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European Energy Markets Observatory

2004 and Winter 2004/05 data set
Seventh edition, October 2005

in collaboration with

SG
CROSS ASSET RESEARCH

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Introduction

It is my pleasure to introduce the 7th edition of the European Energy Markets Observatory. The aim of this Observatory, launched in 2001, is to give an update on the electricity and gas markets indicators as well as to monitor the progress of deregulation in the European countries. It is by using public data sources, combined with our methodology and knowledge, that we are able to explain and anticipate the major market events and trends in the industry.

This year we have dropped "Deregulation" in the title in order to reflect the deep evolution of the electricity and gas sectors, where deregulation issues are no longer the only factors that are transforming our industry.

During the period covered by this study (2004 and the winter 2004/05) we have observed that high energy prices, an overall decrease in generation margins, slow progress in interconnections and more generally insufficient infrastructure investments are leading to situations where the security of supply can be endangered.

It is to mitigate this short-term operator's attitude that the new European Directive on Security of Supply as well as National Energy policies have been adopted.

As an illustration of the above points, we have analysed the consequences of severe weather conditions (e.g. the February–March 2005 cold spell or the lack of hydropower in Spain) and we have established that during these periods the supply and demand balance has been endangered and that wholesale prices reached exceptional non-sustainable heights.

Also, for reasons linked to operators' as well as regulators' behaviours, we observed that the retail prices generally do not reflect the effects of increased competition nor the wholesale market evolution.

For this 7th edition, we have partnered with Société Générale Equity Research in order to add an analysis of the 11 main players in the European electricity and gas sectors, providing interesting insights on the financial performance of these companies. This new section focuses on several interesting themes such as market dynamics, operating profitability, share performance, and M&As.

I hope that you will enjoy reading this latest edition of the European Energy Markets Observatory, and that the information and analysis will be useful for you.

Colette Lewiner

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Executive summary

The European energy power markets continue to face a tight balance between supply and demand

This new edition of Capgemini's European Energy Markets Observatory reinforces the ongoing trend reported over the past 3 years for huge tension between supply and demand in the European energy markets. The average generation margin in March 2005 was 5.8% (+/- 1%) in continental Europe compared to 5.4% in December 2002 and 5.5% in October 2003. This figure is dangerously low considering that industry associations recommend each operation should have a margin of at least 5% in order to overcome exceptional weather or generation problems. This situation of low remaining margins is now recurrent for the past 3 years (5.4% in December 2002 and 5.5% in October 2003).

The analysis of the balance between supply and demand at country level shows differences (mainly for historical reasons) but confirms the overall risky situation of the UCTE region (see part I for detailed analysis).

This situation must be assessed against evolution of demand (as explained in detail in part II) in order to appreciate the risk of a shortage of supply in the near term. Despite the somewhat subdued pace of economic development in Europe as a whole, there is evidence of rapid growth in electricity consumption in a number of countries. For example, French electricity consumption growth reached a 2.1% increase in 2004 (following the 4.3% increase in 2003); in Spain and Portugal, the electricity consumption increased respectively by 4.1% and 5.6%; and in the UK it amounted to more than 5.5%. There are also cases of quite volatile patterns in demand both in MWh and peak load—both Norway and Ireland had rapid electricity demand growth in 2004, contrary to sharp decreases in 2003.

It is now clear that such growth in demand combined with extreme climatic conditions such as in March 2005 increase the risk of supply shortages in Europe.

Short-term (2-year horizon) solutions exist:

- Bringing new capacity on stream;
- Improving the availability of existing capacity;
- Providing incentives to customers to reduce their demand in peak periods;
- Improving the short-term mechanism to supply power from one balance zone to another;
- Increasing European electricity interconnection capacity.

New capacities being built throughout Europe are highlighted in part I of the Observatory. Spain is one of the most impressive examples with an addition at the end of 2005 of 11,000 MW of new capacity, mainly gas fired. In Italy, AEEG estimates that in 2004 about 4,000 MW of additional capacity became available from new plants, revamping and other restructuring works. At the same time, 3,000 MW was withdrawn so net new generation capacity was about 1,000 MW. However in 2005, it is expected that about 7,500 MW of new capacity will come online. Restarting mothballed capacity has also been initiated for example in France. Many operators are implementing new asset management programs to further increase plant availability.

Initiatives around demand-side management are very promising and could bring innovation and new offerings, especially with the installation of Automated Meter Readings as explained in part II. Furthermore, White Certificate initiatives (aiming at energy savings) in the UK have successfully demonstrated the potential of such initiatives with, in phase one, total energy savings greater than 80 TWh (for an initial target of 62 TWh) across electricity and gas. In the second phase the intention is to save an equivalent of 10% of the total household energy consumption (130 TWh over 3 years starting 2006). In France, White Certificated initiatives will be implemented at the end of 2005 with an overall 3-year target of off-setting the end consumer's natural growth in energy demand.

1 Remaining capacity without exchanges minus margin against peak load (UCTE definition)

All these considerations demonstrate that there is no longer over capacity in electricity in Europe and that the balance between supply and demand is becoming an evermore critical issue. Actions are required both at national and at European level to provide proper incentives to invest across the electricity value chain in order to prevent wholesale price spikes and/or major back-outs.

In Europe, gas supply is also experiencing tensions mainly due to significant growth in demand and depletion of UK field reserves

The gas sector is also experiencing rapid growth of demand, largely due to the increase of new gas-fired power plants across Europe. This growth has reached 3% throughout Europe, and was especially strong in Spain (+16%) driven by the electricity generation growth.

This sustained gas demand growth is changing the European gas supply patterns:

- Increased dependence of European gas supply from Russia;
- Increased contribution of LNG supply.

While UK North Sea fields are depleting, Norway's production has grown strongly in 2004, increasing output by 20% to 75 bcm[2]. Dutch production has risen by 13% to reach 73.5 Standard[3] bcm in 2004, mainly from North Sea off-shore fields.

Europe's dependence on external gas imports is growing, with notably the stronger integration of Eastern European countries, relying 71% on Russian gas. This situation has resulted in an 8% rise in Russian exports to 124 bcm (and a rise of 14% in exports to EU 15). As we note in part I, as a result, Russia now holds a very strong supply position.

With the exception of direct access to Algerian gas through Spanish and Italian pipelines, LNG imports represent the major source of supply diversification. As such, they have received specific attention from regulators and policy makers. In 2004, LNG was the main access to other non European fields, providing 13 bcm of gas from Nigeria, Oman and Qatar. In 2005, Egypt also began to deliver LNG.

Short-term market mechanisms were tested successfully during the cold spell

The spell of cold weather in March 2005 saw temperatures of between 5°C and 11°C below seasonal averages, providing a sharp test for the ability of short-term markets to cope with the increased demand that resulted.

High spot power prices (€79/MWh on average on peak periods and more than 50 hours above €100/MWh in France) and price spikes (with peaks around €305/MWh at Powernext, €140/MWh at EEX, €200/MWh at APX) provided a clear indication of the exceptional pressure on the electricity system.

Similarly, despite the global availability of adequate gas supplies, the cold spell in March, combined with the outage of some storage capacity in the UK, put a strong strain on the European gas system. Industrial customers under gas or electricity interruptible contracts were called to curtail their demand.

Overall, no blackout systems occurred, which demonstrated a good management of this crisis: electricity imports were efficient, TSOs coordination worked well and the contractual settings with industrial customers helped to reduce the peak loads.

However, long-term issues need to receive more focus

In part I we also analyse the long-term (i.e. after 2012) European offer/demand balance. At that horizon investments are needed not only to accommodate demand growth but also to renew the existing generation capacity (potential 600 to 700 GW of capacity to be installed by 2030).

In 2004 and the first half of 2005, several initiatives were taken to start planning for these long-term investments:

- The EC European Directive of Security of Supply was adopted in 2004 recognizing that:
  - Short-term market mechanisms are not sufficient to trigger private investment;
  - Demand-side management is important to improve security of supply;
  - Flexibilities to implement new power plants are given to market players such as for TSO for example which will be authorized to build new capacities on their control zone for balance purposes;
  - The new French Energy Law in early 2005 has confirmed the nuclear choice for France;
  - Following this decision, Electricité de France (after Finland) got the construction permits for a new-design nuclear power plant called EPR (European Pressurized Reactor). This reactor is expected to start production by 2012 and is receiving great attention both from European power companies (i.e. Enel) and from large industrial end users who are looking for security and stability of supply.

The debate on extending the current nuclear power plants' lifetime was also re-opened in Germany, and to a more limited extent in the UK.

The upward trend of electricity and gas prices should continue in the future

European energy markets faced significant rise of primary energy prices

All primary energy faced strong price increases due to Chinese and American steady demand as well as some geo-political reasons:

- Oil prices rose from $30 per barrel in September 2003 to $53 per barrel in September 2004 and is around $70 per barrel mid 2005;

2 Billon Cubic Meter (bcm) 3 'Standard' relates to the reference conditions: 15° C and 101.325 kPa.

- Following oil prices, usually with a 3-month delay, gas wholesale prices, increased in the same proportion;
- Coal prices faced cyclical evolution from €70/mtons at the beginning of 2004 to a peak of €80/mtons[4] in July 2004 back now to around €66/mtons.

Environmental constraints have contributed significantly to wholesale power and gas price increases

To comply with the Kyoto protocol, which aims to limit greenhouse gas emissions, each European country has implemented a National Allocation Plan for emission rights. This has led to allocate maximum CO_2 emission rights for each industry sector and energy and gas actors (see part I). However the transportation sector, which is a big CO_2 emitter, has no emission limitations.

These CO_2 emission rights have started to be traded on specific spot markets (usually the same as electricity and gas exchanges) and the sharp rise of CO_2 prices was a surprise for all participants. They increased from €5/ton of carbon to €7/ton in 2004 and have reached €20/ton in June 2005.

It is becoming clear now that these emission right quotas will impact the profitability of market players and will contribute to increased retail prices. As an illustration, several utilities became very sensitive to a change of primary energy mix for electricity generation due mainly to poor/good hydraulic conditions. For example, in Spain, Endesa reported a €94m negative impact on its 2004 profitability due to lack of water in its dams. In contrast, Enel reported a positive impact on CO_2 exposure due to favourable hydraulic conditions.

Interestingly enough, Iberdrola, the number 2 Spanish utility and the number 1 wind power company in Europe, appears to be leading one of the most aggressive low carbon energy policies.

In most markets, spot electricity winter prices steadily increased and the overall 2004 annual average spot prices converged around €30/MWh

The combination of thin remaining margins, the rise in primary energy prices, the impact of the limits on CO_2 emissions, the hydraulic conditions and the March 2005 cold spell, all contributed to increased spot electricity prices on most markets (see part IV):

- The "continental price"[5] mostly represented by the closely linked Powernext and EEX spot prices declined on average in 2004 vs. 2003 (-15% from €33.79/MWh during 2003 to €28.52/MWh for 2004) but rose during winter periods (+2% from €33.09/MWh during the winter 2003/04 to €33.84/MWh during the winter 2004/2005);
- Italian prices were significantly above the continental European price with an average of €50/MWh;
- The spot prices at Nordpool were kept low thanks to good water availability, whereas the dry weather in Spain and Portugal pushed wholesale prices upward;
- Spanish pool prices were very volatile in 2004 and 2005. Having declined in 2004 to reach their lowest 5-year level, prices have soared by 70% since the beginning of 2005, with prices up to €73.1/MWh;
- On the other hand, NordPool's average price was €28.92/MWh in 2004, against €36.69/MWh in 2003, and the APX average price in base was €31.57/MWh, against €46.47/MWh in 2003.

While there have been increases in spot winter prices, overall it is interesting to note that the price variances on all exchanges decreased in 2004.

Impacts of wholesale price variations on end users' prices were negligible

The degree and speed of linkage between wholesale and retail price movements varies considerably between countries. This reflects a complex mix of different contract types and end clients' purchasing strategies, competition amongst players, development of capped or stepped price offers and also the continued influence of regulation or semi-fixed tariffs in some countries.

In some countries, the residential markets' retail price increases are clear. This was especially true in the UK, where prices rose by 25% and have now reversed the decreases since 2001. As a result, the UK has moved from the third cheapest to the third most expensive amongst the ten countries where residential customers are already eligible.

However, in order to keep their operating margins at a decent level over time, retailers will eventually have to reflect the wholesale price increases in their end customer prices. It is competition or the fear of competition that has sometimes prevented them for doing so until now.

The observed prices show that the correlation between eligibility and price levels is—at least for now—rather weak.

One of the key challenges also for those markets yet to be deregulated will be the pace at which the current tariffs, which are regulated by the national governments and not by the market, will disappear.

Europe has seen numerous initiatives to improve market mechanisms

Initiatives to complete market mechanisms are numerous and provide further evidence that deregulation of European markets is still progressing.

Several of these initiatives are worth mentioning:

- **Wholesale power markets:** Overall, fourteen power wholesale markets are operating in Europe capturing an increased share of physical trades.

4 Metric Tonne (mton) 5 Average price on "continental Europe" all European countries except Nordic and electric peninsulas (Iberia, Italy and UK)

Nordpool and EEX confirmed the sustainability of their models while IPEX, the new Italian market, has shown astonishingly good liquidity for its first year of operation, reaching 46% of physical volume. Worth mentioning is the rapid implementation of power markets in eastern Europe; in Poland (PoIPX), in Slovakia (Borzen) and in Czeck Republic (OTE);

- **Gas trading hubs** are slower to emerge. Projects are numerous and will bring liquidity in the wholesale gas market in the medium term;
- **Initiatives around emission rights** are numerous. Amongst others, Powernext launched Powernext Carbon in June 2005, followed by EXAA initiative in Austria;
- **Market coupling initiatives** represent the most dynamic and flexible way of reaching another power market through interconnection—for example the market coupling project between France, Belgium and Netherlands.

All of these country-by-country initiatives are contributing to dynamic wholesale markets that are instrumental to enable short-term physical trade and physical balancing of loads. This also demonstrates that the European power market is today only a collection of national markets.

Despite national regulators' efforts, retail competition intensity varies significantly from country to country

Nordic and UK—the first to deregulate—are the most liquid (see part II). The churn level is significantly higher (around 50%) than the ones in continental Europe (around 20%).

Two short-term levers to spur competition and liquidity of markets are closely monitored in our Observatory:

1. **Availability of sourcing:** Despite players' consolidation, access to local gas and electricity sourcing for new entrants is improving. Virtual Power Plants or gas release auctions (as detailed in part I) are contributing positively to this improvement. Nevertheless this is not enough to create proper conditions for real liquid markets;
2. **Cross-border exchanges:** Progress in cross-border power trade is noticeable with the emergence of market coupling initiatives that will allow more dynamic allocation of cross border trades—for example as is already used in Scandinavia. Regarding the gas sector, as detailed in part III, significant problems with existing TPA arrangements prevail and these are still slowing the development of competition.

Overall, we believe that the competition intensity increase requires more focus and actions not only at individual country level but also at a European level—the lack of a European regulator is a factor here.

Electricity and gas market players have adapted their strategies to improve performance and best compete at a European level

Capgemini and Société Générale have decided to study together the gas and electricity sectors' structure evolution, as well as the main market players' financial performance. In part V, we analyse the market player's portfolios, their profitability and stock price performance, as well as the recent merger and acquisition activity.

The major players have significantly improved their operational results and their overall financial situation.

Major players are benefiting today from strategic decisions:

- To focus on core business activities (see below);
- To launch cost-reduction programmes (for example, programme of €2.6bn cost reduction launched in 2000 for RWE and €2bn for E.ON, €0.6bn for Suez, €7.5bn for EDF, etc.);
- To continue reducing their capital investments. The investment/turnover ratio has dropped steadily during the past 10 years, from a peak of around 10.3% in 1998 to less than 5.5% in 2004. However this is threatening security of supply and investments in infrastructure need to increase again.

Their profitability has also improved as a result of growth in demand and increase in wholesale and, sometimes, in retail prices.

Most performing players' as far as operational margin is concerned are today Enel (29% margin on EBITDA) Vattenfall (28%), Endesa (27%) and EDF (26%).

On stock market capitalization, the most performing Price Earning Ratio players are

Electrabel (Price Earning Ratio of 26.8x), Scottish & Southern Energy (18.7x) and Gaz de France (17.1x). The overall sector is around 13.6x.

They are also increasing their competitive advantage by improving the balance of their core business activities

Recent evolutions in the major market players' portfolios are showing common trends:

1. **Focus on energy markets:** It is worth mentioning the recent divestiture of telecom activities by Enel (Wind—€12.4bn) and by Endesa (Auna—€2.1bn) or the divestiture of all E.ON activities in real estate (Viterra—€7bn);
2. **Dual fuel offering** illustrated by E.ON's Ruhrgas acquisition and more recently by Gaz de France and Centrica's common investment in SPE (electricity actor in Belgium);
3. **Control of strategic activities** (Suez acquiring 100% of Electrabel for €11.2bn);
4. **Balanced portfolio** of non-regulated assets (generation, trading, supply) and regulated activities, which bring stable revenues and contribute 41% of operational results for the eleven European main players;
5. **Focus on European markets:** Recent divestitures of Pacificorp (US) by Scottish Power and the departure of all European players (except the Spanish players) of Latin American (Edenor in Argentina sold by EDF, Agua de Buenas Aires sold by Suez, etc.) are good examples of this strategy;
6. **The concentration moves** recently illustrated by the E.ON bid for Scottish Power and the Gas Natural hostile bid for Endesa, which challenge the Regulators who wish to maintain a good level of competition.

Conditions seem ripe for a new phase of consolidation

We are anticipating evolutions in the near future.

The overall state participation in the main utilities players is decreasing and the right conditions are evolving for private contribution to the development of the sector. During the past 12 months, Public Offerings have amounted to €9bn, mostly Gaz de France (€4.5bn), Enel (€4bn) and Elia (€0.5bn).

To date, only EDF and Vattenfal remain state owned.

Market players have reduced their debt level from an overall 99% gearing ratio[6] in 2002 to 69% today and have consolidated their cash position to maximise expansion or consolidation opportunities.

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6 Gearing ratio: Debt/total asset

I Dynamic of Offer

Looking at the current offer and demand balance

From the point of view of dynamic of offer, the events witnessed over the 2004/2005 study period emphasise the following two key points:

- Confirmation of the tightness of the European offer/demand balance (cf. February 2005 cold spell) confirming the end of the overcapacity period;
- The emerging sector's awareness of the need to cope with the situation and the first decisions to start dealing with it (cf. 2004 EC Directive on Security of Supply, 2005 French Energy Law and nuclear choice confirmation, European energy efficiency initiatives).

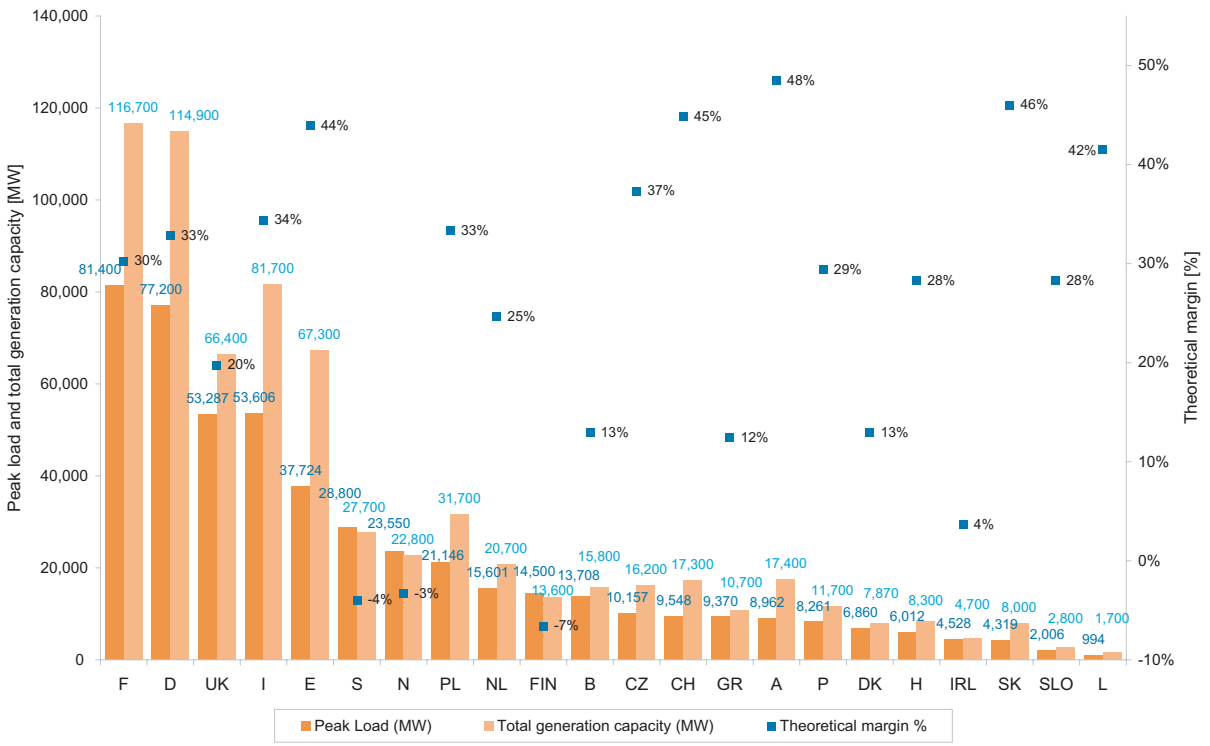
We have therefore chosen in this edition to focus this first section on the potential ability of offer to meet the expected demand on the short-, medium- and long-term horizons; this offer/demand equilibrium being a good indicator of:

- The competitive intensity in generation and the impact on market prices;
- Short-term system reliability and the prospect of outages and price spikes;
- Longer term system balance and security of supply issues.

Installed capacities

As we did in the previous editions, the report first takes a look at installed capacities. Table 1.1 shows the total generation installed capacity in each country of Europe (bars in light orange) versus the highest consumption recorded in the same period (bars in darker orange). From these figures can be derived the theoretical capacity margin (margin between peak load and total generation capacity) which, in 2004, remains in the ballpark of 20 to 40%.

Table 1.1 Peak load, generation capacity and theoretical margin (2004)



Source: UCTE, Nordel, NGC, ESB, EirGrid

As compared to 2003, we can note that theoretical margins stayed almost unchanged, mainly because peak load and generation capacities increased on average in the same proportion (around 2% for Europe). However, some countries experienced drastic changes like Spain, where generation capacity rose by a significant 12.5%, and the Netherlands, where the peak load increased by 8%.

Remaining capacity at peak load vs. theoretical margin (2004)

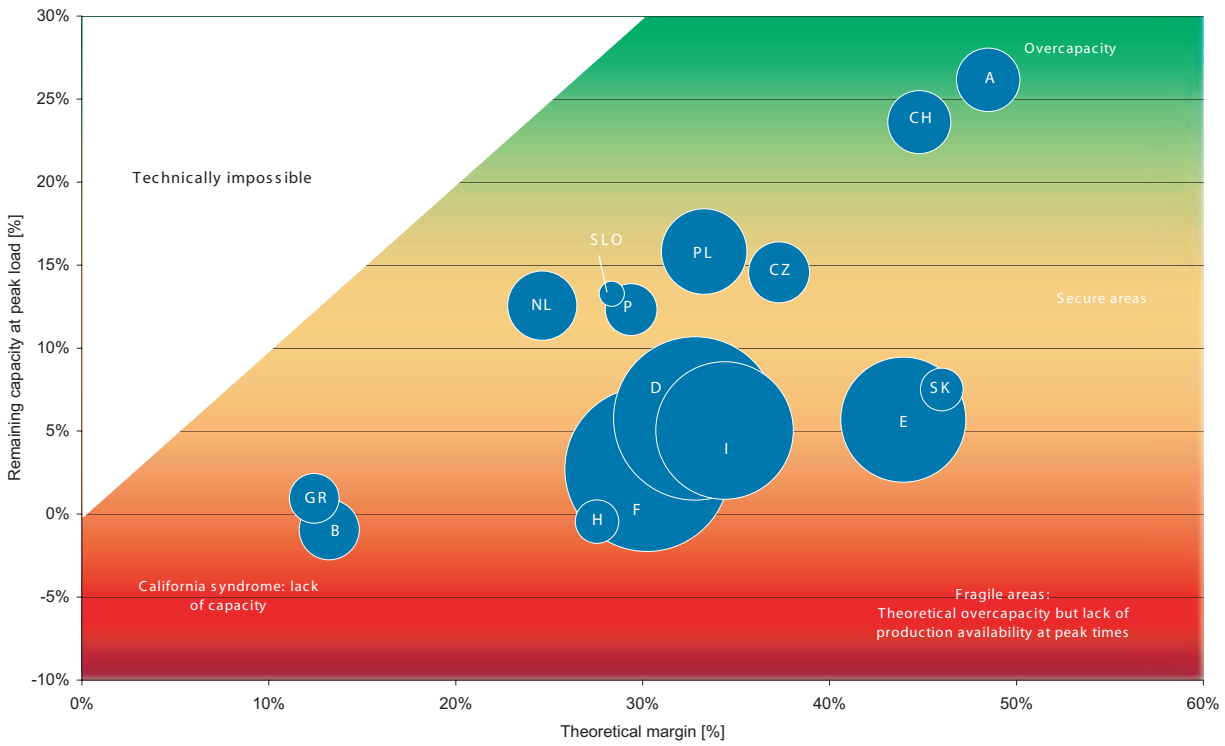
Nonetheless, when talking about capacity margins, we must be very careful to distinguish "theoretical margin" from "real margin". Interestingly, as shown on Table 1.2, the picture does significantly change when we start looking at the actual margin over reliably available capacity (defined as the theoretical capacity netted from the impact of non-usable capacity, overhauls, outages and system reserves): 2004 annual average margin figures then typically fall at or below the 5% level for large European systems such as Germany, France, Italy, and Spain.

It is usually admitted in the provisional approaches that the remaining capacity without cross-border exchange, after covering a margin against the peak load, must be at least 5% (or even 10% for some countries) of the global generating capacity. The graph therefore clearly illustrates the situation, with significant countries having globally moved away from the secure 10%+ areas.

In addition, when looking at country-by-country monthly numbers, we find lower and even negative margin figures for a number of geographies, including interestingly France with a UCTE estimated minimum monthly margin at—5.9%. Luckily the periods of "margin stress" do not always occur at the same time on every system, allowing for a certain European balancing. Nevertheless it is worth noting that, as shown on the graph, the tightening of the actual capacity margin is a phenomenon impacting all major European systems, meaning that individual countries will not be able for long to rely on their neighbours in tight periods as every one will face the same supply issues.

Today's situation is explained by a sustained demand growth over the past years (as an example, French demand grew on average by 2% p.a., reaching 2.1% in 2004) while (peak) production capacities in some countries remained mainly stagnant, or even declined (e.g. thermal power plants mothballing in

Table 1.2 Remaining capacity at peak load vs. theoretical margin (2004)



Source: UCTE, Nordel, NGC, ESB, EirGrid

France) partly on the basis of rather mild winters over the past 15 years. The analysis of previous years' UCTE statistics confirms this stagnation, no significant plan, at a European scale, to increase generating capacities having yet come to motion.

Today, the European average real margin of 5.8% therefore confirms (i) the end of the European over-capacity situation, (ii) a rising tension on the current systems and (iii) the need to rapidly cope with the lack of available capacity, especially at peak times.

Solutions to the capacity shortage threat

Potential solutions to the capacity shortage threat must be differentiated by time horizon:

- In the short term (from now to 2 years ahead): Building new infrastructures is not feasible; intermediary mitigation solutions must be found;
- In the medium term (from 2 to 8/10 years ahead): Investments into (peak) generating assets can start coming on line and relieve the stress;
- In the long term: More strategic choices can come into play, on the offer side as well on the demand side.

Coping with short-term bottom-line requirements

Short term (i.e. from now to 2008) is a period of time when measures to construct new power plants are mostly inefficient. Answers to the capacity shortage must be derived from:

- Improving existing asset performance, availability and flexibility:
  - By revising their traditional yearly maintenance programs (cf. lessons learned regarding large planned outage periods after the 2005 late February cold spell), taking into account progressive shifts in demand (increasing the weight of the air-conditioning during summertime), as well as optimising maintenance (trade-off between material life extension and reliability, between immediate and long-term performance);
  - By anticipating possible fuel switches in order to cope with gas supply restrictions coinciding with electricity peak demand periods (usually the case during cold spells) as Italy and Spain did earlier this year;
  - By boosting, when feasible, the output of their existing assets (e.g. generator re-powering);
  - By de-mothballing plants (e.g. EDF's current plans for four fuel power plants to be implemented before the 2006 winter), these options being looked at again as they offer a quicker answer than building new plants and as the gas price increases impact the economics of new combined cycles;
- Developing flexibility within the counterparty portfolios:
  - Within long-term contracts with other operators as we saw that climatic events do not always impact every country with the same magnitude (see Frame referring to 2005 cold spell example);
  - With their industrial and residential customers through curtailment options

Focus on the impact of hydro power availability on the supply/demand balance

Reservoir levels, at certain periods of the year, can significantly impact the supply/demand balance of a country and lead to significant wholesale price variation. It is one of the sources of differentiation between theoretical and real reserve margin illustrated on Table 1.2.

Several European countries such as the Nordic ones, Switzerland, Austria, France, the Iberian and Italian peninsulas rely quite significantly on hydro power (from 11.4% for France to 98.9% for Norway with a European average of 15%). During the past 10 years, hydro generation, while remaining predominant, has lost ground in favour of other renewable sources: wind power, biomass and waste.

In 2004, several situations were encountered:

- In Norway, the 2004 situation was quite favourable: reservoir levels were low at the start of 2004 and increased during the year. In the Nordic area, the hydro levels reached 102.5% at year end. However, heavy rainfall and high temperatures towards the end of the year made the prices fall slightly;
- In Denmark, Elsam, whose financial results are closely linked to the hydro-heavy Nordic area and the thermal-dominated continent, saw its profits drop but its turnover largely increase in 2004. This was due to lower prices on the Nordic market, with which Denmark has good transmission connectivity and dramatic increases in coal and freight prices compared to 2003;
- In France, even though several regions have experienced some months of drought, the assessment for the full year 2004 is quite normal;
- In Spain, 2004 was a dry hydro year, affecting Iberdrola, which produced 20,000 GWh, compared to 30,000 GWh in average years;
- Portugal faced its worst drought on record. Hydro electricity production fell 63% in the first 2 months of 2005, compared with the same period last year. The hydro index fell to 0.22 in February 2005 against 0.78 a year earlier (an index of 1 represents an average year). This resulted in a significant price increase between 4.99% and 9.82%, in the second-quarter of 2005 for large end-users decided by ERSE, the energy regulator;
- In Switzerland, extremely dry weather has impacted the results of the two hydropower companies. Ofible of Blenio, based in Locarno, was the worst hit with production at 20% less than in 2003, and the price per kWh increased by over 40%.

(as EDF and REE did during the 2005 cold spell);

- Using deregulated market mechanisms through power exchanges and wholesale bilateral trades, within and across geographical markets.

Answers revolving around asset performance improvement, counterparty portfolio flexibility and market mechanisms are nevertheless insufficient in the long run, namely because:

- Expected performance and flexibility improvements can only be limited;
- Cross-border balancing will no longer be useful as all European countries start facing the same challenges in terms of capacity tightness and the need to respond to climatic events.

Addressing medium-term needs

In the medium term, which ranges from 2–3 years to approximately 8–10 years (i.e. 2008[1]–2012), potential solutions to the expected capacity shortage mainly come from additional capacity development, starting with peak load assets. In France for example, the RTE 2005 report shows a requirement for an additional 1,000 MW per annum by 2008–2010 for peak-shaving purposes.

As for the short-term horizon, drivers for these medium-term capacity additions need to protect themselves from price volatility especially over peak periods. Recent capacity addition announcements include the following examples:

- In France, EDF announced in its 320 million euro plan aiming at bringing 3,100 MW additional capacity (mainly peak) by end of 2008, the construction of a 500 MW turbine power plant outside Paris;
- In Spain, projects have already started. Over 5 years, Spanish companies invested 59% of a total 17.8 billion euro budget in CCGT. At the end of 2005, Spain will have more than 11,000 MW powered by gas and this trend will continue as more gas-fired projects are expected;
- In Italy, AEEG estimates that in 2004 about 4,000 MW of additional capacity became available from new plants, revamping and other restructuring works. At the same time, 3,000 MW was withdrawn so net new generation capacity was about 1,000 MW. However in 2005, it is expected that about 7,500 MW of new capacity will come online.

For some players who are aiming to gain a regional presence and penetrate neighbouring countries, sourcing and hedging their projected customer portfolio through access to a generation asset is particularly key. The current tension on the offer/demand equilibrium and on wholesale prices gives them a good opportunity to consider building a plant of their own. Examples over the study period include:

- In France, Endesa's business plan for its French subsidiary SNET with investment into 2,000 MW of combined cycle gas turbine capacity in France;
- In Germany, Statkraft and energy company Mark-E's plan to build a 400 MW gas-fired plant;
- In Portugal, Gas Natural's project to build a 400 MW power plant in the harbour of Sines;
- Globally throughout Europe, Electrabel's announcement that it would invest 4 to 5 billion euros by 2009 to develop its production capacities.

It is to be noted though that new entrants' access to generating capacities continues to be also ensured through Virtual Power Plants (VPP—see related Frame for detailed figures and examples in 2004), an efficient way to spur competition but which does not lead to capacity additions. A more private form of access to virtual plants also exists in the shape of bilateral capacity swaps, as shown by Enel and Gaz de France in their recent negotiations with EDF in France.

Finally, large industrial "electricity-intensive" consumers are another category of players interested in securing not only peak price volatility but also base load price levels and production costs all together, some of them showing an interest in participating in generation asset investments.

Generation investment decisions are nevertheless relatively capital-intensive and require a certain degree of confidence in the revenues of the future plant output, which basically depend on two key factors (apart from the plant technical availability issue): the magnitude of the volume off take and the price level. Although wholesale price trends observed over the 2004/2005 period are encouraging private investors, banks, which start receiving—again—financing requests, are still reluctant to put money into merchant IPPs that would not rely on some sort of PPA. Without a regulatory framework that provides a certain level of confidence on the expected returns, private investment can therefore be slow to emerge, accentuating the trend of increasing tension on the offer/demand balance and wholesale prices.

It is also worth noting that the 2004 European Directive on Security of Supply (The "SoS Directive") introduces for the first time in European regulatory activity, the idea that the classical market laws might not function properly concerning electricity, especially when it comes to giving price signals for investment in peak generation capacities. As a response, the Directive proposes to simply let the member states decide what specific measures they should implement to secure their demand/offer balance in high demand periods, proposing some methods as:

- Use of tendering in order to acquire new capacity (Greece and Ireland have already made use of this option);
- Create capacity payments (in France, RTE pays EDF several million euros in order to have 1,500 MW available at any time);

1 Note that 2008 is also the milestone for a new CO_2 emissions allocation mechanism (see dedicated section on CO_2 for more details) with related uncertainty as to the impact of CO_2 emission costs on generation technology choices

Focus on the early 2005 cold spell

Europe witnessed atypical winter conditions in early 2005. From mid February to mid March, Western Europe and in particular France and then Spain went through a climatic event that statistically occurs once in 50 years, characterised by an abnormally cold (with temperatures of 5°C on average, up to 11°C below seasonal average) and dry period. In a deregulated market context, high spot prices (€79/MWh on peak average and more than 50 hours above €100/MWh in France) and price spikes (with peaks around €305/MWh at Powernext, €140/MWh at EEX, €200/MWh at APX) were also a clear symptom of a non-standard pressure on the system.

In France, the highest ever recorded demand for electricity (86,000 MW) happened on 28 February 2005. Usually a 1°C drop below normal temperature triggers an increased demand of 1,600 MW; on that day the peak demand put an additional stress of 15,000 MW on the system. It put France in a net importer position with up to 3,200 MW or about 3% of total consumption coming from cross-border interconnections. Apart from imports, answers to the above-normal demand were found through hydro reserves usage, increased solicitation of running plants (maintenance outage postponement), market purchases, and utilisation of interruptible rights in wholesale counterparties as well as customers contracts, both tariff (use of 9+3 peak-day curtailment credits in February and March, out of a total 22-day annual stock, each day representing around 3,000 MW) and industrial (where contractual curtailments exceeded 1,000 MW some days in France and impacted over 180 customers in Spain).

The peculiar fact in this cold spell was its timing, late in the winter, at a time when average forecasts encourage operators to position large maintenance outages, right after the statistically coldest months when plants are heavily utilised. In France, planned maintenance made an equivalent of 10,000 MW unavailable at the time of the cold spell, only partly compensated by the very good availability of other running nuclear plants. The dry winter intensified the strain with water levels lower than normal in hydro-rich countries such as France (where January to March hydraulic production was down 24% compared to 2004) and Spain (where the hydraulic production reached the 6th lowest value ever recorded in this period). Apart from outages in Corsica, the system load and system reserves were nevertheless met by Electricité de France.

Four additional facts are worth noting on the way the cold spell impacted European national systems:

- Luckily the cold spell peak did not hit every country simultaneously: it struck France and Spain with a one-day time lag allowing Spain to support the French load on 28 February and then France to do the opposite the day after, supplying 1,400 MW on 29 February;
- Some countries coped more easily with the cold wave: Germany, more accustomed to severe winters and with a less thermo-sensitive residential demand than in France (where residential electric heating is used by 30% of French households and represents up to 13% of the national consumption) weathered the cold period with less trouble. In the UK, the necessary investments (de-mothballing) had been made to face a cold winter;
- The cold spell also saw the inversion of the France-Germany spread, probably revealing the impact of the tightness of the French offer/demand balance and the risk associated with its thermo-sensitivity, on market prices, with a mark-up on the French 2006 calendar reaching €2/MWh at the end of June 2005;
- Beyond (and sometimes through) power production, pressure was also put on gas:
  - Globally, despite the overall availability of supply, this climatic event, combined with the outage of Rough storage capacity in the UK, put a strain on the European gas system, underlining the sensitivity of the system to late cold spells (when storage stocks are at their lowest) when combined with an important facility shutdown;
  - In France, Gaz de France had to cut about 200 interruptible clients for the first time in the existence of these contracts;
  - In the UK, wholesale prices skyrocketed to 165 p/th (around €80/MWh). Although new infrastructure due to come on line in the next 2 to 3 years should provide more breathing space, in the meantime, the situation is worrying operators, as shown by high forward winter prices, despite Ofgem's reassuring communication;
  - In Spain, shortage of gas led some CCGT plants to switch from gas to fuel and rolling curtailments were put in place;
  - In Italy, where the vast majority of heating relies on gas and oil, industrial gas customers were partially curtailed, dual-fuel power stations were put on alert to prepare to switch fuel, and fossil fuel strategic reserves were solicited and very closely monitored.

Focus on Virtual Power Plants (VPP)
As noted in the previous Observatory, regulators and competition authorities are continuously requiring capacity to be released as a way of preserving/encouraging competition. Several examples are worth noting during the studied period:

- In the Netherlands, Nuon was originally set to auction 900 MW but the NMA, the Dutch competition authority, reduced it to 200 MW after Nuon sold its 800 MW offtake agreement for power from Intergen's Rijnmond plant to Eneco Energie. The authority forced Nuon to hold the auction as a condition of its purchase of Reliant's European power plants in March 2003;

- In France, EDF organised its 12th capacity auctions in June 2004. First, 335 MW VPP baseload (on 370 MW available) were sold, starting in July 2004 for amounts ranging from 14,600 to €17,317/MW/month. Second, 180 MW VPP peakload (on 232 MW available) were sold, starting also in July 2004 for amounts ranging from 5,604 to €8,071/MW/month. The third auction was on 1,000 MW of baseload, from October to November 2004, 617 MW were sold at prices ranging from 17,325 to €19,947/MW/month. And finally, a fourth auction, for the same period, was for 250 MW of peakload, with 10 MW sold at prices ranging from 8,218 to €9,882/MW/month.

EDF's 14th auction took place in November 2004. A total of 890 MW, in which 692 MW of baseload and 198 MW in peakload were sold.

In May 2005, EDF offered 729 MW, or 417 MW of baseload and 312 MW of peakload, starting on 1 July 2005 for durations of 3 to 36 months. EDF also offered a maximum of 760 MW—700 MW baseload and 60 MW peakload—starting on 1 October 2005 for durations of 3 to 36 months, or on 1 November 2005 for durations of 12, 24 and 36 months. This auction, the 16th, is part of EDF's 2001 deal with the European Commission to release 6,000 MW of power for up to 5 years, to allow competitors access to its generation after it took a controlling stake in Germany's EnBW.

In its last quarterly auction on 2 March 2005, 10 of the 34 bidders were successful in bidding for 772 MW of the 862 MW offered for contracts starting from 1 April 2005;

- In Belgium, Electrabel offered a total of 415 MW to the market, comprising 277 MW of baseload VPP capacity and 138 MW of peakload VPP capacity, starting either on 1 October 2004 or on 1 January 2005. Products range from 3-month to 3-year delivery. Altogether, the company has offered a total of 1,150 MW of VPP capacity since its first auction held on 9 December 2003;

- In Hungary, the state-owned power conglomerate MVM held a VPP auction for the first half of 2005 and, as planned, sold 60 MW in baseload and 180 MW in peakload;

- In Czech Republic, the power company CEZ has held its first round of VPP auctions in August 2005, offering 400 MW of capacity with a delivery date across 2006. The total offer of electricity will be split into eight blocks of 50 MW with reduced deliveries of power in the summer months of June, July and August.

- Allow the TSO to buy generation power plants;
- Create capacity subscriptions that could be sold by the TSO;
- Use interruptible contracts.

The intervention of the regulatory or public arm to encourage investment in new capacities can also be the opportunity to put in place the appropriate signals to influence the choice of generation technology, thus ensuring national and European objectives in terms of energy security of supply, energy efficiency and environment protection are met. As a tool to support national and European decisions, it is worth noting that the SoS Directive will put in place a European-wide consolidated offer and demand forecast based on national plans produced by each country over a 7 to 10 year horizon.

And as a direct illustration of a current medium-term energy trend, it should be noted that currently capacity additions mostly rely on gas turbine technology, coal remaining a second choice with very few clean-coal technology projects. This market move raises the issue of Europe's dependence on gas, both in terms of volume and price, in the context of the depletion of North Sea reserves:

- In terms of volume, because peaking periods in electricity can coincide with peak demand in gas, as observed during the early 2005 cold spell, hence worsening the energy shortage situation;
- In terms of price, because gas which remains indexed to oil, may not be such an economical choice in the decades to come given the oil market current context and prospects.

Anticipating the long-term equilibrium

In the long term, from 8 to 10 years ahead onwards (i.e. after 2012), the analysis and management of the offer/demand balance looks at the European demand growth forecast and options for the renewal of the global generation fleet, rather than

incremental investments (600,000 to 700,000 MW to be installed by 2030). Beyond this period, price signals, and more generally deregulated market mechanisms, do not provide an overriding incentive as to the choice of an energy option. The thinking on this long-term equilibrium relies above all on political and strategic energy choices. Much more than on shorter time horizons, it becomes the responsibility of national governments and European bodies to make sure the adequate regulation frameworks are in place to allow the necessary investments to be made, on the offer side as well as the demand side.

On the offer side first, strategic choices revolve around energy mix options and the three key underlying questions of:

- National and now European security of supply;
- Competitiveness and economic strength;
- Environment protection and sustainable growth[2].

In this respect, the 2004/2005 study period saw the approval of the SoS European Directive and also the re-opening of the nuclear debate. As mentioned earlier, medium-term answers to the capacity shortage are likely to increase the prominence of gas in the European energy mix, therefore increasing the sensitivity of the overall energy balance to oil prices. In the current energy context which features:

- The end of the oil industry overcapacity situation, leading to increased and seemingly sustainable pressure on oil price;
- Recent significant price increases in coal (commodity + freight) as well, mainly driven by Chinese economic development;
- A clear objective to implement Kyoto directives and curb greenhouse gas emissions;
- A mixed outcome from the recent renewable experience (in Germany for example) with the initial 22% of the generation mix target by 2010 now deemed probably not reachable (see section dedicated to this topic);
- No near-term perspective of a nuclear fusion breakthrough (the ITER project recently initiated is given around 50 years to deliver an industrial solution);

…the issue of a nuclear comeback is of course at the forefront of every discussion on security of supply and long-term energy choices[3].

Together with Finland, France, after years of hesitation, has hence confirmed the nuclear choice in its new 2005 energy law. Electricité de France managed to obtain approval for the new generation of nuclear power plants called EPR (European Pressurized Reactor) expected to start production by 2012. In addition, other countries such as Italy, where nuclear power is officially banned, are nevertheless looking at possible participation in the EPR venture, with France remaining the geographical base to develop and run these nuclear power plants, for political and public opinion reasons (the "Not in My Backyard" syndrome). The debate on extending the life of current nuclear power plants and even putting an end to the current nuclear moratorium was also re-opened in Germany, partly linked to the legislative election campaigns.

In the security of supply debate held at the European level, the development of stabilizing cross-border interconnections and the management of its potential detrimental incentive for some countries like Italy, for example, not to invest in their own generating capacities, hence weakening the global system, is also to be addressed. The SoS European Directive has indeed been watered down on the subject of constraints on national states (see also Part III on Physical Infrastructures). Finally there is still a long way to go to harmonize, at a European level, the countries' individual energy policies (a real challenge if we consider the US example where there has been no nationwide consensus on energy policy since 1965 and recent attempts by the Bush administration were ineffective).

In the long term, the offer/demand balance should also be looked at on the demand side as demand-curbing initiatives launched today can have sizeable impacts in the long run. The objective is not only to reduce demand in terms of volume but also in terms of profile—the peak demand being the first driver for capacity addition requirements. The green book on energy security of supply previously adopted by the European Commission even came to the conclusion that the largest levers were residing on the demand side. The 2004 SoS Directive confirms that at a European level, effort should be focused on managing demand, which is both cheaper and works more quickly than, for example, efforts to continuously increase generation capacity on the basis of extrapolations from the current situation. Strong European-wide commitments for energy savings and demand management programs are therefore on the agenda and progressively being put in place. Notable examples are:

- The white certificates scheme put in place in the UK and coming to fruition in France;
- The June 2005 green book on energy efficiency sponsored by Energy European Commissioner Andris Piebalgs with a target of 20% total energy savings by 2020 (see the section on White Certificates and on the dynamic of demand for more details) and a detailed implementation plan expected for 2006.

Perspectives

As we have seen through this section, the overcapacity period has come to an end and the offer/demand balance is now a key concern to be addressed in the short, medium and long terms. A number of decisions and initiatives have recently been taken to start dealing with the situation, although a number of issues are still to be tackled:

2 Note that 2012 is also the deadline for the Kyoto protocol 3 Note that the uranium price has also experienced a huge price rise and doubled in the recent past, although this energy source remains competitive and medium-term depletion is not perceived today as an issue as it is with fossil fuels

- In the medium-term:
  - Efficient mechanisms to ensure market capacity auto-regulation and in particular to encourage new investments are still to be improved, with the emerging recognition that free market dynamics may not be sufficient on the medium term horizon;
  - The heavy reliance on gas combined cycle projects may be questioned in light of the oil market developments and of the continuing link between oil and gas prices.
- In the long term, the objective of a coherent European energy supply strategy requires a certain level of harmonization (and therefore constraints) of the countries' individual energy policies, which is still a long way off.

Renewables: Dynamic but still short of the European Union objectives

The European countries are currently increasing the share of renewables:

- In electricity consumption, from 13.4% to 14.88% (2003);
- In primary energy consumption, from 5.08% to 5.48% (including power, heat and transports).

Though showing positive dynamics, these figures clearly reveal that the objectives set by the European Union for 2010 may be out of reach (21% and 12% respectively for power consumption and for total primary energy consumption).

From the perspective of the top European companies, Iberdrola (2,885 MW), Endesa (1,203 MW) and Enel (888 MW for wind and geothermal) are the most dynamic producers of renewable power in their domestic market (excluding large hydro). Other companies are usually taking smaller stakes in renewables, often in other European countries or outside Europe (EDF, Scottish Power until mid-2005). They usually focus R&D and investments on their main energy (the Germans on lignite, coal, gas, the French on nuclear).

On the electricity side, wind is by far the most active segment

Spain installed slightly more wind capacity than Germany in 2004 (+2,065 MW), while Denmark has from now onwards a stable mature generation capacity. Denmark gives an idea of the maximum potential contribution of wind to the power mix. With 643 "wind" kWh generated per inhabitant, wind covers about half the electricity-specific needs of an average Danish inhabitant. With 300 to 400 kWh, Germany and Spain cover about a third to a fifth part of the households electric specific needs with wind.

The solar photovoltaic has experienced a nearly 70% growth rate. For the first time Germany is ranked 1st worldwide, ahead of Japan. Spain is implementing a proactive policy that should provide results in the near future. It passed a law making solar photovoltaic or solar thermal installations compulsory for all new buildings (initially a regulation imposed by mayors in some Spanish cities such as Barcelona).

On the heat side, wood energy is the renewable heavyweight contributor

About 85% of wood primary energy is used for heating (individuals, collective-tertiary, district heating), the remainder being for electricity generation. Recent boilers and stoves for households are efficient technologies (65% to 80% efficiencies).

France, Sweden, Germany and Austria were the most dynamic markets in 2004, yet France, Germany, Spain and Italy still have considerable forest resources. For instance, France could double its volumes. A mature market such as the Finnish one covers 50% of its heating needs and 20% of its primary energy consumption, with about 14,000 kWh per capita.

In terms of the Solar Thermal capacity, the growth of the leading German market has been lower than the previous year, possibly because of individual trade-offs made by customers from solar thermal to solar photovoltaic, which benefited enhanced subsidies in 2004. Dynamics may be coming in 2005 from France (with a new 40% income tax credit) and Spain (solar decrees in 40 municipalities including Barcelona passed into national law).

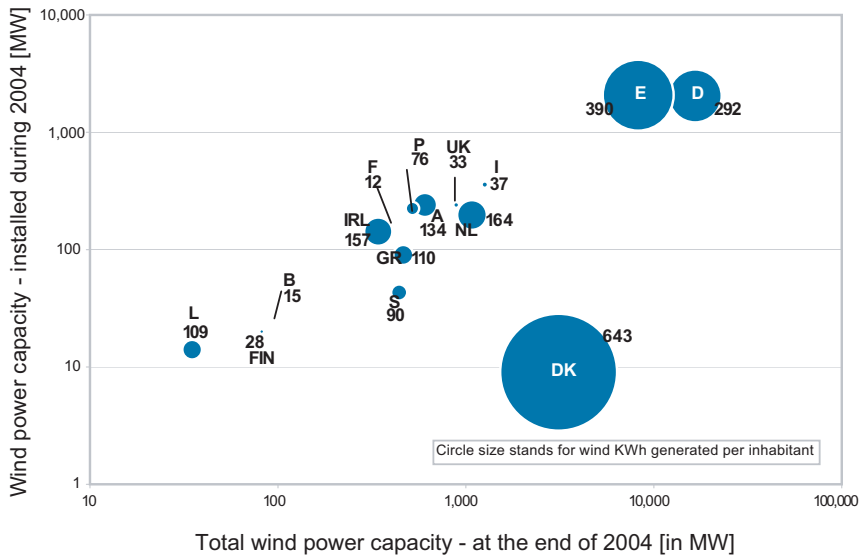
Heating Pumps account for about 4,000 MW thermal capacity, and Geothermic energy for about 800 MWe (electricity) and 1,100 MWth (heat) across Europe.

Table 1.3 Main renewable energies, energy generated and installed capacity (in 2004)

	Wind		Solar PV		Biogas	Wood Energy*	Solar Thermal	
Type of energy	Power		Power		Power (and heat)	Heat	Heat	
Additional power in 2004 Total power End 2004	+ 9,4 TWh 54 TWh	+ 5 861 MW 35 229 MW	In the order of 1 TWh	+ 410 MW 1 005 MW	+ 1 TWh 11 TWh (+4 TWh of heat)	+ 29 TWh 500 TWh	6,5 TWh	+ 1 200 MW 10 700 MW
Most dynamic countries in 2004	Spain, Germany		Germany		UK, Germany	France, Sweden, Germany	Germany, Austria, Greece	
European schedule	In advance		On time		In advance	Late	Late	

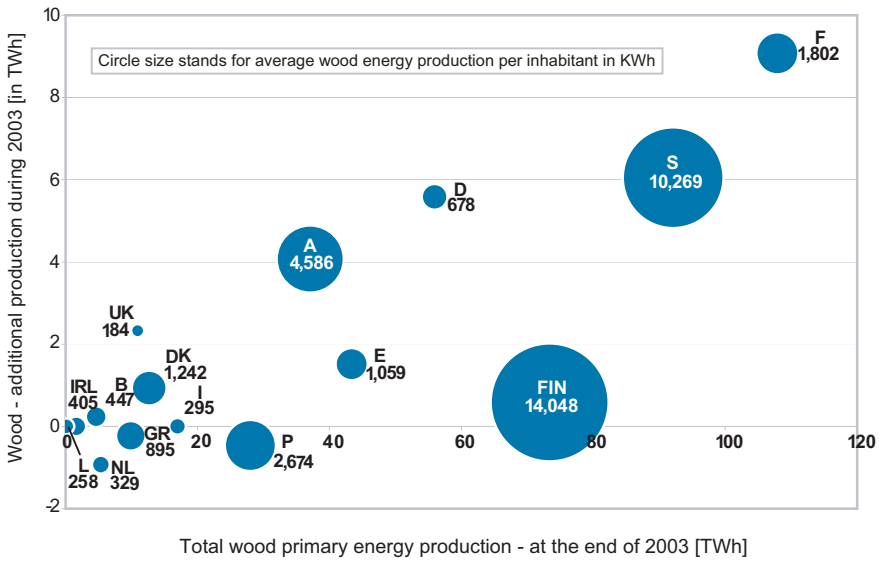
Source: EurObservER, Capgemini analysis *2004 figures, excepted Wood, 2003

Table 1.4 Wind power (2004)



Source: EurObservER

Table 1.5 Wood primary energy production (2003)



Source: EurObservER

Green Certificates, Guarantee of Origin, Feed-In tariffs: still a great diversity of renewables support mechanisms… and some confusion

Renewable certificates always authenticate that the source of a given unit of electricity generation is from renewable energy. Certificates are issued and redeemed. This attribute can be used for tracking volumes in Feed-in tariffs systems (in Germany, but in France or in Spain the feed-in tariffs are based on contracts), or for enabling Ecotax exemptions and Production subsidies (UK, Netherlands).

Sometimes they may also be tradable or exchangeable. The resulting certificates markets can be mandatory or voluntary:

- **Mandatory certificates** markets exist where the government requires companies to source a predetermined percentage of power with renewables (quota systems in UK, Italy, Belgium, Sweden),
- **Voluntary certificates** markets exist where the volume is not created by a regulatory obligation but by the players' voluntary actions, for instance for "Green labelling" commercial offers to final customers (France). No European distributor is able to charge the full cost of power coming from renewables to customers. Services Industriels de Geneve is known to provide the only one counter example in Europe.

In 2004, the situation remained unclear, with several systems coexisting:

- "Green certificates" sometimes refer to any of these voluntary or mandatory systems, sometimes in the most restrictive way of tradable guarantee of origin associated with quota obligations, for example in the UK or Flanders;
- "Guarantee of Origin" (GO) refers to the official local certificate system imposed by the Commission. The Directive 2001/77/EC regarding the promotion of renewables imposed on each member state to be able to prove the origin of renewable power by October 2003, to nominate one or several issuing bodies,

to recognise the certificates in all the countries. International recognition is far from being implemented currently;

- "RECs" refers to Renewable Energy Certificates issued according to the RECS standards (Renewable Energy Certificate System) and the related AIB (Association of Issuing Bodies). It gathers nineteen countries (European countries plus Switzerland and USA), of which nine are also appointed for issuing official GO (Guarantees of Origin).

A few illustrations in Europe:

- In France, Observ'ER is the issuing body for RECs, while the grid operator RTE has been appointed by law for GOs in June 2005. Further in 2008, the government planned to consider the possibility or not to create official green certificates:
  - Producers using the feed-in tariffs cannot claim for RECs;
  - RECS: as of 15 July 2005, 913 MW capacity is registered. 777,925 certificates were issued, 445,703 were retired (0.77 TWh and 0.45 TWh);
  - EDF has sold 0.264 TWh of its green-labelled offer "Equilibre" between 2002 and 2004. It is mainly successful among the professional and small businesses segment. EDF had initially targeted it at medium and large businesses.
- The Netherlands converted its RECS system into a GO system in January 2004.
- In the United Kingdom three systems (GO, RECS and and Levy Exemption Certificate—LECs) are available:
  - GOs cover all renewable technologies and comply with the directive obligation, while Renewable Obligation Certificates (ROCs) and LECS cover only a subset of technologies and are renewable support mechanisms;
  - ROCs concern the Renewable Obligation made to distributors to buy a determined volume of renewable each year;
  - LECs enable companies to claim exemption to the CCL tax (Climate Change Levy).

2004/2005, a turning point for carbon emissions management

The period 2004/2005 may be considered a turning point in energy policies for three reasons:

- The coming into force of the European carbon market on 1 January 2005 and of the Kyoto Protocol on 16 February 2005 are two major milestones of the year. Russia had previously ratified the Kyoto Protocol in November, providing the 55% quorum (enough countries representing 55% of worldwide greenhouse gases emissions) necessary without the US commitment;
- The dramatic increase in climate change awareness among the general public (intense coverage by the mass media, catastrophes such as the Katrina hurricane...);
- The increasing sensitivity of politicians and administrations to potential greater difficulties in securing oil supplies triggered by the significant rise in oil prices and potential oil depletion (peak oil).

The completion of the National Allocation Plans (NAPs)

Without waiting for the official implementation of the Kyoto Protocol, the European Union had prepared its own Emissions Trading Scheme (ETS). In April 2004, a so-called "Linking Directive" linked the EU Trading Scheme with the Kyoto mechanisms. It took more than a full year to develop all the National Allocation Plans, which took place on 1 January 2005:

- In July 2004 the commission urged members to avoid overallocating quotas. The first NAP drafts of Austria, Ireland, Netherlands and Finland were considered too lenient and failing to meet the Kyoto targets. The risk was to debilitate the CO_2 market through a lack of demand;
- The first countries to have their NAPs fully approved were Denmark, Ireland, the Netherlands, Slovenia and Sweden unconditionally, and with minor changes Austria, Germany and the UK;

IBERDROLA, the low carbon business model of the future?

Iberdrola, the Spanish n°2 utility, leads the most aggressive and diversified low carbon energy policy in Europe.

Iberdrola has become in 2004 the world wind leader, overtaking Florida Power in the US (2,885 MW versus 2,700 MW). It is the Spanish hydro leader. Iberdrola announced 450 MW of solar thermodynamic power plants (the sun heats steam, which fuels a generator—a worldwide innovative technology different from photovoltaic).

A quarter of its power mix is nuclear fuelled.

Though producing 7.5 TWh of coal fired electricity, Iberdrola fought harshly for a stricter Spanish carbon NAP (National Allocation Plan), clearly advocating for climate cleaner gas generation against coal generation. It invests heavily in new CCGT plants, ranking first in Spain for this type of production.

- The last countries to have their NAPs approved were Italy and Greece in June 2005.

Quantitative strategies were different in each country

- UK relaxed its NAP by 3% at the end of 2004, after an initially more demanding draft;
- Germany, on the other hand, reduced allocations more than the utility companies had expected, by 2 $MtCO_2$ yearly down to 503 $MtCO_2$ by 2007, with stricter rules concerning early actions and conditions on old lignite plants. Germany bears 3/4 of Europe's emission reduction. German operators' concern is that new coal plants will become economically unfeasible;
- France has been asked by the Commission to double the number of industrial and power sites that have to comply with $C0_2$ quotas from 644 to about 1,400 sites. The French NAP is

the only one to allow the players to bank allowances from the first period to the second period of the ETS;

- Italy's first NAP draft targeted an increase to 570 $MtCO_2$ by 2010, in contrast with the 476 Mt in 2012 Kyoto objective. It also relied heavily on JI and CDM mechanisms. The EC approved the plan on 25 May 2005 after some corrections and with reserves;
- The Netherlands' NAP relies for half of its planned reduction on JI & CDM actions;
- In Spain, Endesa called for extended quotas for covering cheaper coal generation, while Iberdrola defended CCGT with stricter allowances. The first NAP version was considered far off track; the November version clearly favoured gas over coal;
- In Sweden, operators negotiated for enough allocations to cover nuclear phase-out in order to ensure coal technologies remained feasible for replacements;
- In Belgium, the shortage of emissions rights should be significant, especially in Flanders where they should reach about 30% in 2005 and up to 40% in 2007 as compared to 2003. Flanders NAP targets 80% of the emission reduction on power facilities. Electrabel considered the Flemish NAP unfeasible in the short term: closure of nearly all coal-fired plants, significant increase in renewable, risk of shutdowns.

Carbon intensity: favourable position for nuclear, hydro and gas fired producers

The initial position is more favourable for producers with low carbon intensity (generation based on large hydro and nuclear, with additional thermal fired generation, under 0.4 tCO_2/MWh), while those producing power mainly through fossil-fired generation, including coal/lignite, are in weaker initial positions (high carbon intensity ranging over 0.5 tCO_2/MWh).

All the companies have lower carbon intensity than the average of their country (excepted Endesa and Enel): this means that the majors-owned generation capacity is less carbon intensive than the second players. As they often sell more energy than they generate, they have to buy carbon intensive kWh from secondary players, and the CO_2 impact on EBITDA should be amplified as compared to the mere CO_2 trends due to owned generation.

Similarly, they often have lower carbon intensity on their domestic market than on their international markets: when they happen to take positions in other countries they often buy more carbon-intensive capacities (for instance Endesa buying French coal-fired SNET).

2004: not all major producers managed to decrease their carbon intensity

Considering a price of €20/tCO_2, a difference from one year to the other of 1 $MtCO_2$ accounts for 20 million euros in the company potential EBITDA. For instance the negative impact for Endesa amounts to €94 million (+4,7 $MtCO_2$).

Some conclusions can be derived from the 2004 trends:

- Hydraulic conditions weigh heavily on CO_2 markets from one year to the other. It appears to be a major factor affecting CO_2 positions. Spanish 2004 weather conditions—though normal—were less favourable than the particularly wet 2003 year. This accounts for a major part in the $C0_2$ emissions increase of the Spanish companies. By contrast, the improved Italian hydraulic conditions in 2004 contributed significantly to Enel's good results;
- Nuclear increased availability rates in 2004 helped EDF, while Endesa and E.ON suffered lower nuclear outputs;
- For majors, the impact of "new" renewables (excluding hydro) is low, except for Iberdrola and Enel which spared nearly 1 $MtCO_2$ in 2004 thanks to heavy investments in wind generation.

Table 1.6 Carbon intensity (2004)

CARBON INTENSITY IN 2004 (DOMESTIC MARKETS)

	DETERIORATED		IMPROVED
HIGH	**ENDESA** **Spain & Portugal** 0,507 mtCO2/TWh + 0,028 mtCO2/TWh ↗ + 6,0 % 49,534 mtCO2 +4,7 mtCO2	**RWE*** **Germany** 0,748 mtCO2/TWh na na 113 mtCO2 na	**ENEL** **Italy** 0,504 mtCO2/TWh - 0,015 mtCO2/TWh ↘ - 2,8 % 63,4 mtCO2 -8,1 mtCO2
MEDIUM	**ELECTRABEL** **Belgium** 0,274 mtCO2/TWh + 0,003 mtCO2.TWh ↗ + 1,1 % 18,9 mtCO2 + 0,2 mtCO2	**EON** **Central** 0,406 mtCO2/TWh - 0,002 mtCO2/TWh ↘ - 0,4% 53,3 mtCO2 -2,6 mtCO2	
LOW	**IBERDROLA** **Spain** 0,190 mtCO2/TWh +0,056 mtCO2/TWh ↗ + 43,3 % 13,0 mtCO2 + 4,2 mtCO2	**EDF** **France** 0,042 mtCO2/TWh - 0,004 mtCO2/TWh ↘ - 9,1 % 20,9 mtCO2 -2,0 mtCO2	**VATTENFALL** **Nordic** 0,001 mtCO2/TWh - 0,002 mtCO2/TWh ↘ - 82,6 % 0,09 mtCO2 - 0,18 mtCO2

Legend:

PRODUCER
Domestic market

Carbon Intensity & Evolution

Total CO_2 emissions in million tons & evolution

Source: Sustainability and Annual 2004 reports, excepted *2003 figures

Global physical gas supply capacity

European domestic production is becoming more and more concentrated in the North Sea:

- While UK North Sea fields are depleting, Norway's production has shown strong development in 2004, raising its turnout by 20% to 75 bcm. Dutch production rose by 13% to reach 73.5 Standard bcm[4] in 2004, mainly from North Sea off-shore fields;
- This concentration of domestic production has increased following Eastern European integration, as Poland is the only new EU member providing some local production, covering a third of its consumption;
- This concentration is shown on Table 1.7: only two countries remain self sufficient—the Netherlands, and Denmark, as the UK became net importer in 2004—even though these two countries chose to import some gas to be able to export more of their production.

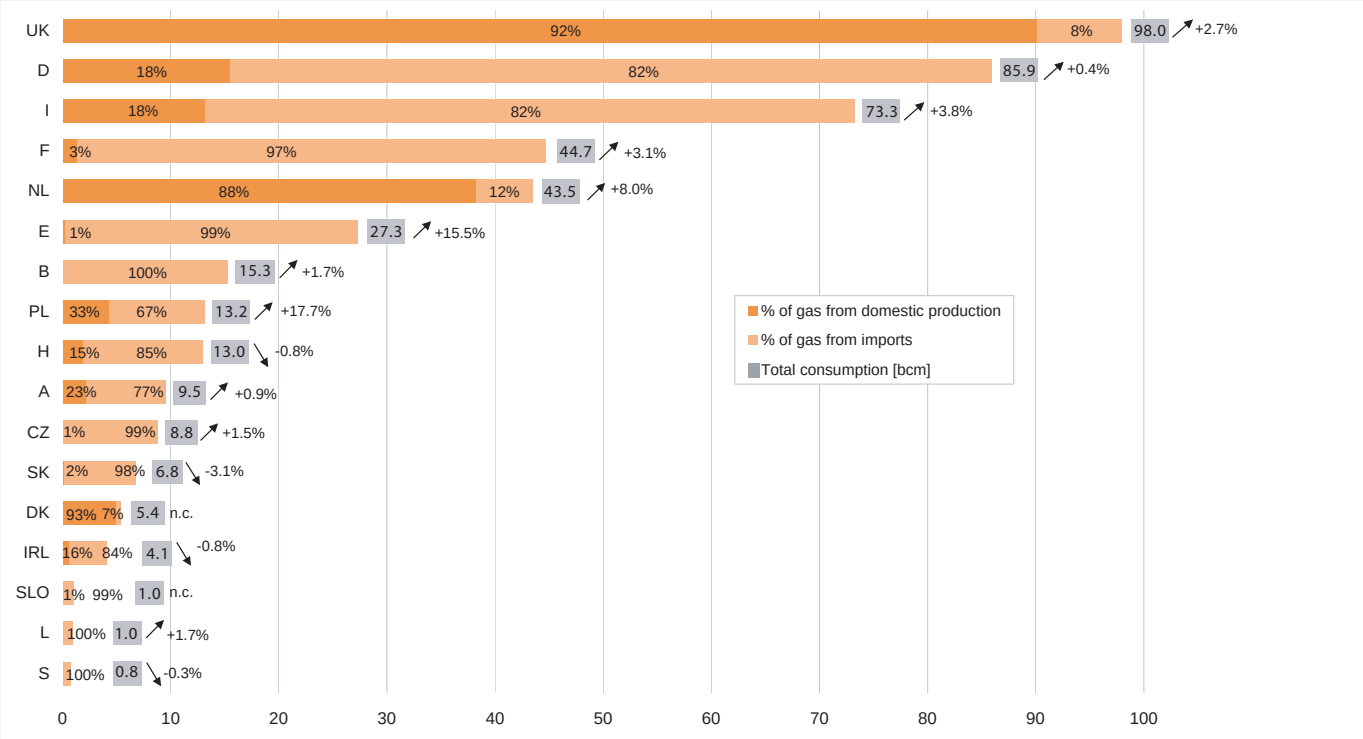
Increasing European dependence on imports

Though some European fields are being developed (Norwegian Ormen Lange's giant offshore field, Statoil's re-development of the Statfjord oil field for gas production, RWE's investment in Saturn and Cavendish fields…), these developments have to be balanced by the depletion of other domestic fields: UK production has already begun to decrease (all proven reserves represent 590 bcm, which could in principle cover 5 years of consumption). Dutch production is due to decline from 2008 onwards, with concerns about investments to exploit remaining reserves of small fields. When Norway will reach its "gas peak" is not clearly known: Norwegian proven reserves are on an absolute upward trend, but on a downwards slope in terms of years of remaining production at current production rate, as shown on Table 1.8.

This balanced evolution of the European domestic gas sector will not answer the rapid growth of demand, largely due to the multiplication of gas-fired power plant projects across all Europe. This growth has reached 3% throughout Europe, and was especially strong in Spain (+16%).

As a result, Europe's dependence on external gas imports is growing, all the more so with the stronger integration of Eastern European countries, relying 71% on Russian gas. This situation has resulted in an 8% rise of Russian exports, to 124 bcm (and a rise in 14% of exports to EU 15), leaving Russia, as shown on Table 1.9, in a very strong supply position.

Table 1.7 Gas domestic production vs. imports (2004)



Source: European Commission, BP Statistical Review of World Energy 2005

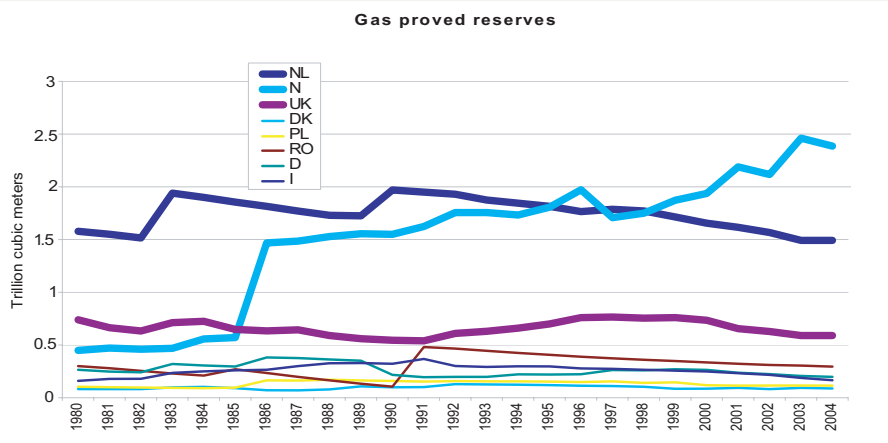
4 'Standard' relates to the reference conditions: 15° C and 101.325 kPa.7

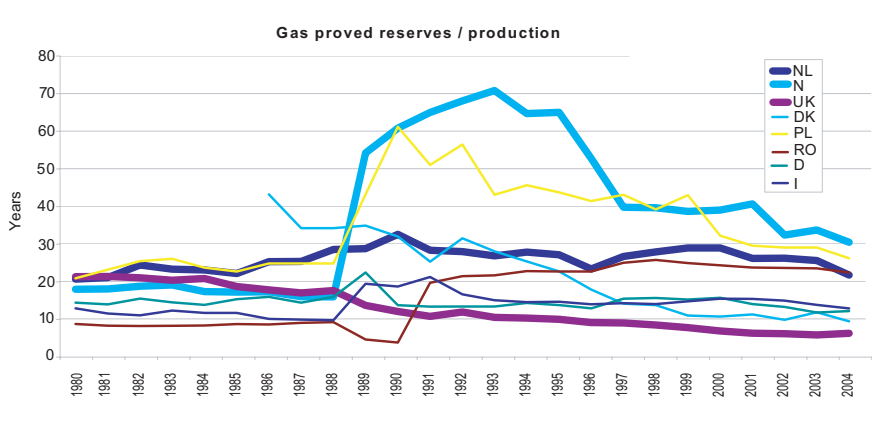
Gas release
Similar to VPP in the electricity sector, gas release programs are set up to encourage competition, either via auctions or bilateral sale.

It is worth noting that:

- In France, in October 2004, 6 TWh (0.5 bcm) of gas were bought by several European companies, delivered at the southern gas exchange point and with a delivery period between 1 January and 1 July 2005. This is the first auction of a 3-year gas release programme, under the agreement between CRE and Gaz de France to release a total volume of gas of 45 TWh (with a minimum of 18 TWh through auctions and 27 TWh through bilateral contracts). The regulator said gas release was an interim measure, "allowing the entrance of new suppliers in the south of France, where there is currently no competition, without waiting for necessary investment" such as a planned LNG terminal at Fos and new interconnectors with Spain;
- In Austria, the third annual gas release programme, organised by EconGas (50% owned by OMV) took place on July 2005 for 250 bcm;
- In Germany, for the third time E.ON Ruhrgas auctioned off natural gas from its long-term supply contracts in May 2005. This auction offered a total of 39 TWh over a contract period of 3 years, at the Emden/Bunde delivery point;
- In Hungary, the government was asked by the Energy Office to enact a law forcing the dominant supplier MOL to sell some of its gas through a release programme. MOL controls the imports and capacity in the east of the country at the Ukrainian border, where capacity is overbooked, and gas in the east of the country through the Hungary-Austria line is much more expensive, so competition has been stifled at either end.

Table 1.8 Gas domestic proved reserves



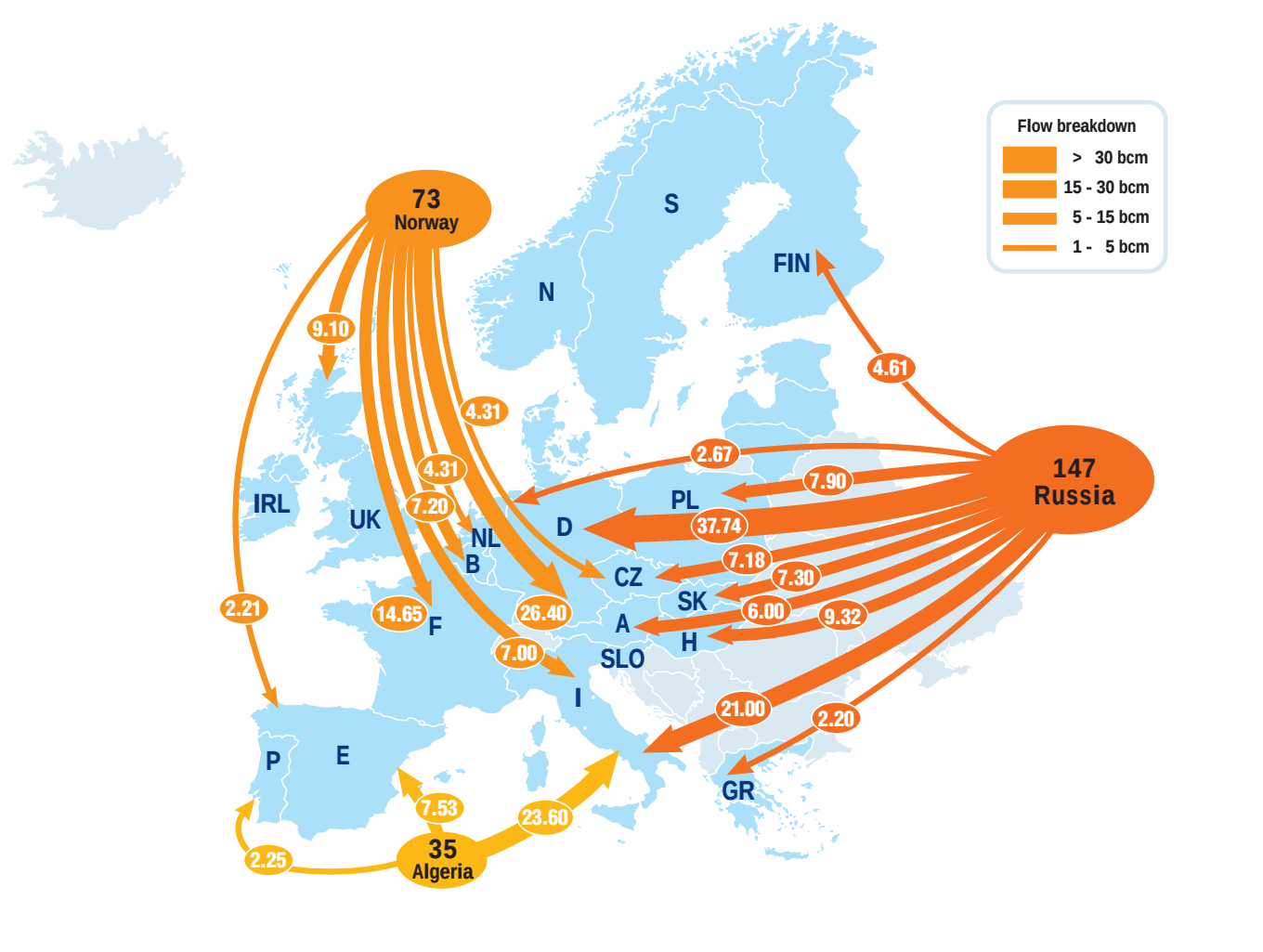


Source: BP Statistical Review of World Energy 2005

Sound diversification opportunities

Algeria is the other major exporter in Europe. It has seen its exports stabilize, at 52 bcm, its LNG capacity being hampered by the explosion of a liquefaction train in Skikda in February 2004. The start of deliveries from the giant In Salah gas field in southern Algeria, and the development of the Medgas and Galsi pipes may trigger a stronger development in the years to come. Besides LNG development, covered in the LNG overview in part III, other fields may be accessed through future pipes: Libya Green Stream has come on line in 2005, and Nabucco pipe—if built—may give access to Caspian Sea area gas.

Table 1.9 Gas flows—Pipelines (2004) in bcm



Source: BP Statistical Review of World Energy 2005

II Dynamic of Demand

Development of electricity eligible markets

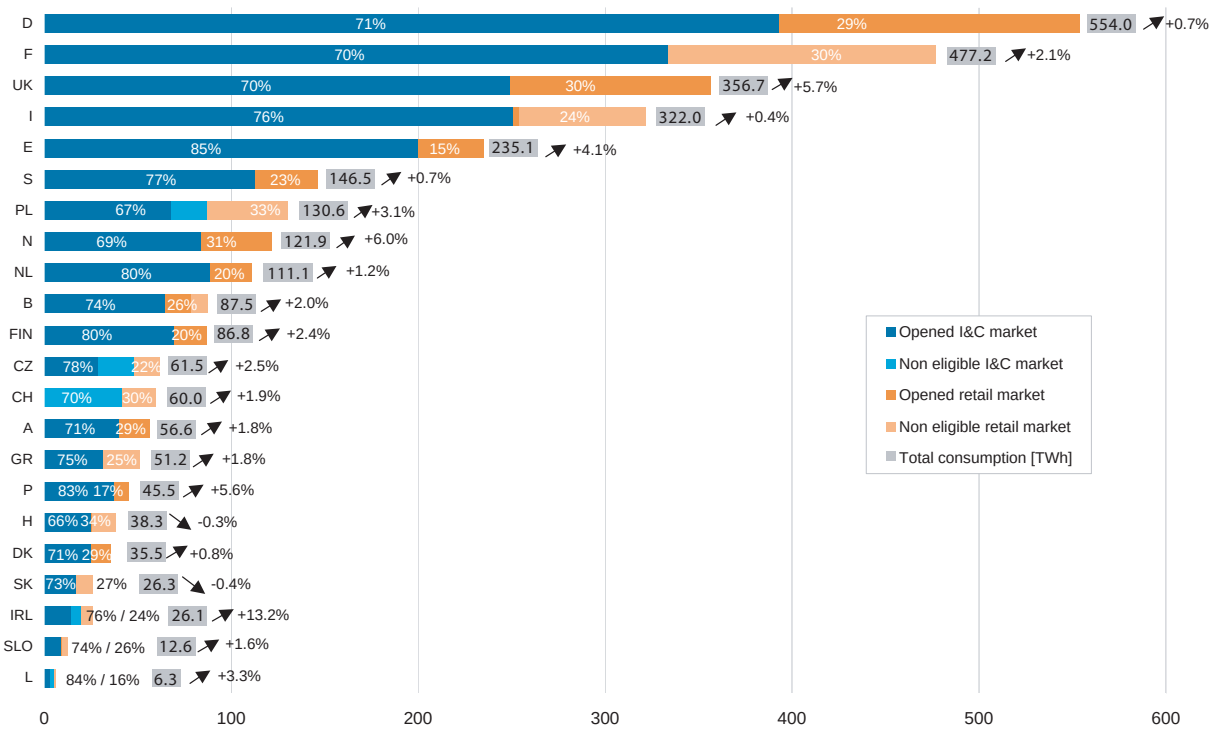
2004 saw an important milestone in the development of retail competition. As of 1 July 2004, all I&C customers in EU15 countries were able to choose between competitive offers. As a result, at least 70% of total load in all markets is now open to competition.

The opening of the market for all I&C customers meant a very substantial increase in the number of customers subject to competition. As we have commented in previous editions of the Observatory, there was some concern about how well the new arrangements would perform. In the event, the new systems and procedures seem to have survived the test. And although in some areas the number of customers actually changing supplier is still limited, the fact that the initial launch has gone so well is still a notable achievement. Of course, this achievement has not prevented the EU initiating a detailed enquiry into the development of competition across European energy utility markets.

Growth of overall electricity demand

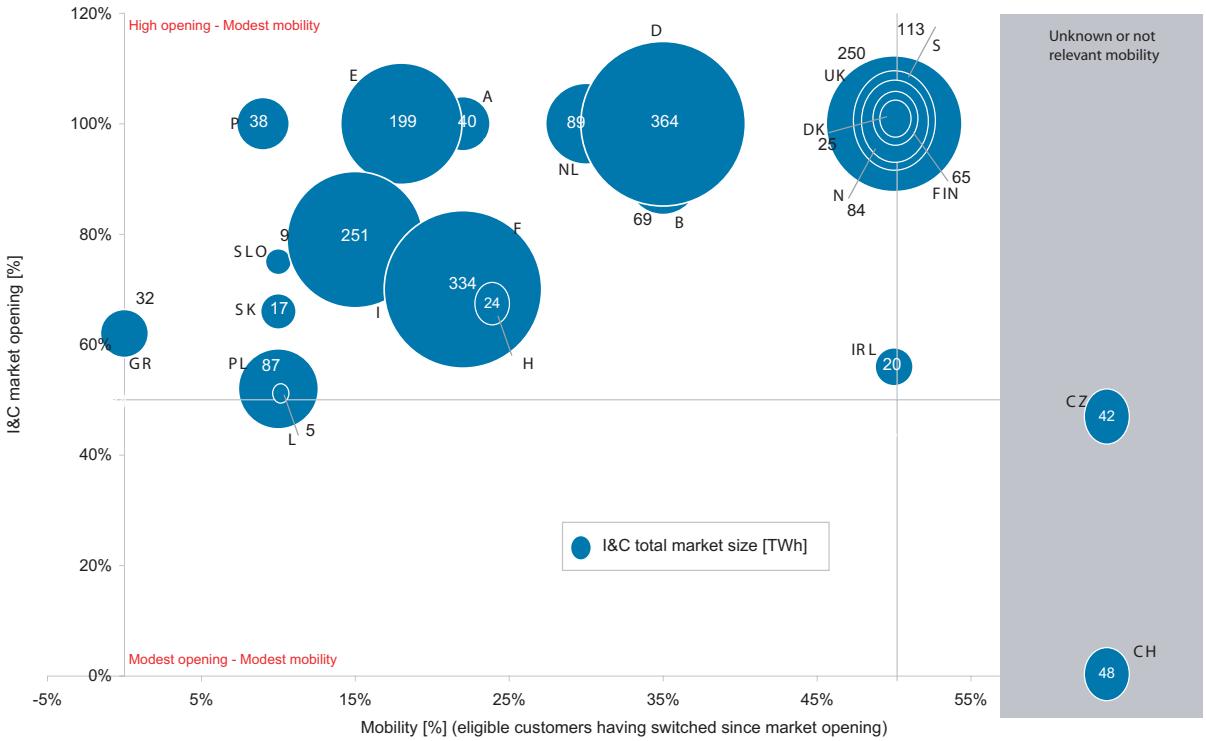
Despite the somewhat subdued pace of economic development in Europe as a whole, there is again evidence of rapid growth in electricity consumption in multiple countries (Table 2.1). France for example saw an increase of 2.1% in 2004 (following the 4.3% increase in 2003); Spain and Portugal, facing a severe drought in 2004, increased their consumption by respectively 4.1% and 5.6%; the UK also saw growth of over 5.5%. There are also instances of quite volatile patterns in demand—both Norway and Ireland saw rapid growth in 2004, which reversed sharp falls in 2003.

Table 2.1 Size of I&C and Residential electricity markets opened to competition (2004)



Source: UCTE, Nordel, European Commission, DTI, EirGrid

Table 2.2 Dynamic and opening of the I&C electricity markets (since market opening)



Source: European Commission

Competitive dynamic in the electricity I&C retail markets

The opening of all the Industrial & Commercial (I&C) market is evident in Table 2.2 with only Switzerland and some of the newest EU members still to complete the market opening. The data in this edition of the graph shows the cumulative dynamic since market opening. There is a clear correlation with the longevity of the markets, with the longer established markets in the UK and Scandinavia showing mobility of 50%+. France, Italy and Spain show mobility of just under 20%—which for France and Italy reflects the fact that the market will take some time to mature and/or the lack of free sourcing. Germany and the Netherlands show mobility of around 30–35%. In the case of Germany, there has been quite a lot of recent comment about the reconsolidation of the industry and the significant roles played by the largest four companies. However, while the mobility figures may be somewhat behind the UK and Scandinavia, there has also been a significant extent of incumbent re-negotiation, where the customer benefits from lower prices whilst staying with its original supplier.

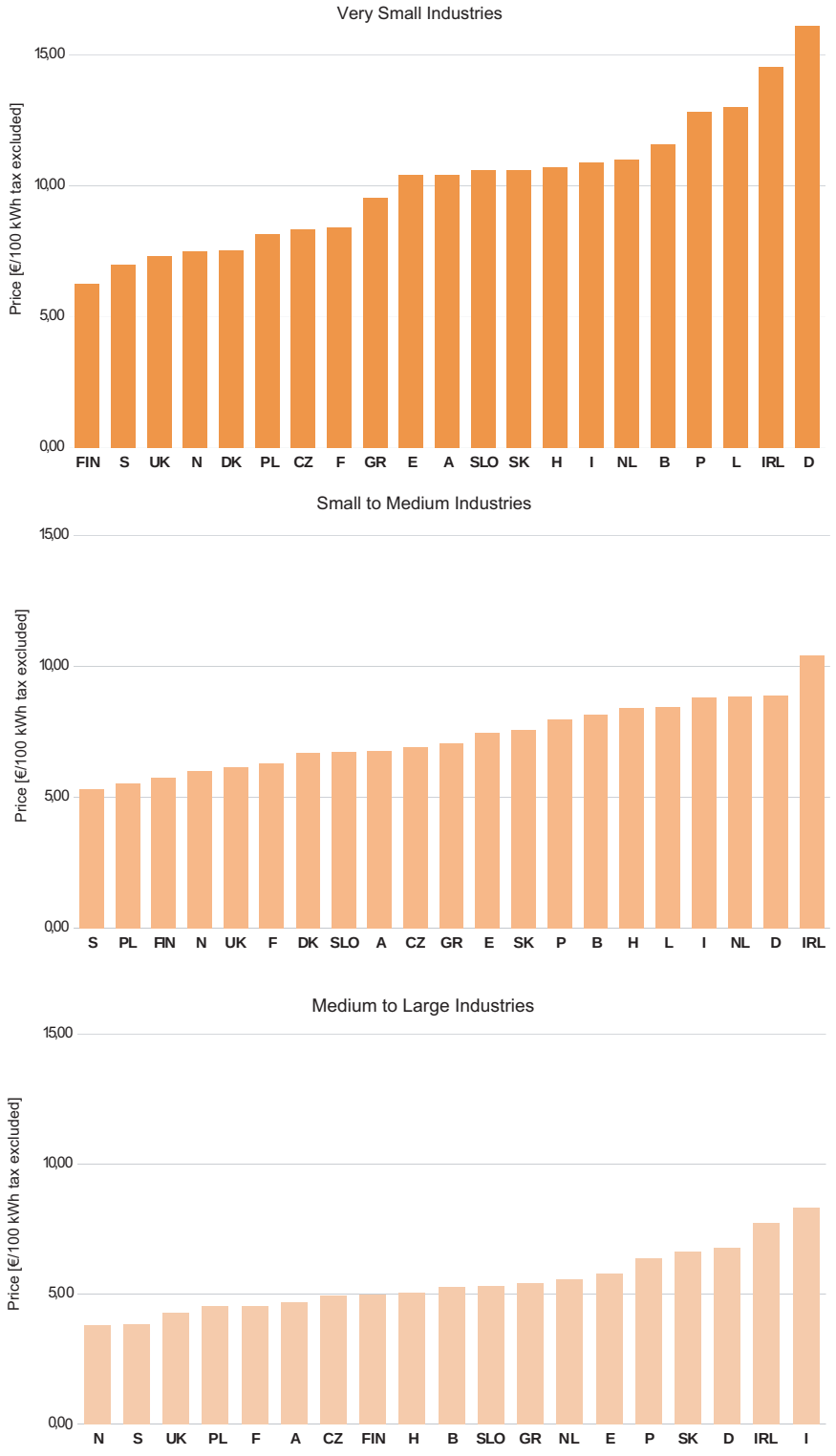
Electricity price developments—I&C customers

The price graphs (Table 2.3) provide further evidence that the simple association of "deregulation will mean lower prices" is incorrect. A combination of pressure in fuel costs and a tightening in the supply/demand balance has contributed to upward pressure in wholesale market prices, and this is now starting to be seen in retail prices as well.

The degree and speed of linkage between wholesale and retail price movements appears to vary quite considerably between countries. This reflects a complex mix of different contract types and purchasing strategies, competition amongst players, the development of capped or stepped price offers and also the continued influence of regulation or semi-fixed tariffs in some countries.

The charts of relative prices (Table 2.4) between countries emphasize that there are still very considerable price differences within Europe. Making cross-border comparisons on a true "like for like" basis is notoriously difficult. However, even allowing for the possibility of some degree of distortion in the comparisons, the graphs indicate that a true single market remains a long way off. For the largest two categories of I&C customers, the most expensive countries have prices twice those of the cheapest countries. And for

Table 2.3 I&C electricity prices (€/100 kWh tax excluded)—January 2005



Source: Eurostat

the smaller end of the I&C market, the differential is closer to three times.

These comparative graphs (Table 2.4) also indicate that some degree of tariff rebalancing within countries is likely. In Germany for example, prices for the very small group are 2.5 times those for the largest customer group. In contrast, in the UK, the relative figure is only 1.7. Over the past few years, most major retailers in the UK have begun to focus explicitly on the smaller I&C customer groups, and this has resulted in some narrowing of the relative gap with large customers.

Electricity price developments—Residential customers

The upswing of retail prices is also evident in the residential markets. This was especially true in the UK where prices rose by 25% over the period January 2004 to January 2005, and have now reversed the falls seen each year since 2001. As a result, the UK has moved from the third-cheapest, to the third most expensive amongst the ten countries where residential customers are already eligible.

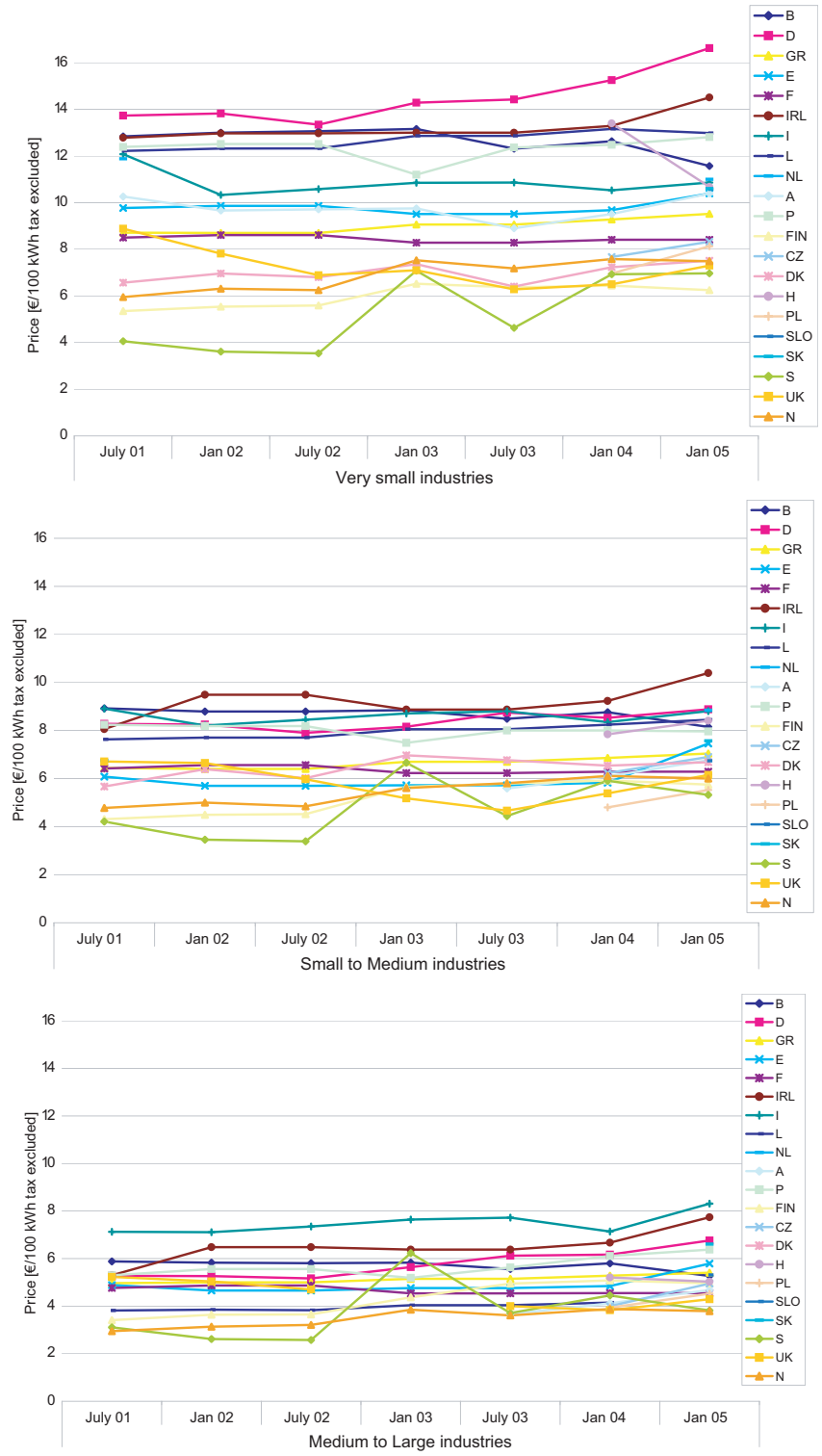
The relative country prices emphasize that the correlation between eligibility and price levels is—at least for now—rather weak. One of the key challenges for the markets yet to open will be the extent to which the current tariffs are allowed to be adjusted prior to competition. In France for example, there are some doubts about the extent to which new competitors will be able to compete unless the current regulated tariffs are increased.

Energy efficiency, a major stake for Energy Policies in the short and the long run

The Commission has placed Energy Efficiency on top of its key priorities for the next 5 years.

As stated previously, demand-reduction initiatives launched today can have sizeable impacts in the long run on the offer/demand balance. The Green Book on energy security of supply previously adopted by the European Commission

Table 2.4 Change in I&C electricity prices (€/100 kWh tax excluded)—July 2001 to January 2005



Source: Eurostat

even came to the conclusion that the largest levers were linked to the demand side.

Strong and European-wide commitments for energy savings and demand management programs are on the agenda. A consultation Green Paper on energy efficiency was published in June 2005 in order to prepare a detailed Action Plan to be issued at European level in early 2006:

- It states that the 1.4% annual improvement in energy efficiency in the 1980's has declined to 0.5%;
- It points out that 20% of annual consumption by 2020 could be saved in a cost effective way, with 50% of this target being allowed by merely applying the current European legislation;
- Benefits are expected to be a real gain in employment through expansion in the energy efficiency goods and services, exportable know-how (to China, India) and an increase in Europe's competitiveness.

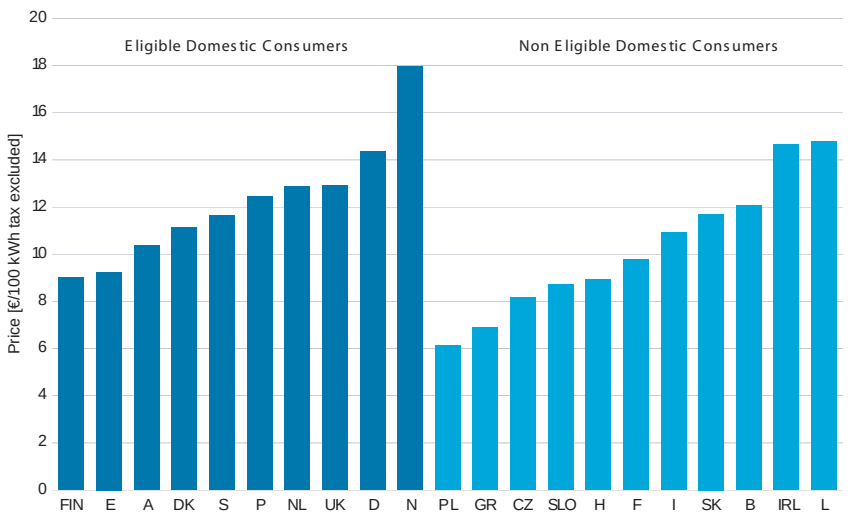
White Certificate systems on trial in UK, France and Italy

White certificate systems require energy suppliers to save a fixed volume of TWh. They exist in the UK, Italy and France.

In the UK, the delivery of the first Energy Efficiency Commitment ended in May (EEC 1, 2002–2005).

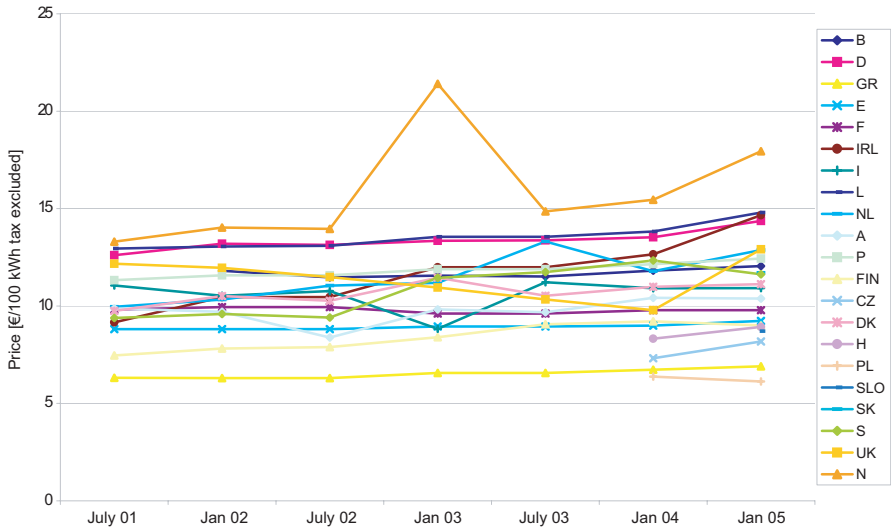
- It required energy suppliers to save 62 TWh of energy by providing energy efficiency measures to households across Great Britain (50% of which to priority low-income households);
- 84 TWh have been achieved: mainly through insulation, and secondly through lighting for priority groups and brown and white electrical appliances for non-priority groups.
- EEC 2 (2005–2008) has already started. The target is 130 TWh, still evenly distributed across priority and non priority groups. Electrical appliances are no longer taken into account, but Ofgem will give incentives (extra certificates) for innovative actions, such as new

Table 2.5 Residential electricity prices (€/100 kWh tax excluded)—January 2005



Source: Eurostat

Table 2.6 Change in residential electricity prices (€/100 kWh tax excluded—July 2001 to January 2005



Source: Eurostat

technologies or micro-CHP boilers up to 50 kW for households;

- The EEC system will be revised in 2007 and new targets proposed for 2008–2011. It is a part of the Climate Change Program aiming at a 60% cut in CO_2 emissions by 2050.

In Italy, the government issued two decrees on 20 July 2004, aiming at enhanced end-use energy efficiency, energy savings and development of renewables;

- Distributors, since the beginning of 2005, have been required to meet energy conservation targets. The objective is to curb Italian primary energy consumption by 2.9 Mtoe per year (34 TWh per year) during the first period (2005 to 2009), corresponding to the yearly average growth of domestic consumption;
- 162 companies have been accredited as "energy service companies" as of 16 February 2005: for example they design, carry out and subsequently manage energy conservation projects, and offer a variety of full or partial financing schemes to end-consumers. They receive energy efficiency certificates for these actions;
- The White Certificates can be sold on the certificates market being organized by Market Operators or under bilateral contracts;
- Distributors can buy White Certificates or carry out on-location projects for end-consumers directly as "energy service companies" through agreements.

In France, the White Certificate system will be operating in early 2006.

- A list of designated utilities are required to save up to 54 TWh over 3 years (about 30 TWh for electricity operators, 15 TWh for gas operators, 7.5 TWh for fuel, 1.5 TWh for others);
- Certificates are tradable, utilities can comply with their obligation by

themselves or through buying certificates on the market;

- Volunteering players (industries, municipalities) can also receive certificates, but conditions are more restrictive for them if they do not ally with the designated utilities;
- Along with traditional energy saving actions, heating renewables (solar thermal, heating pump, CHP) are also eligible.

Other illustrations of energy savings initiatives at customer level

- In the Netherlands, companies signing the Benchmarking Energy Efficiency Branch commit to remain within the 10% most efficient companies in the world;
- Carrefour and Schneider Electric have signed an energy efficiency contract with guaranteed performance. The energy that could potentially be saved in the supermarkets amounts to 113 GWh (10 to 15%);
- The UK created in 2004 the Energy Service Contracts (ESC) consisting of a long-term engagement in exchange of bill reduction and energy efficiency services ("a 5-years loyalty in exchange for a 15% lowering in charges").

Some initiatives around metering

- In Sweden, a law passed in 2004 requires monthly meter reading for all electricity consumers by July 2009, making it necessary to install 5.2 million new meters;
- In Finland, Vattenfall began the installation of real-time remote readable smart meters in May 2005, based on TeliaSonera's mobile telephone system. By the end of 2005, Vattenfall will have installed 105,000 such meters;
- "Customers have been active and have given many new ideas regarding additional services for the system", Vattenfall report says;
- All of Vattenfall's 1.5 million Nordic customers will have new meters;
- In Italy, benefiting from the new smart meters, ENEL proposes six new tariffs based on customer profiles, claiming up to €80 savings for clever customers, with positive impacts on the Italian network availability and reliability.

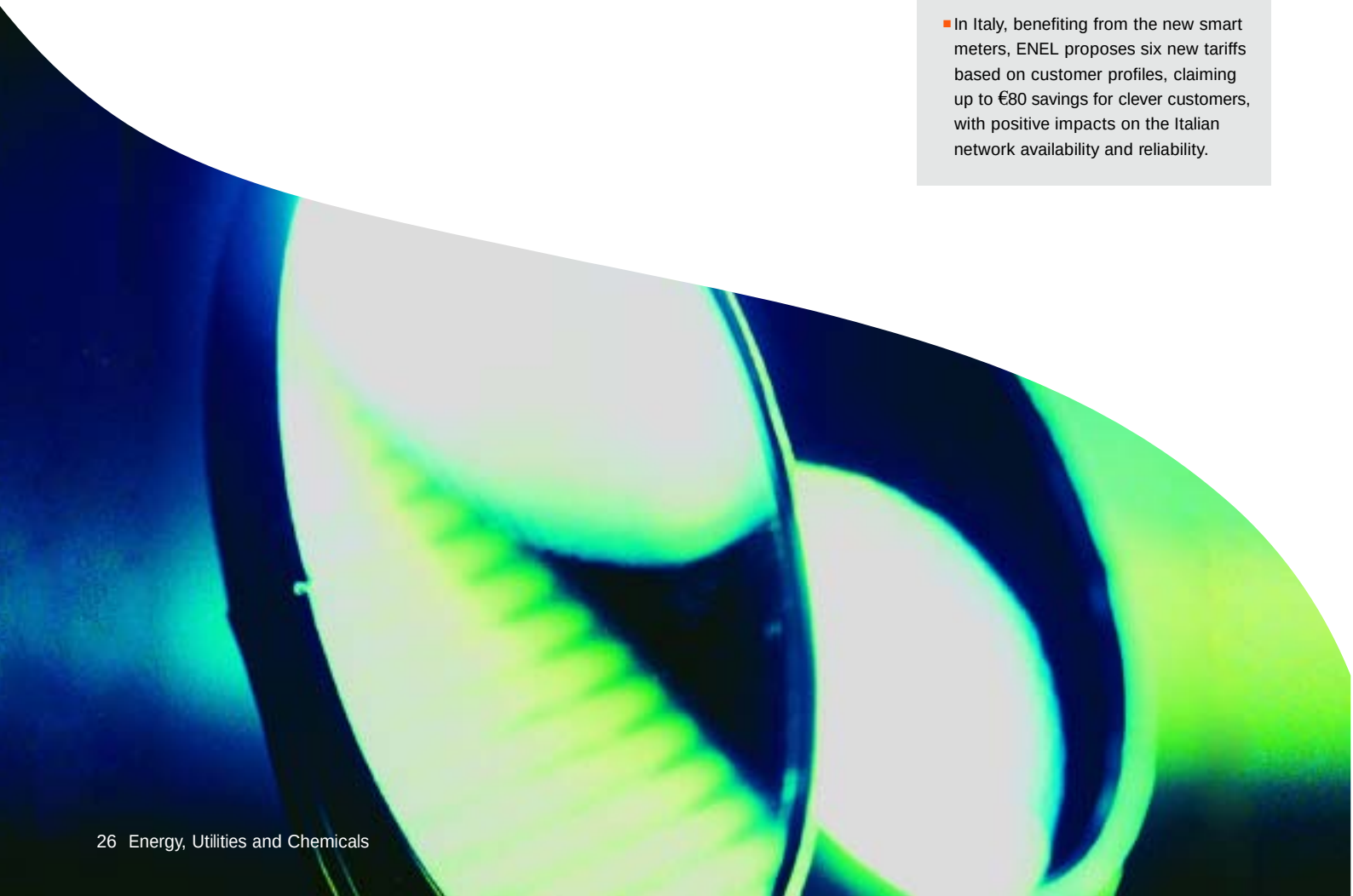
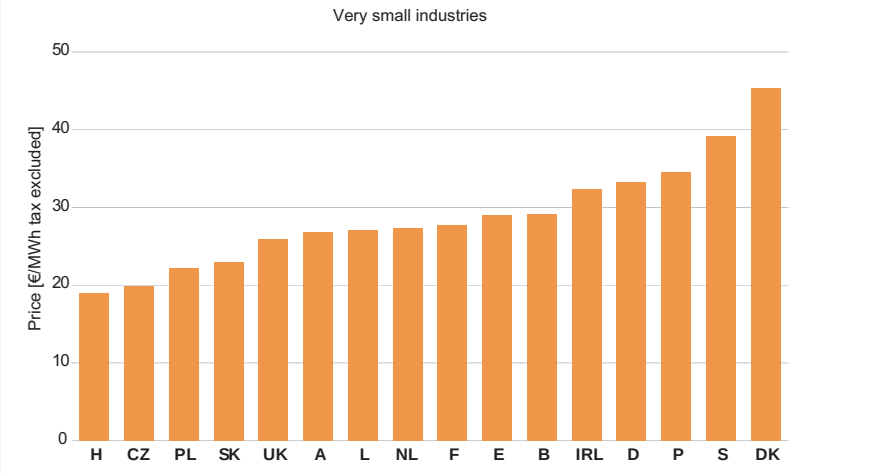
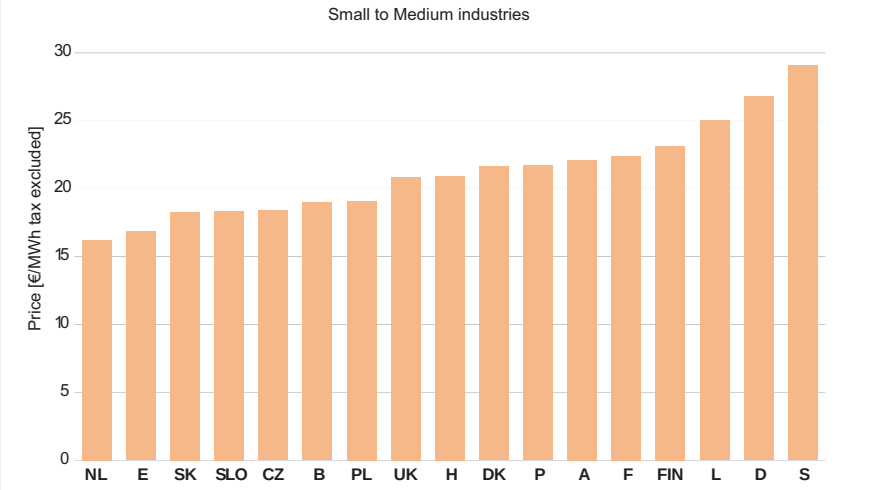
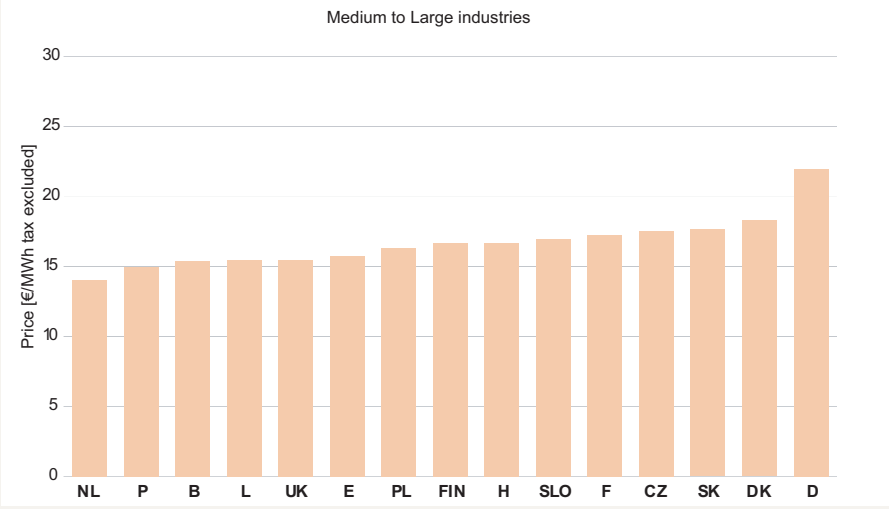


Table 2.7 I&C gas prices (€/MWh tax excluded)—January 2005







Source: Eurostat

Gas price developments—Industrial and Commercial customers

A general rise in gas prices

Gas prices for industrial end-users in most EU countries rose from January 2004 to January 2005, due to a significant increase of oil prices during this period: from $30 in September 2003 to $53 in September 2004 (a 3-months lag is considered between gas and oil prices). As most of the reasons explaining the rise of oil are not applicable directly to the European gas industry—political situation in the Gulf, rise of East Asian consumption, lack of refining capacities, fears of peak oil—this highlights the importance of the indexation of gas prices to oil prices.

A collection of individual situations

A wide disparity between I&C prices was experienced in very small industries, with prices ranging from nearly €19 to €45/MWh.

These strong discrepancies can be explained by different factors: the Danes have the most expensive gas due to steep environmental taxes. Germans and Swedes were sustaining high transmission fees, while Portuguese had to cope with an emerging gas market, still to be developed. On the other end of the scale, Eastern Europe customers were benefiting from highly subsidised tariffs.

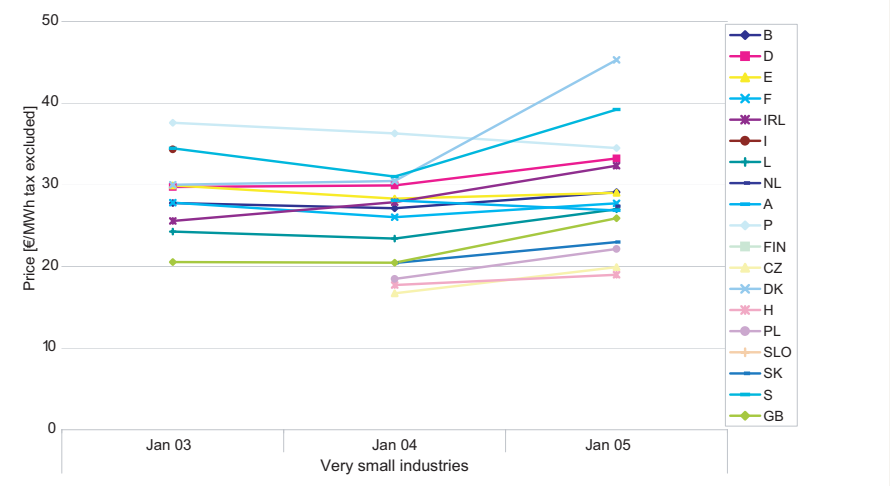
More homogeneous situation for larger customers

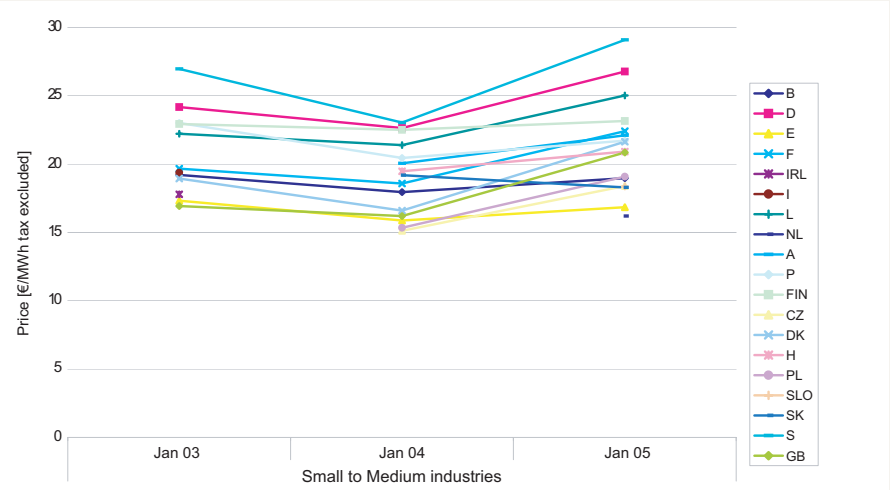
Prices are more homogeneous for larger customers. For these customers, Eastern Europe prices are no longer subsidised, therefore prices are far less advantageous. Germany remains the most expensive country, with important differences of prices within the country.

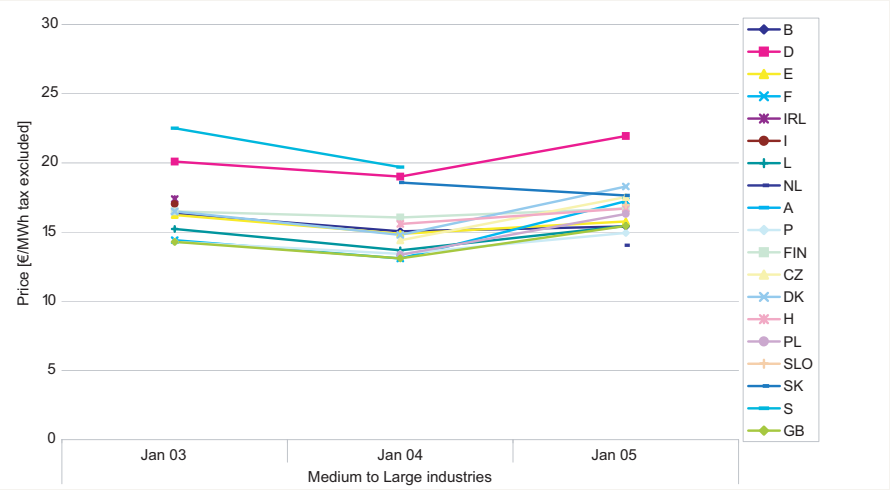
A clear upward trend

The upward trend was followed by nearly every country for the three segments (Table 2.8). The only exceptions are Austria and Portugal for very small industries, and the Slovak Republic for larger ones.

Table 2.8 Change in I&C gas prices (€/MWh tax excluded)—January 2003 to January 2005







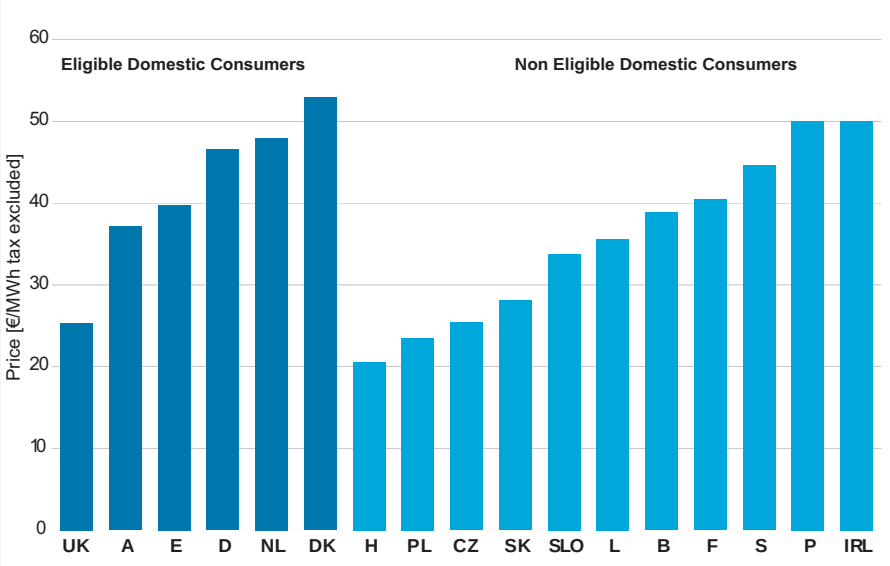
Source: Eurostat

Moreover, the rise was of the same magnitude whatever the segment considered.

Though, between countries, price rises have varied considerably:

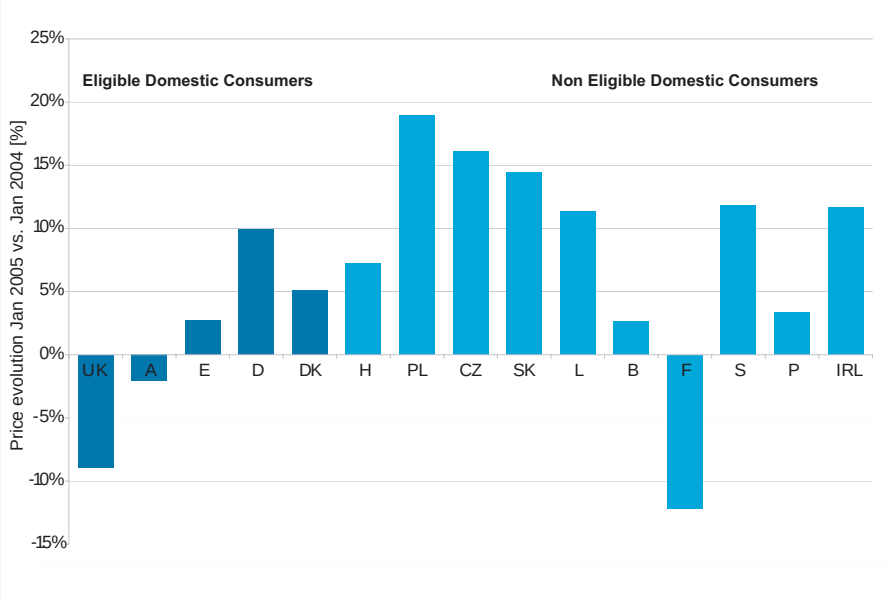
- For smaller customers, for which regulated tariffs still apply in many states, political issues explain some of the differences. For instance, Gaz de France was refused a requested tariff rise, giving one of the smallest prices rises for a very small industry;
- By contrast, the increases in the wholesale prices in the UK were fully passed on to very small (27% rise) and to small-to-medium industries (29%). Despite this increase British industrial gas prices remain some of the cheapest in Europe;
- Some explanations may also be found with the type of indexation of long-term contracts, as heavy fuel prices for instance have increased much less than crude oil;
- Poland and the Czech Republic have experienced over 20% rises, thus catching up with Western prices for smaller customers.

Table 2.9 Residential gas prices (€/MWh tax excluded)—January 2005



Source: Eurostat

Table 2.10 Change in residential gas prices—January 2005 vs. January 2004



Source: Eurostat

Gas price developments—Residential customers

A wide dispersion both on eligible and non eligible clients

Residential prices are widely dispersed (Table 2.9), ranging from roughly €20/MWh in Hungary to nearly €53/MWh in Denmark. Distribution tariffs, which represent an important part of the gas price for individual customers, is one important factor. The level of subsidies is another important explanation, especially in Eastern Europe. And environmental taxes explain Denmark's soaring prices. As in the previous years, it is striking that eligibility is not by far the main issue to explain residential gas prices.

As for industrial customers, residential customers paid more for their gas in 2004. Two exceptions are notable: France, thanks to a government decision, and the UK, where the significant price reduction increases the gap between British customers and their Western Europe counterparts. Eastern European countries, despite high increases, remain much cheaper, but the gap is narrowing fast.

III Physical Infrastructures Contribution

Cross-border transits

Access to national markets via cross-border transits is probably the most immediate mechanism (if transit capacities are available) term basis (e.g. access by new entrants to other markets) and on a shorter term basis (day ahead, intraday and arbitrage).

Initially designed to secure supply and to reinforce the reliability of the network, today cross-border interconnections are critical in supporting the activities of:

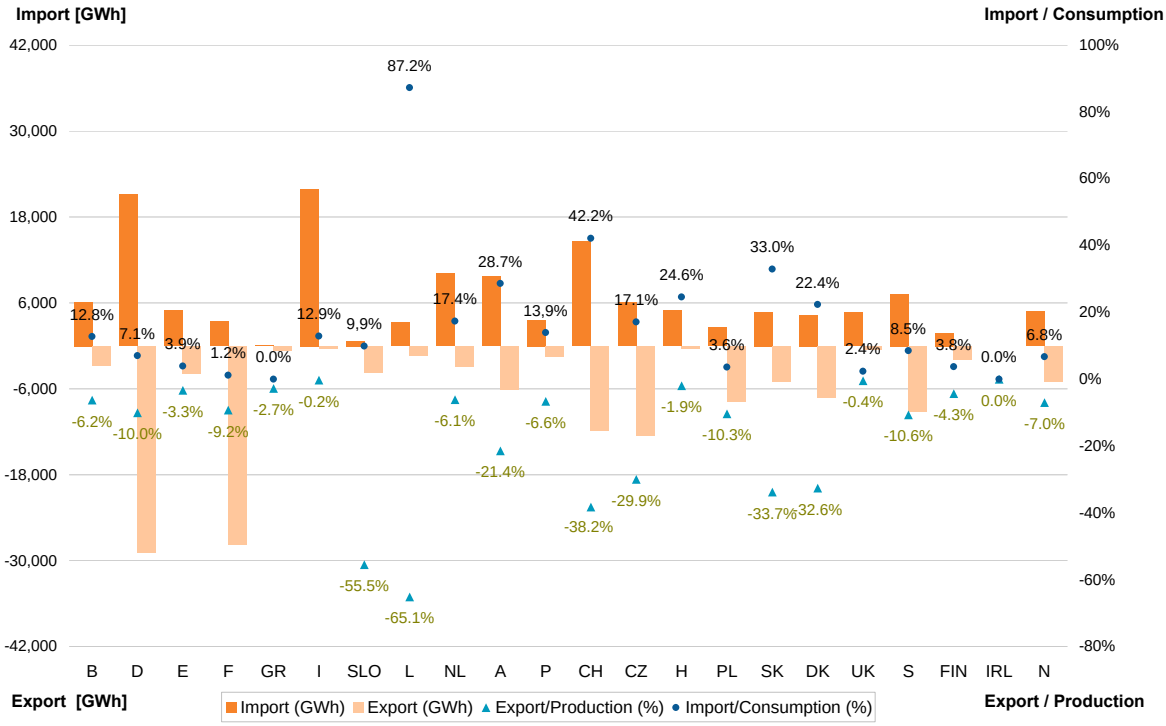
- **Incumbents**—who must honour their long-term contracts (export or import);
- **Network operators**—who help each other in order to adjust load and assure the reliability of the interconnected networks;
- **Market participants**—to hedge risk through bilateral or organised market, trades or to perform arbitrage when there is a price spread.

The analysis period is the winter (October 2004 to March 2005).

The graph (Table 3.1) confirms the net exporting or importing situations of the European countries:

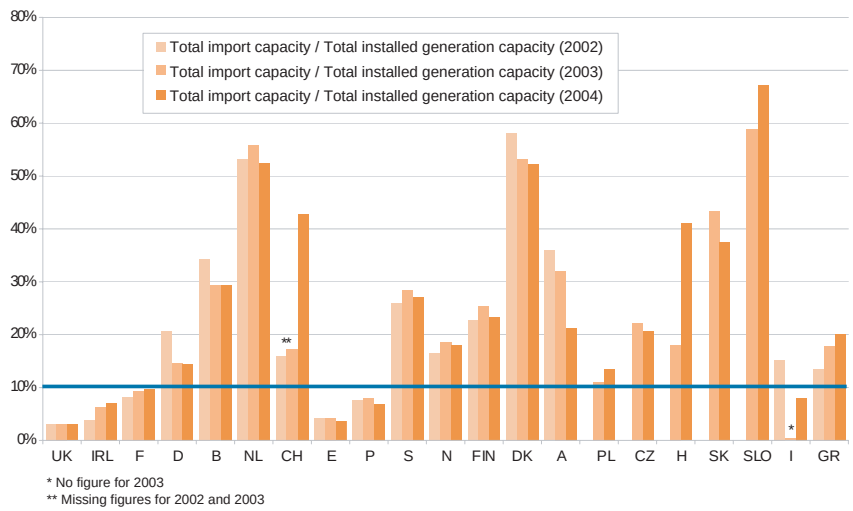
- Germany and France remain the two major net exporters. However, compared to last winter, when both countries exported more than 30,000 GWh, during the winter 2004/05 they were above this level. This is probably due to the cold spell when both countries were facing difficult situations and had to rely on imports from their neighbours;
- Italy remains Europe's biggest net importer, while improving its situation compared to last winter;
- It is worth noting that Germany has similar levels of imports as Italy;
- Sweden became a net exporter during this period while it used to be a net importer in the previous periods.

Table 3.1 Cross border transits (October 2004–March 2005)



Source: UCTE, Nordel

Table 3.2 Transit capacities through interconnections



Source: ETSO, UCTE, Nordel, NGC, ESB, EirGrid

Evolution in physical infrastructure

In the regulatory activity of 2004, the European Directive on Security of Supply obviously marked a clarification in TSO roles and obligations on two subjects:

- Supervising reliability and quality of transmission and distribution infrastructures in the member states

  Especially in a period where renewables are newly connected to the European grid (offshore wind farms, distributed generation) and where public opinion is concerned about blackouts (Switzerland, Sweden or Italy), the measures taken are:
  - Member states must define standards to be met relating to the security of Transmission and Distribution networks (average duration of power shortages, number of shortages…);
  - Each national TSO must submit a multi-annual investment strategy to its regulator;
  - With that report, the regulator must take into account the TEN (Trans European Network) guidelines and submit the resulting strategy to the European Commission;
  - Regulators now have the right to intervene to accelerate the completion of projects and where necessary issue a call for tender on certain projects in the event that the TSO is unable or unwilling to complete the concerned projects.
- Constructing interconnections to reach the level of 10% of countries' generation

  This level was defined at the Barcelona summit in 2002 in order to enhance competition between market players of different countries and to secure the supply in a country that should experience a series of breakdowns in power plants.

  Currently, some countries have already reached the goal (as shown in Table 3.2).

The graph:

- Confirms the existence of "electricity peninsulas" far from the recommended amount of 10% (the UK, Ireland on one hand and Spain, Portugal on the other hand);
- Illustrates the central electrical position of some countries on the continental area like Denmark, Belgium, the Netherlands that are far beyond the 10% level;
- Shows the northern interconnected network (Sweden, Norway and Finland);
- Shows a relatively stable percentage in the past 3 years mainly due to:
  - The long time required to achieve such projects;
  - Newly installed generation capacities that automatically reduce the ratio or keep it flat.

The Italian case is difficult to determine since capacity data are not always available, or are only partially available.

We believe that, because only a few countries are below the recommended level, a higher percentage may constitute a better incentive or constraint for TSOs to building new interconnections.

News and events concerning transit capacity:

- A new 380 kV line linking Alqueva in Portugal and Balboa in Spain, in the southern half of both countries has been implemented. This is the second circuit of Cartelle-Lindoso 380 kV line in the north of Spain and Portugal;
- Work has started on a third 380 kV connector between France and Belgium. This has to be commissioned before the end of 2005;
- In Netherlands, the National Regulator agreed to the construction of a DC cable-connection between the Netherlands and Norway. This submarine cable will have a capacity of 700 MVA and a length of 580 km, and will be taken into service at the beginning of 2008;
- A new 110 kV tie-line interconnects the power systems of VKW (control area of EnBW, Germany) and LEW (control area of NOK, Switzerland);
- In France, the balancing mechanism that started on 1 April 2003 has evolved: it has been extended to the France-GB interconnection since 9 November 2004 and to the France-Spain interconnection since 1 December 2004 (in addition to France-Switzerland);
- The construction of a new 380 kV tie-line between Italy and Switzerland

started at the beginning of 2005;

- Switzerland´s seven largest electricity utilities have established "Swissgrid", an independent, national grid company. The new privately owned company assumed responsibility for operating the Swiss transmission grid on 1 July 2005.

Many projects during the analysis period consist of reinforcements of existing interconnections. Local resistance from the population due to environmental impacts and political delays do not help TSOs in initiating new development projects. In recent years, the reinforcement of existing lines (adding new circuits for example) took precedent.

Access to interconnection/ market zone

Cross-border capacity auction activity is reported for the analysis period (winter 2004–2005).

As most capacity allocation mechanisms are not entirely based on market mechanisms, this section is enhanced with a map showing Net Transfer Capacity (NTC) at each border as well as the applicable allocation mechanism.

Another point to note is that, for the most part, current interconnection mechanisms tend to favour existing long-term contracts by giving priority to established contracts.

During 2004 and the beginning of 2005, we have observed a clear tendency to resolve network congestion problems with non-discriminatory market-based solutions in order to give efficient economic signals.

Those market based solutions are fully consistent with Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.

Central Europe on the way:

- Czech TSO CEPS has successfully organized a three-way auction of transmission capacities, on 24 November 2004;
- Polish operator PSE has established an effective congestion management mechanism and a market-based method of transmission capacity allocation to market participants;
- Central Europe TSOs have already started to work on a common congestion management project to be implemented in 2006.

But also in Western Europe a number of developments have occurred. The French TSO RTE has set up a capacity allocation mechanism based on a "pay-as-bid" monthly explicit auction on the French-Italian border as of 1 January 2005.

The TSOs of South-East Europe (SEE), under the umbrella of ETSO (the Association of European Electricity Transmission System Operators), adopted by consensus on 30 July 2004 a cross-border trade mechanism for 2004. This mechanism has removed all existing border and transit fees among the signatories while an injection fee of €1/MWh is applied from perimeter countries.

Network and regulatory activities

Physical infrastructure is instrumental in the creation of local, national and sub-national markets. A market can be defined by a network area, with limited congestion allowing a single trading zone. Development of interconnection capacity and approaches to interconnection management can create markets larger than the historical network control areas.

On the way to a unique synchronous zone:

- In 1991, the UCTE system was split into two separately operating synchronous zones following war events in ex-Yugoslavia. The reconnection of the two synchronous zones was successfully achieved on 10 November 2004;
- On April 2005, first investigations began to examine the feasibility of a synchronous interconnection to support further developments of the electricity markets between the UCTE electricity transmission systems and far east

The Florence Regulatory Process

The major event in the field of cross-border trade of electricity and the management of scarce interconnection capacity was most probably the 11th Florence Forum (16–17 September 2004) and the series of Mini Forums that followed.

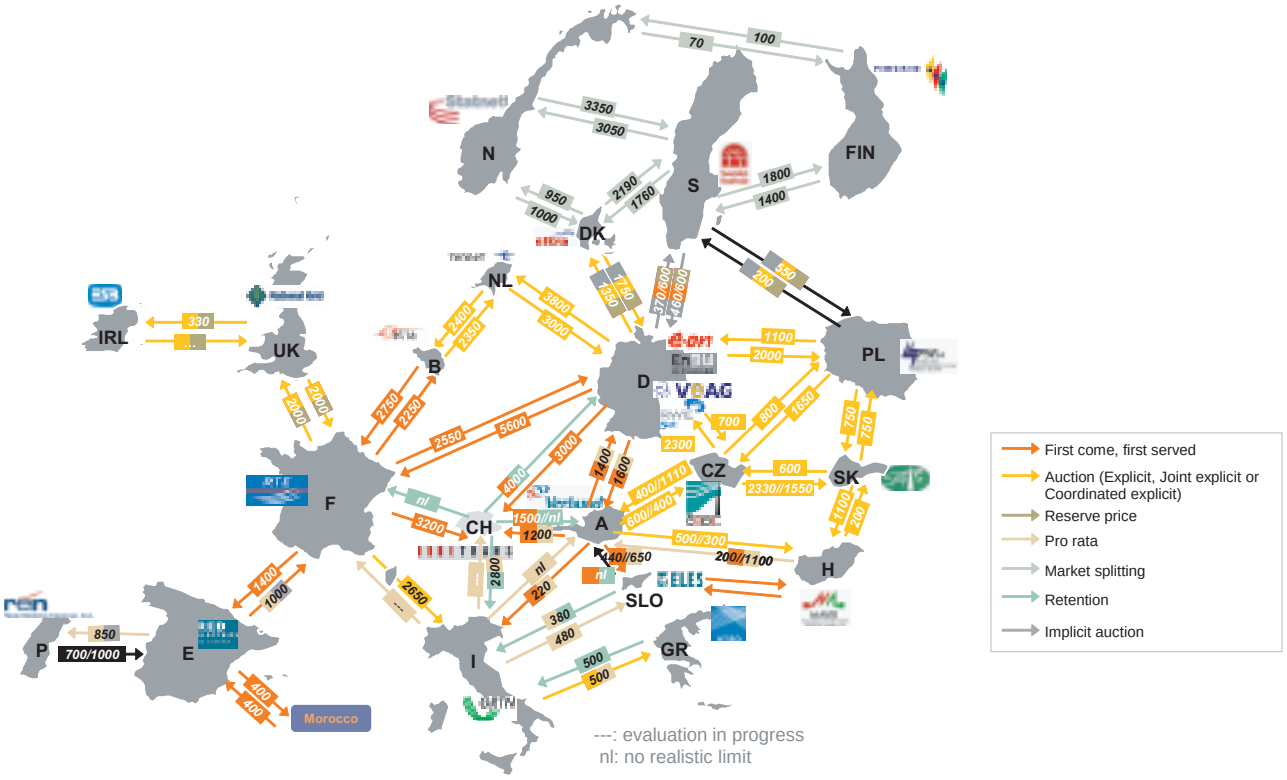
As a result some actions were proposed/agreed:

- Explicit auctions will be introduced to several interconnections to replace methods not compliant with the Regulation 1228/2003, concerning the:

  a. Germany-France border
  b. France-Belgium border
  c. France-Spain border

- Market coupling between France, Belgium and Netherlands to start mid 2005;
- Market splitting in the Iberian electricity market (Portugal–Spain);
- A three-step approach to introduce market coupling to the France–Spain border, which first step was achieved in mid 2005;
- Market coupling between Netherlands and Norway through the Norned cable in 2008;
- Market coupling through the existing Kontek cable (Denmark–Germany).

Table 3.3 Cross-border capacity and access method (Winter 2004–2005)



Explicit Auction

Each market participant offers a price for use of the NTCs. The bids of the participants are stacked, highest bids first, until NTC is completely used. *Often, a "transmission market" clearing price is calculated and each participant pays this. Several methods to fix both the clearing price and the volume of capacity allocated exist. Once the NTC is completely used, either the process is stopped, or there is some re-dispatching, according to the level of the clearing price and the process may go on with the extra trade possibilities.*

Implicit Auction

The transmission capacity is managed implicitly by the spot markets. This means that network users submit purchase or sale bids for energy in the geographical zone where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical power exchange between the market zones.

Reserve price

The auction reserve price refers to the initial price level from which the auction bidding will commence.

Retention

The capacity is reserved for vertical integrated utilities. This applies especially to Switzerland and to all old long term contracts.

First come, first served

The first reservation made for a given period of time has priority over the following reservations. Once the interconnection capacity is reached, the transactions are not accepted by the TSO anymore.

Pro rata rationing

In this case no real "priority" is defined. All transactions are carried out but the TSO curtails them in case of congestion according to the ratio: existing capacity/requested capacity.

Market splitting

This method consists of splitting a power exchange (PEX) into geographical bid areas with limited capacities of exchange; a power pool price is set according to amounts of demand and generation offered in the whole market area. Then the TSO computes a load flow and identifies constrained lines. Geographical areas, composed of one or more bid areas, are defined on either side of the bottlenecks. In each geographical area, a new pool price is defined, flows across areas being limited to he capacity of the interconnection lines. Then each area has its own pool price: areas downstream of a congestion will have a higher pool price, areas upstream of a congestion will have a lower pool price.

Source: ETSO

countries (Russia, Balkan States, Moldavia…);

- As of today, the UCTE synchronous area comprises Morocco (linked by the AC cable with Spain), Algeria and Tunisia. The investigations on further interconnection of Tunisia with Libya (already forming a synchronous block with Egypt, Jordan and Syria) are under way;
- After preparatory steps, studies for the future synchronous interconnection of Turkey will be launched in 2005.

It is worth noting that the UCTE was very active in creating a unique synchronous zone. In a few years, we will probably have a unique frequency from Portugal to Russia and from The Netherlands to the Kingdom of Jordan.

Portugal and Spain are to postpone the launch of a single Iberian energy market (Mibel) for a third time. The start-up scheduled for 1 July 2005 has been postponed indefinitely to allow more time for the harmonization of legislation and an increase in interconnection capacity.

European TSOs' investments on infrastructure

For the first time, this edition of the Observatory analyses the amounts invested by the European TSOs on their networks for the past 3 years.

This report analyses the Investment/Asset ratio extracted from the TSOs' annual reports.

The graph (Table 3.4) illustrates that all the TSOs are in the same range of ratios (around 5%).

Wind impacts on grid management

Integrating the electricity capacities generated by the booming wind power in a reliable electricity system will be very challenging in the next few years for several reasons:

- Unfavourable geographical spread of wind capacities;
- Extensive long-distance electricity transports (offshore wind farms, …), which additionally stress the existing congested regions and can detrimentally influence the secure operation of neighbouring grids;
- Increasing share of intermittent power generation.

The following events were observed during the analysis period:

- During the most part of 2004, and especially during the winter 04/05, high unscheduled flows were observed through the Elia grid from the north to the south, 80% more than in the previous year. These flows originate from the growing number of wind farms in the North of Europe, particularly in Germany and Denmark;
- On 30 December 2004, extremely high power flows from North to South (Northern Germany/Eastern Europe to France/ Switzerland), caused by large wind generation, day-ahead forecast at the interconnection RWE–TenneT could not be maintained for a short period of time.

- It is worth noting a general increase in the past 3 years for most of the TSOs;
- GRTN seems to be lagging behind the other operators;
- In 2003, the TenneT acquisition of the 380 kV and 150 kV network of the regional distributor TZH explains the high increase of the ratio;
- There is no data from Germany since the TSOs are still integrated with the generators.

We will follow this new indicator in future editions of the Observatory in order to track the efforts on grid investments made by the TSOs.

LNG Overview

LNG imports represent a major diversification opportunity in terms of type of gas sources. It represented in 2004 the only access to other non-European fields, giving access to 13 bcm of gas from Nigeria, Oman and Qatar. In 2005, Egypt also began to deliver LNG.

LNG continues to increase its importance to deregulating energy markets with much activity both for infrastructure and supply developments. The reasons for the growth of LNG business are linked primarily to:

- Cost reductions—components of the LNG supply chain, for example, liquefaction costs and tanker construction, have reduced by between 30% and 50% over the past decade;
- The relative ease with which LNG supply can be brought to market—for example, LNG supply can by-pass potential constraints that exist with long distance pipeline capacity, and give access to major gas reserves (Qatar and Iran gas reserves combined excess Russian reserves).

The regulatory treatment of access to LNG infrastructure is also favourable for project investors, with European regulators demonstrating a willingness to grant quite substantial derogations from the requirement to offer TPA terms, e.g. in UK, Italy, France, largely on the basis of the financial viability of the proposed projects.

LNG infrastructure

These factors have led to a current projected growth for LNG terminals in Europe from the current twelve terminals twenty-one terminals by 2010, where the additional nine are all quite well advanced in the development stages, providing an additional 60 bcm of import capacity. If one also considers other potential terminals, and expansion of existing terminals, this adds an additional ten or so facilities and a staggering amount of additional capacity of up to 100 bcm! Hence, as described elsewhere in this report, the potential talk of a gas oversupply or "gas bubble".

This is particularly the case in Italy, where around a dozen LNG projects have been launched, enough to cover the entire Italian consumption. Though, there is no assurance that any will be built. Indeed, local authorities have often in the past cancelled such projects because of strong local opposition. Major relevant developments include:

- An agreement was signed in May 2005 for an offshore LNG plant between partners Edison, ExxonMobil and Qatar Petroleum located in the Adriatic, about 10 miles offshore. Plant capacity will be 8 bcm per year and 80% of the gas will be destined for Edison for a 25 year period;
- Shell and the Italian fuel refiner and marketer ERG has signed an agreement to develop an LNG terminal at Syracuse in Sicily in an area already populated by oil refineries. The terminal is planned to start construction in 2007 with completion in 2010, delivering 8 bcm per year at a project development cost of around €400 million.

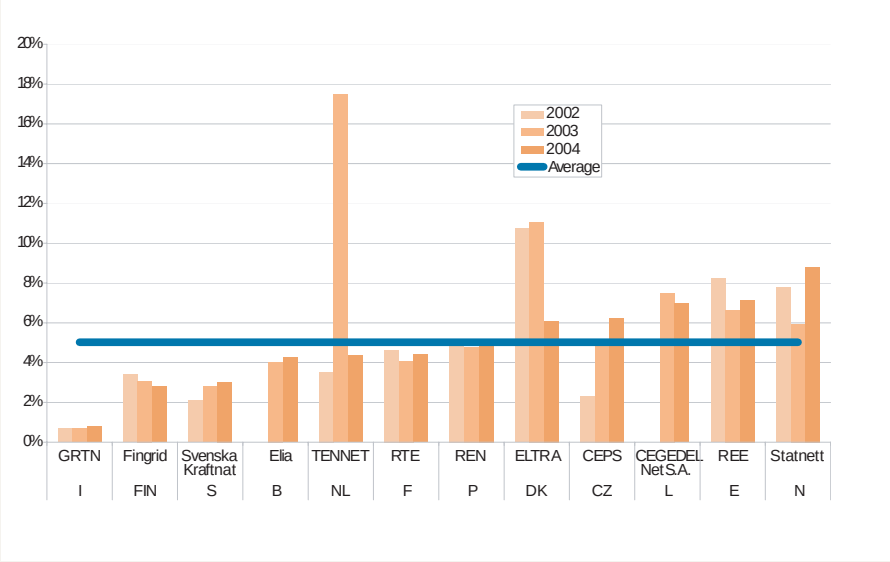
Besides these developments in Italy, in the UK, National Grid Transco announced that it was investing around €500 million in the expansion of its Isle of Grain LNG terminal (east of London) to take the terminal capacity to 15 bcm per year (around 12% of total UK gas demand) —NGT expects the expanded terminal to start operations in 2008, underpinned by 20-year contracts with Centrica, Sonatrach and Gaz de France—the initial phase of the Grain terminal started operation during 2005. It is to be followed in the UK by the huge Milford Haven terminal.

In the South of France, Fos Cavaou's LNG terminal will help reduce constraint in the South of France, where newcomers have to rely on gas release to avoid paying high transmission tariffs. 10% of its capacity will be reserved for third parties, while the bulk of the capacity is to be shared between Gaz de France and Total.

Finally, two rulings concerning LNG terminals are worth noting:

- In Italy, the regulator fined the LNG company GNL, part of the ENI group, at least €50,000 for its refusal to allow Spain's Gas Natural access to the terminal.

Table 3.4 Evolution of European TSOs' investments on grids



Source: Annual reports 2004, Capgemini analysis

GNL had claimed that all the available capacity had been reserved for ENI;

- In Spain, Gas Natural suffered a much greater fine (€8 million) for itself denying access to LNG plants run by Enagas—back in 2001 Gas Natural and Enagas signed a 15-year contract, which the regulator later deemed provided an unjustified level of capacity for Gas Natural—Gas Natural has appealed against the ruling on the basis that the contract was signed before the relevant regulations came into force.

LNG Supply

In relation to LNG supply, major relevant developments include:

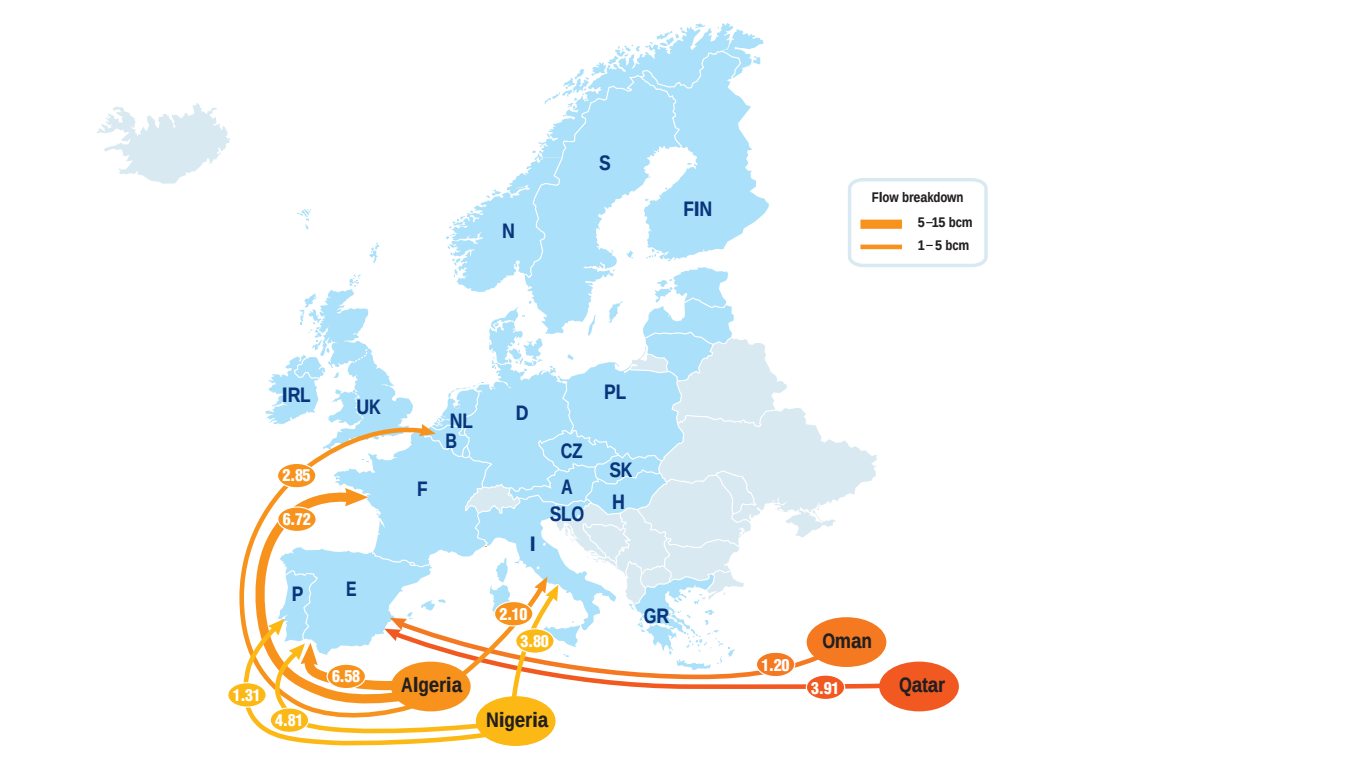
- Qatar announced ambitious plans to be a participant in all the main LNG markets around the world, and is gearing up to export 77 Mt of LNG by 2015—Qatargas is constructing the largest LNG terminal in the world, at an estimated total project cost of around €8.4 billion, in order to support export growth to Europe (among other destinations) where it projects LNG imports will grow from 35 Mt in 2004 to 110 Mt in 2015;
- However, somewhat in contrast to the otherwise positive LNG prospects, the two major gas producers Sonatrach and Gazprom stated that EU regulations and lack of investment could make the European market so unattractive that major suppliers ship their LNG to other markets, because of arbitrage opportunities. Some market commentators interpreted these statements as veiled threats in support of the maintenance of long-term supply contracts, potentially causing supply security problems for Europe.

Contractual gas supply accessibility

No real questioning of long-term contracts occurred in 2004. Several long-term contracts have been signed, like the one between Wingas and Eni, for the delivery of 1.2 bcm at Eynatten, or have been implemented, as the delivery of Egyptian LNG to Gaz de France.

Moreover, if destination clauses are theoretically illegal, most European gas suppliers cannot afford to put their relationship with their major supplier at risk, especially in Eastern or Northern Europe where Gazprom holds a dominant position. The EC has launched a series of probes concerning Gazprom and Sonatrach: it imposed the cancellation of such clauses between Austria's OMV and Gazprom, Gazprom and Rurhgas officially dropped destination clauses, and Sonatrach's contracts in Italy are under investigation.

Table 3.5 Gas flows—LNG (2004) in bcm



Source: BP Statistical Review of WorldEnergy 2005

As these long-term contracts form the basis of durable and secure supply at the national level, national regulators are not so keen on questioning them. They would rather implement gas release programmes, as in France or in Germany, allowing some competition to take place downstream.

This situation implies that newcomers' access to supply remains challenging, especially in areas not covered by hubs or by gas release programs.

Gas infrastructure development

One of the key success factors of gas industry deregulation is whether necessary investments are made attractive enough to investors. As described in the supply part of this report, these investments are directly needed to answer the growth of the demand by developing new production fields and by giving access to these fields. They are also needed to ensure diversified access to several suppliers.

Besides the numerous but uncertain LNG projects, several major pipe infrastructures are coming on line, mainly to cover UK field depletion. First, two projects are due to come on line by 2007: the Langeled pipe coming from the giant Norwegian field of Ormen Lange, and by the BBL pipe allowing importation of continental gas from the Netherlands. Gazprom has a partnership with E.ON Ruhrgas to develop two major infrastructures targeting UK and Northern Europe: the Baltic pipe, and the Yamal 2, a pipe doubling existing transit capacity through Poland.

In Italy, two pipe projects are planned: the Galsi, coming from Algeria, and the upgrading of the TAG pipe, importing Russian gas from Austria.

Eastern Europe represents a particular issue. Currently, Eastern European infrastructure reflects Russian gas dominance. The Nabucco project is trying to offer an alternative, giving access to Caspian Sea resources, and is officially supported by European Community. Its development is the key to the development of a really open market in this area.

Gas Third Party Access comparison—European market scan

Once again, the picture emerging from the developments of gas Third Party Access (Table 3.6) across Europe presents a somewhat mixed outlook. On the positive side, the EC continues to make steady, but perhaps typically pedestrian, progress towards the adoption of legally binding rules for access to gas transmission networks. However, at the same time, a number of industry observers still perceive significant problems with existing arrangements that need to be addressed before meeting the EC objectives of non-discriminatory, transparent and "easy" access to pipelines.

Third Party Access (TPA) developments

Perhaps the key development is the continuing progress towards the position whereby all member states sign up to legally binding rules for access to gas transmission networks. The European Parliament agreed this approach in March 2005, but bizarrely, its implementation was then delayed because Malta, a country with no gas networks, required more time for deliberation. The rules cover the general regulatory requirements for access, including non-discrimination and transparency, together with more detailed requirements such as tariff design, anti-capacity hoarding and secondary capacity trading. The rules are due to be adopted in July 2006.

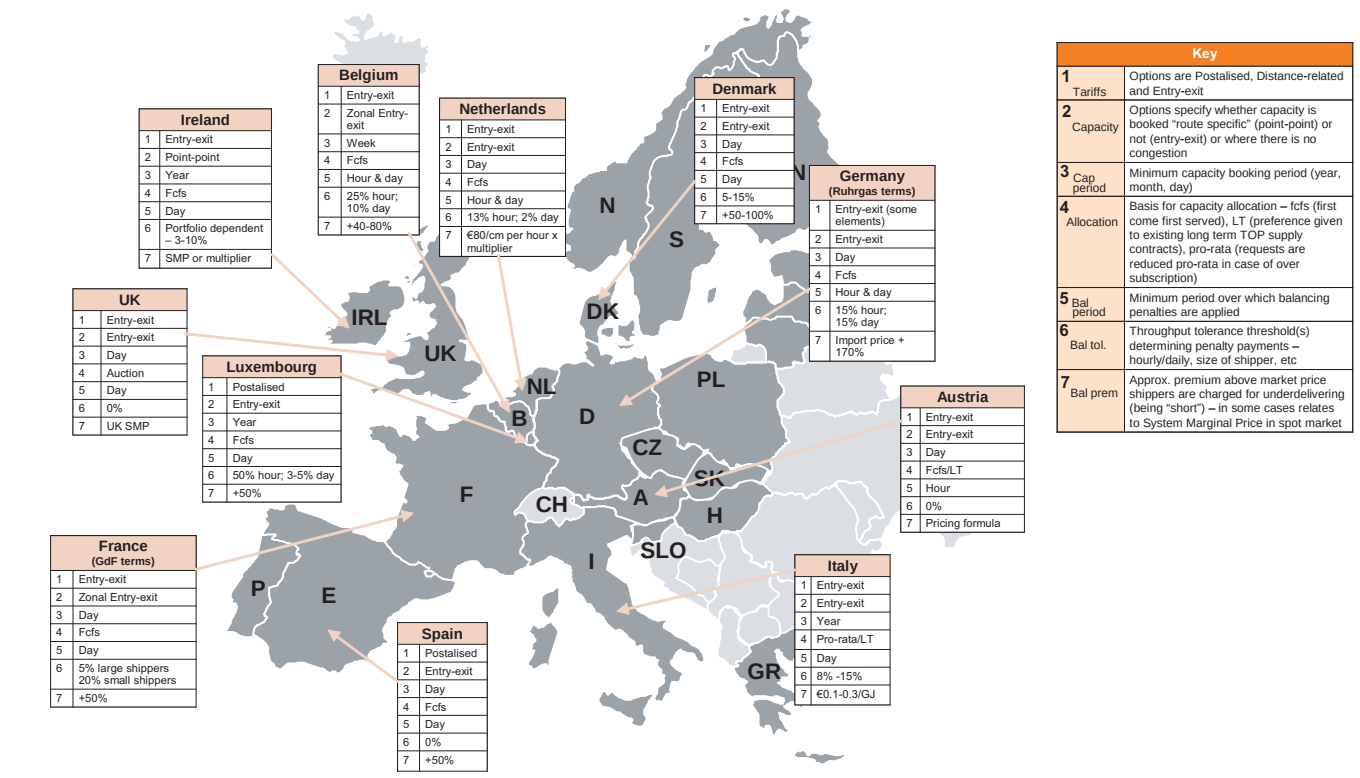
The necessity for such legally binding rules was identified over the last few years as a result of various regulatory and market studies. However, it remains to be seen whether or not the rules, as currently specified, will provide an adequately well-defined solution, or whether, following the transposition into national law, some of the current inadequacies will still remain.

For example, in Germany, a recent draft of the decree on gas grid access was received with some scepticism from industry participants, who claimed that the proposed arrangements were still too complex, and that some of the proposed features would be either very difficult to achieve (response to transport requests within 2 working days) or would result in adverse commercial consequences for gas suppliers (reduction of hourly balancing tolerance from 15% to 10%).

Other recent developments relating to TPA include:

- A recent survey concluded that gas transmission tariffs in the Netherlands, Belgium and the UK were the lowest in Europe. The study further deduced that it was in countries operating entry-exit and zonal charging systems where the cheapest tariffs typically occurred. Ireland and Spain experienced some of the highest transmission tariff levels;
- The UK regulator, Ofgem, confirmed that the proposed UK-Netherlands interconnector, the BBL (Bacton Balgzand Line) pipeline, has been granted an exemption from the requirement to offer access under regulated TPA. This allows the pipeline owners (Gasunie, Fluxys, E.ON) to agree access terms with potential purchasers on a negotiated basis until 2022, or indeed to directly utilise the pipeline capacity themselves;
- Also in the UK, National Grid Transco has reaffirmed that transmission users should indicate their potential longer term demand for transmission entry capacity via auctions to be held later in 2005. NGT is particularly concerned that users should actively engage in the process due to the changing supply and demand patterns developing in the UK, where competing, and conflicting, supply sources, including LNG and pipeline interconnectors, are increasing the uncertainty of NGT's investment programmes;
- In Italy, the regulator AEEG has recently proposed lowering the potential return that gas distribution companies can earn from the current 7.9% to a figure in the range 6.2%–7.1%. This brings Italy more into line with other European countries in this respect, and AEEG stated that it hoped the change would also foster competition in Italy. Interestingly, the AEEG decision was shortly followed by a

Table 3.6 European market scan—Key gas TPA term comparison (2004)



Source: European Commission/Capgemini

ruling by a local Italian court that potentially allows ENI and other gas distribution companies to exceed their regulatory price caps—a decision that was immediately appealed by AEEG and Italian consumer associations.

Transmission System Operator (TSO) models

As European countries gradually implement the legal separation of gas transmission operator from parent supply company as required by the 2003 EC Directive (2003/55/EC), a number of different detailed approaches have been adopted, and issues raised. Examples include:

- In the Netherlands, Gasunie completed the legal unbundling of its transmission operation and its supply business with effect from 1 July 2005. As part of the transaction, the Dutch government bought out the previous 25% shareholdings in the transportation arm each owned by Shell and Exxon, thereby taking 100% ownership of the transmission interests and removing any potential for supply interest bias in the TSO. Shell and Exxon retain their 25% shareholdings in the Gasunie trading company, the remaining 50% being state-owned;
- In Poland, the former subsidiary of the state-owned oil and gas company PGNiG, Gaz-System, has become the new independent gas TSO, and will offer its services to potential new gas market players. Gaz-System will lease all the necessary infrastructure from PGNiG, namely the transmission and storage systems, and a range of transit rights, according to a series of contracts, with the long-term objective of buying the networks;
- In the Czech Republic, RWE Transgas (recently renamed following RWE's 100% takeover) continues to develop options for TSO unbundling in discussion with the regulator—RWE Transgas is targeting the end of 2005 for completion of the process, following a 12-month delay in the approval process for the new Czech energy law;
- In France, the regulator CRE continues to have concerns over the independence of the gas TSO—a position reinforced by Gaz de France's retention of its name in the name for its infrastructure businesses.

Storage

As European gas markets continue to restructure and to implement the EC Directives into national laws, the separation of gas supply from transmission from storage serves to re-emphasise the key role of storage in system balancing. The value of storage is enhanced in most

European gas markets because of the limited supply and demand flexibility e.g. minimal swing on gas purchase contracts and/or minimal demand interruption capability. Indeed, the market with the highest level of historic supply/demand flexibility, the UK, is itself moving towards a position of reduced flexibility, because of the increase of long-distance imports via continental interconnector pipelines.

In recognition of the key role of storage, and the associated value it provides, there has been increasing market and regulatory pressure for storage to be offered on open access terms. This has culminated during 2005 in calls from the gas industry groups Gas Infrastructure Europe (GIE) and Eurogas for the common implementation of the Guidelines for Good Practice for Storage System Operators (GGPSSO), a set of rules covering areas such as necessary storage services, capacity and congestion management and tariff structure. Whilst the guidelines will initially be implemented on a voluntary basis, GIE is proposing to monitor their implementation and report back in around a year's time. There is general agreement that the guidelines will help to encourage a level playing field for users, thereby facilitating competition and, potentially, stimulating market-led investment in storage facilities. Market commentators do, however, recognise that active monitoring will be required to maximise the effectiveness of the implementation.

Other recent developments related to storage include:

- In Italy, the regulator, AEEG, has published a Delibera specifying the key elements of the envisaged TPA storage regime in Italy. The ruling includes requirements in the areas of storage capacity booking priorities, capacity trading and transfer (the latter when downstream customers switch between gas suppliers), and gas trading. AEEG believes that the Delibera will serve to encourage the development of competitive storage services in Italy. However, it notes that structural changes may also be required—for example, complete separation of the near-monopoly storage provider, Stogit, from its parent company ENI;
- In France, following a period of consultation on the TPA terms proposed by Gaz de France and Total, the regulator CRE has asked the operators to make improvements in a number of areas. The regulator's proposals include shorter notice periods for the establishment of new contracts, multi-annual contracts and increased flexibility in the tariff terms on offer. Gaz de France and Total did, however, refute the CRE's claims that their tariffs were above the general level of storage tariffs in Europe;
- In Spain, the regulator CNE recently concluded that gas storage needed to be a key element in the country's developing gas strategy. Spain currently suffers from a scarcity of gas storage resources, with only two gas storage fields, one onshore and one offshore, representing around 45 days of total gas demand. Both these existing facilities have expansion plans, and other storage development projects have been initiated. CNE, however, also has concerns around the behaviour of the country's major gas companies in terms of their use of the storage facilities—this culminated during 2004 when the Spanish government issued a decree requiring companies to keep a minimum quantity (35 days) of their gas sales in the form of storage;
- In Austria, RAG (Rohol-Aufsuchung) has teamed up with Germany's Wingas and Gazprom subsidiary, Gazexport, to develop a major new storage facility at Haidach in Upper Austria. The new facility, built on the same site as the existing Haidach gas field, will comprise 2.4bcm of storage capacity and is due to be commissioned in 2007. Wingas plans to use the facility to provide additional flexibility in managing its supply portfolio, and potentially to supply the spot market.

Gas infrastructure company/ structural changes

In addition to the developments relating to TSO models, as described above, other structural changes continue to occur, primarily influenced by the unbundling requirements as they are translated into national legislation from the 2003 EC Directive. These changes have included the following:

- In Germany, a recent survey of energy supply companies concluded that unbundling was likely to provide the greatest challenge to the industry in the immediate future. The prevailing view was that the unbundling process would be costly and would drive additional industry consolidation, thereby squeezing out smaller suppliers. In particular, the survey concluded that industry unbundling would not lead to lower customer prices;
- In the Netherlands, the government's plans to require network ownership unbundling have already prompted a number of transactions, with NRE and Intergas selling their commercial operations to E.ON and DONG respectively, whilst NRE has also sold a minority interest in its network business to the Infrastructure Fund of the Australian merchant bank Macquarie (buyer of one of National Grid Transco's distribution networks in the UK). The four largest Dutch companies by turnover (Essent, Nuon, Eneco and Delta) have thus far been resisting ownership unbundling on the basis that it will make them more vulnerable to foreign takeover;
- In the UK, the consumer interests body Energywatch has stated that the sale of four of the eight gas distribution networks owned by National Grid Transco will bring little or no short term benefits for gas customers. The networks attracted a 20% sale premium above market value, putting pressure on the buyers to justify the investments. Energywatch believed that any benefits accruing from the sale would be passed on to shareholders rather than customers.

IV Organised Markets

Looking at gas and power exchange development

One key aspect of looking at the development of energy wholesale trading in Europe is the monitoring of the development and maturity of power and gas exchanges, which can be assessed by analysing four main drivers:

- Geographic accessibility and coverage;
- Market horizons and products traded;
- Liquidity of markets;
- Price references in terms of levels and volatility.

Since the last Observatory, market operators have been continuously developing their business both in terms of geographic coverage and range of products. Liquidity on spot markets has developed while forward price references still need to be reinforced. It is also too early to assess how emerging carbon markets will impact energy trading business.

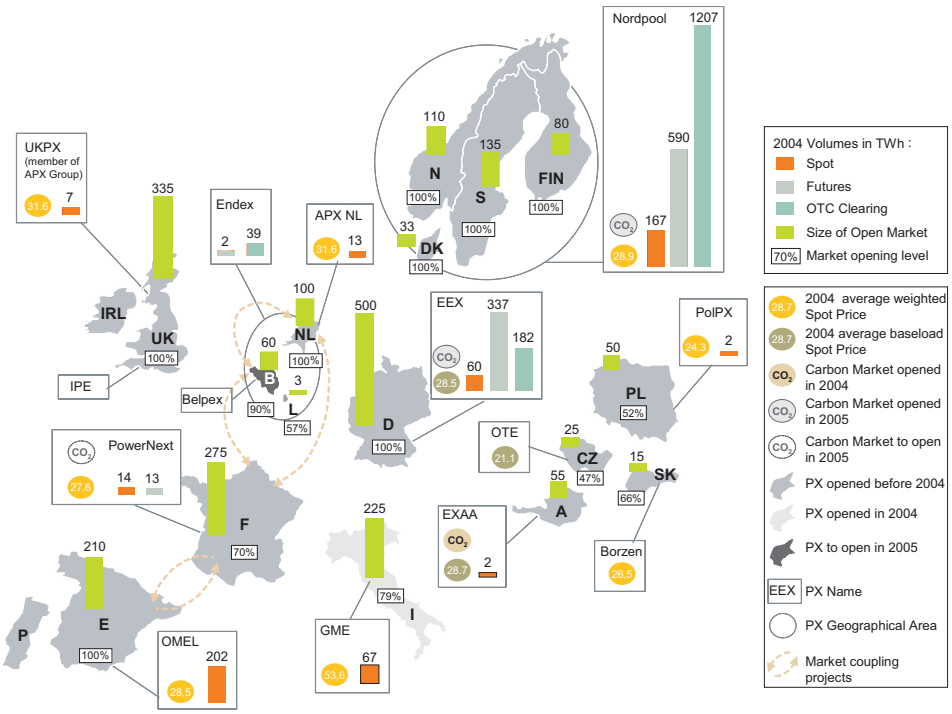
With power exchanges being developed almost everywhere in Europe, market operators are turning on gas exchanges

The mapping of European power exchanges shows that almost every European market is now equipped with a voluntary or mandatory Power Exchange, giving transparent price references to pan-European traders.

Among the fourteen Power Exchanges across Europe, six market operators actually lead the business:

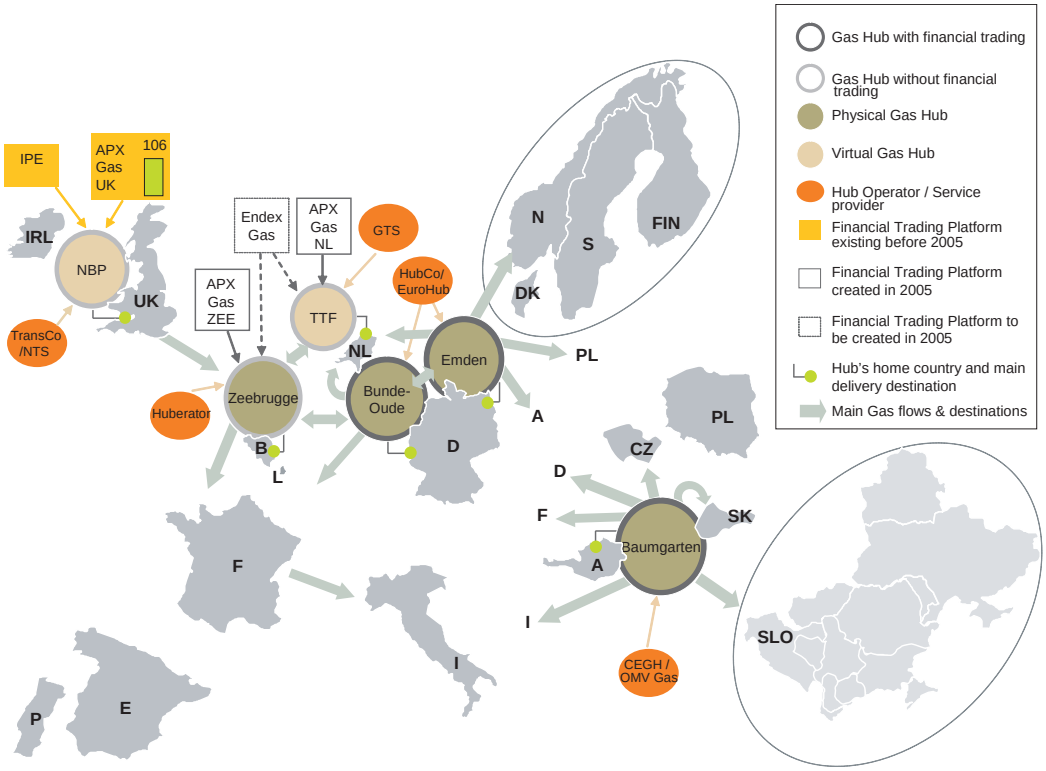
- NordPool, the largest European power exchange, totalling spot and futures contract volumes of 757 TWh, with 364 members, saw a strong start in 2005 with spot volumes keeping pace with the level seen in the record spot year of 2004, financial market surging by 173% and OTC Clearing volumes by 79%;
- EEX, which booked total spot and

Table 4.1 European electricity trading map (2004)



Source: Power exchanges' websites and annual reports 2004, European Commission, Capgemini analysis

Table 4.2 European gas trading map (2004)



Source: Capgemini analysis

futures volumes of 397 TWh in 2004 and increased memberships from 112 in 2003 to 123 in 2004, is looking to expand into Central and Eastern markets. An agreement settled with Austrian Power grid allows for physical power delivery in Austria from mid 2005. In addition, futures markets will be established with the launch of physical futures in early summer 2005, which would also open the door to Eastern markets;

- Spanish OMEL is the third largest power exchange in Europe, leading the spot exchange volumes with 202 TWh in 2004; OMEL only trades spot contracts and all trades must be executed on the mandatory pool. However, 2005 price volatility generated great debate on the robustness of the Spanish market model, which could lead to a complete review of market rules;
- Powernext's spot market is developing despite the weak degree of retail competition in the French market, and it successfully launched its futures market in June 2004;
- APX continued to enhance its UK–Netherlands converging gas and power offering and was directly involved in the establishment of Belpex and in the trilateral Dutch–French–Belgian Day Ahead Market coupling project, which will interconnect the French, Dutch and Belgian Exchanges in early 2006;
- Italian IPEX, launched by GME in 2004, has already established itself as one of the biggest spot markets in Europe with 67 TWh traded in the past year.

Gas trading exchanges are slower to emerge. Despite liberalisation, many former national monopolies have kept a tight grip on their customer base, thereby limiting gas hub liquidity.

Only since Europe's second largest gas market, Germany, has undergone some changes have continental gas exchanges started to expand around the North West hub:

- In February 2005, Dutch APX Group launched two gas exchange platforms with APX Gas ZEE, serving the Zeebrugge Hub (Belgium) and APX Gas NL, serving the TTF (Title Transfer Facility) hub (Netherlands). The two gas exchanges offer Day Ahead Market products and are integrated with the established UK Gas Exchange and APX Gas UK (formerly EnMO), enabling online transactions to be fully cleared and conducted anonymously. In 2004, APX Gas UK handled 106 TWh of spot

trades (up 8% vs. 2003) for over 50 European market parties;

- NordPool is working on a medium-term project of gas exchange in Denmark.

South West Europe is still not equipped with any gas exchange. However, trading on virtual hubs is developing:

- About 60 mcm of natural gas were traded at Italy's fledgling gas hub PSV in its first year of operation from October 2003 to September 2004, with twenty players active at the virtual hub, including gas importers like BP, Spain's Enagas, Belgium's Electrabel, and Switzerland's EGL, as well as a number of Italian energy traders. Liquidity at the PSV remains limited—the 679.5 mcm was equal to less than 1% of demand;
- In Spain, several bilateral physical trades had been concluded between companies at the Centro de Gravedad, a virtual point within the Enagas pipeline system. This could serve as a basis to transform Spain's growing bilateral gas market into a virtual gas hub similar to the UK NBP, but without capacity auctions.

Though market operators offer a wide range of market horizons and products, markets remain short term and physical

- Most increases in trading are limited to physical and short-term markets in Europe;
- Progress in Futures markets is encouraging but faces important challenges. Powernext launched futures products in June 2004—in April 2005, total trades reached 9 TWh for the month that is 182% superior to the previous record of November 2004. NordPool's futures volumes were up 8% in 2004 vs. 2003, while EEX's futures volumes remained stable;
- Meanwhile, OTC clearing is developing. It is the leading activity of NordPool in terms of volumes. Endex OTC clearing volumes also surged in 2004 (up 361%) with a total of 22 TWh of electricity cleared at the beginning of 2005.

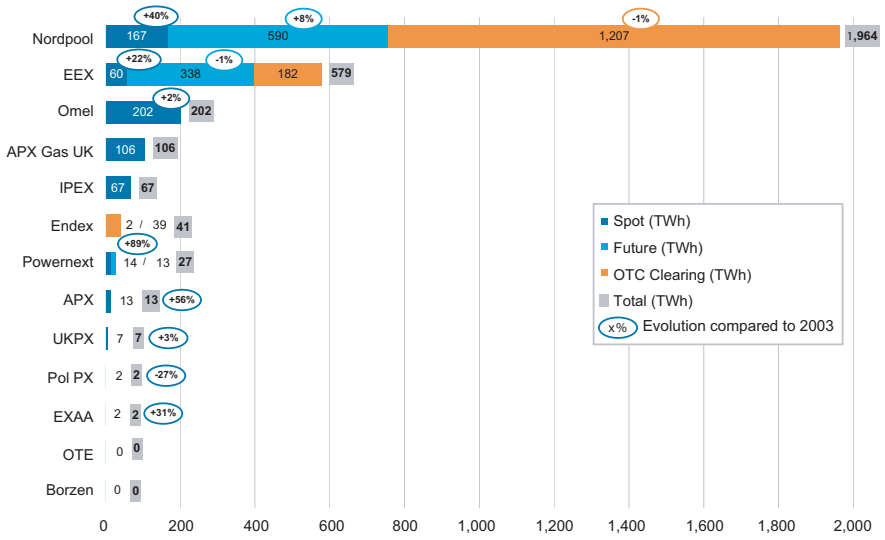
Alliances among power exchanges and diversification in gas and carbon markets are meeting the requirements for improved liquidity, achieving cost synergies and developing additional sources of revenue:

- In Germany, the merger of the neighbouring gas hubs on the Netherlands-Germany border—Dutch Gas Transport Services (GTS), owned by Eurohub, and German gas hub Hubco—led a number of firms to deal on the northwest European gas trading hub, increasing it to thirty firms including BP (BP.L), Centrica, EnBW (EBKG.DE), RWE's (RWEG.DE), Total Gas & Power, VNG and Wingas, Merrill Lynch, Essent, etc;
- APX launched two gas exchanges in close cooperation with Belgian and Dutch Gas Transmission System Operators: Fluxys and Gas Transport Services (GTS). In Belgium, APX Gas Zee is owned by APX Group and Huberator, the Zeebrugge hub operator and a subsidiary of Fluxys. APX Gas Zee provides a trading platform and clearing, while Huberator facilitates physical deliveries. In the Netherlands, APX and GTS signed an agreement in which GTS will support and facilitate APX Gas NL on the TTF hub;
- The carbon business is seen as very promising. After NordPool, European Climate Exchange (ECX), and German European Energy Exchange (EEX), Austrian Energy Exchange (EXAA) and Powernext launched their CO_2 market in June 2005. As carbon competition intensifies, volumes on the emissions markets are growing rapidly. From May to June 2005, volumes on both the ECX—whose contracts are traded on the IPE—and NordPool more than doubled. Strong volatility in this market is attracting many new players and gives a healthy boost to liquidity.

Liquidity on spot is improving almost everywhere

West European Power Exchanges have experienced significant day-ahead volume growth, with the French Powernext exchange leading the way with a 90% spot volume increase in 2004 vs. 2003 and +56% in winter 2004/2005 vs. winter 2003/2004.

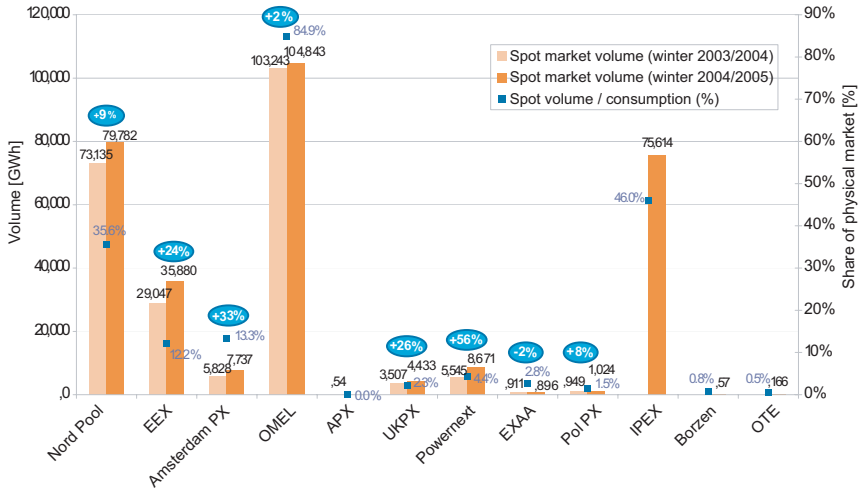
Table 4.3 Volumes on gas and electricity exchanges (2004)



Source: Power exchanges' websites and annual reports 2004

- NordPool increased the volume of transactions by 9% in 2004, compared to 2003, to be set at 590 TWh;
- APX recorded +12% in 2004 with a record number of exchanges, to 1.2 TWh in December; on the last day of the year, for deliveries on 1 January 2005, the market recorded its highest number of exchanges since 2002, with 55,000 GWh. UKPX recorded volumes of exchanges of 7.14 TWh, a rise of 3% over 2003. For gas, the APX Gas (ex-EnMO) traded 106 TWh, an increase of 8% over 2003. APX's traded volume was, for its three markets, around 126 TWh in 2004;
- On Powernext, trading was concentrated on the short term, with a new monthly record reaching a daily average above 44 GWh.
- European trading integration is in progress with several market coupling projects being initiated. The creation of a regional France-Belgian-Dutch day-ahead power market is being developed for an early 2006 launch. APX and Powernext take a 10% stake each in Belpex. Dutch system operator TenneT and French RTE may take 10% stakes themselves, leaving Belpex 60% owned by Elia, the Belgian system operator. Powernext is also planning to launch in early 2006 a day-ahead market coupling mechanism with OMEL, which would lead to the creation of a regional Spain-France power exchange market;
- In the meantime, OTC spot trading in Belgium showed increased liquidity due to the combined effect of VPP and alignment with the German, French and Dutch markets in the Day Ahead Market. In Italy, power traders greeted the opening of Italy's new power market as they can complete the positions already taken in the UK, France, Germany and Spain.

Table 4.4 Spot market volumes (October 2004–March 2005)

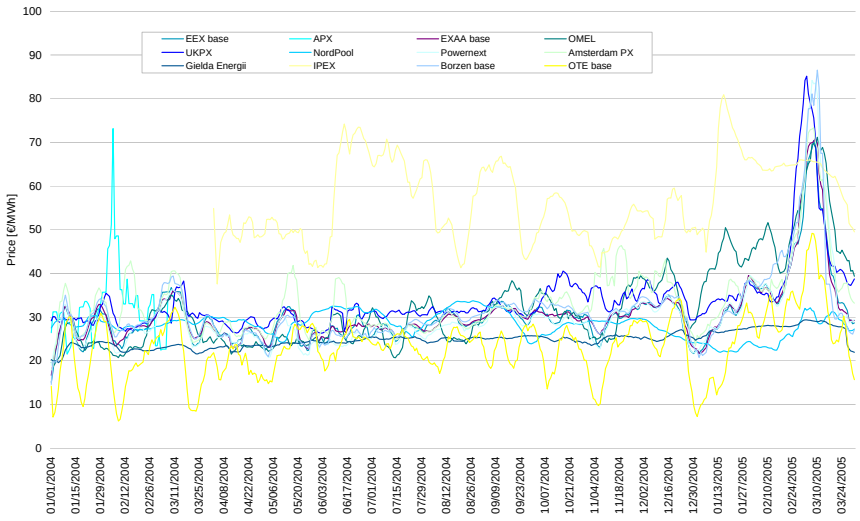


Source: Power exchanges' websites

Prices are converging around €30/MWh for most developed exchange, increasing for others

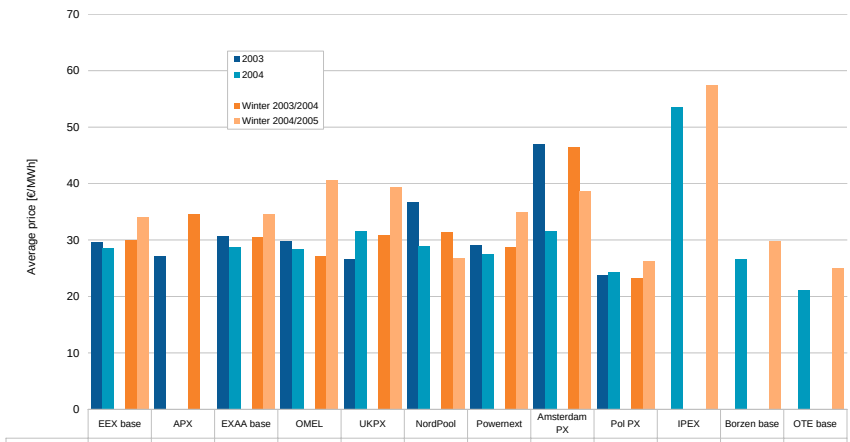
- Apart from the traditional price spikes in February–March period, northern markets saw a convergence of wholesale prices at around €30/MWh in bilateral markets and standardized power exchanges in 2004. NordPool's average price was €28.92/MWh in 2004, against €36.69/MWh into 2003; and APX's average price in base was €31.57/MWh, against €46.47/MWh in 2003. Forward markets show that price increases are likely with prices for baseload for 2005 significantly exceeding €30/MWh;
- Powernext spot prices declined on average in 2004 vs. 2003 but rose in winter periods;
- The Italian Exchange (GME) recorded for its first day of activity a value of €55/MWh, which is close to double the prices recorded on the European exchanges for the same day, reflecting the transalpine average price—one of the highest in Europe;
- The Spanish pool showed itself to be very volatile and irregular in 2004 and 2005. After having declined in 2004 to reach their lowest level for 5 years, prices have soared by 70% since the beginning of 2005 giving a spectacular hike year, with prices rising to €73.1/MWh. Though these figures are still far from the historical record reached in 2002, certain analysts believe that the current upward trend should be maintained and relates to an already high average for January and February of €45/MWh;
- Though volatility and liquidity became notable during summer 2004 as if the market were reacting to the excesses of the summer 2003, it is interesting to note that price variances have decreased on all exchanges when comparing 2004 with 2003—except for APX and the newly created IPEX, which experienced exceptional price variations;
- If it is difficult to explain this trend in particular, there is at least one question that everybody has in mind: what will be the impact of CO_2 markets on power markets? If it is too early to answer, a quick overview of CO_2 developments underline the dynamism of these newly created markets.

Table 4.5 Market prices (January 2004–March 2005) Average over a period of 7 days, Average weighted price except when specified



Source: Power exchanges' websites

Table 4.6 Average price evolution—Average weighted price except when specified



	EEX base	APX	EXAA base	OMEL	UKPX	NordPool	Powernext	Amsterdam PX	Pol PX	IPEX	Borzen base	OTE base
2003	29.57	27.20	30.74	29.72	26.54	36.69	29.02	46.90	23.74			
2004	28.52		28.71	28.46	31.56	28.92	27.60	31.57	24.28	53.57	26.54	21.11
Winter 2003/2004	30.01	34.53	30.59	27.24	30.93	31.39	28.77	46.43	23.30			
Winter 2004/2005	34.04		34.50	40.63	39.32	26.77	34.88	38.69	26.25	57.52	29.84	24.98

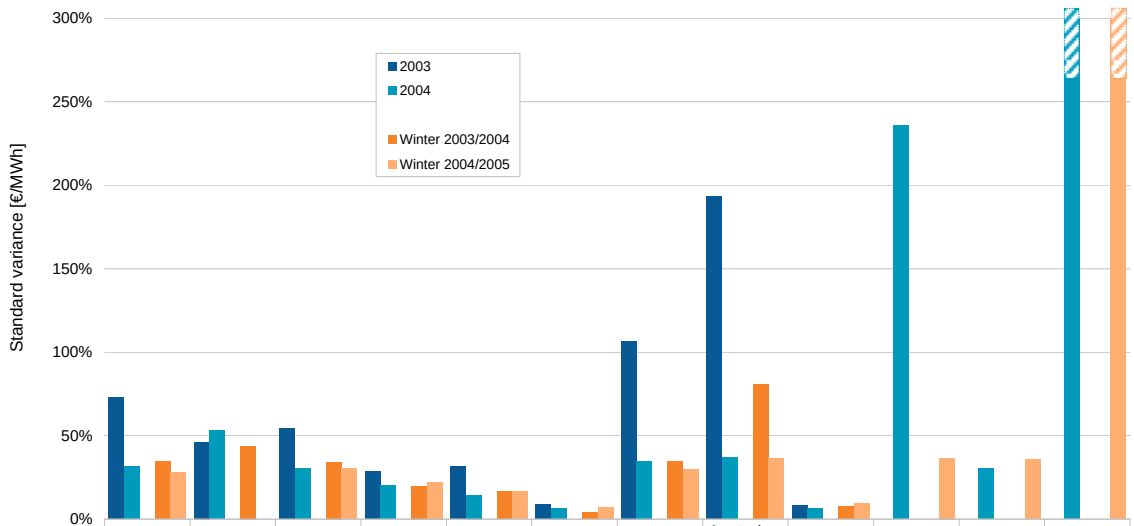
Source: Power exchanges' websites

Focus on the newly created CO_2 markets

Powernext Carbon launched in June 2005. There were eight trades done, for a total of 32,000 tonnes, with a low price of €23.20 ($28.04) a tonne, a high price of €23.45 and a closing price at €23.20. Nine companies started trading Powernext Carbon: Accord Energy, Carbon Capital Markets, Endesa Trading, Electrabel, Gaselys, Greenstream Network, Societe Generale, SNET and Total Gas & Power. Electrabel acted as a quotation provider, displaying firm bid and ask quotes, with the aim of enhancing liquidity to provide a reliable and transparent price reference.

As for Austrian Energy Exchange (EXAA) launched in June 2005, the price for the emissions certificates was €23.95 a tonne, which was in line with the prices at other European exchanges (€23.99 at Paris-based Powernext and €23.85 at Germany's EEX). Eight companies traded 7,500 tonnes of EUAs between them at the auction. Swiss company EGL was the market-maker, while the other energy-company first movers were Energie Handelsgesellschaft, Steweag-Steg, Tiroler Wasserkraft and Verbund. Even end-users took part, including industrials Tondach Gleinstätten and D Swarovski & Co, as did Etech Management Consulting. EXAA will hold the auction every Tuesday and believes the number of emissions-trading participants will increase to at least 30 within two years. The exchange expects a total turnover of 200,000 tonnes of certificates to be traded in 2005.

Table 4.7 Price variance on spot markets—Average weighted price except when specified



	EEX base	APX	EXAA base	OMEL	UKPX	NordPool	Powernext	Amsterdam PX	Pol PX	IPEX	Borzen base	OTE base
2003	73%	46%	54%	29%	31%	9%	107%	193%	8%			
2004	32%	53%	30%	20%	14%	7%	35%	37%	6%	236%	30%	2,777%
Winter 2003/2004	35%	44%	34%	20%	16%	4%	35%	81%	7%			
Winter 2004/2005	28%		30%	22%	17%	7%	30%	36%	10%	37%	36%	1,823%

Source: Power exchanges' websites

CO_2 market dynamics in Europe

In 2003, some companies started engaging in demonstration trades of spot and forward European Union Allowances (EUAs) in anticipation of the implementation of the EU ETS. All such transactions were forward trades. The volume traded has increased steadily, from an estimated 650,000 tCO_2 in 2003 to about 9 $MtCO_2$ in 2004. Since January 2005, the formal start of the EU ETS, trading volumes and price volatility vastly increased: the volume exchanged on the market reached an estimated 34 $MtCO_2$ in the first 3 months of 2005.

According to Point Carbon, more than 70 $MtCO_2$ were exchanged between January 2005 and August 2005 for €900 million. The majority of the transactions took place via brokers (62.5 Mt), with the organized markets only starting to emerge.

Prices of EUAs in over-the counter transactions and on the various trading platforms appear to be quasi-identical, with only very small spreads. It is thus possible to speak of a unique marketplace for EUAs.

Price variation over time has been very important. As has been widely reported, the price of EU Allowances has increased from about €7–9 in 2004 to record levels over €20 in June 2005. At the time of writing, EUAs were trading at about €18.8/tCO_2 (Point Carbon, 24/07/05).

According to the International Emission Trading Association (IETA), current prices may still not be representative of the supply/demand equilibrium. Only a limited number of companies from a very small number of countries (essentially the UK, Germany, France, Belgium, and the Netherlands) have participated so far in the market. There has been very limited participation of entities from Eastern European Member States, where the bulk of the supply is expected to come from.

V Financial Performance and Players' Strategy[5]

Table 5.1 Analysed electricity and gas companies

Market dynamics and financial performance

This new part of the Observatory examines the measures taken by the leading European energy utility companies to adapt to market deregulation and reviews their financial performance. Data is analysed for the top eleven companies in the sector ranked by 2004 revenues.

For both historical and regulatory reasons, the number and size of listed electricity and gas suppliers varies sharply from one country to another. Certain European states, such as France, Belgium, Sweden, Finland and Italy, boast national champions. In others, a limited number of players share the market between them (Spain, Germany and the UK), while the market remains highly fragmented in places such as Switzerland, the Netherlands, certain Nordic states and most countries in eastern Europe.

The time period is 2004, but in some cases transactions made during the first half of 2005 are also included.

Structure of the energy market

Description of energy markets

Over the past 15 years or so, the European Union has encouraged its members to deregulate and privatise their electricity and gas markets.

Under this pressure, the value chain has altered and become more complex, as major players are now involved both in production and futures markets, and in the wholesale and retail segments.

Regulated markets and their respective weightings

The UK, which has been one of the leading advocates of deregulation, initially obliged electricity and gas companies to restrict themselves to certain segments of the value chain (production or distribution/sales). Unbundling was taken a step further with the legal separation of distribution and sales. Some players have remained focused on one of these segments (i.e. British Energy), but a certain rethink of the industry landscape has seen the emergence of companies involved in both regulated and deregulated activities. A number of national champions, like EDF and Gaz de France, have remained active over the whole of the value chain, while beginning to hive off their regulated businesses to subsidiaries in order to meet EU regulations.

Having operations in both deregulated and regulated markets enables companies to achieve a better balance of risks. For the industry leaders, network operations contribute on average 40% of operating income generated in historic markets, albeit with some notable exceptions:

The main points of transmission & distribution regulations in Europe are fairly similar, with price caps, fixed by the relevant regulatory authorities for reference periods. The regulated rates take account of acceptable financial return on existing assets and new investments, along

5 This section was written in collaboration with Société Générale Equity Research

Table 5.2 Top European energy utility companies by decreasing order of revenues (2004)

	Revenues (€m)	% electricity	% gas	% other	No. of customers (m)	Historic market (% revenues)	Installed capacity (MW)	% installed capacity in nuclear
E.ON	49,130	64%	35%	1%	34.0	61%	44,283	14%
EDF	46,928	95%	0%	5%	42.0	63%	125,447	50%
RWE	42,137	66%	17%	18%	102.0	55%	34,957	18%
Enel	36,489	76%	2%	22%	31.9	95%	42,000	0%
Centrica	26,905	5%	45%	50%	17.7	90%	2,910	0%
Gaz de France	18,474	1%	86%	13%	12.4	92%	748	0%
Endesa	18,065	98%	2%	0%	22.0	63%	18,995	19%
Vattenfall	12,586	89%	0%	11%	5.8	36%	47,061	17%
Electrabel	12,148	65%	17%	18%	5.0	60%	28,193	24%
Scottish Power	10,068	100%	0%	0%	5.8	54%	15,720	0%
Scottish & Southern	7,532	88%	0%	12%	6.0	100%	5,700	0%

Source: SG Equity Research/Capgemini

with annual price reduction formulae to encourage companies to generate productivity gains and enable clients to benefit from the most attractive tariffs.

The implementation of these points does, however, differ from one country to another. Table 5.5 provides a comparison of the main features of existing regulations as well as the rates of return accepted by regulators in each market.

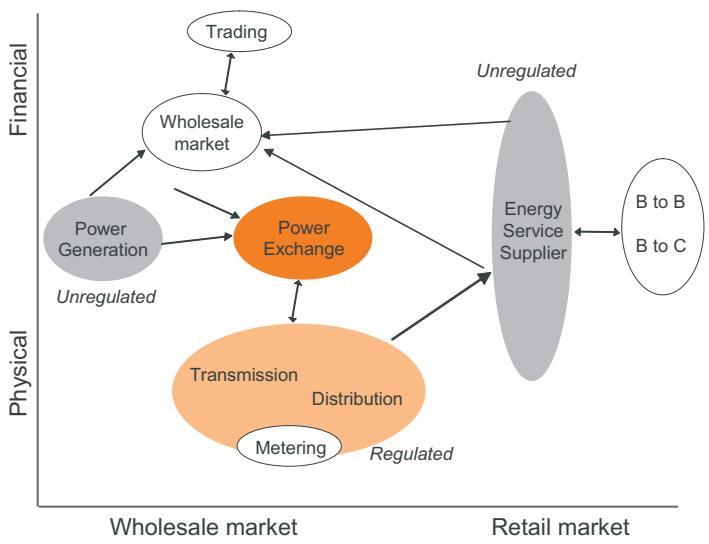
Operating profitability

Strong improvement in operating income (+10% p.a. in 2002–04)

Energy utility company operating margins have increased in recent years under the combined impact of:

- Refocusing on core businesses;
- The search for internal growth, implying growing revenues at constant structures and employee numbers;
- Substantial cost savings in recent years, including from the merger of operating units and improved processes: a €2.6bn programme introduced by RWE management in 2000; €2bn at E.ON; €600m at Suez in 2003-2004; €7.5m at EDF);
- Price increases, notably in the wholesale markets in recent months, which are enabling a significant improvement in margins;
- A slowing pace of maintenance investment since the early 1990s (7% of 2004 sales vs. 10% in 1999).

Table 5.3 Disaggregation of the energy value chain



Source: Capgemini

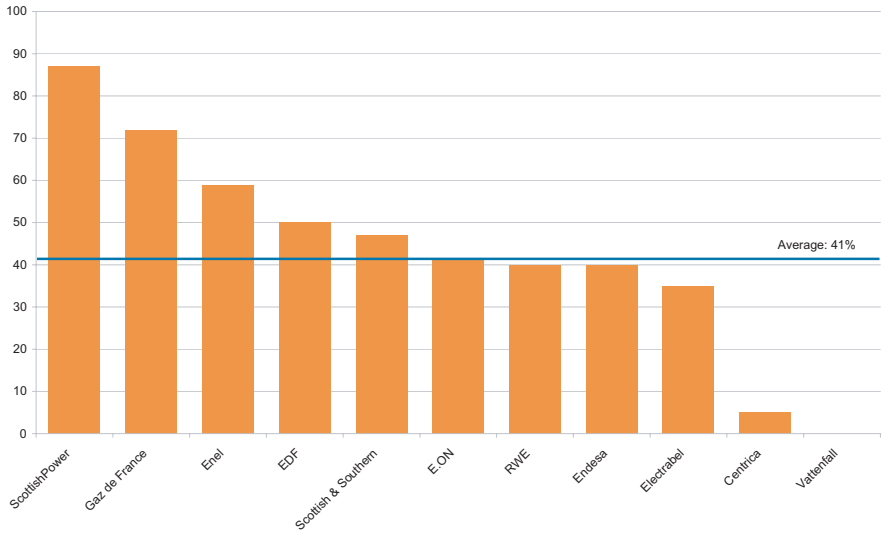
Operating margins by company

The average EBITDA (earnings before interest, taxes, depreciation and amortisation) margin for the eleven companies in the sample is 22%. Stripping out the gas producers Gaz de France and Centrica gives a margin of 23%. The EBIT margin is 14%, and 15% excluding Gaz de France and Centrica.

The most profitable companies are Enel (29% EBITDA margin), Vattenfall (28%), Endesa (27%) and EDF (26%).

A number of companies have room to improve margins by cutting costs. For example, savings in personnel costs could be achieved through increased efficiency and improved management of the age pyramid.

Table 5.4 Regulated markets contribution to operating income as a % (2004)



Source: SG Equity Research/Capgemini

Note that comparisons are slightly distorted by the use of different accounting rules. The application of IFRS rules by all the energy utility companies from 2005 should eliminate this bias.

High capital intensity

The utilities sector is capital intensive with a sales-to-assets ratio of 0.7. This reflects the high level of investment required in electricity (generation, transportation and distribution), gas (transportation and distribution), water services (treatment and supply) and waste management (incineration).

The changing pattern of demand and increasingly stringent environmental protection standards are prompting changes in production methods. This is leading to the discontinuation of the least environmentally friendly processes and to tighter landscaping restrictions on energy transportation infrastructures, implying the use of higher cost alternative solutions.

Table 5.5 Return on assets and regulatory periods by country and industry market (as of July 2005)

Country	Sector	Regulator	Current regulatory period	Rate of return
UK	Electricity Gas	Ofgem Ofgem	April 2005 – March 2010 (distribution) April 2005 – March 2007 (transportation) From April 2007	Real rate of return on assets of 4.8% after tax
	Water	Ofwat	April 2005 – March 2010	Real rate of return on assets of 5.1% after tax
France	Electricity	CRE	No fixed regulatory period	Not indicated (in process of approval by government)
	Gas	CRE	No fixed regulatory period	Real rate of return on assets of 7.75% after tax for transportation and distribution
Germany	Electricity	RegTPE	No fixed regulatory period	Real rate of return on equity of 6.5% before tax
	Gas	RegTPE	No fixed regulatory period	Real rate of return on equity of 7.8 % before tax
Spain	Electricity	CNE	Jan. 2003–Dec.2006	Real rate of return on equity of 6.5% before tax
	Gas	CNE	Feb. 2002 – Dec. 2005	Real rate of return on equity of 6.5% before tax
Italy	Electricity	AEG	Jan. 2004 – Dec. 2007	Real rate of return on assets of 6.8% before tax for distribution, 6.7% for transportation
	Gas	AEG	Oct 2001 – Sept. 2005	Real rate of return on assets of 7.94% before tax

Source: SG Equity Research/Capgemini

Table 5.6 Key operating data by company, ranked by decreasing EBITDA margin (2004)

(€m)	2004 sales	No. of employees	Personnel costs (% sales)	EBITDA 2004	*EBITDA margin*	EBIT 2004	*EBIT margin*	Comment
Enel	37,512	61,898	8.8%	11,010	29%	6,325	17%	
Vattenfall	12,586	33,017	15.1%	3,486	28%	2,177	17%	
Endesa	18,065	26,985	7.1%	4,937	27%	3,242	18%	
EDF	46,928	156,152	20.4%	12,127	26%	5,648	12%	French Gaap
Scottish Power	10,068	16,142	11.1%	2,470	25%	1,760	17%	Net losses in 2004/2005
Gaz de France	17,760	38,251	12.5%	4,214	24%	2,235	13%	IFRS
E.ON	49,103	69,170	9.6%	10,520	21%	7,361	15%	US Gaap
RWE	42,137	106,130	14.5%	8,400	20%	5,127	12%	IFRS
Electrabel	12,148	16,585	11.5%	2,192	18%	1,376	11%	Local GAAP
Scottish & Southern En.	7,532	9,560	5.6%	1,216	16%	947	13%	
Centrica	26,905	43,414	7.2%	2,467	9%	1,704	6%	No production operations
Average			11.2%		22%		13%	

Source: SG Equity Research/Capgemini

Valuation

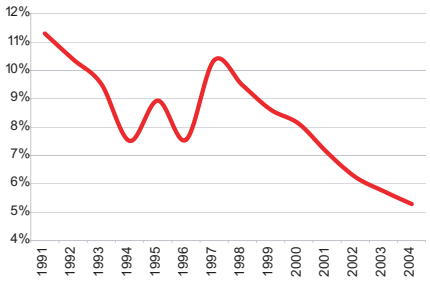
Sector performance over 10 years

European utilities stocks have made up the ground lost both during the technology bubble in 1998–1999 and in 2003 when diversified utilities were rocked by the Enron crisis. The worst hit by the Enron affair were highly indebted companies and companies most exposed to emerging markets and therefore to exchange risks.

Utilities have outperformed from 2000 YTD. The first 2 years of outperformance can be explained by the decline in the premium awarded to tech stocks. More recently, however, the performance of utilities stocks has reflected improved fundamentals.

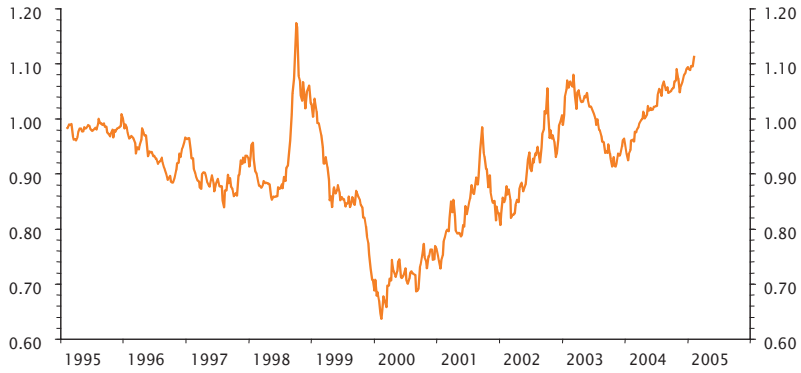
Markets feared that the effect of progressive deregulation would be to weaken the ability of the utilities to negotiate prices and to intensify competition. In practice,

Table 5.7 Capital expenditure as a % of sales



Source: SG Equity Research/Capgemini

Table 5.8 Utilities sector compared with the European equity index



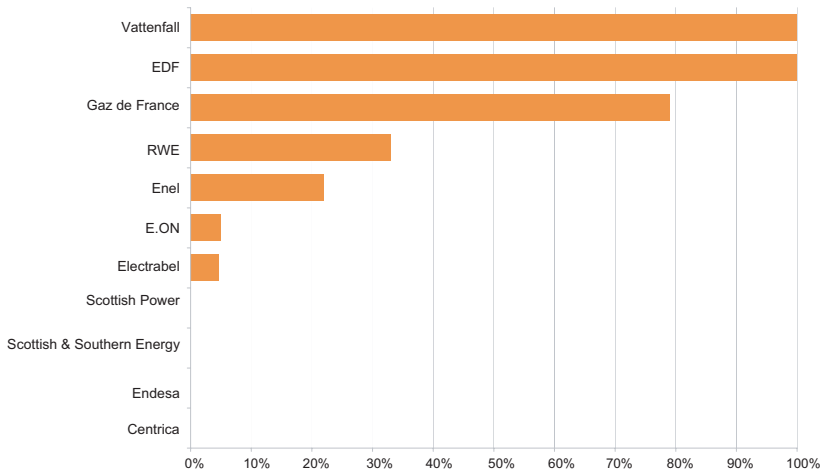
Source: SG Equity Research/Capgemini

Table 5.9 Stock market performance and valuation, by alphabetical order (2004)

	Share price (1 Sept. 05)	Market cap	12-mth absol. perf	12-mth rel. perf.	2004 P/E	Market cap/sales	2004 yield
Centrica (£)	249.75	9.3	12.8	-7.5	13.1	0.51	3.5%
E.ON	77.35	53.5	32.7	12.4	13.2	1.09	3.0%
Electrabel	412.2	22.6	49.3	29.0	26.8	1.86	2.9%
Endesa	18.3	19.4	20.2	-0.1	12.3	1.07	4.0%
Enel	7.19	44.2	13.2	-7.1	15.6	1.18	5.0%
Gaz de France	27.1	26.7	-4.9	-25.2	17.1	1.50	1.7%
RWE	54.18	28.4	34.6	14.3	14.3	0.67	2.8%
Scottish & Southern Energy (£)	986.00	8.4	33.8	13.5	18.7	1.65	3.8%
Scottish Power (£)	501.50	9.3	24.7	4.4	14,2	1.35	4.1%
Average			24.0	3.7	16	1.21	3.4%

Source: SG Equity Research/Capgemini

Table 5.10 State ownership of energy utility companies (as of July 2005)



Source: SG Equity Research / Capgemini * Municipal companies holdings

after a number of companies exited the sector, an oligopolistic market emerged and companies regained control of prices by eliminating excess capacity and passing increases in raw material prices onto customers.

The increase in raw material costs, along with the rise in environmental expenditure, linked to the new legislation on CO2 emission rights, has made the sector less defensive.

Nevertheless, these hikes have resulted in earnings growth, as most groups have managed to pass on the increase in input costs to end-users. Buoyed by low interest rates, the sector has even managed to outperform rising markets.

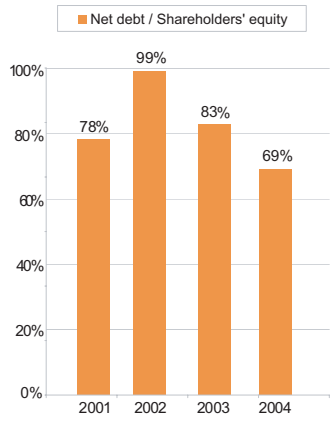
Share performance

The 2005 price earnings ratio (PE) for the utilities sector is currently 13.6x (14.8x for the companies reviewed in Table 5.9).

The companies with significantly higher than average PE ratios are:

- Electrabel (PE of 26.8x 2004), owing to Suez's offer to buy out the company's minority interests owing to the company's strategic relevance;
- Scottish & Southern Energy (PE of 18.7x 2004), which enjoys strong positions in its domestic market;
- Gaz de France, where a strong focus on gas concessions make it a solid investment for the long term.

Table 5.11 Net debt as % of equity



Source: SG Equity Research/Capgemini

Table 5.12 Financial flexibility, assuming 100% gearing at end 2004

Company	Shareholders' equity (€bn)	Gearing	War chest
E.ON	37.7	15%	32.2
Electrabel	7.0	0%	7.0
Gaz de France	10.9	40%	6.5
Centrica	3.8	0%	3.8
Vattenfall	7.8	77%	1.8
Scottish & South Energy	2.5	82%	0.5
Scottish Power	5.9	103%	-0.2
RWE	11.2	111%	-1.2
EDF	18.5	107%	-1.2
Endesa	15.2	109%	-1.3
ENEL	20.4	119%	-3.9

Source: SG Equity Research/Capgemini

Mergers and acquisitions provide respite

Acquisitions undertaken at the end of the 1990s, including the mergers of RWE/VEW, Veba/Viag (a €38bn deal for former E.ON) and Suez/Lyonnaise des Eaux/SGB/Tractebel, resulted in a sharp increase in debt in the utilities sector, to nearly 2x shareholders equity at the end of the 1990s. These transactions form the backbone of the European energy industry as it exists today.

Since the beginning of the decade, we have seen complete overhauls (and restructuring) of sector companies involving over €100bn. This process covered a variety of moves.

1 **Disposals of non-strategic businesses,** i.e. not directly linked to electricity and gas businesses. Since the beginning of 2005, we registered €30bn of assets sold, of which:

- Pacificorp (US) by Scottish Power for €4bn, in May;
- Edenor in Argentina by EDF in June;
- Enel's telecoms subsidiary Wind for €12.4bn, in July;
- Endesa's telecoms subsidiary Auna for €2.1m, in July;
- E.ON's real estate subsidiary Viterra for €7bn, in August;
- The sale of Argentina' Edenor by EDF in June.

2 **Business consolidation** in the form of Suez's buyout of Electrabel minority interests for €11.2bn

3 **Acquisitions in core businesses or enlargement of activity** (geographical development and commodities trading) outside historical markets. We can note, as an example, the entry of UK's operator Centrica and French' Gaz de France into Belgium electricity producer SPE.

4 **Further reductions in government shareholdings.** More than €9bn worth of IPOs (including €4.5bn in July from the Gaz de France initial public offering) and stock market placements (including Electrabel's placement of shares in Belgian transmission system operator Elia for €0.5bn in June and the placement of a further tranche of Enel shares for €4bn, also in June).

Where to now?

The US Energy Bill, coupled with the end of the rules established by the 1978 Public Utilities Regulatory Policy Act, should give rise to a new M&A cycle in the industry in the US.

In Europe, balance sheet strengthening appears to be laying the foundations for possible industry consolidation over the coming months and years.

Only a handful of companies are positioned to benefit from any consolidation of the European energy market.

E.ON has some €30bn with which to go on the offensive. Any such move on its part would likely trigger a wave of mergers and acquisitions, with key participants likely to be Electrabel, Gaz de France and Centrica.

Glossary

Base load
The minimum amount of electricity delivered or required over a given period, at a constant rate.

Bilateral contracts
A contractual system between a buyer and a seller agreed directly without using a third party (exchanges, etc.).

Black Certificates
Exchangeable or tradable CO_2 allowances or quotas within the European Trading Scheme and Kyoto protocol (see EUA).

CHP
Combined Heat and Power.

Clearing
Administrative and financial settlement of a contract.

Clearing house
Organisation that clears contracts on behalf of contractual parties. Generally a service offered by exchanges or banks.

Cogeneration
Using heat (steam) produced by a natural gas-fired power plant to produce even more electricity or heating. In essence, cogeneration produces energy (electricity or heat) from two sources. While electric production may be somewhat less, more energy from the fuel reaches users (as steam or electricity) than is the case with a boiler or turbine designed to produce only electricity.

Combined cycle
A process in a power plant that produces steam from otherwise lost heat. This heat is routed to a conventional boiler or heat-recovery system generator for use by a steam turbine to produce additional electricity (see also cogeneration).

Decentralised generation
High efficiency production of electricity near the point of use, irrespective of size and technology, capacity and energy sources.

Demand-side management
Any effort aimed at getting customers to use less energy.

Distributed generation
Any technology that provides electricity closer to an end-user's site, like a home or business. It may involve a small on-site generating plant or fuel cell technology.

EBIT
Earnings Before Interest and Taxes.

EBITDA
Earnings Before Interest, Taxes, Depreciation and Amortization.

ETS
Emissions Trading Scheme. The European regulatory frame for greenhouse gases management. It is focused on the main power and industrial sites of each country. It encompasses only CO_2 emissions for the first phase.

ETSO
European Transmission System Operators.

EUA
European Allowances. The official name for the CO_2 allowance units distributed through the NAP (within the ETS).

Forwards
A forward is a commodity bought and sold for delivery at some specific time in the future. It is differentiated from futures by the fact that a forward contract is customized, non exchange traded, and a non-regulated hedging mechanism.

Future
Tradable contract for supply at a given moment in the future, whereby the clearing is done via a clearing house.

Green Certificate
A Guarantee of Origin certificate associated to renewables targets fixed by national governments. Green Certificates are often tradable.

Greenhouse effect
The warming of the atmosphere caused by the build up of 'greenhouse' gases, which allow sunlight to heat the earth while absorbing the infrared radiation returning to space, preventing the heat from escaping. Excessive human emissions including carbon dioxide, methane and other gases contribute to climate change.

Guarantee of Origin
A certificate stating a volume of electricity that was generated from renewable sources. In this way the quality of the electricity is decoupled from the actual physical volume. It can be used within feed-in tariffs or Green Certificate systems.

Installed capacity
The installed capacity represents the maximum potential net generating capacity of electric utility companies and auto-producers in the countries concerned.

IPE
The International Petroleum Exchange.

Kyoto Protocol
The United Nations regulatory frame for greenhouse gases management. It encompasses 6 greenhouse gases: CO_2, CH4, N2O, HFC, PFC, SF6.

Market coupling
Market coupling links together separate markets in a region, whereas market splitting divides a regional market into prices zones. Market coupling minimises prices differences and makes them converging wherever transmission capacity is sufficient. Cross-border market coupling also drives better use of interconnection capacity.

Market splitting
See Market coupling.

LNG
Liquid Natural Gas.

NAP
National Allocation Plan. List of selected industrial and power installations with their specific emissions allowance for the first phase. NAPs must be submitted to the European Commission approval (within the ETS).

NBP
National Balancing Point.

Nordel
Organisation for Nordic power co-operation.

NTC
Net Transfer Capacity. NTC is the expected maximal electrical generation power that can be transported through the tie lines of two systems without any bottlenecks appearing in any system, taking some uncertainties of the future network state into account.

Off peak
Off-peak energy is the electric energy supplied during periods of relatively low system demands as specified by the supplier.

On peak
On-peak energy is electric energy supplied during periods of relatively high system demand as specified by the supplier.

OTC
Over The Counter, bilateral markets.

PE
Price Earning ratio.

Peak load
The highest electrical level of demand within a particular period of time.

Peak shaving
Reduction of peak demand for natural gas or electricity.

Remaining capacity at peak load
This value is obtained by deducting the system services reserve, outages, overhauls and non usable capacity from the installed capacity and is compared with the peak load. Yearly values are an average of monthly remaining capacity at peak load.

RES
Renewable Energy Sources. Energy (electricity or heat) produced using wind, sun, wood, biomass, hydro and geothermal. Their exploitation generates little or no waste or pollutant emissions.

Spot contract
Short-term contract, generally a day ahead.

Switching
The process whereby a customer moves from an existing energy supplier to a new one.

Take-or-pay contract
Contract whereby the agreed consumption has to be paid for, irrespective of whether the consumption has actually taken place.

Theoretical capacity margin
This value is obtained by deducting the peak load from the installed capacity.

TPA
Third Party Access.

TSO
Transmission System Operator (High Voltage distribution network).

UCTE
Union for the Co-ordination of Transmission of Electricity. European organisation of network co-ordination gathering network operators.

UK-DTI
Abbreviation designating the British Ministry of Trade and Industry.

White Certificate
A certificate stating a volume of engaged energy savings (electricity, gas, fuel, …) at end-users' site, like a home or a business. They are tradable or not.

Country Abbreviation	Country Name	Regulator	TSO	Power Exchange
A	Austria	E-Control (Energie-Control GmbH)	Verbund	EXAA
B	Belgium	CREG (Commission pour la Régulation de l'Electricité et du Gaz)	ELIA	Belpex
CH	Switzerland	Etrans		
CZ	Czech Republic	ERO (Regulatory Office)	CEPS	OTE
D	Germany	BNetzA (Bundesnetzagentur–Federal Network Agency for Electricity, Gas, Telecommunications, Posts and Railway	EEX	
DK	Denmark	DERA (Danish Energy Regulatory Authority)	Eltra	Nordpool
E	Spain	CNE (Comisión Nacional de Energía)	REE	Omel
F	France	CRE (Commission de Régulation de l'Energie)	RTE	Powernext
FIN	Finland	EMV (Energiamarkkinavirasto–Energy Market Authority)	Fingrid	Nordpool
GR	Greece	RAE (Regulatory Authority for Energy)	HTSO	
H	Hungary	HEO (Hungarian Energy Office)	MAVIR	
I	Italy	AEEG (Autorità per l'Energia Elettrica e il Gas)	GRTN	GME/IPEX
IRL	Ireland	CER (Commission for Electricity Regulation)	ESB	IIPEX
L	Luxembourg	ILR (Institut Luxembourgeois de Régulation)		
N	Norway	NVE (Norges vassdrags–og energidirektorat– Norwegian Water Resources and Energy Directorate)	Statnett	Nordpool
NL	Netherlands	Dte (Dienst uitvoering en toezicht Energie– Office of Energy Regulation)	TenneT	APX
P	Portugal	ERSE (Entidade Reguladora dos Serviços Energéticos)	REN	
PL	Poland	ERO (The Energy Regulatory Office)	PSE	PolPX
S	Sweden	STEM (Swedish Energy Agency)	Svenska Krafnät	Nordpool
SLO	Slovenia	Energy Agency of the Republic of Slovenia	ELES	
SK	Slovakia	RONI (Regulatory Office for Network Industries)	SEPS	Borzen
UK	United Kingdom	Ofgem (Office of Gas and Electricity Markets)	NGT	UKPX

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