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CO_2 ALLOWANCE & ELECTRICITY PRICE INTERACTION

Impact on industry's electricity purchasing strategies in Europe

IEA INFORMATION PAPER

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1. Key messages

- The value of emissions trading mechanisms is to achieve environmental goals at least cost.
    - Governments should refrain from using CO_2 allocation processes as means to address other energy policy goals.
    - Governments should provide visibility on long term emission objectives to foster investment in cleaner generation technology now.

- In a competitive market, the pass-through of CO_2 prices in electricity prices is inevitable.
    - Electricity prices that reflect the cost of CO_2 are needed to encourage investment in clean generation, demand-side response and adoption of efficient end-use technologies.
    - Auctioning allowances to power generators should not trigger higher electricity prices. Revenues could be used to alleviate negative impacts on certain categories of end-users.

- The competitive "pool" model in which all supply meets all demand at all times to define prices is not the norm for electricity markets in Europe. Several models and regulatory frameworks exist.
    - Various electricity pricing mechanisms are found across European countries. The main categories include: market prices set by the marginal generator or bidder; "screen prices" with trading of blocks for baseload needs; annual contracts and regulated tariffs

- Changes in electricity costs for energy-intensive industries cannot be estimated from day-ahead or forward electricity prices – although supply contracts are sometimes indexed to exchange prices.

- Electricity costs can be lower than day-ahead and so-called "block" prices, when industrial users accept to share risk with generators (e.g., sharing capital cost, locking-in prices, or guaranteeing a certain volume of electricity demand).

- New business models have emerged, in response to increased volatility and higher electricity prices. These include:
    - Pooling companies' power purchases in long-term contracts to increase their negotiation power.
    - Self-generation with or without third parties, at electricity prices close to production costs.
    - Supply contracts indexed on indicators with less volatility than electricity prices.
    - New intermediaries to manage price risk and seeking investment opportunities in generation.

2. Executive Summary

With the introduction of CO_2 emission constraints on power generators in the European Union, climate policy is starting to have notable effects on energy markets. This paper sheds light on the links between CO_2 prices, electricity prices, and electricity costs to industry. It is based on a series of interviews with industrial and electricity stakeholders, as well as a rich literature seeking to estimate the exact effect of CO_2 prices on electricity prices. Beyond a theoretical look at the CO_2 and electricity pricing interactions, it describes how electricity markets are organised at present, how industrial users purchase their electricity and how such practice may affect the CO_2 price signal. The variety of situations presented here should be of interest of other countries and regions as they consider how to best reduce emissions from power generation, the single largest contributor to energy-related CO_2 emissions in OECD countries.

Emissions Trading Systems in Europe and Elsewhere

The European Union introduced the EU emissions trading scheme (EU ETS) on January 1, 2005, which sets caps for the CO2 emissions of some 11,500 plants across the EU-25. Installations have the flexibility to increase emissions above their caps provided that they acquire emission allowances to cover emissions above. Installations with emissions below caps are allowed to sell unused allowances. The EU ETS has sparked a vibrant EU allowances (EUA) market, with transactions totalling EUR 14.6 billion in 2006 (Point Carbon, 2007), and created a visible price of CO_2. This price is now another cost component for covered installations, including power generators, by far the largest emitter in the scheme. Other local or regional governments are at various stages of discussion or implementation of emission trading systems (Ellis and Tirpak, 2006).

CO_2 Prices in Electricity Prices: a Condition for Cost-Effective CO_2 Reductions

Economic theory explains why, under a cap-and-trade system, the price of emissions ought to be treated as a marginal cost. As a generator holds allowances, the production of CO_2-emitting electricity competes with the possibility to sell the unused allowances. This so-called opportunity cost of CO_2 allowances, equal to the CO_2 market price, is therefore incorporated in operators' decisions to generate electricity. So far, EUA have been distributed for free to installations. Whether or not the full opportunity cost of such free allowances finds its way to end-user electricity prices depends on several elements including: contractual agreements between suppliers and end-users, regulatory frameworks, but also the elasticity of demand and the rules used by governments to allocate EU allowances. The possibility that future allowances be distributed on the basis of current emissions creates an incentive not to pass through the full opportunity cost, as this may result in lower demand, lower emission and a lower "rent" allocation. The economic rationale behind a "cap-and-trade" system is nonetheless that the price of emissions should be reflected in final prices, to encourage lower consumption, and to encourage cleaner generation through higher expected revenues. Only then can such a scheme trigger an overall cost-effective response to the emission constraint.

If any evidence is needed of the CO_2 pass-through into electricity prices, it was provided by the abrupt fall of the CO_2 price in May 2006, as market players were made aware of the excess quantity of EU allowances for the year 2005. The fall by EUR 10/tCO_2 was immediately followed by a drop in wholesale electricity prices of EUR 5-10/MWh (Point Carbon).[1] This electricity price adjustment can be directly attributable to the CO_2 price fall, itself not connected to other energy market movements that could also affect electricity prices.

There is no universal answer on how the EU ETS has affected electricity prices. First, there is no single EU electricity market, but several market and regulatory frameworks across the EU (EASAC, 2006). Second, many other factors affect generation prices such as high natural gas prices in 2005 or the potential use of market power by electric utilities.[2] Third, as no data can be gathered on the bidding strategies, and the marginal supplier to the market, determining the precise level of pass-through of CO_2 prices in electricity prices is not possible. Without adequate information on the price-setting technologies across markets, countries and load periods, and without explaining away other volatility factors in the price, empirical estimates of pass through rates remain tentative. Several studies did provide estimates: Sijm et al. (2006) find rates ranging from 39 to 73 percent for Germany and the Netherlands for the period January-July 2005 and from 60 to 80 percent for the same countries between January-December 2005.

From Electricity Generation Prices to Industrial Electricity Costs

Considering that end-user prices are a mix of various market prices and differ between end-user categories (e.g., energy-intensive users, small enterprises, residential, etc.), the impact of CO_2 on end-user electricity prices is even less well known than the impact on generation prices. How does the electricity cost faced by industrial energy users relate to the prices observed on electricity markets (whether they are organised through an exchange or not)? Obviously, the relationship hinges on industrials' power purchasing strategies. As a result, changes in electricity costs for energy-intensive industries cannot be estimated from day-ahead or forward electricity prices variations – although supply contracts are sometimes indexed to exchange prices.[3] For example, some industrial electricity users are still bound by long-term contracts. Others may have adopted purchasing strategies based on forward electricity prices, thus limiting their exposure to both electricity and CO_2 allowance price volatility.[4]

In Europe, industry has access to various electricity pricing mechanisms, depending on their country or region of operation. Here are the main broad categories identified:

- *Market prices set by the marginal generator or bidder.*

In Scandinavia**,** hourly prices formed on the Nord Pool exchange, representing the hourly marginal cost of the marginal generation plant, are the dominant element of electricity supply contracts.

[1] EurActiv (2006): Crashing carbon prices puts EU climate policy to the test, May. http://www.euractiv.com/en/sustainability/crashing-carbon-prices-puts-eu-climate-policy-test/article-154873

[2] The European Commission published its final report, January 10, 2007, on the energy sector competition inquiry, concluding that consumers and businesses are losing out because of inefficient and expensive gas and electricity markets. Particular problems include high levels of market concentration; vertical integration of supply, generation and infrastructure leading to a lack of equal access to, and insufficient investment in infrastructure; and, possible collusion between incumbent operators to share markets.

[3] In the European countries where exchange-based transactions represent only a fraction of total electricity supply, this index may appear questionable.

[4] Contracts for future delivery of electricity also include a measure of CO_2 pass-through. Purchasers of electricity through such contracts ensure some protection against future volatility, including CO_2 price volatility

- *"Screen prices" with trading of blocks for baseload needs.*

In the UK, prices paid by industrial facilities can be set on broker or market electronic platforms (i.e., "screen pricing") through the trading of blocks (daily, monthly, trimester). Costs of intra-day adjustment are added to obtain the final supply cost. An exception to "screen pricing" is the long term contract signed between a power supplier and a generator where the electricity price is indexed to international coal prices and CO_2 prices.

In continental Europe, the main supply contracts are based on "screen prices" for annual blocks.

- *Annual contracts*

In Italy, prices are based on annual contracts via tenders.

- *Regulated tariffs* are found in Spain, in particular, although industry and generators are currently negotiating on long-term contracts based on coal-based generation costs.

Table EX 1 illustrates several electricity purchasing strategies theoretically available to energy-intensive industries (EII) in various regulatory environments - although we note that not all European countries offer all options shown below and not all industrial facilities are in a position to negotiate with generators for supply contracts in which case they accept the supply price that suppliers offer on the bilateral market.[5] For example, bilateral electricity supply contracts can be: indexed contracts (e.g., indexed on fuel plus CO_2 prices, on other commodities' markets, etc.); cross-market contracts (e.g., the spark spread option – the buyer of such a contract has the option to switch one unit of gas for one unit of electricity at a specified price); floating contracts including cap and floor prices; fixed price contracts; or contracts for differences (i.e., compensation is paid for price differences over periods agreed in advance).

Table EX1 assesses:

- Whether there is a strong link between the electricity price paid by the EIIs and the day-ahead price; and whether the different electricity purchasing strategies allow EIIs to hedge their electricity bills against power price variations.

- The extent to which each strategy involves a price risk from the industrial facility's view point, or allows risk sharing between generators and consumers (when the EII does not self-generate electricity). Risk sharing can occur, for example, from capital investment sharing or from price risk endorsement (i.e., both parties agree to supply prices that can be somewhat independent from the wholesale market prices). Does risk sharing allow lower price volatility exposure? Does it permit EIIs to pay prices lower than wholesale price levels – and thus limit increases in electricity prices due to CO_2 prices?

- Whether EII's purchasing strategies allow them to have choice of generation technologies from the supplier.

[5] Scandinavia has the most developed derivatives market, while in Italy or Eastern Europe, organised derivative markets do not exist.

Table EX 1: **Summary of Different Purchasing Strategies**

	RELATION TO DAY-AHEAD PRICE	RISK BORNE BY EII	EII'S ROLE IN GENERATION TECHNOLOGY
Annual power contracts for baseload for a single facility/company	Low	Low	None
Aggregation of purchasers	Low	Low	None
Aggregation of purchasers – share in payment of upfront cost of capital	Depends on the contract	Depends on the wholesale price level	Strong
Day-ahead price indexed contracts	Strong	Low	None
Fixed prices and quantities	None	Low	None
Fuel indexed contracts	None	Low	None
Cross-market contracts	None	Low	None
Floating price with a cap and a floor	Yes but in a limited manner	Low	None
Contract for difference	Low	Low	None
Regulated prices	Depends on the price setting body	Low	None
Investment in generation assets alone	Depends on the mark to market intensity	Full	Strong
Investment in generation assets with several owners	Depends on the mark to market intensity	High	Medium to strong

Whether or not industrial contract prices are below the market price (i.e., day-ahead) depends on the contractual agreement between the parties. One possibility to access electricity at a price that is lower than the general market price is through sharing the risk traditionally borne by generators alone. Some EIIs have agreed to take on part of the price risk undertaken generally only by the electricity generator (e.g., by securing long-term contracts, by sharing part of the investments, etc.).[6] The industrial buyer is thus in a stronger position to negotiate the contractual price. In doing so, however, it is also exposed to the risk of a lower market price in the future.

[6] It is not because generators and EIIs have decided to cross-subsidise EII at the expense of smaller users.

Electricity Price Risk Management

One characteristic of energy-intensive users is that their profitability varies strongly according to energy prices. If such producers are unable to transfer their cost volatility onto their prices, it is in their interest to minimise the cost components' volatility. Volatility is inherent to the electricity market, and electricity prices are more volatile than other fuel commodities. CO_2 prices and their associated volatility may have participated in increasing the electricity price volatility.

Although not all options are on the table for all regions, electricity users could rely on some of the following options to manage the electricity price risks.

- Some energy intensive industries may use the services of energy management companies that hedge against electricity price variations by purchasing derivatives, when available.
- Industrial users are increasingly seeking to aggregate electricity purchases in order to gain additional negotiation power, and sign tailor-made long term contracts. This could create a greater demand for technologies with more certain operating costs, including those less exposed to fuel and CO_2 price changes (e.g., nuclear).
- Several EIIs may also be willing to take direct stakes in power generation projects, and hence exchange (at least some) carbon and electricity price risk for the risk associated with equity ownership of power generation assets.
- Lastly, EIIs may decide to self-generate electricity to ensure their supply of base-load electricity at low cost. Ownership is a physical hedge against fluctuations in electricity prices.

How these possible strategies will play out in the bigger picture of electricity markets in the EU is difficult to gauge, yet they indicate that EII are interested in pursuing new purchasing strategies – all the more so as CO_2 prices have added a new cost to electricity generation. It will be interesting to see how, as these strategies become more common, they affect investment choices and lead to an effective response to the price of CO_2 through the promotion of less CO_2-intensive generation modes.

Policy Implications

There has been an intense debate between power producers, EIIs, and governments on the legitimacy of electricity price increase as a result of the CO_2 constraint – either because some power pools have low CO_2 intensities yet saw a general rise in prices as marginal price-setting plants are CO_2 intensive, or because CO_2-intensive plants have recorded large operational profits as the result of the CO_2 pass-through, which seems to fly in the face of the "polluter pays principle". The continuation of a free allocation of allowances to existing CO_2-intensive plants and new ones (through countries' new entrant reserve) may raise growing political problems. Auctioning allowances to the power producers may not alter all electricity price effects, but would avoid the need for governmental allocation and its associated political issues. This could be a measure establishing a more level playing field between competing installations in different countries with different emission caps. If auctioned, allowances could also generate revenues that can be used by governments in a number of ways, including to mitigate the cost to specific economic actors. For example, energy efficiency measures could be financed to facilitate a response to higher electricity prices.

Overall, whether through auctioning of allowances or other mechanisms, governments should reinforce the environmental effectiveness of any CO_2 constraint on power generation, and seek to address distributional issues.[7] Emissions trading systems are only acceptable if they eventually deliver emission reductions, while still offering flexibility to capped sources.

Electricity price uncertainty and CO_2 price volatility have strengthened the need for more predictable electricity costs for industrial facilities. Not all electricity markets facilitate this objective. Governments should consider whether there have been barriers to the development of price hedging instruments and other forms of purchasing strategies. New business models are starting to emerge to address rising price levels and price uncertainty - including CO_2 price volatility: investment in self-generation capacities (alone or multiparty); risk-sharing between generators and industrial consumers.

Governments implementing emissions trading systems should work to provide as much long-term visibility as possible on the required emission constraints to power generators. The fundamental question that policy-makers must face in the design of cap-and-trade systems that affect power generation is its ability to trigger sustained reductions in emissions through proper signals to investors. Ultimately, a low-CO_2 electricity system would carry a low cost of CO_2 for electricity users, delivering both the intended environmental outcome and closing the debate on windfall profits and high costs to EIIs.

If emissions trading is to be the instrument of choice for such a goal, its rules of operation must focus on providing least-cost options to lower CO_2 emissions, and should not be used to achieve other energy policy goals (e.g. energy supply diversity) that can fly in the face of lower CO_2 emissions. Other policy goals should be promoted via other measures. The alternative can only undermine the economic efficiency of emissions trading.

[7] The alternative to opportunity cost pricing would be to only pass on to consumers the actual costs of meeting CO_2 objectives – i.e. any investment, and any purchase of CO_2 allowances to offset increased emissions. This "average cost" approach however blurs the CO_2 price signal for producers and consumers alike and could deliver a less efficient outcome overall.

3. Introduction

Climate policy is having increasing effects on energy markets, especially in the electricity sector where several governments have, or may have, introduced a constraint on power generators. What we are presenting in this paper is of importance because it explains how CO_2 and electricity prices interact. It also assesses whether this interaction affects the cost competitiveness of energy-intensive users exposed to international competition and their electricity purchasing strategies.

The IEA Information Paper on "Emissions Trading and its Possible Impacts on Investment Decisions in the Power Sector" [IEA/SLT(2003)42] concluded that introducing an emissions trading scheme was expected to increase power prices, adversely affecting energy-intensive industry costs. However, the extent of the carbon costs and of their pass through to generation prices has been subject to debate – partly on the basis of expected windfall profits in the power generation sector, as CO_2 allowances have, for the most part, been distributed for free (i.e., grandfathered).[8]

The impact of CO_2 allowances and of their pass through on retail power prices is even more complex than on generation prices. End-user prices, for non auto-generating installations, depend on a combination of different underlying arrangements in the wholesale market (EU Quarterly Review, January 2005). This means there may not be a direct correspondence between rising and falling electricity market prices and those being paid by customers.

The aim of this project is to explain that changes in electricity prices for industry installations cannot be simply attributed to day-ahead or future electricity prices variations, or indirectly to CO_2 cost movements. There are significant differences in the way each industrial installation purchases its electricity. A major challenge in this project is to gather data that represents the general situation of generators and industrial consumers alike in the EU-25 and beyond.

The impact of CO_2 allowances on retail power prices requires, among others, an analysis of contractual arrangements between industrial and power suppliers in the different countries - part of the aim of this report. However, precise data on the type of supply contracts is unavailable. Based on our knowledge and with interviews of market participants, we list the different elements we believe are part of industry electricity prices (e.g., market prices, regulated tariffs, etc.).

To give an overall picture of industry's different electricity purchasing methods, we distinguish three electricity purchasing strategies.

1. The installation purchases directly or indirectly on the electricity market (both organised or bilateral), through either short term contracts or long-term contracts;

2. The installation produces the majority of its electricity consumption;

3. The installation adopts regulated tariffs, where such an option exists.

This paper should not be considered as restricted to the European region. Two reasons explain this. The first is that, although the industrial electricity purchasing strategies described are based on interviews with European players, they may be extendable to other countries where liberalisation has

[8] In the Nordic market, the biggest windfall profits have been gained by the nuclear and hydropower generators due to the high power prices (and no extra costs due to EU ETS).

led the path to various electricity markets (e.g., Australia, North America, etc.). The second reason is that currently, there are several non-EU countries which are proposing to introduce a cap-and-trade scheme covering the electricity sector. The interaction between CO_2 and electricity markets explained in this report may be applicable to markets which have the same price-setting formation The two most recent are regional or state initiatives in the United States (e.g., California, the Regional Greenhouse Gas Initiative in 7 North Eastern states), and state or national in Australia. Although none have led to implementation, power generation is usually a core element of these systems.

Table 1 highlights the main differences between the proposed systems.

Table 1: **Non European Cap-and-Trade Schemes covering the Electricity Sector**

	PROPOSED SYSTEM IN AUSTRALIA	PROPOSED REGIONAL GREENHOUSE GAS INITIATIVE	NEW SOUTH WALES SYSTEM	PROPOSED SYSTEM IN CALIFORNIA
Gases	6 GHG	CO_2	6 GHG	CO_2
Sources	Stationary energy (including electricity plants with a capacity above 30MW)	Only electricity generation plants with a capacity of 25MW and greater that burn more than 50% of fossil fuel and sell more than 10% of their output to the grid. There is a possible extension to other sources in future	NSW electricity generators that supply directly to retail customers (i.e., >100GWh per year), and some major energy users, collectively referred to as benchmark participants***	Energy-use activities of California's leading utilities, the state's up- and downstream oil sector, as well as other as-yet-unnamed large source GHG emitters
Allocation	10 year allocation in three broad trenches: 1/some permits will be allocated for free to those existing generators estimated to be significantly adversely affected by the scheme; 2/ some permits will be allocated for free to firms in trade-exposed, energy-intensive industries;3/ the remainder of permits will be auctioned.	20% to a Public Benefit Purpose*; 5% to Regional Strategic Carbon Fund; the remainder at the discretion of the states	Yearly allocation. The State benchmark is multiplied by the total state population and the total volume of electricity sales to produce the electricity sector benchmark in tCO_2e. Each participant is allocated a share of the benchmark relative to its share in the total state electricity demand. That allocation is then compared by multiplying each retailer's purchased electricity volume by the state benchmark,	Not yet decided
Allocation basis	Free allowances to generators should reflect the anticipated reductions in operating profits that those existing generators would experience under the scheme, calculated in net present value	Equivalent to the average emissions of the highest 3 years between 2000 and 2004.	State GHG benchmarks (CO_2 per head of State population) are to be the basis for the calculation for the GHG benchmark for each benchmark participant	Not yet decided

	terms over a 20-year period.			
New entry allocation	New generators should not be entitled to receive free allowances.	New source set-asides will be created at the discretion of each state.	Intensity based allocation	Not yet decided
Timescale	Possible start 1.1.2010	1.1.2009 (to 2018)	2003-2012	? - 2020
Non-compliance penalty	Sources are not asked to offset their emissions above a target, but pay a penalty on the excess emissions.	Yes. Penalties and enforcement similar to NOx program – 3 allowances surrendered for each ton from next year's account (no automatic monetary penalty).	Yes. AUS$10.5/t shortfall Safety valve	Not yet decided
Use of offsets	Yes	Yes but limited to 50% of the difference between the projected business as usual emissions and the emissions cap. The amount allowed may increase with the price of carbon.	Yes	Not yet decided
Banking	Yes, unrestricted	Yes, unrestricted	Yes for some project types	Not yet decided
Unit	1 metric ton CO_2-eq	1 short ton CO_2-eq	1 metric ton CO_2-eq	Not yet decided

* Public benefit purposes may include the use of allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, promote renewable energy technologies that will reduce emissions of CO_2 from power generation in the state.
** the Strategic Carbon Fund shall be used to achieve additional environmental benefits through the development of projects that achieve supplemental GHG reductions and carbon sequestration beyond that required to achieve the cap.
*** Full details on the scheme are available at www.greenhousegas.nsw.gov.au
Sources: IEA, 2005a; Ellis and Tirpak, 2006; different scheme proposals

4. Definition of Terms and Methodology

Electricity markets can include both day-ahead and future prices. In this paper:

- Forward and future electricity prices are assumed to have one meaning: purchasing at a price fixed in advance for delivery in the future.

- Day-ahead prices are considered to be spot prices.[9] The electricity spot market in Europe is essentially a day-ahead "pre-balancing" market allowing to exchange megawatt hours in the best possible market conditions, in order to respect commitments towards the transmission network (Powernext).[10]

Transactions on the generation market can either be physical or financial.

[9] Spot prices also include intra-day prices for balancing, but these will not be looked at in this report.
[10] Hence, the electricity spot market should not be considered equivalent to a spot price in commodity price hedging markets, which is the price at which an asset changes hands on the spot date.

- **Physical markets** (differentiating between peak and off-peak electricity) include the **balancing market** and the **spot -** intra-day and/or day-ahead markets - which can be both on power exchanges and bilaterally (so-called over-the-counter or OTC).

- **Financial markets** including futures contracts (i.e. traded on an exchange) and forward contracts which are generally traded bilaterally. Some futures and forward contracts can nevertheless entail physical delivery.

Energy-intensive industries are defined as industries whose purchases of energy products and electricity exceed a certain threshold. These contain the iron and steel, aluminium, cement, paper and pulp and chemical sectors among others.

To evaluate whether industrial facilities are exposed to the pass-through of CO_2 allowances on market prices, the methodology is the following.

- The **different electricity markets** are listed (see 6). The relevant market prices per country or region are estimated based on external sources. In the case where forward prices are the main indexation in supply contracts (and not regulated prices for example), we question whether there is a relation between forward prices and day-ahead prices.

In an EU-25 comparison, the aim would be to compare the different ranges of spreads (i.e., the difference between market price and generation costs of the marginal producer, where the opportunity costs of CO_2 allowances are in theory added) – and see whether underlying factors can explain differences (e.g., market concentration, regulatory intervention, etc.). However, lack of data makes this an arduous task because it would require knowing the bidding strategy of all price-setting power plants across Europe (i.e., for day-ahead prices) or traders and market players (i.e., for forward prices).

- The **combination of different underlying supply arrangements for industry** in EU-25 are listed (i.e., through a supplier/generator, regulated tariffs, directly on an organised or brokered market, etc.) – see 7. For each contractual arrangement, we indicate its relation to generation prices.[11] By estimating this relation, the indirect impact of CO_2 price variations on prices paid by industrials is also discussed. This section is verified and approved by the market players (e.g., industry, suppliers).

- There are different load and consumption profiles for industry. Nevertheless, we focus on industries with essentially baseload bulk consumption. In this paper, it is presumed that industrial facilities needing flexible consumption cannot buy it in advance. They can only buy it on short term markets (i.e., day-ahead or balancing market) and are, as a result, exposed to more volatile prices. In section 7, the increase in production costs following the EU emissions trading scheme will be appreciated by comparing the electricity price paid under each agreement for bulk consumption with market prices. Our purpose here is to shed light on such **electricity supply strategies**, from the stand point of electricity cost and exposure to price volatility. We indicate the possible merits and demerits of various purchasing strategies, and whether risk sharing between generators and industrial users, when possible, allows lower exposure to price volatility. Section 7 will also expose the impacts of a CO_2 emissions trading system on EIIs risk management strategy

[11] i.e., the production costs of the marginal generator.

with respect to electricity supply and purchasing. In the case where electricity prices are not regulated, risk management of electricity prices may theoretically be done through several channels: the use of market derivatives (e.g. hedging contacts or price-indexed contracts); energy management companies that manage the electricity price risk for EIIs; self-generation; or risk-sharing between the electricity generator and the electricity consumer.

- Section 8 will focus on the **self-generation option as a hedging instrument**. The aim is to see whether the design of the emissions trading scheme in the different EU countries encourages a CO_2-free electricity market. The aim is also to expose how uncertainty in climate change policy may influence the investment decision.

5. The First Years of the EU Emissions Trading Scheme (2005-2006)

5.1 Main Drivers of CO_2 Prices

This section is mainly aimed at setting the context of CO_2 price evolution over the first year of trading. The main drivers of CO_2 price variations are shortly recalled, focussing on the importance of electricity production in the overall level of prices.

CO_2 now has a price for those companies that are subject to emission caps, or wish to voluntarily offset their emissions. Some governments are purchasing CO_2 quotas from other governments, or based on greenhouse gas reduction projects. The European Union has brought this logic a step closer to reality. Since January 1, 2005, under the EU emissions trading scheme (EU-ETS), some 11,500 plants across the EU-25 are capped in their CO_2 emissions, and have been able, since 1 January 2005, to buy and sell permits to emit carbon dioxide (EUAs), covering about 45% of the EU's total CO_2 emissions. These installations include combustion plants, oil refineries, coke ovens, iron and steel plants, and factories making cement, glass, lime, brick, ceramics, pulp and paper. Table 2 highlights the main features of the EU ETS.

Table 2: **Key Features of the EU Emissions Trading Scheme**

FEATURES	DESCRIPTION/REQUIREMENTS
Type of target	Absolute target, e.g. X tCO_2e. One allowance in the EU-ETS allows the owner to emit one tonne of CO_2e; its validity is limited to a specific period.
Allocation mode	During 2005-2007, mostly free allocation by Member states following common criteria Up to 5% auctioning allowed during 2005-2007 Up to 10% auctioning allowed for 2008-2012
New entrants	Member States shall take into account the need to provide access to allowances for new entrants; how and how much is to be decided by each Member State.
Plant closure	Member States shall decide whether allowances should be surrendered or can be kept by plants after closure. Likewise, the transfer of those allowances to a new facility (on the condition that both are owned by the same company) is to the discretion of each member state.
Penalties	A non-compliance penalty tax of €40 per tonne of excess CO_2 emissions in the first compliance period and of €100 in the second period, plus restoration of the GHG emitted without having surrendered allowances.

Source: Reinaud, 2005

The sector whose share is the largest in terms of total emissions covered under the first phase of the EU ETS is the power sector. This sector represents over 50 percent of the total CO_2 emissions covered by the scheme. Its emission abatement costs are also thought to be the lowest compared to the other sectors covered – notably through fuel switching from coal to gas and from lignite to coal.

There is a significant difference between energy commodities and CO_2 allowances (EUAs). There is not, *a priori*, a daily or hourly need for emission allowances, while industrial installations hinge on a steady energy supply to operate. Installations subject to the EU ETS only need to hold allowances matching their emission levels once a year. Further, they have been allocated the vast majority of their needs already under the first national allocation plans (NAPs). That said, traders are clearly seeking to hedge against price movements and to maximise profits from their speculative activity. However, this fundamental difference between CO_2 and standard commodities may make this market structurally less liquid and deep than, say, oil markets.

A number of factors influence the price of carbon under the EU ETS:

- *The overall stringency of caps imposed on installations.* This is a function of the initial allocation – how much lower is it from business-as-usual emission projections? – and the economic environment of the underlying activities. For example, a sustained steel demand from China would obviously increase emissions in the near term and drive up demand for allowances. Similarly, demand for electricity-intensive products would also put pressure on the power sector to reduce emissions;

- *External supply of project-based mechanisms.* An abundant supply of project-based credits (i.e, certified emission reductions - CERs - and emission reduction units - ERUs) could have a dampening effect on the price, as project-based reductions are generally expected to cost less than EUAs. This is borne out by current observations: project-based units being priced mostly at EUR 13-15 per tCO_2 in August 2006 for delivery in 2007 and EUR 6-13 per t CO_2 for delivery in 2009-2012 against EUR15-20 for spot EUAs (Point Carbon). It is not clear, however, that CDM and JI can deliver large enough volumes of credits to meet a significant portion of Kyoto Parties' demand. On the other hand, a limited demand for EUAs could increase the relative importance of project-based units;

- *Relative fuel prices.* For some industries, especially power generation, the price of gas relative to the price of coal affects operating choices. A relatively high gas price encourages more use of coal, which should drive up demand for CO_2 allowances, all other things equal, as coal emits twice the CO_2 content of natural gas. If such phenomenon is sustained and EUA supply becomes tighter, CO_2 prices may reach a level that allows gas, a cleaner fuel, to be more competitive again.

- *Weather (temperature, rainfall, cloudiness).* Power generation represents the majority of the total EUA allocation. Hence, factors that affect power generation are bound to affect the supply and demand of EUAs. A dry year in Scandinavia is likely to trigger more demand from fossil-based generators and increase emissions – a situation that has frequently caused Denmark's emissions to rise significantly, as its coal-based generation capacity was replacing the reduced hydro-based generation from Norway and Sweden. While this illustrates an impact on emissions, even measured against an annual total, it is less clear how day-to-day temperature variations should impact CO_2 prices – even if this has been reported as a factor by financial information services.

- *Regulatory features.* Several national allocation plans (NAPs) specify, in most instances, that EUAs that are yet to be allocated will be lost upon closure of a plant, e.g. for year 2006 if closure took place in 2005.[12] The possibility of selling unused allowances due to plant closures is therefore minimal. Consequently, installations are less likely to resort to such measures as a means to reduce emissions. This should, in a tight market, put upward pressure on prices.

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[12] For instance: Austria, Denmark, Finland, France, Sweden, and the United Kingdom. Others, like Germany, Hungary, Portugal, or Slovenia make it possible to transfer to firms that are opening plants.

- *Policy uncertainty.* Climate change is inherently a long-term, uncertainty-ridden challenge, on its scientific, technologic and economic side. Given that political systems are skewed towards addressing more immediate concerns, few governments are well prepared to consider and adopt long-term action against long-term risks (Blyth and Yang, 2006).[13] The fact that there will be ongoing new allocations and targets means that investors will only have a short (3-5 years for the first and second commitment periods) foresight into ETS (which will be the potentially most important value driver) when they commit themselves to a 20-30 year investment (IEA, 2004). It represents the risk that irreversible investment decisions will be based on pre-implementation expectations of climate change policy, and that the actual marginal cost of abatement may differ from those expectations. Uncertainty may therefore lead to a delay in investment- thus impacting the overall level of CO_2 allowance prices (Blyth and Yang, 2006).

- *Other Market Price Drivers*:

    - Opening of registries. At the early stage of the market where most allowances registries were not operational, it is likely that trading was motivated by speculative purposes, as opposed to compliance purposes. Theoretically, it is only when a significant demand for allowances is driven by compliance needs that the price reflects the actual marginal cost of an avoided tonne of CO_2 in the market.

    - Abatement options. While marginal CO_2 abatement cost might, in the long-run, direct investments towards abatement projects, fuel switching from coal to gas or from lignite to coal for power and heat production is probably the single most important measure in the short term. This is firstly because the power sector is the largest in terms of emissions for most of the Member States. Secondly, coal emits about twice that of natural gas per consumed unit.

    - Hedging strategies of power producers engaged in forward transactions. According to NERA, in practice, generating companies sell nearly all of their output in advance, in forward contracts.[14] When generators (or traders) contract such agreements, they secure their positions simultaneously on the electricity and fuel markets. The current practice is to include CO_2 allowances as production costs components. Thus to secure margins captured by those trades on any particular date, the forward prices of EUAs on that date are included. This allows generators (or traders) to fix the margin to be earned.

Figure 1 highlights the price evolution of CO_2 allowances since 2003, a year when it was traded bilaterally. The high volatility over 2005 is essentially attributed to the announcements of the NAPs for the first trading period – which determine the overall stringency of the cap imposed by each member state, and also to the illiquid nature of the market in its early stages.[15]

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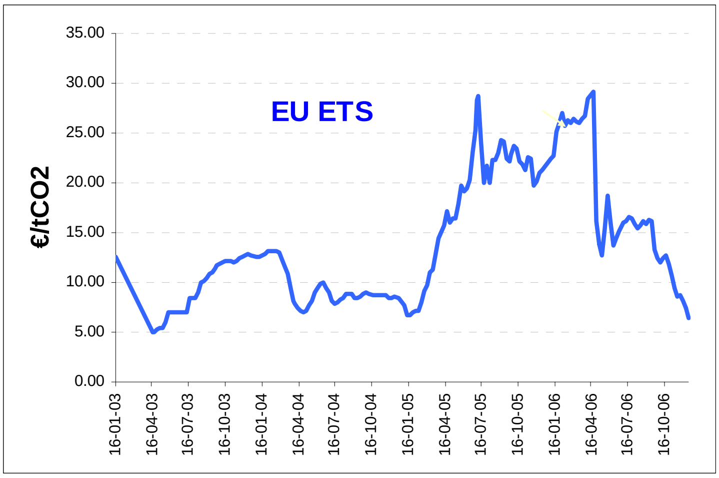
13 There are two main sources of climate change policy uncertainty: *Regulatory risk* which comprises uncertainty associated with the introduction of new measures to address climate change (i.e. the timing, extent and form of policy), deferred decisions associated with policies that have already been implemented (e.g. future permit allocation under the European Union Emissions Trading System), and intervention risk (i.e. a change in policy direction) and; *Implementation risk* which comprises uncertainty associated with the efficiency and effectiveness of climate change policies that have been announced but are yet to be implemented.

14 Nevertheless, this does not prevent them to be active on the spot markets.

15 See http://www.iea.org/textbase/work/2005/5ghg/2_buen.pdf for a more detailed explanation on 2005 price volatility.

Figure 1: **CO_2 Price Evolution in the EU ETS**



Source: Point Carbon

According to market analysts, the price of CO_2 is no longer the result of a simple calculation of what it would take to convince a coal-based generator to stop and operate a gas plant instead. This implicit rule applied until July 2005. After that date, the majority of registries opened, granting access of allowances to sellers – coal to gas, if it ever was, was no longer the marginal means of delivering avoided emissions, as confirmed by the results of the first year. Moreover, May 15, 2006 is the day when the European Commission published emissions data from installations included in the scheme and made known an excess in supply of allowances for 2005. This information led carbon prices to collapse; although the tumble started before, when the first countries reported that actual verified emissions during 2005 were 10 percent or more below the allocations they had granted to their industries. Participants realised that there were going to be far more spare allowances out to 2007 than they had thought.

5.2 Actual Cost Components of Generating Electricity

Electricity prices are determined by a multitude of physical conditions such as weather, hydrology, outages, fuel costs and the impact of environmental policies and measures, for example emissions trading, and by market factors such as the demand-supply curve and investment needs. This multiplicity of factors as well as the non-storability of this commodity makes it difficult to forecast any electricity prices. [16]

Several technologies generate electricity in the EU-25. Naturally, the evolution of their cost components strongly influences generation prices over the recent years. It is reasonable to say that coal, natural gas and fuel oil prices are essential in explaining electricity prices variations across Europe as they are the dispatched technologies which participate in forming the day-ahead market most often.

[16] In the marginal dispatching electricity model which is the dominant model in Europe, the bidding prices on the spot market include only the variable costs. Variable costs comprise mainly in fuel prices, operational and maintenance costs and CO_2 emission allowance costs since 2005 in European markets. Costs of capital or any fixed costs are not included.

5.2.1 Natural Gas Prices

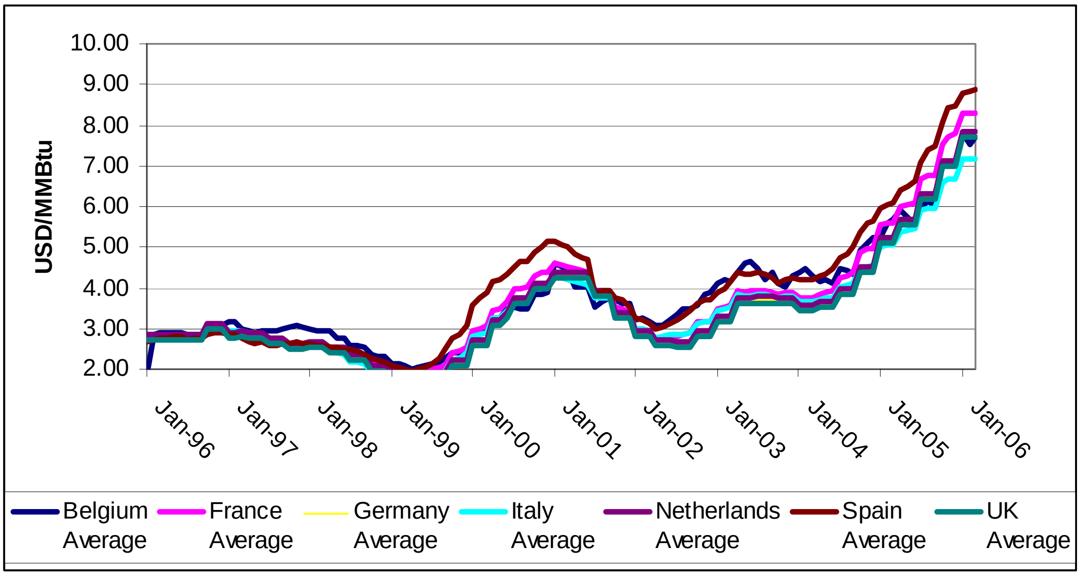
Natural gas-fired technologies, mainly combined cycle gas turbines, are often the marginal technologies which set the peak electricity price on day-ahead market. Gas-fired technologies may also often set off-peak prices, namely in the Netherlands, in Italy and in Spain. These facilities may drive base-load prices during spring and summer where generators supplied by yearly take-or-pay contracts need to burn their gas instead of losing it. Consequently, developments in the gas markets have a direct impact on the electricity market – both in terms of the price level and price volatility.

Much of continental Europe has been importing gas for a long period, principally from the CIS and Algeria, as well as Norway and a few other countries. The price of these bilateral contracts has been linked to the international oil market since the beginning of the import/export relationship, with contracts renewed along similar lines each time they expired. These contracts take into account the prevailing economics of demand and supply of gas to a limited degree – unlike in liberalised markets such as North America and the UK, where the price has tended to develop according to the balance of supply and demand - , by adjusting the variables in the formulae (IEA, 2006). [17]

In the last few years, gas prices have sharply risen as illustrated in Figure 2. This is true for both gas imported on the basis of long-term contracts with an oil-linked price and prices on the few traded markets in Europe. Several factors explain this increase in Europe- two, in particular, which point to a steady increase in oil prices; a tightening of environment constraints which tend to encourage the use of natural gas as opposed to the consumption of oil or coal.

[17] The logic for this indexation to oil was that to maintain competitive pricing between gas and its principal substitutes, it should be priced with reference to them to preserve market shares. Principal uses for natural gas are for power generation, where it can be replaced by gas oil (diesel) and for home-heating and industrial boilers which are also markets for low-sulphur fuel oil. The price of gas is therefore usually linked to those two products over a period of six to nine months to smooth volatility, and rebalanced by a factor to equate the energy content of the three fuels. In certain countries, such as Italy, this arrangement is modified to some degree by using a basket of oils rather than one or two products (IEA, 2006).

Figure 2: **European Import Gas Price Evolution**



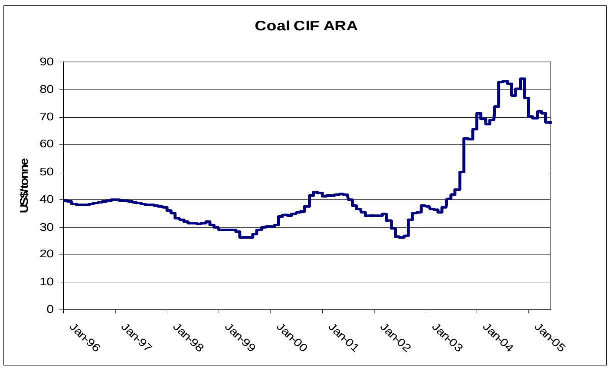
Source: 2003 Energy Intelligence Group

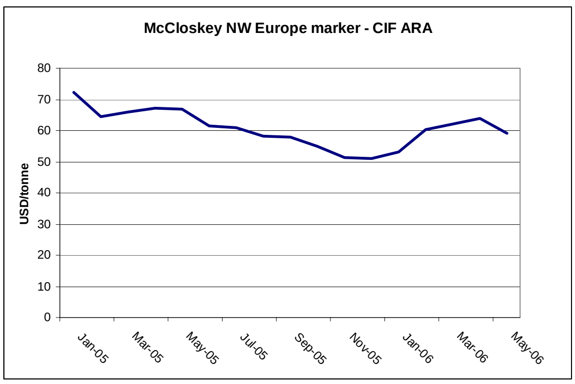
5.2.2 Coal Prices

In countries where large capacities of coal-fired facilities have been installed, coal often sets the base-load price. This is the case in Germany, Estonia or Poland.

There is no "official" market place or marker for coal. Spot prices are always estimates coming from discussions between coal market players and published in two or three main coal newspapers. Antwerp, Rotterdam, Amsterdam (ARA) are the main coal-importing ports for North-West Europe and are used as a basis for price quotations for all deep-water ports in North-West Europe. Nevertheless, the ARA index price gives a good approximation of the European coal import prices for countries which do not produce coal domestically.

Figure 3: **Coal ARA Prices (US$/tonne)**





Source: The McCloskey Group

Over 2005-2006, European demand for coal was driven by high oil and gas prices, despite high CO_2 prices. CIF ARA prices have increased since 2004, but its volatility is less than that of natural gas prices on the spot market. 2007 and 2008 forward prices for coal ARA are also growing and a tonne was traded around US$ 68 in July 2006.

5.2.3 Fuel Oil

In countries such as France and Lithuania, oil-fired electricity may set the price for peak or super hours. Since 2004, price of standard crude oil has increased, and reached a record price of $75.35 per barrel in April 2006. As crude oil is the main feedstock for fuel oil, this has led to an increase in electricity prices for peak, wherever fuel oil generation is in operation at peak.

The rise in electricity prices over the last few years has happened in a context of high fossil fuel prices, with an upward trend in oil and gas prices. Since 2005, electricity prices have been affected by two major fundamental changes: an increase in fossil fuel prices and natural gas in particular, and the introduction of a CO_2 price, itself boosted by gas prices. The two factors have been compounded into higher market prices – and costs - for energy-intensive users.

5.3 Is there a CO_2 Pass-through Component in Power Prices? CO_2 Allowances and theoretical Impacts on Generation Costs and Market Prices

The aim of this subsection is to explain how CO_2 allowances affect generation costs. We will provide the different ranges of pass-through found in literature, first discussing its theoretical legitimacy, and then limits to full opportunity cost pricing.

5.3.1 Theory of CO_2 Pass-through onto Power Prices

In theory, the value of carbon emission allowances should be reflected in the plants' generating costs, assuming that it is driven by profit maximisation.[18] Generation always competes with the possibility to sell the unused allowances on the market – at the carbon market price. This so-called opportunity cost exists whether the allowances were grandfathered (allocated freely) or auctioned to companies.

If we assume that the generator maximise profit, whether there is full competition or the market structure is oligopolistic or monopolistic, the pass-through rate will also be of 100 per cent (see Sijm et al, 2005 Section 4.4 and Appendix B). Nevertheless, this does not imply that power prices will increase by that amount. Although counter-intuitive, the more concentrated the market, the smaller the total increase in prices. Overall power prices will be higher under monopoly, but the rise in prices due to the pass-through should be lower.[19]

However, the decision to pass on the full opportunity cost of allowances or only part of it may vary depending on several factors (Reinaud, 2003). The most important elements are:

[18] Nevertheless, it may be that certain power producers pursue other strategies than near-term profit maximisation. They may seek to maintain a market share, i.e. to be dispatched against competitors, in which case they now have the opportunity to cut the level of CO_2 pass-through. While this represents a loss from the full opportunity cost, it cannot be ruled out, given the free allocation to generators.

[19] According to Sijm et al., actually, the pass through is 100 percent, but under monopolistic conditions 50 percent of the pass through is absorbed by a lowering of the monopolistic price mark-up.

Elasticity of demand

With regard to the passing through of CO_2 costs, Sijm, Neuhoff and Chen (2006) distinguish between the behaviour of individual generators and the impact on the price system as a whole by defining the 'add-on' and the 'work-on' rate. The 'add-on' rate is the extent to which individual generators pass on CO_2 costs into their bidding prices (which is usually 100 percent). The 'work-on' rate is the rate that is effectively passed-on to the power prices on the market (which is often less than 100 percent due to a variety of reasons). "One reason why the work-on rate may be lower than the add-on rate is market demand response." Higher electricity prices may reduce the total demand, and prevent an expensive generation unit to operate as the marginal producer. The electricity price will thus be lower, but the variation in price will be lower than the change in marginal costs due to emissions trading. As a result, the add-on rate will remain at 100 percent and the work-on rate will be lower than 100 percent.

The allocation mode

- *Updating.* According to Neuhoff et al (2005), the opportunity cost of emitting CO_2 may be reduced when allocation is updated. They argue that updating implies a cost of not-emitting: high emissions today hold the promise of a higher allocation tomorrow. In case of updating and an elastic power demand, power producers will not pass on the full opportunity costs as this will reduce their output/emissions and, as a consequence, the amount of free allocations in the next period. Hence, they will balance these two (opposing) effects until an optimal equilibrium is reached (Sijm et al, 2005). Overall, if updating is applied beyond the first commitment period, it may not only reduce today's electricity prices but also future electricity prices (*op cit*).

- *Treatment of new entrants.* In the case new entrants need to pay for all CO_2 emissions, incumbents may be encouraged to pass-through the opportunity cost of CO_2 allowances. Nevertheless, if their aim is to build barriers to market entry, then they may be encouraged not to pass-through the full opportunity cost. In the case where new entrants receive allowances for free, it may result in a reduction of the so-called fixed cost margin of the power price and, hence, over time, to a lower power price (see Section 4.2 of Sijm et al 2005).

Regulatory intervention

In some European countries (i.e., Ireland, Spain), governments announced they would impose a limit to an increase in power prices following the start of the EU emissions trading scheme (EU ETS). Two types of regulatory interventions exist: those which influence liberalised prices, and regulated prices. In the case of Ireland, the regulator declared that price increases from the public generator would be restricted to 2-5 percent. This limit would not apply, however, to private generators.

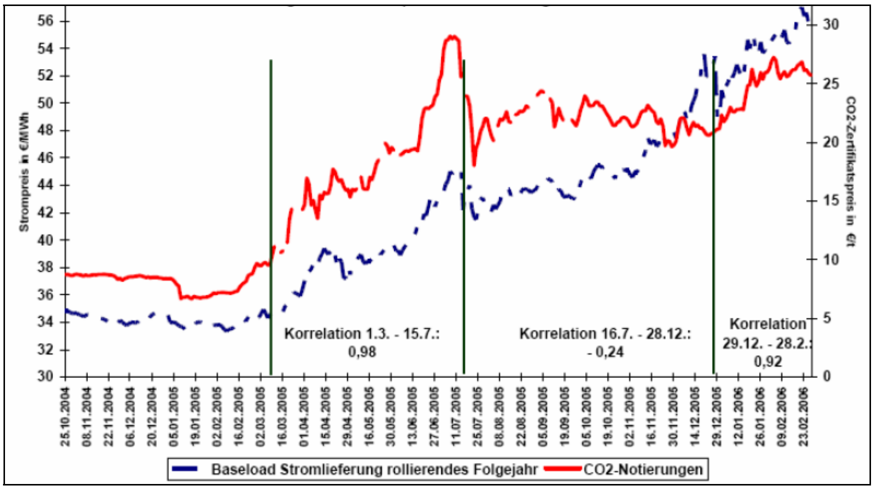
In a report from the Energy Information Administration which assesses the impacts of a greenhouse gas emissions regulation on electricity prices in the US through a cap-and-trade scheme, it is expected that if a portion of allowances is provided for free to regulated utilities, "regulators are expected to pass these savings on to consumers" (EIA, 2007). Increases electricity prices equivalent to the opportunity costs of free allowances would not occur. The report concludes that "the impact on electricity prices is slightly smaller than in a full auctioning scenario". It also notes that "in contrast, in regions where electricity prices are set competitively, the changes relative to the reference case are the same in both partial and full auction cases”.

5.3.2 Empirical Studies

5.3.2.1 Evidence of a strong Correlation between CO_2 and Electricity Prices

In several European countries, a strong correlation between CO_2 prices and electricity prices has been shown – as illustrated in Figure 4 for German base-load electricity prices. Nevertheless, the strong correlation decreased between July and December 2005 when CO_2 prices remained constant. As mentioned in 5.1, after July 2005, the majority of registries opened, granting access of allowances to sellers – coal to gas, if it ever was, was no longer the marginal means of delivering avoided emissions.

Figure 4: **Correlation between Base-load Electricity Prices and CO_2 Allowance Prices in Germany**

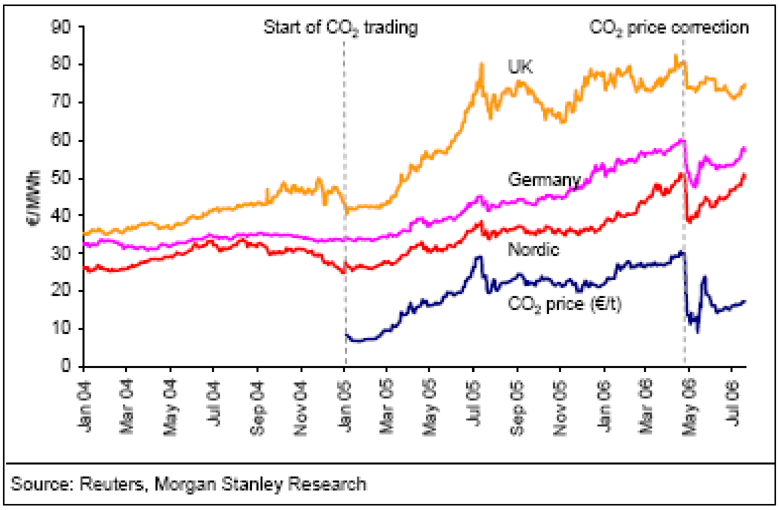


Source: VIK, 2006 [20]

Moreover, the effects of the drop in CO_2 prices on the day-ahead prices in May 2006 clearly demonstrate the reality of the pass-through. Carbon prices dropped by more than 50 percent mid-May 2006 upon reports that the Czech Republic, Estonia, France, the Netherlands and the Walloon region emitted far less CO_2 in 2005 than initially anticipated by the market (see Figure 5). As a consequence, power prices on the European market exchanges dropped. A 10 EUR/tCO_2 fall in the price of EU allowances was immediately followed by a drop in electricity prices of at least 5-10 EUR/MWh in Europe (Point Carbon).[21]

[20] http://www.vik.de/fileadmin/vik/Stellungnahmen/2006-04-21/SN_preliminary_findings_sector_inquiry.pdf
[21] http://www.euractiv.com/en/sustainability/crashing-carbon-prices-puts-eu-climate-policy-test/article-154873

Figure 5: **Electricity and CO_2 Prices between January 2004 and July 2006**



Source: Cartal, 2006 sourcing Morgan Stanley

The low correlation between CO_2 prices and power prices between July and December 2005 (Figure 4) implies that changes in power prices can not be adequately explained by changes in carbon prices (but are largely due to other factors). However, this does not imply that producers did not pass on carbon costs to power prices.[22]

The following two chapters will review literature on the pass-through assumptions or estimations in several European countries, namely Finland, Germany and the Netherlands.[23]

5.3.2.2 Empirical Study of EU ETS Price Impacts on the Finnish Electricity Market

A Finnish study (Honkatukia et al, 2006) proceeds to empirically assess the developments of the EU ETS in the first 16 months. Based on econometric calculations from the collected data, the estimated results indicate that, on average, approximately 75 to 95 percent of the price changes in the EU ETS are passed on to the Finnish Nord Pool day-ahead prices.

The authors analyse the development of daily and hourly Nord Pool prices in the Finnish market area of Nord Pool and test their correlation regarding several factors: various scarcity capacity indicators, input cost indicators such as the prices of coal, natural gas and CO_2 allowance prices, and demand shaping indicators (e.g., weather, working day or week-end, etc.). They run three econometric models on Finnish electricity prices running from February or May 2005 to May 2006. [24]

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[22] Similarly, if during a certain period changes in power prices can not be adequately explained by changes in fuel prices – because other factors are more important during that period – this does not imply that producers do not pass on fuel costs during this period.

[23] Studies other than the several mentioned in the report also seek to evaluate whether electricity prices have increased following the implementation of the EU ETS (e.g., Newberry, 2005 and Levy, 2005).

[24] The three econometric models are: the error correction model which is convenient for the simultaneous analysis of long-run, equilibrium relationships between variables as well as for their adjustment to deviations from these equilibriums in the short term; ARMIA – Autoregressive Integrated Moving Average, a model expressed in terms of differences and; AR-GARCH – Autoregression – Generalised Autoregressive Conditional Heteroskedasticy where the level of electricity price is related to levels of explanatory variables.

The authors also simulate to what extent the passing on of allowance prices varies when the state of the power system varies (and hence the power prices), as illustrated in Table 3. Increases in EUA prices of 15 percent, 25 percent and 50 percent are used, assuming a baseline level of EUR21.30 per ton of CO_2. The presented indications for the extent to which the prices of the EU ETS are passed on to electricity prices reflect a situation of the past over historic data from May 2005 to May 2006.

Table 3: **Shares of Rise in EUA Prices passed on to the Electricity Spot Price for different Single Day EUA Price Increases for different Typical Loads**

	LOW LOADS	**MEDIUM LOADS**	**HIGH LOADS**
Variation in percentage	Share of variation in EUA price passed onto spot price		
15%	0.47	0.97	1.11
25%	0.45	0.94	1.07
50%	0.43	0.89	1.02

Source: Honkatukia et al., 2006

What are the mechanics of these differences? At low loads, non-fossil generation technologies can compete with fossil fuel technologies more effectively. This implies that the tendency to pass-on 100 percent of the CO_2 costs is less since fossil-fuel technologies may risk losing all the market if they do so.

According to the authors' estimations, higher loads lead to higher shares of EU ETS price increases passed on to spot electricity prices. Generally, higher loads imply more fossil-fuelled, higher CO_2-emitting capacity on the market and hence an increased need for covering emissions with allowances. On the other hand, higher load levels also correspond to lower competition levels and consequently greater possibilities to increase prices (hence the share of variation in EUA prices onto spot prices above 100 percent). The results also show the larger the price change on the permit price in a day, the smaller the share of EUA price variation is passed on.

5.3.2.3 Ilex, 2004

According to a report by Ilex (2004), in the several European electricity markets studied, it is likely that CO_2 allowance prices will be passed onto electricity wholesale and retail prices as illustrated by Table 4. Key elements influencing the pass-through rate include the market structure (MS) of generation, new entry and closure rules, tightness or looseness in NAPs (NAP-T/L) and the influence of government and regulators (RP). Ilex makes a general assumption for all countries that there will be a full pass-through of CO_2 allowance prices onto wholesale and retail prices unless there are specific reasons for expecting otherwise. In those countries where there is incomplete pass-through, regulatory or political intervention is the main factor that will curtail price rises. Nevertheless, in its report, Ilex assigns relative confidence levels to its estimates, *1* being low confidence, and *3* being high. They mention uncertainty with respect to Germany in particular: full pass-through is by no means guaranteed as a result of a relatively achievable NAP, dominant generators, and uncertainty as to the level of intervention by the regulator.

Table 4: **Ilex Estimation of CO_2 Allowance Pass-through onto Wholesale and Retail Electricity Prices in several EU Countries**

	PASS-THROUGH ON WHOLESALE PRICES	PASS-THROUGH ON RETAIL PRICES	DETERMINANTS IN THE PASS-THROUGH	CONFIDENCE IN THEIR JUDGEMENT (HIGH =3, LOW =1)
France	100%	2.5%	RP	2
Germany	100%	100%	RP, MS, NAP-L	1
Ireland	100%	23%	RP	3
Italy	0%	0%	RP, NAP-L	2
Netherlands	100%	100%	MS, NAP-T	2
Nord Pool	100%	100%	NAP-T	3
Spain	8%	8%	RP	3
UK	100%	100%	MS	2

Source: Ilex, 2004

Countries such as Ireland, Italy, Spain and France, are the markets where the pass-through rate is expected to be less than 100 percent.

- The Irish energy regulator has made clear that it intends to limit the pass-through. It has indicated that it might use adjustments in transmission and distribution charges to ensure that the full pass-through of carbon into wholesale electricity prices does not feed through into retail prices. Ilex estimates that retail prices may only increase by the amount that reflects the real cost incurred by generators (i.e., estimating a 23 percent shortfall in the total allowances).

- The 0 percent pass-through rate in Italy is explained by the anticipated regulated increase in power prices in the country. Ilex explains that considering the already high price levels in Italy, it expects that government will ensure that wholesale prices will not rise by more than the overall cost expected to be incurred by generators.

- Spain's case is similar to that of Italy. The Spanish regulator is expected to regulate price levels to ensure that market prices do not rise more than generator's overall costs. At the time the Ilex study was published, the draft Spanish NAP indicated an 8 percent shortfall of allowances for the electricity sector.

- In France, according to Ilex estimations, retail prices have traditionally been insensitive to changes in market prices. Ilex believes that retail prices will remain relatively unaffected by the EU ETS, although they may increase by the amount of shortfall of French electricity generators (i.e., 2.5 percent).

Ilex also analyses whether carbon allowances are built into forward electricity prices for 2004 to 2006. However, their analysis is inconclusive. Reasons stem from the illiquid nature of the carbon market in 2003. At the end of 2003, apart from England and Wales, electricity prices in Europe had not begun to include the impact of carbon prices.

5.3.2.4 Sijm et al, 2006

To estimate the CO_2 pass-through rate onto power prices, Sijm et al (2006) rely on empirical and statistical analyses of trends in prices of fuels, CO_2 and electricity in Germany and the Netherlands over the period January-July 2005. Rates of pass-through of CO_2 costs onto power prices are estimated based on four cases: Germany for peak and off-peak hours where prices are mainly set by coal-fired producers; the Netherlands for peak and off-peak hours where peak prices are set by gas-fired plants while off-peak prices are fixed by coal plants.

Table 5 provides the authors' estimates based on several methodologies:

- Two statistical regression approaches called the Ordinary Least Squares (OLS) method and the Prais-Winston (PW) method, and;

- One simple regression-line approach developed by ECN.[25],[26]

The difference between the OLS and PW methods mainly concerns the incidence of so-called autoregression or autocorrelation among the data used. The existence of such autocorrelation could bias the estimated results. While the PW method corrects for this incidence/bias, the OLS does not.

The method developed by ECN is based on an analysis of dark/spark spreads over a certain period, both excluding and including CO_2 costs. When the costs of CO_2 are included, these are called clean dark/spark spreads (see Box 1 for definitions). The authors assume that the trend line of these spreads in Germany and the Netherlands should be flat when including the CO_2 costs, assuming in effect that all remaining variations of these spreads can be attributed to random variables with an expected value of zero. The method consists in solving for the pass-through rates that will satisfy this condition.

Box 1: **Definitions of Different Spread Indicators**

Dark spread: the difference between the power price and the cost of coal to generate a unit (e.g. a MWh) of electricity.

Spark spread: the difference between the power price and the cost of gas to generate a unit of electricity.

Clean spreads: the difference between the power price and the cost of fuel – including carbon costs – to generate a unit of electricity. This is an indicator for the coverage of other (non-fuel, non CO2) costs of generating electricity, including profits. These other costs are, for example, maintenance or operating costs, or investment costs.

25 The Ordinary Least Squares method is a standard linear regression procedure used to analyse associations between a continuous dependent variable and either categorical or continuous independent variables.

26 The Prais-Winston transformation is an improvement to the original Cochrane-Orcutt algorithm for estimating time series regressions in the presence of auto correlated errors. The Prais-Winston transformation makes it possible to include the first observation in the estimation.

Table 5**: Comparison of estimated Pass-through Rates in Germany and the Netherlands over January-July 2005**

Country	Period	Fuel (efficiency)	OLS[a] [%]	PW[a] [%]	ECN [%]	ECN [€/MWh]
Germany	Peak load	Coal (40%)	72	69	73	9.5
	Off-peak	Coal (40%)	42	42	46	5.9
NL	Peak load	Gas (42%)	40	44	39	2.8
	Off-peak	Coal (40%)	53	47	55	7.2

[a] All regression estimates are statistically significant at the 1% level.

The pass through rates of European CO_2 allowances (EUAs) vary between 40 and 72 per cent - between EUR 3 and EUR 10 per MWh in absolute terms, depending on the carbon intensity of the marginal production unit and other, market or technology specific factors concerned. However, empirical estimates of pass through rates need to be treated with due care as the authors took the 'most representative' technology as the marginal technology for a certain market/country during a certain (peak/off-peak) period considered, while in practice the marginal technology may change during certain hours, days and/or over time during the peak period (including changes in the marginal fuel efficiency, etc.). [27]

Why are there differences between peak and off-peak pass-through rates? Has it to do with different levels of competition within the two periods (e.g., lower level of competition during off-peak periods in Holland; and peak periods in Germany) or are there other more important explanatory factors? The authors did not examine or try to explain the empirical differences in pass-through rates between countries and/or load periods. The difference between peak and off-peak periods in Germany might be due, for example, to a difference in competition. In addition, the pass-through rate during the peak period in Germany might be overestimated since during certain hours of the peak period the power price might be set by a gas-fired plant (characterised by rising fuel prices which push power prices up) rather than a coal-fired plant (which is assumed to set the price during the whole peak period). For the Netherlands, the difference in estimated rates for the peak and off-peak periods is probably mainly due to the difference in fuel technology used. While the power price during the off-peak period is set by a coal-fired plant, it is set by a gas-fuelled station during the peak periods. Normally, one would expect a higher pass-through rate during the peak (compared to the off-peak), but since during the observation period considered (January - August 2005) the gas prices increased rapidly (while the coal prices remained stable), it was probably harder to pass on CO_2 costs during the peak than the off-peak (assuming that changes in fuel prices are always fully passed on to higher power prices).

Sijm, Neuhoff and Chen (2006) update this analysis with a longer observation period and a more refined statistical approach. [28],[29] They find much higher pass-through rates as illustrated in Table 6. The very high rate for Germany may be partially explained by increasing gas prices during 2005. “Given that gas generators (instead of coal generators) set the marginal price in Germany during some

27 In their COMPETES modelling work, the authors were able to make a further differentiation of load periods throughout a calendar year. While the marginal technology may remain constant throughout (most of) these load periods, the authors noticed a switch in marginal technology between these periods.

28 Bootstrapping: a method of calculating errors using only the data at hand as a distribution.

29 As explained by the authors, they constructed a subset data by bootstrapping samples from a window of a two-month period (e.g., January-February), and then ran their regressions based on the combined data from the

peak hours, this could contribute to power prices' increase in peak forward contracts. As coal generators benefit from this gas cost-induced increase in power prices, it leads to an overestimate of the pass-through rate of CO_2 costs for coal-generated power".

Differences from results in Table 5 may be explained by several factors, namely: the electricity price bidders' slow integration of the EU allowance prices early on, rapidly rising gas prices, higher power prices due to increasing scarcity and/or market power. The method used, which consists in "assuming away" other factors behind price variations (averaged at 0), makes the observation period crucial, and may explain the differences in estimates in Tables 5 and 6.

Table 6: **Empirical Estimates of CO_2 Pass-through Rates in Germany and the Netherlands for the Period January-December 2005, based on Year ahead Prices for 2006 (in %)**

Country	Load period	Fuel (efficiency)	OLS	Bootstrap (2 months)	
				min	max
Germany	Peak	Coal (40%)	117	97	117
	Off-peak	Coal (40%)	60	60	71
Netherlands	Peak	Gas (42%)	78	64	81
	Off-peak	Coal (40%)	80	69	80

Source: Sijm, Neuhoff and Chen (2006)

5.3.3 Reviewing CO_2 Pass-Through Estimates

The ECN study described in the previous section focuses on the spread between costs of generating electricity from the marginal technology and the market price. Attributing the level and volatility of this mark-up to the movements of CO_2 prices is arguable. Among other reasons, specific regulatory interventions (e.g., price caps, fixed tariffs, etc.) may increase or decrease market prices – blurring the understanding of the mark-up between costs and prices. Generating constraints such as plant maintenance or transmission line constraints may justify one-time price spikes. Similarly, the exercise of market power by withdrawing capacity may also influence the mark-up. The limit to this method is that grandfathered CO_2 allowances are included but also a wide range of other costs are included when calculating both dark and spark spreads (i.e. difference between power price and fuel costs per unit generated) – and thus a broad definition of profitability. These other costs consist of investment costs, management and maintenance, etc. It is only under the condition that these other costs remain the same, with and without EUAs, that the component of profit margin derived from buying fuel (and EUAs) and selling electricity, captures the net effect on profits. It is not, however, possible to estimate this unless non EUA scenarios are created – which is not the aim of the project.

The robustness of this assumption can be questioned (as outlined in the ECN study), but the authors justify its use by the relatively short time period (January-July 2005) and the two countries considered in the empirical/statistical analyses (Germany and the Netherlands). They point out that no other factors besides fuel and/or CO_2 costs can satisfactorily explain the significant increases in power prices in these two countries over the period considered. Of course, if the time period considered were extended, other factors - such as changes in market (demand/supply) structures - have to be included, although it may be hard to find appropriate data on such factors. The authors point this out as well. Changing the time period and/or countries (i.e. electricity markets) considered may lead to other

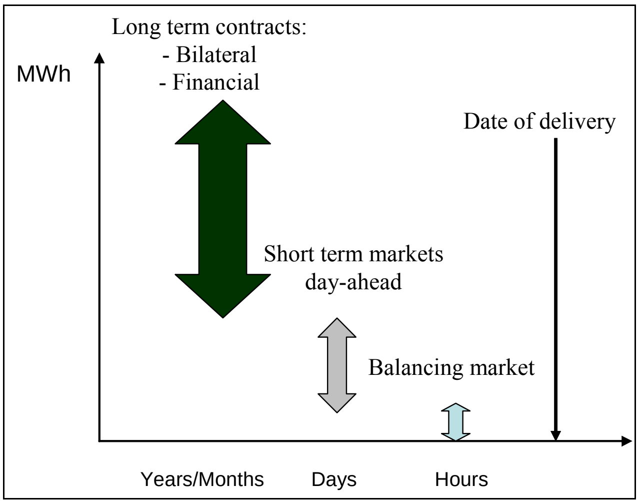
bootstrapped subset data and from the remaining months (e.g., March-December). They repeated this process by sliding the two-month window resulting in a total of six regressions with bootstrapped data.

estimates of the pass through ('work-on') rates, but will most likely not change the fundamental conclusions and policy implications regarding the relationship between grandfathering and power prices leading to high profits for the power producers.

A precise estimate of the pass-through rate is also not possible for several other reasons, one reason being that not all electricity prices in Europe are set through a pool-like type of bidding procedure, where the marginal technology sets the market price. As will be explained in 7.2, in continental Europe, the dominant electricity price is set through electronic platforms by a limited number of traders and generators. Likewise, there might not be one, but several, relevant electricity prices for end-users in the electricity markets (i.e., over-the-counter, forward, day-ahead, financial, physical, etc.). The bulk of electricity is traded through long-term contracts, which can be done either through financial or physical contracts (ECN, 2003). Nevertheless, not all electricity can be traded in long-term contracts as demand and supply need to match consistently. As a result, market players constantly need to buy and sell electricity at very short notice to match their positions. Short term day-ahead markets as well as the balancing market are used for this purpose (Scheepers, Wals et Rijkers, 2003).

Figure 6 illustrates the relative size of each electricity market in countries where all three markets co-exist. Section 6.3 provides the 2005 share of electricity traded on the day-ahead market compared to that of forward markets. Note that in some European countries, no power exchanges markets exist – and consequently no organised day-ahead or futures markets.

Figure 6: **Relative Size and Position of Different Electricity Markets**



Source: Scheepers, Wals et Rijkers, 2003

Also, for reasons explained below, bids on the day-ahead market may be carried out at a price which does not reflect either full variable costs of production, or the day-ahead price of CO_2 allowances.

- *Specific contract prices are not reflected on the day-ahead market*

At certain hours of the day and year, the market price is close to zero. This does not mean that the cost of generation is null or that the generator is not paid for its power. Such a situation may reflect the nature of over-the-counter (OTC) contracts – where bids on the market are noted at a price close to zero in order to be dispatched (see 6.2 for more details). The real price paid in those contracts is unknown to actors out of the contract. This is the case, for example, in the Nord Pool clearing market.

- *Some price bids are close to zero on the day-ahead market*

Certain gas-fired power plants need to run full-time in order to burn the gas contracted under take-or-pay contracts instead of losing it. In such cases, the pass-through rate of CO_2 allowances may be close to zero in order for the plant to be dispatched.

- *Other interconnecting measures such as priority dispatching*

Certain technologies such as combined heat and power – CHP – may be qualified for priority dispatching on the merit order. In such cases, CHP generators bid on the market at a price of zero in order to be dispatched. As a result, this priority dispatch requirement may cause excess unused generation capacity in certain periods, a situation where utilities will take on profit losses.

- *Forward prices include the forward prices of EUAs on the day of the contract – and not the spot price of EUAs.*

Deutsche Banks estimates indicate that for German and UK power companies, approximately 60-70% of the electricity produced is sold forward.[30] If generators or traders signed medium-term delivery contracts at the start of the year, contracts may have essentially been based on forward energy prices and EUA prices at that time. [31] Thus, for example, for EUA prices between January and July, generators who sold power forward at that time will only have captured a margin sufficient to cover the full price of the allowance bought forward (or less if they did not pass through 100% of allowances).

Passing-through the full opportunity cost onto generation prices should occur, but this is mostly to the appreciation (or strategy) of the trader (or generating company). For example, an electricity incumbent interviewed for this study added a special clause to its supply contracts that reserves the right to bill a CO_2 cost at the end of each year. This CO_2 cost is based on the purchase of CO_2 allowances for yearly compliance. This suggests that actual costs, not the opportunity cost, are charged onto market prices. If the latter possibility were the case, there would be no need to charge for the cost of CO_2 purchase, the opportunity cost would more than cover this cost.

[30] In France, because the wholesale market is less liquid (only 1,5 times of the eligible consumption is traded compared to 8-10 times in Nord Pool), if an industrial facility or its supplier bought its entire electricity in one day, it would strongly influence the demand curve, and put an upward pressure on power prices. This compels the purchaser to fraction its purchases, and indicates that the French wholesale market may not be liquid enough to make the futures market a robust index price (Ministère de l'économie, des finances et de l'industrie, 2005).

[31] As a result, generators who trade in advance may not have benefited from electricity price rises in 2005, following the introduction of the EU ETS.

5.4 Section Summary

There are several drivers of both CO_2 and electricity prices. CO_2 is an additional cost component to electricity generation prices, whether allowances are distributed for free or paid for. The pass-through of CO_2 allowance prices onto power prices is real, and several surveys have reviewed this effect.[32] Estimates vary, but none can be considered accurate as none found adequate information on the marginal price setting technologies across markets, countries and load periods. Likewise, none expanded their research to electricity markets which do not follow a merit order price setting principle (e.g., regulated tariffs).Further, the pass-through can vary depending on the time period and/or countries (i.e. electricity markets).

We now look into the different market prices (both organised on an exchange or bilateral) that can serve as a basis for electricity contracts: day-ahead, forward. Balancing prices are not considered as they represent a small share of industries' electricity consumption and involve more complicated price formation and regulatory rules. Nonetheless, as we will see in section 7, this list is not exhaustive – other fixed prices exist which do not make reference to market prices – although market prices will always serve as a benchmark to value the gain or loss attributed to each contract.

[32] Nevertheless, we did not focus on the demand side of electricity which is also an important component influencing price levels.

6. Relevant European Electricity Market Price Indicators

While the European power market is gradually becoming integrated, it remains divided into national and, to a degree, regional markets. Differences in regulatory regimes and power transmission bottlenecks between countries hinder increased integration. There are several electricity markets in Europe. For each market or region, there are electricity prices that are more relevant indicators to most market transactions or contracts than others. Likewise, there are different prices depending on date of delivery of the electricity (e.g., intra-day, day-ahead, month- year- ahead, etc.).

The purpose of this section is three-fold:

- To identify the different delivery periods of bulk electricity for industries and suppliers on various market places, and to indicate the weight of these markets in the overall electricity picture of the region.
- To identify where and how both day-ahead and forward prices are formed.
- To shed light on the relation between day-ahead prices and forward prices in the different EU-25 markets.[33]

The aim of this section is also to identify what price indicators are most representative of transactions in each market – and may thus serve as an element or a benchmark in industrial contract prices. Furthermore, we will try to assess to what extent the reference power price is linked to the day-ahead price which may reflect market fundamentals (e.g., supply and demand, variable costs, and the opportunity cost of CO_2), depending on how much the day-ahead market captures in terms of total electricity bought and sold.

6.1 Transactions Over-the-Counter or on Power Exchanges

When buying electricity in bulk, transactions are executed either via power exchanges or bilaterally over-the-counter (OTC).[34] In Europe, power exchanges can be divided into broad groups (EC, 2006). In the first group, financial incentives are provided if power is traded on the exchange or companies need to trade on the power exchange if they wish to supply the greatest number of customers (e.g., OMEL, GME, Nord Pool).[35] Volumes of transactions on those exchanges are much higher than that of the second group, where no incentives are provided (EEX, APX, Powernext, EXAA, Pol PX, and the UKPX). For example, in Spain, only the electricity traded via OMEL is entitled to receive capacity payments. In Italy, generators are encouraged to transact via the GME as the Single Buyer (Acquirente Unico), the regulatory entity which buys electricity for the captive market (i.e., 50 percent of the total Italian electricity demand), covers an important share of its energy requirements

[33] This will be useful for the industrial price section 7 since large-users' electricity contracts are mainly composed of forward prices (or long-term contracts) if the latter exist.

[34] Over-the-counter refers to trading that is not done over a formal exchange.

[35] One reason for the bigger Nord Pool volume is that cross-border trading in the Nordic market is dedicated to Nord Pool. Nord Pool provides cross-border trading within its whole market area without any additional transaction costs compared to national exchange trading.

on the GME.[36] On the Nordic market, there is a need for market participants to transact via Nord Pool once crossing different areas, since the market mechanism applied there is also implicitly used to allocate transmission capacities between different price regions.

Table 7 provides the main characteristics of the European power exchanges. It underlines which market exchanges have organised future markets and those which have not.

Table 7**: European Power Exchanges**

POWER EXCHANGE	**ZONE**	**NATURE**	**DAY-AHEAD**	**FUTURES**	**OTC CLEARING**	**OPTIONS**
Nord Pool	Scandinavia	Voluntary pool[37]	Yes	Yes (max 5 y)	Yes	Yes
OMEL	Spain	Voluntary pool *	Yes	No	No	No
APX	Netherlands	Exchange [38]	Yes	Yes (Endex)	Yes	No
EEX	Germany	Exchange	Yes	Yes	Yes	Yes
APX-UK	UK	Exchange	Yes	No	No	No
Powernext	France	Exchange	Yes	Yes	No	No
GME	Italy	Exchange	Yes (IPEX)	No	No	No
EXAA	Austria	Exchange	Yes	No	No	No
OTE	Czech Republic	Exchange	Yes	No	No	No
PolPX	Poland	Exchange	Yes	No	No	No
Borzen	Slovenia	Exchange	Yes	No	Yes	No
Belpex	Belgium***	Exchange	Yes	No	No	No
OMIP	Portugal	Planned	No	Yes	Yes	No

** Bidding in the exchange is mandatory for generators of over 50 MW for the total of their capacity, excluding the portion of power traded through bilateral contracts*

*** Eurelectric (2005)*

**** Belgium had no organised market until November 2006. Before, trading was essentially bilateral. In the absence of an exchange, Electrabel published the Belgian Power Index (BPI) – which allows participants to buy and sell day-ahead base-load power in blocks.*

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36 Until the market is fully liberalised in 2007, Acquirente Unico, the single buyer, purchases power in the market to cover the demand of consumers in the regulated sector of the market. In July 2007, when the market segment is open, it will continue to supply customers who decide not to switch to the "free" energy market.

37 A power pool is an association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

38 A power exchange is the entity that will establish a competitive spot market for electric power through day- and/or hour-ahead auction of generation and demand bids.

On both OTC and market exchange platforms, prices are set when both the supply side and the demand side come to an agreement. The price paid by the electricity purchaser can be determined in basically two ways:

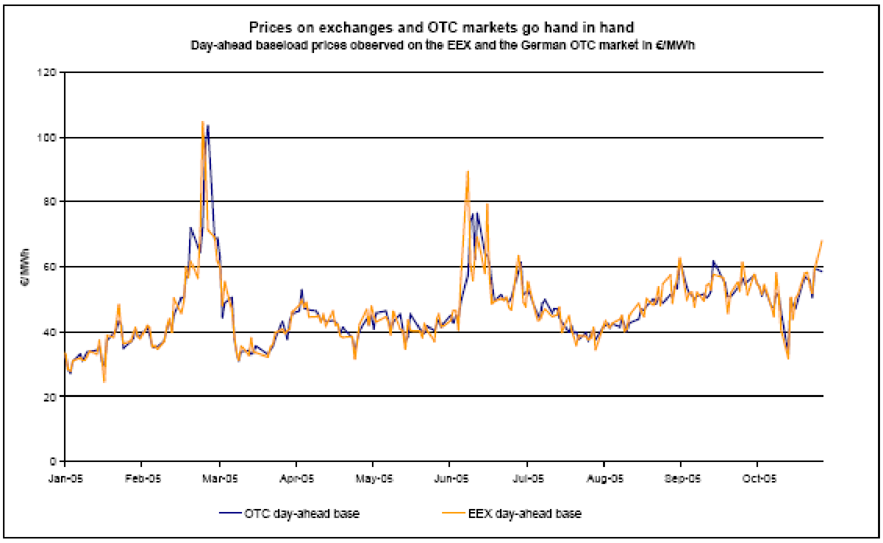
- *Bilaterally,* in which case no purchases are necessarily made at the same price level. This is also called pay-as-bid. Continuous trading, which involves the immediate execution of orders upon their reception by market makers and specialists, is one form of bilateral trading. Bilateral trading is not reserved to OTC markets. For example, bilateral trading is available in the UK NETA power exchange.

- *Uniform-price*, in which the price that is received by all dispatched generators is the bid that was received by the marginal bidder. In theory, this is the marginal cost of supply in the system (Bjornsson et al, 2004).

Nord Pool, for example, uses a bilateral market for longer-term transactions and a uniform-price auction market for day-ahead transactions.

Theoretically, in perfectly competitive markets with perfectly informed customers, price levels formed through the two ways should be equivalent as actors can arbitrate between using either trading platform. This is confirmed by the strong correlation between the day-ahead OTC and exchange price in Germany as illustrated in Figure 7. In Germany, market exchange prices are set by uniform pricing, while OTC transactions are traded bilaterally.

Figure 7: **Correlation between OTC and Power Exchange Prices in Germany**



Source: EEX, Argus Media

Source: EC, 2006

The reason is also that market prices are often used as a reference for bilateral OTC contracts. The market price is often regarded as a transparent indicator which can serve as the index for contractual prices.[39] Thus, OTC and power exchange prices are similar, and in this report, there will be no real

[39] Further, increasingly, transactions on traded bilaterally are cleared by third parties, such as brokers or power exchanges (the so-called "price-independent bids", for which no price information is provided on the exchange), thus helping liquidity to develop.

distinction between the two traded prices. Nevertheless, the legitimacy of using the power market price as a representative indicator of most trades is questionable. In some European countries, transactions on exchanges represent a small share of the total electricity consumption. In the absence of a pool, these transactions may not provide a price reflecting the total demand and supply equilibrium. With the exception of Scandinavia, only a relatively small portion of the total electricity supply transits through the power exchange as will be illustrated in 6.3, which indicate the extent of the volumes that are actually traded for a price on the exchanges.

6.2 Day-ahead and Forward Market Prices: Fundamentals and Links

Energy consumers need a clear, transparent and easy-to-calculate pricing formula to estimate their energy costs. Following several interviews, it is possible to summarise several basic rules when considering the majority of industrial facilities' electricity purchasing strategy. They are the following:

- The more volatile day-ahead prices are, the fewer buyers rely on day-ahead transactions; they turn to forward markets instead, if they exist (EC, 2006). In this section, we will thus concentrate on forward prices and the relevant trading platforms (e.g., organised exchange or bilateral transactions) depending on the EU country;

- Industrial companies purchasing over-the-counter (OTC) will often purchase tailor-made forward contracts indexed to power prices or fuel prices – a single fuel or a basket of fuels as in Italy (see 7.2.3.2).

- In countries where only day-ahead prices exist on the power exchange, power suppliers or brokers may offer annual contracts. The latter indices are generally constructed from previous years' day-ahead prices – if there is sufficient historical data - among other indices.

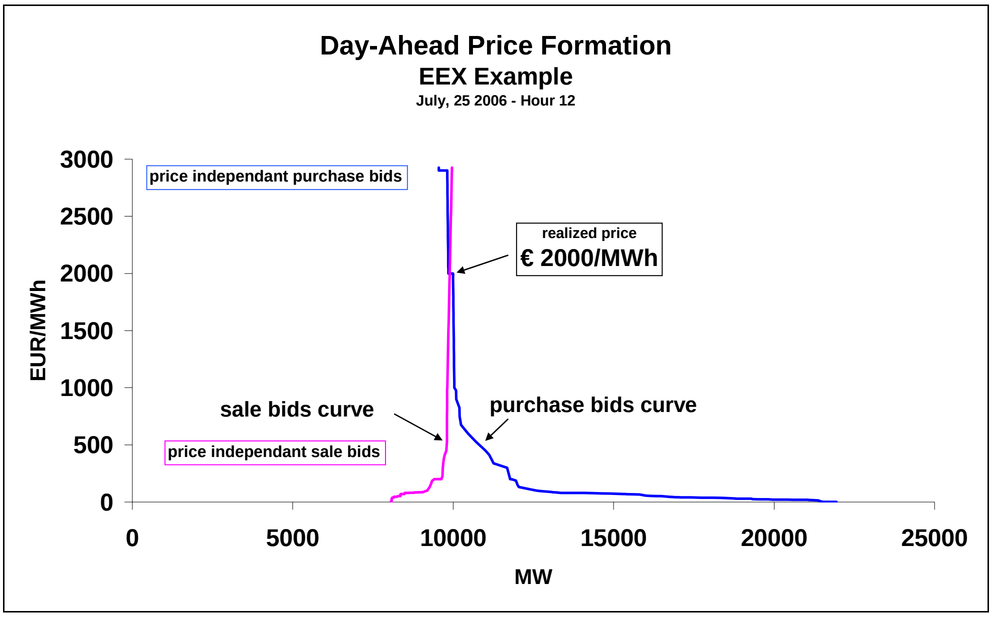
The non-storability of electricity makes electricity that is delivered at any given future time a separate asset from the electricity that is delivered straight away. According to the Commission's preliminary report on electricity and gas markets, factors influencing prices in the short run can be different from those in the long run. Whereas forward prices are largely driven by supply and demand fundamentals that are expected to occur in the future prices are determined by the outcome of these fundamentals. Short term prices are, according to market experts, mainly influenced by plant availability, fuel prices, precipitation, wind speed, interconnector availability, temperature, and since 2005, CO_2 prices.

In theory, in centralised day-ahead electricity markets with uniform-price auctions, prices are built on the basis of a merit order, where bids are dispatched following the level of bid and capacity offered. In general, power plants with no possibility of resource storage (i.e., run-of-river or wind facilities) are used for base-load production. Conventional power plants come next, with nuclear facilities distinguished from fuel-fired power plants (Houpert and De Dominicis, 2006). These plants are brought on-line by increasing variable cost, i.e., generally nuclear, lignite, coal, gas, heavy fuel oil and light fuel oil. All other things equal and depending on the level of demand, the use of coal and gas shifts back and forth according to the relative prices. Physical spot prices are set by an equilibrium model where supply and demand curves of all the market participants are matched day-ahead.[40]

[40] By no means do exchange-based transactions reflect the totality of supply and demand.

However, in reality, in Europe, no countries have centralised mandatory pools where such a merit order scheme exists. In Europe, where exchanges have been created, day-ahead prices are not formed by a collective merit order since the use of such platforms is not mandatory. Rather, prices on these exchanges are set by companies' and traders' "bidding strategy". Most day-ahead electricity bids are price-independent, and the market exchange is only there to secure the physical exchange of the electricity.[41] Only the price-dependant bids set the day-ahead price and they do not necessarily depend on the marginal producer's generation costs but rather on strategic bids. As illustrated in Figure 8, the market clearing price is at the intersection of the demand and supply curves.

Figure 8: **Example of formation of a day-ahead price on the EEX market exchange**



Source: Alcan

Overall, the volume of price-dependent electricity traded day-ahead in continental Europe may represent less than 5 percent of the total electricity demand.[42] Indexing supply contracts on day-ahead prices could, in such cases, be questioned.

Prices on the long-term are predominantly determined by forward fuel prices, new or existing generating capacity – or capacity retirement, water reservoir levels, weather trends, interconnector capacities, CO_2 prices and economic growth. Forward prices will also include a risk element.

[41] In the case of EEX, for hourly contracts, bids for block contracts are integrated by changing the blocks into price-independent bids for the hours concerned. Then price/volume combinations for every hour are transformed into a sale and purchase curve of every participant by using linear interpolation. The resulting supply and demand curves are aggregated to a supply and a demand curve for Germany. The price level at the intersection of the two curves is referred to as the market clearing price (OSCGEN Newsletter, Issue 3, June 2002). The trading participant of the price-independent volume will always obtain the market price (http://www.risoe.dk/rispubl/SYS/syspdf/ris-r-1441.pdf).

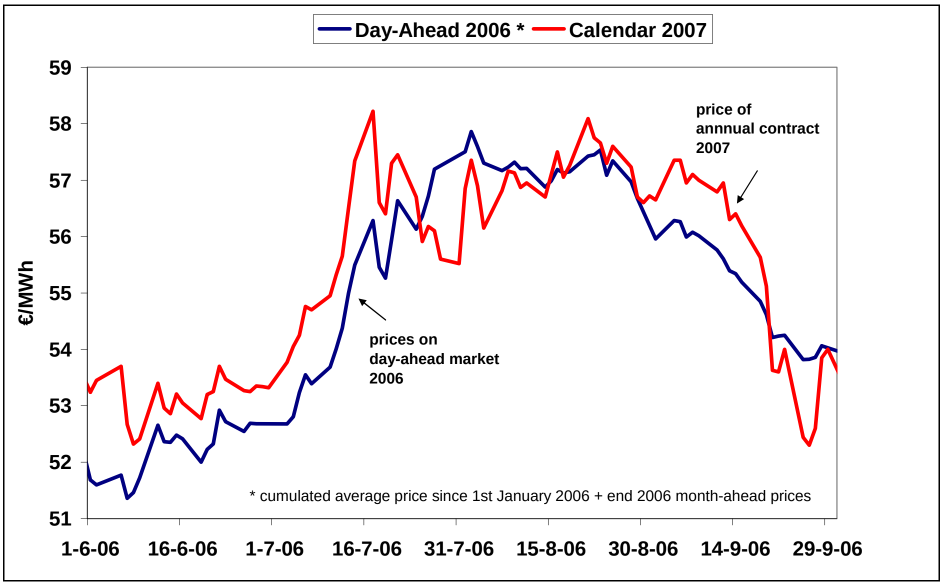
[42] Bilateral long-term power purchasing agreements (for physical delivery) obviously limit the volumes traded on a regular basis on electricity markets. As discussed in 7.2.1, several European countries have a large quantity of generated electricity reserved through long-term contracts. These are believed to be the main causes for the low volumes of electricity traded on markets (EC, 2006). This electricity can be sold either to a power supplier, or directly to an industrial facility. Moreover, electricity sold under long-term contracts (for physical delivery) removes a large share of the demand and supply from the price bidding system.

Depending on whether buyers and sellers attach a higher value to price certainty over unknown spot prices in the future, this will be a premium or a discount.

Future prices of non-storable commodities can deviate significantly from day-ahead prices because of anticipated changes in supply or demand. Nonetheless, in some cases, price movements in the day-ahead market influence the variation in the forward market. Future electricity prices are to some extent determined by the current day-ahead prices, or a rough average. The legitimacy of this correlation is questionable because of the nature of electricity as a non-storable good.[43] This is why they are sometimes contested as not really reflecting the fundamentals of supply and demand – because today's "spot" prices are a reflection of a small share of the total traded electricity, and also the reflection of plant availability, weather, etc. which have no influence whatsoever on what the conditions will be some months or year down the line.

In Germany, annual supply and day-ahead prices are connected as illustrated in Figure 9. It compares the volatility of 2006 day-ahead prices with that of supply contracts for calendar year 2007. The correlation between the two price volatilities is high. Hence, this means that electricity price bidders transfer their daily portfolio risk to annual supply prices. Day-ahead prices influence the price for next year delivery.

Figure 9: **2006 day-ahead prices compared to annual contract prices for 2007 on the German market exchange EEX**



There is a correlation between day-ahead and forward prices in the Nord Pool market. Explanations may come from the particular attributes of the Nord Pool generation portfolio where part of the electricity is storable since hydroelectricity can represent a large share of the Scandinavian power (e.g., 55 percent in 2002). Through the storable nature of hydroelectricity, electricity produced today is in competition with the electricity generated in the future. In Scandinavia, future prices seem to derive directly from the moving average day-ahead prices.

[43] The French electricity trading platform Powernext writes "As a reflection of a momentary, thus both unique and unpredictable situation, the spot price, strongly correlated with the weather conditions, cannot be used as a basis for a long term commitment, even if it is an undisputable very short term reference".

As explained above, if there is sufficient data available and sufficient liquidity in the market – thus lowering the risk of market manipulation, historical day-ahead prices may be used as part of a base to build forward prices. It is possible that traders in the Nord Pool market use (among other elements) the current or average day-ahead price and reservoir indicators to generate forward prices. Thus, in the case where industry supply prices are based on annual prices built on forward prices, which are themselves correlated to day-ahead prices, this link is again questionable from a cost competitiveness view point for energy-intensive users as day-ahead electricity prices reach higher price spikes than future prices.

6.3 Relevant Price Indicators in Europe

Depending on the liquidity of OTC and market exchange, for each EU-25 country/region, there may be a market more representative of most transactions (e.g., between a brokered platform such as Spectron and an organised market exchange such as EEX) and industrial electricity purchases.[44] Likewise, there may be one power exchange more representative for a region then another (see ANNEX 1 for further details).

Table 8 provides the share of traded spot volumes compared to OTC volumes as a percentage of electricity consumption between June 2004 and May 2005. In many cases, exchanges do not represent a significant share of the pool in the region. This is the case in the UK, Poland, and Austria. On the other hand, in countries such as Spain, Italy and in the Nordic market, the power exchange is a better reference for demand and supply confrontation. For the exchanges where needs or incentives to trade exist, traded spot volumes are often larger than OTC spot markets. Thus, market results on the former seem to be setting the pace for the overall spot market (EC, 2006).

[44] Nevertheless, as mentioned above, in reality, regarding price formation, there is no distinction to make between blocs sold on brokered platforms (e.g., GFI Net, Spectron, etc.) and those sold by organised power exchanges (e.g., EEX, Powernext, etc.), nor by power generators' trading platforms (e.g., Endex).

Table 8: **Spot Traded Volumes on Exchanges and "over the counter" as a Percentage of Electricity Consumption (June 2004 – May 2005)**

	POWER EXCHANGES	OTC BROKERED
OMEL (Spain and Portugal)	84.02%	Negligible
GME (Italy)	43.67%	n.a.
Nord Pool – Nordic region	42.82%	n.a.
EEX (Germany)	13.24%	5.40%
APX (the Netherlands)	11.88%	5.90%
Belgium	No power exchange	0.04%
Powernext (France)	3.37%	1.50%
EXAA (Austria)	2.96%	n.a.
UKPX (or APX Power UK)	2.17%	8.60%
PolPX (Poland)	1.28%	n.a.

Source: EC, 2006

Table 9 provides the same breakdown for traded forward volumes between June 2004 and May 2005. The number of active participants on the power exchanges (EEX, Powernext) trading futures products is significantly lower than on the respective OTC markets with the exception of Nord Pool. Thus, when considering the relevant trading platform in European markets for forward prices, only Scandinavian countries used their organised market exchange.

Table 9: **Forward Traded Volumes as a Percentage of Electricity Consumption (June 2004 – May 2005)**

	POWER EXCHANGES	OTC BROKERED	POWER EXCHANGE + OTC
OMEL (Spain and Portugal)	No exchange trading	Negligible	n.a.
GME (Italy)	No exchange trading	n.a.	n.a.
Nord Pool – Nordic region	151%	n.a.	n.a.
EEX (Germany)[45]	74%	565%	639%
Endex (the Netherlands)	39%	509%	548%
Belgium	No exchange trading	22%	22%
Powernext (France)	6%	79%	85%
EXAA (Austria)	No exchange trading	n.a.	n.a.
PolPX (Poland)	No exchange trading	n.a.	n.a.
UKPX (or APX Power UK)	0%	146%	146%

Source: EC, 2006

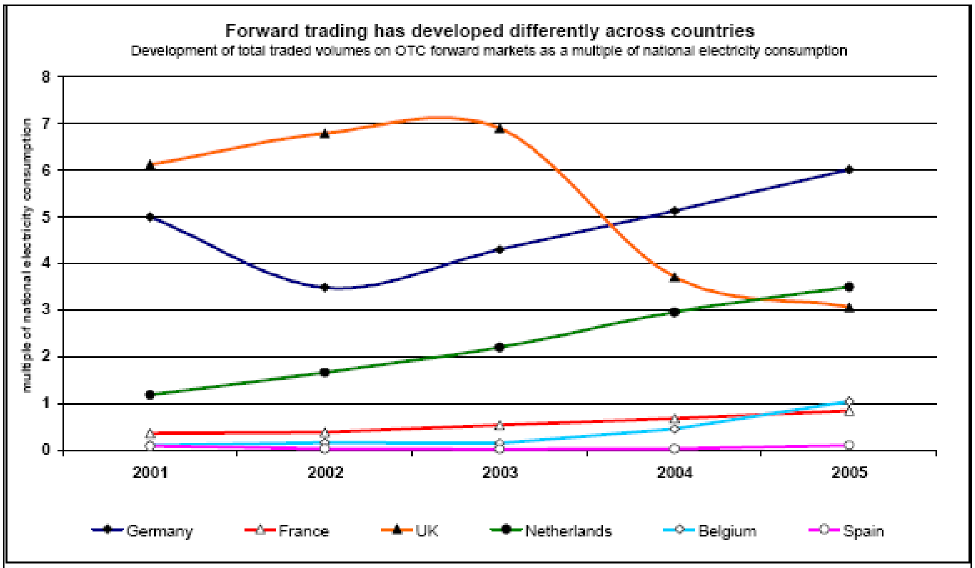
In the Netherlands and in Germany, the churn rate of bilateral forward trading is high.[46] Around five times the country's total amount of electricity consumption is traded on this market. This shows that the OTC forward market is very liquid compared to other countries.

Figure 10 provides the evolution of forward trading on OTC market. In Spain, forward trading remains insignificant. In contrast, the Dutch and German OTC forward markets traded by far the highest volumes (relative to consumption) on the continent (EC, 2006). The UK is the only market in comparison where traded volumes have significantly declined since 2003. In its report, the European Commission mentions that reasons may lie in the ongoing vertical reintegration of the industry (i.e., the trend to bring independent generation and the supply businesses into a single operation under the same ownership). In France and Belgium, volumes continue to be low owing to the high concentration level and vertical integration.

[45] In the German power exchange, EEX, futures are quoted to the year n+5. However, the liquidity of the market strongly decreases between n+2 and n+3 (Ministère de l'Economie, des Finances et de l'Industrie, 2005). The market is thus mainly active on a time horizon of two years. Electricity market players are mostly concentrated on securing electricity supply for the year to come – confirming what industry told the IEA during interviews.

[46] The churn rate is the action during which a single contract changes hands and pricing many times, indicating liquidity.

Figure 10: **Evolution of Forward Trading in Several EU Countries**



Source: Energy Sector Inquiry 2005/2006.

The most traded product by far on the forward markets is the yearly contract for base-load hours (EC, 2006). An exception is the UK electricity market where products for different seasons are the most traded (EC, 2006).

6.4 Section Summary

Electricity markets differ widely across Europe, from the Scandinavian pool which gathers 59% of total electricity output to other exchanges that account for much smaller shares[47]*. All nonetheless provide a public price, which can be used as index for other transactions.*

Depending on the liquidity of OTC and market exchange, for each EU-25 country/region, there may be a market more representative of most transactions and industrial electricity purchases. Nevertheless, as mentioned above, in reality, regarding price formation, there is no distinction to make between blocs sold on brokered platforms (e.g., GFI Net, Spectron, etc.) and those sold by organised power exchanges (e.g., EEX, Powernext, etc.), nor by power generators' trading platforms (e.g., Endex).

The average price paid by industrial facilities depends on their access to these various markets, and, more broadly, on their purchasing strategy – this is what we will explore in the next chapter. Does the CO_2 element appear in the different strategies (i.e., through which markets), and if yes, where? Are purchasing strategies exposed to day-ahead and thus indirectly CO_2 price volatility? Do specific purchasing methods allow industrials to pay supply prices below market prices? What hedging instruments are available to meet industry's electricity needs?

[47] During year 2006, weeks 1-44, i.e. 1 January - 5 November, the share of electricity traded via Nord Pool Spot has been 59.5% (202 TWh) in the whole Nordic market and 43% in Finland. The volume traded via Nord Pool's financial market has been (over the same period, weeks 1-44) 660 TWh and the volume of OTC contracts cleared via Nord Pool has been 1172 TWh. So the total volume of financial trade cleared in Nord Pool has been 1832 TWh. This is 563 % of the physical consumption in the Nordic power market.

7. End-user Prices – Industrial Prices

There are many combinations of different underlying arrangements in the electricity market for industry in EU-25. In countries where generators sell a considerable share of their electricity months or even years in advance of actual delivery, and where forward markets exist, it is a common practice for suppliers to offer fixed price supply contracts (mostly with a duration of 1-2 years) to their large business or industrial customers. Fixed price contracts also appear to reflect industrial energy users' preference (EC, 2006).

The intent in this section is to explain how and whether the electricity price energy-intensive industries pay differs from market prices. Are there configurations where the electricity cost is higher or exposed to volatility? For example, is direct participation in a generating facility a means to prevent an increase in price (e.g., CO_2 allowance pass-through)? What about self-generation?

A major challenge in such an analysis is to gather data that represents the general situation of generators and industrial consumers alike (e.g. to what extent do quoted electricity prices in continental Europe's power exchanges give a complete picture of industry's actual electricity expenditures? Do large electricity users still rely on more stable contracts to secure delivery and prices over longer periods? What is the practice to reflect the cost of carbon in these contracts, etc.)? In this context, the impact of carbon on end-users' prices is even more uncertain than the impact on generation costs and the pass-through on market prices.

Although there are many types of consumption patterns for industry (e.g., flexible consumption, etc.), in this section, we will focus on a facility consuming essentially base-load (a "ribbon" type of profile).

7.1 Energy-intensive Industry's Profile and Consumption

One characteristic of energy-intensive users is that their profitability varies strongly according to energy prices. If such producers are unable to transfer their cost volatility onto their prices, it is in their interest to minimise the cost components' volatility. Regarding the electricity cost component, before liberalisation of the European market, predictable prices were provided by long-term arrangements with power producers. However, currently, the possibilities of such contracts are more limited due to the increased instability of energy market fundamentals (European Commission, 2006).

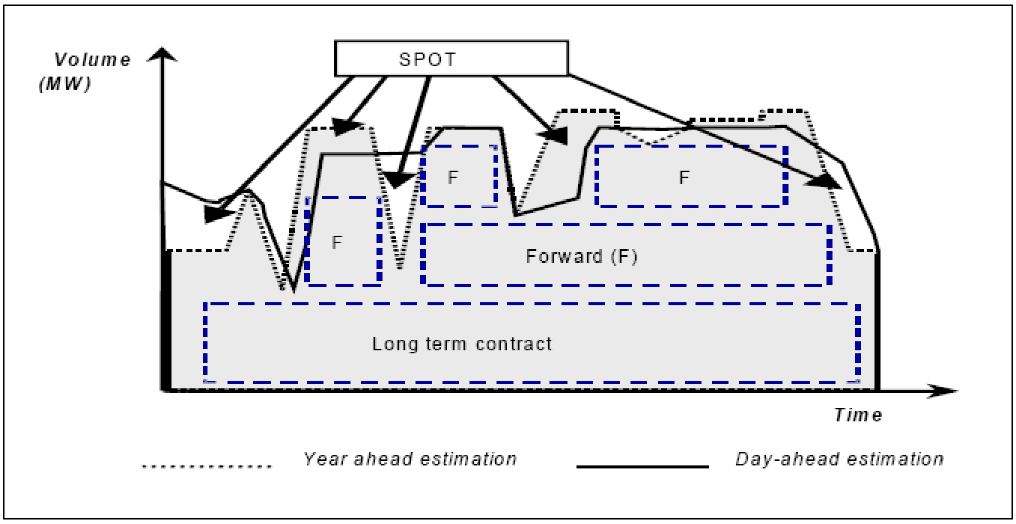
The energy-intensive industries that mainly serve the local market and sell products which do not travel long distances for economic reasons, may be able to pass any extra or volatile costs they face onto their price, without undergoing external competition. This depends, of course, on the level at which the price of the products is established (be it international, regional, domestic), whether competitors face similar increases in costs, and on whether the market is local or not. This category of energy-intensive industries can be distinguished from those which cannot pass-through any increase in production costs and as a result will try to limit the increase and volatility in the price of production components. Nevertheless, this does not mean that there are no risk averse players in the first category – in which case they may seek to lower input price volatility (e.g., electricity).

There are several elements which can limit the pass-through of cost increases onto prices: prices are set at an international level; freight costs are low compared to the value-added of the products; competitors do not face similar cost increases; prices of the products are fixed.

Electricity consumption patterns of industrial facilities differ between sectors and within sectors. Nevertheless, optimisation of the production process leads a number of electric-intensive consumption profiles to mimic a “ribbon” of base-load electricity – with or without interruptibility possibilities. The cost to serve the industrial facilities’ consumption is equivalent to the actual cost of covering forward the customer’s consumption on the market. This practice applies irrespective of whether the consumer will in reality be supplied from the supplier’s own generation portfolio or covered by electricity purchases from the market.

Figure 11 gives an example of an energy-intensive facility’s consumption load and the way electricity can be purchased to minimise price volatility. The consumption profile can be cut in several blocks. Where electricity can be purchased in advance, the industrial facility may choose to do so. EII purchase electricity from a mix of instruments: long term contracts and forward contracts for the bulk of their consumption. Then come quasi-instantaneous needs, here represented by areas between the dotted lines and the full line. This demand can be met by a market qualified as day-ahead. Then come intra-day or intra-hour adjustments which are quoted differently.

Figure 11: **An Example of an Industrial Facility’s Electricity Purchasing Strategy**



Source: Boisseleau, 2003

In general, there are two categories of prices paid by eligible customers. In the first, the final price paid by the industry is based on the sum of several elements: the price for a block of electricity set by trading entities via electronic trading platforms, a negotiated "fee" to manage the load curve based on daily consumption and compensate for sales costs and regulated grid charges. Energy-intensive users mainly belong to this category (eligible customers). In the second category, many customers purchase at an “all-included price”. This practice is mainly exercised in the framework of regulated prices. This is the case for Spain for example, where many industrial facilities have remained in the framework of regulated prices (e.g., A-4 tariffs and so-called interruptible tariffs).

Nevertheless, there is also a third category, where prices can be made of different components. This is the case for industries that self-generate their electricity. In theory, unless dealt with differently, the price for electricity should be the sum of the variable costs components to produce electricity, and fixed costs associated to the plant.

Tariffs for industrial users are more varied than tariffs for domestic users (EASAC, 2006). To give an overall picture of industry's different electricity purchasing methods, we have distinguished three main electricity purchasing strategies:

1. The installation purchases its electricity directly or indirectly through market mechanisms – both on a short term or a long-term basis (see 7.2);

2. The installation produces the majority of its electricity consumption alone or with a third party (see 7.3);

3. The installation adopts regulated tariffs, where such an option exists (see 7.4).

Financial risk management is often a high priority for participants in deregulated electricity markets due to the substantial price and volume risks (i.e., the risk of not being supplied) that the markets can exhibit.[48] Although it will not lower the supply price of electricity (and thus not impact the pass-through of CO_2 costs onto power prices), price risk management may prove useful in the cases where electricity is self-generated or purchased through market mechanisms. However, not all European electricity markets offer such risk management possibilities, reasons being that markets are not yet mature. Section 7.5.1 will cover several complex financial products that may be available, depending on the country, for energy consumers who wish to manage the price risk of their electricity consumption.

7.2 Market Mechanisms: Direct Purchase on the Market or Purchase Agreement with a Supplier

The prospective consumer's hourly consumption (most often over 1 to 2 years) is estimated on the basis of past consumption patterns. The energy-intensive industry has the option to use the market to purchase its electricity, either directly or going through an intermediary – or supplier. Moreover, industrial facilities can purchase for their own use only or for a group of companies.

The final price quoted to the consumer will depend on whether the industrial consumer is able to negotiate with a supplier or whether it purchases its electricity directly through the market. On a centralised market exchange, the consumer may be a price taker, whereas on a brokered market, he may be able to discuss the price for bulk consumption with the electricity supplier or trader. The final cost of electricity to an industry facility contains other cost components such as expected cost of balancing, distribution costs, or the supplier's own profit margin (EC, 2006).

In this section, short term and long-term contracts are differentiated. Supply contracts will be considered short term if they last for three years or less.

[48] With financial contracts, the payments under the contract are made in addition to the payments for power, but are linked to the day-ahead price. As long as generators and consumers can rely on an underlying physical market, a purely financial contract carries the same value to them as a contract with physical commitments (IEA, 2005b).

7.2.1 Long-term Supply Contracts coming to an End – or New Agreements with Suppliers?

The volume of long term contracts has undergone a cyclical movement. Before liberalisation, and during its first years, long-term contracts were frequently concluded between energy-intensive industries and power producers – essentially the incumbent monopoly in each country – and many of these contracts are still running. The majority of the long-term contract prices were established on a cost-plus basis from the generator's perspective. However, a number of these long-term contracts are coming to an end in the EU-15 countries. At present, given the current lack of confidence in short term markets and the large increases in price over the past ten years, long-term contracts have become attractive again from the competitiveness of energy intensive industries, in particular as they take major new investments into account.

At present, pre-liberalisation type long term contracts are being replaced among others by:

- *Shorter term contracts* – no longer than one to two years in the majority of European electricity markets.[49] This will be further discussed in the next section.

- *A new form of long-term contracts* in which industry shares part of the investment risk. In some Member States, agreements have been concluded, or are being planned, which promote long-term partnerships between customers and energy suppliers (First report HLG, 2006).

An industrial facility can, for example, pay a fraction of the cost of capital or guarantee the purchase of a fixed amount of electricity for a fixed number of years. In France, in 2006, a consortium, Exeltium, was founded by seven energy-intensive companies. Membership requires purchasing shares in the independent company, at a price corresponding to an advanced payment of the long-term supplies. This is designed to provide funds to invest in generation.[50] Exeltium launched a call for tender, addressing European electricity producers, with the aim of creating an electricity supply mechanism by mid-2007. The mechanism is based on the acquisition, by the industrial groups, of drawing rights with a duration of at least fifteen years, which would reserve a stable energy supply for them, at prices linked to the most competitive production costs.[51] Industry members should then pay for the variable costs of the purchased electricity. The members' aim is to secure blocs of electricity for a fifteen to twenty year period. The price risk left to manage by each industrial is the adjustments between the contracted capacity and the facilities' real consumption. A French law was promulgated in order to define which energy-intensive users would be entitled to participate.[52] The mechanism created by Exeltium is open to other industrial groups, within the limits of criteria set by the French authorities. On the whole, some 50 companies are eligible, in addition to the seven founding members.

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[49] Since long-term contracts are being replaced by shorter-term contracts, long-term price risk management for industries is becoming more complex. Nevertheless, it is also fairer to generators. In other words, the risk is shared more evenly.

[50] In our interviews, it was mentioned that the cost of capital would be based on a fictive nuclear plant.

[51] Details of the agreement were not disclosed, although it was mentioned that the final price paid by the consortium would be around EUR 40/MWh (La Tribune, 16 January, 2007).

[52] Participants must have a ratio of electricity consumption to value added equal or above 2.5) and consume more than 8000 hours per year. A company like Arkema which consumes at least 4TWh per year may not be able to cover the essential of its consumption through the Consortium as there may not be enough electricity for all. The distribution between all members is a factor of the cost of capital paid upfront.

Likewise, in the Netherlands, a consortium of nine electricity-intensive companies started at negotiations over a long-term electricity contract with two power companies. The option of supply from a new coal power plant is discussed, and pricing may be on a cost-plus basis, the "plus" containing the value of CO_2 allowances. However, no information was found on what CO_2 prices would be used (i.e., forward, day-ahead), nor whether electricity prices would contain the full opportunity cost of allowances or, the value of allowance purchases for compliance or, some mix of the two. The consortium hoped to make a deal in October 2006.

- *Fuel-indexed long-term contracts.*

For example, in the UK, Centrica – a gas and power supplier - announced a five-year coal priced electricity supply contract with Drax Power Limited in 2006. The agreement, which will provide Centrica with access to 600MW of power, enables it to further stabilise the cost of supplying electricity to its British Gas customers. The agreement will supply base-load power to Centrica under a contract linked to international coal prices, which will include seasonal fixed clean dark spreads. [53],[54] (Whether or not Centrica will in reality be supplied by Drax is not the question, the idea behind this type of contract is that both parties have accepted to sign a contract based on a coal market risk). This agreement provides the supplying company with greater coal and CO_2 exposure – the price of coal is less volatile than electricity or gas price among others. Although this agreement is not between an industrial and a supplier, it may very well be possible that similar contracts begin to develop between these players.

- *Long-term contracts similar to those under the regulated market, but at a price "not acceptable" by energy-intensive users*, as they used to be until a few years ago.

Today, getting into long-term agreements without sharing part of the investment risk is not attractive from the viewpoint of a power generator. Two reasons may explain their non-attractiveness. One reason is that the electricity companies may not see the economic rationale to tie up prices for up to 20 years ahead in the current volatile market, when they may not even know from which source the electricity will be produced, and thus offer "non-acceptable" prices. The second reason is the supposed fear that such long-term contracts will be deemed illegal due to competition law. This second reason remains in a grey area, and further research needs to be carried out on the subject.

Long-term contracts can have fixed or flexible prices, indexed on specific elements such as fuel prices or the industry's product prices. The contracts can cover a customer's entire consumption, or only a share of the consumption. Contractual agreements can also be based on a specific technology or on a mix of technologies.

The impact of the CO_2 constraint on contract prices is unclear and depends on the negotiated terms of the contract and whether the environmental constraint was regarded as probable at the time of negotiation. It is possible, for example, that fixed long-term contracts not indexed on market prices and concluded before market liberalisation, do not take CO_2 prices and costs into account. In such a case, generators or suppliers cannot pass-through the opportunity cost of allowances or the purchase

[53] There was no mention that Centrica would not pay the full opportunity cost of CO_2 allowances. Limits on the payment of all CO_2 allowances associated with the reserved electricity from coal-fired generation would probably have resulted in a different contract settlement according to internal sources.

[54] The agreement will run to the end of the EU Emissions Trading Scheme phase 2 in December 2012.

of allowances for compliance. In our interviews, it was indicated that the new long-term contracts indexed on coal prices include an indexation to CO_2 prices.

Nevertheless, we should be careful in considering that long-term contracts can influence the pass-through. What matters in a well functioning market is only the reference price. Thus, although such contracts protect industrials from increases in power prices (which can be due to CO_2 allowances), if the reference price includes a share of the CO_2 cost, long-term contracts which are indexed to market prices would in fact include a CO_2 cost.

7.2.2 Shorter-term Contracts

7.2.2.1 Direct Purchasing from the Market

For large industrial facilities which estimate that their future consumption patterns are largely based on their past consumption patterns, the latter may purchase their electricity directly on the market (i.e., exchange or brokered electronic platform). They generally make a distinction between their baseload consumption (both peak and off-peak), and their flexible consumption (see Figure 11). The electricity needs which facilities cannot forecast – or flexible consumption – can be bought on the day-ahead or balancing market. The latter are more volatile than forward market prices. This short-term volatility in competitive electricity markets creates the need for risk management arrangements - described in some detail in 7.5.

An industrial can spread the price risk by purchasing different electricity volumes at several delivery periods. Table 10 illustrates the different supply periods available on the French, German, English, Iberian and Scandinavian power exchanges. Only in the UK are annual contracts unavailable, they are mainly seasonal or monthly.

Table 10**: Forwards' and futures' Delivery Periods exchanged on Powernext, EEX, Nord Pool, APX UK, and OMIP**

DURATION	POWERNEXT	NORD POOL	EEX	APX UK***	OMIP****
Annual	3 Years baseload* and off-peak	5 Years baseload**	6 Years baseload and peak	None	1 Year
Trimester	4 Quarters baseload and off-peak	9 Quarters baseload	7 Trimesters baseload and peak	4 Quarters baseload and peak 10 Seasons base-load and peak	4-7 Quarters
Monthly	3 Months baseload and off-peak	6 Months baseload	6 Months baseload and peak	6 Months baseload and peak	3-5 Months
Weekly	None	6 Weeks	None	4 Weeks baseload and peak	3 Weeks

Source: Web sites

* *Baseload is defined as the minimum amount of electricity delivered or required over a specific time period at a steady rate, it includes consumption during peak and off-peak hours. Peak hours are referred to as the hours of the day where the demand is highest, e.g., from 8 am to 8 pm in France, and off-peak where the demand is low, e.g., from 8 pm to 8 am in France.*

** *Futures can only be bought 8-12 months in advance.*

*** *The products are only forward.* **** *OMIP started operation July 3, 2006*

Many of the largest electricity consumers spread risk by contracting a certain share of their anticipated consumption in one form of contract and other shares in other forms. The key point is that contracts can effectively shield consumers from short-run price fluctuations (IEA, 2005b).

7.2.2.2 Intermediary: Supplier or Generator

Suppliers have a similar method to industrials that purchase on the forward market in setting prices for fixed term contracts (EC, 2006). The cost to serve the bulk consumption of industrials is assessed with the help of forward price quotations prevailing at the time the offer is prepared.[55] The result is the actual cost of covering forward the client's consumption on the market (EC, 2006).

If there is transparency in the price settlement, depending on the contract established with the supplier, industrials' power purchasing strategy *can be equal,* depending on whether the installation purchases directly on the market or signs a purchase agreement with supplier/generator for power contracts.[56] Price settlement is considered transparent when the price is indexed to a market indicator known by all parties or prices are fixed.[57] In the case where the buyer decides to take the same price risk as that of the supplier, it could build a similar price system as the one offered by the supplier.

As mentioned above, the facility's electricity consumption can be represented by the load curve over 8760 hours. It is given by the industrial facility's historical or forecasted consumption pattern. Nevertheless, there is still uncertainty in the final electricity consumption. As a result, the final price offered by the supplier can be a mix between baseload prices representing for example 95 percent; balancing prices 5 per cent; plus a constant determined by each party.

In the UK, typical supply contracts run from April to March of the following year and are renegotiated each year. They are indexed to a large extent on market prices and often include a link to gas forward prices as well. As a result, industrial end-user prices are usually more volatile in the UK than in other countries in Europe.

In France, for industrials which do not have long-term fixed prices, in most cases, the contractual prices may be the sum of several elements: the baseload curve price which depends on the market price (90% or more based on future/forward prices or other indexes); a flexibility of the consumption curve which depends on the power consumption volatility; a cost of adjustment in case of very short term changes in consumption (based on the balancing market prices); and the supplier's margin.[58]

The pricing formula may be the same in other European countries, and where no forward or future markets exist, such as in Italy, the common practice may be for suppliers to build annual supply contracts based on: historical day-ahead prices if the market is mature enough, forward prices of the different price components (e.g., fuel, CO_2), or based on the suppliers' own generation portfolio if the latter owns one.

[55] The wholesale market price that is comparable with a contractual price is, for example, the price of an annual forward contract on the same day as the "bilateral" annual contract is agreed on between a supplier and a customer.

[56] This depends on the duration of each indicator (e.g., monthly; quarterly; cal; cal +1, etc.) and the risk the supplier is willing to take.

[57] Supply prices can be fixed when forward markets exist (e.g., Germany, UK, France, and the Netherlands).

[58] According to the supplier we interviewed, this tends to represent 1-3% of the price

The preliminary question to ask regarding the influence of CO_2 allowance costs on contractual prices is whether they are "all included prices" or whether the contractual price makes reference to a market indicator. If, the electricity price is indexed to an electricity market indicator, then it is probable that these include the opportunity cost of CO_2 allowances for reasons explained in 5.3.1 – unless regulatory intervention threatens to or has blocked any pass-through (e.g., Italy). If the breakdown of the contractual price is opaque, then, and the final customer pays "all-included" prices, then the influence of the CO_2 cost component cannot be assessed.

Moreover, the final price paid by energy-intensive industries is often lower than the contractual price. Reasons are that the latter may obtain several discounts by signing additional clauses to the supply contract (e.g., interruptible contracts), or by diversifying the sources of electricity purchases:

- *Interruptible supply contracts* [59]

In several European countries, certain industrial facilities may have their power consumption cut off by a determined quantity if market prices reach a certain level – specified in the contract. The reduction/cut off may be announced before, and the duration of the interruption is fixed. In such a case, the industrial receives a pay-back generally based on the balancing market price minus the supplier's fee. These are compensations which are generally paid by the TSO to energy-intensive industries for each MWh they declare interruptible. If the industrial does not reduce its consumption, it must pay for its additional consumption (total consumption - agreed consumption) normally at the balancing market price.[60] In Germany, industrial auto-generation facilities which can produce electricity when the market price reaches a certain level represent approximately 10 percent of the total German production (Ministère de l'économie, des finances et de l'industrie, 2004).

Often, energy-intensive industries which subscribe to interruptible contracts receive lower tariffs than those which do not, through paybacks. In Italy, for example, without prior announcement of interruptibility, industrials are paid €21/MWh; with 24 hour announcement, they receive €8/MWh. Likewise, Sweden has taken steps to sign up large industrial customers who are willing to be interrupted in return for a discount on regular electricity rates. [61] In Norway industrial consumers can sell options to the TSO related to security of supply

- *The industrial has bought blocs directly on the market and needs electricity for adjustments (flexible consumption).*

The contract between the supplier and the consumer can be based solely on adjustments between the blocs of electricity bought directly by the industrial facility and its real consumption. In such cases, the supplier can offer to buy the adjustments at the market price (e.g., day-ahead) and charge a commission.

- *The industrial is ready to take on part of the price volatility risk.*

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59 Interruptibility of power can be made with short or no announcement.

60 In France, however, industrials are not encouraged to sign these type of contacts as the industrial does not benefit from lower transport costs – which are determined by total consumption volume and not dependent on grid congestion management.

61 http://www.icfi.com/Newsroom/Energy_Nordic_Countries.asp

Where the industrial facility is not risk averse to price volatility or speculates that power prices will decrease, the contractual positions can be left open to renegotiation. For example, clauses can be introduced whereby prices are re-quoted every three months.

7.2.3 Elements Influencing Supply Contracts

In the scenario where industry contracts a power supplier, several elements may influence the final price paid by industry. These include the level of competition and regulatory involvement.

7.2.3.1 Market Structure: Competition Intensity

Depending on the market structure of the electricity market, energy-intensive industries may be in a position to negotiate the details of their contract and the level of suppliers' and/or generators' margins. Issues to consider include the vertical integration of suppliers, the switching rate of customers, etc. For example, in the case of monopoly on the supply side, customers will not be able to negotiate with the supplier unless they have the possibility to purchase electricity on the market themselves.

To counterbalance players in the upstream electricity market (e.g., generators, suppliers), industrial facilities can increase their negotiation power by aggregating their demand. Article 3 of the second electricity liberalisation directive specifies that "nothing in this Directive shall prevent Member States from strengthening the market position of the domestic, small and medium-sized consumers by promoting the possibilities of voluntary aggregation of representation for this class of consumers".[62] Industrial facilities can either create a consortium which purchases their electricity needs on their behalf (e.g., the case of Exeltium in France), or use the services of an existing "aggregator". An aggregator is a person or group that combines multiple retail customers or single customers with multiple sites or both into one or more buying groups or pools for the purpose of purchasing power. An energy supplier can provide this function, but a separate entity such as a broker or aggregator can also provide this function and then negotiate a service contract with an energy supplier on behalf of an aggregated customer group.[63] In Germany, in 2004, 31 electricity and 15 natural gas aggregates were listed, covering the purchases of 750 companies. Aggregators also exist in the UK and in the United States among others.

7.2.3.2 Regulatory Intervention

Beyond regulated tariffs which will be described in 7.4, regulatory intervention in liberalised power markets may be direct or indirect. It can influence market prices through several channels: building price indicators that can be used as a reference in contractual agreements; limiting price increases; organising virtual capacity auctions at prices which can be disconnected from markets; preventing market power.

- **Price indexes.**

Sometimes, governments play a role in market indices. In Italy, government intervention is not direct. The price index (Ct) it provides is an optional price indicator for electricity supply contracts. Ct was the best known indicator in the market, periodically calculated by the Italian Regulatory Authority for

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62 http://europa.eu.int/eur-lex/pri/en/oj/dat/2003/l_176/l_17620030715en00370055.pdf

Electricity and Gas (AEEG) for other purposes (i.e. in order to calculate the tariff of the captive customers). Using Ct for the bilateral transactions made it easier to calculate the economic advantage of the bilateral price compared to the tariff of the captive market. The Ct parameter was officially abolished by AEEG in December 2005; however, for information purposes, the Authority has been publishing a parameter called "VCt" (in Italian "Old Ct") in 2006, calculated in accordance to the same algorithms of the abolished Ct. Since Ct has gone out of use, other pricing formula were suggested to the consumers. Consumers frequently asked for a formula that reproduced the characteristics of the old Ct (basket commodities, indexing, and so on) because it proved more understandable, and made estimations easier.

- **Virtual capacity auctions**

In France, Belgium, the Netherlands, Italy, Denmark and the Czech Republic, incumbents' generation capacity has been made available to competitors through virtual power auctions. The first case in which virtual power plants were used was triggered by the European Commission's decision in 2001, following the merger between EDF and EnBW in order to solve competition concerns.[64] EDF, the French incumbent, was obliged to auction off 6 000 MW for five years to any operator wishing to procure electricity produced in France. Likewise, in Belgium, in 2003, Electrabel, the Belgian incumbent, started to auction off 1 200 MW of capacity to open up its generation sector to more competition. In Ireland, ESB is auctioning off 400MW of virtual capacity to open its generation sector (Public Utilities Fortnightly, 2005). In Spain and Hungary, governments also announced that virtual capacity auctions would be put in place.

The buyer of a virtual power purchasing (VPP) contract obtains a right (but not an obligation) to the output of virtual capacity, which entitles it to issue dispatch instructions and receive electricity output on the high voltage grid. Though the capacities are not associated with any particular generation unit, they do have certain traits that mimic base-load or peaking characteristics: Belgium VPPs distinguish base-load and peak load VPPs.[65] The durations of the contract were between three and thirty six months, and the price of each product was set after a series of six auction rounds. [66]

Where available, this mechanism may provide a means by which facilities could directly purchase their long-term electricity consumption at a fixed price, bypassing the need for a supplier or over-the-counter transactions.

- **Reducing possible market price distortions**

In the Spanish White paper on the Reform of the Spanish Competition System published in 2005, the government announced it would try to raise limits on how much generating capacity can be operated by those companies owning generation assets that set the marginal price of the pool. Likewise, the

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63 www.cis.state.mi.us/mpsc/electric/restruct/glossary.htm

64 In Denmark, the use of VPPs on an indefinitely time horizon was considered as appropriate to solve competition concerns that were raised in the merger between Elsam A/S and NESA A/S (2004). In the Netherlands, this type of remedy was used in the takeover of Reliant by NUON after the assessment of detrimental effects on competition in the Dutch electricity markets resulting from the proposed takeover.

65 Nevertheless, the duration of the contracts would need to be extended in order to provide price stability to the energy-intensive users. This has been requested by several industry representatives, and regulators. For example, the French energy regulator has proposed to increase the duration from 3-36 months to 3-15 years for energy-intensive users.

66 http://www.belpexvpp.be/pdf/General_Context_for_the_%20VPP_Auctions_v2_Belpex.pdf

way the market works would also be altered so that vertically integrated companies cannot simultaneously take up buying and selling positions in the same hourly slot.

- **Price variation limits**

In other cases, government intervention is explicit in determining movements in power prices. This has been the case in several European countries, although only in announcement.

In the Czech Republic, Poland and Hungary, there is a practice to use the major state-owned wholesaler companies (CEZ, PSE and MVM, respectively) to absorb, at the cost of their profits, increasing producer prices instead of allowing this increase to be reflected immediately in final prices (Kaderják, 2005). In 2003, the wholesale margin was minus 9 percent in Poland, while the Czech and Hungarian wholesale companies were running in a "non-profit" mode.

- **Rebates based on special provisions**

Although similar provisions may exist for energy-intensive users in other European countries, because of lack of availability of data, this section focuses on one particular example.

In Italy after market liberalisation, the government decided to assign electricity produced from renewable and assimilated sources (so-called CIP 6 energy) to energy-intensive customers at a lower price than the market price (fixed ex ante every year) in order to find a cheap source of energy for intensive customers,.[67] There is no formal right for the energy intensive customers to buy this energy as it is destined to the market. Nevertheless, this energy is sold to the market is through flat ribbons of energy for the whole year (MW per 8760 hours). This of course means, in practice, that for customers that have high and flat demand curves for the entire year, it is much easier to buy this energy. They are able to buy much more than the other customers (i.e. customers that have a modulated demand curve or who don't work 8760 hours per year, all year long). This is exactly the case for energy intensive customers and some bigger traders.

7.3 Self-Generation with or without a Third Party

The decision to auto-produce electricity is mostly available at the project design phase: afterwards, the choice is largely irreversible. Industry experts explain that, the building of on-site cogeneration is economically justified only in the case of industrial processes use both electricity and heat. Generally, energy-intensive users decide to generate their electricity in mainly three cases:

1. The fuel price is low (i.e., access to low cost natural resources);
2. The quality of the transmission or electricity is "bad" and/or;
3. The cost savings from grid transportation are high.

An industrial facility can do so either by investing in the majority of a generation asset or in only a share (directly or indirectly thorough a consortium). By integrating vertically to ensure the supply of base load electricity at low cost, industrial facilities are able to manage the supply of their base-load needs and the price volatility.

67 The plants that produce CIP 6 energy (the existing ones) are well identified and today their production accounts for 55 TWh per year (more or less).

In Europe, several manufacturing sectors own power generators. Table 11 provides the self-generation capacity in the EU-19 for cement, chemicals and fertilizers, equipment manufacturers, metals mining and smelters, pulp paper and forest products, sugar mills and refinery plants. These numbers include another category, "autogenerators" which belong to an industrial or commercial sector. Overall, out of 695 GW representing the total capacity in operation in EU-19, 63 GW belong to industry. The largest self-generating sector in EU 19 is the chemical sector with 8.25 GW installed capacity, followed by the pulp and paper sector with 6.8 GW, refineries with 4.7 GW and metals and mining with 4 GW.68 The main fuel used in the case of self-generation is natural gas fired in a gas turbine, followed by oil and coal.

Table 11: **Self-generation Plants in Operation in EU 19**

TOTAL PLANTS IN OPERATION IN EUROPE	MW 63,220
Oil	9,069
GT	1,512
Steam	6,069
Internal combustion	1,324
CCGT	163
Gas	15,481
GT	7,566
Steam	1,940
Internal combustion	1,319
CCGT	4,656
Fuel Cell	1
Coal	8,071
Nuclear*	1,740
Hydro	2,107
Geothermal	-
PV	19
Wind	218
BioEnergy	1,918
BioGas	46

Source: Platts, IEA

** Two TVO reactors in Finland*

Ownership is a physical hedge against fluctuations in electricity prices (IEA, 2005b). The role and significance of such a physical hedge must be analysed in the context of other contracting opportunities in the market. All electricity suppliers (including self-generators, since they can sell to the industrial facility or to the grid) have the opportunity of selling the electricity on the market instead of to identified end–users. The market price represents, therefore, the opportunity cost of selling to end-users (i.e., industrial facility) (Lewis et al, 2004).

Whether the industrial facility will pay an overall price lower than the market depends on an internal company decision (or among plant shareholders if there is multiple ownership in the generation assets). For example, the electricity produced can be sold at production cost. This is the case for the

68 In this classification, "autogenerators" was not considered as a homogeneous sector. If it were, it would

Finnish electricity company Teollisuuden Voima Oy (TVO), a cooperative of large electricity consumers and municipal utility companies, which owns two nuclear power plants already in operation and an EPR to be commissioned in 2012.[69] TVO agreed to sell electricity "at cost" during the life of the EPR plant (40 years) to its investors in proportion to their contribution to the investment. This is the so-called "Mankala principle".[70] This structure of investment should ensure stable electricity prices and become a "physical" hedge towards fluctuations in electricity prices. Moreover, it reduces investment risks by securing the demand of energy generated through long-term commitments. The downside to these long-term contracts lies, nevertheless, in the fuel price volatility over the life-time of the investment.

If the industrial facility fully owns the generation plant and pays the market price, the extent of the CO_2 pass-through to its cost will depend on the pass-through on the market. In reality, however, there will be a lump-sum transfer within the company since allowances are allocated for free with the exception of CO_2 allowances purchased to cover excess emissions. Thus, although the benchmark price for the internal contracts may be the market price, overall, industrial facilities in such situations will pay less than their competitors who go through suppliers or purchase electricity directly on the market. There is only a wealth transfer between the electricity producing division and the electricity purchasing division. It is also possible that although the reference price remains the market price, they may agree on a price between cost-plus basis and the market price. Table 12 highlights the main savings an industrial facility may obtain by producing its own electricity.

Table 12: **Savings from Self-generation**

FREE ALLOWANCES	AUCTIONED ALLOWANCES
• Lower transmission costs • Share in savings from free CO_2 allocation • Share from lower production costs if the market price is not the reference price (i.e., production costs plus a margin)	• Lower transmission costs • Share from lower production costs if the market price is not the reference

Table 13 provides examples of self-generation plants, whether fully owned by the industrial facility or shared among several companies. The advantage of having a consortium-type of structure over the ownership of a generation facility also relates to the company debt. A consortium allows a company

be second with 7.7 GW of installed capacity.

69 TVO is part of the Pohjolan Voima Group, under the parent company Pohjolan Voima Oy (PVO), which owns some 60 percent of TVO shares. PVO was established by large industrial electricity consumers, mainly from the Finnish pulp and paper industry. These large industrial electricity consumers still represent the largest share of the owners but today PVO is also partly owned by local municipalities – either directly or through municipality owned utilities (IEA, 2005b).

70 Among other power companies that operate on the same principle are Etelä-Pohjanmaan, Kemijoki and Teollisuuden Voima.

to deconsolidate the debt as the consortium may legally be an independent company in which members have participation.[71]

Table 13: **Examples of Self-generation Situations**

TYPE OF ACTIVITY	EXPLANATION
Power plant	RWE and Electrabel of Belgium formed in 2001 a consortium (Zandvliet) to build a combined heat and power plant 400MW for BASF at its production site in Antwerp. Most of the electricity produced will be used by BASF to meet its own needs on the site, while the remainder will be fed into the grid to supply the respective customers of the two partners.
Power plant	A partnership (DK6) between Gaz de France and Arcelor was signed in 2002 for the construction and operation of a combined cycle gas plant of 800 MW including 225 MWe reserved for the transformation of steelworks and coke oven. In this partnership, DK6 is the owner, builder, and operator of the plant while Dunelys – an unconsolidated GDF subsidiary - is in charge of the purchase of natural gas, and the sale of electricity.
Power plant	An agreement was made in 2004 between Electrabel and the steam host, Solvay for a 400 MW combined-cycle unit in Rosining in Italy. The project, called Roselectra, results from an agreement with Electrabel, which will build, own and operate the power unit on grounds supplied by Solvay. Part of the power station's production and steam will be assigned to Solvay in the framework of a long-term contract. Surplus electricity will be sold on Italy's deregulated market. It is expected to start operating from 2006.

Source: Author; European Commission, 2006

To conclude on whether self-generation contracts make reference to CO_2 prices and include a pass-through rate is unfeasible because each situation is specific and information on such contracts is confidential data. The answer depends on the tariff practice of the different generation plant shareholders, but reference to CO_2prices and inclusion of a pass-through rate is possible.

7.4 Regulated Tariffs

In Europe, not all countries have maintained regulated tariffs for energy-intensive industries – although the second electricity liberalisation directive does not explicit their removal. ANNEX 2 in summarises the current position by member states for large industrial user price controls.

In several European countries (e.g. Italy, etc.), government has planned tariffs to prevent intensive energy industries to relocate in countries where the electricity is cheaper – "delocalisable electricity intensive companies". Many large energy users have found themselves paying more since leaving regulated tariffs for market prices. This is partly why several countries have allowed industries to re-enter regulated tariffs (e.g. Italy, Spain, and since November 2006, France) (EASAC, 2006). These

[71] I.e., separation of the debt from the other financial accounts

countries should be differentiated from those that do not allow non-captive customers to re-enter regulated prices (e.g., France before the adoption of a decree November 8, 2006). [72]

The retail market in Spain is characterised by the existence of the "tarifas integrals" to which all industrial consumers are allowed to come back.[73] Furthermore, certain industrial facilities are entitled to so-called G4 tariffs.[74] Spanish regulated tariffs are disconnected to market prices: in June 2006, the latter reached approximately EUR24, while day-ahead power prices were around EUR55. The White book that was published in 2005 nevertheless underlines the necessity to bring these tariffs in line with the actual cost incurred by companies. As a result, supply companies are expecting that the regulated tariff will incorporate part of the cost associated with the CO_2 constraint.

In Italy, industrial customers can, whenever they choose to do so, come back to the captive market (whose customers are supplied by the Single Buyer). In this case they would pay a tariff linked to the weighted average portfolio cost of the Single Buyer (plus some cost components stated by AEEG – the electricity regulator). An ad hoc tariff for industrials, nevertheless, does not exist.

In Hungary, an eligible customer can move from the administratively priced captive to the free market segment and vice versa at almost no cost. The advantage of the free market can last only until it is cheaper than public service. The size of the competitive free market segment is determined by the relative prices on the free market and of public supply.

In CENTREL markets, the electricity Directive foresees the transition to full market eligibility in a vague manner.[75] While "vulnerable" consumers might be supplied by electricity at an administratively set tariff, there seems to be no explicit constraint on who else might also be eligible for the status of a "regulated" consumer after July 2007. Until eligible customers have the right to choose from the administrative and the competitive price- and this is a low cost choice- a strange competition between the two market segments may develop. A consequence might be that the free market price will converge to the administratively set price. It is, therefore, up to each regulator/government to decide whether regulated prices pass-through the CO_2 cost.

In the case of regulated tariffs, the decision to pass-through the opportunity cost of CO_2 allowances depends on each government. In the Energy Information Administration report, it is expected that if a portion of allowances is provided for free to regulated utilities, "regulators are expected to pass these savings on to consumers" (EIA, 2007). Increases electricity prices equivalent to the opportunity costs of free allowances would not occur.

The risk of not allowing the full pass-through of CO_2 allowances discourages investment, from the viewpoint of generators, if they are unable to recover the full cost of a new facility. This comes back

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72 http://www.senat.fr/leg/tas06-021.html

73 Nevertheless, customers who change to regulated tariffs from market prices and vice versa must guarantee to not change scheme before at least one year (Decree 1435/2002, 27/12/2002, Article 4, subparagraphs 1 and 2).

74 Eligible customers must have a contracted load of 100MW, and consume electricity more than 8000 hours a year, or more than 800GWh annually. Furthermore, on a monthly average, the facility must consume electricity more than 22 hours a day and at a 145kV voltage.

75 CENTREL is the regional group of four transmission system operator companies: ČEPS, a.s. of the Czech Republic; Hungarian Power System Operator Company- MAVIR ZRt. of Hungary; PSE-Operator S.A. of Poland; Slovenská elektrizačná prenosová sústava, a.s. - SEPS, a.s. of the Slovak Republic. www.centrel.org

to the discussion on the influence of ETS's design, i.e. whether new entrants must pay for their CO_2 allowances. This will be examined in the next section.

7.5 Risk Management through Market Derivatives, Energy Management Companies and Self-generation

Volatility is inherent to the electricity market, and electricity prices are more volatile than other fuel commodities as illustrated in Table 14. CO_2 prices and their associated volatility have also participated in increasing the electricity price volatility.

Power exchanges in France, Germany and the Netherlands have more price volatility than natural gas markets. The ownership of generation facilities may, as a result, lessen the price risk of an industrial facility. Similarly, short-term (i.e., balancing and day-ahead) prices tend to be more volatile than forward prices (i.e., monthly, quarter, trimester, annual) and peak prices are less volatile than base-load prices.

Table 14: **Price Volatility Comparison between Natural Gas and Electricity Prices**

	POWERNEXT	**EEX**	**APX**	**NORD POOL**	**ZEEBRUGGE**	**NBP-ENMO**
Products	Electricity	Electricity	Electricity	Electricity	Natural gas	Natural gas
Volatility	61.4%	50.15%	125.55%	6.41%	6.07%	10.69%

Source: Chevalier and Rapin, 2004

Industrial facilities (i.e., electricity consumers) exposed to price risk are those which borrow one of the purchasing strategies seen above – with the exception, to some extent, of regulated prices and agreements signed with suppliers on the basis of fixed prices. [76] Regulated tariffs also carry a risk, as they are subject to unpredictable governmental decisions.

- **Through a supplier:** Generally, a risk premium is included to the total contract price. This risk premium allows the supplier to take into account the price volatility during the contract. Industrial facilities may not need to manage the price risk.

- **Self-generators:** The nature of price risks self-generators face are among others fuel price volatility – if they are not tied with long-term supplying contracts for the fuel they purchase; or those that use market prices as a benchmark for the valorisation of their production.[77], [78]

[76] Both theoretical and empirical evidence support the hypothesis that generators hedge most of their output through derivatives contracts (Termini and Cavallo, 2002). According to Powell (1993) and Green (1999), the fact that consumers tend to be more risk averse than generators gives the latter an incentive to sell derivatives contracts in pursuit of the risk premium.

[77] Note that the fuel hedging contracts are different from the hedging contracts for electricity. Reasons lie in the non-storability of electricity, the seasonality and the price spikes of electricity. Thus the notion of convenience yield – which captures the benefit from owning a commodity minus the cost of storing it, and which makes the link between spot and future prices – cannot apply.

[78] A study by VIK in 2003 reveals that industries that own auto generation facilities tend to play a more active role in their purchasing strategies – by building more complex strategies – compared to those which do not, and have a propensity to accept supply offers put together by suppliers (Ministère de l'économie, des finances et de l'industrie, 2004).

- **Direct purchases**: As illustrated in Figure 11, when contracting on the power market, industrials will partition their electricity consumption in several blocs according to its predictability. Depending on the price volatility in the different markets (i.e., balancing, day-ahead, forward, etc.) and the different degrees of risk associated to each market, to protect them from high price volatility, they can enter into "hedge contracts" with counterparties or use market derivatives to manage the price risks that arise.

7.5.1 Hedging Instruments beyond Forward Contracts: the Use of Market for Electricity Purchasing or Self-Generation

Risk management in electric markets involves various forms of financial instruments for hedging in the long-term bilateral markets as well as products offered in the short-term organised markets (FERC, 2004). Nevertheless, consumers will have to pay in order to hedge price risk, and this payment is itself a form of economic risk.

Derivatives are contracts, financial instruments which derive their value from that of an underlying asset – in this case electricity or fuels in the case of contract indexation. As long as generators and consumers can rely on an underlying physical market, as far as they are concerned, a purely financial contract has the same value as a contract with physical commitments (IEA, 2005b). Such instruments allow, for example, electricity buyers to transfer the price risk to other players who could profit from taking the risk. The structure of these contracts varies by regional market due to different conventions and market structures.

Risk management can be made either directly by the industrial, using internal competencies or by intermediates (e.g., banks, brokers, service companies etc.). Moreover, hedging products can be standardised (e.g., futures), traded at power exchanges where clearing is often offered, or tailor-made to the customers' needs (e.g., forwards), traded on a bilateral basis. They can also cover the price risk or the volume risk as volume also needs to be managed. [79]

Beyond different future and forward contract which allows hedging of short term/medium term selling and buying of electricity, more tailor-made hedging contracts have emerged in parallel with liberalisation. On the OTC market, the two simplest and most common forms are simple fixed price forward contracts for physical delivery of a fixed quantity, and contracts for differences where the parties agree a strike price for defined time periods. However, more complex price structures exist on the OTC market. For example, OTC supply contract can be indexed contracts, cross-market contracts, floating contracts including cap and floor prices or not, or contracts for differences.

- *Fixed prices and quantities*. These contracts are for physical delivery at a defined location. They protect the consumer from market price volatility but may not isolate the consumer from a CO_2 cost element. For example, such contracts concluded in 2006 may make reference to 2005 market prices, and therefore include a part of 2005 CO_2 prices.

- *Indexed contracts.* One way to hedge against price volatility is to index the electricity price to the output price. For example, the electricity price that the facility pays is determined by an index based on aluminium or steel prices. In such cases, the consumer is protected from the CO_2

[79] Thus, many bilateral contracts on the OTC market have a flexible underlying volume of electricity. The buyer of such contracts has the right to *swing* his load. Such contracts are called *swing options*.

element factored in to market prices. Through such contracts, the facility can also obtain fixed margins, i.e. the ratio between electricity costs and revenues (Unger, 2002).

- *Cross-market contracts.* These types of contracts are mainly initiated by industrial facilities which auto-generate their electricity, or for electricity producers. Since the fuel costs the dominant share of generation costs, a generator may wish to hedge the fuel price uncertainty.[80] There are products linking fuel prices with electricity prices in order to offset the spread risk (i.e., difference between electricity prices and fuel costs). These cross-market contracts can be a fuel-electricity swap for example, or options on this swap (Unger, 2002). A widely used cross-market contract is the spark spread option – the buyer of such a contract has the option to switch one unit of gas for one unit of electricity at a specified strike price. Such derivative products do not necessarily make reference to CO_2 prices. The only reference made to CO_2 prices is through electricity prices –an indirect reference.

- *Floating price with a cap and a floor.* A contract with a fixed quantity (but a floating price) is a long-term contract where the buyer pays a short-term price in each period – often the day-ahead price. The floating price can be seen as an indexed contract, where the index is the day-ahead market or any other short-term reference price (Unger, 2002). The reference to CO_2 allowance prices is not explicit is these derivative contracts and is made through the indexation to market prices. The exposure to the market prices (and CO_2 price volatility) is therefore similar to when the consumer pays a price indexed to market prices and can be limited by the use of a cap and a floor price.

- *Contract for difference.* In the case of a contract for difference, if a resulting market price index (as referenced in the contract) at any period is higher than the "strike" price, the generator will refund the difference between the "strike" price and the actual price for that period. Similarly, a retailer will refund the difference to the generator when the actual price is less than the "strike price". The exposure to market prices (and the indirect payment of CO_2 allowances) is similar as in the previous derivative contract, and can be contained with the use of a strike price.

It is not possible to hedge against electricity price risk in every European country. In Slovakia, for example, since traders are not yet active, the risk management services that are provided by traders and balancing circles on other central European country (CEC) markets are not yet available for market customers. The bulk of daily OTC trade in Hungary aims at smoothing the profiles of relatively large balancing circles in order to avoid paying relatively high balancing energy prices. As a result, the share of balancing energy in total electricity consumption is negligible in that country (Kaderják, 2005).

7.5.2 Risk Management Service Companies

Along with introducing competition in electricity and natural gas markets, price volatility exposure created demand for commonly understood and accepted risk management procedures. This has entailed new business opportunities for so-called energy management service companies. Their role is, among others, to develop services around energy consumption and electricity purchasing. They may identify, define and offer guidance on risk management for their clients (i.e., small and medium

[80] Nevertheless as noted by Unger (2002), the amount of fuel to hedge is not known for the generator which sells its electricity on the dispatch market.

sized companies or large industries). However, their role may go beyond hedging price volatility. They may also monitor electricity investment opportunities for companies that wish to enter the self-generation market and arbitrate between consuming their own electricity and selling it onto markets. In such cases, they can be considered as a new intermediary between generators, consumers, and energy markets.

Table 15 describes two energy management service companies created following industry's initiative concerned about recent developments in the price of electricity in the Nordic countries. The 15-year electricity supply agreement between the Swedish company BasEl and United Power, which was signed at the end of 2005, [81] serves as a model for the type of services these service companies aim to develop.

Table 15: **Examples of Energy Management Service Companies created by Industry**

Sweden	BasEl was formed in June 2005 by a number of electricity-intensive companies primarily active in the forestry, steel, chemical and mining industries and operating in Sweden and elsewhere. BasEl's aim is to safeguard the interests of these companies and of Sweden's basic industry in terms of a long-term, stable and competitive electricity supply. BasEl focuses on tangible projects aimed at boosting the supply of competitively priced electricity in Nord Pool's markets. These projects may involve both electricity generation, in Sweden and elsewhere, and electricity transmission capacity. At the initial stage, BasEl's objective is to boost the electricity supply in the Swedish market by approximately 10 terawatt hours per year.
Finland	ElFi was created in the summer of 2006 by 60 companies ranging from glass or steel producers to supermarkets. ElFi's role is to provide expert services to parties in the energy market. If a power generator decides to sell shares in a new power generating facility, for example, ElFi should, in theory inform its shareholder, who can then decide whether or not they wish to take participation. ElFi also offers price risk management (portfolio management service), but its mandate is not to purchase electricity on behalf of its members (i.e., the role of an aggregator)., Several members of ElFi may nevertheless decide to regroup themselves to purchase electricity or invest in generation assets.

7.6 Conclusions on Level of Supply Prices and Exposure to Market Price Variations (and Indirectly to CO_2 prices)

7.6.1 European Regional Disparities

In its medium term strategy paper for Europe's internal electricity markets, the European Commission intends to regionalise European power markets between 2005 and 2009 into several trans-national markets before integrating it in a single EU market by 2010. The regions are: west continental Europe,

[81] The agreement is on the supply of 8.7TWh per year from Russia starting in 2009. This agreement covers supply over 15 years, and approximately 30 percent of BasEl's power needs. At this stage, the agreement is both preliminary and conditional, because the process for seeking a license for setting up the cable to supply United Power with Russian nuclear electricity remains open.

Iberia, Great Britain/Ireland, East Europe, South East Europe, Nordic region and the Baltic States. [82] In Europe, since not all regions carry the same markets, purchasing strategies differ by area. Based on interviews with industry, the most representative price indicators paid by industrial facilities are the following:

- *Market exchange prices set by the marginal generator.*

In Scandinavia**,** prices formed on the Nord Pool exchange, representing the hourly marginal cost of the marginal generation plant, are the dominant element of electricity supply contracts

- *"Screen prices" with trading of blocks for baseload needs.*

In the UK, prices paid by industrial facilities can be set on electronic platforms (i.e., "screen pricing") through the trading of blocks (daily, monthly, trimester), which are generally formed by continuous trading. To have the final cost of supply, costs of intra-day adjustment are included. The main exception to "screen pricing" is the long term contract signed between Centrica and Drax, where the price is indexed to international coal prices and CO_2 prices.

In continental Europe, the main supply contracts are based on "screen prices" for annual blocks.[83] The final cost of electricity includes the purchase day-ahead needs with prices set on the market exchange as well as intra-day consumption adjustments.

- *Annual contracts*

In Italy, prices are based on annual contracts via tenders.

- *Regulated tariffs*

In Spain, "regulated" tariffs may be a chosen option although since 2006, there is a negotiation between industry and generators for the supply through long term contracts based on the generation costs of domestic coal-fired plants.

7.6.2 Conclusions based on Generic Purchasing Strategies

On a more general and less-EU focused view point, there are several ways energy-intensive users purchase their electricity as listed in Table 16. It assesses:

- Whether there is a strong link between the electricity price paid by the EIIs and the day-ahead price;
- The extent to which each strategy involves a price risk from the industrial facility's view point, or allows risk sharing between generators and consumers (in the case where the industrial does not self-generate electricity). Does risk sharing allow lower price volatility

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82 http://ec.europa.eu/energy/electricity/florence/doc/florence_10/strategy_paper/strategy_paper_march_2004.pdf

83 There is a mistake to avoid when considering the annual supply contracts electricity companies offer. When electricity suppliers offer such contracts, this does not correspond to a risk management strategy on the generator's behalf (although they secure the supply of electricity over one year or more). A generator will not necessarily use forward or future contracts to secure his price.

exposure? Does it permit EIIs to pay prices lower than market price levels – and thus limit increases in electricity prices due to CO_2 prices?

- Whether EIIs' purchasing strategies allow them to have an overview on the choice of electricity they are being supplied with.

While some may involve minimum risk sharing with the power generator but provide no oversight on the generation asset, others may entail high risk sharing with the generator notably in the case where the industrial has built its own generation asset to supply its needs. Note that in all cases, day-ahead market prices are always used as the benchmark to which contractual prices will be billed or compared, in the case of self-generators.

Table 16: **Summary of Different Electricity Purchasing Strategies**

	RELATION TO DAY-AHEAD PRICE	RISK BORNE BY EII	EII ROLE IN GENERATION TECHNOLOGY
Annual power contracts for base-load for a single facility/company	Low	Low	None
Aggregation of purchasers	Low	Low	None
Aggregation of purchasers – share in payment of upfront cost of capital	Depends on the contract	Depends on the market price level	Strong
Day-ahead price indexed contracts	Strong	Low	None
Fixed prices and quantities	None	Low	None
Fuel indexed contracts	None	Low	None
Cross-market contracts	None	Low	None
Floating price with a cap and a floor	Yes but in a limited manner	Low	None
Contract for difference	Low	Low	None
Regulated prices	Depends on the price setting body	Low	None
Investment in generation assets alone	Depends on the mark to market intensity	Full	Strong
Investment in generation assets with several owners	Depends on the mark to market intensity	High	Medium to strong

Source: IEA assumptions

** Indirectly CO_2 price movements*

7.7 Section Summary

Whether or not industrial contract prices are below the market price which includes the full opportunity cost of CO_2 allowances depends on the contractual parties (i.e. suppliers, generators, EIIs).

The main factor to bear in mind when stating that industrial prices can be lower than market prices is when the industrial facility accepts risk sharing by investing directly or indirectly (e.g., shares in a company owning the power plant) in the cost of construction of a power plant and is, therefore, in a stronger position to negotiate the contractual price. There may be another reason: are we comparing the same or relevant contracts? The market price that is comparable with a contractual price based on forward prices is, for example, the price of an annual forward contract the same day the "bilateral" annual contract was agreed upon between a supplier and a customer. This has not been a very easy comparison in the last couple of years, when forward and contract prices have been quite volatile.

Regardless of the price EIIs pay, they most often remain exposed to electricity price volatility.CO_2 price volatility has also participated in its increase. There are different ways in which electricity users may decide to manage the risks associated with volatility – e.g. various financial contracts on electricity markets. Energy-intensive industries are increasingly seeking ways to engage in long-term contracts or to take stakes in power generation projects. Obviously, such contracts may also carry the risk that future market prices are below the contracted price.

Self-generation as a risk management approach- but also as a way to benefit from increased market prices- will be further assessed, as well as the implications emission trading schemes may have for investment in low-carbon technologies and investment in general in the next section.

8. Self-Generation Investments

Several questions arise on the matter of future electricity capacity building, if we consider self-generation investments. Are there any projects for new self-generation capacity building? Do the rules in the emissions trading scheme raise barriers to new entry in the power sector? In the case where new entry is free, what incentives are there to build CO_2-free technologies?

In this section, we will concentrate mainly on the way new entrants (i.e., for self-generation purposes) are treated in the different emission trading national allocation plans (NAPs). We will not cover the issues of plant closure or transfer provisions and or how the power sector is treated in the NAPs. By describing possible investments, we will also discuss the impacts on the overall CO_2 content in the electricity market. Lastly, we will explain the way uncertainty in current and future CO_2 allocation plans may delay or dissuade self-generation investments.

8.1 Investment Decision Factors in Electricity Production

The decision to auto-produce electricity is mostly available at the project design phase: afterwards, the choice is largely irreversible. The decision is based firstly on financial matters. Electricity plants are highly capital-intensive, but once built, they can last for decades. When deciding to build a self-generation plant, therefore, analysis should be made on the immediate- but also the future- environment. Several elements need to be taken into account, including (Kara, 2006):

- Electricity price development. When building a power plant for self-generation purposes, as mentioned above, the cost of the self-generated electricity is compared to market prices. If prices are above for a certain period, then it is rational to invest. Estimates for prices beyond forward price indications are needed.
- Political steering. Political risks include, for example, the creation of economic or environmental constraints that may change the profitability of self-generation investments.
- Price development of fuels and emission allowances. Naturally, prices developments of the power plant's feed costs are of critical importance in the outcome of the investment's profitability.
- Electricity consumption estimates may also be an important factor, but this mostly depends on whether the industrial facility has additional available capacity and sells the latter to the market.

Table 17 details the technologies under construction in the EU-19 for industry's self-generation purposes. These include plants from several industry sectors: sugar mills, cement, chemicals, equipment, metals and mining, pulp and paper, food products, shipping and transport (e.g., airports). In this table, private power developers were not included as no information was given on their activity. [84]

[84] If they were, 5 GW should be added to the 'under construction' number.

Table 17: **Self-Generation Plants under Construction in EU-19**

UNDER CONSTRUCTION	MW
Gas	320
GT	228
Steam	38
IC	54
CCGT	0
Fuel Cell	0.2
Coal	20
Hydro	2.8
Geothermal	0
PV	4.7
Wind	0
Bio Energy	167
BioGas	0

Source: Platts, IEA

Most self-generation projects rely on gas. What are the possible additional CO_2 emissions associated with the self-generation power plants under construction before 2008? Any estimates of additional direct emission from new self-generation facilities would be full of uncertainty. It is, indeed, difficult to predict what generation technologies these new investments would displace.[85]

The choice of gas over coal, for example, is positive from a CO_2 perspective as gas-fired electricity emits half the amount of CO_2 than coal fired. However, it is not clear at this stage whether the existence of a CO_2 cap in Europe is the primary driver for such choice, or whether the flexibility of gas-based turbines and the existence of by-products that could be combusted with gas restricted the choice of technology.

Box 1: **Do Electricity Supply Contracts influence the CO_2 Pattern of Investments?**

Unless an industrial facility is a generator or owns a share in the new plant, when signing a supply electricity contract based on a specific technology, a contract implies two parties that agree to pay the price of electricity based on indices. It can be an agreement between parties to share the price risk associated with a given technology, including paying the cost of capital of a fictive plant. Thus, apart from self-generation, no purchasing strategy described here has a direct impact on the generator's investment choices. A generator may agree to sell electricity based on a nuclear index and yet produce from gas, and invest in a non-coal generation technology. brings about lower CO_2 emitting plant, nor changes the investment patterns unless these low-CO_2 emitting technologies are less risky from the

[85] Furthermore, regarding new entry and overall additional CO_2 emissions, there is a distinction to make on the load at which the new plants will enter the market (i.e., base-load or peak). If the new technology is designed for base-load, it may displace more CO_2-intensive technologies on the merit order, unlike peak facilities which will displace a lower amount of capacity. If the new power plant enters the peak supplying market, the effect on electricity prices will be less depending on the number of hours of use during the year as new plants are assumed to be more efficient and thus need less fuel for the same output. Indirectly, CO_2 prices may also be lower as the high energy efficiency rate of the new facility may generate less CO_2 emissions than the displaced technologies.

generator's perspective (e.g., wind or biomass from a price risk perspective).[86] It remains to the generator to decide in the investment decision.

8.2 Scheme Design and new Entrants Impacts on Choice of Technology for Self-generation

- **Do the different NAPs raise barriers to self-generation investment decisions?**

Within the EU ETS, member states follow several means to incorporate new installations into the emissions trading scheme. Aside from the exceptional cases of Malta and Cyprus, where no new growth is planned before 2007, each state operates a New Entrant Reserve (NER) of allowances that expires at the end of the first period. If the size of the NER turns out to be too small, distribution of free allowances for new entrants on a "first-come, first-served" basis generally applies. By contrast, governments in Germany and Italy guarantee that all new entrants will receive allocation for free and government authorities will purchase the allowances to refill the NER, if necessary (Öko Institut and Ilex Consulting, 2006).

The only exception is Sweden which requires new installations in the power sector (other than CHP plants of a certain degree of efficiency) to buy their allowances on the market.[87,88] New entrants are therefore, for the most part and in most countries, treated the same way as incumbents; the CO_2 constraint only becomes a financial cost if the facilities emit beyond their allocated cap, which itself depends on the choice of allocation method (e.g., emissions based on Best Available Technology (BAT) installations; on average benchmarks; etc.).

Table 18 provides an overview of the size of the NER size in Italy, UK, Spain, Poland, Germany and Netherlands for the first NAPs. It indicates that the share of NER in the total allocation is different in the six countries. Italy provides the greatest reserve for the new entrants in comparison to the others. The reserve for the UK seems at first to have approximately the same magnitude as Italy, but the UK reserve applies to all sectors, whereas in Italy, almost all of the reserve is intended for new entrants in the power sector (Öko Institut and Ilex Consulting, 2006).[89]

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[86] One exception is the purchase of "green" electricity, i.e. MWh that are certified as originating from renewable and other sources. In this case, although the actual power may come from a fossil-fuel plant, there is certainty that renewables have been used to generate power somewhere in the system.

[87] Each member state has developed special rules regarding investment in new CHP plants, and those rules vary considerably between countries. For example, a new natural gas CHP plant would receive allowances corresponding to 130 percent of its emissions in Germany, 120 percent in Finland, 90 percent in Denmark and 60 percent in Sweden.

[88] By forcing companies which invest in new plants to purchase allowances, the emission constraint might represent an entry barrier (Reinaud, 2003).

[89] The NER in Germany seems small, but is to be replenished when empty

Table 18: **Overview of the NER Size in six European Countries**

Country	Total number of allowances[a]	Size of the NER	Share of NER of total
	Million EUA/a	million EUA/a	%
Germany	499	3.0	0.6
Italy	232.5	21.7[b]	9.3
Netherlands	95.5	2.5[c]	2.6[c]
		For unknown new entrants:	
		2.5	2.6
		For known new entrants:	
		not yet defined	-
Poland	239.1	0.94	0.4
Spain	174.4	2.9[d]	1.7
UK	245.3	15.1[e]	6.2

Notes:

[a] Figures do not take into account any opt-ins and opt-outs of installations in accordance with art

[b] Italy: For the energy sector the reserve is 20.33 million EUA/year.

[c] Netherlands: only for 'unknown new entrants', the reserve for 'known new entrants' has not yet been conclusively defined.

[d] Spain: 1.0 million EUA/year is earmarked for the electricity sector and is already included in the 86.4 million EUA/year allocation established for the sector. The remaining 1.994 million EUAs/year are allocated to industrial sectors (pool) and 0.364 is for cogeneration activities associated with sectors not listed in Annex I to the Directive.

[e] UK: 4.63 million allowances are set aside for good quality CHP and the remainder is open to all new entrants (including CHP if their reserve runs out). A further 0.5 millions allowances are set aside for incumbent installations that are identified late.

Sources AVANZI, ILEX, ILEX Iberia, ESC, Öko-Institut

o **Do the different NAPs encourage the investment in low CO_2-emitting technologies?**

A cap on CO_2 emissions should, in theory, encourage new investments towards low-emitting technologies. However, in practice, investment signals may be distorted in a number of ways. The implementation details of any emissions trading scheme prove decisive, as they eventually determines environmental effectiveness – and reinforce or undermine the scheme's legitimacy. New entrants and closure rules are the main focus in this debate. One of the main criticisms made of the EU ETS has been that it discourages investment in new and low-carbon technologies (Egenhofer, 2006).

Between six European NAPs studied by Öko Institute and Ilex Consulting (i.e., Italy, UK, Spain, Poland, Germany and Netherlands), all countries except the UK allocate much more generous allocation to power plants, using hard coal than to installations fired with the more-environmentally friendly natural gas. For example, in Poland, installations will receive free allocation to cover their emissions, provided that BAT standards for coal generation are fulfilled.

For the second national allocation plan, Germany has guaranteed free allowances to new build power plants for 14 years. The move was designed to encourage new build in power plants, including coal and lignite-fired installations, as the country's nuclear plants are phased out. While this guarantee provided some certainty for power firms considering investment options, it also closed the possibility that allowances be auctioned for the commitment period following 2012 – at present, a maximum of 10 percent of allowances can be auctioned for 2008-2012, a possibility that not all countries have expressed interest in.

Moreover, free allocation available only for CO_2 emitting new entrants, whether coal or natural gas, will reduce the investment cost of the latter relative to non-CO_2 emitting technologies, such as renewable or nuclear. This may in turn have the perverse effect of leading to more carbon emitting capacity relative to CO_2 free capacity than would otherwise be the case. Under free allocation to new entrants, the overall demand for allowances could be increased from a scenario where CO_2-intensive new entrants would need to pay their way into the market (Ellerman, 2006). All other conditions being equal, this in turn would increase the price of CO_2 allowances, raising the price of electricity for all consumers. The effect of free allocation to fossil-fuel new entrants is therefore questionable, not only from the perspective of the ETS environmental effectiveness, but also from a competitiveness point of view.

8.3 Impact of Climate Change Policy uncertainty on Investment Decisions

Policy uncertainty influences the kind of investment likely to be made. If the choice of policy instrument were stable or predictable, by integrating it into the investment decision, uncertainty may be manageable. Uncertainty, which creates financial risk, is seen in a new light; today's market players show a preference for less capital-intensive and smaller units. Planned gas additions – for self-generation but also for generation in general - show that this fuel is dominating the European power scene. [90]

Climate change policy uncertainty has several dimensions, namely uncertainty resulting from the size and approach of the new entrant provision; and uncertainty regarding the future allocation to industrial plants having invested in facilities covered by the climate change mitigation scheme. For countries in which the "first-come, first-served" principle applies, the uncertainty for the plant operator is high, since the operator cannot assume that free CO_2 allowances will still be available in the reserve (Öko Institute and Ilex Consulting, 2006).[91]

Uncertainty over future policies may push investors to delay investment or to abandon it altogether as too risky. Blyth and Yang (2006) explain and model how companies using real option theory may delay or cancel their investments in power facilities as a result of climate change policy uncertainty, in the case where allowances are auctioned or there are no more free allowances in the NER. Real option theory is basically an extension of DCF analysis, but adds one very important element – accounting for the flexibility that managers often have over the timing of their investment when faced with uncertain future cash flows. Because DCF analysis assumes that the timing of an investment is fixed, it can often underestimate project cost (Blyth and Yang, 2006).

Investors would prefer a stable regulatory framework based on long-term commitments by policy makers with no political uncertainty. However, this is unlikely in the context of market liberalisation. Uncertainty may be reduced, for example, if an environmental measure is deemed credible and investment is made in a targeted low-carbon emitting technology (e.g., wind, hydro, etc.). Perhaps the

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[90] Utilities are likely to respond to uncertainty by maintaining flexibility in fuel choices and avoid large investments that lock them in to a specific compliance method before more efficient and cleaner technologies have crystallised (Söderholm and Strömberg, 2003).

[91] Based on the countries Öko Institute and Ilex Consulting evaluate, this applies to Spain, Poland and the UK in general. In the Netherlands, the NER is divided in two parts: one for "known new entrants", and one for "unknown new entrants". Only the operators whose plans to build new facilities are not part of the "known new entrants" face an uncertainty on whether they will receive allocation.

primary action that government may undertake is to provide long-term clarity and certainty on the EU ETS, in line with the capital cycles of the power sector. This applies primarily to rules on GHG emissions but would also include treatment of nuclear power and the long-term support for renewable energy.

A palliative solution to this problem may be in the investment risk-sharing between generators and consumers – although it does not eliminate all uncertainty. Long-term contracts may also have an important role in the entry of new participants in the electricity market, and particularly when new generation capacity has to be built (Anderson and Hu, 2005). When retailers or industrial facilities sign long-term contracts with a new generator, a stable and predictable cash flow is provided to the investors. As a result, the investment decision is less risky and new entrants may be encouraged to enter the market.

8.4 Section Summary

What will influence the CO_2 pattern of electricity investments? Unless the industrial facility is the generator or owns a share in the new plant, its electricity purchase strategies can have no direct bearing on the choice of technology by the generator. The choice of a low CO_2 technology is in the hands of the generator.

A cap on CO_2 emissions should, in theory, encourage investments in low-emitting technologies. However, in practice, investment signals may be distorted in a number of ways. The implementation details of the emissions trading scheme are decisive in ensuring its environmental effectiveness. Provisions to remove allowances upon closure and repeated negotiations of future allocation could delay investments in cleaner technologies.

Governments need to provide long-term visibility on the required emission constraints to power generators. Failing to do so will lead to slower investment, higher cost of CO_2 reductions and unduly high electricity prices for competition-exposed industry.

9. Conclusion

- **The interaction between CO_2 and electricity prices**

Installations subject to emission caps now face a price for their CO_2 emissions. For fossil fuel generators, holding CO_2 allowances carries a cost, the so-called opportunity cost, which can be reflected in their electricity prices. The relation between CO_2 prices and electricity prices must, however, be considered as dynamic.

- Assume low electricity prices: these encourage higher electricity consumption, resulting in higher CO_2 emissions. Demand for allowances may increase as a result, if electricity companies are not in compliance with their initial allocation, and therefore increase the pressure on the CO_2 allowance market. The growth in CO_2 prices and in generation costs may, in turn, raise power prices, leading to adjustment in demand. This assumes, of course, some price elasticity on the demand side.

- Fuel prices also play a strong role in setting the observed electricity and CO_2 prices. High gas prices encourage more coal use for base-load electricity supply, which should drive up demand for CO_2 allowances - coal-based power emits roughly twice as much CO_2 as natural gas. If such phenomenon is sustained and supply of allowances tightens, CO_2 prices may reach a level that allows gas, a cleaner fuel, to win over coal. A lot of the early CO_2 price movements have been predicated on this relationship: switching from coal to gas appeared to be the only CO_2 reduction option under the EU ETS, and CO_2 prices had to reach the level where gas would supersede coal.

There has been intense debate between power producers, EIIs, and governments on the legitimacy of electricity price increase as a result of the CO_2 constraint – either because some power generation systems have low CO_2 intensities yet faced a general rise in prices as marginal plants are CO_2 intensive, or because CO_2-intensive plants have recorded large operational profits as the result of the CO_2 cost pass-through, which seems to fly in the face of the "polluter pays principle". The permanence of a free allocation of allowances to existing – and new – CO_2-intensive plants may raise growing political problems, triggered by the competitiveness problems of EIIs.

With few exceptions, the free allocation of allowances to CO_2 generators does not prevent the pass-through of the opportunity cost.[92] This is as it should be, in light of the policy objectives of cap-and-trade systems, which is to internalise the price of the targeted pollution. In sum, this is meant to trigger a downward adjustment of electricity demand, for as long as power is carbon intensive. In theory, the price of electricity should rise by the same amount whether the allowances are handed to the generators for free or auctioned.

The allocation methodology will, however, have a significant impact on who benefits from holding the newly-created rent – i.e. the emission allowances. If auctioned, allowances will generate revenues that can be used by governments in a number of ways, including to mitigate the cost to specific economic actors. Energy efficiency measures could, for example, be financed to create a response to higher electricity prices.

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[92] In Italy, generators have been reluctant to charge the opportunity cost of allowances, as the regulator clearly indicated that it would not tolerate such practice, in light of high existing prices.

Nevertheless, auctioning all allowances to power generators will never raise enough money to fully compensate for the increase in electricity prices resulting from the CO_2 opportunity cost. Indeed, as long as marginal plants – fossil based – set the tone for the price of all electricity generators, hydro, nuclear, wind, biomass, and all technologies that deliver electricity at a cost that is lower than the marginal supplier's, will also receive enjoy the CO_2 opportunity cost component of the electricity price. This point is illustrated below.

Why 100% auctioning to power producers cannot compensate for increases in electricity prices

If we assume a country with 90 TWh from non-fossil based generation, and 10 TWh from coal based generation, the total emissions equal roughly 10 $MtCO_2$.[93] If the government decides to auction CO_2 allowances at EUR10/tCO_2, the total amount raised reaches EUR100 million. If we also suppose that the marginal supplier is the coal generator and it sets the electricity price including 100 percent of the actual cost, if we assume that the original price was EUR40/MWh, the new price for all electricity sold on that market increases to EUR50/MWh.[94] The total new "cost" on electricity consumers equals EUR1,000 million (or 100 TWh *(50 - 40 EUR/MWh)). Overall, the government cannot compensate the additional cost to consumers through the redistribution of auction revenues as it only raised EUR100 million.

- **An increase in price volatility: impact on EIIs' electricity purchasing strategies**

Several elements influence an industrial facility's electricity purchasing strategy, namely the existence of electricity markets, their maturity and liquidity; whether the facility possesses by-products it can burn to produce electricity; the resources and availability a company has to purchase electricity directly and manage the price risk or whether it can rely on the services of an intermediary; and also the company's attitude towards price risk.

CO_2 prices have been rather volatile in the EU, and have added volatility to the observed electricity prices - although liberalisation is the main driver of electricity price volatility. Managing this volatility is essential for industrial facilities, as it may damage the competitiveness of companies – mainly for those which cannot pass-through an increase in costs onto their prices. Along with the rise in prices driven by the new CO_2 cost component, electricity price uncertainty and CO_2 price volatility have encouraged industry to seek more predictable electricity prices.

Risk management is a main theme in this report because in order to understand EIIs' strategic decisions, looking at electricity prices in isolation is not sufficient. EIIs combine price levels and price risks when developing their purchasing strategy. EIIs do not always, however, have a full choice of supply strategies. Some countries no longer offer regulated prices. Furthermore, the option to self-generate electricity as a hedge against market price variations is not immediately available. Several companies/installations may also need to pool resources to make this option viable.

To some extent, several electricity purchasing strategies may allow EIIs to bypass or lower the opportunity cost – although it is difficult to assess, in the final analysis, which of the mark-up or of the CO_2 opportunity cost is reduced through such strategies. Self-generation from either non CO_2 emitting electricity plants (e.g. TVO) or plants with lower production costs than the price-setting technology is

93 In this example, we assume that a MWh (roughly 1 tCO_2 / MWh for a coal-based generator)

one example. In this case, owners of these plants may even be able to collect the rent created by the opportunity cost if they sell their excess electricity on the market while the market price is set by a fossil fuel technology that includes the opportunity cost. Further, supply contracts for consumers with sufficient bargaining power to negotiate the electricity price (e.g., through load curve aggregation) is another illustration, as reflected in the growing pressure to allow such practice.

- **Is the CO_2 constraint leading to lower CO_2 emissions?**

Free allocation to CO_2-emitting technologies may have the perverse effect of leading to more carbon emitting capacity relative to CO_2 free capacity than would otherwise be the case (Ellerman, 2006). The new entrant rules actually work against the system's intended goal. Whether through auctioning of allowances or other mechanisms, governments should reinforce the environmental effectiveness of any CO_2 constraint they apply to power generation, and seek to address distributional issues, at least in a transition phase. Emissions trading systems are only acceptable if they do eventually deliver emission reductions and offer flexibility to capped sources.

On whether the EU ETS is currently driving CO_2 abatement in the power sector in general, CO_2 prices may need to climb higher before generators switched from coal to gas fired, or non-CO_2 generation technologies. This can be seen as evidence that indeed, policy uncertainty matters: in the absence of further clarity on the next period's allocation, investing now in new capacity can prove dangerous – and the cost of waiting one year to have further information should not be dramatic . With its low capital cost and short lead-time, however, CCGT may be the "cheapest mistake" that investors in generation could make, in the light of uncertainties. This is shown in the table below by the high number of CCGT capacity currently under construction in the EU-19 compared to coal or oil.

Table 19: **Total Power Generation Capacity under Construction in the EU-19**

Under Construction (MW)	**32691.4**
Oil	371
Gas	22041
GT	2597
Steam	38
IC	148
CCGT	19258
Fuel Cell	0.2
Coal	3228
Nuclear	1720
Hydro	1819
Geothermal	1
PV	16
Wind	2615
BioEnergy	837
BioGas	37

Source: Platts, IEA

[94] The opportunity cost is equal to the full cost: \$10/MWh (\$10/tCO_2 * 1tCO_2/MWh).

Governments in charge of implementing existing, or upcoming emissions trading systems will need to provide as much long-term visibility on the required emission constraints to power generators. Failing to do so will lead to slower investment, higher cost of CO_2 reductions and unduly high electricity prices.

The fundamental question that policy-makers must face in the design of cap-and-trade systems that affect power generation is on the system's ability to trigger sustained reductions in emissions through proper signals to investors. Ultimately, a low-CO_2 electricity system would carry a low cost of CO_2 for electricity users, delivering both the intended environmental outcome and closing the debate on windfall profits and high costs to EIIs. If emissions trading is to be the instrument of choice for such a goal, its rules of operation must focus on providing least-cost options to lower CO_2 emissions, and not on giving signals on other energy policy goals (e.g. energy supply diversity). Other policy goals should be promoted via other measures. The alternative can only undermine the economic efficiency of emissions trading.

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12. Glossary

Base-load Capacity: The generating equipment that is normally operated to meet demand on a 24-hour basis.

Base-load Plant: A physical plant that normally operates continuously to take all or part of the minimum load of a system and that consequently generates electricity at an essentially constant rate.

Bilateral Market: Buying and selling electricity based on contractual agreements (in contrast to a market exchange).

Forward Contract: A financial instrument that specifies the amount, price and time of delivery of electric power. The contract terms are typically customized by both buyer and seller.

Futures Contract: An agreement in which a purchaser is obligated to take delivery from a seller who is obligated to deliver a fixed amount for a predetermined price at a specific location; such contracts require a daily payment based on the present value of the agreement in the marketplace and are traded on a centralized exchange and have standardized terms.

Off-Peak: Generally, the hours from 11:00PM to 6:00AM, when demand for electricity is low.

On-Peak: Generally, the hours from 6:00AM to 11:00PM, when demand for electricity is high.

Wholesale Market: The bulk power market.

ANNEX 1: RELEVANT POWER EXCHANGES IN EUROPE

The availability of liquid exchange-based markets is accompanied by a regionalisation of electricity markets. In its medium term strategy paper for Europe's internal electricity markets, the European Commission intends to regionalise European power markets between 2005 and 2009 into several trans-national markets before integrating it in a single EU market by 2010. The regions are: west continental Europe, Iberia, Great Britain/Ireland, East Europe, South East Europe, Nordic region and the Baltic States. Nevertheless, a pre-condition to market regionalisation is network integration between countries. Until regions are more interconnected, national/sub-regional markets stand out as the price-setting reference for entire regions.

Note that often, there is a strong correlation between OTC and exchange prices. The reason is that market prices are often used as a reference for bilateral OTC contracts. The market price is often regarded as a transparent indicator which can serve as the index for contractual prices.

Continental Europe

While much of Continental Europe's power trading is conducted through bilateral agreements, the liquidity of key Continental power exchanges is growing. The price set by the German power exchange EEX is increasingly being accepted as a reference price, and liquidity in the German day-ahead market is growing (Argus, 2006).[95] Leipzig-based electricity and emissions exchange EEX is gradually linking central and western Europe. EEX has announced collaboration with Austria's EXAA exchange to extend its market to include the Austrian trading zone. Two-way market coupling, where interconnection costs are determined by price differentials between exchange clearing prices, is already underway between EEX and EXAA exchanges. As a result, EEX might, in some cases, be considered as the relevant price indicator for Austria and also for France. In effect, French forward and day-ahead prices are strongly correlated with German forward prices (Ministère de l'Economie, des Finances et de l'Industrie, 2004).

In Belgium, the Belpex project, which links grid firm Elia with the exchanges and grid operators of the Netherlands – APX and Tennet – and France – Powernext and RTE, is moving ahead, although the July 2006 launch date has been postponed. The link-up of Belpex – a day-ahead spot exchange - with the neighbouring exchanges will be the first time that a three-way market coupling has been attempted.

Northern Europe

Nord Pool has tied itself to the German market through implicit auctions on its Kontek market between Denmark and Germany.[96] Nevertheless, Nord Pool mostly acts as the benchmark for electricity prices in Scandinavia. In recent years spot market trading has accounted for 50-60 per cent of electricity consumption in the Nordic region.

UK

[95] Energy Argus, Power Europe, Volume VI, 12, 29 June 2006.

[96] http://www.eex.de/get.php?f=481599360c2f41b2af0244dda2547691.pdf&m=download&session=85575dd2159728e332f00a4566d19021

The United Kingdom is considered as a region in itself because of limited interconnection. The United Kingdom includes made up of England, Northern Ireland, Scotland, Wales, and the Isle of Wight. When the UK moved away from the pool, policy makers expected various liquid forward markets would develop through commercial exchanges, including a day-ahead spot market. This has not materialised and as a result there is no clear market price that investors – particularly new entrants – can use as reference (IEA, 2006). The current level of forward trading is not very liquid and transparent because of vertical integration, and a spot market setting a strong reference price has not emerged.

Iberia

The Iberian market exchange Mibel was launched in July 2006, and Spanish and Portuguese electricity prices are still set on the power exchanges. In Spain, as mentioned above in **Error! Reference source not found.**, there is a strong incentive to trade on the power exchange. It is only through this distribution canal that power producers receive compensation for their stranded costs.[97] Nevertheless, on the power exchange, the government has decided – for one year - to impose a cap on the deals between utilities' generation and distribution divisions at €42.35/MWh.

Italy

Italy is considered as a European region. In Italy, IPEX is the only power exchange which trades day-head.[98] One of the major hurdles to establishing a futures market is the need for legislation to grant energy traders access to the market. Under Italian law, only brokerage firms can operate on financial markets and authorisation from the stock-exchange regulator, Consob, is required.

Eastern Europe

In the five of the new EU member states – the Czech Republic, Hungary, Poland, the Slovak Republic and Slovenia, the free wholesale market is dominated by domestic bilateral contracts (Kaderják, 2005). Organised wholesale markets – or electricity exchanges - exist in the Czech Republic, Slovenia and Poland. Nevertheless, in Slovenia, the organised spot market, Borzen, only traded 3.1% of the consumed energy in 2003. Likewise, in Poland, which has the largest power exchange in the CEC's, liquidity is still insufficient, and only 1.3 percent of the Polish electricity consumption was traded in 2005.[99] In the Czech Republic, the day ahead spot market is also characterised by volumes that regularly fail to provide price signals for certain hours. As supply is very concentrated, and most generated electricity is sold through long-term power purchasing agreements, the market is very thin. As a result the exchange price does not represent the price of electricity in those countries, and the behaviour of wholesale prices remains non-transparent (Von Hirschhausen and Zachmann, 2005).

There is a strong trade integration between the German, the Slovenian and the Czech free wholesale markets (Kaderják, 2005). In the Czech Republic, wholesale prices are pegged closely to the neighbouring German market because of a strong cross-border trading activity. Czech Power

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[97] Spain has been accumulating a payment deficit, in part because the government is liable to refund distribution firms the difference between the price paid by regulated customers and higher wholesale prices.

[98] In the dispatching market, there is also a balancing (real-time) session, but the related bids/offers are submitted by market actors in D-1 (not in day D).

[99] Total volume traded in Borzen, the Slovenian power exchange, reached 0.30 percent of the total consumption in 2004.

Company (CEZ) usually offers at a rate competitive with Germany (Kaderjàk, 2005).[100] CEZ also have a strong influence on prices in Poland (Platts, 2004). However, there is a significantly higher Polish exchange price in the CEC region, which indicates that the local power market is relatively isolated.

Baltic States

In the Baltic countries - Lithuania, Latvia, and Estonia – there are no power exchanges. Electricity contracts are essentially bilateral. These countries are still part of the North-West Russian electricity system (Von Hirschhausen and Zachmann, 2005) and have isolated power markets from the rest of the European Union. The first electricity link between the Baltic States and European countries that were not part of the former Soviet Union is projected to have started only in November 2006, between Estonia and Finland. Larger interconnections are in the pipeline, although progress is slow (Argus Power Europe May 4, 2006). Other long-standing projects include a proposed interconnector between Lithuania and Poland, and between Lithuania and Sweden.

[100] www.cez.cz/presentation/eng/GetFile?type=FilFile&version=-2&id=92567

ANNEX 2: LARGE INDUSTRIAL USER PRICE CONTROLS

	CONTROLS Y/N	PRICE LEVEL "LARGE" EUR/MWH
Austria	N	48
Belgium	N	65
Denmark	Y	58
Finland	N	50
France	N	49
Germany	N	68
Greece	Y	58
Ireland	Y	72
Italy	Y	78
Luxembourg	N	55
Netherlands	N	n.a.
Portugal	Y	62
Spain	Y	51
Sweden	N	51
UK	N	48
Norway	N	42
Estonia	Y	43
Latvia	Y	36
Lithuania	Y	48
Poland	Y	44
Czech Republic	N	45
Slovakia	N	68
Hungary	Y	62
Slovenia	N	49
Malta	Y	57
Cyprus	Y	76

Source: European Commission, 2005a