VATTENFALL'S VIEWS ON THE ELECTRICITY MARKET 2006

VATTENFALL

Contents

Exchange rates
Closing day rates 30 sept 2006
1 EUR = 9.4300 SEK
1 PLN = 2.4400 SEK
1 SEK = 0.1060 EUR

Preface

For the fifth consecutive year, we at Vattenfall present our views on the electricity markets in Germany, Poland and the Nordic region. The aim is, as always, to provide a broad description of the main features of these markets and place them into a European context.

We believe that our best contribution to building trust in the market is by being open about our beliefs and sharing our knowledge and understanding of the present state of our home markets, the trends on the internal electricity market in Europe and how we view its development. Our hope is that by doing so, we can improve the understanding of the electricity markets in a wider audience and contribute to building a good basis for reasonable expectations.

The 2006 report is slightly different than previous versions. Instead of using our understanding of which the most important issues are that we wish to share with our readers, we have used questions frequently asked as a basis for selecting which issues to include in the report. As a result, you will find many of the headings formulated in the format of a question. In doing so, we hope that we will be able to address the issues from the perspective of a concerned and interested electricity customer, wishing to understand more about the electricity markets. Previous reports (2002-2005) can be downloaded from Vattenfall's website www.vattenfall.com.

A broad team has worked together to compile this report, consisting of Vattenfall staff in several different countries, across group functions and business units. Arthur D. Little has supported us in this effort. Arne Mogren has had the overall responsibility for this report.

Stockholm, December 2006

Lars G. Josefsson
President and Chief Executive Officer
Vattenfall AB

Background and Summary

The European energy markets are changing rapidly, and in several different dimensions. At the consumer end, the most visible changes are those in electricity price levels. But the underlying effects which influence the electricity markets cannot be sought in a single dimension, which is why it can be difficult to explain what is going on in the markets by looking at a single aspect. In response to this, Vattenfall has in this year's report tried to answer some fundamental questions about the electricity market and how it is developing. The questions have been summarised into six chapters, each discussing different aspects of market development. Where relevant, we have indicated our own views on the subjects covered, as well as those held by others. Liberalisation is this time considered in a historic context, and with regard to subjects currently in the public debate. Electricity prices are discussed in terms of the major driving forces that influence their movements. You will find information not only about electricity, but also about other energy forms. Climate policies and their impact on shifting out fossil fired electricity and bringing in renewables are described. We also consider the need for new capacity, whether investments are sufficient, as well as what new technologies will be available and when to meet growing energy needs.

The interested reader will not fail to notice that Vattenfall has some strong beliefs about how we would prefer to see the European energy markets develop in the coming years:

- Vattenfall encourages full implementation of liberalisation and integration of the EU energy markets and looks forward to increased competition and transparency

- Vattenfall agrees that development of regional markets as an intermediate step towards an integrated EU-wide electricity market is the right way forward

- Vattenfall favours increased harmonization of retail markets, so that competition increases at the consumer end too

- Vattenfall is working to find solutions for how to successfully combat global climate change and is investing in renewable energies in our core markets to contribute to the development of a sustainable, low carbon emitting society

Chapter 1: Is competition and liberalisation working as intended?

Why was the electricity market liberalised? Who initiated the change?
European electricity markets are being liberalised to improve efficiency, avoid costly surplus capacity and create an efficient pricing mechanism. This development began in the 1980s and has continued ever since, at different paces in different countries.

The old monopoly markets had created a costly surplus since the electricity industry could build new capacity without having to consider how to recover the investment on the marginal plant. The investment cost was simply passed on to customers together with all other costs. Planning of new capacity in many countries was a central task performed by policy makers, striving to meet not only energy-political needs but also social, environmental and employment objectives. Producers of electricity carried little risk. There were few incentives to improve efficiency or cost-effectiveness. Employees in distribution were up to four times as many as they are in efficiently run operations today. This system worked well as long as the electricity industry was in a build up phase, but from an economic point of view, once the infrastructure was largely in place, it became inefficient.

In Europe, electricity market reform was at first thought of by economic advisors to the UK government who were able to demonstrate the inefficiency that existed in the electricity sector. The response from the UK government was to split up and restructure the electricity sector, privatise the different parts, and introduce a competitive market design. After the reform, electricity prices fell and remained low for a long time.

In Scandinavia, the Norwegian government was first to adopt the idea of liberalisation, creating a spot market for power in Norway. Sweden followed shortly after. The first step in Sweden was taken in 1992 when Vattenfall was incorporated and the transmission grid was separated into a special entity, Svenska Kraftnät.

Market concentration was recognised to be a problem in each of the Nordic electricity sectors. There were simply not enough players around to create a competitive market, and each country had a dominant incumbent (Vattenfall in Sweden and Statkraft in Norway). The solution was to create a regional market with Nordpool as the first and so far only regional power exchange in Europe. As a consequence, no Nordic market player today has a market share larger than 25 % (Vattenfall 23 %, Fortum 12 %, Statkraft 11 %, E.On Sweden 8 %, Elsam/DONG 5 %, Others 41 %). Today, discussions in Europe focus on how to create efficient regional markets in order to reduce market concentration and increase liquidity. In a European and international context, the Nordic market is often referred to as a good example for how to achieve that.

Figure 1: Electricity supply in a historical perspective

Are high electricity prices caused by liberalisation?
Why has the reform not resulted in lower prices?

Liberalisation itself does not cause neither high nor low prices as such. What liberalisation does is to set free the market forces of supply and demand, thus creating a price setting mechanism reflecting the true value of the commodity. If there is too little supply in relation to demand, prices will be high. If there is too much supply, prices will be low. In this way, producers receive signals from the market that capacity is in short or long supply, which gives them incentives either to build more capacity or take excess capacity out of operation.

After the reform, prices in most wholesale markets for electricity fell dramatically. In the Nordic countries, prices initially rose because of low reservoir levels, only to fall in the subsequent year when there was abundance of water. In those countries where consumers were able to switch suppliers, their prices fell too. Only the largest industrial consumers, which had special contracts with very low prices in most European countries, may have seen their prices remain flat. Some countries took the opportunity and raised electricity taxes as prices fell, so that the end-user price level was maintained or even increased.

The fact that prices have subsequently risen in all European markets is a result of the fact that the costs of producing power in the price-setting plants have risen. In a competitive market where suppliers have different variable costs of production, and low cost production resources are scarce and cannot be replicated easily, existing capacity will be utilised in order of variable cost. This makes good economic sense, as it minimises the total cost of electricity generation. Generators will produce electricity only if the market price meets at least their variable cost, otherwise, their plant will stand idle. Often, in both the Nordic and EEX market, it is coal-fired or gas-fired plant that is the last to be utilised to meet demand. The cost of running this capacity has risen because of higher fuel prices and the added cost of CO_2 allowances. To run it, producers require higher market prices. This will be explained in detail in later chapters.

What is happening with respect to liberalisation in different countries? What are the main issues being discussed? [1]

Liberalisation of the European natural gas and electricity markets is progressing in all Member States, but at different paces. In 2007, full compliance with the EU Directives must have been achieved in all Member States and full market opening introduced in all segments. In its 2005 progress report [1], the Commission concluded that the lack of integration between national markets is a principal shortcoming. As indicators for this, it notes the absence of price convergence across the EU and the low level of cross-border trade. This is due to the existence of barriers to entry, inadequate use of existing infrastructure and – in the case of electricity – insufficient interconnection between Member States. Many markets display a high degree of concentration, impeding the development of competition.

The focus is now on creating regional electricity markets as an intermediate step towards a fully integrated, pan-European power market. Vattenfall fully supports this effort, based primarily on its experiences in the Nordic market, and well aware of the advantages it would bring in other core markets. At the heart of this matter are issues such as

- Increasing physical interconnection
- Improving transparency to create market trust
- Coordination of transmission system operators
- A more efficient regulatory process in addition to national mandates and properly empowered national regulators

As noted by Paul Bulteel, head of the industry association EURELECTRIC in a recent interview [2], the electricity industry itself will be a major driving force behind regional markets. Companies realize it is not in their interest to be stuck between regulated and liberalized markets, and are also aware of the criticism that competition in the sector needs to be accelerated. Vattenfall fully agrees with this.

European Commissioner Nellie Kroes indicated recently that ambitious actions are being planned to speed up the pace of liberalisation in both electricity and gas. Key proposals are to focus on transparency and further unbundling of network and supply activities. Stronger regulation will ensure that sufficient and relevant market information is available both for authorities and market participants to act upon.

[1] Communication from the Commission to the Council and the European Parliament: Report on progress in creating the internal gas and electricity market [SEC(2005) 1448]

[2] Platts Power In Europe 2006-10-09

What is the purpose of an electricity exchange? How does it work?
Exchanges are a key part of the liberalised electricity market. Prior to liberalisation, electricity trading was bilateral and bundled. Only small customers (households and small commercial customers) bought their electricity on tariffs, which were published and in that sense, perfectly transparent. Industrial customers bought electricity on contracts, where the terms were kept confidential. Because the sale of electricity was bundled with balancing and distribution services, it was very difficult to know what the underlying costs were in each part of the value chain, and whether the electricity company was efficient in its operations or not. In short, there was no cost transparency, and it was accepted practice that some customers had tariffs which exceeded underlying actual costs, while others were subsidised (so-called cross-subsidisation), if they bought very large volumes or had very flat offtake profiles. The reasons why this was considered acceptable were many, including national policy objectives such as supporting the competitiveness of domestic industries. Cross-subsidisation is not permitted in the liberalised power markets, since it would defeat the free market pricing mechanism.

Today, power is traded on an open market where prices are fully transparent, and buyers and sellers anonymous. This means that buyers and sellers are acting on market information rather than on knowledge about individual players and their positions. That builds trust in the exchange as a fair market, so that more and more players will use it, trading larger and larger volumes, building market depth (number of active participants) and liquidity (volumes traded in individual products). In parallel to the electricity exchanges, brokers have established an alternative market place referred to as the OTC (over-the-counter) market. Their trading platforms have similar characteristics as the exchange and it is in practice not possible to arbitrage between these two markets.

Bilateral trading is used as a complement, for example when large customers want very long term contracts (a product which is not traded on the exchange because liquidity is too low – there are too few deals in a year to guarantee anonymity). But more and more power generators, including Vattenfall and most recently RWE, use the exchange for selling most or even all of their power output. In this way, transparency is internalised, since the retail part of the company has to buy its power requirements on the exchange too.

Nordpool is the common power exchange of the Nordic market. EEX is the German power exchange, headquartered in Leipzig. In Poland, the name of the power exchange is Towarowa Gielda Energii (Polish Power Exchange). APX is the exchange of the Dutch market. The UK exchange is called APX Power UK – part of the same group as APX. The French exchange is called Powernext. Very recently, a new exchange opened in Belgium (Belpex), integrating the Dutch, French and Belgian markets. In the future, it is foreseeable that energy exchanges will be increasingly interlinked, some may even merge. Vattenfall sees advantages if one power exchange could evolve in each regional market, and eventually, one common European power exchange for the Integrated European energy market.

Most exchanges offer a physical day ahead (spot) market. It is called "day-ahead" because generators and buyers have to place their bids one day in advance, normally at noon (12.00 am), for delivery the next day. Some have a financial futures and options market too, which is used to hedge future prices, i.e. lock in a particular price today for a volume of power to be sold or bought in the future. There are variations in the products offered and clearing mechanisms used, but the underlying market principles are very similar. Liquidity and the number of participants vary. Some exchanges trade power which is also traded on other exchanges. Nordpool has had an intraday market for some time. The intraday market allows market participants to adjust and close their positions close to the hour of operation. Only very recently, both Nordpool and EEX launched intraday trading in Germany, as did APX in the Netherlands. Exchanges can also trade in green certificates (where relevant) and in CO_2 allowances.

Today, most exchanges operate in the same way, that is to say based on generators bidding in generation which is picked up by buyers in an anonymous auction. This means that capacity will be made available in order of marginal cost, as more and more capacity needs to be brought on line in order to meet incremental demand in a particular hour of consumption. Nordpool and Belpex are the only regional exchanges, the others are national. This is probably one reason why liquidity is still low on many exchanges compared to Nordpool. Only EEX in Germany has a liquidity that is comparable.

Chapter 2: What factors influence the electricity price?

What are the main driving forces in different energy markets?
What is the role of the Emissions Trading Scheme (ETS)? Are prices reasonable?
What will happen to prices in future?
In recent years, electricity prices in Europe have risen to unprecedented levels. Many consumers, large and small, are concerned about this development. Claims have been made that the ETS, in combination with high fossil fuel prices, is largely to blame for this development.

The main driving forces for the price of electricity are those of supply and demand, which in turn are influenced by all factors that either have an impact on the costs of production (supply), or the willingness to pay (demand). In a competitive market where suppliers have different costs because the underlying production resources required meeting demand are not the same for all producers, prices are more likely to reflect marginal rather than average cost, especially when capacity is scarce. If they did not, there would be no incentive to invest.

The role of the ETS is to reduce CO_2 by making it more expensive to produce electricity from fossil fired sources than from sources that do not emit CO_2. Because of the influence on short-term production costs, there is also an impact on price. Whether prices are reasonable or not is a question that can only be answered in relation to the political motives behind the introduction of the measures aiming at supporting renewables via market mechanisms and providing incentives for increasing energy efficiency.

As electricity prices are formed by supply and demand, the main driving forces are the availability of generation capacity and the total level of consumption. Competition between producers ensures that the market price reflects the variable cost of the last plant required to meet demand (short term marginal cost).

Short-term marginal costs only cover the cost of operating the plant and not the cost of the capital invested in the plant. In many cases, operating costs are exposed to factors that can change very quickly, such as fuel prices and the price of emission allowances. This is why short-term electricity prices can vary dramatically, even during the course of a day.

Physical connections between different interlinked geographical markets also play a role, as they can be used for exports and imports. Those connections are very important for smoothing out supply and demand balances, thus equalising prices between markets.

The ETS was introduced in the EU as a means of controlling CO_2 emissions. The ETS mechanism is not a device which by itself reduces emissions. Instead, it sets the maximum acceptable level of emissions. That level is then meant to be gradually reduced.

Figure 2: The European Merit Order and impact of a €20/ton CO_2 price according to the IEA

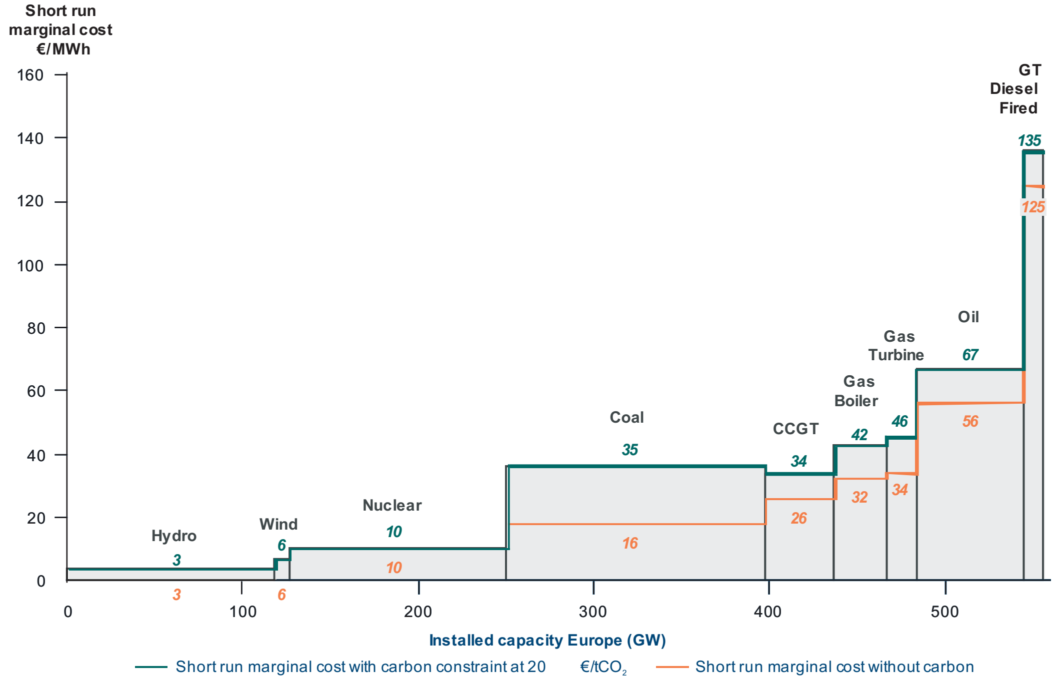


Figure 2 shows the European merit order or power plants, according to the IEA (in the Nordic market, wind power enters the merit order before hydro, because of lower operating cost). In Germany, wind power enters the market at a price of zero because of a guranteed feed-in tariff. Plants are typically taken into operation in order of short run marginal cost, i.e. the variable cost of running the plant. This cost does not include capital costs.

As can be seen in the diagram, coal fired plants are dispatched before gas fired CCGTs in the merit order if CO_2 costs are not included in the variable costs. This is because the cost of gas is higher than the cost of coal per kWh produced. However, with a CO_2 allowance cost of 20 €/ton, the order is reversed: gas fired electricity in the assumed price scenario becomes cheaper to produce than coal fired electricity.

All plants which emit carbon dioxide need emission allowances to produce electricity. If they wish to emit more than they are allowed to, they need to purchase allowances on the ETS market. When many producers want to purchase allowances at the same time, the price for emission allowances (also called CO_2 price) goes up. When it is unattractive to use fossil fuels to produce electricity, producers sell their allowances instead, and the CO_2 price falls. Since it is often the fossil fuelled plants that set the price in the electricity market, the ETS has had a great impact on electricity prices all over Europe. Vattenfall warned that this would happen before the ETS was introduced, and that the effect would become more pronounced with a rising CO_2 price.

Support systems for renewable electricity have been introduced in several EU countries. These support systems will bring new capacity with low operating costs into the market, and push the more expensive fossil fuel fired capacity (i.e. capacity with the highest variable cost) out of the system. This may have a lowering effect on electricity prices, provided that it does not delay other investments in new large scale generation capacity.

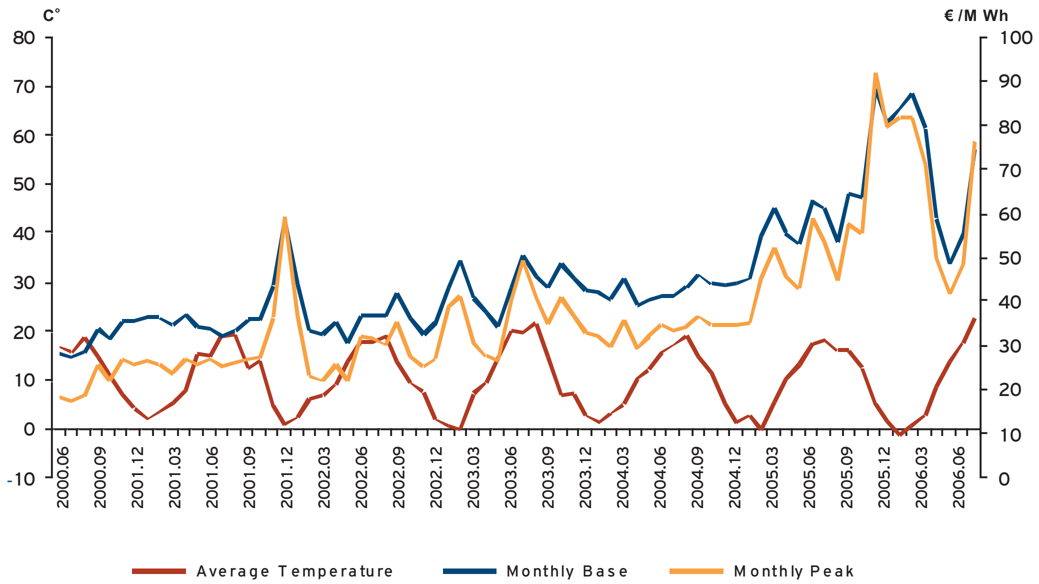
Price development and volatility over the past year – how much is attributable to fundamentals and how much to psychology?

In 2005 and 2006, the power markets in the Nordic region and in Germany were characterised by increasing electricity prices. Generation availability, unusual weather conditions, fuel prices and CO_2 prices led to high volatility and rising prices.

The development of electricity and CO_2 prices since the introduction of the ETS has offered some surprising developments. At first, CO_2 prices rose much more than anyone ever had expected, and then, when it became clear that an oversupply of allowances had been allocated in many countries, they fell rapidly. The effects on electricity prices were dramatic. With improved transparency in the market for allowances such dramatic changes can probably be avoided.

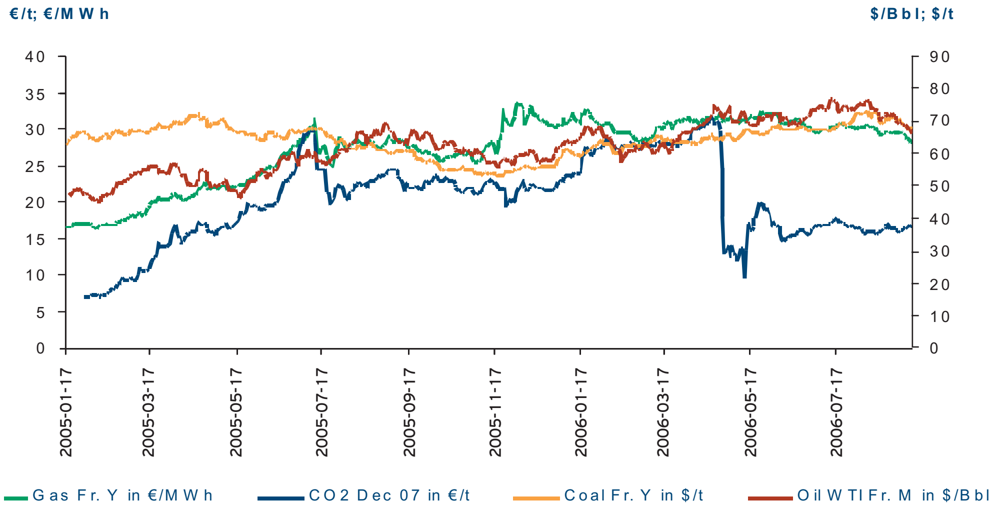
Many European countries experienced some unusual weather conditions during the past year, with temperatures sometimes deviating from the seasonal average, and water tables in rivers and reservoirs sometimes being very low. The impact on electricity demand and supply was quite strong. In the summer of 2006 for example, unusually high temperatures all over Europe boosted consumption (because of air conditioning), while generation was reduced as power plants ran their annual maintenance routines and nuclear and coal fired plants had cooling problems. Wind and hydro power could not balance the shortfall in supply, and prices in the spot market peaked.

Figure 3: Monthly average temperatures and EEX average prices



Fuel prices have also rocketed during the past two years. High crude oil prices, shortages of refining capacity, the long hurricane season of 2005 and a cold winter contributed to this. Natural gas prices, which are linked to oil prices, followed suit, as did coal prices. Thus, the global climate has had an impact on national electricity markets via oil and gas prices.

Figure 4: Fuel and CO_2 price development



CO_2 prices have influenced all European power markets. During the first half of 2005, there were many signs indicating a tight supply of allowances, including political decisions to tighten National Allocation Plans[3] and increased fuel prices. CO_2 prices climbed to a peak of almost 30 EUR/tonne. This was considerably higher than expected prior to introduction of the system. Prices traded in a stable range of 20 to 23 EUR/tonne until the end of 2005, after which they again rose just as the EU-wide publication of real emission data for 2005 was due. Based on the assumption that the market was going to be short, prices again rose to more than 30 EUR/tonne. After premature disclosure of the preliminary emission data, which showed that considerably less CO_2 had been emitted in the EU than expected, prices plummeted to 15 EUR/tonne within four days.

Market participants in the Nordic and German electricity trading areas began to see that their markets seemed much more aligned than before. Whilst Nordic traders used to look at the hydrological balance, the Continental market paid much more attention to fuel prices. Now, both markets are affected by fuel prices. Several reasons account for this effect. The first is the start of the ETS, which, along with fuel prices, influences the marginal cost of production. In addition, the closure of the Swedish nuclear plant Barsebäck makes the Nordic electricity system more sensitive to shortages and more dependent on imports. This leads to an increased exposure towards all factors that influence electricity prices in the exporting countries such as prices for coal, gas, and oil. Trading in the Nordic region has become more aligned with the German market and the focus of traders is increasingly shifting to the Continent. This becomes evident when the supply side is tight, whereas in periods with a high reservoir levels such as during the very wet autumn of 2004, water levels continue to be the main price driver on the Nordic spot market.

While the spot market for electricity is purely driven by supply and demand, the long-term market is sometimes influenced by sentiment and expectations. Competition and interconnection cause the impact of change to spread much more quickly than it used to in the old regulated monopoly markets. Concern about oil and natural gas availability can lead to price spikes in long-term electricity contracts. This happened at the beginning of 2006, when a dispute over gas payments between Russia and the Ukraine, political instability in Nigeria and a sensitive situation in Iran triggered fears of oil and gas supply cuts, causing oil prices to increase. There were hardly any sellers in the electricity market and high risk premiums had to be paid as a result.

[3] National Allocation Plans determine how many allowances are awarded to each plant that emits CO_2

What will happen to oil prices – are continuing rises inevitable?
Oil prices have risen dramatically in recent years, from around $ 10/bbl in early 1999 to over $ 75/bbl in mid-2006. Looking forward, there are widely diverging views about the extent to which this trend will continue. Are high oil prices here to stay, will they eventually revert towards historic oil price norms of around $ 25-30/bbl (real 2006 US dollars), or are recent changes merely part of an inevitable oil price cycle that has been apparent since the early 1970s?

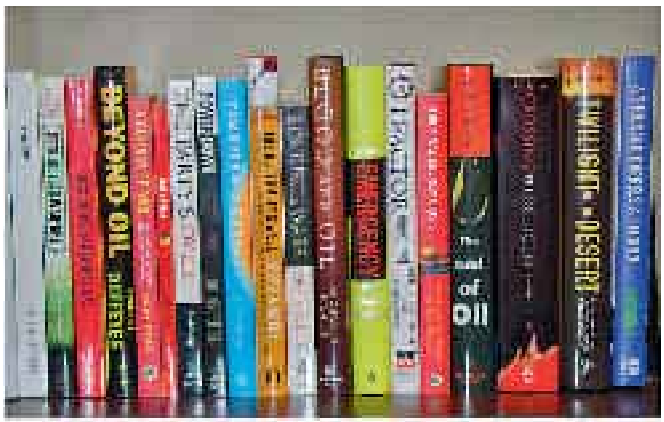
There are different views concerning the development of future crude oil prices, production capacity and reserves. However, there is a consensus concerning the increasing dependence on a limited number of politically unstable OPEC-countries and Russia. The IEA has expressed concern about energy security due to insufficient investments in the oil industry within these countries. All these factors increase the risk for supply disturbances and variable and high oil prices in the future.

In the long run, the oil price will be determined mainly by the ability within OPEC to maintain and increase oil production. The reason is that the total non-OPEC oil production from current conventional oil sources is soon expected to reach a maximum and thereafter to decline. To what extent this can be compensated for by increased OPEC-production is a key question.

Any analysis of future oil prices must centre on a number of key issues – including demand growth, resource availability, geopolitics, dislocation of supply and demand, and alternative energy resources – and how these factors interact. Each is discussed briefly below:

Demand growth. In many ways, this is the element easiest to predict. Demand for primary energy, including oil and gas, will continue to grow. Despite protocols aimed at limiting carbon emissions (e.g. Kyoto), oil consumption alone looks set to rise by more than 10 % – to over 95 million bbl/day – by 2015. The main drivers for this are the (inevitable) growth of the world's population and the (highly probable) increasing pace of global economic development, notably in countries such as China and India. However, demand itself is also somewhat sensitive to price; for example, the IEA has recently (10th October 2006) reduced its estimate of global oil demand for 2007 by 200 000 bbl/d (to 86 MMbbl/d), citing high oil prices and a weakening US economy as the main reasons behind this.

Resource availability. There are widely diverging views about the world's remaining hydrocarbon resources. On the one hand "peak oil" theorists argue that current oil production is at, or near, its maximum and that near-term decline are now inevitable. These views are set out in a number of recent "best-sellers" (examples below) and have attracted a lot of media attention in recent years.



On the other hand, other reputable sources such as the US Geological Survey estimate there are over 800 billion barrels of oil and 4 500 tcf (125 trillion cubic meters) of natural gas still to be found (excluding non-conventional sources), while IEA estimates place world hydrocarbon reserves at 20 trillion barrels of oil equivalent (boe), of which 5-10 trillion boe are technically recoverable. These reserves are far larger than the world's cumulative production to date of 1.5 trillion boe, suggesting resource availability will not be a major issue for decades to come.

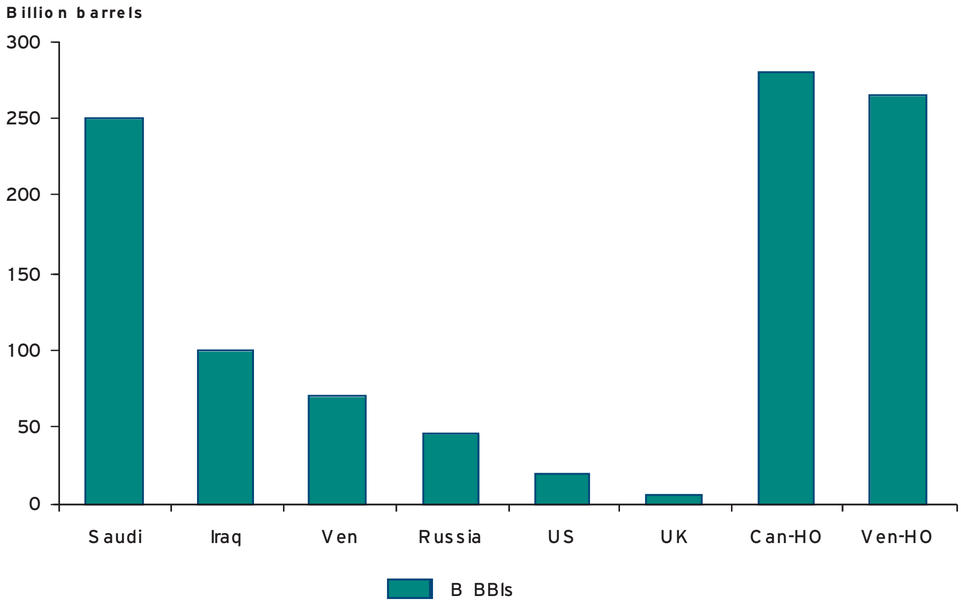
Geopolitics, and dislocation of supply & demand. Even if there are abundant hydrocarbon resources globally, their geographic location does not correspond to the main areas of consumption. Most of the world's remaining conventional oil reserves are located in OPEC countries, or those largely closed to foreign investment (e.g. Russia, Mexico), meaning that future oil supplies are heavily dependent on the willingness of these countries to make the very large capital investments needed to meet future demand increases, and their ability to deliver such projects. Furthermore, the recent tight margin between supply and demand – which has on occasions fallen as low as 1 million bbl/day, from its historic norm of around 3 million bbl/day – has recently been put under further pressure by conflicts (Iraq, Lebanon), political tensions (Iran, Venezuela), social unrest (Nigeria) and natural phenomena (e.g. hurricane Katrina).

Inevitably, these factors combine to raise fears about "security of supply" within importing nations and other big primary energy consumers. Such fears are widely believed to have been a more important contributor to recent "oil price spikes" than was any inherent tightness between supply and demand.

That said, the scale of recent investments by international oil companies (around $ 190 billion in 2005, vs. $ 100 billion in 2000) mean that non-OPEC oil supplies will increase gradually from 2006 peaking in 2010 or 2011. Indeed, this peak in non-OPEC production will probably be extended beyond 2011 by further capital investment by the IOCs. Longer term, though, huge investments in "conventional" hydrocarbon reserves by oil rich nations (e.g. Russia and OPEC countries), and similarly sized expenditures by the West in "non-conventional" energies (see below) will be needed to match production to ever-increasing demand.

Alternative energy sources. Concerns about carbon emissions are driving investment in a range of zero/low-carbon energy sources, such as wind, solar and biofuels. However, at the global level, these sources are not expected to stem the increasing demand for fossil fuels for decades to come. High oil prices and security of supply concerns are also leading to a re-appraisal of the merits of nuclear energy and, in the even shorter term, to a dramatic increase in the extraction of so-called non-conventional hydrocarbons, such as tar sands and oil shales. The size of these resources in Canada and Venezuela alone surpass the conventional oil reserves in the Middle East.

Figure 5: Conventional oil reserves in six countries compared with heavy oil in Canada and Venezuela



Conclusions. Complex interactions between many factors mean that future oil prices are impossible to predict with any precision or certainty. However, in the absence of major new external shocks (e.g. large-scale conflicts, political upheavals in the Middle East, or a prolonged global recession) the following "most likely" outcomes seem reasonable:

- Prices significantly higher than those recently seen ($ 75/bbl) are not likely to be sustainable over the medium-term, due to their adverse effects on world economic growth (decreasing demand) while incentivising the rapid addition of new supplies (e.g. Canadian non-conventional oil)

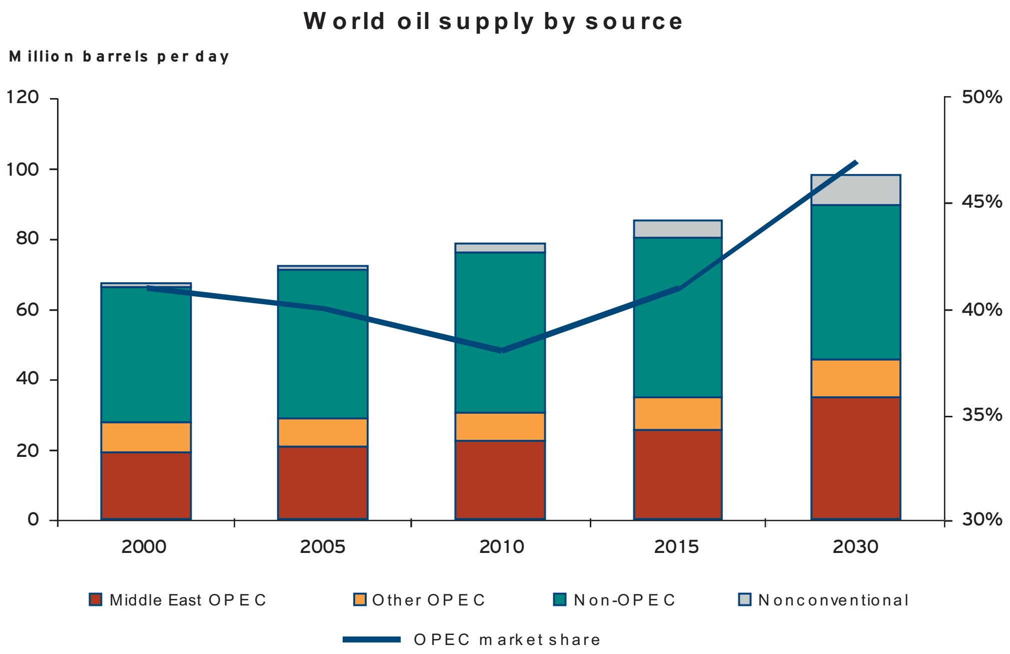
- Although the underlying supply/demand balance will remain tight; in the near-term, increasing demand will be met from two main sources
  - New non-OPEC supplies; a consequence of the huge investments made by the international E&P industry since 2000
  - Increased production from the one OPEC country with significant spare production capacity – Saudi Arabia

- The mid-2006 oil price "highs" will be seen to have been driven more by short-term speculation / security-of-supply concerns, and by worries about the oil industry's ability to cope with strong oil demand growth over the medium term, than by any inherent supply/demand imbalances

- Significant short-term price falls are likely to meet by OPEC attempts to re-impose production quotas. The very recent (October 2006) fall in oil prices to below $ 60/bbl has led to calls from some OPEC members to cap production at around 27 million bbl/day, compared to current rates of 29 million bbl/day. However, the ability of OPEC to set a sustainable floor for oil prices is, at best, unproven

• The contribution to primary energy supply from "alternative" energy sources will, with the exception of heavy oil / tar sands, be negligible over the short-term from an oil market perspective, and will therefore exert no significant effect on oil prices over this timescale. Longer-term, a re-appraisal of the benefits and costs of nuclear energy in a global context may mean that this becomes a significant source of supply in some countries over the medium term.

Figure 6: Graph of predicted OPEC production

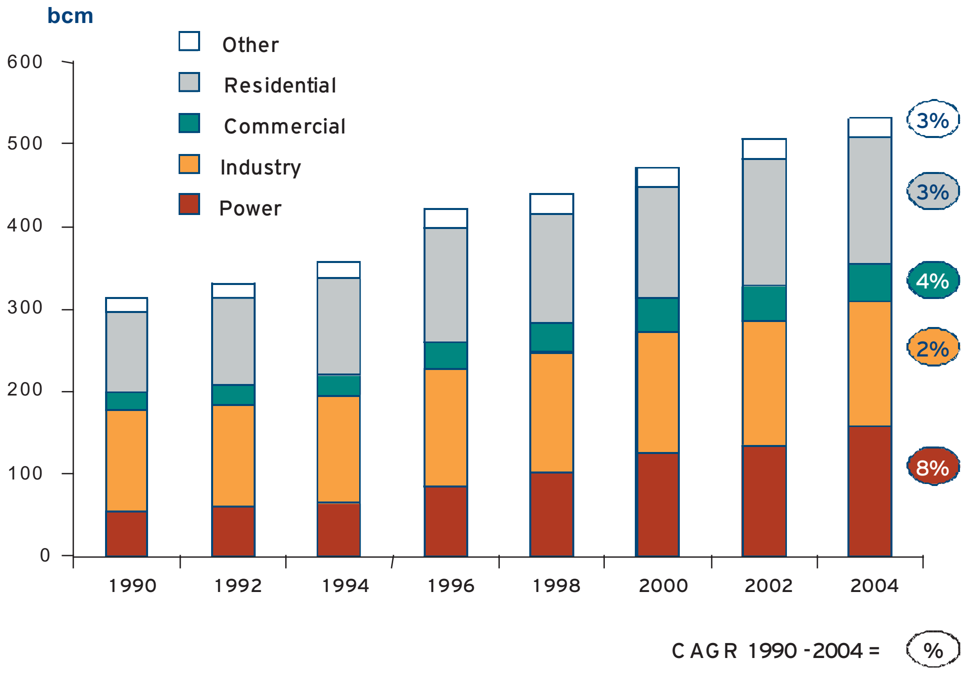


Source: IEA – Internationel Energy Outlook 2006

Will there be enough gas for Europe in the next decade? What new sources will be available to meet the growing market?

European gas demand has grown strongly over the last 10-15 years, especially in power generation. Since 1990, the average growth rate of gas demand has been 4 % per year, compared with 8 % per year in power generation. The share of gas in primary energy demand has risen from 13 % to 20 % between 1990 and 2004.

Figure 7: European gas demand, OECD Europe



Source: IEA

Today's high oil prices are likely to slow growth rates for gas as other fuels and technologies become more economic. Despite this, many actors expect gas demand growth rates to increase in future as oil and gas prices fall.

In many countries, gas is viewed as a desirable source of energy for several reasons:

- Low relative carbon emissions due to high energy density and efficiency of gas fired burners and CCGT power plants
- No or very low emissions of NOX, SOX and particles (relative to oil and coal)
- Short construction times, relative ease of permitting, low capital and maintenance costs

High gas prices have encouraged some actors to diversify away from gas. New coal fired capacity is planned both in Germany and the UK. Others continue to focus on gas. Many new LNG terminals are planned in several countries, including France, the UK, Italy and Spain. The Norwegian government has approved a gas fired CCGT plant in Mongstad. But in many other locations, gas is not competitive with coal at current price expectations.

Expectations of future growth in European gas demand is indicated by the many new infrastructure projects which are being developed or planned. These have been illustrated in Figure 8. Significant new import infrastructure projects include Medgaz, GALSI, Nabucco, Nordstream, Langeled, BBL pipes and many LNG projects: Le Verdon, Dunkerque, Lion (NL), Gate (NL), Wilhelmshaven, Milford Haven, Teesside, OLT (Italy), Adria. New gas fields being planned to feed the growing European gas market include Ormen Lange, expansion Qatar's North Field, Nigerian LNG, Angola LNG, the Stockman field in the Barent's Sea, South Russia, Bovanenko, Kharasavey, and Shakh Deniz.

Figure 8: New planned import infrastructure to Europe

It is worth noting that regulatory changes stalk the European gas theatre (unbundling, implementation of 2nd Gas Directive, forced reduction of transport tariffs). Progress in liberalisation has been slower in the gas sector than in electricity. Europe faces the dilemma of a desire for more competition, integration, cost pressure and efficiency improvement on the one hand and the need to stimulate investment and increase security of supply on the other. The UK has shown one potential way for how to resolve this problem – new infrastructure is not regulated to the same degree as existing infrastructure. Europe is moving at different pace from country to country, accommodating local issues.

Where are the resources? And how much gas is there?
UK gas reserves are depleting rapidly, and the Netherlands is expected to decrease from 2015 onwards. The closest major gas supply source for North West Europe is Norway, with around 2.5 Tcm (trillion cubic metres) of gas reserves. This equates to 25 years of total UK demand of around 100 bcm per year. European demand of 530 bcm per year could be met by Norway for only 5 years, so Europe will definitely need to increase imports. Key gas supplies to meet future European gas demand will come from Russia, Algeria, Libya, Nigeria and the Middle East. Russia, with reserves of 48 Tcm, could meet European demand for the next 80 to 90 years.

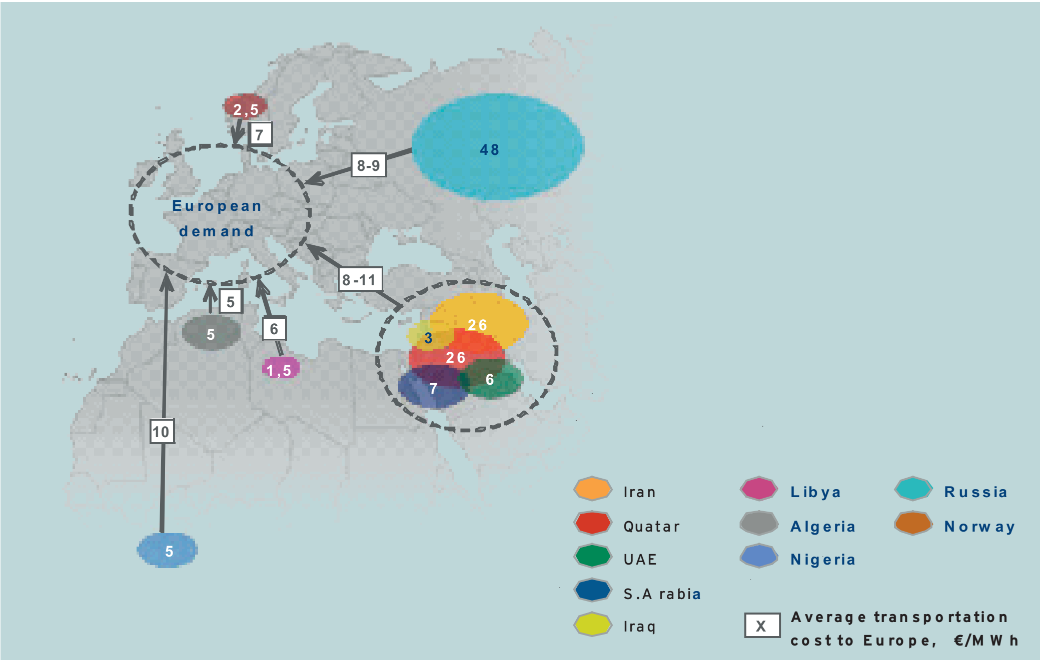
A 1 GW gas fired power plant operating at baseload (8 000 hours at 55 % efficiency) would use around 26 bcm over 20 years, and a town with 500 000 households could be expected to consume up to 20 bcm over 20 years.

The high gas prices which may temporarily choke off demand growth also serve to make practically all upstream projects extremely attractive and profitable investments. So many new projects are now being contemplated, if resource owners want to develop them. Most do, but in a careful way – rising resource nationalism and a determination to avoid sowing the seeds of a painful price correction downwards.

Other threats to future gas supplies include the following:

- Other markets (US, Japan, Korea, India...) pay more for gas than Europe, potentially offering a more attractive outlet for suppliers within economic transport distance
- A major gas accident persuades consumers that gas carries very high technical risks, compared with the alternatives
- Security of supply is currently a key concern due to the suspicion of politically-motivated supply curtailments in the Ukraine. Investment in new infrastructure should alleviate some of these concerns

Figure 9: Gas reserves, Tcm



Source: BP Statistical Review / Arthur D. Little analysis

How much of the consumer's cost for electricity consists of taxes?

Household consumers are paying a lot more for their electricity than they did 15 years ago. This is only in part due to higher electricity prices. Taxes on electricity have risen much more than prices have. Taxes also vary much more between countries than the price of electricity and network charges. Denmark has the highest electricity taxes, 59 %, while the United Kingdom has the lowest, 4 %. In Sweden, added taxes and fees include green certificates, electricity tax and value added tax. In some other countries, the tax consists only of value added tax.

Depending on how high they are, taxes can have a significant impact on consumption, and the choice of energy solutions.

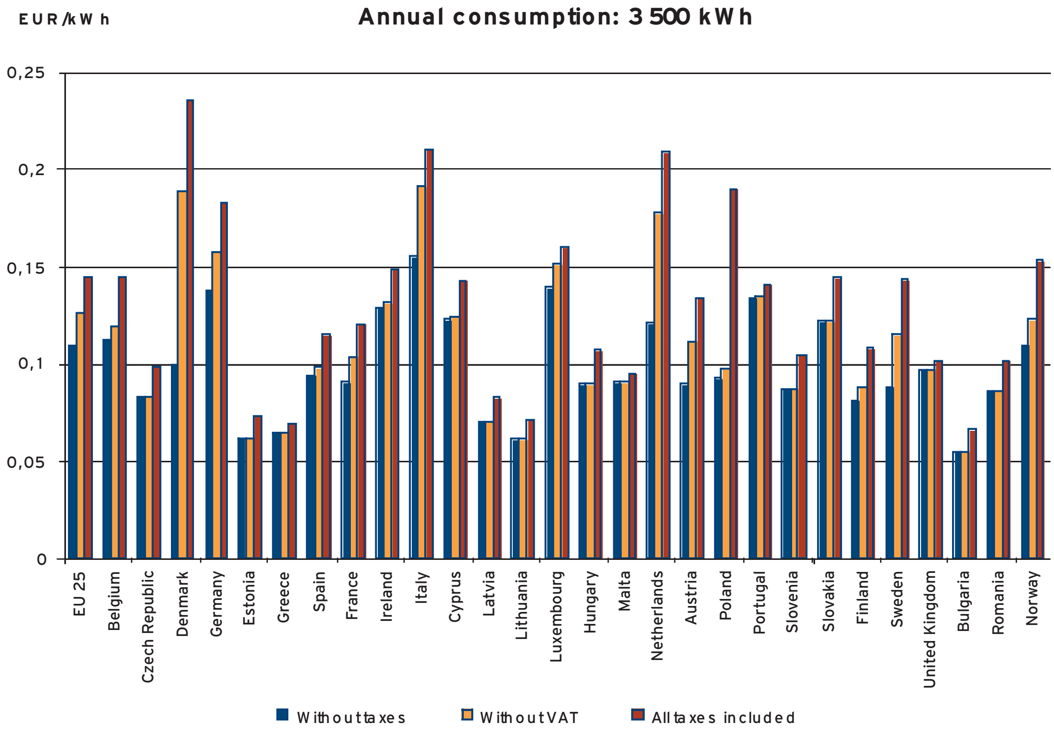
Electricity prices for household consumers vary tremendously between different countries, especially when taxes are included. In fact, taxes vary much more between countries than the price of electricity and network charges.

Energy taxes and VAT together account for 59 % of the electricity cost in Denmark, 39 % in Sweden, 24 % in Germany, 23 % in Poland, 24 % in Finland but just around 4 % in United Kingdom and Portugal.

The reason why taxes vary so much between countries has to do with different political objectives pursued. For example, in Norway, Sweden and Finland the tradition has been to deliver electricity at low cost, made possible by the availability of large hydro power resources. Prior to deregulation, taxes were quite moderate. Since then, the environmental objective of reducing consumption has become more pronounced. For this reason, taxes have gradually been raised to provide incentives for household consumers to be more conservative in their consumption patterns.

In other countries, such as Italy which is quite short in terms of domestic primary energy resources, the policy has been to keep energy prices high in order to keep household consumption at a minimum. Partly as a result of this (but also because of a warmer climate), consumption of energy and electricity per capita in Italy is much lower than in the Nordic countries.

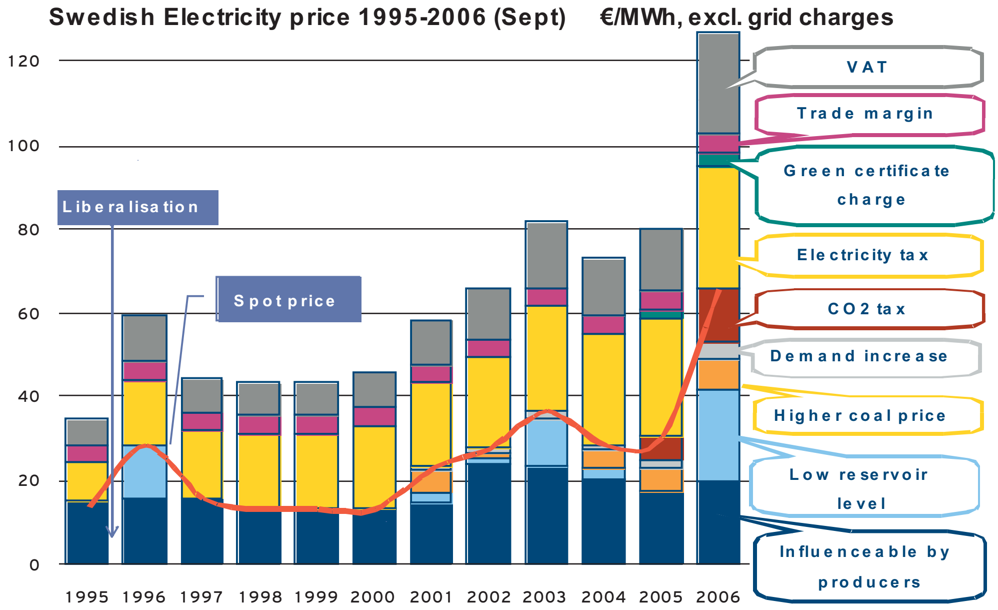
Figure 10: European household electricity prices



Source: Eurostat

In Sweden, energy taxes have raised consumer prices significantly since deregulation. Politically, this has several underlying reasons. The most important one is a goal to reduce per capita consumption of electricity by making consumers more careful in how they use electricity. Consumers have been compensated for this by lowered income taxes.

Figure 11: Swedish electricity price development since 1995



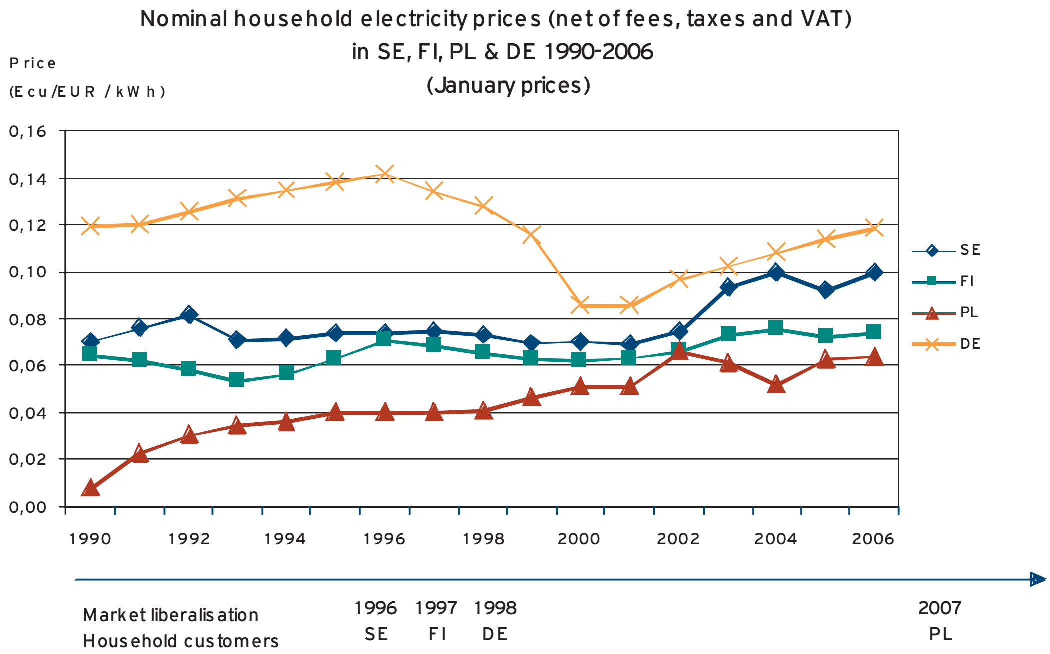
Source: Tentum

How do electricity markets prices compare between different countries in different customer segments?

The European Union has been liberalising its electricity markets for some time, but a lot remains to be done to achieve an integrated European electricity market. Not all countries have yet introduced full competition at all markets levels, this is to be achieved by 2007. A stepwise integration of electricity markets by establishing regional markets will stimulate liquidity on the trading markets and appropriate conditions for competitive prices.

Electricity end-user prices have historically been lower in the Nordic region compared to other parts of Europe. A key explanation is the relatively low cost hydropower generation in the Nordic countries compared to more expensive fossil fuel based power generation in continental Europe. The integration of the European electricity market has pushed prices to become more harmonised and as expected price differences have begun to level out. Increased transmission capacity and trade between the Nordic region and continental Europe have caused prices to become increasingly correlated and convergent.

Figure 12: Electricity price developments in EUR for the 5 000 kWh household customer segment (in Germany 3 500 kWh), 1990-2006 (prices excluding taxes and VAT and for Germany also excluding concession fee, Kohlepfennig and CHP and RES support)

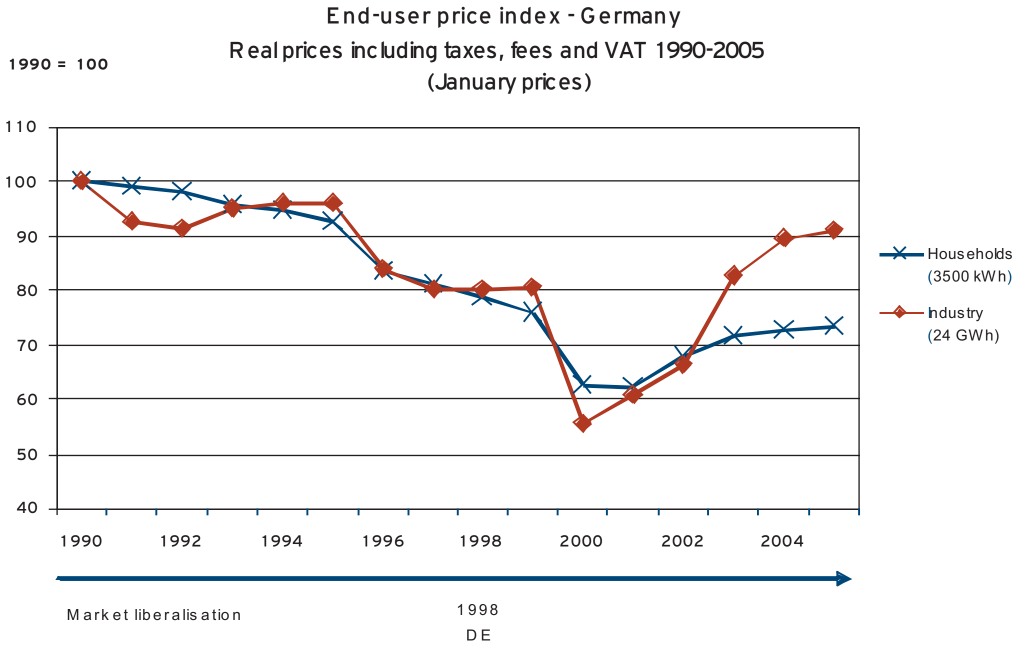


Source: Vattenfall Power Consultant AB

Germany, which has had high electricity prices historically, recently has experienced a more pronounced decrease in electricity prices than Finland and Sweden. A well-integrated Nordic market is the main reason behind the high degree of correlation between prices in Finland and Sweden. In contrast to Germany, Polish electricity prices have risen in Euro terms from being much lower than in Germany, Finland and Sweden, to reaching similar levels.

End-user prices have developed differently for household and industrial consumers. In real terms, according to Eurostat figures, the price fall for industrial customers, in Europe as a whole, was over 15 % in 2004 compared to the price level of 1995. During the same time, household customers have experienced raised taxes and charges, which together with increasing fuel prices have counteracted the trend of decreasing end-user prices in many European countries. However in Germany, both household and industrial customers have experienced reduced end-user prices compared to pre-liberalisation, despite higher taxes and fuel prices.

Figure 13: Electricity price index for Germany 1990-2005. Household segment (3 500 kWh) and Industry segment (24 GWh). Real prices including taxes, fees and VAT. (Industry does not pay VAT). Prices include energy and network fees. National harmonised consumer price indices (CPI) and producer price indices (PPI) are used to recalculate nominal prices into real prices



Source: Vattenfall Power Consultant AB

A lot remains to be done to achieve an integrated electricity market. A stepwise integration of electricity markets by establishing regional markets will stimulate liquidity on the trading markets and establish appropriate conditions for competitive prices.

How competitive are electricity prices paid by the energy intensive industries in different countries?

Energy intensive industry consumers often claim that they have to pay higher electricity prices than their competitors, and threaten to move their business operations to countries with lower electricity costs. Contract prices are to a large extent dependent on timing and degree of hedging. If you sign a fixed price contract at a time when the market is tight, you may experience, at a later date when prices have fallen, having to pay higher prices than the market price. If, on the other hand, you manage to sign your contract when market prices are low and expected to remain so, you may well see yourself buying at more attractive prices than the market offers most of the time during the life of the contract. Whether actual prices paid are competitive or not depend on the terms negotiated in individual contracts, the time of the agreement, and price developments since then. All these uncertainties are known and taken into account when the contract is negotiated. Price statistics paint a distorted picture since the largest consumers are often not included as their contract terms are kept confidential.

Statistically, the power-intensive industrial sector is treated as a subset of the industrial group referred to as "Basic Industry", that is, industry which refines natural resources such as iron, ore or wood into raw materials (e.g. steel, copper wire, or pulp) that can be developed further into consumer goods. In these processes, energy is a primary input.

In 2002, total power consumption in the EU-15 was 2 387 TWh. The total consumption of the Basic Industry sector was 560 TWh. This means that the Basic Industry sector accounts for approximately 23 % of total consumption.

The commercial terms in bilateral contracts between generators and the power-intensive industrial sector are always kept strictly confidential. Power prices are one of the most important factors affecting competitiveness in this sector, which is why they are kept secret. As a result, actual power prices paid by this sector are not published and difficult to obtain.

There are a number of industrial processes where electricity is a primary input. In some cases, electricity costs account for more than those of any other input or raw material. There is, however, a relatively large variation between the different segments. Aluminium and metal alloys are by far the most energy intensive products. According to SKGS (the Swedish Association of the Forest, Power, Mining and Steel Industries) the cost of electricity represents between 10 and 40 % of the value added in production within the power-intensive industrial sector.

As an example, the primary aluminium segment has a power cost corresponding to on average around 30 % of total production cost. The other major cost element for a primary aluminium smelter is the cost of alumina, the raw material. Alumina is transparently priced on the world market and therefore the cost of alumina becomes a neutral factor in the competitiveness of different smelters. The costs of capital, transport, labour etc vary but are less significant in comparison to the cost of electricity. For this reason, the cost of electricity is the determining factor of competitiveness.

The general commodity market during the past few years has undergone a remarkable shift. For a considerable period of time, prices for aluminium were quoted on the London Metal Exchange in the region of US$ 1 100-1 300 per ton, with temporary peaks around $ 1 500. In the past few years, prices have escalated to levels above US$ 2 000. Aluminium prices have peaked at levels exceeding US$ 3 000 during 2006. The same pattern applies to other commodities as well, including steel. This general price escalation has reduced the immediate impact of the power price increase on the metal producing industries' earning capacity. However, this is not the situation for all energy intensive industries. For example, pulp & paper producers have not generally enjoyed the same price development on their main products.

Aluminium smelters enjoy the lowest electricity prices of all industries. This is due to the tradition to rely on long-term electricity contracts, 20 years in length or more. However, a number of electricity contracts with aluminium smelters in Europe are estimated to have expired during 2005 and 2006 (> 1 000 MW). Subsequent negotiations for new supply contracts have been conducted in an environment with generally higher price levels on the electricity markets. The result of these negotiations can be expected to have raised contract price levels significantly for the individual smelters affected, as well as the average for the aluminium industry as a whole.

Finally, the actual electricity price paid by the power-intensive industrial sector on the European market is the result of customer behaviour, timing and risk management, and the underlying market price. It was also observed in the 2005 Electricity Market Report that the estimated electricity prices to the pulp & paper sector in different Western European countries are converging, this implies that the competitiveness of the energy intensive industry sector should be viewed from a global perspective.

Chapter 3: How do climate policies influence the electricity markets?

How does the Emissions Trading Scheme (ETS) work?
How does it affect the consumer?

The Emissions Trading Scheme, which was introduced in the EU during 2005, has had a profound impact on electricity prices and their development. Building on the Kyoto Protocol, its purpose is to make it more costly to use carbon-emitting energy sources, thus promoting the use of alternatives. However, the effects have been more wide-reaching than foreseen, interacting with other forces in a way which was not anticipated.

A key aspect of the scheme is that it allows companies to use credits from Kyoto's project based mechanisms Joint Implementation (JI) and Clean Development Mechanism (CDM). This means that the system will not only provide a cost effective way for the EU to reduce emissions but also create incentives for investing in emission reduction projects outside the EU. This is intended to transfer environmentally sound technologies to other parts of the world.

The ETS is a market based mechanism (see Chapter 1 for impact on electricity prices) aiming at increasing the cost of generating electricity from fossil-based fuels, thus making them less competitive. The ultimate objective is to gradually make it so expensive that the least efficient fossil fuelled power plants are pushed out of the so called merit order, the economic pecking order of power plants. Because of the fact that fossil based plants also are, typically, setting the market price, electricity prices will rise as a result. In this way, it is hoped that two effects will be achieved: the main one is to cap CO_2 emissions, and the other one is to make room for the introduction of more expensive new technologies with lower or zero emissions (such as renewable energies, or CCS, carbon capture and storage) into the merit order. The net effect of this is that all CO_2-free generation, including existing hydro power and nuclear power, benefits from higher prices, although this is not the primary purpose of the ETS.

The Member States of the European Union have agreed to reduce greenhouse gas emissions, including CO_2, by 8 % from 1990 levels until 2012. A so called burden sharing agreement defines each country's reduction obligations. One measure adopted to reach this goal is the implementation of the ETS for large industrial emitters. The ETS was introduced at the beginning of 2005 as a so called cap-and-trade system. This means that there is a total amount of permitted emissions in every year that must not be exceeded. This amount will gradually be reduced over time to reach the ultimate goal.

There are two so called trading periods for which emission budgets have been set, Phase 1 and Phase 2. Phase 1 runs from 2005 to 2008. Emission allowances are issued annually in line with the Phase 1 budget. Emission allowances are standardized and tradeable, each allowing the bearer to emit 1 t of CO_2. In Phase 2 (2008-2012), the number of emission allowances issued annually will be reduced, to meet a reduced total budget. How allowances are allocated to emitting plants is prescribed in the National Allocation Plans (NAP) of each MS. These carry a strong element of national policy, so do not follow the same principles in each MS.

At the end of each year, an installation which emits CO_2 has to submit an amount of allowances corresponding to what has actually been emitted to the national authorities. Companies which hold more allowances than they need to cover their actual emissions may sell the surplus on an open market. This could be the result, for example, of a decision not to run the plant because it is more economical to sell allowances at the forecast price. Those who are short of allowances can purchase additional ones. Thus, trading will help to ensure that the environmental objective of reducing emissions is reached at the lowest possible cost. Each company has the choice of either reducing emissions, e.g. by investing in more efficient equipment and sell allowances, or continue with current equipment and ultimately having to buy more allowances (as the cap is reduced). Companies, which are able to reduce their emissions at low cost, will have a surplus of allowances, which they can sell. With these revenues the investment can be financed. Companies faced with relatively high abatement costs will opt for buying allowances instead of reducing emission by investing in new equipment. Thus, the mechanism directs investments to those projects which create the largest reductions per Euro spent. Consequently, the total cost to reduce CO_2 emissions will be considerably lower than if everyone was to reduce their emissions by a certain factor individually.

As allowances become scarce and increasingly in demand, a market value will develop. This value creates an additional production cost element on top of the variable operating cost, regardless of what was originally paid. The reason for this is that the plant owner is faced with the economic choice of either producing the power and using the allowance, or selling the allowance and realizing its economic value (opportunity cost principle). When the last dispatched unit in the merit order of power plants is a CO_2 -emitting facility (which is most of the time on the Nordic and German electricity markets), the cost of the emission allowance will thus have a direct influence on the electricity price. This is independent of whether the allowances are allocated free-of-charge or against payment via auctions.

Increasing wholesale market prices automatically lead to higher electricity prices for household customers. But consumer prices are also influenced by other price components, such as for example taxes.

What is the difference between the Emissions Trading Scheme (ETS) and renewable support schemes? What effects do they have – respectively?
European Union Member States are committed to reducing emissions and halting climate change. At the same time, they wish to avoid direct public intervention, and instead rely on market based mechanisms, in order not to distort competition. To achieve the desired results, they have introduced mechanisms which gradually make emissions more costly for those with installations that do emit CO_2, and which improve the cost competitiveness of renewables.

There are several different mechanisms which aim to reduce emissions and promote production from renewable sources. Different Member States use different models. Both the ETS and electricity certificates are market based mechanisms, which are quite sophisticated and complex in their setup in comparison to investment grants and other subsidies. Feed-in tariffs are more straight forward in offering an additional price payable by suppliers to producers of renewable electricity. All three have had an impact on consumer prices, and the ETS is often cited as one of the main driving forces behind the currently very high electricity wholesale price. Electricity certificates and feed-in tariffs do not affect wholesale prices directly, as their cost is passed through as a surcharge to consumers. As more renewables with low costs are introduced into the merit order, an indirect effect on wholesale prices may develop, as expensive fossil fuelled power is eventually pushed out of the system.

The main difference between the ETS and support schemes is that the ETS tries to cap emissions by making it costly to emit CO_2, while the described support schemes try to force consumers to pay a small surcharge which is channelled to producers of new renewable electricity in order to support them economically, and make investments in renewable energy commercially attractive.

At present, most renewables cannot compete on their own merits with conventional technologies. Renewable technologies include for example wind, solar, wave, hydro, and biofuels. They all have different challenges to overcome in order to be able to compete with conventional power sources. In some cases, a significant obstacle is reaching a large enough sales volume to be able to reduce costs by mass production. In others, grid connections need to be extended or reinforced because of location far from consumer centers or even offshore, requiring additional investments. In yet other cases, the installations are so small that high costs per unit of production are unavoidable.

Financial support is needed to increase the share of electricity produced by renewable energy sources. Support schemes are often complemented by other incentives, such as tax breaks, investment grants, and similar. Some EU Member States have introduced a quota mechanism combined with green certificates. In a quota system, electricity supply companies are obliged to buy green certificates corresponding to a proportion of their total energy sales. Renewable generation facilities receive green certificates corresponding to energy produced. Green certificates can be traded separately from the energy produced. Any electricity company that does not obtain a sufficient amount of green certificates has to make buy-out payments. Such additional costs for power companies will be included in generating costs and therefore lead to an increase of customer electricity prices.

ETS and electricity certificates are market based mechanisms which are volume driven and the supply and demand balance of emission allowances and respectively green certificates set the market price. The effectiveness of such system in real life is extremely dependent on a stable long term framework (e.g. reduction path, quota development, penalties).

Feed-in tariffs, by contrast, are guaranteed tariffs payable to producers of renewable energy over a certain period of time, to provide a certain income over the economic life of the investment. The costs are paid by suppliers in proportion to their sales volume and are passed through to consumers as a surcharge. In order to encourage technology improvement, the tariffs are gradually reduced over time for new investors.

Table 1: RES Support schemes used in different EU Member States and Norway
(simplified, several countries apply mixed systems)

RES Support Scheme	
Quotas/green certificates	SE, UK, IT, BE, PL
Feed-in tariffs	All other Member States* except Malta and Finland
Tax Incentives	Malta and Finland

*A feed in tariff system was recently proposed for Norway too

A recent study by the Commission of the European Communities ("The support of electricity from renewable energy sources", 7.12.2005) has assessed existing support systems in terms of effectiveness. In commenting on benefits and drawbacks, it highlighted that feed-in tariffs have the advantage of investment security, the possibility of fine-tuning and promotion of mid-long term technologies. But feed-in tariffs are more difficult to harmonize across the EU, and there is a risk of over-funding.

Green certificates, which are market based, have a theoretical potential of ensuring best value of investment. They could work in a wider EU context and there is a lower risk of over-funding. However, they imply an increased uncertainty for investors in relation to feed-in tariffs (since the price of the certificate is set on a market and the supply and demand on that market is difficult to foresee), and is at present a more costly system to administrate.

In terms of performance, the study goes on to conclude that support varies significantly among Member States, but that in general, feed-in tariffs so far seem to be more effective in producing more renewable energy. However, effectiveness is a question of evaluation time too – feed-in tariffs may be more effective in the short term, but in the long term, certificates present a more sustainable solution since they do not lead to overinvestment.

Is it possible to halt climate change? What are the options?
Vattenfall is strongly committed to a responsible handling of the climate change issue while recognizing that action has to be taken in a long term, investment cycle time perspective, based on cost-effective measures.

The overriding environmental challenge of our time is climate change. In relation to Kyoto and beyond, humanity is facing some really tough choices. There is no such thing as a handful of simple short-term solutions. Economy, energy and environment are closely interlinked, so we have to realize that we are implementing a major shift in the world economy that will ultimately influence everything and everybody. A really long-term perspective must be applied, stretching up to 100 years. Combating climate change must and will be a part of everyday life all over the globe.

To address this challenge, Vattenfall has during the past year outlined a global adaptive burden-sharing model built on the following principles:

- All countries should participate – participation is a part of being a member of the global community
- Emission allowances are allocated to each country in relation to its share of global GDP
- Emission caps should be binding
- No poor country shall be denied its right to economic development – no extra cost burden on the poorest
- No rich country shall have to go through disruptive change
- Richer countries pull a larger weight (emission caps do not embrace countries until they have reached a certain economic level; poorer countries with caps get higher allocations compared to richer countries)
- There shall be a level playing field. The proposed framework shall not change relative competitiveness
- The system must be robust. As new knowledge is accumulated parameters may change, but not the principles underlying the system

The model is based on the assumption that an overwhelming majority of all countries really commit to participate in the system from the very beginning (after 2012) given that they will only face restrictions once the country is wealthy enough in relative terms. The long-term predictability and the flexibility needed for economic growth can thereby be sustained. Most important is that we start now by forming a burden-sharing model built on commitments to long-term reductions.

Common efforts and initiatives are needed to promote a realistic and at the same time sustainable roadmap to the low carbon economy, that is, a global economy where there always is a cost for emitting greenhouse gases.

An extensive background to Vattenfall's model, the report "Curbing climate change – an outline of a framework leading to a low carbon emitting society" is available at http://www.vattenfall.com/files/news_and_comments/climate_change_report.pdf

Chapter 4: Will there be enough investments in new capacity?

What determines the amount of renewable capacity being built?
A combination of political incentives and business opportunities determines the amount of renewable capacity being built. However, increasing environmental awareness due to the growing problem of climate change has made many people question why the pace of replacing old capacity with renewable capacity is so slow.

Renewable electricity production is based on sources which are constantly replenished (e.g. through precipitation). The main benefits of this are environmental performance and sustainability. Most of the as yet technically feasible renewable energy solutions are still relatively small scale, with high investment costs. Also, dependence on nature in many cases leads to a very variable supply. These sources will take time to develop before they make a significant contribution to total energy supply.

The attractiveness of investing in renewable technology varies by country depending on the natural conditions of the country in question and the strength and apparent robustness of the support system in place.

- Biomass

Biomass is becoming increasingly important in the search for renewable production. Biomass can be divided into solid, fluid and gaseous fuels, and, in general, has high operating costs (because of the price of the fuel and its energy intensity – a far larger volume of biomass is needed to produce a kWh than is the case for example for oil). Biomass has the best economics if supplied locally – this lowers transportation costs. The best fuel efficiency is achieved in CHP plants which produce both power and heat (Combined Heat and Power), but biomass can also be used in traditional condensing plants (producing power only). Economics are tight and subsidies are required to make the investment attractive and the plant competitive. Biomass is used in many different applications, not all of which in energy, so there is competition for supply which drives up prices. As more and more countries try to replace hydrocarbons with biomass this competition can be expected to increase. The amount of biomass that can be made available is limited by the amount of land available for specific purposes such as forestry, growth of energy crops or straw harvesting within a certain country and the optimum rate at which lumber and crops can be harvested.

- Hydropower

Hydropower is produced where the potential and kinetic energy of water can be used to drive a turbine. There are three different types of hydroelectric plant, run-of river, reservoir and pumped storage. Run-of-river are turbines placed directly within the stream of water for example of a river. In the case of a reservoir, the water is stored and led to the turbine in a controlled stream. Pumped storage has the same basic function as a reservoir and is used for peak-shaving purposes. Large scale hydropower requires access to a suitable water stream and also a number of relatively closely located stations to reach sufficient economies of scale. Because of potential effects on the local ecosystem, there are often restrictions regarding the construction of new hydro power plants, and also concerning the operation of existing ones. The investment cost is high, but with a long economic life and very low operating costs, hydro can be attractive. Dry years with little precipitation and limitations in transmission between countries can cause large price fluctuations, but with reservoirs this can partly be compensated for. In the short and medium term, reservoirs also support the need for regulatory power.

- Wind

Wind turbines are typically very small scale. On land, they vary in size between 850 kW to 2 MW. There is a trend towards larger and larger turbines, the largest ones tested having a capacity of up to 5 MW. Wind turbines are built in clusters, so called wind farms, in order to increase economies of scale in operation and distribution of electricity. Investment costs are high and operating costs low. The operating hours of a typical wind plant is 2 500 hours of full load equivalent and, sometimes with a variation of 20 % depending on wind conditions. That, in combination with the unpredictability of the output creates the necessity to have a stable base load produced by other sources of power and/or imports as back-up for times when power is needed but there is no wind.

An investor in renewable energy is focused on attractiveness in combination with the risk related to the investment. The total production cost per kWh for renewable energy sources in general is quite high - higher than the expected market price, and thus not attractive to an investor. This means that for investments to occur, some sort of economic support mechanism is needed to finance the investment.

The EU has set targets via directives for the minimum share of renewable capacity that each country should be aiming to have by 2010.

This target is set at a stretch level in comparison to the present situation and is based on how the supply works in that country today. Some countries have set even higher ambition levels.

Hydropower is included in the EUs target levels, so for Sweden the target is the second highest in the EU (only Austria has a higher target) with 60 % of gross consumption (compared to the present situation where the share of renewable energies is approximately 50 % of gross consumption).

Table 2: Targets for minimum share of RES

Country	Target 2010 % of gross consumption	Today
Sweden	60	50
Finland	31,5	25
Denmark	29	19
Germany	12,5	8

Due to the high cost of new renewable capacity most countries have created some sort of economic support system to stimulate investments and thereby fulfil the EU directive. Examples of this include the EEG (Erneuerbare Energien Gesetz) in Germany, providing so called guaranteed feed-in tariffs for renewable energy, and electricity certificates in Sweden. However, investments in renewable capacity depend also on market prices and business opportunities, and how the support system is designed.

Can investments in wind power be motivated from an economic perspective?
Investments in wind power have become increasingly more frequent in recent years, although it is well known that the cost of power produced from wind is significantly higher than conventionally produced electricity. One could ask whether the investments are really profitable or whether they have been undertaken for other reasons. Wind power has a higher total production cost than many other production technologies and is dependent on subsidies to be profitable.

Wind power has a higher total production cost than most other production technologies, including hydropower, fossil based generation and nuclear power. Wind power is even more difficult to predict than hydropower, because of large variations and lack of prediction techniques. This causes a weakness in the security of supply. When there is no wind, a back-up source of power is needed. The cost of this back-up affects the investment case for wind power. To be able to develop wind power it is necessary to have long term stable support schemes due to the higher production costs.

To find locations with attractive wind conditions is essential. There is a major difference in the number of operating hours equivalent to full effect (to understand how much electricity is produced, we measure production in terms of hours at full effect) depending on location. Close to the Atlantic Ocean, e.g. in Scotland and western Jutland, there are many attractive locations with more hours of wind per year than in Middle and Eastern Europe. Cold and damp air has a higher density which increases the kinetic energy that can be converted into electricity. Building new capacity in difficult places also requires investments in new infrastructure, as wind farms often are located in the mountains or off shore.

If wind power is economically motivated or not must be put into relation to other opportunities (i.e. bio and hydro) and what value is put on improved environmental performance. To the extent that economic support schemes are put in place by politicians to stimulate investment in renewable energies, it follows that investments are both politically and economically driven.

Table 3: Typical economics of different types of new generation capacity, excluding carbon costs

Production type	Full effect operating hours**	Security of supply	Typical plant size	Full cost of production €/MWh
Wind	1 800–3 200	Unpredictable output	100–200 MW*	50–70 (on shore) 60–90 (off shore
Hydro	4000	Varies with amount of rain/ snow but possible to store	250 MW	20–100***
CHP	5 000 (SE)* 3 000 (DE)*	Availability of biomass	800 MW	25–55 50–70 bio
Thermal power	8 000	Market supply of gas, coal	1 000 MW	20–40 coal 30–45 gas 25–40 nuclear

* Large wind farm ** Depending on local conditions *** Upper level is micro hydro
Source: Business Insight 2006

Carbon costs can add between 5 and 7 €/MWh to the cost of coal or gas fired thermal power, depending on the price level of CO_2 allowances.

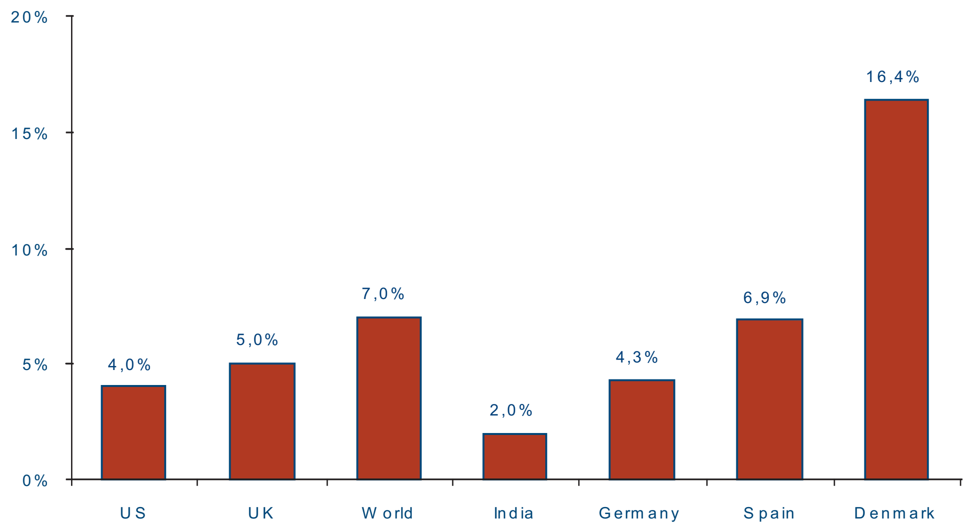
How large a part of total electricity supply can wind power provide, given the fact that the wind is not always blowing
The need for secure supplies limits the amount of electricity that can be based on wind, since back-up is needed for times when there is no wind. How much wind capacity that can be operated within a given system depends on the amount of balancing power installed within the network, and the grid connections required to transport power from the source to where it is used.

Based on existing technology and depending on the production mix of a particular region/ market, wind power could technically provide between 5 % and 20 % of the electricity supply. In a power system it is essential to maintain a stable grid frequency (effect) and to have a balance between supply and demand, as it is not possible to store electricity. Wind is more difficult to predict than precipitation (rain and snow) and at the same time, different from water, as it is not possible to store for later use. This means that in a power system with a high proportion of wind it is necessary to have some balancing power to compensate for times with poor wind. The transmission grid too may need upgrading since it will have to accommodate larger variations. Hydro is a very effective regulatory system, as you are able to store water and change the flow through a turbine at very short notice. Large thermal plants (coal fired or nuclear, for example) by contrast have very limited possibilities to compensate for lost production at short notice, but are not reliant on precipitation.

It is important not to exaggerate the need for back-up power though. In a large system with a lot of wind power installed in different places, it is unlikely that wind conditions will be such that the wind ceases to blow everywhere at the same time.

Denmark has the highest proportion of wind power and is close to the limit. Wind turbines are some times shut down or reduced in output in order to keep the short term balance in the system.

Figure 14: Share of wind in total electricity generation in 2005



Source: BP Statistical Review of World Energy June 2006
Note: NB. 2004 for Denmark and UK

How much does it cost to build a windmill, and how much electricity can it supply?
In view of the need to build more renewable energy to combat climate change, the cost of wind power in relation to market prices is of major interest.

The investment costs for wind power in general are higher than for thermal power or hydro-power. The total production cost including operation, maintenance and capital costs is

Onshore wind power	50–70 €/MWh
Offshore wind power	60–90 €/MWh[4]

Over time, wind power plants are growing in size as a result of technological developments. Wind mills built today are more than 100 meters high with a turbine diameter of about 100 m. The typical efficient annual operating time is 2 000–3 000 h. The capacity is up to 3 MW and the annual generation is up to 8 GWh. To achieve economies of scale many plants are gathered in wind power farms. For example, the wind farm of Lillgrund (planned to be taken into operation in 2007) will consist of 48 wind mills with an annual generation of more than 300 GWh. The largest planned wind farm at present is Krieger's Flak, estimated to produce 2 TWh per year.

What are the pros and cons of different energy alternatives – really? Is this just a matter of opinion or are there objective, hard answers to this question?
Renewable capacity plays an important role in the effort to bring climate change under control. At the same time, these solutions are rather small in scale and some larger scale base production is needed to cope with the unpredictability of especially wind but also of hydro. A balanced generation mix is necessary, as all technologies have advantages and disadvantages. Large-scale production also offers stability to power prices. In looking at the alternatives you have to look at what technologies are available and then what fuel alternatives you have.

[4] To obtain a comprehensive view of the costs of wind power production, the costs of back-up power and added grid costs should be considered too. These costs have not been included here since they vary depending on local conditions

Important factors in determining the production mix for a specific market is:
- Attitudes to climate change
- The need to lower greenhouse gas emissions has a great impact on the choice of solution
- The availability of natural resources determines the production mix of a specific country. Areas like the Nordic, with access to waterfalls will have a higher proportion of hydropower, while areas rich in lignite (brown coal), like Eastern Europe, or natural gas, like the Netherlands, will use those fuels for their base production
- The demand for district heating. In areas like the Nordic, with high heat demand, Combined Heat and Power plants are more common and an increasing part of buildings are heated via district heating. In Western Europe, natural gas is the most common source of heating

Table 4: Production mix power generation in different countries (2004)
(% of total production)

	Hydro	Other RES*	Gas	Coal	Nuclear	Oil
Austria	60	1	18	18		3
Belgium	2		26	16	55	1
Denmark		12	21	62		5
Finland	11		17	44	27	1
France	12		3	6	77	1
Germany	4	0	10	54	28	2
Netherlands		1	60	32	4	3
Poland	2		2	94		2
Sweden	39	0	0	7	51	3
UK	1		38	37	22	2

*Renewable Energy Sources
Source: Datamonitor/IEA

Large-scale production technologies:
- **Thermal power (Condensing power)**

Base load power production suitable for large-scale operations. Can be based on a number of different fuels, solid, liquid or gasous. Energy efficiency ranges between 30-60 %, with the highest levels achieved in natural gas fired CCGT (combined cycle gas turbine) plants.

- **CHP – Combined Heat and Power production**

The most energy efficient production technology combines heat and power production. Energy efficiency can be up to 80-90 %. For CHP to be attractive a reasonable heat demand is required in the vicinity of the plant in order to achieve acceptable utilization levels. CHP plants are optimised for simultaneous production of power and heat. The output of electricity is therefore lower in the summer, when heat demand is lower.

- **Heat Extraction**

In areas with lower heat demand, heat extraction may be an attractive alternative to CHP. Heat extraction uses waste heat from a conventional thermal plant to supply a district heating system. This improves plant efficiency when there is demand for heat without affecting electricity output levels at any time.

Fuel alternatives:

- **Coal will remain the world's largest single source of power generation**

The price of CO_2 emission allowances will balance the market in the long run so that the attractiveness of using coal or gas converges. The advantage of coal is that it is available from politically stable areas and that the proven reserves are substantial (more than 250 years of reserves remaining at current production rates). The new generation of coal-fired power plant operates with much higher efficiency and improved environmental performance. If it becomes possible to separate and store CO_2 at low cost, coal could become a very attractive option with reasonable investments and stable production costs also in a CO_2 restricted environment. There are several ongoing projects aiming to develop cost-competitive carbon separation technology, but commercialisation is not expected until the next decade.

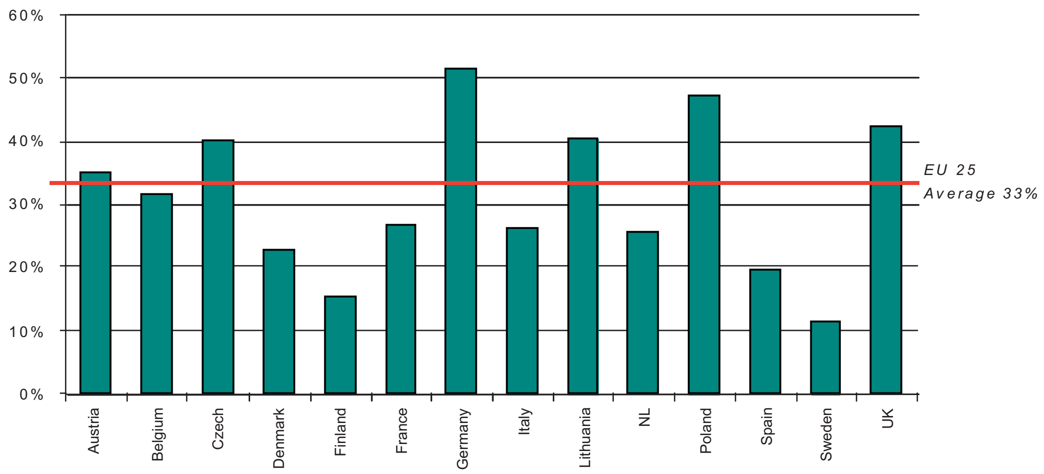
- **Production from nuclear may increase**

High energy prices for both fuel and electricity in combination with concern for climate change and CO_2 emissions have increased the interest in nuclear. The fuel is available in stable regions and the nuclear process itself is free of CO_2 emissions. The investment cost is high but the operating cost is low. Focus today is very much on life extensions and on developing a more efficient and robust generation of plants.

- **Natural gas is expected to increase to meet new demand**

Natural gas could become the fastest growing fuel used in power generation as new sources of gas become available, if gas prices are competitive. The market is in early phases of deregulation in Europe and natural gas offers a convenient alternative to coal and oil, with cleaner handling and lower emissions, especially SOX, NOX, particulates and also CO_2. The investment cost is lower and the construction time shorter than for coal fired or nuclear plant. However gas prices are strongly linked to oil prices and the largest proven reserves are mainly located in Russia and the Middle East. Natural gas often also needs investments in new infrastructure to become available, unless power plants are built next to pipelines which are already in place and not fully utilised.

Figure 15: Share of capacity that needs to be replaced by 2020



The production capacity in Europe is ageing and in several countries it needs to be replaced. The need is lower in countries with a high part of the production in hydropower as the life time for these plants typically is more than 100 years while the life time for a coal plant is approximately 40 years.

What are the views on nuclear power as an energy source today?
In many countries, the view on nuclear has been reported to be changing in recent years. The reason for this is the combination of climate change and a perceived shortage of capacity. Finland is building a fifth reactor and considering a sixth. The UK Government has reviewed its long term needs for more power generation, and decided that new nuclear may be an option. In Germany public opinion is beginning to shift and discussions about prolonging the life of nuclear plants is continuing. In both the Netherlands and Belgium nuclear power is being discussed as an alternative to more gas or coal fired capacity. In Sweden, public opinion has been reported to be more favourable towards keeping installed capacity in operation. Generally the view on nuclear seems to be shifting as nuclear offers CO_2 free production, long term competitive and stable generation costs and an alternative to coal, oil and gas.

The International Energy Agency (IEA) in a report to be released in November 2006[5] is reported to be urging the world to invest in nuclear power. The report considers the challenge of how to meet the combined problem of securing energy supply and combating climate change.

In the 1970s, nuclear power was in many countries seen as an attractive source of energy and a way to reduce the dependence on oil. But two nuclear accidents, one in Three Mile Island, Harrisburg, USA, and one in Tjernobyl, Ukraine, raised concern, and caused many countries to decide against nuclear power. Low cost energy was available everywhere and the relatively expensive nuclear power became uncompetitive.

Today, investment costs are still high, but operating costs are low and the operating lifetime is estimated to be 50–60 years, maybe more. Recently, uranium prices have risen dramatically because of a shortage of production capacity, but this has only a small impact on operating costs. Current oil prices are high and energy prices in general have increased dramatically. Thus, nuclear power has once again become a potential alternative to fossil fired production in many countries.

How competitive would a new nuclear power plant be?
A few years back, new nuclear power used to be viewed as prohibitively expensive and uncompetitive. But electricity prices and the attitudes against climate change have changed, and today the situation may be different.

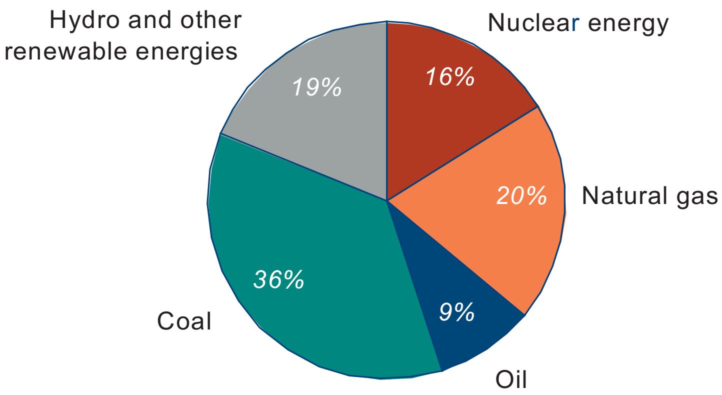
Building a new nuclear power plant requires a total planning period of at least 10 years. The investment cost is much higher than for other production alternatives as the safety requirements of the plant are much higher. Given the low fuel costs, operating costs are low. The time to recover the investment is longer, but at the same time the lifetime of the plant is also long (40–60 years). A main advantage is that there are no costs for emissions of CO_2, so the higher the cost for CO_2, the more competitive nuclear will be.

The third generation of nuclear reactors that are presently built are larger units. Safety is improved by increased water storage in the primary coolant system and fourfold safety systems. Increased protection against consequences of a core meltdown is also available. The design is generally more robust than that of previous generations.

Nuclear is presently in place in 13 of the EU 25 countries and accounts for 32 % of the total electricity production while the worldwide share of nuclear is 16 % (2003).

[5] Montel Powernews 2006-11-02

Figure 16: Power generation worldwide by energy source, 2003



New nuclear power plants are at present mainly built in China, India and Japan. In Europe Finland and France are constructing new plants. Several more countries are reviewing their alternatives and other countries have life extension and capacity increase.

Chapter 5: How will technological development influence the electricity markets?

What are the most exciting new energy concepts on the horizon?
Fossil based power (generated in plant using coal, lignite, oil products, peat or natural gas as fuel) has the disadvantage of producing carbon dioxide as part of the combustion process. Carbon dioxide (CO_2) is a greenhouse gas, and, according to many scientists, one of the main reasons behind the global climate change that the earth is experiencing. Several strategies are being pursued to reduce CO_2 emissions, for example replacement of fossil based power generation with renewable, carbon-free power generation. But the potential of available carbon-free technology is as yet not large enough to replace all fossil fired plant, so the world is going to have to continue to rely on fossil fuels in the foreseeable future. For this reason, methods are sought for dealing with CO_2 emissions in order to reduce the effect on the global climate.

This is what Carbon Capture and Sequestration tries to do. It involves isolating the carbon dioxide produced in fossil fired power plants and storing it permanently in suitable geological formations. Carbon dioxide is a colourless, odourless and non-poisonous gas. CCS techniques involve separating the gas from other exhausts such as vapour by various chemical and mechanical means.

Challenges include the development of an energy efficient capturing technology (with current technology, separating CO_2 from emissions consumes energy), and demonstrating the integrity of CO_2 storage (i.e. that CO_2 will not accidentally leak into the atmosphere). Vattenfall is contributing to the development of CCS technology by investing some 60 MEUR in a pilot plant in Schwarze Pumpe, in Germany. Commercial, full-scale technology is expected to be available by 2020.

The Generation IV nuclear technology programme is an initiative by several nations to improve nuclear technology by increasing electrical efficiency and addressing issues of safety and security. The programme is long term oriented, targeting commercial deployment by 2030.

A strong candidate for joining hydroelectric power; biofuels and wind power as a commercially sound renewable technology is wave power. Wave power has several advantages, including relatively high energy density and utilisation. The challenge lies in developing technology that limits investment and maintenance cost and profitably utilises the average wave for energy production, while surviving the extreme energy of storm waves.

What is the status of research and development on different renewable technologies?
Renewable energy production does not contribute to global warming, nor does it use limited resources (provided that the use of biofuels does not exceed regrowth). It is therefore thought of by many as a highly attractive form of energy. Due to the generally dispersed nature of renewable energy, however, the cost per kWh of collecting and converting this energy into useful electricity or heat is relatively high (with the exception of hydro power). A large amount of research, development, and demonstration has been going on in the world for a long time to reduce the costs and increase the efficiency of different types of renewable energy production. In the renewables field, three types of generation can be regarded as mature technologies: hydro power; biofuelled thermal power; and wind power. Other production types, including solar power, wave power, and geothermal power are struggling to reach cost levels that are acceptable to society. According to most researchers and organisations, it will be at least another 25 years before they can make any significant contributions to the energy balance.

Wind power is the fastest growing renewable energy source, with a global market growth exceeding 20 % annually. The trend goes from farms with maybe 10 or 20 small wind generators onshore towards farms of more than 100 huge generators in coastal waters or at sea (offshore). Vattenfall is involved in several large projects off the coasts of Sweden and Germany under construction or planning.

As for other mature technologies, R&D focus is on continuous improvement of operation and efficiency, environmental performance, and reduced cost for investments and maintenance. In the wind area, there are also R&D efforts relating to the challenges of going off-shore, and the development of larger and larger turbines.

Examples of R&D topics include:
- Improving wind forecasting with regard to location and time (micro-forecasting)
- Reducing the risk of oil leakages into rivers from hydro power Kaplan turbines
- Reducing slagging, fouling, and corrosion in biofuelled boilers

According to the International Energy Agency's recent report "Energy Technology Perspectives", biofuels, wind and hydropower are expected to dominate the renewables field as far into the future as 2050.

Emerging technologies include wave power, geothermal, and solar power. Wave power has already been mentioned (see above). Geothermal power can be commercially attractive in countries with surface volcanism. The high cost of drilling deep and large enough holes, in combination with reliable tools for sufficiently detailed assessment of geological conditions at depths several km below the earth's surface, limits its use. In northern Europe, there is some potential for geothermal heat production. Demonstration plants are regularly being built and commissioned, but without significant breakthroughs in assessment and drilling technologies, geothermal heat (and electricity) production can be expected to remain marginal. It should be noted that assessment and drilling technologies are critical to the oil & gas exploration and production industry, and that very large R&D investments thus already have been made to bring the subject to its present status.

Electricity production from solar cells (photovoltaics) is costly. Night and winter limit the time when solar cells produce electricity, and, thus, revenues and the ability of solar revenues to contribute to covering capital costs. Like wind power, solar power is intermittent, i.e. the production varies depending on available sunlight. Due to the sun's variations, a typical solar power installation has a utilisation factor of less than 10 %, i.e. in relation to its capacity, the produced energy is less than 10 %. In addition, some raw materials required to produce solar cells are in limited supply (silicon), which further increases production costs.

Support schemes put in place in several European countries can however make solar electricity production competitive. This has resulted in a boom for solar cell producers and installations. Current feed-in tariffs are hardly sustainable for deployment of solar cells corresponding to more than small parts of the total electricity demand, however. In spite of more than five decades of R&D, solar cells do not reach conversion efficiencies in excess of 15 % (the conversion efficiency is the fraction of solar energy that is converted into electrical energy). Breakthroughs in efficiency improvement are required if solar power is to be produced at a cost affordable to society, at least in northern Europe.

Solar heating can be interesting as a complement to conventional heating, even in northern Europe. The commercial viability depends largely on taxes and incentives for different actors in the value chains.

Nuclear fusion can be regarded as unlimited energy for all practical purposes, since the required deuterium (a variant of ordinary hydrogen) is found in abundance in the water of the world's oceans. The technical challenges involved in fusion for commercial energy production are staggering, however. An internationally funded large size research fusion reactor, ITER, will be constructed in France, and commissioned during the coming decade. After that, a research programme of at least 20 years is expected to be necessary, before a demonstration plant for electricity production can be built. Even optimists do not put the commission of the first commercial fusion power plant before the year 2050. Until then, other types of production will have to be used to curb climate change.

Is it possible to phase out oil?

Today, oil is the foundation of the world primary energy supply. In transportation, it is the completely dominating energy source. Not least due to the emerging economies of countries like China and India, the world demand for energy in transportation is rising steeply, while the discovery of new oil reserves has stagnated. Moreover, in order to curb climate change, it is necessary to all but eliminate the carbon dioxide emissions from transportation. In the long term, oil will phase itself out as a fuel for transport and energy production as the prices of oil and associated emissions rise. The world will not run out of oil, but as the price increases, it will be used only for applications that can carry these higher costs. By combining more efficient cars, trucks, and airplanes, alternative fuels like ethanol and synthetic diesel (made from coal with carbon capture) as well as electric propulsion in so called plug-in hybrid vehicles, it is believed that oil can be phased out while meeting the growing demand for transport. In addition, it must be assumed that international and market oriented incentives such as emissions trading will be required to drive the change in technology with sufficient momentum.

Most private vehicle transports on a daily basis are shorter than 50 km. This should open opportunities for so called plug in hybrid cars, if made sufficiently economically attractive. Vattenfall would like to encourage car manufacturers to focus more on developing plug in hybrids to replace pure petrol or diesel fuelled cars for short range transports.

The time it will take is much discussed and depends on many factors. One conclusion by the International Energy Agency's recent report "Energy Technology Perspectives" is that it will be possible to decarbonise the transportation sector by the latter half of this century.

How is the electricity industry working to prevent supply interruptions caused by storms and other unforeseen events?

In November 2006, there was a temporary blackout in Europe cutting power supplies to millions of customers in several countries for about half an hour. The exact causes are still under investigation, but it seems that a temporary shut down of a power line in Northern Germany in combination with increased wind production resulted in a chain effect which rippled across the European networks, destabilising their frequencies. Human error may also have contributed. In most places, the damage could be repaired quickly, but it remains alarming that so many consumers can be affected by a single event. Increased transmission capacity may be the remedy required to avoid such incidents in the future.

In Sweden, severe storms in the past few years have resulted in considerable network damages with long periods of supply interruptions as a consequence. It is generally perceived that such long interruptions are not acceptable, and that the networks need to be adapted to avoid such incidents. Many distribution companies have started a very extensive program of investment to remedy the situation.

Most interruptions due to storms and other natural disasters are due to failure of the distribution systems. Generation and transmission systems are normally designed to withstand most storms, although there are exceptions. But distribution systems, since they are so dispersed, are more vulnerable to storms.

Distribution companies have initiated a broad program to increase the ability of the system to withstand heavy storms. In Sweden, for example, the following improvements are made:

- Redesign of the network by laying cables underground where possible

- Improved maintenance, with better and increased frequency of line inspections and woodcutting in areas with overhead lines

- Decrease of down time by better coordination of emergency work. This is done by cooperation between distribution companies e.g. on sharing emergency generation and personnel, and coordination with local and regional organizations

- Improved information to customers and authorities in order to help them plan their actions in order to cope with their own problems.

The trade association of the European Electric Industry Eurelectric has issued a report that discusses political and regulatory consequences of natural disasters and their effects on the electricity industry and formulated some recommendations both for companies and authorities [6]. The study discusses not only the 2005 storm in Sweden and its effects, but also incidents of freezing rain in Canada in 1998, a wind storm in France in 1999, and a heavy snow storm in Poland in 2004.The study concludes that there is no universal recommendation that can be made for how to handle and be prepared for such incidents. Grid structure, national regulation, geographic conditions and local weather will influence the optimal solution for each country to a very large extent.

Is there a need for new generation capacity and when will it become critical?

Security of supply is a subject that has received a lot of attention in the past year. High and rising fuel prices, fears concerning the continuous availability of natural gas from Russia, declining oil and gas production levels, growing energy demand in South East Asia and the

[6] Eurelectric: Impacts of severe storms on Electric Grids – Task Force on Power Outages, January 2006

large needs for new electricity generation capacity in Europe have added to concerns. At the same time, power producers have ensured the market that enough capacity is available. As the demand for electricity increases and old capacity is decommissioned, there is a continuous need for new capacity. According to Vattenfall's analyses of our core markets, a sufficient amount of new capacity will be built during the coming years.

In a competitive energy market, new generation capacity will be built when it is economically attractive to do so. One of the most telling examples that show that the electricity markets are working as intended in this respect is the ongoing new investments. According to the German Electricity Association VDEW, 31 400 MW of new plant is being planned for in the German market, much of it by new entrants. Finland is building its fifth nuclear reactor and planning for a sixth. In Sweden, a gas fired power plant has recently been built in Gothenburg and is scheduled to be commissioned after testing in mid November 2006. Swedish industry is considering investment in wind power and hydropower, utilising its remaining exploration rights. Due to the support schemes for renewable power, considerable investments or investment plans are being made in wind power, both onshore and offshore, in Denmark, Norway, Sweden and Germany.

New plants will be competitive if they have lower costs than old plants, if they cover new demand or if they replace old capacity that is taken out of operation. Lower costs can be the result of new technology, improved efficiency, increased ability to profit from by-products such as heat, or because of subsidies.

Hence, market forces together with the regulatory framework decide if, when and what new capacity comes on line, and this also determines the future electricity price. If only expensive new generation is made possible by the political framework, then future prices will be high.

In Vattenfall's view, a sufficient amount of low cost capacity will be coming on line in the next few years on Vattenfall's home markets to cover increasing demand and plant closures. Capacity shortages will thus in our view not be the reason for increasing electricity prices or decreased security of supply in the future.

Does Sweden/Germany/Poland/Denmark/Europe have too little capacity because of liberalisation?

There have been claims that liberalisation of the electricity markets in the Nordic countries led to peak capacity being taken out of operation because it was not profitable for the owners to retain. Also, some people say that – for the same reason – new reserve capacity will not be built. Margins have decreased, but during the foreseeable future there will be enough capacity to cover demand at a satisfactory level of supply security.

One effect of liberalisation has been that some of the surplus capacity which existed in the old Nordic system was indeed phased out. This was one of the aims of the reform, since the excess capacity was underutilized. As a result, security of supply margins has decreased in the Nordic countries. There is, however, according to both UCTE and Nordel, no sign that the security of supply is at risk in any of the countries under discussion.

In other competitive markets however, a different effect was seen at liberalisation. In the UK, liberalisation initially led to a phenomenon known as the "dash for gas". At the time gas prices were quite low in comparison to today's prices. Most of the existing generation capacity in the UK was coal-fired, and not particularly efficient. Electricity prices, based on the cost of existing plant, were very attractive from the point of view of potential investors in gas-fired plant. As a result, there was overinvestment in gas-fired plant, and the UK became awash with generation capacity. So liberalisation does not always lead to surplus capacity being taken out. It depends on market circumstances. What is important is to put market regulations and rules in place that allow capacity to be built in time when the price signals are right.

How is supply and demand balanced physically?
Can there be a surplus of electricity at any one time?
Electricity cannot be stored, so there can not be a surplus, ever. Because of this, there are certain balancing mechanisms in place that allow market actors and transmission system operators to keep the system in balance.

Balancing of the electricity system is something that takes place at several different levels, for different time periods. At the very highest level, producers, suppliers and large customers plan for expected output and offtake on an annual and seasonal basis. How much electricity will I be able to sell during the next year? How much capacity is needed to produce it? When is it a good time to shut down a plant for maintenance, considering the loss of production and revenue?

Electricity is traded in the forward markets to lay the foundations for the power that will be needed on particular days and in particular periods in the future. In this way, markets actors can feel safe that they have secured large enough volume at known prices.

As the time of consumption draws nearer, a certain fine-tuning is needed. This is because it is difficult to predict exactly how much will be consumed at a given moment. All sorts of things can happen that influence consumption, most of them weather related. But a World Cup final is also likely to have an impact. On the supply side too things can change. There may be an unusual amount of rain, filling the reservoirs. A reactor may need to be taken temporarily out of operation. These variations are dealt with on balancing markets.

On the spot markets, bids are made by both sellers and buyers on an hourly basis for the next twentyfour hour period. That means that as a producer, for example Vattenfall will indicate that it has a certain amount to sell at a particular hour at a particular price. Buyers then buy "lots" of power in an auction to obtain the amount they believe they will need to cover sales or intended consumption. In this way, a market price is being set at exactly the point where the last buyer gets the power he thinks he will need.

Buyers and sellers need to be in balance themselves (i.e. purchased equals sold volume), but also with the system (feed-in equals offtake). After the spot market has closed, the intraday market provides a possibility for market participants to adjust and close their positions and level out physical imbalances. It is offers continued trading of physical electricity, and is open up to a few hours before the time of consumption.

As the hour of operation draws nearer, balancing moves to the regulation or balance markets. Here, it is the system operator that acts as a counter party. The system operator (TSO) carries a responsibility to ensure that the electricity system is physically kept in balance, so that feed-in equals offtake. If the physical balance breaks down, there may be a black out. To avoid that, the system operator controls that the system balance is maintained.

The TSOs have agreements with the generators regarding how to regulate the system. If there is a surplus – too much generation at a given moment – a number of generation plants automatically reduce their output. But the automatic regulation (primary regulation) cannot always compensate in full, and during the hour of operation the control room personnel have to manually compensate for this. This is done by ordering certain generators to increase or decrease their generation by a certain quantity of MW (secondary regulation). These generators are chosen on the regulation market, where the generators indicate bids for up- and downwards regulation.

Appendix

The Nordic electricity market

The Nordic wholesale electricity market covers Sweden, Norway, Finland and Denmark, with a total electricity consumption of 394 TWh in 2005. About 56 % was hydropower, 2 % wind energy, 23 % nuclear and 18 % other thermal generation.

The Nordic electricity exchange, NordPool, is the centre of this market. On the NordPool spot market with 119 members the turn over in 2005 was 176 TWh, about 45 % of the electricity delivered in the area. With this high market share and large number of participants the NordPool spot price is recognised as a reliable market price. It is also used as a reference price for the bilateral trading and deliveries between different business units in integrated companies that is not traded on the spot market. The spot price development on the Nordic market is shown in figure 1.

The NordPool financial market provides standardized financial contracts that now can be traded up to five years ahead in time. The turnover in this market was 786 TWh in 2005. Generators and retailers can hedge their deliveries to reduce the financial risk from the variation in spot prices.

Electricity certificates
An electricity certificate system to support generation from renewable sources was introduced in Sweden in 2003. By the end of 2005, the renewable generation had increased from 6,5 TWh to 11 TWh. The increase has mostly been obtained by conversion of fossil fuel to bio fuel and expanded capacity in existing plants. It has now been decided to extend the system until 2030 and limit the period during which certificates are issued to a producer of new renewable electricity to 15 years. The certificate quotas have been set to reach a level of about 17 TWh of new generation capacity by 2016, a 12 TWh increase from the 2005 capacity level. This is an ambitious target, corresponding to 18 % of current Swedish hydropower production, to be reached in ten years.

Electricity consumption
Annual electrical energy consumption in the Nordic market is about 395 TWh, disregarding deliveries to interruptible electric boilers (boilers that use electricity only when electricity prices are low, and whose output then is replaced by boilers fired with other fuels).

Estimates of future electricity consumption are based on a number of factors, including economic development, expected changes to the structure of commerce and industry, population changes, changes in energy prices and technical development.

Vattenfall does not expect dramatic changes in the underlying factors. GDP in the Nordic area is assumed to increase at an average rate of 2 % per year. Energy taxes are assumed to follow inflation or to increase slightly.

The development of the electricity intensive industry and the use of electricity for heating purposes are of great importance for future Nordic consumption levels. Electricity prices are expected to level out internationally and other factors such as competence and proximity to market will become more important for competitiveness. If the ETS remains limited to the EU, this could however render the European electricity intensive industry a disadvantage. Viewed overall, we have assumed an upturn in consumption for the electricity-intensive industry in the Nordic countries, above all for pulp and paper, but a downturn in the use of electric for heating, especially in Sweden and Norway.

For Sweden, Vattenfall expects a small increase in consumption, mainly in the pulp and paper industry and in the service sectors. This is balanced by a decrease in the use of electricity for heating.

In Norway, consumption is expected to grow slowly. It is very high in all sectors compared to other countries and Vattenfall expects the general increase will be small. Some of the electricity intensive consumers are likely to cease operations before 2015.

Finland has the highest growth rate in consumption among the Nordic countries. It is mainly industry that is growing, although growth is also discernible in other sectors.

Denmark has the lowest per capita consumption in the Nordic area. Vattenfall anticipates some growth in industry and service sectors, as well as in households.

Availability of electrical energy during the next 10-year period
During a normal year (with average levels of precipitation), the total generation capacity available is around 410 TWh. Of this about 395 TWh is base load generation capacity. In addition, links with neighbouring countries offer import possibilities.

Vattenfall expects the following changes in the generation system during the period between 2006 and 2015, with 2005 as the base year:

Sweden
- Upgrading of capacity in the remaining nuclear power plants
- A natural gas fired combined heat and power (CHP) station will be built in Malmö
- Biofuel-fired CHP will be expanded
- More wind power will be built
- Hydro power generation in existing plant will increase

In total, this will result in an increase of about 26 TWh.

The electricity certificate system has had a major impact on the capacity expansion.

Norway
- Wind power will be expanded
- Hydro power generation will increase
- Natural gas fired CCGTs will be built

In total, this will result in an increase of about 22 TWh.

A support system for renewable power based on feed-in tariffs has been proposed.

Finland
- CHP and back-pressure plants will be expanded
- Some older coal-fired condensing power units will be decommissioned
- Small increases in wind and hydropower
- A fifth nuclear unit is under construction

In total, this will result in an increase of about 12 TWh.

Denmark
- Wind power will be expanded, mainly off-shore
- Some older coal-fired units will be closed down

In total, this will result in an almost unchanged capacity.

Figure 1A: Changes in base load generation capacity 2006–2015

Sweden	TWh
Wind	6,1
Hydro	1,8
Nuclear power upgrading	9,4
Natural gas CHP*	3,5
Biofuel CHP*	5,5
Total	**26,3**
Finland	**TWh**
Wind	0,8
Hydro	0,3
CHP*	4,2
Nuclear	12,0
Decommisioning of coal condensing units	-4,9
Total	**12,4**

Norway	TWh
Wind	5,2
Natural gas	10,8
Hydro	6,2
Total	**22,2**
Denmark	**TWh**
Wind	2,7
Decommisioning of coal condensing units	-3,5
Total	**-0,8**
Total	**60,1**
Increased electricity demand	20,0

* CHP and back-pressure generation
Source: Vattenfall, November 2006

Vattenfall expects that the total change in generation capacity in the Nordic countries will result in an increase of around 60 TWh. This means that in our view there is no immediate need for further investment in new capacity for electricity production in the Nordic area.

This is an estimate, and as such contains assumptions about what might happen. Some of the capacity increases included is subject to uncertainty, which is related to economic and political conditions.

In Sweden, the expected increase in wind power seems lower than earlier projections. This is mainly due to the forecast increase in biomass fired CHP. As long as the goal of 17 TWh of new renewable capacity is not increased, Vattenfall expects that investments in new wind power will be in the range of 6 TWh during the next ten years. If the certificate system was to be expanded to meet a higher goal, we think it would be possible to expand investment in wind power capacity even further.

Energy balances

In a normal year, the Nordic energy balance (i.e. the ability to cover electric energy demand at different levels of water availability) is currently satisfactory. The price of electricity in a normal year is typically determined by the cost of coal-fired condensing power in Finland, Denmark, Poland and Germany.

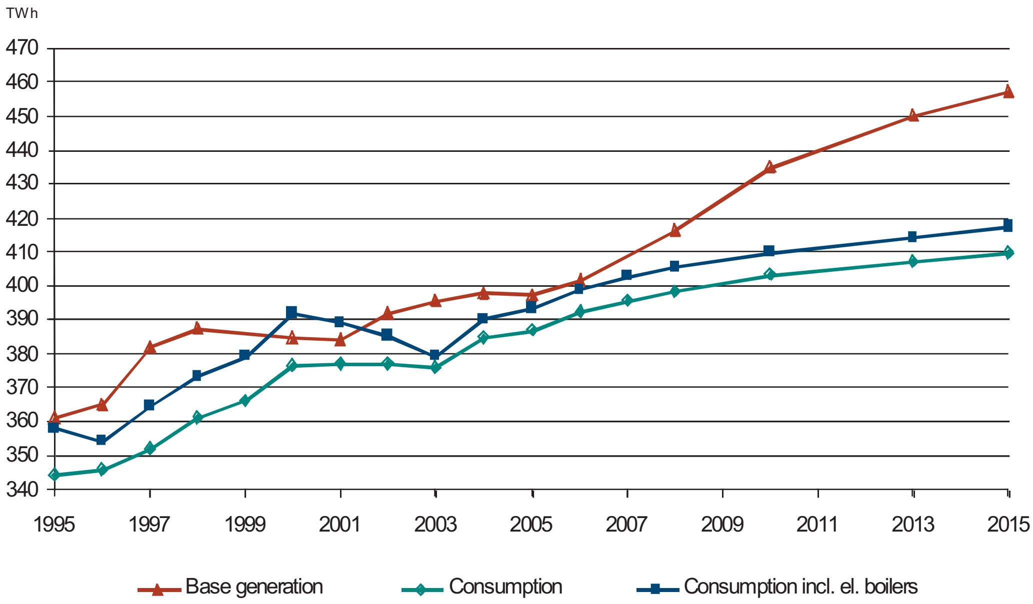
The Nordic countries have transmission links with continental Europe, so that energy can be imported during dry years and exported during wet years.

The total import capacity to the Nordic system is around 4 000 MW. This represents a possible electrical energy import of around 20 TWh per year.

Hydropower accounts for almost half of the Nordic generation capacity in a normal year. In dry years, the hydro capacity can decrease by as much as 17 TWh. Large long-term reservoirs in Norway and in Sweden are used on such occasions to make up the difference. The price of electricity in a dry year will be higher than in a normal year, but we still have a comfortable capacity margin for meeting energy demand.

If two dry years in succession should occur, hydropower generation in the second year will be lower, since the long-term reservoirs will already have been used in the previous year. Hydropower generation in the second dry year could be up to 40 TWh lower than in a normal year. Electricity prices would be very high and interruptible electric boilers would be taken out of operation to meet demand. Other forms of electricity consumption will also be reduced. A combination of reserve capacity and imports will be used to cover demand in such extreme conditions. On extremely cold days, it may be necessary to top up supply with peak capacity. In recent years, it has become evident that transmission system bottlenecks could present a problem to meeting the need for peak load capacity in some areas, a problem that needs to find a long-term solution.

Figure 2A: Base load generation capacity and consumption in the Nordic countries



Source: Vattenfall, November 2006

Electricity Market Glossary

Bottleneck	Congestion in transmission capacity in the electricity system that can temporary affect the price structure with variation in prices between different areas
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CPI	Customer Price Index
Cross border trade	Electricity transmission between countries
EEG	German Renewable Energies Act
EEX	European Energy Exchange, the German power exchange
ETS	Emissions Trading Scheme
EU	European Union
GDP	Gross Domestic Product
Green certificate	A tradeable certificate issued for renewable energy In Sweden called electricity certificate
GWh	Gigawatt hour – 1 million (106) kWh
IGCC	Integrated gasification combined cycle – a type of modern coal fired power production technology with low emissions
kWh	kilowatt hour – amount of energy produced when running 1 kW of capacity for one hour. Amount of energy required to run a 40 watt light bulb for 24 hours.
Liberalisation	Removal of monopoly rights and obligations in order to open up for competition
Lignite	Brown coal
MWh	Megawatt hour – 1000 (103) kWh
Nordpool	The Nordic power exchange in Oslo
OTC	"Over the Counter" Trading of physical and financial contracts in parallel to the organized exchanges
PPA	Power purchase agreement
Regulator	Authority that supervises the market in order to ensure effective competition and fair pricing.
Spot market	Short term physical trading place
System price	The spot price used for settling financial contracts
TSO	Transmission System Operator
TWh	Terawatt hour – one billion (109) kWh
Value chain	Generation, transmission, distribution and sales of electricity.
VTS	Vattenfall Trading Services
Wholesale market	Market place where distributors or retailers buy a product in large quantities for resale to customers

This is Vattenfall

Vattenfall is Europe's fourth largest generator of electricity and the largest generator of heat. The Group's sales amounted to SEK 129,158 million in 2005. Vattenfall's vision is to be a leading European power company. The company currently has operations in Sweden, Finland, Denmark, Germany and Poland. Vattenfall is active at all stages of the electricity value chain - generation, transmission, distribution and sales. Vattenfall is also active in electricity trading and generates, distributes and sells heat. The group has more than 32,000 employees and the parent company, Vattenfall AB, is wholly owned by the Swedish State.

Key figures (IFRS)

	2005	2004	2005 (EUR)[1]
Net sales, SEK millions	129,158	113,366	13,697
Operating profit, SEK millions	27,730	17,112	2,941
Operating profit (EBIT) excl. items affecting comparability, SEK millions	24,744	19,327	2,624
Profit before tax, SEK millions	26,319	14,614	2,791
Profit for the year, SEK millions	20,518	9,604	2,176
Earnings per share, SEK	146.05	67.91	15.49
Return on equity excl. items affecting comparability, %	22.0	15.6	
Return on net assets excl. items affecting comparability, %	15.9	13.3	
Total assets, SEK millions	330,421	285,205	35,039
Equity/assets ratio, %	26.8	29.1	
Funds from operations (FFO), SEK millions	31,386	24,302	3,328
Investments, SEK millions	24,497	12,731	2,598
Electricity generation, TWh	169.1	167.1	
Heat generation, TWh	34.1	34.5	
Average number of employees in the Group	32,231	33,017	

1) Exchange rate 9.43 SEK/EUR.

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