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Price-setting in the Electricity Markets within the EU Single Market.

Briefing Note

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Author:

EASAC
(European Academies Science Advisory Council)
6-9 Carlton House Terrace
LONDON SW1Y 5AG
U.K.
Tel: +44 (0) 20 7451 2697
Email: fiona.steiger@royal.soc.ac.uk

Administrator:

Miklós Györffi
Policy Department A - Economy and Science
Internal Policies Directorate-General
European Parliament
Rue Wiertz 60 - office number
B-1047 Brussels ATR 0L004
Tel: +32-2-2832505
Fax: +32-2-2849002
E-mail: miklos.gyoerffi@europarl.europa.eu

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✉ Rue Wiertz – B-1047 Bruxelles - ☎ 32/2.284.43.74 Fax: 32/2.284.68.05
✉ Palais de l'Europe – F-67000 Strasbourg - ☎ 33/3.88.17.25.56 Fax: 33/3.88.36.92.14
E-mail: poldep-esc@europarl.europa.eu

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Introduction

This report was commissioned from EASAC by the European Parliament Committee on Industry, Research and Energy as part of its over-arching framework contract.

The European Commission recently put forward a detailed report describing progress in the creation of the internal electricity (and gas) market[1] and is planning another one on *competitiveness in gas and electricity* to come in the first half of 2006. In preparation for this, at least where it refers to the electricity market, the European Parliament has requested an analysis of some important issues, namely:

1 the characteristics of the main electricity markets within the EU single market

2 an assessment of the pricing structures and comparison between markets, showing price trends

3 the impact on prices to end-users of emissions trading certificates/allowances

4 the impact of long-term contracts on the efficiency of electricity markets

Our report is based on the contributions and input of the following experts, working on a volunteer basis:

- Professor John Fitz Gerald, Economic and Social Research Institute, Dublin, Ireland
- Professor Jean-Michel Glachant, University Paris Sud, France
- Professor Ferdinand Gubina, University of Ljubljana, Slovenia
- Professor David Newbery, University of Cambridge, UK
- Professor Wolfgang Pfaffenberger, Bremen Energy Institute, International University, Germany
- Professor Pekka Pirilä, Helsinki University of Technology, Finland

The experts were supported by a secretariat consisting of Chris Doyle, Stephen Hansen and Fiona Steiger. The report has been reviewed by the EASAC Council.

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[1] COM(2005) 568 final, Communication from the Commission to the Council and the European Parliament, Report on Progress in creating the internal gas and electricity market, {SEC(2005) 1448}

Summary

Through the legislation being implemented at European Union level, the EU will have the most integrated energy market in the world: from 1 July 2007 both the domestic and industrial markets will be fully open. Additionally, the legislation seeks the unbundling of production and supply activities in the energy markets.

This report has been commissioned to facilitate further consideration of the electricity markets within the EU by the members of the Industry, Research and Energy Committee of the European Parliament. It considers four areas: the main characteristics of the EU electricity markets, their price structures, how the recently implemented emissions trading allowances scheme will impact on the prices charged to end-users, and how long-term contracts will impact on the efficiency of the electricity markets.

Electricity markets within the EU are highly diverse. However, in general it is clear that interconnectivity is low and that pricing is complex and dependent on the regulatory framework, capacity and global energy prices. Emission Trading Allowances are also complex and have the capacity to affect prices and generating mix, though it is too early for any such effects to be clear. Long-term contracts are necessary for improved stability, efficiency and competitiveness.

Characteristics of the electricity markets

The electricity markets of the EU are generally divided into six regions, some of which, such as the Baltic region or the Nordic region, are relatively homogenous entities with an operating regional market, while others, such as the Western European region, are not yet very integrated but share similar characteristics. Cross-border trade currently accounts for only about 8% of EU electricity consumption, a figure that can be attributed to a low level of interconnecting capacity between Member States and the relative isolation of national markets.

The characteristics of the markets considered in our study are

- International interdependence
- Competition
- Network unbundling
- Public vs private sectors
- Regulation

It is not possible to make broad generalisations about the EU electricity markets across any of these characteristics, and even at a regional level the markets are often more conceptual than actual functioning entities. However, one parameter where more of a distinctive regional similarity can be seen is in the opening up of the markets, with the new accession countries generally showing lower degrees of market opening than the EU-15 states. But even that distinction is not a clear one. Though the ultimate aim of European electricity policy is to create an EU-wide market for electricity, there is common agreement that this is still some way off and that at this stage it would be premature to talk of an 'EU market' for electricity.

Pricing structures

Examining price structures in the EU electricity markets is not simple because of the market liberalisation that has already taken place, which has led to many more competing tariffs and companies not being eager to share commercially sensitive information. However, the EU electricity markets share many similar pricing structures, including more flexible tariffs for industrial users.

While the price structures are largely similar, areas of difference do exist, including a number of Member States offering social tariffs to domestic customers, usually the poor or disadvantaged. Value added tax is charged on electricity in all the Member States, though the accession members tend not to have any extra taxes on electricity while the EU-15 largely do. Not surprisingly, unregulated markets offer more tariffs, structures and services to customers.

The median trend for prices, exclusive of taxes, was downward between 1995 and 2000 for both domestic and industrial users of electricity. Prices were then stable for five years before beginning to rise in 2005. The price decreases after 1995 were consistent with the predicted effects of market liberalisation, but it should also be appreciated that energy prices fell and productivity rose, both of which would contribute to falling electricity prices. It is not just market liberalisation that can cause lower prices. Conversely, the stability in prices and then the recent rises do not mean that liberalisation has ceased to be effective; rises in the price of gas and oil have impacted on electricity prices in the past year. Moreover, when liberalisation began the European electricity market had excess capacity; this has now dwindled, leading to an upward pressure on prices.

Interconnection of electricity supply and provision would logically seem to lead to a convergence of prices. The evidence seems to support this as the regions across the EU have more convergence in prices than the EU-25 as a whole. However, the same price can have a different impact in different countries when energy prices are converted to a percentage of the cost of living.

In summary, the format of electricity prices is common to most EU countries, with industrial consumers having a wider choice of tariffs than domestic customers. Prices have dropped since liberalisation began, but did increase in 2005, for a number of reasons. Since the markets began to open prices have begun to converge at regional level, though not across the EU as a whole.

Emission trading allowances

A new impact on prices is the Emissions Trading Scheme which started in 2005 as part of the EU's commitment to meeting its Kyoto targets. Under the scheme, businesses that emit carbon dioxide must hold allowances at the end of each year equal to the volume of CO_2 emitted. If they do not have sufficient to cover their emissions they must buy extra allowances on the open market, but conversely they are also able to sell unused allowances on the open market. The price of the allowances is not fixed but will respond to the demands of the market place. In the second half of 2005 the price of an allowance stabilised after shooting up in the summer. The factors behind the sudden rise would seem to be the rapid increase in gas prices, the droughts in south-west Europe and extreme weather in spring and early summer leading to unexpectedly high demand for energy.

Only a year into the scheme it has been difficult to quantify the effect that Emissions Trading Allowances (ETAs) have had on the price of electricity, but their impact seems to be different on wholesale prices than on end-user prices. Theory suggests that costs will be passed on to consumers, unless a significant proportion of energy comes from zero-emissions sources. But there are also scenarios that suggest that no significant rise changes will result. There is certainly the potential for the Scheme to alter the generating mix, however, if costs for cheap but environmentally intensive sources rise above those for more expensive but cleaner technologies.

Analysis by David Newbery has led to the conclusion that most of the allowance cost has been passed through into the wholesale price. The impact on end-user prices seems to be less than on the wholesale price, because most European households are on regulated tariffs which are protected from costs arising from the ETAs. Industrial customers, although generally operating in free markets, can, in some countries, switch back to regulated tariffs. The long-term contracts that some industrial users are on are only partially linked to the wholesale markets; so far, this has lessened the impact of ETAs on industrial end-user prices. At this stage, though, we would emphasise that it is still too early in the lifetime of the ETAs to conduct meaningful analysis.

Long-term contracts

Although long-term contracts are used in the EU it is difficult to say exactly how much of the market is covered by them. Long-term contracts are the means for industrial electricity users to shield themselves from the volatility of the market. This stability persuades players in the market to take the risk of participating. The lack of long-term contracts is considered to be the sole reason behind the California electricity crisis in 2000-01.

The main advantage of long-term contracts is that they encourage investment in a very capital-intensive, slow-return industry by allowing investors to manage their investment risk. If customers are not prepared to sign contracts for more than a couple of years then new entrants will not be encouraged to enter the market. By being able to lock in a secure revenue from long-term contracts new firms are likely to be prepared to enter the market, which promotes further competitiveness.

As well as giving new providers the incentive to enter the electricity market, long-term contracts serve to aid efficient timing of essential maintenance work to electricity plants as generators schedule their work for the cheapest times in the market, which is when there are plenty of other sources of electricity available for customers.

Contract trading would be fundamental to the efficiency impact of long-term contracts on the electricity markets: with a liquid and functioning market for long-term contracts it is likely that the risk reducing and efficiency enhancing consequences of the contracts would dominate. However, in a small, static market it will have a negative effect.

Another argument in favour of long-term contracts is that they could discourage collusion as high rewards give the provider an incentive to 'cheat' on a cartel. As the short-term, 'spot', market becomes less of a source of income for providers, the quantity of income gained through collusion declines and so collusive activity becomes less attractive.

The conclusion among commentators is that long-term contracts would improve efficiency in the electricity industry due to three main benefits: stability of prices, encouraging investment and undermining exploitation of market power. However, long-term contracts will not solve mismatches between market demand and supply.

1 Characteristics of the main electricity markets

This section of the report will first list the key characteristics of the main EU electricity markets. After considering what we mean by 'main EU electricity markets', we then examine the markets by a range of indicators – including international dependence, competitiveness and network unbundling.

1.1 Main electricity markets

In its March 2004 strategy paper *Medium-term vision for the internal electricity market*, the European Commission set out its current policy which is based on a regional stepping-stone approach towards electricity integration. The medium-term aim is successful integration of countries into local regional markets; with this then ultimately being followed by further integration into a fully-fledged European market.

Currently, cross-border trade is relatively low at about 8% of EU electricity consumption. This can be attributed to the previous relative isolation of national markets. There has also been an historical lack of interconnecting capacity between countries, with critical bottlenecks in some areas, though the European Council meeting in Barcelona 2002 attempted to tackle this by insisting that countries possess interconnecting capacity equal to at least 10% of their generating capacity.

Though the ultimate aim of European electricity policy is to create an EU-wide market for electricity, there is common agreement that this is still some way off and that at this stage it would be premature to talk of an 'EU market' for electricity.

It makes sense to talk of 'regional markets' on two levels. First, there are examples of regions where countries do, to some extent at least, have an operating regional market – such as the Nordic market and to a lesser extent the Iberian market. Second and more broadly, 'regional markets' tend to group countries together on the basis of similar markets, common regional characteristics and cultural and physical links where it is imagined that, in time, these countries could likely form the basis of true regional markets.

Thus, it is important to note the limitation of discussing regional markets - that not all 'regional markets' actually function as true markets at this time (Eastern Europe for example). It remains necessary to examine countries individually as well as collectively, as for most countries the electricity market would most correctly be defined on a national rather than a regional basis.

There exists roughly broad agreement on regional market definitions, though there is not unanimity on the classifications. Here we discuss six areas and the degree to which they are functional as a regional market:

(i) *Western Europe: Austria, Belgium, France, Germany, Luxembourg, Netherlands,*

This represents the major (nascent) regional market for electricity within the EU. Though it does not yet represent a true integrated market, there are already signs of it developing – for example in Austria and some parts of France and Germany a common wholesale price area has developed because of the high level of local interconnection.

(ii) *Iberia: Spain and Portugal*

Moves towards a single Iberian electricity market started in 1998. November 2001 saw the signing of a Collaboration Protocol in which it was stated that the aim was to create a single Iberian market for electricity. The first stage of the process will be the establishment of a common wholesale electricity market, with convergence of the retail markets to follow later. Although it was initially intended for the Iberian market to begin operating on 1 January 2003, this has been delayed because of changes in the political situation – though further agreements have been signed since then.

(iii) *UK and Ireland*

Though there are linkages between them, and discussions of extending these in the future, the UK and Ireland do not truly form a single market, but they do stand together as isolated islands in Northwest Europe with limited scope for connection to the rest of Europe in the immediate future. There has also been significant progress in achieving integration within this region, ie improving interconnection between the Republic of Ireland and Northern Ireland, and between England, Wales and Scotland.

(iv) *Nordic: Denmark, Finland and Sweden (and also Norway)*

The Nordic market represents the greatest degree of integration of any of the regional EU markets. This integration has been developing over a number of years, and the region now boasts the removal of separate border tariffs and a common wholesale market for electricity shared between Denmark, Finland, Sweden and Norway – the 'Nord Pool'. The share of trading through the Nord Pool has risen to 40% of total electricity consumption in 2004, with the rest through bilateral trades directly or using over-the-counter services. The level of price setting in the Pool is generally dominated by hydropower producers because of their low marginal costs and typical status as marginal producers; though this depends upon hydrological conditions which, when poor, can drive prices significantly higher.

Under normal load conditions the interconnections between different areas of the Nordic power system are sufficient to fulfill all transmission needs, but under various circumstances bottlenecks limit transmission. Therefore, by no means are these countries fully integrated; in fact for about half of the hours of the year the market area is split into several price areas as the transmission network cannot cope. When this sort of splitting occurs, prices are determined separately for each price area assuming that the interconnections between each area are used fully. There are plans to reinforce the network at several key points, as these splits significantly compromise operation of the market; in addition, the fact that this problem is so acute in such a strongly interconnected area throws doubt upon plans to extend the market to areas with much weaker connections anytime soon.

(v) *Baltic: Estonia, Latvia, Lithuania*

In February 2000, Estonia, Latvia and Lithuania decided to create a common Baltic electricity market and establish transmission links between the three countries; the three countries now have a joint power pool known as 'Baltic IPS'. One of the major objectives of the Baltic IPS system is the enhancement of regional cooperation and its integration into the Western European electricity market. There are plans for improvements to the transmission grid, through interconnecting it with the Polish electricity system. It has been noted that this cross-border transmission project between Lithuania and Poland is of great importance for the development of an integrated EU electricity market and for the improvement of the reliability of supply.

(vi) *Eastern Europe: Czech Republic, Hungary, Poland, Slovakia and Slovenia*

The Eastern European countries are in the early stages of electricity market reform and have some way to go before they form a true regional market. However, having electricity markets in similar states of evolution they can conceptually be usefully grouped together.

Adaptation of laws within the reforms and their interpretation in different Eastern European markets varies, leading to different market developments. As an example, coordinated explicit transmission capacity auctions between the Polish, Czech, Slovak and German transmission system operators are taking place. Similarly, Slovenia with its adoption of the European market model influences the Balkan power region.

The central European network gets congested because of the priority given to renewables. With 20 GW of electricity in Germany required to be sourced from wind energy, at certain times (wind peak, low electricity demand and wind not behaving as projected) planned transactions have to be rescheduled and the effects are felt outside the German borders. This is an obstacle to trade in the network. Experts agree that fluctuating wind energy has to be integrated into the system management. At present that would be illegal.

In addition, there are several countries that do not fit into any of these regional markets neatly: Malta, Greece and Cyprus fall into this category because of their isolated geographic locations. Here we also include Italy, which does not fit well into any one market – some commentators place it in the Iberian ('Southern Europe') market, some the Western European, while others argue it is a special case for various reasons such as its location and its relative lag in establishing a competitive generation market and national electricity pool.

We use these definitions of regional markets where it makes sense to do so, but focus upon national markets where this provides a more accurate scope of analysis. Therefore, where it appears there are meaningful regional trends, we provide regional figures.

Table 1 gives some key figures on electricity production and consumption for the EU on a country by country basis. What is immediately striking is the variation, particularly by fuel mix. Note also that this variation shows no regional pattern: there is as much variation within regions as between regions.

For example in the Nordic countries, Sweden uses very little coal, while Finland and Denmark are significant users of it as a fuel source. In Eastern Europe, Poland is almost entirely reliant upon coal, whilst other countries in the region use it far less: Slovakia and Slovenia are much larger users of nuclear energy, whilst Hungary is also significantly dependent upon gas. Nuclear energy has a varied use across the EU: France and Lithuania, for example, use over 77% and 79% respectively as their source of electricity production, while 12 countries, including Austria, Cyprus and Poland do not use any nuclear energy. Two of the newest and smallest EU countries, Malta and Cyprus are entirely dependent on oil for their energy production but a few countries, including the Czech Republic and Estonia use less than 1% oil.

On usage, again there is no consistency across the EU-25 countries, with some countries, such as the UK, Hungary and France having their highest usage among residential customers while in others such as Germany, Finland and Poland industry uses most electricity.

1.2 International interdependence

By international interdependence we mean the degree to which EU countries depend upon each other for electricity through international trade; we also discuss the current limitations on trade imposed by scarce interconnection capacities. There is another dimension to this issue that we do not discuss here, which is the degree to which countries depend upon one another for fuel resources that they then use to generate electricity within their own borders.

Table 1 Key characteristics of EU electricity markets

	Total electricity production* (GWh)	Total final consumption* (GWh)	Electricity production fuel mix: Coal %	Oil %	Gas %	Biomass %	Waste %	Nuclear %	Hydro %	Other %	Consumption usage: Industry %	Transport %	Agriculture %	Commercial & public services %	Residential %	Other %
Austria	63,173	60,848	14.9%	2.8%	17.8%	2.6%	0.6%	0.0%	60.7%	0.6%	40.3%	5.4%	2.0%	25.0%	27.2%	0.0%
Belgium	84,630	79,732	13.7%	1.2%	25.5%	0.7%	1.3%	56.0%	1.6%	0.1%	50.2%	1.9%	0.4%	14.9%	32.6%	0.0%
Cyprus	4,044	3,637	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.9%	0.8%	3.1%	44.9%	35.6%	1.6%
Czech Republic	83,227	52,407	62.0%	0.4%	3.7%	0.6%	0.0%	31.1%	2.2%	0.0%	39.2%	4.2%	2.1%	24.0%	27.7%	2.8%
Denmark	46,264	32,434	54.7%	5.1%	21.2%	3.6%	3.2%	0.0%	0.0%	12.2%	30.1%	1.1%	5.9%	31.3%	31.7%	0.0%
Estonia	10,159	5,573	92.2%	0.4%	6.9%	0.3%	0.0%	0.0%	0.1%	0.1%	36.4%	1.7%	3.7%	29.5%	28.6%	0.0%
Finland	84,228	80,843	31.8%	1.1%	16.6%	11.2%	0.9%	27.0%	11.4%	0.1%	54.8%	0.8%	1.1%	18.1%	25.2%	0.0%
France	566,902	408,433	5.2%	1.5%	3.0%	0.3%	0.6%	77.8%	11.3%	0.2%	32.5%	2.9%	0.8%	27.5%	34.5%	1.7%
Germany	599,470	509,265	52.4%	0.8%	9.8%	0.7%	1.5%	27.5%	4.1%	3.2%	45.5%	3.2%	1.5%	22.4%	27.4%	0.0%
Greece	58,478	48,595	60.1%	14.9%	13.7%	0.2%	0.2%	0.0%	9.1%	1.7%	29.1%	0.5%	5.7%	30.8%	33.8%	0.0%
Hungary	34,145	31,396	27.1%	4.8%	34.8%	0.4%	0.2%	32.3%	0.5%	0.0%	30.5%	3.3%	3.4%	27.5%	35.2%	0.0%
Ireland	25,235	22,531	32.6%	9.7%	51.7%	0.3%	0.0%	0.0%	3.8%	1.8%	31.5%	0.1%	0.0%	34.8%	33.6%	0.0%
Italy	293,865	291,436	15.0%	25.9%	39.9%	0.5%	1.1%	0.0%	15.1%	2.6%	49.5%	3.2%	1.8%	23.1%	22.3%	0.0%
Latvia	3,979	5,201	0.6%	2.1%	38.5%	0.6%	0.0%	0.0%	57.0%	1.2%	30.9%	2.6%	3.1%	35.9%	27.3%	0.2%
Lithuania	19,488	7,179	0.0%	1.7%	12.9%	0.0%	0.0%	79.5%	5.1%	0.9%	36.6%	1.3%	2.3%	33.4%	26.4%	0.0%
Luxembourg	3,620	6,015	0.0%	0.0%	72.1%	0.5%	1.3%	0.0%	25.3%	0.7%	66.1%	1.7%	1.3%	18.4%	12.5%	0.0%
Malta	2,236	1,806	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	30.8%	0.0%	0.0%	34.8%	34.4%	0.0%
Netherlands	96,775	100,520	28.4%	3.0%	58.8%	1.3%	2.7%	4.2%	0.1%	1.6%	40.5%	1.6%	4.0%	30.8%	23.2%	0.0%
Poland	151,631	98,712	94.0%	1.6%	1.6%	0.3%	0.2%	0.0%	2.2%	0.1%	40.7%	4.8%	4.3%	27.8%	22.3%	0.0%
Portugal	46,852	43,164	31.0%	13.2%	16.5%	2.6%	1.2%	0.0%	34.3%	1.3%	39.0%	1.0%	2.1%	30.5%	27.4%	0.0%
Slovakia	31,178	22,952	20.5%	2.3%	7.7%	0.3%	0.1%	57.3%	11.8%	0.1%	49.4%	3.2%	4.0%	21.5%	22.0%	0.0%
Slovenia	14,019	12,521	36.4%	0.4%	2.6%	0.9%	0.0%	37.1%	22.5%	0.0%	52.6%	1.4%	1.1%	13.2%	24.0%	7.6%
Spain	260,727	217,898	29.1%	9.2%	15.1%	1.1%	0.3%	23.7%	16.8%	4.6%	44.2%	2.4%	2.3%	26.3%	24.9%	0.0%
Sweden	135,615	129,773	3.1%	2.9%	0.4%	3.9%	0.3%	49.7%	39.3%	0.5%	42.9%	2.2%	1.5%	21.8%	31.6%	0.0%
UK	398,620	337,443	35.2%	1.8%	37.3%	1.3%	0.4%	22.2%	1.5%	0.3%	33.8%	2.5%	1.2%	28.2%	34.3%	0.0%
EU 25	3,118,560	2,610,314	31.8%	5.2%	17.7%	1.2%	0.8%	31.2%	10.4%	1.7%	41.1%	2.7%	1.8%	25.2%	28.8%	0.4%

Source: IEA Energy Statistics - 2003 data

* *Production and consumption differ because of imports and exports, transformation (ie electricity used by heat pumps and electricity used by electric boilers), the energy sector (ie own use by plant and electricity used for pumped storage), and distributional losses.*

** *This is against total domestic production.*

The EU figure is weighted by electricity production for fuel mix, and electricity consumption for use.

The Imports and Exports columns of Table 2 show figures for actual cross-border trade in electricity, normalised against domestic production in the relevant country. The regional and EU figures in Table 2 do not represent the block as a whole, but the averages of all the countries in that block. So, for example, the Baltic figures represent the average import and exports of all the countries in the Baltic area (including with each other), not the imports and exports of the Baltic area with other areas.

Table 2 International interdependence

	Imports %	Exports %	Import Capacity as a % of Installed Capacity*
Austria	30%	21%	24%
Belgium	17%	10%	29%
Cyprus	0%	0%	0%
Czech Republic	12%	32%	23%
Denmark	15%	34%	50%
Estonia	1%	20%	66%
Finland	14%	8%	14%
France	1%	13%	13%
Germany	8%	8%	11%
Greece	7%	4%	12%
Hungary	41%	21%	38%
Ireland	5%	0%	6%
Italy	18%	0%	8%
Latvia	67%	1%	100%
Lithuania	21%	60%	50%
Luxembourg	179%	77%	90%
Malta	0%	0%	0%
Netherlands	21%	4%	17%
Poland	3%	10%	10%
Portugal	13%	7%	8%
Slovakia	28%	35%	37%
Slovenia	43%	41%	68%
Spain	4%	3%	4%
Sweden	18%	8%	29%
UK	1%	1%	3%
Western Europe	9%	10%	15%
Iberia	5%	4%	5%
UK & Ireland	1%	1%	3%
Nordic	16%	12%	27%
Baltic	28%	30%	69%
Eastern Europe	16%	21%	23%
EU	10%	8%	13%

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes

UCTE July 2003 forecast, Nordel winter 2003-4 forecast, NGC and ESBNG 7 year statement, ETSO Winter 2004-05 NTC data, includes capacity from Switzerland and South East Europe, excludes Morocco Ukraine and Russia; IEA Energy Statistics - 2003 data.

Averages for regional blocks and for the EU are weighted by electricity consumption in each country

The import capacity column shows data for the Net Transfer Capacities (NTC) of all countries provided by ETSO (European Transmission System Operators). This figure gives an indication of the maximum level of exchange between a given country and all of its neighbours that is possible at one time. These NTC figures are related to installed capacity, which is typically much higher than peak load – relating it to this would give higher figures. The figure for Netherlands, therefore, represents the maximum the country could exchange with Belgium and Germany - adjacent countries to which it is connected. This indicates the size of physical connections, and has nothing to do with economic factors such as how much power it actually does import, or whether local countries would be willing to trade this much.

The Import capacity figure therefore illustrates how interconnected a country is with the rest of Europe, and to what degree it could rely on importing electricity instead of generating it locally. We see a wide variation. Some countries such as Luxembourg and Latvia are so well connected they have the capability to import almost all their power, while more geographically peripheral countries such as Ireland and Italy have much lower figures. At the regional level, the Nordic and particularly the Baltic countries on average show relatively high levels of international interdependence, whilst UK and Ireland show very little. The Eastern European countries show higher international interdependence than Western European countries.

1.3 Competition

The key aim of electricity regulation and of recent Directives has been to provide a competitive and sustainable electricity market. It is increasingly widely agreed that the best way to achieve this is through an open, competitive market, with entry by a number of private firms. The degree to which this has been achieved varies widely across the EU; in some countries such as the UK the move to a competitive industry has been broadly completed, while in many Eastern States the process is just beginning.

For a fully competitive electricity market, both the generation and retail markets need to be competitive. A firm with a dominant position in the generation market could perhaps foreclose the retail market, projecting its dominance from one sector to the other.

Table 3 gives key indicators of competitiveness in both generation and retail markets. In the generation market we see the market share of the largest producer and largest three producers combined; and in the retail market we examine the combined share of the largest three producers and the number of significant suppliers.

It is hard to discern notable trends amongst these figures – for example the Czech Republic appears to have a highly competitive market, but Slovakia less so; France appears to have a relatively uncompetitive market, while Austria appears to be the opposite. In assessing the competitiveness of a market, however, it is not only the concentration figures that are important: the extent of network unbundling, which we examine in the next section, is crucial in determining how easily rivals can enter the industry to tackle any excessive levels of profit.

It is also notable that electricity companies in the EU have engaged in significant merger and acquisition activity in recent years, driving higher concentration levels. Although moves towards larger regional markets or an EU-wide market could counter these rising concentration levels in the longer term, in the shorter term this trend could be a cause of concern as it could give companies market power to raise prices.

However, not all integration has been horizontal in nature. Recent years have also seen a trend in vertical integration, with generators and retailers combining. This has a logical economic reason behind it, in that it allows firms significantly to reduce risk as returns at one level are inversely related to returns at the other: higher electricity prices imply greater return for generators, but lower returns for retailers. Therefore, combining the two can clearly eliminate much of this variation and risk, providing a good argument for allowing these types of mergers.

In fact, as Jamasb and Pollitt note, in pre-liberalisation days the market was organised on the basis of vertically integrated organisations, with restructuring often attempting to reduce this, only to see privatised utilities attempting to reverse this and re-integrate. The reason for lesser efficiency of the horizontal structure may lie in the inadequate market design with numerous flaws and cross subsidies, leading to frequent changes of the market model.

Table 3 Competition in retail and generation markets

	Retail market		Generation market	
	Number of suppliers with market share >5%	Top 3 suppliers' share (all consumers)*	Largest producer by capacity**	Top 3 producers by capacity**
Austria	4	67%	45%	75%
Belgium	2	~90%	85%	95%
Cyprus	1	100% (1)	100%	100%
Czech Republic	8	46%	65%	75%
Estonia	1	n/a	90%	100%
France	1	88%	85%	95%
Germany	3	50%	30%	70%
Greece	1	100%	100%	100%
Hungary	7	56%	30%	65%
Ireland	4	88%	85%	90%
Italy	6	35%	55%	75%
Latvia	1	99%	95%	100%
Lithuania	1	100% (1)	50%	80%
Luxembourg	2	100% (2)	n.a.	n.a.
Malta	1	100% (1)	100%	100%
Netherlands	3	88% †	25%	80%
Poland ††	3	32%	15%	35%
Portugal	3	99%	65%	80%
Slovakia	4	84%	75%	85%
Slovenia	6	71%	70%	95%
Spain	5	85%	40%	80%
UK	6	60%	20%	40%
Nordic market -			15%	40%
Denmark	5	67%		
Finland	6	30%		
Sweden	4	70%		

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes. The figures for the generation market for Denmark, Finland and Sweden include Norway.

**Includes both eligible and non-eligible markets*

***Rounded to nearest 5%*

† For household customers

†† Consolidation is currently occurring in Poland

Another important statistic related to competition is customer switching, which demonstrates the tendency of customers to move between rival suppliers. High levels of switching drive competition between competitors, as firms know they will rapidly lose market share if they price uncompetitively, so they must constantly strive to deliver value to customers and estimate their degree of satisfaction with services.

Table 4 shows the degree of consumer switching for both large industrial and smaller commercial or domestic users over a range of time frames. A clear regional trend is initially visible here – all the countries in the Nordic and UK & Ireland regions have seen over 50% of industrial switching since market opening – however this most probably reflects the fact that these markets have been open longer than those of some other regions. During 2003, the highest switching countries included the Nordic countries of Denmark and Finland, but also the Eastern European countries of Hungary and Lithuania: in other words it is difficult to identify meaningful regional trends in these figures.

Table 4 Level of customers switching supplier

	Large eligible industrial users*		Small commercial / domestic	
	Since market opening	During 2003	Since market opening	During 2003
Austria	22%**	7%	3%	1%
Belgium	35%	8%	19% †	19%
Cyprus	0%	0%		
Czech Republic				
Denmark	>50%	22%	5%	5%
Estonia	0%	0%		
Finland	>50%	16%		4%
France	22%			
Germany	35% ††		6% ‡	
Greece	0%	0%		
Hungary	24%	19%		
Ireland	>50%	6%	1%	1%
Italy	~15%			
Latvia	0%	0%		
Lithuania	17%	17%		
Luxembourg	10%			
Malta	0%	0%		
Netherlands	30%		35%	n.k.
Poland	10%	7%		
Portugal	9% ‡‡	7%	1%	1%
Slovakia	10%	3%	4%	
Slovenia	10%	10%		
Spain	18%	5%	0% §	0%
Sweden	>50%	5%	n.k.	10%
UK	>50%		>50%	22%

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes; Regulators.
** In general this refers to clients consuming more than 1GWh/year*
*** 100% have renegotiated with their existing supplier*
† Flanders region only
†† The remaining approximately 65% have renegotiated with their existing supplier
‡ A further approximately 25-50% have renegotiated with their existing supplier
‡‡ Corresponds to 19% of high voltage customers' consumption
§ Approximately 18% have renegotiated with their existing supplier

Consumer switching has limitations as an indicator of the state of competition in a market. In many markets we observe low rates of consumer switching because of high levels of competition, which ensures all producers price low so that there is no need for consumers to switch to another producer. Therefore we would typically expect high levels of switching in the beginning of a market opening process, and high rates for large consumers because small price differences can be financially important. In the often regulated residential market, regulation itself can keep switching rates low because it leads to price convergence.

1.4 Network unbundling

Network unbundling – the provision of open third-party access to the grid including legal separation of market-oriented activities and transmission/distribution network ownership and operation – is generally recognised as an essential step in creating efficient and competitive electricity markets. Transmission and distribution networks are, by their very nature, natural monopolies where there is little scope for competition. It is therefore important that these functions are vertically separated from the potentially competitive generation and retail supply sectors, and that access to these networks is non-discriminatory and cost-reflective. This facilitates competition and the entry of rival firms, which need to use these networks to compete, and also prevents cross-subsidy of generation by transmission. The evidence to date is that vertical separation of networks can yield significant benefits.

It is important to distinguish between the vertical separation of the network functions from other sectors in the vertical chain, and separation of generation and retailing functions from each other. Vertical integration of the latter kind has a justified economic reason, in that it allows firms to reduce risk exposure, which is why it is a commonly seen phenomenon: generators and retailers are exposed to opposite price risks – when electricity prices rise generators gain and retailers lose (if they have sold to final consumers at an agreed price), and vice-versa. By integrating, these two risks will largely offset each other; the merger should not raise anti-trust issues provided that both generation and retail markets are sufficiently competitive.

Table 5 shows the extent of ownership unbundling – that is whether the network operators have a separate ownership or legal treatment, whether they are simply under separate management or merely have a distinct accounting treatment. The unbundling index follows Jamasb & Pollitt in assessing a range of factors to create a score reflecting the degree of unbundling in a country.[1] This looks at whether the system operators have published accounts, a compliance officer, separate corporate identities, separate locations, and whether transmission system operators (TSOs) are ownership unbundled and distribution system operators (DSOs) are legally unbundled. A score of zero indicates a very low level of unbundling, while a score of 5 demonstrates that unbundling is at a very advanced stage.

Note again the low levels of regional correlation, and that Western European countries by no means always have more unbundled markets than more recent members of the EU.

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[1] Jamasb, Tooraj, and Michael Pollitt. 2005. *Electricity market reform in the European Union: review of progress toward liberalisation and integration.* The Energy Journal Special Issue, 11-41

Table 5 Network unbundling

	Ownership unbundling		Unbundling index (5 max)	
	Transmission system operator	Distribution system operator	Transmission system operator	Distribution system operator
Austria	Legal	Legal	4	3
Belgium	Legal	Legal	4	3.5*
Cyprus	Management	None	2	1
Czech Republic	Legal	Accounting	3	2
Denmark	Legal	Legal	4	3
Estonia	Legal	Legal	3	3
Finland	Ownership	Accounting	5	1.5
France	Legal	Management	4	1
Germany	Legal	Accounting	4	1.5
Greece	Legal	None	1	0
Hungary	Legal	Accounting	3	1
Ireland	Legal	Management	3	3
Italy	Ownership	Legal	5	3
Latvia	Accounting	Accounting	3	3
Lithuania	Legal	Legal	4	4
Luxembourg	Management	Management	1	1
Malta		**	-	1
Netherlands	Ownership	Legal	5	3
Poland	Legal	Accounting	3	0
Portugal	Ownership	Accounting	5	3
Slovakia	Legal	Management	3	1
Slovenia	Legal	Accounting	3	1
Spain	Ownership	Legal	5	4
Sweden	Ownership	Legal	5	4
UK†	Ownership	Legal	5	4.5

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes
**Brussels region not yet legally unbundled and no compliance officer in Flanders region*
*** Single buyer model*

1.5 Public vs private sectors

All EU electricity markets are moving towards full market opening, and the ending of state monopolies, though they differ in how far along this process they have gone. Table 6 demonstrates how this varies across the EU, and illustrates how this varies from complete market opening to no opening whatsoever. In some markets, such as the UK, this process of market opening has been completed for some time. However, in others – particularly the recent members – the process of liberalisation still has some way to go.

This is illustrated in Table 6, which shows the achieved extent of market opening. This statistic does show clear variation by regional market. The markets containing the accession countries, that is the Baltic and Eastern European markets, show much lower degrees of market opening than the other markets, where this is mainly or entirely complete.

Full market opening and state ownership are not mutually exclusive. For example, the Nordic region boasts complete market opening yet it is increasingly moving towards an oligopoly of the four 'national champions' – Vattenfall, Fortum, Statkraft and Elsam.

Table 6 Market opening

	Market opening		Market opening
Austria	100%	Malta	0%
Belgium	~90%	Netherlands	100%
Cyprus	35%	Poland	52%
Czech Republic	47%	Portugal	100%
Denmark	100%	Slovakia	66%
Estonia	10%	Slovenia	75%
Finland	100%	Spain	100%
France	70%	Sweden	100%
Germany	100%	UK*	100%
Greece	62%	Western Europe	89%
Hungary	67%	Iberia	100%
Ireland	56%	UK & Ireland	97%
Italy	79%	Nordic	100%
Latvia	76%	Baltic	42%
Lithuania		Eastern Europe	56%
Luxembourg	57%	EU	85%

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes
** In Northern Ireland, the electricity market is open to non-households*

In fact, as Jamasb and Pollitt point out, the EU electricity Directives say nothing about the need for private ownership. UK and Portugal have seen the greatest instances of privatisation, while Italy has seen privatisation to a lesser extent.

1.6 Regulation

Regulation is key in an industry naturally characterised by extremely inelastic demand and difficult entry, where firms can easily gain market power. Table 7 describes the key role that regulation plays across the EU, with the role of the regulator in law and the identity of the agency responsible for oversight of the wholesale and balancing market. In the table, 'advisory' means that the regulator will be consulted but has no legal powers of enforcement.

Price caps for end-users are common in most Member States as a means of regulation where competition is not yet developed enough to guarantee low prices.

Gilardi studies the independence of regulators in several industries across a range of European countries, scoring the agencies by a system he has developed. It is inspired by similar indices often seen for central banks and consists of twenty-one indicators grouped under five equally weighted dimensions, namely the status of the agency head, status of the members of the management board, relationship with government and parliament, financial and organisational autonomy, and regulatory powers.

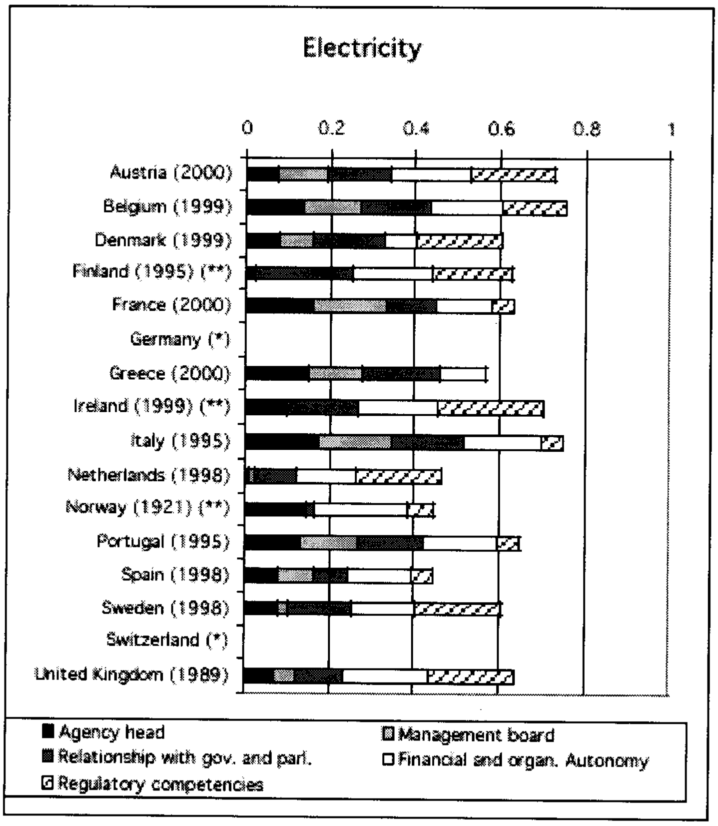
His results are presented below in Figure1. Unfortunately his analysis does not include Baltic or Eastern European countries so we are not able to get a full pan-European picture, however the findings are still instructive. Not only do we see how independence varies across the EU, we also see that countries with regulators of similar independence achieve their score for different reasons, such as France and Denmark.

Table 7 Regulatory role

	Role of regulator in competition law	Monitoring of wholesale & balancing market
Austria	Advisory	Regulator
Belgium	Advisory	Regulator studies
Cyprus		
Czech Republic	Limited or no formal role	None
Denmark	Limited or no formal role	TSO (Nord Pool) & competition authority
Estonia	Limited or no formal role	None
Finland	Limited or no formal role	TSO
France	Concurrent powers / regulator within competition authority	Regulator
Germany	Limited or no formal role	Competition Authority (BKA)
Greece	Limited or no formal role	None
Hungary		
Ireland	Advisory	Regulator
Italy	Advisory	Regulator
Latvia	Concurrent powers / regulator within competition authority	None
Lithuania		None
Luxembourg		
Malta		
Netherlands	Concurrent powers / regulator within competition authority	Regulator
Poland	Advisory	Regulator
Portugal	Advisory	Regulator
Slovakia		
Slovenia		
Spain	Advisory	Regulator
Sweden	Advisory	TSO
UK	Concurrent powers / regulator within competition authority	Regulator

Source: Report from the Commission on the Implementation of the Gas and Electricity Internal Market (2005) - Technical Annexes

Figure 1 Regulatory independence



Source: Gilardi, Fabrizio, 'Delegation to Independent Regulatory Agencies in Western Europe: A Cross Sectional Comparison', Paper prepared for the workshop 'Delegation in Contemporary Democracies', ECPR Joint Sessions of Workshops, Edinburgh (UK), 29 March - 2 April 2003

1.7 Conclusions

It is not simple to generalise about the characteristics of EU electricity markets, and in attempting to do so it is likely one would miss much important local variation. So, despite our desire to conceptualise the EU as consisting of a handful of regional markets, it is key that we keep a national focus until talk of regional markets is more reflected by the realities in practice.

Nor can we make the broad assumption that Western European countries have more developed electricity industries than their Eastern counterparts. In fact on a number of indices the opposite appears to be true: the Baltic countries have made stronger advancements than France and Germany in forming a true regional market and in network unbundling, though they do lag in market opening and in creating competitive markets.

For this very reason, any analysis of EU electricity markets cannot be simple, and there is not always a clear unambiguous answer to policy questions. However, this does not mean that no light can be shed on the subject: in the following sections we look at pricing and pricing structures and the effects of emissions trading and long-term contracts upon the industry.

2 European price structures and trends

This section of the report outlines first electricity price structures within the EU and then price trends. Many of the intended benefits of electricity liberalisation derive from lower prices, so understanding their current state is important when assessing progress toward an EU common market. In turn, long-term trends of prices reflect functioning of the market, which should primarily increase the effectiveness and productivity of the power systems, with lower electricity prices as a welcome by-product.

2.1 Price structures

2.1.1 Data source and description

The Eurostat publication *Electricity price systems 2004* describes electricity price structures for each of the twenty-five Member States, and the following draws heavily on this document. It was written in accord with Council Directive 90/377/EEC for improving price transparency, and is the most thorough and recent official source dealing with price structures.

Market liberalisation has made the task of summarizing price structures more difficult. In the era of state electricity monopolies, data on pricing plans was mostly straightforward and easily obtainable by the public at large. With market opening neither is necessarily true (Bower). First, liberal reforms have brought many more competing tariffs into the market. Second, whereas before deregulation, price information for electricity was quickly and reliably passed by public providers to Eurostat, private companies now have an incentive to withhold the same information from competitors (Bower).

Electricity price systems 2004 therefore suffers from some limitations. It details the pricing structure for regulated markets, and in unregulated markets it describes such contract conventions as have arisen between suppliers and consumers. In some unregulated markets no price structure information is given either because suppliers have withheld information, or because contracts are too idiosyncratic.

2.1.2 Summary of common elements of price structures

The following features capture the basic structure of European electricity prices.

- Tariffs for industrial users are more flexible and varied than tariffs for domestic users.
- Industrial users are offered different tariffs according to the voltage of their connection to the grid.
- Industrial users pay a tariff with three distinct elements: a standing charge (measured in time units), a charge based on maximum contracted demand (measured in kW), and a consumption charge (measured in kWh).
- Industrial tariffs reflect the cost of providing electricity service, so that higher-voltage customers pay a higher standing charge and lower per-unit consumption charge than lower-voltage customers.
- Industrial tariffs are not sector specific.
- Domestic users have a tariff with two components: a standing charge and a consumption charge.
- The consumption charge for both industrial and domestic users can either be the same for each kWh consumed, or vary according to night and day, summer and winter, and peak and off-peak times.
- Suppliers impose higher standing charges in exchange for offering discounts on consumption during certain time periods.

Just because countries share the same general price structure in no way implies however that countries share the same prices.

2.1.3 Differences in price structure across countries

While price structures in Europe are broadly similar, some differences do exist. First, some countries (including Belgium, France, Greece, Lithuania, and Portugal) offer social tariffs to certain groups of captive consumers, usually the poor or disadvantaged; however, this practice is not widespread. Second, while all countries charge value added tax (VAT) on electricity, the Eastern Europe and Baltic regions do not have any extra taxes on electricity for the most part, whereas the EU-15 countries largely do. Another interesting aspect of taxation is that many EU-15 countries actually exempt energy-intensive companies from paying non-VAT taxes if they improve their energy efficiency; thus the tax for certain industrial users creates investment incentives. By contrast, domestic consumers can do little to avoid paying tax.

Finally, of most relevance for this report are differences in price structure between unregulated and regulated markets. Although section 2.1.2 above points out features common to both markets, unregulated markets stand out for various reasons. Liberal reforms have brought into the market multiple companies, each of which offers tariffs that are potentially more nuanced than those of state monopolies. For example, in most countries large industrial operations obtain their electricity through bilateral contracting with service providers, meaning that each customer could in theory negotiate a different price plan. Also, in most unregulated markets, companies offer long-term fixed-price contracts that insure consumers against price volatility, along with flexible billing and energy management services. Moreover, in free markets customers can obtain network and retail services from two separate companies, and pay a different tariff to each (although the principles of section 2.1.2 apply to both tariffs). As electricity market reforms continue, one would expect more innovative price structures to emerge as companies vie for new customers.

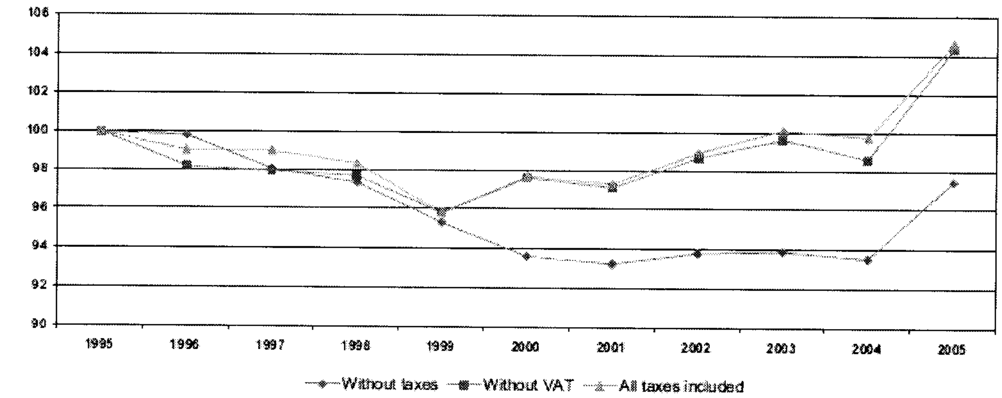
2.2 Price trends

The main impacts on prices that a liberalised electricity market is supposed to bring are reductions and convergence; indeed, these price effects are 'the single most important performance indicator' of successful liberalisation (Jamasb and Pollitt 2005). Accordingly, this section will determine to what extent the two phenomena are apparent in the data.

2.2.1 Evidence of price reductions

The primary source for this section is the Eurostat publication *Gas and electricity market statistics – Data 1990-2005*. Figures 2 and 3 chart EU-15 real (adjusted for inflation) prices with and without taxes for domestic and industrial users over the eleven year period ending in 2005. Similar EU-25 charts are not available since data on the accession countries is missing before 2004. The average price without taxes for one kWh of domestic electricity consumption fell 6% between 1995 and 2000, at which point it stabilised before creeping up in 2005. Even more striking is the 12% drop in the average industrial price over the same time period, although much of the fall was wiped out by 2005. Moreover, between 1997 and 2003, the price for small industrial consumers fell 20% while the price for large consumers fell 9.5% (Jamasb and Pollitt 2005). When taxes are included, both industrial and domestic consumers have seen prices rise from 1995 to 2005 owing to Swedish, German, and Dutch tax increases in 2000; however, prices without taxes are the most relevant for discussing market liberalisation since taxes cause end-user prices to rise and fall regardless of reforms.

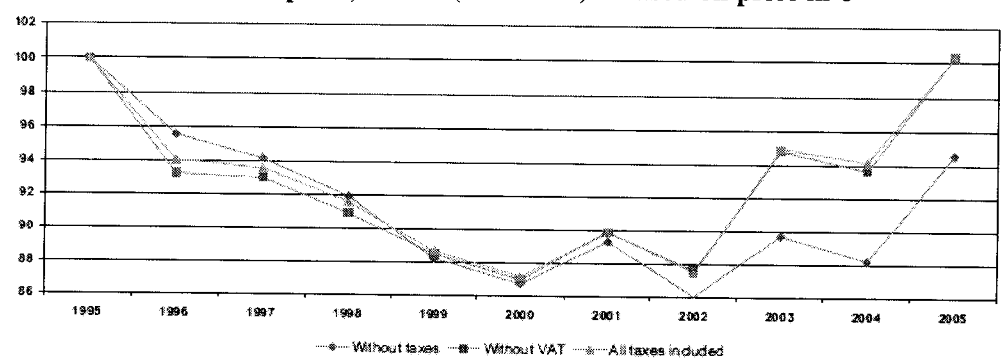
Figure 2 Development of the average price of one kWh for domestic electricity consumption, EU-15 (1995=100) – based on price in €



Note: Based on standard consumer Dc (3 500 kWh/year) on the 1st of January of each year, weighted by consumption.

Source: Eurostat and INSEE

Figure 3 Development of the average price of one kWh for industrial electricity consumption, EU-15 (1995=100) – based on price in €



Note: Based on standard industrial cosumer (I.e) (2000MWh/year) on the 1st of January of each calendar year.

Source: Eurostat

Table 8 displays domestic price data at a country level in order to illustrate that the EU aggregate-price masks considerable individual country heterogeneity: Denmark, Ireland, Hungary, the Netherlands, and Slovenia experienced price increases during 1995-2000 and 2000-2005, while Belgium, France, Italy, and the UK all saw prices fall for both periods. Furthermore, Sweden and Ireland both had large price increases from 2000-2005.

2.2.2 Interpreting the evidence on price decreases

While price decreases from 1995 through 2000 are certainly consistent with the predicted effects of liberal markets, other hypotheses are also worth considering. First, energy prices fell gently over this period (Jamasb and Pollitt 2005). Second, labour productivity growth in the gas, electricity and water sectors grew 5.7% a year from 1995-2001 (EC Commission Report 2004). In other words, falling costs of production might explain falling prices. These points do not discredit the impact of liberalisation, but do show that many different factors can potentially drive electricity prices.

Along the same lines, the flat prices after 2000 and the price rises from 2004-2005 do not in themselves establish that progress in electricity markets has stalled or reversed, the fear of which prompted the European Commission to launch an inquiry in June 2005 into restricted or distorted competition within the EU (EC Commission Report 2005).

For example, gas and oil prices have increased even more than electricity prices in the recent past. Since gas plays a major role in European electricity generation one could reasonably conjecture that producers are passing on their increased costs to consumers. Tax increases as well as the introduction of emissions trading might also help explain the recent price rises.

Table 8 Electricity for households - average price by country of one kWh, without taxes - in cent

	1995	2000	2001	2002	2003	2004	2005	Change 1995-2000 (%)	Change 2000-2005 (%)
EU-25						10.0	10.46		
EU-15	11.02	10.31	10.27	10.33	10.34	10.30	10.74	-6	4
Austria		9.49	9.45	9.32	9.26	9.81	9.64		2
Belgium	12.31	11.71	11.84	11.37	11.2	11.45	11.16	-2	-5
Cyprus		8.45	9.90	8.45	9.15	9.28	9.15		9
Czech Republic		4.75	5.38	6.42	6.54	6.60	7.29		29
Denmark	6.08	7.18	7.81	8.65	9.47	9.15	9.27	17	29
Estonia				4.57	5.50	5.50	5.76		
Finland	7.03	6.45	6.37	6.97	7.38	8.10	7.92	-7	23
France	10.06	9.28	9.14	9.23	8.9	9.05	9.05	-8	-3
Germany	12.98	11.91	12.2	12.61	12.67	12.59	13.34	-6	12
Greece	6.47	5.64	5.64	5.80	6.06	6.21	6.37	-2	15
Hungary	4.55	6.22	6.34	7.23	7.33	7.94	8.51	152	32
Ireland	7.34	7.95	7.95	8.83	10.06	10.55	11.97	7	51
Italy	15.09	15.0	15.67	13.90	14.49	14.34	14.40	-4	-4
Latvia						4.87	7.02		
Lithuania						5.35	6.09		
Luxembourg	10.67	10.56	11.2	11.48	11.91	12.15	12.88	2	22
Malta	4.84	6.09	6.17	6.31	6.03	5.88	5.85	16	0
Netherlands	8.46	9.38	9.78	9.23	9.70	10.31	11.02	15	17
Poland			7.10	7.61	7.21	6.13	5.83		
Portugal	12.57	11.94	12.0	12.23	12.57	12.83	13.13	-3	10
Slovakia						10.24	11.23		
Slovenia	6.71	8.3	8.37	8.58	8.33	8.41	8.61	59	24
Spain	10.56	8.95	8.59	8.59	8.72	8.85	9.00	-14	1
Sweden		6.37	6.29	7.01	8.38	8.98	8.46		40
UK	9.46	10.56	9.96	10.31	9.59	8.37	10.15	-12	-11

Note: Based on standard consumer Dc (3 500 kWh/year) on 1 January of each calendar year. Source: Eurostat

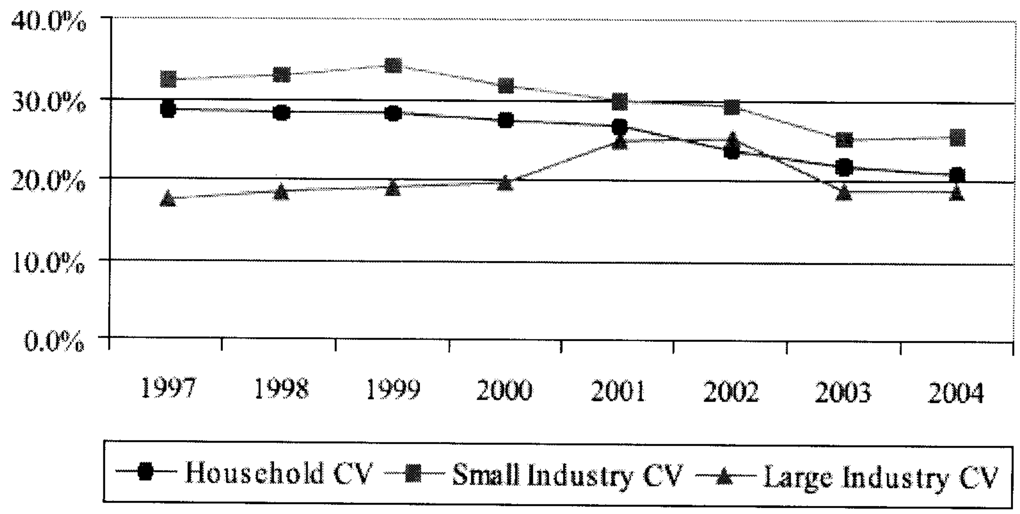
Another important mechanism behind the price trends is electricity supply. When the EU reforms began, the European electricity market had excess capacity, meaning there was room for competition to push prices down. This excess capacity has since dwindled, leading to upward pressure on prices. One would expect firms to respond to higher prices with increased investment in capacity, but new installations take several years to become operational, so prices are slow to adjust even in free markets.

One final point to note is that in many countries (especially Scandinavia) electricity prices are determined in large part by hydrological conditions, so price trends can also depend on weather patterns.

2.2.3 Evidence of price convergence

Some evidence exists of price convergence in EU markets. Jamasb and Pollitt (2005) compute the coefficient of variation (the standard deviation divided by the mean or CV [coefficient of variation]) for three different groups over an eight year period; the results are shown in Figure 4. A higher CV means prices are more divergent. As seen in the figure, small-scale users have seen moderately converging prices, while large industrial users have not.

Figure 4 Price convergence – coefficient of variation (CV)



Source: Based on European Commission (2004b, 2005)

In theory price convergence should occur in an open electricity market because of a straightforward mechanism that the following simplified example illustrates. If a consumer in France is buying electricity from a Greek supplier, and a Slovenian company offers a lower price, then the consumer will presumably switch supplier. The Greek company will either have to match the Slovenian price, or else go out of business; either way, the price gap will disappear. Of course, this argument rests on the assumption that electricity can actually flow to France from Slovenia and Greece. In other words, the electricity systems of Europe need to be interconnected for EU-wide price convergence to occur. Section 1.2 shows that serious gaps are present in interconnectedness, and so for this reason alone one would not expect to see price convergence. To examine further the argument that interconnection is the key to achieving price convergence, one can take the raw price data from Table 8, compute the CV for regional blocks, and examine whether the resulting statistics are lower than the EU-wide CV computed with the same data. Table 9 gives the results.

Table 9 Coefficients of variation for regional electricity markets

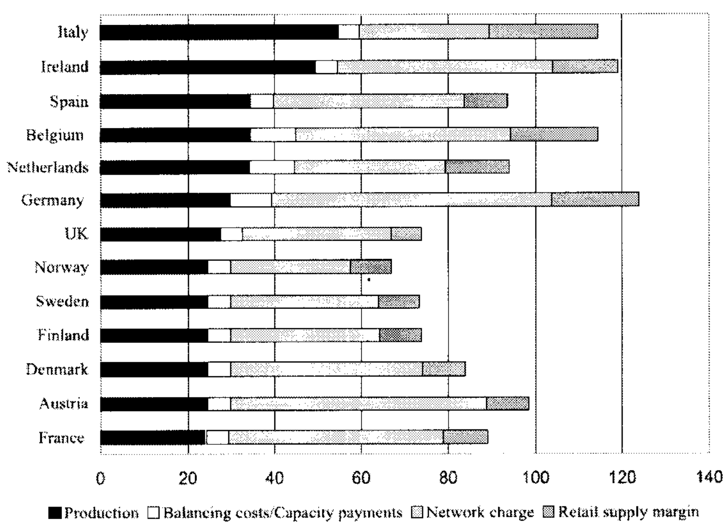
	1995	2000	2001	2002	2003	2004	2005
EU-25	34.5	29.6	29.6	26.8	25.9	28.5	27.4
Western Europe	16.6	11.5	12.4	14.0	14.5	12.8	15.2
Iberia	12.3	20.2	23.4	24.7	25.6	26.0	26.4
UK and Ireland	17.8	20.0	15.9	10.9	3.3	16.3	11.6
Nordic	10.2	6.7	12.5	12.7	12.4	6.4	7.9
Baltic						6.3	10.4
Eastern Europe	27.1	27.8	18.6	12.0	10.0	20.7	24

Source: Author's calculations

The most interesting feature of Table 9 is that each region taken separately shows substantially more price convergence than the EU as a whole, meaning that interconnectedness (combined with other forms of integration) does indeed lead to price convergence. Every region in every year has less variation in prices than the EU-25 as a whole. The large and erratic fluctuations in the actual CV figures from year to year derive from spot price data which is itself widely variable. Also, some of the regions have relatively few members, so price changes in one country can affect significantly the total region's variability. Still, the pattern is clear: regions demonstrate more price convergence than the European average.

One caveat to the discussion is that the same price in two countries can have different implications. For example, if the price of electricity in Luxembourg is the same as the price of electricity in Poland, then Poles, whose incomes are significantly lower, are actually paying much more for electricity in real terms. In other words, one can check for price convergence controlling for income differences. Space constraints prevent such an analysis in this report.

Figure 5 Estimated breakdown of expected electricity prices 2004 (50 mWh /year customer) (€/mWh before taxes)



Source: European Commission (2004b)

The final obstacle to achieving price convergence lies in network costs, which are not subject to competitive pressure. Figure 5, taken from Jamasb and Pollitt (2005), shows the various sources that contribute to final electricity prices. Network charges are both a large part of prices and highly variable. One mechanism that might bring about more uniform network charges is continued network unbundling combined with independent incentive regulation of networks. The former prevents anti-competitive network pricing by vertically integrated firms, and the latter brings efficiency improvements through methods such as price caps (Jamasb and Pollitt 2005).

2.3 Conclusions

The structure of electricity tariffs is common to nearly every European user and country. One main difference is that industrial users have a larger array of tariffs than domestic consumers. Also, electricity service providers in open markets have more flexibility in adjusting tariffs than those in regulated markets.

Prices have decreased since the start of liberalisation, although most of the falls occurred before 2000. At an EU level prices have slowly converged for some groups since the opening of markets, while at a regional level price difference are much less. Several factors other than failure of market reforms might be driving recent price rises as well as lack of convergence.

3 Impact on electricity prices of emissions trading

This section first discusses the creation and operation of the European Union's Emissions Trading System (EU-ETS). It then studies the impact of the EU-ETS on prices at a theoretical level before presenting preliminary empirical evidence.

3.1 Background information

3.1.1 The Kyoto Protocol and the EU

Recognising the importance of limiting greenhouse gas (GHG) emissions in the struggle against global warming, negotiators from around the world finalised the Kyoto protocol in 1997. Forty-one industrial countries agreed to reduce GHG emissions by an average of 5% from 1990 levels over the period 2008-2012. The EU signed up to the agreement as a bloc, and agreed to reduce GHG emissions by 8% over 2008-2012 (Levy 2005).

3.1.2 The structure of the EU emission trading scheme (ETS)

Several options exist to meet GHG reduction targets, including carbon taxes, regulation, legislation and emissions trading. For a variety of reasons, the EU decided in 2002 to adopt the latter option. An initial trial phase began in January 2005 and will run through to the end of 2007, before a second trading period runs from 2008-2012, the Kyoto commitment period (Levy 2005).

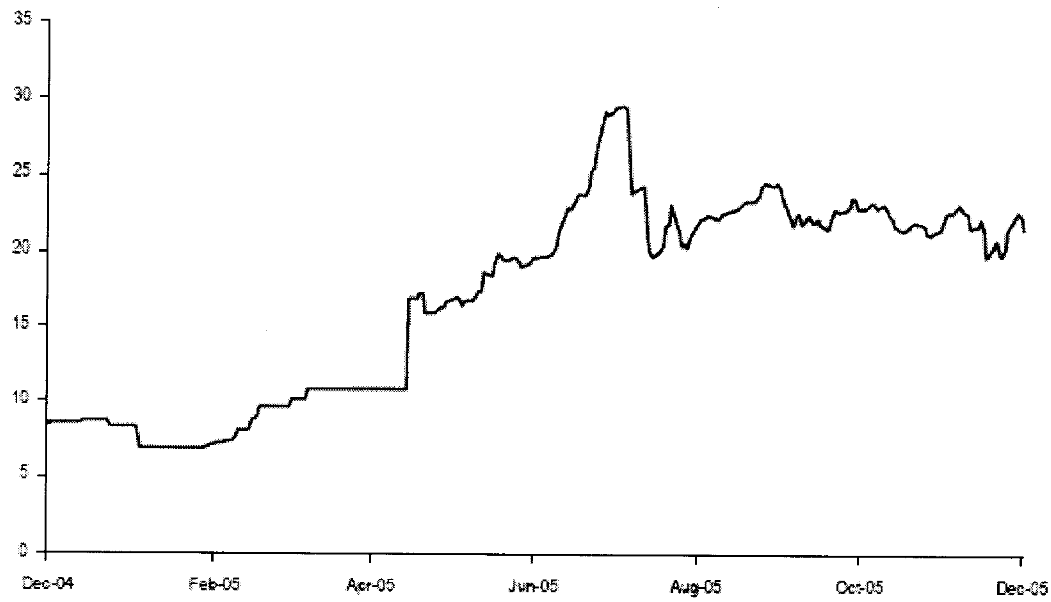
The EU-ETS is a 'cap-and-trade' mechanism: governments distribute a fixed number of pollution allowances (where one allowance corresponds to one ton of emissions), thereby capping emissions; after receiving allowances, companies are free to trade them. Allowances acquire a market price that equates supply and demand. At the end of each year, every company must hold allowances equal to total emissions or else face a fine – which does not buy them out of emission compliance, as they have to present the missing allowances in the next year. Thus, companies that cannot keep emissions below the level of their initial allowance allocation must purchase additional allowances on the open market from companies that can (Royal Society 2002).

The initial phase of the EU-ETS covers only carbon dioxide (CO_2), the primary component in GHG emissions. 11,400 installations currently participate, which together account for 55% of total EU CO_2 emissions and 45% of total GHG emissions. Governments distribute total allowances of 2182 Mega-tonnes a year; the electricity sector receives 55% of them, reflecting its importance in total emissions (Levy 2005). An important point is that polluters are allocated their initial allowance free of charge, an allocation method called grandfathering (Royal Society 2002).

3.1.3 Trading on the allowance market

After spending the first few months of trading near ten euros, the price of an allowance shot up to thirty euros by July, before stabilising between twenty and twenty-five euros in the last half of the year. Several factors might have caused the price rise. First, gas prices grew faster than coal prices over 2005, increasing the competitiveness of coal (which generates more emissions) relative to gas generation. Second, water power also suffered relative to dirtier fuels during 2005 because of the droughts in South-West Europe. Finally, extreme weather led, in March and June, to unexpectedly high demand that was supplied by heavily polluting oil facilities. All these factors increased demand for allowances, pushing up prices (Levy 2005). Figure 6 shows how the price (in euros) of an allowance has developed since the start of trading in January 2005.

Figure 6 Evolution of the price of an EU emissions allowance (in €)



Source: Bloomberg

3.2 Electricity price effects of the EU-ETS: theory

3.2.1 Links between carbon costs and prices

Standard economic theory predicts that the market price of a good is positively related to the marginal cost of the final unit supplied, ie the cost of producing the last unit sold to meet demand. In light of this relationship, the introduction of the EU-ETS has one definite and one potential effect. First, whoever supplies the final unit will certainly have an additional element in marginal cost: the price of the allowance used up in production. Even if the supplier receives this allowance for free, in producing the final unit it is giving up the opportunity to sell its allowance on the market, and so it incurs a real cost.

The only exception would be if the marginal supplier created no emissions, like a nuclear or wind facility. However, this situation will not likely apply to any European country as a whole for a long time. Based on this analysis, one would expect the marginal supplier to pass through 100% of the CO_2 costs into the wholesale electricity price (Reinaud 2003).

The potential effect of carbon trading is to change the identity of the marginal supplier. According to economic theory, the lowest cost producer supplies the market until its capacity is exhausted, at which point the next lowest cost producer steps in to supply the market until its supply is exhausted, and so on until some producer succeeds in satisfying demand. As explained in the last paragraph, this producer supplies the marginal unit and so determines market price. Now, when carbon costs are introduced into the power market, the cost-ranking of facilities potentially changes (NERA 2005). For example, without considering emissions costs, coal is cheaper than gas. However, gas is cleaner than coal, so when emission costs are included, there is some threshold allowance price beyond which gas is cheaper than coal. So, in a market where, before EU-ETS began, a coal facility was the marginal supplier, one could see a gas facility become the marginal supplier. If the coal facility remained the marginal supplier then the impact on electricity prices of emissions trading would be much larger than if a gas facility became the marginal supplier: since gas does not create as much pollution, fewer costs get passed onto the market.

3.2.2 Countervailing forces

On the other hand, Julia Renaud's International Energy Agency (IEA) report published just before the start of the EU-ETS identifies some scenarios under which allowance trading would not lead to substantial price changes. The first is when carbon-intensive technologies are the marginal producers in a market where supply competition is intense. In this case, if one of the companies treated its allowances as real costs and raised its price, it might lose market share to a competitor. Companies would have an incentive not to treat grandfathered allowances as real costs in order to give themselves more flexibility. Price competition among the marginal producers in order to maintain market share could be the most salient economic force, limiting the impact on electricity prices. A similar argument would apply if the rate of customer switching were high (Renaud 2003).

Another point is that if a producer has a large market share, it might decide not to pass on allowance costs to consumers in order to keep the price as low as possible, limiting new entrants. One final situation in which prices might not increase is if the allowance allocation formula for each year depends on either past production or CO_2 emissions. In either case producers have an incentive to maximise market share during the year in order to receive a large allocation of allowances in the next year (NERA 2005).

3.2.3 Impact on end-user prices

So far the main price under consideration has been the wholesale price, since the wholesale market is the one onto which generators in a competitive market sell their power and pass on costs. However, consumers of electricity do not buy at the wholesale price; they buy from retailers, who in turn purchase electricity at the wholesale price.

There are several reasons to believe that the impact of emissions trading on the retail price is less than on the wholesale price. Most European households are still on regulated tariffs, and regulators are not likely to agree to pass on costs arising from grandfathered permits. Moreover, even though industrial users operate in generally free markets, they can switch back to regulated tariffs in some countries, and so have protection against large price increases (Levy 2005).

Referring back to figure 5, end-user electricity prices depend on much more than generation costs, so a rise in the latter will cause a less than proportional rise in the former. Furthermore, many industrial users negotiate long-term contracts with suppliers that stipulate prices only partially linked to wholesale markets, although this may change as the nascent free market develops. Even in the freest markets, however, industrial users have scope to bargain with retailers over how prices are set (Levy 2005).

3.2.4 Summary of effects

In short, many different forces combine to translate allowance costs into wholesale electricity and end-user price changes. Table 10 summarises the analysis of four different studies that have attempted to disentangle them.

Table 10 Estimates of price impacts of emissions trading

	Allowance price	Effects on electricity price
McKinsey	25€ (modelling result)	+30% on wholesale, +15% on end-use
ICF Consulting	5€ (2005-2007), €10 (2008-2012) (assumptions)	+19% on wholesale
Reinaud (2005)	20€ (assumption)	+21% on wholesale
Levy (2005)		+(30%-60% of allowance costs) on wholesale

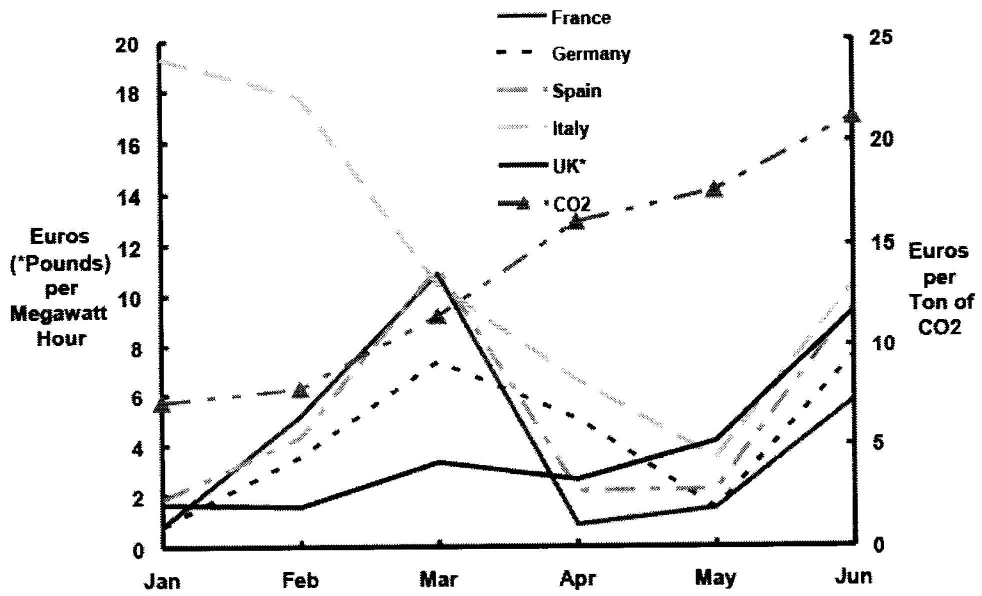
Reinaud (2005) provides the information on the McKinsey and ICF studies.

3.3 Electricity price effects of the EU-ETS: evidence

Since there is only a year's worth of trading information since the EU-ETS began, any attempt to quantify how prices and wholesale prices relate can only be indicative and is bound to be incomplete.

Levy (2005) finds that in the first quarter of 2005, CO_2 and electricity prices did not move together in Spain, France, the UK, Germany or Italy, but that in the second quarter they did. In addition, in the second half of 2005 wholesale power prices grew more in correlation with prices of emission allowances. This could imply that companies began passing on allowance costs three months after the system began, or simply that some third variable changed in the second quarter that was related to both CO_2 and electricity prices. To explore the issue further, Levy proceeds to construct measures of the marginal cost of electricity in the same five markets. She then compares the five differences in wholesale price and marginal cost to examine whether the resulting gaps relate to the CO_2 price – evidence that all carbon costs are factored into prices. Figure 7 shows her results. The scale on the left hand side of the figure measures the difference in the listed countries, while the right hand scale measures the price of CO_2.

Figure 7 Differences between marginal costs and wholesale power prices

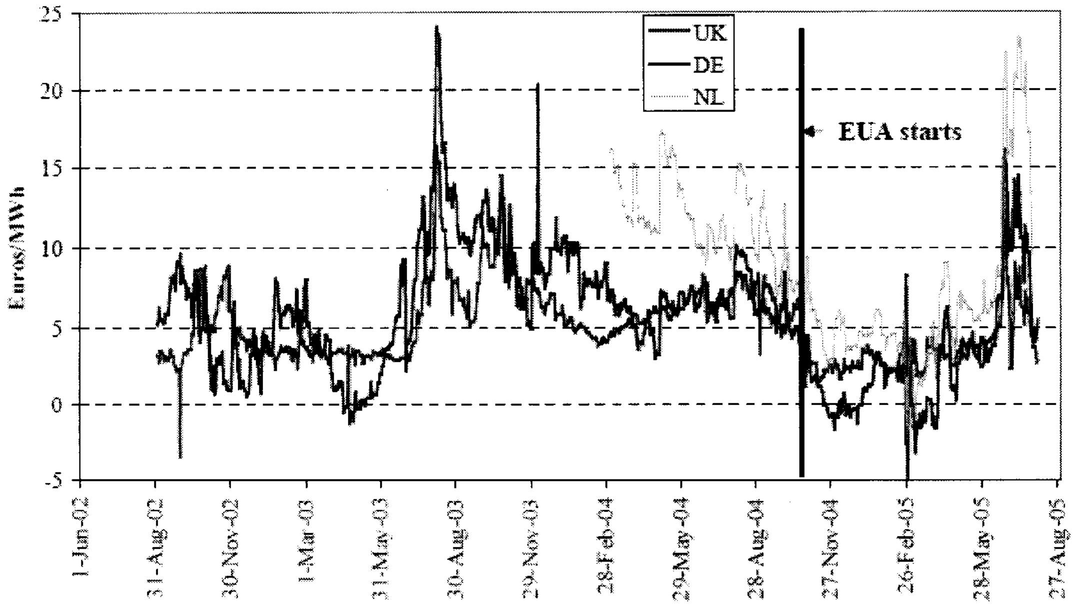


Source: CERA

The two months for which the gap is significant in the five countries are March and June, and these are precisely the months in which prices suddenly increased owing to weather-related demand shocks. Otherwise, the gap between marginal cost and price does not appear large in any country. Moreover, from April to May the CO_2 price rose while the price-cost gap shrunk. On the other hand, as Levy notes, in Germany the gap increased on average during the first six months, while in the UK the gap increased every month. Furthermore, preliminary evidence indicates that in France, Germany and the UK the gap continued to grow through the summer. In the end, Levy's analysis provides only limited evidence of any price impact of emission trading, although given such a short timescale it is difficult to know how much weight to put on the results.

David Newbery has recently completed his own investigation into carbon and electricity price links using a similar methodology, but with an expanded data set containing more months. He considers the difference between electricity prices and fuel costs for gas facilities (a statistic known as the spark spread) in Germany, the Netherlands and the UK through August 2005. The spark spread measures profitability. To examine price effects of emissions trading, he takes the spark spread for the EU-ETS period and subtracts the cost of an allowance. If the gas-fired power sector does not pass on any of its emission costs to consumers, the spark spread net of allowance costs during EU-ETS should drop relative to spark spreads before January 2005. If the sector passes on its entire costs, then the spark spread net of allowances should be equal before and after January 2005 (Newbery 2005). Figure 8 shows the data.

Figure 8 Spark spreads of UK, DE, and NL before and after EU-ETS



After an initial fluctuation period, profits inclusive of allowance costs have returned to roughly their level before the commencement of trading. Newbery thus concludes that 'most if not all of the [allowance] opportunity cost has been passed through into the wholesale price,' though again much more data is needed fully to establish this claim.

Newbery's results are clearly much stronger than Levy's, as well as more in line with theory. As Levy notes, however, it might simply take companies time to learn how to operate under the new system, and her data set ends in June 2005. She cites interviews in summer 2005 with German and French power executives in which they say their companies increasingly factor CO_2 prices into the wholesale price. As can be seen in Figure 8, it was not until the summer that gas-fired plants fully internalised CO_2 costs.

One further piece of evidence comes from Pekka Pirilä, from the Helsinki University of Technology. Having controlled for changing hydrological conditions in Scandinavia during the trading period, he finds that emissions trading has led to a 10 €/MWh increase in electricity prices, which is around fifty percent of the increase in marginal cost of coal fired condensing power brought about by the EU-ETS.

In the present EU-ETS the cost compensation provided by free allowances is always given to the power producers, even in situations where increased prices eliminate economic losses. At the same time higher electricity prices induce losses to electricity consumers, including industries that cannot transfer additional costs to their product prices because of international competition. Thus losses caused by political decisions are 'compensated' to a large extent to companies that have not suffered any losses but cannot be compensated to the real loser.

3.4 Efficiency of price rises due to EU-ETS

Price increases from trading allowance schemes may or may not be efficient for society. On the one hand, producers might simply be passing on to the market the costs of real emission reduction efforts; on the other some companies might be enjoying windfall profits resulting from the good luck of getting more allowances than they need. Especially in schemes where producers are given allowances for free (such as EU-ETS), the risk of the latter is always present. Companies have a powerful incentive to hide planned emissions reduction investments from the authorities in order to maximize the amount of allowances they receive (Royal Society).

Once the trading scheme begins they can go through with emissions reduction and have leftover allowances to sell on the market, in effect getting something for nothing.

Auctioning is an economically more rational means of allocating licenses. When companies have to bid for allowances, they would pay only what they believe the allowances are worth, and companies would not likely obtain superfluous credits. The allowance allocations would more truly reflect actual market conditions, and the price increases that consumers experience would probably be financing CO_2 emissions reductions. The main obstacle to auctions is that they constitute a transfer of wealth from polluters to government, while the free distribution scheme transfers wealth in the opposite direction. Politically, then, free distribution is often the easiest way to begin an emissions trading system.

Basic economics, however, suggests that the EU should move to an auctioning system sooner rather than later, or else risk undermining its goal of reducing emissions as efficiently as possible. As in many other situations, market forces are more likely to allocate goods efficiently than government authorities. In future trading periods of the emission trading scheme, the allowances are bound to become real costs to the producers since their amount will steadily decline.

3.5 Conclusions

Economists and consultants agree that there should be an impact on electricity prices deriving from the EU-ETS, but they do not agree on the size of the impact. The first link is between 1) increased production costs coming from the introduction of pollution costs and 2) the wholesale price. Increased wholesale prices should also lead to increased end-user prices in open markets. Both links are complicated by a myriad of factors, the most important ones of which deal with market structure. As this report has established, many different markets co-exist within the EU, and the structure of each one contributes to how emissions costs affect prices.

The little available empirical evidence confirms a relationship between EU-ETS and wholesale electricity prices. Much more work in this direction is needed once the system has been in place for longer.

4 Long-term contracts

In this section of the report we analyse the possible effects that long-term contracts could have upon the EU electricity markets. We review existing contractual arrangements and then assess a range of possible advantages and disadvantages of the market moving towards longer-term contracting.

4.1 Background

Long-term contracts are seen between generators and electricity retailers, though it is possible that in time others such as brokers may increasingly become contracting parties, especially as the system develops. Long-term contracts could be signed for any term the parties wish, with contracts stretching far into the future a possibility. It is not precisely known how much of the electricity markets long-term contracts currently account for, though we know that in several markets they play an important role. For example, in the UK 5-year contracts were introduced back in 1993, and in Finland long-term contracts bound to ownership form an essential component of the nuclear power plant being constructed – such ownership solutions have been used there for decades and remain an important factor in securing electricity for large industrial consumers.

Efficiency in this context means that electricity is produced at the lowest cost that is sustainable in the long run, that producers cannot exploit market power to raise prices above competitive levels and that firms have an incentive to invest up to the amount that the market is willing to pay for the benefits. In other words, social welfare is maximised in such a perfectly competitive market model.

Long-term contracts would cover the quantity of power supplied and fix a price, and would include clauses covering a variety of circumstances such as legislative and production cost changes. The trading of long-term contracts can take various forms; it can be bilateral (perhaps mediated by a broker), or with an independently operated contracts exchange, which could feature secondary trading of contracts.

4.2 Benefits of long-term contracts

4.2.1 Stability

The fundamental trouble with electricity markets is that demand is almost completely unresponsive to price fluctuations, supply faces binding constraints at peak times, and storage is not easy. These characteristics necessarily imply that short-term prices for electricity are going to be extremely volatile. This inherent instability poses risks to everyone involved in the system – generators, distributors and final consumers.

Long-term contracts can provide a way of market participants insulating themselves from these inherent risks: after having signed a long-term contract a party is relatively unaffected by any sudden changes in the market such as rapid price fluctuations or supply shortages. Using long-term contracts in this way is not a new idea, or one that is only considered within the area of electricity. In fact, it is common to see long-term contracts in other industries that feature a great deal of spot price volatility in order to smooth transaction prices.

4.2.2 Case study: California

A strong example illustration of the intrinsic instability of the electricity market, and the role that long-term contracts can (or cannot) play in mitigating crises, is provided by the California power crisis of 2000-2001. This was in the headlines as the State was hit by a wave of blackouts due to chronic shortages of electricity, causing prices to spike at several thousand percent of their normal levels, sending companies to the verge of bankruptcy and costing the State billions of dollars.

Looking at this crisis, James Bushnell (research director of the University of California Energy Institute, Berkeley) cites the lack of long-term contracts between the utilities and wholesale electricity suppliers as the *unique* source of California's crisis.

> *If one considers these three elements – concentration of ownership, lack of price-responsive demand, and lack of long-term contracts, only one element differentiates California from other regions: the lack of long-term contracts.*[1]

For various reasons, utilities did not engage significantly in long-term contracting of electricity (though these were not strictly banned). James Sweeney, Professor of management science and engineering at Stanford University, speaking at a seminar on the issue argued:

> *So there was no long-term protection for the investor-owned utilities ... If you are selling to retail customers who do not want price fluctuations, the way to operate is through long-term contracts to have that security.*[2]

These commentators are not alone in citing long-term contracts as being of prime importance in creating market stability. Severin Borenstein, a University of California, Berkeley, economics professor and director of the University of California Energy Institute, agrees that although price caps were a contributor to the crisis, the lack of long-term contracts was the most important cause.

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[1] Bushnell, James, 'California's Electricity Crisis: A Market Apart?', CSEM Working Paper 119, November 2003

[2] Murray, Bruce, 'Rewinding the California Electricity Crisis', FACSNET.

The difference between California and what happened in every other state is not retail price caps – they all had retail price caps – it was the lack of long-term contracts and long-term procurement.[1]

Summarising, Bushnell remarks

Many factors contributed to the California crisis: market power of producers, a flawed market design that included a freeze on retail rates, inflexible regulatory policies at both the state and federal level, but most uniquely, the lack of contracts or other long-term arrangements and the concentration of transactions in short-term, daily markets.[2]

4.2.3 Encouraging investment

A defining characteristic of the electricity market is that it is extremely capital intensive, with major investments being made up front, and returns made over a long period of time. Long-term contracts provide a means for investors in new capacity to manage their investment risks, and can thus serve to encourage investment - this will increase, and promote a more efficient level of, investment. Currently investment where the return is forecast to be greater than the cost (and is thus 'efficient' in an economic sense) may be deterred by the risks involved. By being able to reduce a large part of this risk through long-term contracts, a more 'efficient' level of investment is encouraged.

John Fitz Gerald discusses this argument in the case of the Irish electricity industry.

He notes that:

Probably the most serious problem with the current market is that new customers are not prepared to sign contracts for power supply with new entrants for periods longer than two or three years. This means that new entrants can not guarantee themselves a market in advance of investing. As the capital costs in building generating stations are very large, this makes investment very risky, increasing the cost of capital. The normal way to finance a new power plant is to borrow, with long-term contracts for sales of electricity providing security. This is not possible in the Irish case because of the impossibility of obtaining matching long-term contracts for sales.

The result of these uncertainties is to greatly increase the cost of capital for new plant and to reduce the incentive to invest. This is a common problem to all electricity systems.[3]

Note that here the investment that is encouraged is not necessarily just by incumbent firms, but could be by potential entrants. By being able to lock in a secure revenue stream from their investment through long-term contracts, firms considering entry will be greatly encouraged and thus this could further enhance the degree of competitiveness in the market, and serve to drive prices down. Incumbent firms could perhaps anticipate this entry, and may then strive to keep prices lower in order not to attract it. Thus there could be a pro-competitive effect even if entry does not actually occur. Long-term contracts are particularly valuable when the market environment is subject to non-commercial risks, notably from political or regulatory opportunism or indecisiveness

Note that the strength of this effect depends upon the length of the long-term contracts available: if a contract is available for the whole life of a generating plant, an entrant is likely to be more encouraged than if he was only able to secure a contract covering part of its life span. The Finnish nuclear plan mentioned above provides a clear example of this argument, the contracts it is based upon are effectively almost life-of-plant and clearly this has facilitated this investment going ahead.

[1] Murray, Bruce, 'Rewinding the California Electricity Crisis', FACSNET.
[2] Murray, Bruce, 'Rewinding the California Electricity Crisis', FACSNET.
[3] Fitz Gerald, John, 'The Irish Energy Market – Putting the Consumer First', ESRI Working Paper 145, August 2002.

4.2.4 Undermining producer market power

Several authors have argued that the nature of the electricity industry – with its highly inelastic demand in the short run, and high costs of entry – necessarily puts suppliers in a position to exploit market power.

Long-term contracts can help undermine collusion between generators, as long-term contracts provide another market mechanism for firms to cheat on others in a collusive agreement. They can also provide a greater incentive for participants to 'cheat' on the agreement: it may not be worth cheating on the cartel for a small short-term contract as the rewards are not large enough. However, with a large long-term contract for several years in the future the gains of undermining the cartel are much larger.

It has also been argued that as generators trade an increasing amount of their power through long-term contracts, and the relative importance of the spot market as a source of sales declines, the incentive to exploit market power in the spot market will also fall. As firms trade less through the spot market, the quantity on which they stand to gain a collusive mark-up falls also, so hence their incentive to engage in collusive activity.

Of course these benefits depend upon one's interpretation of how much of a problem market power and collusion is (and will be in the future) in the various EU electricity markets.

4.2.5 Aiding efficient timing of maintenance work

Long-term contracting can serve to facilitate least-cost (hence efficient) timing and coordination of major maintenance work, where generating capacity is taken out of service. The owner of generating capacity will have an incentive to trade out of the contracts (to supply electricity) for the maintenance period and will schedule the work for when this can be done cheapest – ie when the price of electricity is lowest. This is efficient as this will be when there is plenty of electricity and others can make up for the reduced capacity.

This has the further efficient effect of signalling a maintenance decision to others, via the rise in price of electricity in the forward market, which will discourage them from scheduling work at the same time.

4.3 Risks of long-term contracts

4.3.1 Lack of flexibility

From a buyer's perspective there is of course a risk of locking in a higher price than could have been obtained in the spot market – it is quite possible that the contracted price will not equal the contemporaneous spot price (though of course the reverse is also possible).

Contracts can be flexible, with clauses covering all manner of circumstances – however they are not infinitely flexible. While it may be theoretically possible to contract over a vast number of variables and contingencies, in practice this may be difficult and time consuming. David Newbery notes that in the UK:

> *Risks could have been hedged by long-term contracts between generation and supply companies, but the transaction costs of writing long-term contracts to cover all contingencies (such as the ending of the Pool, the Emissions Trading System, Climate Change Levy, Renewables Obligation Certificates) might make vertical integration more attractive.*[1]

[1] Newbery, David, "Electricity Liberalisation in Britain: The Quest for a satisfactory Wholesale Market Design", The Energy Journal Special Issue on European Electricity Liberalisation.

If a distributor buys a proportion of its forecast electricity needs through long-term contracts, and then the spot price falls a lot, it either has to sell at a loss, or risk that consumers could switch away to other providers that can offer cheaper electricity bought through the spot market. The distributor with the long-term contract could then find itself having excess electricity. For this reason it seems wise that distributors do not buy too much of their electricity needs through long-term contracts, as this situation could prove fatal. In absence of the electricity derivative market, a solution to this problem used by distributors is short-term and medium-term contracts, which over the shorter time span expose them to a smaller variation in price changes. Usually a long-term contract represents a higher risk to a distributor from losses due to lower prices.

4.4 Other factors

4.4.1 Contract trading

A question of fundamental importance is whether the contracts are tradable, and how liquid the market for contracts is. With a liquid and fully functioning market for long-term contracts, it is likely that the risk-reducing and efficiency-enhancing consequences of the contracts will dominate. However, with little or no scope to trade contracts, their impact could be more negative.

The suitability of the contracts for secondary trading will depend on the nature of the contract – it is likely that some contracts may be more tradable than others, such as standardised fixed quantity contracts. However, contracting parties are likely to take account of this point, and the general development of secondary markets, when they draw up their contracts.

4.4.2 Electricity derivatives

Essentially, the key role of long-term contracts is to reduce the price risk to which market participants are exposed. This role can be, and has been, played by electricity derivatives, which can also be used to manage market risks. The effectiveness of derivatives in fulfilling this role partly depends on how well developed and liquid the derivatives market is in a particular country.

In the Nordic market, for example, financial derivatives extending 3-4 years into the future are used extensively by market participants to hedge their risk exposure to price fluctuations, and these form an efficient alternative to long-term contracts which are used as well. For periods of more than 4 years, long-term contracts are more important than derivatives. In contrast, in the Baltic market derivatives are less frequently used and futures and forward contracts have not started to flourish yet, mainly owing to a weak price signal and low liquidity.

Thus one could argue that derivative and long-term contracts are substitutes, and that countries with well-functioning derivatives market have less of a need for long-term contracts. However, most observers talk about derivatives and long-term contracts being complementary, and that allowing participants the full use of both allows them to best manage their risk and provide successful market outcomes.

4.5 Conclusions

Many commentators strongly advocate long-term contracts as a means of improving efficiency in the electricity industry, and of preventing crises like that in California occurring again. Overall, it is generally argued that greater use of these contracts would increase efficiency and be socially beneficial owing to their three main benefits:

- stability of prices;
- encouraging investment (and perhaps entry by new players);
- undermining exploitation of market power.

Whatever the impacts of long-term contracting – even if they are strongly beneficial – they do not directly solve the fundamental underlying driver of market volatility, which is the mismatches between market demand and supply. They simply serve to mitigate the effects of this problem and prevent large fluctuations in electricity bills – they still fail to bring in the demand side of the market with increased demand responsiveness and some degree of real-time pricing which some commentators have argued is crucial and ultimately a more effective approach.

However, even commentators who argue for alternative and perhaps more radical policy measures still admit that long-term contracts have an important role to play.

5 Conclusions

The requirements of this study were to analyse the European electricity market and report on various aspects of it, rather than to make policy recommendations. Our analysis does, however, suggest some directions in which policy might usefully develop.

Clearly, the EU electricity market is very complex, and it is difficult to make generalisations about it. Two things that could clearly be desirable, however, are greater cross-border connectivity and an increase in long-term contracts.

Whilst the concept of emissions trading is clearly a positive one for controlling emissions, it is too early to see how it will effect the electricity markets and consumer and wholesale prices. The market should be monitored for such effects over the coming years.

Likewise, it has been difficult to generalise from pricing trends in the market since recent years have seen deregulation, market liberalisation, fluctuations in global fuel costs as well as a gradual decrease in overcapacity in the market. Since we are now at a point where the market seems stable (with respect to supply balancing demand and general liberalisation), it will be important to monitor prices over the next five years.

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