013) studied a possible asymmetric cost pass-through of emission allowances into electricity future prices in their 2012 paper. Zachmann and von Hirschhausen (2009) have performed a similar study for the German electricity sector in Phase I, where they have found evidence of an asymmetric cost pass-through. Here, Prete and Norman hope to find evidence of this asymmetry in a now more mature market. For their analysis, they use daily future prices for all price series, respectively, EUA prices from the European Climate Exchange, electricity baseload contracts from the European Energy Exchange (Germany and France), the APX-Endex Exchange (Belgium and the Netherlands) and natural gas, as well as coal future prices from the EEX. They also include the VDAX-NEW Index, the Puchasing Managers' Index for the manufacturing and the service sector. They proceed by modelling the electricity price for each country by regressing it on the prices of EUA, coal, gas and the VDAX and including a dummy variable that is dependant on the level of the Purchasing Managers' Indices to account for negative economic expectations. They then estimate an error correction model in which they allow for asymmetric cost pass-through in EUA, coal and gas prices by defining two separate variables for upward and downward changes for each of the three factors. They can check for asymmetric cost pass-through by comparing the adjustment process in the cases of upward and downward changes from CO_2 prices into power prices (in this case upward changes would be reflected quicker and fuller in power prices than downward changes). They find that overall there is no evidence of a positive asymmetric cost pass-through, as they find conflicting results in 3 out of 8 comparisons. They therefore reject their hypothesis of an asymmetric short-term cost pass-through at all conventional significance levels.

Fezzi and Bunn (2009) analysed the interactions of UK electricity, gas and carbon through a structural cointegrated vector error-correction model. To this mean, they use day-ahead prices from the UK Power Exchange, gas prices from the National Balancing Point and daily European carbon allowance prices from Platts. The sample analysed in this study contains data from weekdays between April 1, 2005 and June 30, 2006. Fezzi and Bunn (2009) determine the following vector of endogenous variables: $y_t' = \left[p_{electricity,t}, p_{gas,t}, p_{carbon.t}\right]$ and exogenous variables: $z_t' = \left[t_{hot,t}, t_{cold,t}\right]$. Additionally, they add a set of dummy variables (d_t) to account for price movements from new information and seasonality effects in the series. Their reduced-form VECM is written as follows: $\Delta y_t = \omega \Delta z_t + \alpha\beta' y_{t-1} + \Gamma_1 \Delta x_{t-1} + \cdots + \Gamma_{k-1}\Delta x_{t-k+1} + Cd_t + u_t$, where $x_t' = [y_t', z_t']$. They then run the Johansen trace test on their model, which indicates one cointegration vector. Their findings indicate that the gas price influences the carbon price quickly, while the pass-through of carbon prices into the electricity prices takes several days. In the long run, they found that an increase of 1% in the carbon price increases the electricity price by 0.32%.

Aatola et al. (2013) studied the impact of carbon price on the integration of the European electricity market. Their hypothesis is that the price of carbon has a positive, uneven impact on electricity depending on the marginal production plant. They use daily baseload electricity forwards for the period between February 2003 and August 2011 for Germany, Spain, France, Netherlands, NordPool and the United Kingdom, as well as daily EUA forwards. Then, they proceed to split their observations in three distinct periods: 2003-2005, 2005-2008 and 2008-2011 reflecting the three phases of the EU ETS scheme. Aatola et al. initially perform pairwise Granger causality tests for each sub period. These indicate strong signs of integrating markets as the number of bidirectional and stable cointegration relationships between prices during the sub-periods increase. This indicates that "markets become more interdependent over time" (Aatola et al., p.1243). They then define a vector autoregressive model which is presented as an error correction model on which they run the Johansen trace and eigenvalue test. In the first period, they dropped EUA prices from the test, as they were not yet available. For the next two phases, they tested the level of integration with and without EUA prices and compare the level of market integration of electricity prices. The test for the period 2003-2005 shows one cointegrating vector. They found two cointegration relations in the second period from 2005-2008 whether EUA prices were included or not. But when including them into the analysis the coefficients increased substantially, which indicates a higher convergence level in this case. For the last period of study Aatola et al. (2013) find three cointegration relations without including EUA prices and four when including them, which again reveals a stronger integration level. Aatola et al. (2013) then proceed to look at the impact of EUA price shocks by writing the VAR model in its moving average form, which confirms their expectations of a positive but uneven impact of EUA prices on the different regional electricity prices. Finally, the variance decomposition of the cointegrated VAR model shows that the German electricity price is exogenous and as such is a price driver for the European electricity price. They find that the integration level of electricity prices has increased over the period of study and can confirm their theory of a positive and uneven impact on the integration of prices.

4.2. Model & Methodology

4.2.1. Model

In this paper, the cost pass-through will be measured by modelling the electricity price on the basis of fundamental influence factors: the input fuels and emission allowances, as well as atmospheric temperature, the interest rate and a broad stock index, which allow for exogenous influence. Using input fuel prices has the advantage that the underlying goods are storable and therefore easier to estimate using the theory of storage (see part 3.3.2). The most commonly used marginal power plants are either coal- or gas-based. Their price levels are therefore highly important for the electricity price formation process (Prete & Norman, 2013; Aatola, Ollikainen, & Toppinen, 2013; Peljo, 2013). Atmospheric temperature is included as a proxy for electricity and input fuel demand and the interest rate is included as a proxy for capital cost. Monthly dummies will not be included, as seasonal effects are assumed to be introduced by including temperature as an exogenous variable. The Stock Index will be included as a proxy for expected future economic activity. Broad-based stock market indices are excellent indicators for expectations on future economic activity (Keppler & Mansanet-Bataller, 2010).

The following model will be analysed in the following:

$$Electricity = f(EUA, Coal, NaturalGas, StockIndex, InterestRate, Temperature)$$

Two models are estimated based on cointegration analysis (see below) and allow the reader to get an insight into the short- and long-run dynamics between the variables.

Initially, the long-run equilibrium will be estimated using two approaches: First, this paper assumes exogeneity between the variables. A standard OLS estimation of the relationships between the variables will be estimated to get the long-run estimates according to the Engle-Granger Two Step procedure (see below). The results from this first analysis allow the reader to get a first glimpse at the relationship between these variables.

However, as explained in the previous sections, there are significant interactions between electricity, the input fuels, coal and natural gas, and emission allowances (cf. parts 2.4.2, 3.3 and 3.4), which indicate that the results gotten through this first approach might be biased, as the method used does not accurately represent these interdependencies.

Therefore, in a second part, the long-run equilibrium will be estimated using the approach provided by Johansen, which allows several variables to be estimated simultaneously.

Finally, estimating a vector error correction model will allow the analysis of the short-run dynamics between the variables.

4.2.2. Cointegration

In time series analysis, regressing non-stationary series using standard regression models (such as OLS models) often results in spurious regressions, as was initially pointed out by Granger & Newbold (1974). Non-stationary time series, by definition, are such that they violate the stationarity requirements, which are a constant mean and variance over time. Spurious results occur when results appear to be significant with a high R^2 even though the variables are independent. Cointegration is a common method used to produce stationary time-series. The cointegration equilibrium differs from the traditional economic equilibrium, as the cointegrated variables are generally unstable in their levels, but fluctuate around common stochastic trends, meaning that if two variables are apart, the likelihood that they will move back towards each other is greater than that they move away from each other.

When series are non-stationary caused solely by unit-roots (i.e. integrated of order one, I(1)), the variables are called integrated. They can be brought back to stationarity by taking their first difference $x_t - x_{t-1} = \Delta x_t$. This can also be generalised to higher order stationary time series, which have to be differenced "n" times to obtain stationarity. (Box & Jenkins, 1970) However, when the variables are cointegrated, those regressions are misspecified.

Engle & Granger (1987) give a general definition of cointegration as follows: "The components of the vector x_t are said to be co-integrated of order d, b, denoted $x_t \sim CI(d, b)$, if (i) all components of x_t are $I(d)$; (ii) there exists a vector $\propto (\neq 0)$ so that $z_t = \propto' x_t \sim I(d-b), b > 0$. The vector $\propto$ is called the co-integrating vector".

Cointegration analysis attempts to find linear combinations of variables, which remove unit roots as well. In the bivariate case, this means that for two I(1) processes y_t and x_t, cointegration is trying to find a unique β such that $y_t - \beta x_t$ is I(0). In the case that a cointegration vector exists, they determine I(0) relations, which hold between two individually non-stationary series. (Hendry & Juselius, 2001)

This concept is extendable to the multivariate case. Then, β and X are vectors $(\beta_1, \dots, \beta_n)$ and $(x_{1t}, \dots, x_{nt})'$ and the variables $x_{1t}, \dots, x_{nt}$ are cointegrated if each of the $x_{1t}, \dots, x_{nt}$ are non-stationary and βX is stationary. Here, β is the cointegrating vector. (Fabozzi, Focardi, & Arshanapalli, 2014)

When including more than two variables, it is possible to find several cointegrating relations. For n variables in the model, it is possible to find up to n–1, but not more cointegration relations or linearly independent cointegrating vectors. The cointegration relation in this case is derived from a vector autoregressive (VAR) model in the form $Y_t = \delta + \sum_{i=1}^{k} \theta_i Y_{t-i} + \varepsilon_t$, which may be seen as a more general version of the univariate case. (Verbeek, 2000)

4.2.3. Engle Granger Two Step

Engle and Granger have developed a procedure that allows testing for a single cointegrating relation, better known as the Engle-Granger Two-Step procedure. The main idea is to run a regression depending on the expected cointegrated relation using standard OLS estimators and then testing the residual for a unit-root (Step 1). This demands doing an Augmented Dickey Fuller (ADF) test on the OLS residuals using a specific set of critical values tabulated by Engle & Granger (1987). This is necessary since the test is estimated on residuals of an estimated model and not on a dataset. Cointegration cannot be rejected if there is presence of a unit root. If cointegration can be rejected, the variables are stationary and the model can be specified using first differences, in which case there is no long-run relationship between the variables. If cointegration cannot be rejected, the error correction model can be estimated (Step 2) by using the cointegrating vector gotten from the ADF test:

$$\Delta y_t = \alpha_0 + \gamma_0 \Delta x_t + \delta(y_{t-1} - \beta x_{t-1}) + u_t$$

Inferences may be done on this model, since all variables in it are stationary. This was not possible in the first step, as the variables used were non-stationary.

When using the Engle-Granger approach, several shortcomings have to be pointed out. The model is, for example, restricted to one single cointegrating relation and depends on the variable defined as dependent. It works best over long time periods, rather than short time periods with high frequency; and usually this procedure would be used for the bivariate case, although it can be used for the multivariate case with adjusted critical values.

4.2.4. Vector Error Correction Models

The expression of "error correction" refers to the tendency of cointegrated variables to revert towards common stochastic trends. Error Correction models are used to give cointegrated variables an economic significance, as they can be represented in order to measure the short- and long-term dynamics in the relationship between the variables. Engle and Granger (1987) have shown that when two variables are cointegrated, then there exists an error correction representation of the variables. This may be done by including lags of the cointegration relation in a model. For example, the cointegration relation $z_t = y_t - \beta x_t$, the error correction model may be expressed as:

$$\Delta y_t = \alpha_0 + \gamma_0 \Delta x_t + \delta z_{t-1} + u_t \text{ , or}$$
$$\Delta y_t = \alpha_0 + \gamma_0 \Delta x_t + \delta (y_{t-1} - \beta x_{t-1}) + u_t$$

When the cointegrating vector β is known, it is sufficient to regress Δy_t on Δx_t and z_{t-1}, with $z_{t-1} = y_{t-1} - \beta x_{t-1})$. If the cointegrating vector is not known, then it must be estimated and it is necessary to replace z_{t-1} by $\hat{z}_{t-1} = y_{t-1} - \hat{\beta} x_{t-1}$. In this case, Engle and Granger (1987) have shown that we can still regress the model as before using standard OLS and get significant results. In this relation, all factors are stationary, since for I(1) processes, first differences are stationary and the cointegration vector is I(0), as seen above. Therefore the results are not spurious.

In this error correction model, $\delta z_{t-1} = \delta(y_{t-1} - \beta x_{t-1})$ is referred to as the error correction term, which induces changes in y_t towards the equilibrium. This allows describing how y_t and x_t behave in the short-run by looking at the error correction term δ with a long-run cointegration relationship. (Verbeek, 2000) Specifically, the error correction term indicates the adjustment speed of the model, as it indicates how much of the deviation from the equilibrium will be reduced in the following period. In the long-run relation it is β that defines the relationship. The model may be extended by including more lags of Δy_t or Δx_t, which does not change its functioning. Similarly, for a single cointegrating relation with more than two variables, it is possible to include more variables into the model by modifying the error correction term and add differences of all variables into the model.

For n variables in the model, it is possible to find up to n-1 cointegration relations. However, a standard OLS regression cannot identify more than one relationship. Therefore, it is necessary to estimate these relationships using a system approach. When including more than two variables, the error correction model is typically expressed as a vector error correction model (VECM), which, according to Brooks (2005, p.403) usually takes the form: $\Delta y_t = \Pi y_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + u_t$, where Γ is a coefficient matrix and Π is a matrix of the long-run coefficients. This model is based on the vector autoregressive (VAR) model, hence the name *vector* error correction model. When taking the VAR model from before ($Y_t = \delta + \sum_{i=1}^{k} \theta_i Y_{t-i} + \varepsilon_t$), the long-term coefficient equals $\Pi \equiv -\theta(1) = -(I_p - \sum_{i=1}^{k} \theta_i)$.

In this VECM it is then possible to identify the number of cointegration relations. Since Δy_t and u_t are stationary by assumption, Πy_{t-k} must be stationary as well. If the rank r of the matrix Π is 0<r<k, where k would

be full rank, then Πy_{t-k} are linear combinations which are stationary. Additionally, when the elements of y_t are I(1), then these linear combinations are cointegrating vectors. When Π has a reduced rank r, then there are r linearly independent combinations between the variables of y_t, which are stationary and thus r cointegrating relationships.

A proper representation of the model might require the inclusion of more terms in the equation. For example, it is possible to add deterministic terms, which might take the form of an intercept, a linear trend term or seasonal dummy variables. They can simply be added to the stochastic part, $y_t = \mu_t + x_t$, where μ_t refers to the deterministic term and x_t represents the stochastic process on which the VECM is represented. This would lead to the following VECM model: $\Delta y_t = \upsilon_0 + \upsilon_1 \mathrm{t} + \Pi y_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + u_t$. (Lütkepohl, 2007)

It is possible to introduce trends into the VECM. Since it models differences of the data, a constant implies a linear time trend in the levels of the data and a time trend would imply a quadratic time trend in levels.

Additionally, it is possible to rewrite the VECM as $\Delta y_t = \gamma\beta' y_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + u_t$, when the matrix Π has a reduced rank, since under these conditions, Π may be written as $\Pi = \gamma\beta'$, where γ is a kxr matrix and β is a rxk matrix, both with rank r. This model can be viewed as a generalisation of the bivariate model explained above. (Verbeek, 2000)

4.2.5. Johansen procedure

The Johansen test for cointegration is one of the most widely used tests used to define cointegration relations. The mathematics used in the Johansen approach is quite involved and beyond the scope of this paper, therefore only the main aspects will be outlined here.

The starting point of this test is the VECM, as specified above: $\Delta y_t = \Pi y_{t-k} + \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + u_t$. The Johansen test is sensible to the lag length used in the VECM, it is therefore optimally selected using either cross equation restrictions or information criteria. An example for the former would be a likelihood ratio test, which compares the restricted and unrestricted model. The latter approach allows selecting the lag length by comparing a decrease in the residual sum of squares (RSS) of each equation when adding more lags with an increase in the value of the penalty term. (Brooks, 2005)

The Johansen test focuses on the study of the Π matrix, which may be viewed as the long-run coefficient matrix. As seen above, since y_t is non-stationary, Π does not have full rank. Then, if the rank of Π is non-zero, in which case there would be no long-run equilibrium and no cointegration relation, it is possible to write $\Pi = \gamma\beta'$, where γ is a k x r matrix and β is a r x k matrix, both with rank r. There γ are the adjustment parameters and β are the cointegrating vectors.

The Johansen test uses a maximum likelihood approach which imposes the restriction $\Pi = \gamma\beta'$ on the VECM for a certain value r. The number of cointegrating relations between the variables is calculated by considering the rank of the matrix Π, which can be determined by observing the eigenvalues (λ_i) of Π by rearranging the eigenvalues in ascending order and observing how many are significantly different from zero. For example, when the rank of Π is zero, $\lambda_i \approx 0 \, \forall i$ and hence the variables y_t are not cointegrated. Under the Johansen procedure, there are two test statistics for cointegration: either the trace test (λ_{trace}) or the maximum eigenvalue test (λ_{max}). Both test the H_0 of a specific number of cointegrating relationships against the alternative of more relationships. They differentiate themselves, as the λ_{trace} tests the eigenvalues jointly to identify the presence of H_0: r cointegrating vectors against H_1: more than r cointegrating vectors; and λ_{max} tests each eigenvalue separately such that it tests the H_0: r cointegrating vectors against H_1: r+1 cointegrating vectors. As these tests have a non-normal distribution, Johansen and Juselius (1990) specify critical values for both statistics, which depends on the difference of r and the full rank, g, the number of non-stationary components and the presence of a constant. It is necessary to normalise the cointegrating vectors in β to obtain unique cointegrating relationships, since the parameters γ and β are not unique (different combinations of γ and β can produce the matrix $\Pi = \gamma\beta'$). (Brooks, 2005) When the number of cointegrating vectors has been determined, it is possible to get to cointegrating relation.

4.3. Data

4.3.1. Overview

The data used in the analysis in the subsequent parts to test for cost pass-through of emission allowances into electricity prices are weekly averages of daily futures of electricity prices, EUA prices and fuel prices (coal and gas), as well as a broad stock index, the countries interest rate and daily temperatures. The prices are taken from 2008-2012, which corresponds to the second period of the EU ETS.

The four analysed regions/countries are the United Kingdom, the NordPool region, Germany and France (see part 3.5.2 for a more detailed overview). For electricity prices, wholesale baseload year-ahead futures were used in each case. These are determined every day in the corresponding exchanges: the European Energy Exchange (EEX) for Germany and France, NASDAQ OMX[24] for the NordPool area, and the Intercontinental Exchange (ICE) for the United Kingdom. Prices are in €/MWh for the first three and in GBP/MWh for the latter. By using future prices, it is possible to reduce the variability of the variables, as these are not as strongly affected by today's demand factors (temperature, shortages, etc.). Moreover, futures are the most liquid commodities traded on the European carbon market (Aatola et al. (2010) in Prete & Norman (2013)). The year-ahead futures prices for EUAs are taken from the EEX, since it is one of the most liquid platforms for EUA trading. The fuel year-ahead-futures used in the analysis are the Amsterdam-Rotterdam-Antwerp (ARA) coal futures from the EEX, which is based on Argus/McCloskey's coal price index. Gas prices are taken from the National Balancing Point (NBP), the most liquid gas trading point in Europe. Prices are in USD/t and GBP-pence/therm[25] respectively.

The data, when not available in euros, were converted using the WM/Reuters closing spot rates as calculated by "The WM Company" based on data provided by Reuters at or around 16:00 in London, thus reflecting the middle of the 'global day' and the time of highest liquidity in the foreign exchange market.

After the conversion into euros, coal and gas prices were adjusted, so that they would be in euros per megawatt hour. For gas, the relation is straightforward as 1 Therm is equal to 2.93071×10^{-2} MWh per definition. For coal, the calorific value of 6'000'000 kcal/ton, which equals 6.9763 MWh/ton as defined in the contract specifications for ARA futures (EEX, 2014) is applied. Further, these values are adjusted for the approximated thermal efficiencies of the power plants: 0.49 for natural gas and 0.30 for coal.

The data was accessed through Thomson Reuters Datastream.

[24] Formerly known as NordPool
[25] 1 therm = 29.3071 KWh

Additionally, temperature data for each country was collected from the European Climate Assessment & Dataset[26]. The data used is a mean of sets of two to three daily mean temperatures from different geographic locations within each country/region.

Finally, all data is transformed into their natural logarithms to be able to get an economical interpretation as elasticities and to reduce the impact of extreme values.

4.3.2. Preliminary Analysis

Some basic descriptive statistics for our datasets can be found below.

	EUA	Germany	France	U.K	NordPool	Coal	Natural gas
Unit	€/t_{CO2}	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh	€/MWh
Observations	262	262	262	262	262	262	262
Maximum	28.29	87.80	91.22	177.76	66.75	63.07	87.42
Minimum	0.01	43.46	45.02	36.71	29.25	25.71	24.71
Mean	14.13	54.88	56.91	59.40	44.18	38.09	50.07
Std. Dev.	5.41	9.22	10.05	21.78	7.78	7.45	12.29
Skewness	0.48	1.66	1.94	2.25	0.82	0.84	0.60
Kurtosis	3.08	5.29	6.03	9.58	3.18	4.28	3.77
Jarque-Bera Test	10.266***	117.39***	264.33***	693.56***	29.83***	48.74***	22.10***

*** indicates significance at the 1% level

Figure 12 shows the year-ahead EUA futures prices for the period 2008-2012. Visually, three different periods can be made out. The first one going from the beginning of 2008 until the beginning of 2009 is marked by a rather volatile behaviour, as the price level first fell from around 23 to 20€, then climbed up again to reach about 28€ and then fell again to below 10€. The second period is somewhat calmer with fluctuations that remained

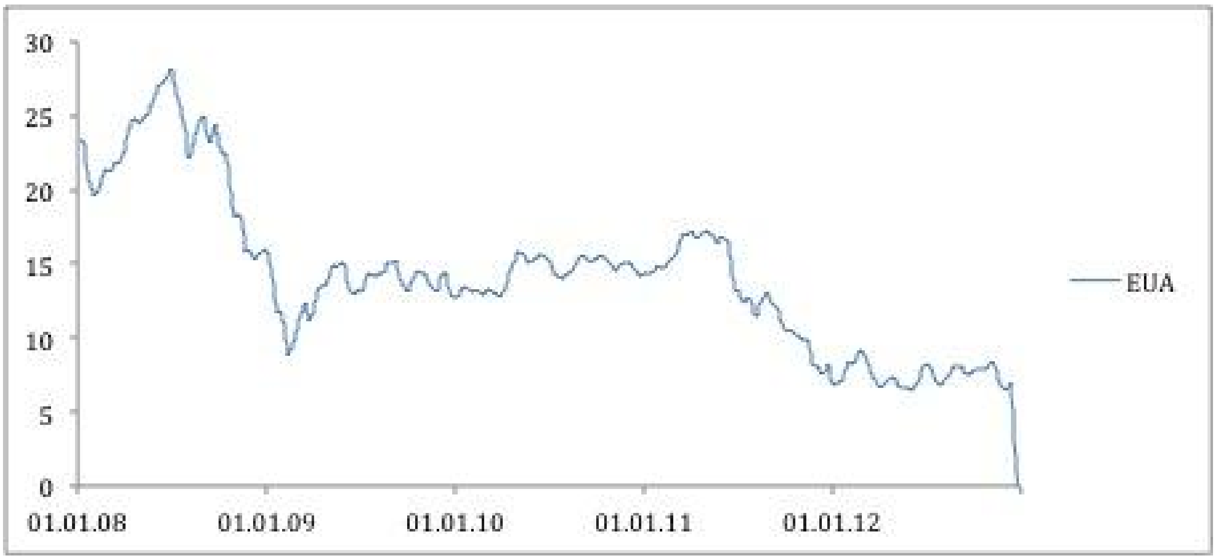


Figure 12: Second period year-ahead EUA future prices 2008-2013 (7-days MA)

[26] http://www.ecad.eu

between around 14-15€, which goes until mid 2011. In the last period, the price fell again from mid 2011 until the beginning of 2012 and then stayed around the value of 7€/t_{CO2} until the end of the 2012. Note that the price fell to zero once again in the end of 2012 as this marks the end of the trading period for second period allowances and since the price series did only take contracts until December 2012 into account. It might be necessary to exclude the values for the period preceding the 16th of December 2012 for the empirical analysis, which coincides with the last delivery period of second period emission allowances.

Figure 13 shows the year-ahead electricity futures for Germany, France, the United Kingdom and the NordPool, as well as emission allowance futures between 2008 and 2012. A first visual inspection suggests that all prices seem non-stationary and without any clear trend.

The electricity prices are moving closely together and seem to follow a common trend. This is especially true for Germany, France and the NordPool. The United Kingdom, however, shows a peak in October 2008, which distinguishes it from the others at first but then reverts to a similar price level as the others. It is obvious that in an initial period, going roughly until the beginning of 2009, prices were significantly more volatile, as they almost doubled and then revert to values below their initial level. One potential explanation for this behaviour might be the financial crisis, which occurred during that time period. The initial growth would be the built-up of a bubble in these series. Then, prices fell, which represents the burst of this bubble. Over the next years, the price levels seem more stable as, overall, electricity prices fluctuate around 48€/MWh.

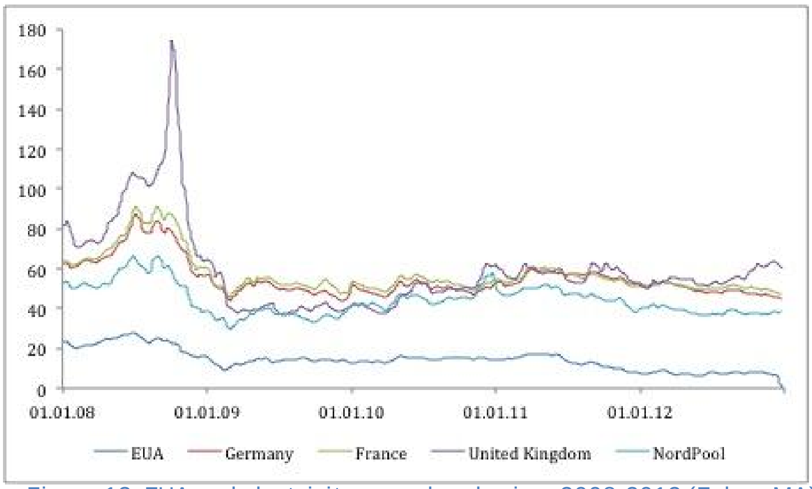


Figure 13: EUA and electricity year ahead prices 2008-2012 (7 days MA)

The EUA futures seem to follow a similar path as the electricity prices. The higher price levels and subsequent drop observed for electricity prices in 2008 can also be observed in EUA prices, although the movements do not seem to be as strong.

Figure 14 shows the development of electricity and emission allowance prices against input fuel prices. The 01.01.2008 is taken as the base value (i.e. all prices equal 100) for all series, to show the price developments between 2008 and 2012.

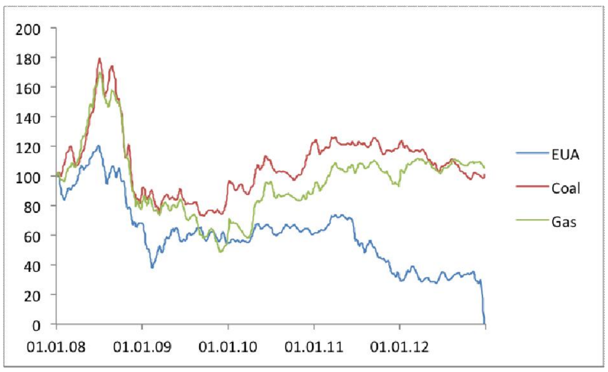
In the first half of 2008, none of the electricity prices experienced a movement as strong as input fuels. While coal and gas prices rose to almost 180% of their base value, electricity prices only experienced movements to between 120-140%. The second half of 2008 showed a downward movement in all price series to below the base value. Germany's and France's price levels dropped to around 80% of the starting value. The price levels then stayed between around 80-90% until the beginning of 2011 after what they slowly moved downwards until the end of 2012 where they ended at around 75% of their initial value. Their prices seem to be closely related to the coal price with which they were moving together until the beginning of 2010. After that, the prices drifted apart but are still showing similar tendencies of upward and downward movements, although these are less pronounced for the respective electricity prices.

In the first half of 2008, Nord Pool's prices moved up to only 120% of their base value, while coal and gas prices had a much more important upward movement (as discussed earlier). On the other hand, the downward movement of Nord Pool's electricity price in the second part of 2008 and beginning of 2009 was much more pronounced as they reached a level of around 55% of the base value. Following this phase of downward movement, prices steadily inched up until the beginning of 2011 where they would attain their initial level, before falling again until the end of the study period. Nord Pool prices seem to be more closely related to natural gas price developments than to coal, although the initial upward move was less pronounced for the electricity price and they started diverging from the beginning of 2011.

The United Kingdom's electricity price is quite distinct from the others. While the initial upward movement in the first half of 2008 can also be observed, it continues its upward movement in the second part of 2008 to reach values way above 200% of its base value. Following this, a period of sharp descent, where prices dropped below 50% of the base value can be observed between the end of 2008 and the beginning of 2009. Then, prices slowly grew until the end of the period, where they ended at around 75% of the initial value.

Initially, the EUA price seems to follow the price movements of coal and natural gas, but at a lower magnitude. Prices moved up in the beginning of 2008 and then experienced a steep fall from mid-2008 until the beginning of 2009 where they reach around 40% of their initial value. The strong negative effect on allowance prices is not very surprising, as a slow-down in expected economic activity surely leads to less expected emission levels and therefore to a significant drop in EUA prices. Note that the price fell to zero once again in the end of 2012 as this marks the end of the trading period for second period allowances and because the price series did only include contracts until December 2012.

All in all, this period is marked by a possible burst of a bubble in mid 2008, which indicates the effect of the financial crisis on these prices. Clearly, electricity prices, emission allowances and fossil fuels are closely related to economic activity, which helps explaining these strong effects. Before mid 2008, prices climbed up at a fast rate and then fell again to below their initial values. The price movements for all electricity prices as well as fuel prices then normalised and seemed to be staying around 80% of their 2008 values for electricity prices and around 100% of their 2008 values for coal and natural gas prices



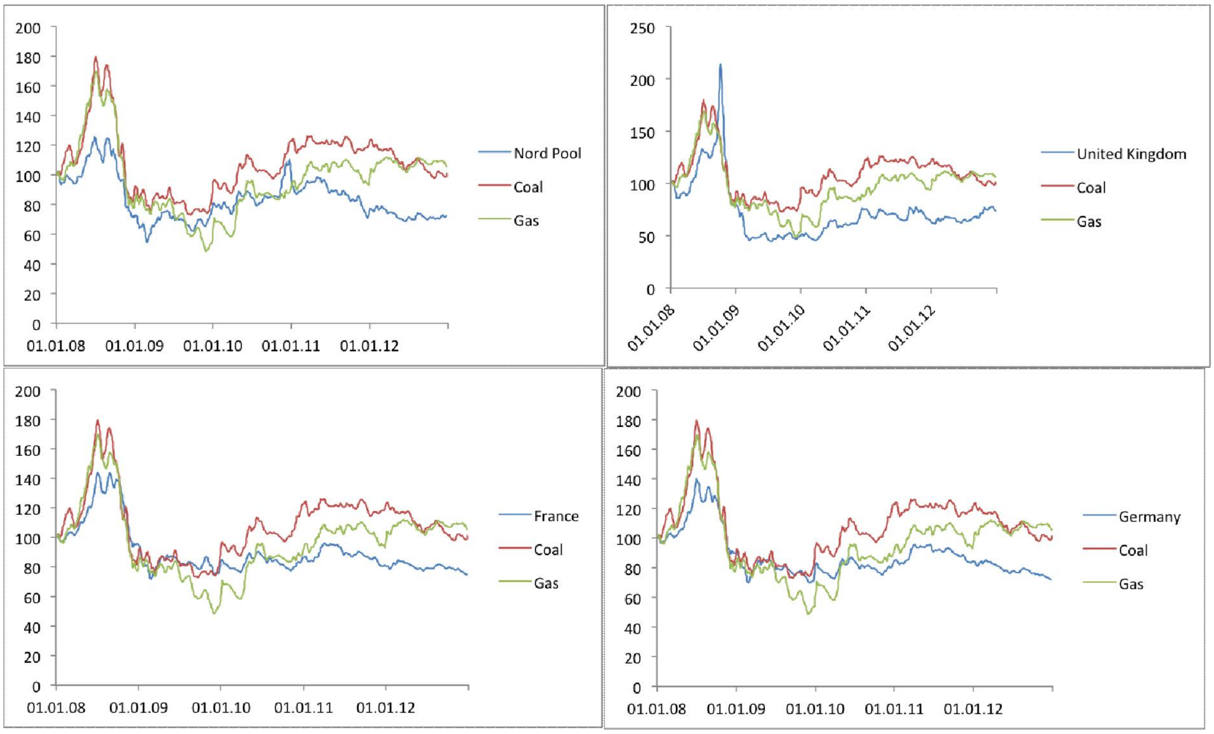


Figure 14: Development of electricity and emission allowance prices against input fuel prices

4.4. Cointegration Analysis: Is there a presence of emission allowance priced into the electricity wholesale prices?

4.4.1. Cointegration Test: Engle Granger

A necessary first step for testing the cointegration relation between the variables is to test if the variables are first order integrated. Therefore, the Augmented Dickey Fuller test for unit roots will be conducted on the variables, as well as on their first differences. The series are considered to be I(1) processes if the test does not reject unit roots for the individual series but rejects unit roots when it is performed on their first differences. No intercept, lags or trend have been used for these tests. The null hypothesis for this test is that there is presence of a unit root in the time series. The results for the augmented Dickey-Fuller unit root test may be found below.

Table 1 shows that none of the electricity prices, the emission allowances prices nor the coal or gas prices are I(0) processes on any conventional level. The same goes for the Stoxx600. For interest rates, it was possible to reject the presence of unit roots at the 10% level. Similarly, it was possible to reject unit roots at the 10% level for temperature data in Germany and the United Kingdom and at the 5% and 1% level for France and the Nord-Pool. The results for temperature are not unexpected, since temperature was taken into the model to reflect the seasonal effects of atmospheric temperature as a proxy for the demand cycle. Temperature can be viewed to be cyclostationary, which means that data points taken at different moments during the year are statistically different, whereas these taken once a year would be stationary. (see Gardnera et al. (2006)) The ADF test on first differences showed that the presence of unit roots can be rejected on the 1% level for each of the series. It can be concluded that most of these series are I(1) processes and hence were not generated by a stationary process.

Table 1: Unit root tests on the variables and on the first difference of the variables

Series	Value of the ADF test	Value of the ADF test on first differences
Germany	-0.840	-12.026***
France	-0.710	-12.059***
United Kingdom	-0.453	-11.464***
NordPool	-0.671	-13.225***
EUA	-1.580	-12.860***
Coal	-0.044	-11.102***
Natural Gas	0.091	-12.723***
Interest Rate Germany	-1.838*	-12.933***
Interest Rate France	-1.836*	-13.032***
Interest Rate UK	-1.893*	-19.745***
Interest Rate NordPool	-1.641*	-12.915***
Temperature Germany	-1.709*	-22.948***
Temperature France	-2.383**	-21.538***
Temperature UK	-1.481*	-21.894***
Temperature NordPool	-2.907***	-19.934***
Stoxx600	-0.650	-14.367***

* /**/ ***indicates significance at the 10%, 5% and 1% level respectively on the critical values defined by MacKinnon (1991)

Next, the following model will be estimated using standard OLS:

$$Electricity_t = \alpha_0 + \alpha_1 EUA_t + \alpha_2 Coal_t + \alpha_3 NaturalGas_t + \alpha_4 Stoxx600_t + \alpha_5 InterestRate_t + \alpha_6 Temperature_t + z_t$$

This specification allows electricity to be viewed as the dependent variable with all other factors being exogenous. Since all variables are non-stationary, the OLS regression might lead to spurious values of R^2, Durbin-Watson and t-statistics. Also, standard inference is invalid, as it is impossible to make inferences about the significance of the t-statistic and p-values, which is why they will not be included in Table 2.

The next step is to test the residuals from the OLS regressions on unit roots, which can be seen in Table 2. If the results indicate that H_0 can be rejected and hence, the residuals seem stationary, it can be concluded that there is evidence for cointegration between these variables.

The test results for Germany, France and the United Kingdom were not able to reject non-stationarity at the 1%, 5% or 10% level. However, the Augmented Dickey Fuller test for the NordPool area indicates that it is possible to reject non-stationarity against the alternative of a stationary process at the 1% level.

Therefore, the results indicate the presence of a long-run relation in the model of the NordPool and that the variables are in a long-run equilibrium. The other three sets were not able to confirm the presence of a long-run equilibrium. However, the critical values defined by MacKinnon work asymptotically and might therefore not be a perfect indicator for the presence of a cointegration relation given the small dataset. Hence, while it is not possible to confirm a cointegration relation using this approach, this does not mean that there is no such relation.

The estimated long-run elasticities are represented in Table 2. The signs of the elasticities of the electricity prices with respect to the prices of emission allowances, coal and natural gas are almost always positive. The only exception is the Nord Pool area, which shows a negative elasticity between electricity with respect to natural gas. Germany's electricity price is strongly affected by the emission allowance, the coal and the gas price. Surprisingly, the gas price seems to play a more important role than coal, which is contrary to the idea that the electricity mix will be reflected in these parameters. In France, the electricity price is strongly affected by the emission allowance prices, coal price, natural gas prices. The first three have a positive influence on the electricity price, while changes in the latter are negatively correlated with the electricity price. In terms of magnitude, emission allowances and natural gas prices suggest an impact of almost double the extent of the other two. These results are in line with expectations, as natural gas plays a more dominant role than coal in France's energy mix. The United Kingdom's electricity price is strongly affected by natural gas and coal in the long-run equilibrium, while emission allowances plays its part, it seems that the United Kingdom's electricity price is less affected by changes in emission allowance prices than the other countries. Natural gas is by far the strongest influence factor with a long-run elasticity double the magnitude of coal and almost ten times the size of emission allowance's elasticity. The comparative importance of natural gas is in line with the energy mix of the UK, which is largely based on natural gas. Nord Pool's electricity price is strongly influenced by the coal and emission allowance price. Even if the Nord Pools energy mix is largely based on hydropower and nuclear power, these two do not typically operate at the margin. Fossil fuels, which are largely coal-based, are the next important input factor, which indicates that the results are in line with the energy mix.

All in all, emission allowances seem to influence electricity prices in all tests. The magnitude, however, varies depending on the country. While the price elasticity is 0.057 in the UK, the value in the NordPool area is almost five times as big (0.232). Also, there is no clear sign, which would indicate that countries with a more emission intense energy mix would have higher elasticities. Germany, whose energy mix is largely coal based only shows a comparatively moderate value. France and the UK, which have comparatively more gas-based energy mixes, show quite different elasticities (0.217 and 0.057 respectively). More so, emission allowances demonstrate the strongest elasticity in the Nord Pool market, whose energy mix is largely based on hydropower, which has almost no emission.

Table 2: Long-run regression – Engle-Granger Two Step

Variable	Coefficient	Germany	France	United Kingdom	Nord Pool
Constant	α_0	2.568	2.724	0.931	0.276
EUA	α_1	0.140	0.217	0.057	0.232
Coal	α_2	0.168	0.094	0.261	0.637
Natural Gas	α_3	0.208	0.259	0.548	-0.066
Stoxx600	α_4	-0.076	-0.116	-0.011	0.155
Interest Rate	α_6	0.090	0.055	0.155	-0.006
Temperature	α_7	0.001	0.001	-0.006	-0.001
ADF test on residuals		-3.510	-3.510	-2.963	-5.630***

*** indicates significance at the 1% level on the critical values defined by MacKinnon (1991)

4.4.2. Cointegration Test: Johansen procedure

The Engle-Granger test for cointegration has several weaknesses. It is an asymptotical test, which ideally necessitates large datasets, which have been taken over a long time period. The most relevant drawback for this paper seems to be that it is not ideal for multivariate regressions. Moreover, the complex price dynamics, especially between electricity, coal, natural gas and emission allowance prices might not be adequately represented by a model of exogenous variables, but much more by one that allows for interaction between the variables. The Johansen test for cointegration, which has previously been introduced, will therefore be used to test for cointegration between the variables. This test is more generally applicable than the Engle-Granger test, but is subjected to asymptotical properties and therefore requires a large sample size. Below, the trace and eigenvalue tests will be conducted.

The model defines the vector of endogenous variables: $y_t = [p_{electricity}, p_{coal}, p_{naturalgas}, p_{EUA}]$, the vector of exogenous variables: $z_t = [temperature_t, p_{Stoxx600}, p_{InterestRate}]$, $x_t = [y_t, z_t]$, from which the following VECM model is written:

$$\Delta y_t = \Pi y_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta x_{t-i} + u_t$$

Here, temperature, the stock market and the interest rate affect the short-run dynamics of the price series. By analysing $\Pi = \gamma\beta$, the equilibrium vector (β) and adjustment coefficients (γ) may be derived.

A necessary first step, which has to be taken before doing the cointegration test, is to choose the lag length of the model. This will be done according to the Akaike information criterion (AIC), which supports the inclusion of one lag for all markets.

The Johansen test for cointegration is used to determine the rank of the parameter Π. It has been shown that, when there is presence of cointegration the rank will be non-zero and not maximal. The trace test examines the null hypothesis of r cointegrating vectors against the alternative of more than r cointegrating vectors, whereas the maximum eigenvalue test tests the null hypothesis of r cointegrating vectors against the alternative hypothesis of r+1 cointegrating vectors.

Surprisingly, the results for the Johansen test for cointegration do not reject the null hypothesis of no cointegration for most markets (see Table 3). Germany, France and the United Kingdom do not reject the null hypothesis using the trace or the maximum eigenvalue test at the 5% confidence interval. Only the maximum eigenvalue test for the NordPool is able to reject the null hypothesis. However, as the Johansen test is only just failing to pass at the 5% significance level, a VECM will still be estimated to see whether significant estimates can be obtained for the cointegration relationship. Hence, the rank of the parameter Π is assumed to be 1 for all relations, which indicates the presence of one cointegrating relation.

Table 3: Johansen cointegration rank test, daily

Series	Maximum rank	Germany	France	United Kingdom	Nord Pool	5% critical value
trace	0	38.46	43.11	43.47	46.34	47.21
eigenvalue	0	17.59	19.82	22.36	29.71*	27.07
	1	–	–	–	11.37	20.97

* indicates rejection of the H_0 of the trace and maximum eigenvalue test at the 5% level

4.4.3. Vector Error Correction Model

The Engle-Granger Two Step procedure handles all variables as exogenous from one another. In a vector error correction model, however, these variables are estimated at the same time. This means that the model has a vector of endogenous variables, as indicated above. The following estimations of the vector error correction model will be carried out using the statistical software JMulti, which has been developed by Lütkepohl and Krätzig (2004). The model used by this software has the following form:

$$\Gamma_0 \Delta y_t = \alpha[\beta' : \eta'] \begin{bmatrix} y_{t-1} \\ D_{t-1}^{co} \end{bmatrix} + \sum_{i=1}^{p} \Gamma_i \Delta y_{t-i} + \sum_{i=0}^{q} \mathrm{B}_i \Delta x_{t-i} + CD_t + u_t$$

Here, y_t is the vector of the observable endogenous variables, x_t is the vector of observable exogenous or unmodelled variables, D_{t-1}^{co} comprises all deterministic variables included in the cointegration relation, D_t contains all deterministic terms and u_t is the residual vector.

In this model, the endogenous vector includes electricity, coal, natural gas and emission allowance prices, defined by $y_t = [p_{electricity}, p_{EUA}, p_{coal}, p_{naturalgas}]$. Further, the exogenous vector contains temperature, Stoxx600 and the interest rate: $x_t = [temperature_t, p_{Stoxx600}, p_{InterestRate}]$. No deterministic terms will be included. Moreover, no dummy variables to account for seasonalities will be included in the model, since these fluctuations are assumed to be included in the temperature variable.

The lag length is chosen according to the Akaike Information Criterion, which indicates that one lag should be included in the vector error correction model. As seen above, there is one cointegration relation, which will be the parameter used for all estimates.

The results for this model are shown in Table 4 and Table 5. Note, that in a VECM, all endogenous variables are simultaneously estimated. Table 4 shows how electricity is influenced by all other variables. While similar representations exist for the effects between the other endogenous variables, these will not be presented here.

In the long run, the vector for the electricity variable has been normalised to 1, which is why it is not indicated in the table below. Since all variables are in natural logarithms, the coefficients can be interpreted as long-run elasticities. Thus, a 1% increase in the German emission allowance price increases the electricity price by 0.300%. Note that a negative coefficient is associated with an increasing effect since the estimates are to be taken as a vector: $1p_{electricity} - 0.300p_{EUA} + 0.292p_{coal} - 0.482p_{naturalgas}$. A first thing to notice is that the estimates for emission allowances and natural gas are highly significant (at the 1% level), while this is not the case for the coefficients of coal, except for the NordPool. The estimates of emission allowances indicate coefficients between -0.202 and -0.330, indicating that an increase of 1% in the emission allowance price results in an increase of the electricity price of between 0.202–0.330%. The coefficients for coal are more country-dependent. They have a decreasing impact on Germany's and France's electricity price (0.292 and 0.303 respectively), while they have an increasing impact on the United Kingdom's and NordPool's electricity price (-0.133 and -0.881 respectively). The coefficients for natural gas indicate an increasing impact on Germany, France and the United Kingdom's electricity prices (-0.482, -0.445 and -0.851 respectively) and a decreasing impact on the NordPool (0.203).

Table 4: VECM long-run regression – one lag

Variable	Germany	France	United Kingdom	Nord Pool
Constant	-2.393	-2.539	0.502	-0.848
	(0.000)	(0.000)	(0.343)	(0.000)
EUA	-0.300	-0.330	-0.281	-0.202
	(0.000)	(0.000)	(0.000)	(0.000)
Coal	0.292	0.303	-0.133	-0.881
	(0.107)	(0.082)	(0.682)	(0.000)
Natural Gas	-0.482	-0.445	-0.851	0.203
	(0.000)	(0.001)	(0.000)	(0.004)

Sample: [3,259], T=257; p-values in brackets

While it is useful to understand the equilibrium price, the long-run vector does not yield any information on the short-term dynamics of the model. To get a better understanding of the short-run adjustments made, it is necessary to have a look at the results presented in Table 5.

In the short run, it can be observed that the error correction term in all models is, as expected, negative and between 0 and 1. This indicates a readjustment towards the long-term equilibrium. By comparing these terms, it can be seen that the German and French markets adjust slower than the United Kingdom and NordPool and that the latter reverts at a rate, which is almost double of the German and French's.

Germany's electricity price is mainly influenced by the lagged emission allowance price and the coal price, both with high significance levels. They have a positive effect on the electricity price. Moreover, the lagged electricity price and the lagged price for natural gas influence the electricity price as well, but at a lower rate than the other endogenous input variables and with low significance levels. The stock market shows a significant and strong positive impact as well as the interest rate, with lesser magnitude and significance level. Temperature does not seem to affect the short-run dynamics of the model.

France's electricity price depends mainly on the emission allowance and coal price, with a high significance level. The lagged electricity price also shows a high coefficient, although with a high p-value for the lagged electricity price. It is less influenced by changes in the natural gas price for which it also shows low significance levels. Similar to the German prices, the stock market strongly affects the short-run dynamics and with high significance levels. The interest rate affects the short-run dynamics to a lesser extent and a somewhat higher p-value. Here again, temperature does not seem to have a strong influence on the model.

The United Kingdom's electricity price is determined by the lagged electricity price with a high significance level, as well as by the emission allowance price, with a slightly less but still significant level. It is also affected by the lagged coal and natural gas prices, but these results show high p-values. The exogenous variables affect the electricity price as follows: The stock market index plays an important part in the price formation with a high significance level. The interest rate influences the short run to a lesser extend and the result shows low significance levels. Temperature has almost no effect on the short-run dynamics of the model.

The NordPool's electricity price is strongly influenced by the lagged emission allowance price with high significance levels, as well as the lagged coal price, although with a lower significance level. The lagged electricity price plays a secondary role and shows a low significance level. Natural gas has no impact on the short-run dynamics of the model. Similar to the other countries, the stock market has a significant and high impact on changes in electricity price. Interest rates also partly explain changes in electricity prices, but to a lesser extent than the stock market and with lower significance levels. Finally temperature has almost no impact on the electricity price.

Table 5: VECM - Short-run interactions

Variable	Germany	France	United Kingdom	Nord Pool
ECT	-0.047	-0.052	-0.079	-0.095
	(0.023)	(0.014)	(0.000)	(0.020)
$\Delta p_{electricity,-1}$	0.019	0.086	0.221	0.040
	(0.854)	(0.380)	(0.001)	(0.599)
$\Delta p_{EUA,-1}$	0.067	0.067	0.098	0.119
	(0.044)	(0.054)	(0.067)	(0.003)
$\Delta p_{coal,-1}$	0.190	0.127	0.048	0.142
	(0.004)	(0.048)	(0.630)	(0.070)
$\Delta p_{natgas-1}$	-0.012	-0.013	0.057	0.000
	(0.803)	(0.792)	(0.523)	(0.994)
$p_{Stoxx600}$	0.202	0.179	0.212	0.445
	(0.000)	(0.001)	(0.030)	(0.000)
$p_{IntRate}$	0.052	0.054	0.035	0.033
	(0.096)	(0.094)	(0.291)	(0.295)
$temp_{-1}$	0.001	0.000	-0.001	-0.001
	(0.226)	(0.450)	(0.287)	(0.008)

Sample: [3,259], T=257; p-values in brackets

4.5. Discussion Engle Granger

The results of the Engle-Granger Two Step procedure indicated that there is presence of a single cointegration vector in the NordPool. The other markets do not show a sufficient ADF test score to reach a significance level of 10%. However, the low significance of these results may be due to the low sample size of the data.

Emission allowances seem to play an important role in Germany, France and the NordPool and a less important role in the United Kingdom. Similarly, the input fuels are essential input factors in all price series. Contrary to what Germany's energy mix would suggest, results indicate that its electricity price is affected more strongly by natural gas prices than coal prices. This might be the result of a strong integration between the German and French market. France's electricity price is affected more importantly by the natural gas price than the coal price, what is in line with their energy mix. The United Kingdom's electricity price is influenced by changes in the natural gas price at almost double the rate that coal affects it. This, again is in line with the UK's heavily natural gas based energy mix. Surprisingly, the NordPool shows a negative influence of changes in the natural gas prices on the electricity price. Coal affects the Nord Pools electricity price, as expected by its energy mix, to a great extend.

All in all, there is evidence of a pass-through of emission allowance prices into electricity prices. The levels of this pass-through vary between countries, as an increase of 1% in emission allowance prices results in an increase of the local electricity price by between 0.057–0.232%. These results confirm economic theory, which suggested that taking the view of emission allowances as opportunity costs would result in different pass-through levels according to the market's characteristics.

4.6. Discussion VECM

The Johansen procedure was not able to confirm the presence of one cointegration vector using the trace and eigenvalue tests, as both tests were not able to reject the null hypothesis of no cointegration vector at the 5% level. The only exception is the NordPool market for which one cointegration relation has been found. However, since most tests just failed the 5% level, the VECM has still been carried out for which it was possible find significant estimates.

Germany's long-run coefficients indicate that there is significant positive impact of emission allowances on electricity prices. Surprisingly, the VECM suggests a negative long-run impact of coal prices on electricity prices, while natural gas prices influence them positively. The German energy mix is largely based on coal production, for which a different outcome would have been expected. However, significance levels for coal are not very high. France's long-run coefficients are similar to Germany's in significance and magnitude, which may be viewed as a confirmation of their advanced level of market integration. The United Kingdom's long-run coefficients indicate a positive influence of emission allowance, coal and gas prices into electricity prices. A price increase in natural gas has a strong and significant impact on the electricity price. The coefficient for coal has the expected sign and magnitude, but it shows a low significance level. The NordPool's electricity price is positively influenced by the emission allowance price. Coal has a significant and strong impact on the electricity price. Natural gas, as in the previous part, has a negative impact on the electricity price.

The VECM allows further analysis of the short-run dynamics of the model. The German and French markets can be seen to adjust at similar rates, which are around two thirds of the UK's adjustment speed and half of the NordPool's. This might be due to the latter two markets being liberalised for a longer time period and therefore having more advanced market structures, which could incorporate deviations from equilibrium quicker than the others. Moreover, the short-run dynamics show that changes in last period's EUA price induce significant positive changes in the electricity price in all regions. Changes in the coal price have a significant positive impact on the electricity price in Germany and France and a positive and slightly less significant impact in the NordPool. The coefficient for coal in the UK is positive as well but not significant. Changes in natural gas prices induce negative changes in electricity prices in the German and French market. The UK reacts with electricity price increases in the short run on price increases in the gas market, but the significance here is low as well. Surprisingly, the NordPool market does not seem to react to changes in the natural gas price, with a coefficient close to zero and a very high p-value

All in all, as in the previous part, emission allowances have a significant positive impact on the long-run equilibrium of the local electricity prices. Moreover, in the short run, the price of emission allowances immediately induces significant positive changes in electricity prices as well. Again, our hypothesis of a cost pass-through of emission allowance prices into electricity prices seems confirmed.

4.7. Model critique

The models above allowed the reader to get an insight into the price dynamics between emission allowances, electricity and fuel prices. However, these results should be treated with caution.

There are some shortcomings of the approaches used, which will now be outlined. The Engle-Granger model works best with big sample sizes, therefore taking data with a higher frequency or a longer time period might lead to improved results. The vector error correction model is analysing very complex interactions and assumes a well specified full system. The specification of such a system is highly demanding and hard to implement. Moreover, the VECM is very sensitive to lag selection and while the selection has been carried out using information criteria, other information criteria might lead to different conclusions regarding the optimal number of lags included in the model.

Another problem faced is that the coefficients for the cost pass-through are difficult to interpret since the pass-through level depends on the plant operating at the margin. While it is possible to state that there is evidence of a cost pass-though, the lack of information on the marginal power plant leaves the coefficient open for interpretation. Moreover, Aatola et al. (2013) show that the European electricity markets become increasingly integrated and more interdependent. Hence, it might be of interest to include these dynamics into the model.

In this sense, when available, further research may use data on the marginal power plant to get the actual pass-through levels. Moreover, a model, which takes the interdependencies between the electricity markets into account, might be of further interest.

5. Conclusion

This paper intended to analyse the occurrence of a possible cost pass through of emission allowances in European electricity wholesale prices. To answer this question, this paper provided a qualitative and quantitative analysis.

In a first part, this paper laid out the economic theory, which suggested that under free allocation of allowances in the EU ETS, their price could be passed through into the electricity prices. As a cap and trade system puts a price on emission, it will be added to the marginal generation costs of electricity producers, which is a central aspect of the electricity price formation process.

The second part of this paper gave a comprehensive insight of the price formation of electricity. It has been shown that it is largely determined by the marginal cost of the power plant, which has to be brought into operation to satisfy total demand. Further, this part gave an insight into the interactions between carbon, energy and electricity prices. Interestingly, on the one hand, emission allowances increase the cost of carbon emission based power plants and therefore decrease the demand for them, but on the other hand a lower demand for these fuels would also affect the demand and therefore the decrease the price of emission allowances. This paper also suggests that the level of pass through differs according to the energy mix of the country, where, again, the marginal power plant is of central importance. Also, this paper expects markets showing higher degrees of integration to show more similar pass through levels.

In a third part, an empirical analysis has been carried out to test if there is evidence for a cost pass through of emission allowances into electricity prices. Two cointegration tests for four distinct electricity markets, namely France, Germany, the United Kingdom and the Nord Pool, have been conducted: the Engle-Granger Two Step and the Johansen procedure. Both concluded that there is evidence in favour of a pass through. The pass through levels differed depending on the individual country/region. A vector error correction model allowed to determine the short-run price adjustments between the variables. It indicated that there is an immediate significant positive impact in electricity prices from changes in emission allowance prices. Hence, the test suggest that a significant impact from emission allowances on the electricity price can be observed, that this impact may be observed immediately and that the effect would be lasting.

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